# REGIONAL EMISSIONS AND CAPTURE OPPORTUNITIES ASSESSMENT – PLAINS $CO_2$ REDUCTION (PCOR) PARTNERSHIP (PHASE II)

*Value-Added Report Prepared for:*

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## DISCLAIMER



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## EXECUTIVE SUMMARY

The PCOR Partnership region is expansive, covering the states of Iowa, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Wisconsin, the Powder River Basin portion of the states of Montana and Wyoming, and the Canadian provinces of Alberta, Saskatchewan, Manitoba, and the northeastern corner of British Columbia. The geographic and socioeconomic diversity of the region is reflected in the variable nature of the carbon dioxide ($CO_2$) sources found there. Over 925 point sources emitting at least 15,000 short tons/yr have been identified for the PCOR Partnership region. The $CO_2$ is emitted during electricity generation; energy exploration and production activities; agriculture; fuel, chemical, and ethanol production; and various manufacturing and industrial activities. The majority of the region's emissions come from just a few source types.

While the $CO_2$ emissions from the individual PCOR Partnership point sources are similar to those from sources located around the United States, the wide range of source types within the PCOR Partnership region offers the opportunity to evaluate the capture, separation, and transportation of $CO_2$ in many different scenarios. The earliest deployment is likely to feature the capture, dehydration, compression, and pipeline transportation of $CO_2$ from the "easiest" sources: primarily gas-processing plants and the fermentation step of ethanol plants. This will likely be followed by capture, dehydration, compression, and pipeline transportation of the $CO_2$ produced during coal combustion at the region's electricity generation facilities, as these are the largest sources of $CO_2$ in the region.

Several processes have been or are being developed to separate and remove $CO_2$ from flue gas streams, with selection of a particular technology based primarily upon the pressure and concentration of $CO_2$ in the gas stream. The technology that is most likely to be employed for capture at the electrical power-generating stations and other industrial applications is chemical absorption. Amine scrubbing will probably be used as it is a commercial (and, therefore, better-defined) technology, although some facilities may choose to apply an ammonia scrubbing system

to their gas streams. Amine scrubbing is typically used to separate $CO_2$ from raw natural gas at gas-processing plants. Amine scrubbing also would be applicable to capture of the $CO_2$ produced during combustion of either natural gas or coal at ethanol plants (if enough $CO_2$ could be captured to make its sequestration economical). In constrast, the $CO_2$ produced during the fermentation step at ethanol plants would require only dehydration and compression.

Employing $CO_2$ capture on a regionwide scale will require considerable energy and financial resources. The cost of capture required for the initial deployment of carbon sequestration in the PCOR Partnership region was estimated. Capture and compression costs and power requirements for ethanol plants, gas-processing plants, and electricity-generating facilities were estimated using the Integrated Environmental Control Model (IECM), a desktop computer model that was developed at Carnegie Mellon University with funding from the U.S. Department of Energy's National Energy Technology Laboratory. The IECM allows the systematic evaluation of monoethanolamine (MEA) scrubbing and various pollution control devices on electricity-generating facilities. While the IECM does not contain an ethanol or gas-processing plant module, Energy & Environmental Research Center researchers found it possible to configure the model in a manner that permitted prediction of these costs, thereby putting the ethanol, gas-processing, and power plant cost and power requirement estimations on the same basis and enabling valid comparisons. To determine the cost of retrofitting the region's electric generating stations with $CO_2$ capture capability, the IECM was used to estimate the costs and power requirements associated with adding an MEA scrubber system to the postcombustion side of all electric generating stations larger than 100 MW. A 100-MW cutoff limit was chosen primarily because the economics and power requirements of capturing $CO_2$ at units smaller than 100 MW would make electric generation at these units no longer feasible. In addition, the IECM has a lower estimation boundary level of 100 MW, meaning that values calculated using the IECM for units smaller than 100 MW may not depict the true costs and power requirements.

The route and cost of a regional pipeline network needed for early implementation of carbon capture were estimated using a pipeline-routing model developed by the Massachusetts Institute of Technology (MIT). The MIT model calculates pipeline diameter and identifies the least-cost path connecting a $CO_2$ source to a given sink. The pipeline network that was developed was solely for the purpose of estimating transportation infrastructure costs and is not intended to be an implementable pipeline system

This study estimated only the costs associated with capture, drying, compression, and transportation by pipeline to a geologic sink; injection costs at the sink or any monetary value assigned to the $CO_2$ have **not** been included in the cost or energy estimates. Drying and compression of the $CO_2$ produced by fermentation at the ethanol plants and at the gas-processing facilities, **without pipeline costs**, would average \$11/ton $CO_2$ captured. Including the cost of replacement power, the per-ton cost associated with capture, drying, and compression of 90% of the $CO_2$ produced at the region's power plants would be \$71/ton $CO_2$ avoided. The total cost of capture, drying/compression, replacement power, **and** pipeline transportation within the PCOR Partnership region was found to range from \$5.08 billion/year for the $CO_2$ produced at the gas-processing plants and during fermentation at the ethanol plants (although the entire pipeline network, which is included in this cost, would probably not be constructed for these sources alone) to \$29.76 billion/yr for the ethanol plants' fermentation $CO_2$, the gas-processing $CO_2$, and

90% of the $CO_2$ produced by the electricity-generating stations of the region that are larger than 100 MW. On a per-ton basis, the second scenario would cost $71/ton. These two scenarios would reduce the region's point-source $CO_2$ emissions by 7% and 61%, respectively.

The increase in the cost of producing electricity caused by the capture, compression, and transport of the $CO_2$ is estimated to be 34% to 189%. (The cost of producing electricity is only a portion of the retail cost of electricity paid by consumers.) Maximizing the value-added benefits associated with enhanced oil recovery as a means of $CO_2$ sequestration will help to offset these costs. Gaining experience through large-scale demonstrations and the earliest applications of CCS is likely to reduce the costs, as will improvements in existing capture technologies and development of new capture, compression, and pipeline concepts.

The estimated high cost of the capture, compression, and pipeline network required for effective implementation of CCS as a means to reduce $CO_2$ emissions illustrates that additional research for cost-effective capture and compression technologies and judicious siting of pipeline networks is necessary, if the approach is to be implemented with minimal financial hardship on the region's utilities, industries, and consumers.

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## INTRODUCTION

This report presents a preliminary economic assessment of the most likely early wide-scale deployment of carbon sequestration in the PCOR Partnership region as a greenhouse gas management strategy. Included in the assessment are costs associated with capture, compression, and pipeline transport of the $CO_2$. The costs of injection at geologic sinks are **not** included nor is any monetary value that might be associated with the sale of the carbon dioxide ($CO_2$) for enhanced oil recovery (EOR) purposes.

The PCOR Partnership region is expansive, covering the states of Iowa, Minnesota, Missouri, Nebraska, North Dakota, South Dakota, Wisconsin, the Powder River Basin portion of the states of Montana and Wyoming, and the Canadian provinces of Alberta, Saskatchewan, Manitoba, and the northeastern corner of British Columbia. The upper Mississippi River Valley and the western shores of the Great Lakes are home to large coal-fired electrical generators that power the manufacturing plants and breweries of St. Louis, Minneapolis–St. Paul, and Milwaukee. Coal-fired power plants, natural gas-processing plants, ethanol plants, and refineries located in the prairies and badlands of the north-central United States and central Canada further fuel the industrial and domestic needs of cities throughout North America. The PCOR Partnership region is also home to much of the world's most fertile agricultural lands.

The geographic and socioeconomic diversity of the region is reflected in the variable nature of the $CO_2$ sources found there. Over 925 point sources emitting at least 15,000 short tons/yr have been identified for the PCOR Partnership region using various U.S. Environmental Protection Agency and Environment Canada databases. The $CO_2$ is emitted during the following:

- Electricity generation
- Energy exploration and production activities
- Agriculture

- Fuel and chemical production
- Ethanol production
- Various other manufacturing and industrial activities

The majority of the region's emissions come from just a few source types:

- Electricity generation, which makes up about two-thirds of the $CO_2$ emitted
- Ethanol production
- Petroleum refining
- Manufacture of paper and wood products
- Petroleum and natural gas processing
- Cement/clinker production
- Chemical and fuel production

While the $CO_2$ emissions from the individual PCOR Partnership point sources are no different from similar sources located around the United States, the wide range of source types within the PCOR Partnership region offers the opportunity to evaluate the capture, separation, and transportation of $CO_2$ in many different scenarios. The earliest deployment is likely to feature the capture, dehydration, compression, and pipeline transportation of $CO_2$ from the "easiest" sources: gas-processing facilities and the fermentation step of ethanol plants. This will probably be followed by capture, dehydration, compression, and pipeline transportation of the $CO_2$ produced during coal combustion at the region's electricity generation facilities as these are the largest sources of $CO_2$ in the region.

It is highly unlikely that $CO_2$ capture would be implemented at all of the region's ethanol, gas-processing, or electricity-generating plants simultaneously. The specific plants that will be the earliest adopters are not known at this time. The costs associated with capture, drying, compression, and transport of $CO_2$ from these facilities will likely be borne by the individual facilities.

Capture of $CO_2$ from coal combustion flue gas will be expensive in terms of both capture and parasitic load on the power plant. To recover a portion of this expense, the geologic storage that will be pursued first likely will be oil fields in which $CO_2$ can be used for EOR and would presumably have some monetary value. It is expected that wide-scale sequestration in brine formations will occur only after EOR opportunities have been exhausted. A network of pipelines capable of transporting the $CO_2$ to the various geologic storage sites will have to be constructed. Pipeline sizing and routing will need to be considered so that the network can accommodate increasing quantities of $CO_2$ while transporting $CO_2$ to the nearest EOR and/or brine formations.

## REGIONAL SOURCE TYPES

As of December 1, 2009, the PCOR Partnership region contains 927 industrial or utility sources that each emit at least 15,000 short tons/yr $CO_2$. Total emissions from these sources is roughly 561,900,000 short tons/year $CO_2$. This figure does not include $CO_2$ emitted from commercial facilities (malls, schools, etc.), residential buildings, or complexes or during transportation of people or goods. Relatively speaking, the PCOR Partnership region emits more $CO_2$ from electric utilities and less from industries than the rest of the United States, probably because the region is made up largely of agricultural and energy-producing areas and the majority of industrial activity is located primarily in the eastern reaches of the region. There are many smaller sources in the east and larger, more widely distributed sources in the west. This distribution of sources can be seen in Figure 1.

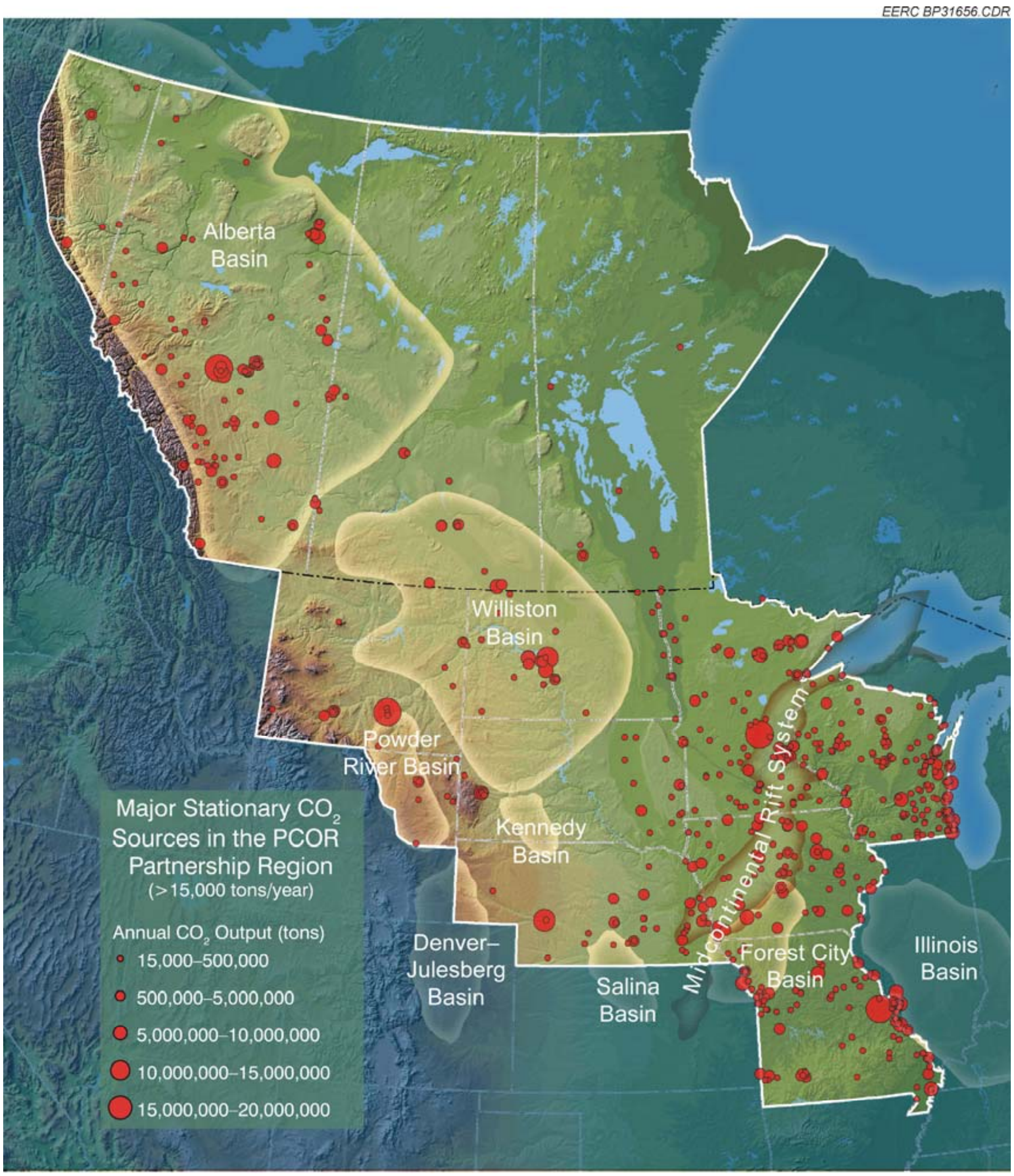


Figure 1. Location and relative output for the PCOR Partnership region's major stationary $CO_2$ sources.

A breakdown by state or province of the number of sources and amount of $CO_2$ emitted from each major source category is presented in Figures 2 and 3, respectively. The broad categories contain $CO_2$ emission sources from several areas. The agriculture-related category includes agricultural and animal processing as well as fertilizer and sugar production. The electricity generation category includes electricity generation and cogeneration. The ethanol/fuels production category includes ethanol production and the production of other fuels such as syngas and chemicals such as ammonia and asphalt. The petroleum- and natural gas-related category includes natural gas processing, natural gas storage facilities, natural gas transmission, combined petroleum and natural gas processing, petroleum processing, petroleum refining, and petroleum transmission. Other manufacturing/industrial activities include cement/clinker and lime production; paper and wood products manufacture; foundries; mining, ore, minerals, and metals processing; institutional and industrial heat and power production; and other manufacturing activities.

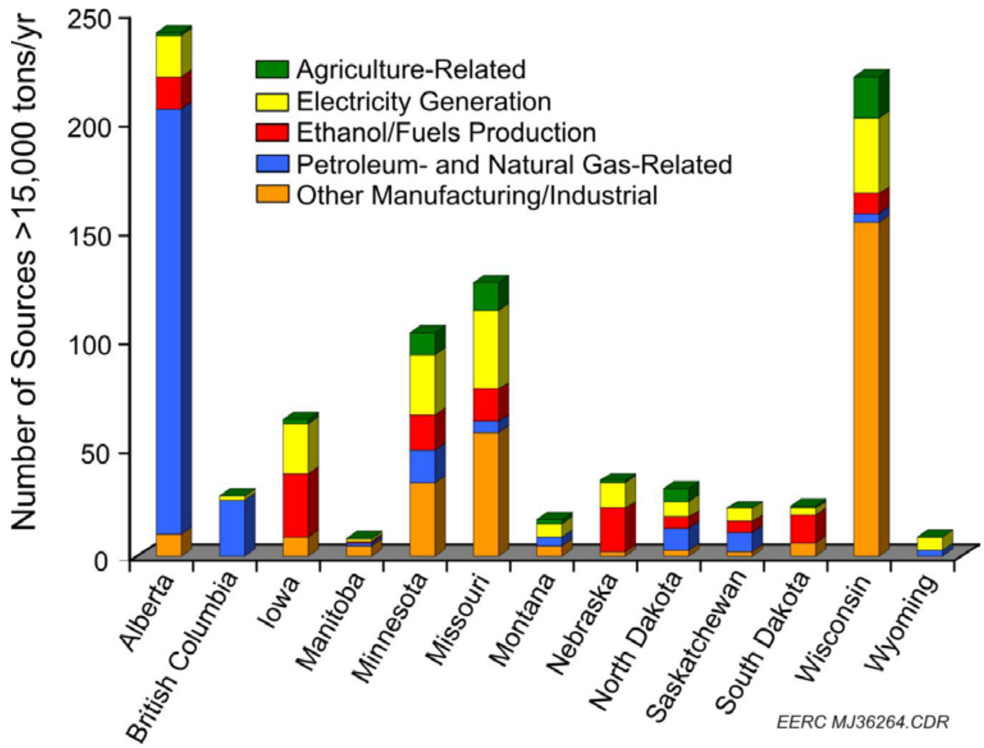


Figure 2. Number of $CO_2$ sources for each state or province, broken down by major source category (it should be noted that the values for British Columbia, Montana, and Wyoming are only for the portion of the state/province that lies within the PCOR Partnership region and are not necessarily representative of the total for those states/that province).

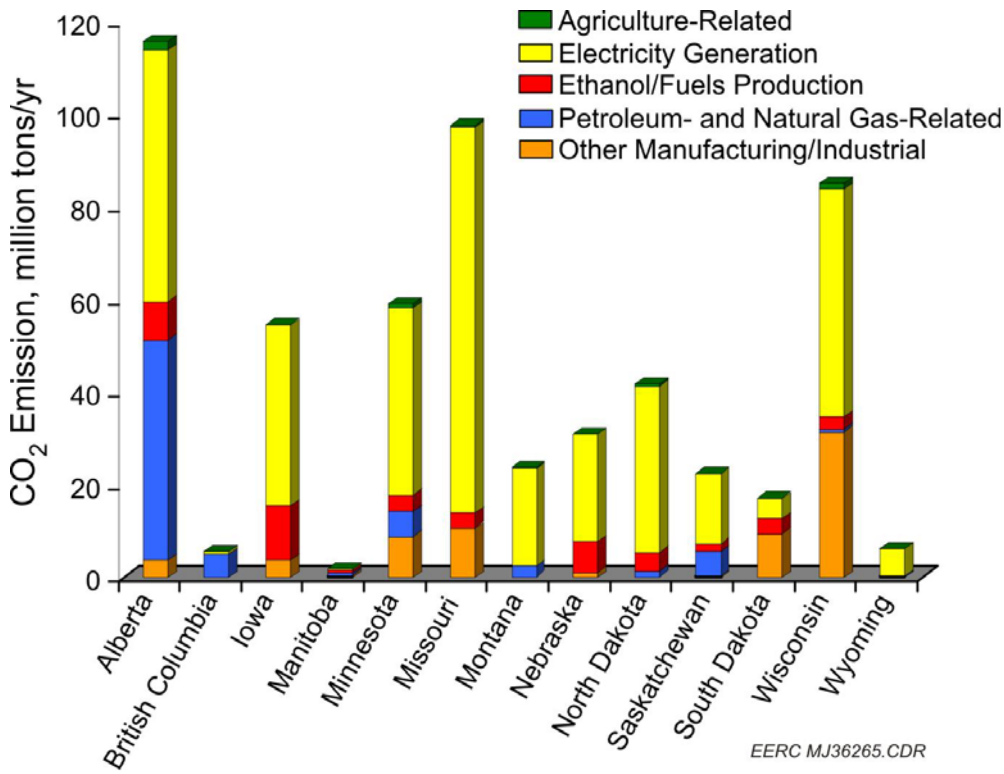


Figure 3. $CO_2$ emissions for each state or province, broken down by major source category (it should be noted that the values for British Columbia, Montana, and Wyoming are only for the portion of the state/province that lies within the PCOR Partnership region and are not necessarily representative of the total for those states/that province).

## COST OF CAPTURING $CO_2$ IN THE PCOR PARTNERSHIP REGION

### Overview of Capture Technologies

Several processes have been or are being developed to separate and remove $CO_2$ from flue gas streams, and these technology options are summarized in Figure 4. Selection of a particular technology is based primarily upon the pressure and concentration of $CO_2$ in the gas stream, as summarized in Table 1. Absorption is commercially available for high-volume, mixed-gas streams. Physical sorbents are ideal for gasification flue gas streams, whereas chemical sorbents are used to remove $CO_2$ from fossil fuel combustion systems. Adsorption can also be implemented for mixed-gas streams; however, no commercial systems are yet available. Membrane and cryogenic systems are ideal for smaller flow rates. Membranes may be applied to gasification or reforming flue gas streams, and cryogenic conditions benefit carbon capture from high $CO_2$ concentration streams.

A complete description of all of the various capture technologies that are either commercially available or under development is beyond the scope of this report. The PCOR Partnership produced a comprehensive overview in 2005 (Jensen et al., 2005); an updated

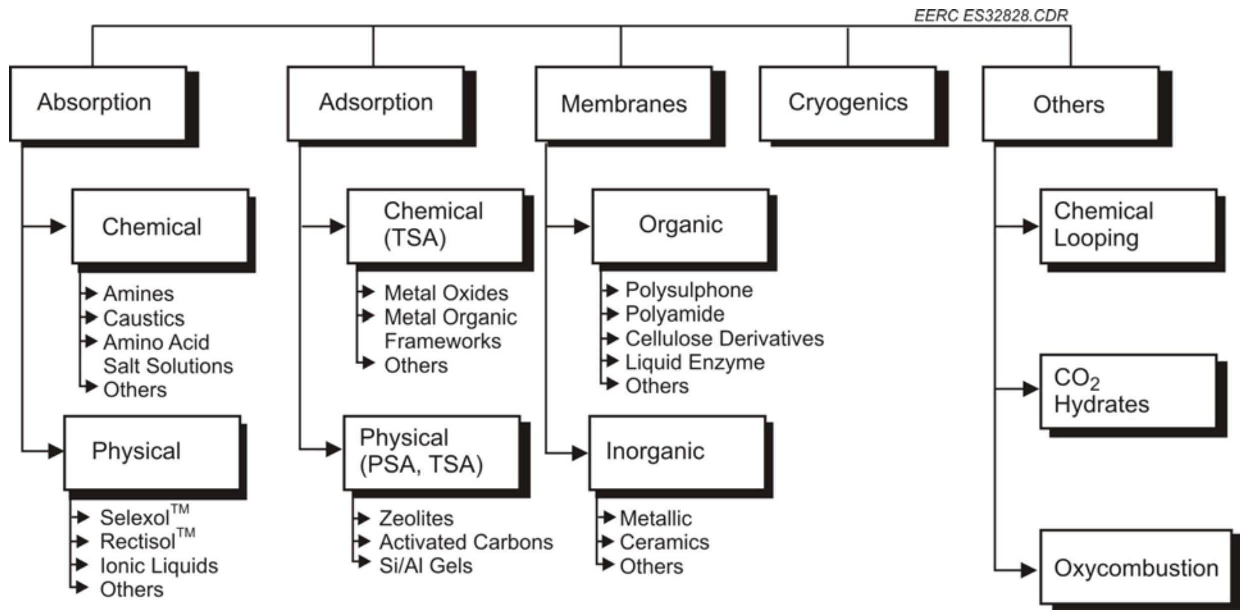


Figure 4. $CO_2$ capture technology options (PSA = pressure swing adsorption, TSA = temperature swing adsorption).

**Table 1. Common Applications for $CO_2$ Capture Technologies**

| Technology | Application |
|---|---|
| Absorption | Commercial plants, mixed-gas streams<br>Chemical – fossil fuel-fired systems, e.g., boilers, gas turbines<br>Physical – gasification systems |
| Adsorption | Mixed-gas streams |
| Membranes | Gasification and reforming, flue gas |
| Cryogenics | High-concentration, mixed-gas streams |

version of the document will be available in early 2010. However, background information regarding the technologies that are the most likely to be employed during early carbon capture and sequestration (CCS) activities within the PCOR Partnership region is provided in the following paragraphs.

**Absorption Processes**

Absorption processes are commonly used in commercial plants to remove $CO_2$ from mixed-gas streams over a wide range of pressures and $CO_2$ concentrations. Two types of solvents are typically used for $CO_2$ removal: physical solvents and chemically reactive solvents. Physical solvents dissolve $CO_2$ following Henry's law but do not react with it. Chemically reactive solvents first dissolve $CO_2$ and then react with it. Physical solvents are better suited to mixed-gas streams that are under high pressure, such as gasification systems. The elevated pressure increases $CO_2$ solubility which, in turn, reduces the solvent circulation rate. The physical solvent can be recovered by flashing off $CO_2$ at a lower pressure. Pressure does not affect the performance of chemically reactive solvents. Chemically reactive solvents require heat to break the chemical bonds and separate the dissolved gas. Commercial experience has shown that the physical solvent process is more economical if the $CO_2$ partial pressure is above 200 psia. At low-inlet $CO_2$ partial pressure and where a very low outlet $CO_2$ concentration is required, chemically reactive solvent processes are more effective. Chemical absorption is applicable to nearly all of the region's point sources in which combustion occurs.

Liquid scrubbing is the most common form of chemical absorption technology used for carbon capture today. The most commonly employed liquid scrubbing solvents are alkanolamines. Alkanolamines used for $CO_2$ removal include monoethanolamine (MEA), diethanolamine (DEA), diglycolamine (DGA), diisopropanolamine (DIPA), and triethanolamine (TEA). MEA scrubbing is currently considered to be the baseline carbon capture technology to which all other technologies (not only chemical absorbents) are compared.

$CO_2$ removal through liquid chemical absorption is a straightforward process consisting primarily of two contacting towers (one for $CO_2$ absorption, one for $CO_2$ desorption/absorbent regeneration) and all of the necessary associated pumps, blowers, tanks, heat exchangers, etc. A schematic of a generic liquid scrubbing system is shown in Figure 5. Because the process uses processing equipment that is familiar to most industrial plant operators and engineers, liquid scrubbing will probably be reasonably well accepted at the facilities at which capture will occur. However, many of these facilities produce flue gas containing $SO_x$ and $NO_x$ that can react with the liquid absorbent to form heat-stable salts. For this reason, application of liquid scrubbing technology to a power plant or other industrial facility that emits $CO_2$ as a result of combustion

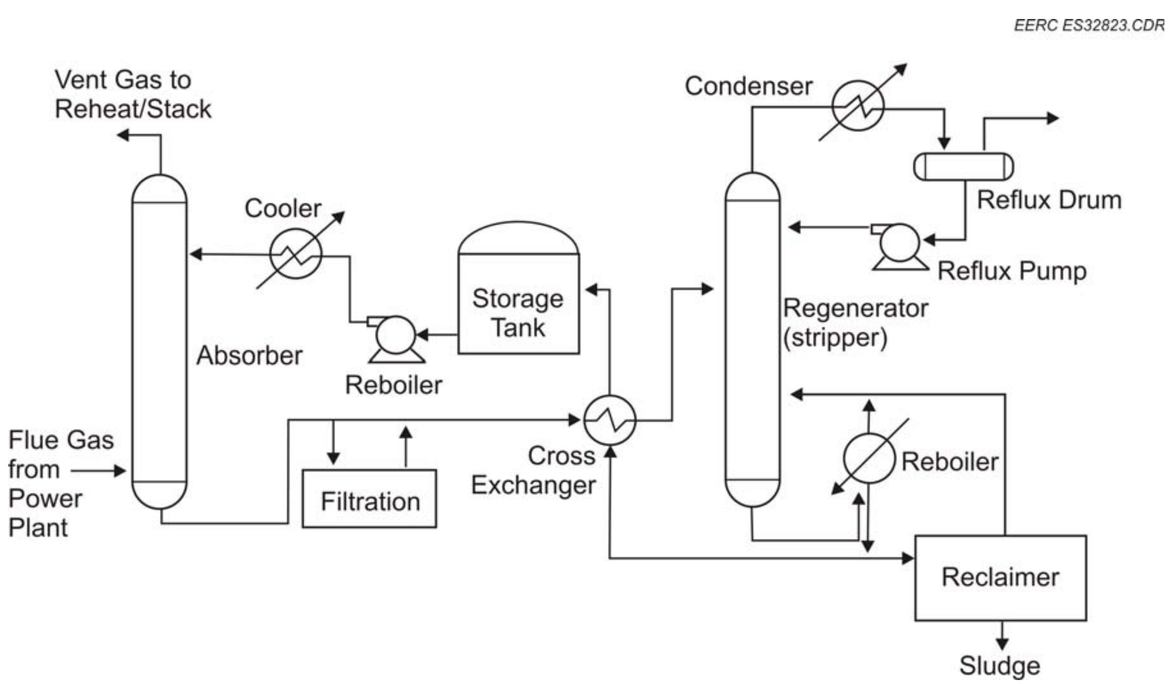


Figure 5. Generic liquid scrubbing system for $CO_2$ capture.

may require the installation of additional pollution control equipment to reduce the concentrations of these contaminants prior to $CO_2$ capture.

Some amine scrubbing technology developers have focused on MEA. Commercial providers of MEA technology include ABB Lummus Global and Fluor Daniel Econamine FG$^{SM}$. ABB Lummus uses a 15%–20% MEA in water solution for its commercial facilities (Imai, 2003). Fluor Daniel uses a 30% MEA solution and incorporates an inhibitor to protect against corrosion (Imai, 2003; Reddy et al., 2003). Together, there are more than 20 commercial MEA scrubbing plants in operation that range in size up to 385 tons $CO_2$/day (International Energy Agency [IEA] Greenhouse Gas R&D Programme, 2008; Reddy, S., 2008). For comparison, a 500-MW coal-fired power plant typically produces up to 8200 tons $CO_2$/day (New York Academy of Sciences, 2008).

Mitsubishi Heavy Industries' hindered amines (designated KS-1 and KS-2) are said to reduce steam consumption for regeneration by about 20% when compared with MEA requirements (Iijima, 2002). A commercial $CO_2$ separation process using KS-1 has been operating at a fertilizer plant in Malaysia since October 1999.

Other developers are featuring specially tailored "designer" amines or combinations of amines. Cansolv specially tailors its amine-based absorbents for fast kinetics (similar to primary amines), very low degradation (similar to tertiary amines), high resistance to oxidation and free radical attack, and the lowest possible regeneration energy (Cansolv, 2008). The Cansolv carbon capture system can be used in concert with the Cansolv $SO_2$ scrubbing system or the Cansolv multipollutant control system, which are used to control $SO_x$ levels prior to $CO_2$ capture. A commercial test of this carbon capture technology is being conducted at NSC in Japan.

In addition to the alkanolamines, liquid scrubbing processes are now being developed using ammonia as the absorbent. Powerspan's $ECO_2$™ technology, which began as a research effort with the U.S. Department of Energy National Energy Technology Laboratory (NETL), is one such process (Powerspan, 2008). Ammonia permits a higher $CO_2$ loading than does MEA, requires less energy for regeneration and release of $CO_{2,}$ and exhibits minimal sorbent degradation by other flue gas constituents. The heat-stable salts that are formed by the reaction of ammonia with $SO_x$ and $NO_x$ can be used as a fertilizer, providing possible value-added benefit for the first 1000- to 1500-MW facilities on which it is installed. Estimates indicate that between 25% and 30% of the U.S. fertilizer market could be met by the quantity that would be produced by the process if it were installed on a 500-MW plant. The $ECO_2$ process is integrated after the Powerspan ECO® process, which provides $NO_x$, $SO_x$, and particulate control. Bench-scale testing has shown a 90% $CO_2$ removal rate with ammonium carbonate solutions. Parametric testing will define absorption rates, ammonia vapor management, and absorptive capacity. Pilot-scale testing of the $ECO_2$ process began in December 2008 at FirstEnergy's R.E. Burger Plant in Shadyside, Ohio, on a 1-MW slipstream (20 tons/day). The testing was scheduled to continue through 2009. Within the PCOR Partnership region, the $ECO_2$™ technology was selected in March 2008 by Basin Electric Power Cooperative for a 125-MW technology demonstration at the Antelope Valley Power Station.

Another ammonia-based technology, ALSTOM's chilled ammonia process, is designed to operate with slurry (Power, 2008). Cooled flue gas flows upward countercurrent to the slurry, which contains a mix of dissolved and suspended ammonium carbonate and ammonium bicarbonate and captures more than 90% of the $CO_2$. The process has the potential to be applied to capture $CO_2$ from flue gases exhausted from coal-fired boilers and natural gas combined-cycle (NGCC) system as well as a wide variety of industrial applications. ALSTOM is installing the technology in the Pleasant Prairie Power Plant in Wisconsin, which is owned and operated by We Energies. ALSTOM has also signed a joint development contract with Statoil for the design and construction of a 40-MW test and product validation facility at Statoil's Mongstad refinery in Norway. This facility will be designed to capture at least 80,000 tons of $CO_2$/year from flue gases from either the refinery's cracker unit or a new combined heat and power plant being built by Statoil and scheduled to be in operation by 2010. ALSTOM plans to offer a commercial product for selected market segments before the end of 2011.

Processes using hot potassium carbonate have been commercialized as the Catacarb® and Benfield processes (Catacarb, 2008; UOP LLC, 2008). Typically, the Catacarb® and Benfield processes are used for either bulk or trace acid gas removal when removing $CO_2$ from synthesis gas in ammonia plants or direct iron ore reduction plants, treating natural gas to achieve either liquefied natural gas or pipeline specifications, or to purify recycle gas in an ethylene oxide facility. They can be corrosive and require larger-scale equipment, an issue when retrofitting space-constrained sites for carbon capture.

Other chemical absorption methods are at bench and laboratory scales of development. A process that uses a potassium carbonate/piperazine complex is being researched by the University of Texas at Austin (Cullinane and Rochelle, 2004). Researchers at the University of Regina, Saskatchewan, are studying PSR solvents, which are proprietary designer solvents formulated for optimized separation of $CO_2$ from any gas stream (Veawab et al., 2001). NETL scientists are focusing efforts on amine-enriched sorbents (Gray et al., 2003), and amino acid salt solutions are also being developed (van Holst et al., 2006). It is unlikely that any of these technologies would be ready for deployment during the first CCS activities in the PCOR Partnership region.

### Application of Chemical Absorption Technology to PCOR Partnership Point Sources

It is most likely that the PCOR Partnership region's earliest application of carbon capture would be at the ethanol, gas-processing and electricity-generating facilities. The $CO_2$ produced at gas-processing plants and during the fermentation step at ethanol plants would require minimal processing to prepare it for pipeline transportation, making these attractive first targets for $CO_2$ capture. Because the region's coal-fired power plants emit roughly two-thirds of the $CO_2$ produced by industrial stationary sources, capture of their $CO_2$ could significantly reduce the overall regional point-source emission of $CO_2$, making them likely targets for capture.

Chemical and physical absorption systems are the only commercial capture technologies that apply to high-volume, mixed-gas streams. Although they have not been demonstrated on each of the source types, amine systems are theoretically applicable to the $CO_2$ emission from virtually all of the PCOR Partnership sources that produce $CO_2$ during combustion of coal or natural gas. The primary exception would be the fermentation step of ethanol processing because it requires only dehydration. Cement/clinker production might also be excluded since a changing variety of fuels is often employed at those facilities, making application of absorption difficult.

During ethanol manufacture, the $CO_2$ vented from the fermenters and beerwell is scrubbed with freshwater and sodium sulfite, which removes alcohol, acetaldehydes, and other volatile organic compounds (VOCs). The water used in the $CO_2$-scrubbing process is reclaimed into the process via the cook water tank and is considered to be a step within the ethanol production process rather than a separate $CO_2$ capture process (Hawkeye Energy, 2008). Typically, the $CO_2$ is marketed to the food-processing industry for use in carbonated beverages and flash-freezing applications.

The cement/clinker industry does not typically capture $CO_2$, although considerable efforts are being made to implement oxycombustion (Worrell et al., 2001). In this scenario, oxygen would be fed to the burner in the kiln instead of air, producing a highly concentrated $CO_2$ stream. This technology is currently not cost-effective, and further research is needed to assess its technical and commercial applicability.

Amine scrubbing is commonly used throughout the petroleum- and natural gas-processing industry for $CO_2$ capture because of the technology's high capture efficiencies and ability to provide the purity needed for EOR efforts. Therefore, amines are recommended for carbon capture in other industries where a majority of emissions are from gas combustion, including agricultural processing, paper and wood products, and petroleum refining. Amine scrubbing can also be used for other fossil fuel combustion, suggesting that this approach may be utilized for coal combustion in the electricity-generating industry.

Table 2 summarizes the match of carbon capture technologies to the largest source of $CO_2$ emissions for each industry.

**Table 2. Various PCOR Partnership Industries and Their Capture Technology Matches**

| Industry | Largest $CO_2$ Emitter | Capture Technology |
|---|---|---|
| Agricultural Processing | Gas combustion | Amine scrubbing |
| Cement/Clinker[1] | Clinker production | Oxycombustion |
| Electric Generation | Coal combustion | Amine scrubbing |
| Ethanol Manufacture[2] | Fermentation step | Water scrubbing |
| Paper and Wood Products | Gas combustion | Amine scrubbing |
| Petroleum and Natural Gas Processing | Gas combustion | Amine scrubbing |
| Petroleum Refining | Gas combustion | Amine scrubbing |

[1] Hawkeye Energy, 2008.
[2] Worrell et al., 2001.

## THE COST OF $CO_2$ CAPTURE

Employing $CO_2$ capture on a regionwide scale will require considerable energy and financial resources. The cost of capture required for the wide-scale deployment of carbon sequestration in the PCOR Partnership region was estimated. It is assumed that initial $CO_2$ capture will occur at ethanol plants and gas-processing facilities. This is because a stream of almost pure $CO_2$ is created during the fermentation step at ethanol plants and from the gas-sweetening activities at natural gas-processing plants and would, therefore, be the easiest to purify. Electricity-generating stations would likely be the next capture target industry simply because so much of the region's $CO_2$ is produced when coal is combusted to produce electricity. A cost assessment was performed by determining the cost and power requirements of various levels of capture at ethanol plants, gas-processing plants, and electricity-generating facilities. For the power plants, replacement power requirements were also calculated. The results of these calculations are summarized in the following sections. The reader should note that any values given for British Columbia, Montana, and Wyoming do not reflect the entire state/province. Details of the capture from power plants on a state-by-state or province-by-province basis are provided in Appendix A.

Capture and compression costs and power requirements for ethanol plants, gas-processing plants, and electricity-generating facilities were estimated using the Integrated Environmental Control Model (IECM), Version 5.22 (released January 28, 2008) (IECM, 2008). The IECM is a desktop computer model that was developed at Carnegie Mellon University with funding from NETL. The IECM is available as freeware at www.iecm-online.com. The IECM allows different technology options to be evaluated systematically at the level of an individual plant or facility and takes into account not only avoided carbon emissions, but the impacts on multipollutant emissions as well; plant-level resource requirements; capital, operating, and maintenance costs; and net plant efficiency. Uncertainties and technological risks also can be defined. The modeling framework is designed to support a variety of technology assessment and strategic planning activities. Four types of fossil fuel power plants are currently included in the model: a pulverized coal plant, a natural gas combined-cycle (NGCC) plant, a coal-based integrated gasification combined-cycle (IGCC) plant, and an oxyfuel combustion plant. Each plant can be modeled with or without $CO_2$ capture and storage. While the IECM does not contain ethanol or gas-processing plant modules, Energy & Environmental Research Center (EERC) researchers found it possible to configure the model in a manner permitting prediction of these costs, thereby putting both the ethanol and power plant cost and power requirement estimations on the same basis and enabling valid comparisons to be made.

### Ethanol Plants

For this study, the IECM was run multiple times to determine the costs and power requirements for various levels of $CO_2$ capture at the PCOR Partnership region's ethanol plants. To model the fermentation step, the IECM was configured as a natural gas-fired combustion turbine with amine scrubbing. Changing various turbine operating characteristics and the flue gas bypass option allowed the model-produced virtual plant to produce the same quantity and quality of $CO_2$ as the particular ethanol plant being modeled. The model outputs for the virtual ethanol plant were manipulated to separate the costs associated with drying and compression of the appropriately sized gas stream from the rest of the capture costs. Capture of the $CO_2$ from the combustion portion of an ethanol plant was performed similarly, except that the costs associated with the amine scrubbing and regeneration steps were included in the results. Specific procedures used to apply the IECM to ethanol plant calculations are presented in detail in Appendix B.

### *$CO_2$ Emission Reduction Potential*

The PCOR Partnership region contains 92 ethanol plants, 90 of which use natural gas as fuel. The remaining two plants are fueled by coal. Collectively, these ethanol plants emit roughly 26.5 million short tons of $CO_2$ each year. Almost 59% of the $CO_2$ is emitted during the fermentation (noncombustion) process, while slightly more than 41% is emitted during combustion. Ethanol plants emit 4.7% of the $CO_2$ produced by the PCOR Partnership region's large point sources. Capture of all of the noncombustion $CO_2$ would reduce the region's $CO_2$ output by nearly 3%. An additional 2% of the region's point-source emissions could be avoided if 90% of the $CO_2$ produced during fuel combustion at ethanol plants was captured. It is generally assumed the practical maximum capture of $CO_2$ produced during combustion is 90%.

Processing the $CO_2$ emitted from the noncombustion ethanol production activities requires only drying and compression. However, ethanol plants also produce $CO_2$ during combustion of fuel, and this $CO_2$ would require capture, assumed in this case to be accomplished by an amine system. Following capture, the $CO_2$ stream would then be dried and compressed. It is assumed that virtually all of the noncombustion $CO_2$ would be captured. Amine scrubbing can reliably remove 90% to 95% of the $CO_2$ from a flue gas, although cost constraints may not permit removal of even 90% of the combustion $CO_2$. Therefore, cost and power requirements were calculated for capture of various levels of $CO_2$, including 10%, 25%, 50%, 75%, and 90%.

### *Energy Consumption During Capture of $CO_2$ from the PCOR Partnership Region's Ethanol Plants*

Table 3 shows the results of energy consumption calculations performed using the IECM. These calculations indicate that drying and compression to 2500 psig of noncombustion $CO_2$ produced during the fermentation step requires an average of 0.112 MWh of electricity for each ton of fermentation $CO_2$ produced at ethanol plants. A compression target of 2500 psig was chosen because the Great Plains Synfuels Plant $CO_2$ stream arrives at its target geologic formation at 2500 psig. Although some targets may require less pressure, 2500 psig was deemed a prudent value as it would not be likely to underestimate compression costs. For the entire PCOR Partnership region, this power requirement totals 300 MW each year. Because ethanol plants do not produce their own electricity, this additional energy would need to be obtained from the region's power grid. If it could not be provided by the existing power plants, additional capacity would have to be added, either by expanding some of the existing facilities or in the form of an additional plant producing 300 MW after capturing its own $CO_2$.

Capture, drying, and compression of the $CO_2$ produced during combustion of fuel at an ethanol plant increases the average electricity requirement to 0.498 MWh on average for each ton of $CO_2$ captured each year. Depending upon the level of $CO_2$ capture, the regional power requirements could be as much as an additional 855 MW, for a total of 1155 MW.

**Table 3. Energy Required to Capture $CO_2$ from Ethanol Plants**

| Capture Efficiency, % | Amount of $CO_2$ Captured, millions of short tons/yr | Regional Power Requirement, MW | Energy Consumption,[1] MWh/ton $CO_2$ | Percentage of $CO_2$ Emissions from PCOR Partnership Ethanol Plants | Percentage of PCOR Partnership Regional Point-Source Emissions |
|---|---|---|---|---|---|
| Noncombustion Emissions | | | | | |
| 100 | 15.6 | 284 | 0.115 | 58.9 | 2.7 |
| Combustion Emissions | | | | | |
| 10 | 1.1 | 83 | 0.711 | 4.1 | 0.2 |
| 25 | 2.7 | 209 | 0.711 | 10.3 | 0.5 |
| 50 | 5.4 | 417 | 0.711 | 20.7 | 1.0 |
| 75 | 8.2 | 626 | 0.711 | 31.0 | 1.5 |
| 90 | 9.8 | 751 | 0.711 | 37.2 | 1.8 |

[1] Assuming 6575 hr/yr of plant operation.

### *Extent and Cost of $CO_2$ Capture at Ethanol Plants in the PCOR Partnership Region*

The IECM-estimated cost to process a ton of $CO_2$ ranges from about \$6.80 to \$22.00 for noncombustion $CO_2$ (which only requires drying and compression) to as much as \$103 to \$852 for capture, drying, and compression of 10% of the $CO_2$ produced during fuel combustion. Typical estimates for drying and compression range from \$5.40 to \$10.90/ton $CO_2$ (\$6 to \$12/tonne) (Dooley et al., 2006). Table 4 shows the range of costs required to capture, dry, and compress $CO_2$ at the PCOR Partnership region's ethanol plants. The higher costs per ton are usually found at the smaller facilities that cannot spread the capital and operating and maintenance (O&M) costs over a large $CO_2$ product stream, thereby missing out on the economic benefit typically afforded large-scale operations. Capture from the combustion stream of facilities producing less than 15,000 tons/yr was deemed to be so uneconomical that they were not considered in the calculations. Similarly, the per-ton cost of capture, drying, and compression decreases as the capture percentage increases because the capital and O&M costs are spread over a larger quantity of $CO_2$.

Even at higher capture rates at the largest of the ethanol plants, the high costs associated with capture of $CO_2$ from the combustion activities may deter plant ownership from pursuing this option, concentrating instead on the noncombustion $CO_2$. If only the noncombustion $CO_2$ were dried and compressed, the total regional cost would equal \$165 million/year. This does not include costs that would be associated with any required expansion of the region's electrical output. Sequestration of this quantity of $CO_2$ would reduce the regional emissions by 3.1%. The levelized annual cost required for capture of various percentages of the $CO_2$ produced during combustion activities is shown in Table 5. As shown in Table 5, these levelized annual costs range from \$281 million/year to \$1.09 billion/year for $CO_2$ capture percentages of 10% and 90%, respectively.

**Table 4. Range of Costs to Capture, Dry, and Compress $CO_2$ Produced at the PCOR Partnership Region's Ethanol Plants**

| Amount of $CO_2$ Captured, % | Lowest Cost, \$/ton $CO_2$ | Highest Cost, \$/ton $CO_2$ |
|---|---|---|
| Noncombustion Emissions | | |
| 100 | 6.77 | 21.69 |
| Combustion Emissions | | |
| 10 | 102.70 | 852.04 |
| 25 | 75.90 | 483.83 |
| 50 | 63.14 | 331.56 |
| 75 | 57.71 | 271.08 |
| 90 | 55.65 | 248.72 |

**Table 5. Total Annual Cost to Capture $CO_2$ at the PCOR Partnership's Ethanol Plants**

| Amount of $CO_2$ Captured, % | Levelized Annual Cost,[1] \$millions/yr | Reduction in PCOR Partnership $CO_2$ Emission, % |
|---|---|---|
| Noncombustion Emissions | | |
| 100 | 148 | 2.7 |
| Combustion Emissions | | |
| 10 | 281 | 0.2 |
| 25 | 466 | 0.5 |
| 50 | 728 | 1.0 |
| 75 | 960 | 1.5 |
| 90 | 1093 | 1.8 |

[1] Includes capital and O&M costs.

Figure 6 shows the percentage of $CO_2$ emissions produced from ethanol plants in the states/provinces with plants that emit at least 15,000 tons of $CO_2$ annually. Charts comparing the energy consumption and cost of capture from ethanol plants among the states and provinces are included in Appendix C.

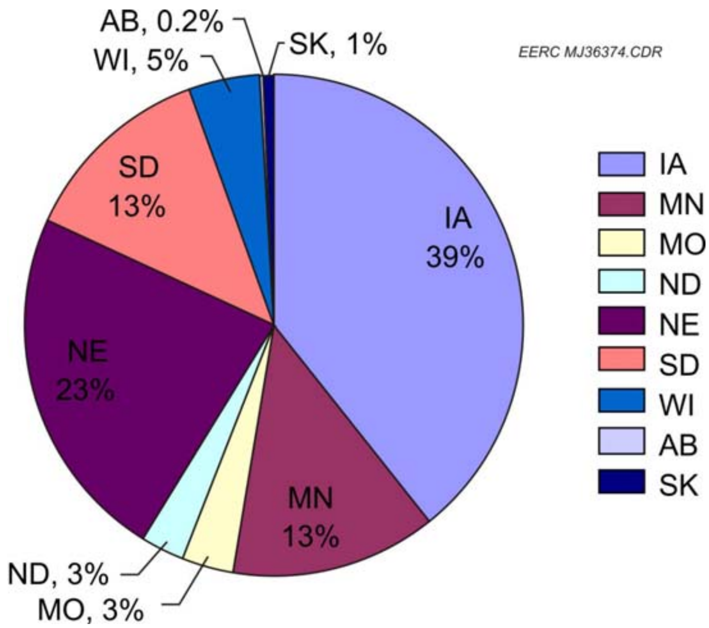


Figure 6. Percentage of $CO_2$ emissions from ethanol plants contributed by each state/province with at least one ethanol plant that produces >15,000 tons/yr.

## Gas-Processing Facilities

### *$CO_2$ Emission Reduction Potential*

Gas processing represents one of the easier sources from which to capture $CO_2$ in a fairly concentrated form because $CO_2$ is separated from the raw natural gas stream during acid gas removal activities. Usually, this stream is vented.

The *Oil and Gas Journal* Worldwide Gas Processing 2008 data set was purchased to ensure that the larger gas-processing facilities, especially those in Canada, were included in the PCOR Partnership $CO_2$ sources database. The data set included data for 982 gas-processing and gas transmission sites that are located within the PCOR Partnership region boundaries. The purchased data set did not specifically include $CO_2$ emissions. Actual $CO_2$ emissions values were found for many of the facilities by searching the Environment Canada Facility Greenhouse Gas Reporting Search Data Web site (Environment Canada, 2009). For the facilities for which $CO_2$ emissions could not be determined, the quantity of captured $CO_2$ was estimated using the following approach. Metz and others (2005) note that about half of raw natural gas production contains $CO_2$ at concentrations that average at least 4% by volume, so $CO_2$ content of the raw natural gas throughput at the various facilities was estimated to make up 4 vol% of this stream. To be on par with the data generated by the other U.S. Department of Energy Regional Carbon Sequestration Partnerships, an average 75% $CO_2$ removal rate was assumed (DOE Regional Carbon Sequestration Partnerships Capture and Transportation Working Group, 2008). Equation 1 shows the calculation used to estimate the amount of $CO_2$ captured in short tons/yr:

$$CO_2\ \text{Out} = g \times 0.04 \times \frac{10^6\ \frac{ft^3}{d}}{\frac{MMft^3}{d}} \times \frac{365\,d}{yr} \times \frac{lbmol}{379\,ft^3} \times \frac{44\,lb}{lbmol} \times \frac{1\,ton}{2000\,lb} \times 0.75 \qquad \text{[Eq. 1]}$$

In this equation, g is the natural gas throughput in $MMft^3/d$, and the gas stream is assumed to be at oil and gas industry standard conditions of 60°F and 1 atm. It should be noted that this methodology does not imply a quality of processed natural gas. It is merely a tool used to estimate $CO_2$ capture and subsequent emission for an "average" gas-processing facility when actual emission data are not available.

Each of the natural gas-processing facility locations was verified by visual confirmation using the Google Earth satellite imagery. If the emission from a site was small and the facility did not appear on the satellite photographs to be a processing facility, the site was considered to be a natural gas transmission site rather than a gas-processing site. In keeping with the rest of the PCOR Partnership $CO_2$ point sources, gas-processing plants emitting less than 15,000 short tons/yr were eliminated prior to their incorporation into the existing $CO_2$ emissions data set.

The PCOR Partnership $CO_2$ emissions data set also includes data for petroleum- and natural gas-processing plants. Some of the $CO_2$ emissions in the database are related to combustion of fuels, but some information is available regarding the $CO_2$ produced during the noncombustion activities, i.e., gas sweetening. Where available data permitted, the $CO_2$ that was captured at these facilities during gas sweetening was catalogued and added to the $CO_2$ produced at the gas-processing plants. The resulting 99 plants producing a fairly pure, 21.1-million tons/yr $CO_2$ stream during natural gas or petroleum processing are summarized in Table 6. The energy requirement and cost associated with drying and compressing the $CO_2$ from these plants are summarized by state/province in Table 7 (not all states/provinces contain gas-processing plants).

**Table 6. $CO_2$ Produced During Gas-Processing Activities in the PCOR Partnership Region**

| State/Province | Number of Facilities | Short tons $CO_2$/yr[1] |
|---|---|---|
| Alberta | 82 | 16,460,000 |
| British Columbia[2] | 12 | 4,470,000 |
| North Dakota | 3 | 120,000 |
| Saskatchewan | 1 | 30,000 |
| Wyoming[2] | 1 | 30,000 |
| Total | 99 | 21,110,000 |

[1] Rounded to the nearest 10,000 short tons/yr.
[2] Only includes the portion of the state/province contained in the PCOR Partnership region.

**Table 7. Energy Required and Cost Associated with Drying and Compression of the $CO_2$ Produced During Natural Gas-Processing Activities**

| State/Province | Energy Required, MW | Annual Cost[1], $ million |
|---|---|---|
| Alberta | 289.7 | 200.9 |
| British Columbia[2] | 81.3 | 46.2 |
| North Dakota | 3.8 | 5.6 |
| Saskatchewan | 0.6 | 0.9 |
| Wyoming[2] | 0.6 | 0.9 |
| Total | 376.0 | 254.5 |

[1] Levelized annual cost including both capital and O&M costs.
[2] Only includes the portion of the state/province contained in the PCOR Partnership region.

## Electric Utilities

### *$CO_2$ Emission Reduction Potential*

An estimated 372,720,000 tons of $CO_2$ a year is emitted by all of the region's electric generating stations, which equates to 66% of all PCOR Partnership $CO_2$ emissions from stationary sources. Several options for capture of $CO_2$ from coal-fired power plants are being developed and were discussed earlier in this document. Of these options, the most commercially viable for power plants is absorption using an amine scrubber with MEA. MEA scrubbing is considered to be the baseline capture technology against which others are measured in terms of cost, efficiency, and parasitic load. To determine the cost of retrofitting the region's electric generating stations with $CO_2$ capture capability, the IECM was used to estimate the costs and power requirements associated with adding an MEA scrubber system to the postcombustion side of all electric generating stations larger than 100 MW. A 100-MW cutoff limit was chosen for two reasons:

- The economics and power requirements of capturing $CO_2$ at units smaller than 100 MW would make electric generation at these units no longer feasible.

- The IECM has a lower estimation boundary level of 100 MW, meaning that values calculated using the IECM for units smaller than 100 MW may not depict the true costs and power requirements. Appendix B outlines the procedures followed when using the IECM to estimate the cost and power requirements for capturing, drying, and compressing $CO_2$ produced from electricity-generating stations.

The results of capturing, drying, and compressing $CO_2$ produced from 100-MW and larger electric generating stations in the PCOR Partnership region are discussed on a state and province level in Appendix A and on an overall regional basis in the remainder of this section.

### *Regional Summary of $CO_2$ Emission Reduction Potential*

The 100-MW cutoff limit excluded several electricity-generating stations from the study. A total of 74 generating stations were determined to have units larger than 100 MW. Out of these 74 generating stations, a total of 132 individual generating units were larger than 100 MW. Each of these units was characterized by coal type, boiler type, unit size, and existing pollution control equipment. This specific information is summarized in Appendix A. The 132 units have an overall generating capacity of 45,096 MW. Figure 7 breaks down the power production considered for $CO_2$ capture implementation in each of the states or provinces. As seen in Figure 7, Missouri generates the most power in these units. Figure 8 shows the amount of $CO_2$ produced from the 132 electricity generating units considered eligible for $CO_2$ capture on a state/province basis. They produce approximately 350 million tons/year, which is 95% of all the $CO_2$ produced from electric generating stations in the PCOR Partnership region. A map showing the location of all the stations considered to be eligible for $CO_2$ capture implementation under this study is shown in Figure 9.

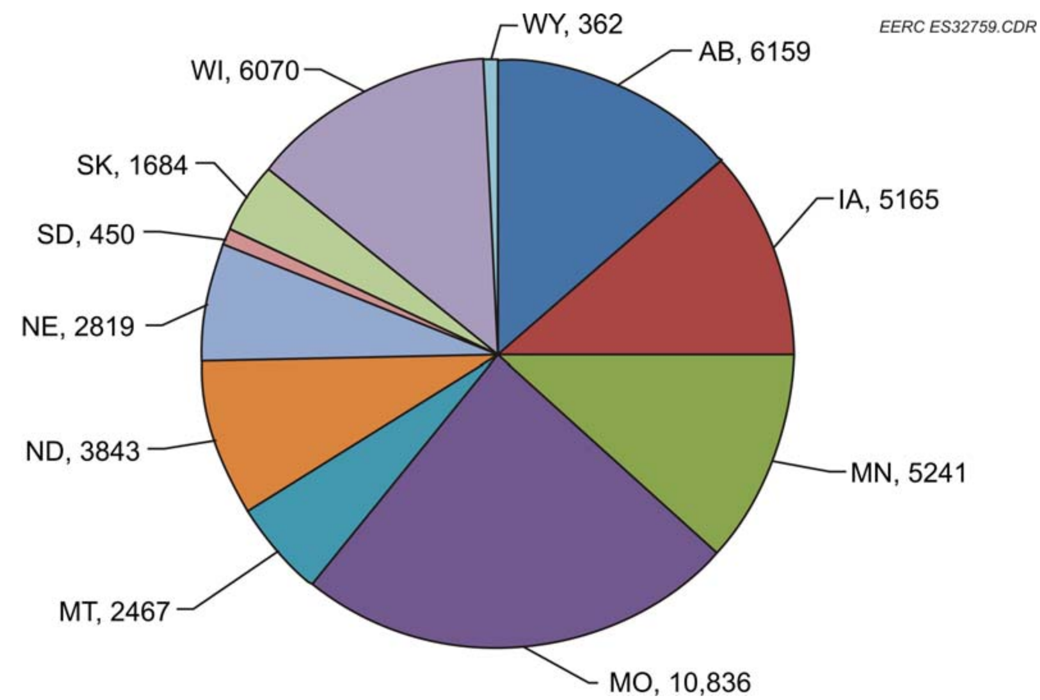


Figure 7. Summary of the total amount of MW considered for $CO_2$ capture in each state or province. Only the portions of each state/province that lie within the PCOR Partnership region were included.

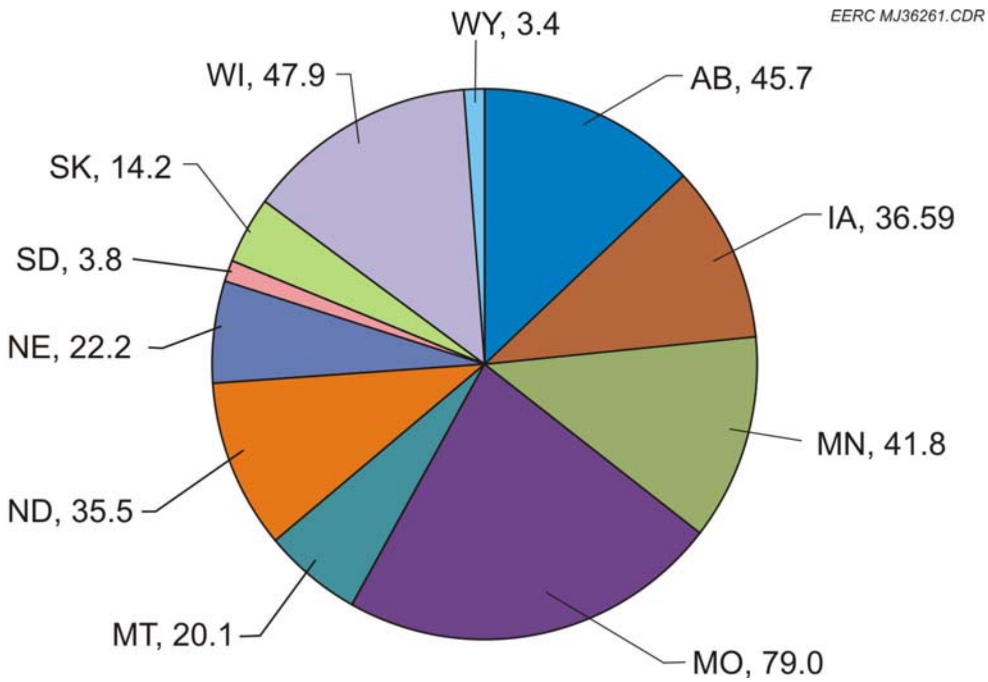


Figure 8. Total amount of $CO_2$ produced (in MMtons/yr) by electricity-generating stations considered for $CO_2$ capture on a state/province basis. Only the portions of each state/province that lie within the PCOR Partnership region were included.

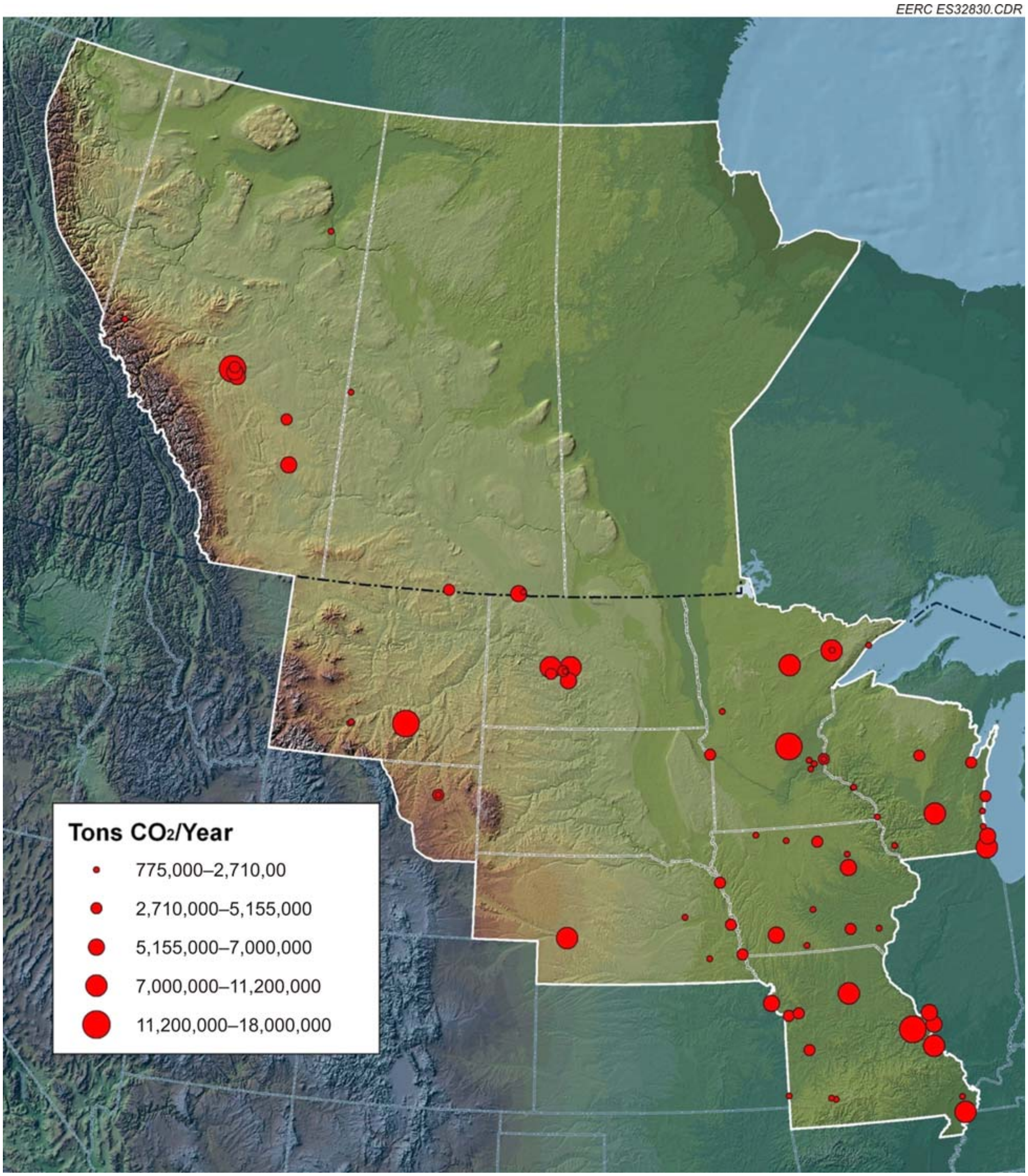


Figure 9. Map showing the location and range of $CO_2$ emissions of the electricity-generating stations larger than 100 MW in the PCOR Partnership region.

### *Energy Consumption During $CO_2$ Capture*

The IECM was used to determine the cost and energy penalty (i.e., the amount of electricity generated by the plant that cannot be put on the grid because it is used for the capture process) associated with implementing $CO_2$ capture on the existing electricity-generating units in the PCOR Partnership region. The results are detailed in Appendix A. The primary parameters of concern were parasitic load of the amine scrubber; additional parasitic load from adding a wet flue gas desulfurization (WFGD) unit, if needed; total $CO_2$ produced; total $CO_2$ captured; cost of adding a WFGD, if needed; and total levelized cost of retrofitting the amine scrubbing system, including drying and compression. The total cost of capturing $CO_2$ is displayed in \$/ton of $CO_2$ captured and includes both the levelized annual cost of the amine scrubbing system and the additional cost accrued from retrofitting WFGD in the cases where it was needed. A WFGD was added to the cost of $CO_2$ capture in instances where $SO_x$ control was not previously installed at the plant. This was done because the cost penalty for not removing the $SO_x$ upstream of the amine scrubbing system is greater than if a WFGD system were added. The $SO_x$ concentration entering the amine scrubber system is an important parameter when determining the O&M cost because of the solvent degradation that occurs in the presence of $SO_2$ and $SO_3$. If the $SO_x$ concentration is greater than about 10 ppm, the solvent degradation can become a significant cost component when $CO_2$ is captured in an amine system. While amine can be reclaimed from the heat-stable salts formed when amines react with $SO_x$ and $NO_x$, the process often produces a hazardous waste with associated expensive disposal costs. Therefore, the preferred choice is to avoid the formation of heat-stable salts.

The IECM was run for every unit in each of the portions of the states or provinces in the PCOR Partnership region at five different $CO_2$ capture rates (10%, 25%, 50%, 75%, and 90%). The results are summarized in Table 8. The cost to capture a ton of $CO_2$ is essentially unchanged for $CO_2$ capture rates of 50% to 90% because of the statistical accuracy of the economic evaluation. The cost for this range of capture was \$46 to \$49/ton of $CO_2$ captured for the capture rates of 90% to 50%, respectively. Although the cost per ton was relatively stable, the total cost and power requirement increased linearly as the capture percentage increased. The lowest total cost of \$2.9 billion annually would be required to capture 10% of the $CO_2$. As much as \$14.4 billion annually would be needed to capture 90% of the $CO_2$. The power requirement ranged from 1797 to 16,036 MW for 10% to 90% $CO_2$ capture, respectively. These results are shown graphically in Figure 10.

The results from the model simulations show a significant cost and energy penalty for capturing 90% of the $CO_2$ emitted from these units. The energy that would be consumed by capturing $CO_2$ at this high rate is 16,036 MW or 35.6% of the current gross output of all of the electricity-generating stations that were considered in this study. At the highest rate of capture (i.e., 90%), an estimated 315,000,000 tons of $CO_2$ would be captured, or roughly 85% of all the $CO_2$ produced by all of the electricity-generating stations in the PCOR Partnership region. The total $CO_2$ produced by point sources in the PCOR Partnership region is about 562 million tons a year. If 90% $CO_2$ capture could be achieved from the electricity-generating stations considered for capture in the PCOR Partnership region, an overall reduction of 56% would be realized from all $CO_2$ emitted by point sources in the region. Figure 11 shows the amount of $CO_2$ captured a year for different $CO_2$ capture rates. Also shown in Figure 11 is the percentage of

**Table 8. Summary of Results for Implementing $CO_2$ Capture on Electricity-Generating Stations Larger than 100 MW**

| Capture % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| Gross Electrical Output, MW(g) | 45,096 | | 45,096 | | 45,069 | | 45,096 | | 45,096 | |
| Amine Scrubber Use, MW | 1686 | | 4181 | | 8363 | | 12,545 | | 15,054 | |
| Wet FGD Use, MW | 111 | | 273 | | 545 | | 818 | | 981 | |
| Total Aux. Load,[1] MW | 1797 | | 4454 | | 8908 | | 13,363 | | 16,036 | |
| Total $CO_2$ Produced, tons/yr | 349,914,627 | | 349,914,627 | | 349,914,627 | | 349,914,627 | | 349,914,627 | |
| $CO_2$ Captured, tons/yr | 34,991,463 | | 87,478,656 | | 174,957,314 | | 262,435,970 | | 314,923,164 | |
| Cost Component | M$/yr | $/ton $CO_2$[2] | M$/yr | $/ton $CO_2$[2] | M$/yr | $/ton $CO_2$[2] | M$/yr | $/ton $CO_2$[2] | M$/yr | $/ton $CO_2$[2] |
| Annual Cost of $SO_2$ Removal[3] | 1057 | 30 | 1227 | 14 | 1511 | 9 | 1794 | 7 | 1964 | 6 |
| Total Levelized Annual Cost (includes both $SO_2$ removal and $CO_2$ capture) | 1838 | 83 | 3847 | 58 | 7079 | 49 | 10,483 | 47 | 12,468 | 46 |

[1] Total auxiliary load from additional components for $CO_2$ capture equipment.
[2] US$/ton $CO_2$ captured + cost of $SO_2$ removal in US$/ton.
[3] In terms of additional $SO_2$ removal for $CO_2$ capture benefit.

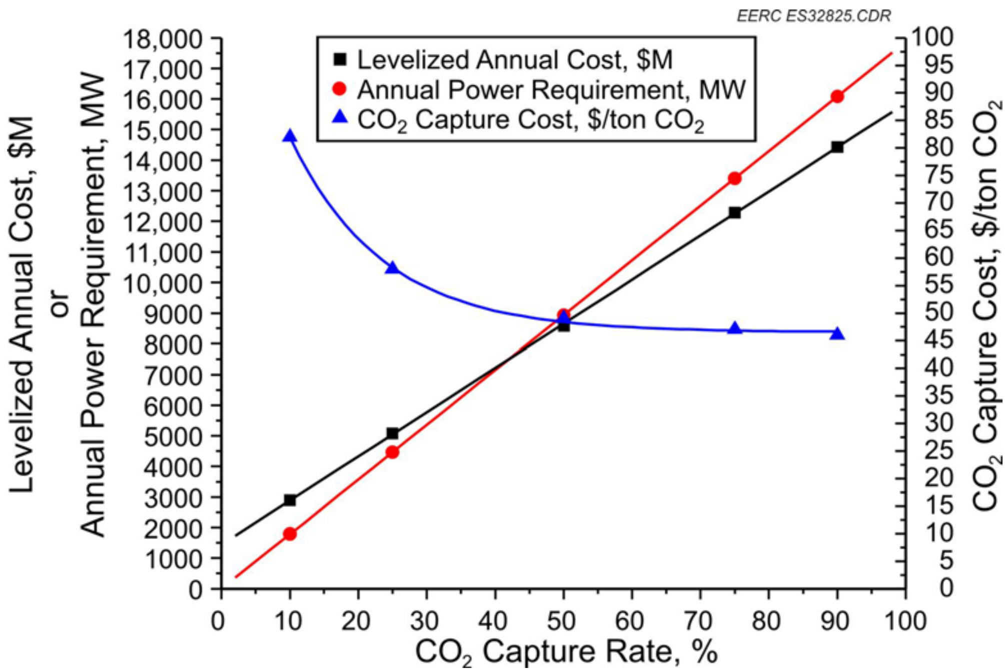


Figure 10. Graphical summary of the costs and energy penalty associated with implementation of $CO_2$ capture at electricity-generating stations larger than 100 MW in the PCOR Partnership region.

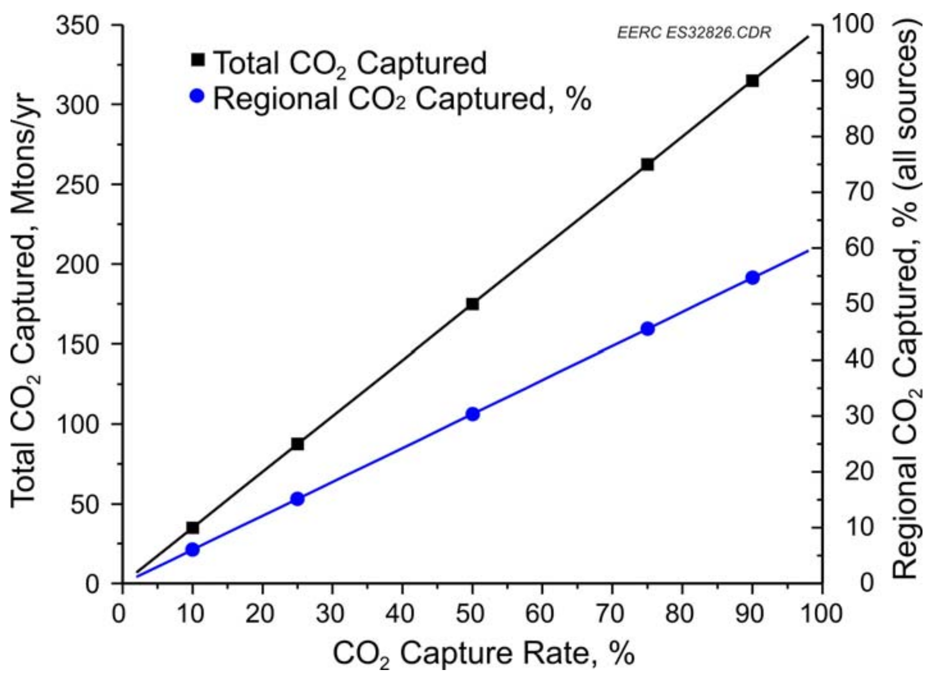


Figure 11. Total $CO_2$ captured from all electric generation stations larger than 100 MW in the PCOR Partnership region.

regional $CO_2$ emissions that would be captured at the various $CO_2$ capture rates if applied to the electricity-generating stations considered in this study.

Considerable energy would be required to capture the $CO_2$ from the electricity-generating stations in the PCOR Partnership region, resulting in power lost to the grid that would need to be replaced. Several options exist for replacement generating stations, but the most likely technology candidates are scrubbed coal and IGCC. Both of these options would have to include CCS. The cost to replace the power consumed by retrofitting $CO_2$ capture ranges from $2431 to $3593 per kW for IGCC or $2279 to $2726 per kW for scrubbed coal, both with the cost of $CO_2$ capture added. For IGCC, the lower value is what is estimated by the IECM, and the higher value is the worst-case estimate found during an Internet search (Energy Justice Network, 2007). For the scrubbed coal facilities, the lower value is the estimate from the Energy Information Administration (EIA) assumptions to the Annual Energy Outlook 2008 (Energy Information Administration, 2008). It should be noted that it is not known if these estimates were all made on the same basis; they are given here to provide a context within which to compare relative costs. A sensitivity analysis was performed on the cost to replace the power consumed by implementing $CO_2$ capture (replacement power calculations take into account the fact that those facilities that would capture $CO_2$ incur additional power needs). This analysis produced a range of the most likely total capital costs needed to replace the power for different $CO_2$ capture rates. Figure 12 shows the results of the sensitivity analysis of the replacement power capital cost. Table 9 provides EIA assumptions regarding the capital cost of new electricity-generating stations for several other technology options.

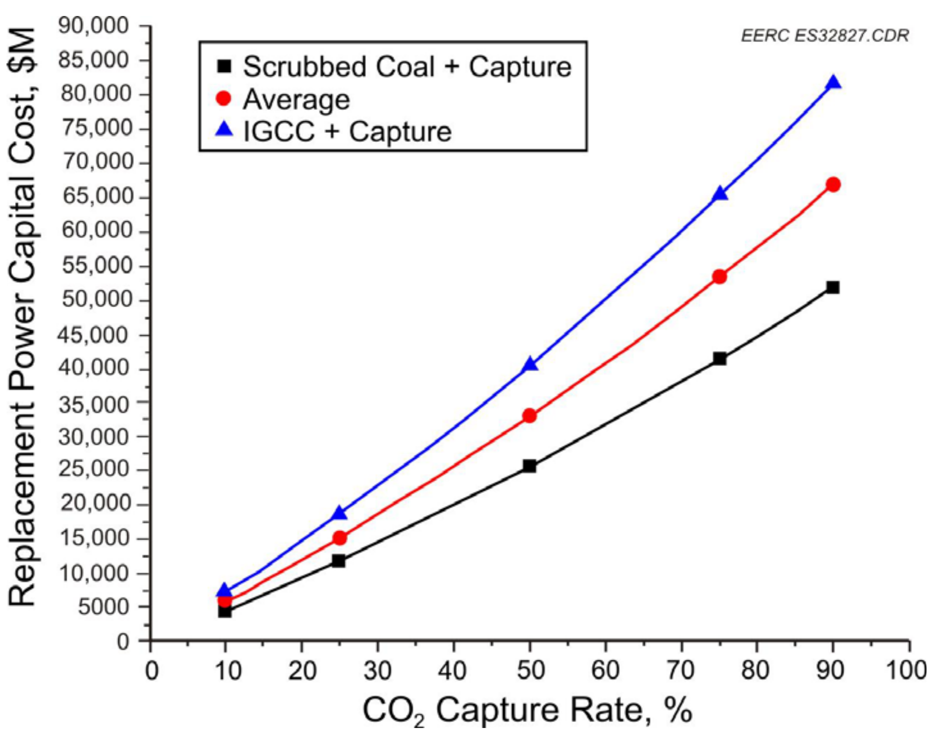


Figure 12. Replacement power capital cost as a function of $CO_2$ capture rate for two power generation methods and their average.

**Table 9. EIA Assumed Capital Costs of New Electricity-Generating Stations**

| Technology | Size, MW | Lead Time, years | Total Overnight Cost in 2007, 2006 $/kW |
|---|---|---|---|
| Scrubbed Coal New | 600 | 4 | 1534 |
| IGCC | 550 | 4 | 1773 |
| IGCC with Carbon Sequestration | 380 | 4 | 2537 |
| Conv. Gas/Oil Comb. Cycle (CC) | 250 | 3 | 717 |
| Adv. Gas/Oil CC | 400 | 3 | 706 |
| Adv. CC with Carbon Sequestration | 400 | 3 | 1409 |
| Conv. Combustion Turbine | 160 | 2 | 500 |
| Adv. Combustion Turbine | 230 | 2 | 473 |
| Fuel Cells | 10 | 3 | 5374 |
| Advanced Nuclear | 1350 | 6 | 2475 |
| Distributed Generation – Base | 5 | 2 | 1021 |
| Distributed Generation – Peak | 2 | 3 | 1227 |
| Biomass | 80 | 4 | 2809 |
| Municipal Solid Waste – Landfill Gas | 30 | 3 | 1897 |
| Geothermal | 50 | 4 | 1110 |
| Conventional Hydropower | 500 | 4 | 1551 |
| Wind | 50 | 3 | 1434 |
| Wind Offshore | 100 | 4 | 2872 |
| Solar Thermal | 100 | 3 | 3744 |
| Photovoltaic | 5 | 2 | 5649 |

### *Extent and Cost of $CO_2$ Capture at Electric Utilities Within the PCOR Partnership Region*

To better understand how the costs are distributed throughout the region, the results were examined on a state and province level. When these costs are examined on a dollar-per-ton-$CO_2$-captured basis, it is evident that the highest costs would occur in Saskatchewan. This is principally because the power plants in Saskatchewan use lignite as a fuel (it produces more $CO_2$ per Btu than other coals) and lack $SO_x$ control equipment. Additional capital cost is incurred when WFGD has to be added to a power plant. The addition also increases the energy penalty. North Dakota's costs would be nearly as high, again primarily because lignite is used to fuel the electricity-generating stations. The lowest cost of capture at all capture rates was found to occur in the PCOR Partnership region portion of Montana because there are relatively few units, the units are already equipped with WFGD for $SO_x$ reduction, and they use a subbituminous coal. Figure 13 compares the capture cost on a dollars-per-ton basis for the various capture rates for the states and provinces.

The comparison of the total annual cost to capture $CO_2$ shows that Missouri would incur the highest cost, followed by Wisconsin (Figure 14). The higher costs in these states are primarily the result of the large number of generating stations within these areas. As expected, the lowest total annual cost was found in South Dakota and the PCOR Partnership portion of Wyoming because they have a relatively small number of generating stations.

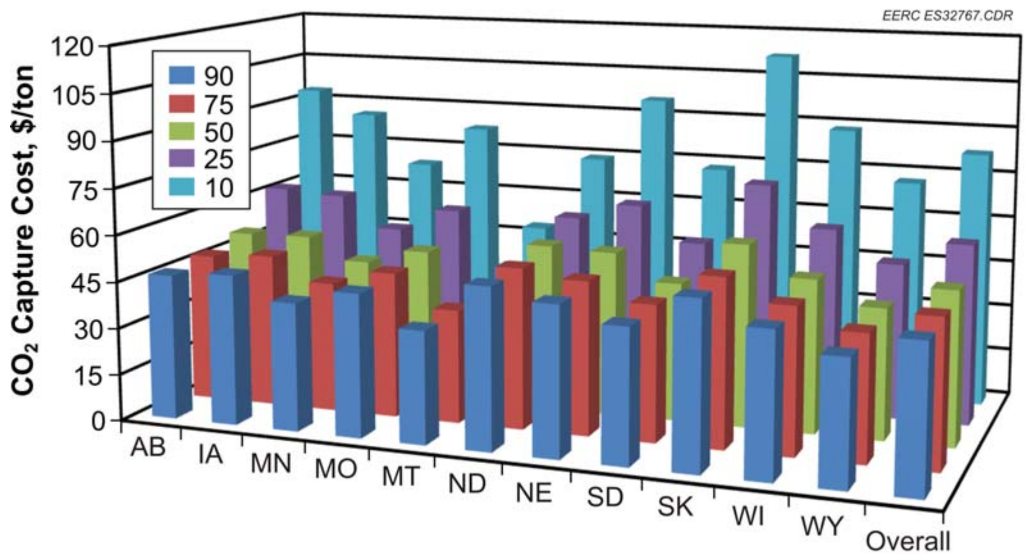


Figure 13. Comparison of $CO_2$ capture cost for all of the states/provinces in the PCOR Partnership region on a dollars-per-ton-$CO_2$-captured basis for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

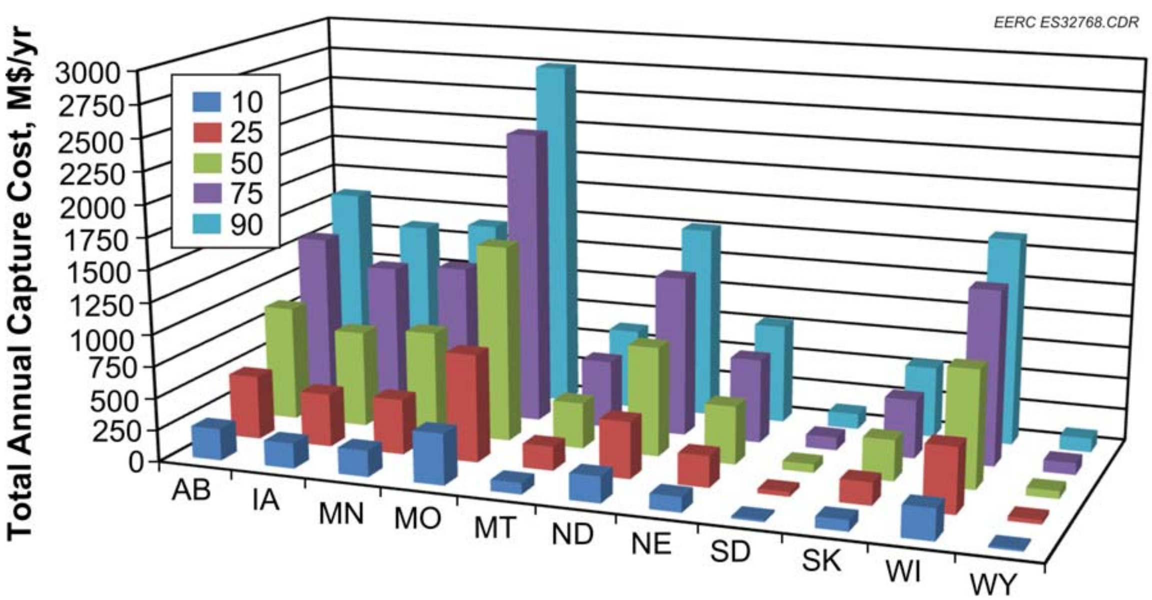


Figure 14. Comparison of total annual $CO_2$ capture cost for all of the states/provinces in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

The comparison of the total energy required for $CO_2$ capture at the facilities that are larger than 100 MW in each state revealed similar results, with Missouri requiring the most energy because the existing power output is high relative to the rest of the region. This comparison is shown in Figure 15. Alberta and Wisconsin are the next highest, also because the power output of the electricity-generating stations there is high. Because of the relatively few electricity-generating stations, South Dakota and Wyoming would have the lowest power replacement requirements.

In terms of an energy penalty or the percentage of energy consumed by capture activities from the base load, North Dakota has the highest energy penalty associated with $CO_2$ capture. This can be seen in Figure 16. This is most likely caused by the unit types and the use of lignite fuel throughout the state. The energy penalties that would be incurred in Wyoming are similar to North Dakota's. The remaining states/provinces in the PCOR Partnership region are very similar in terms of the energy penalties associated with implementing $CO_2$ capture.

Reduction of $CO_2$ emission can be viewed in several ways. The total mass of $CO_2$ that could be captured in each state is compared in Figure 17. The figure shows that Missouri could capture the most $CO_2$, approximately 70 million tons/yr at a rate of 90% capture. Looking at the data from the perspective of reducing the $CO_2$ emissions from the state/province's power plants, Figure 18 shows that the largest percentage of $CO_2$ emission reduction from all power plants

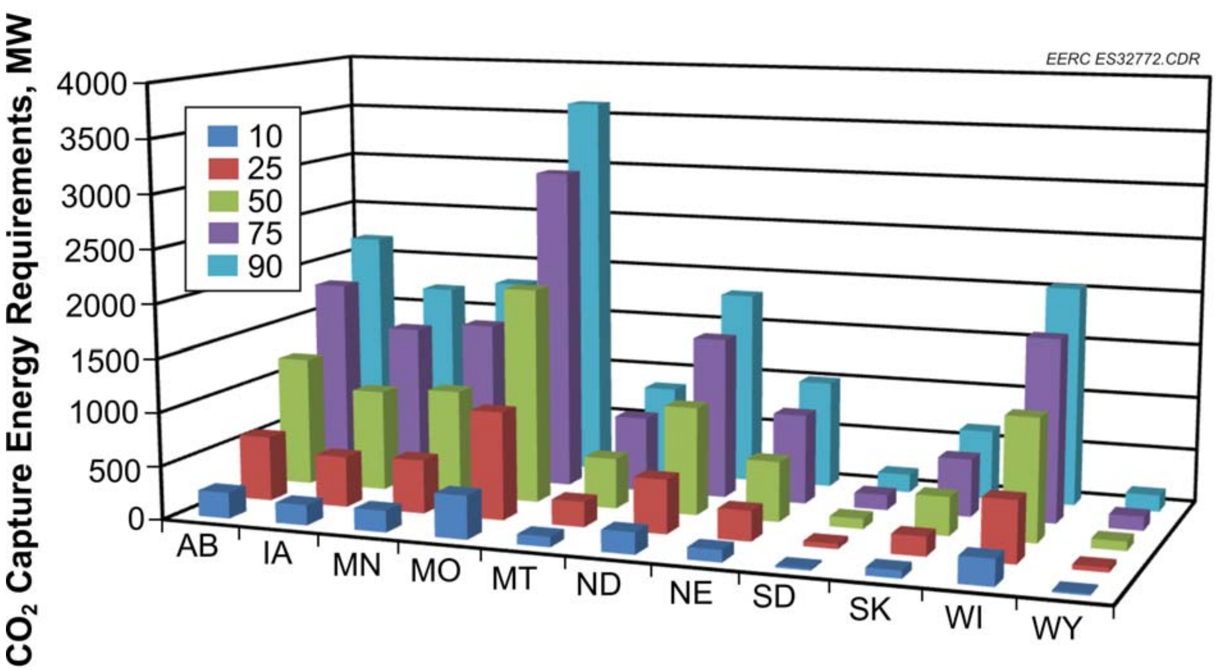


Figure 15. A comparison of the energy required for $CO_2$ capture in each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

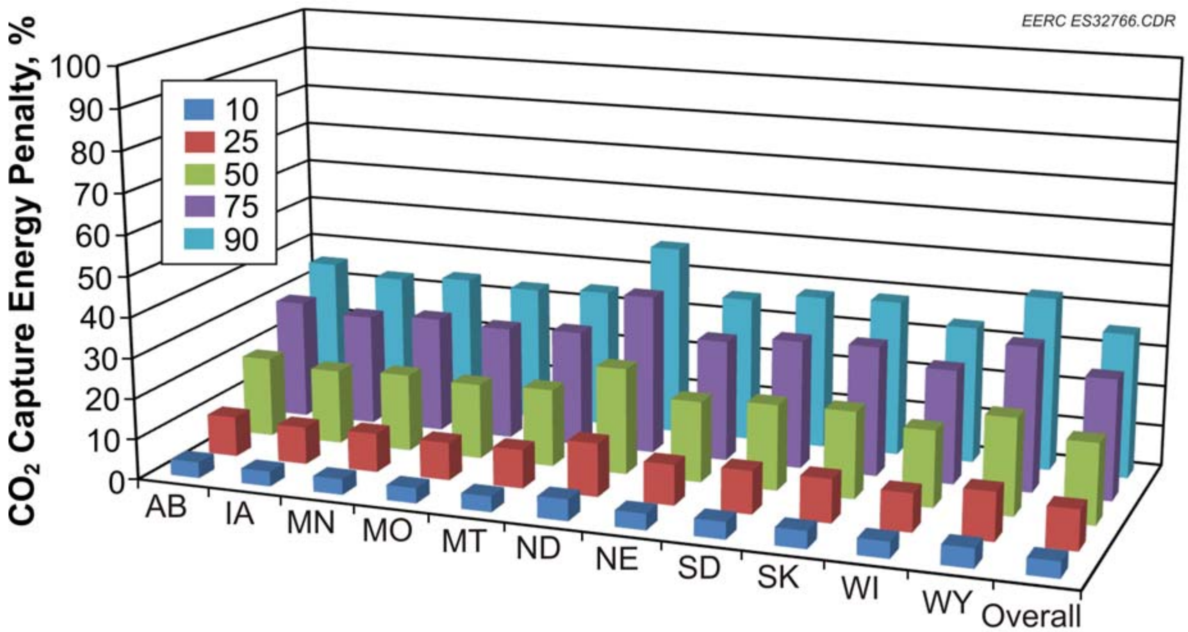


Figure 16. A comparison of the energy penalties incurred during $CO_2$ capture for each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

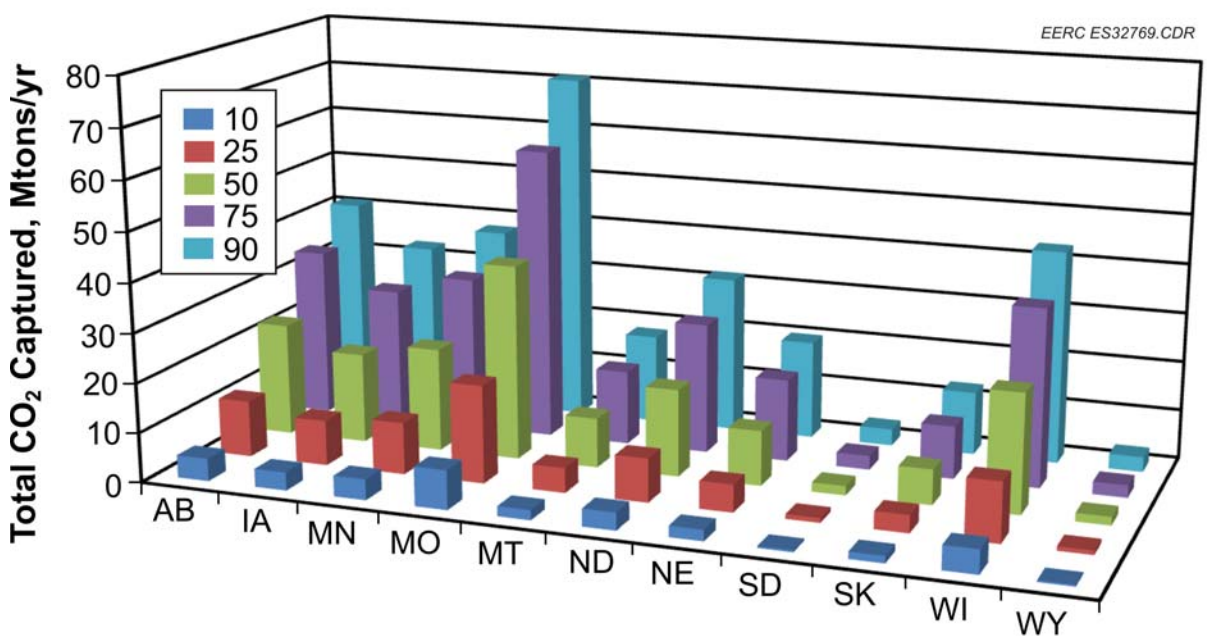


Figure 17. Comparison of the total amount of $CO_2$ that could be captured for each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

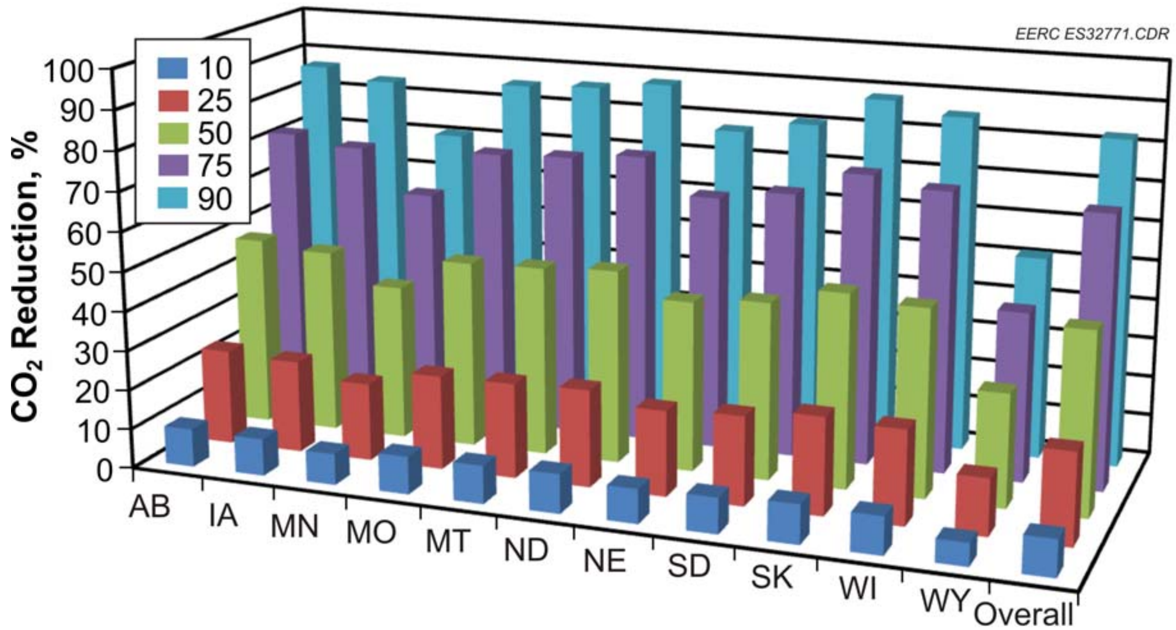


Figure 18. Comparison of the percentage of $CO_2$ reduced from all electricity-generating stations in each state/province in the PCOR Partnership region when $CO_2$ capture is implemented at the large (100 MW+) electricity-generating stations (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

(including those smaller than 100 MW) could be made in North Dakota. This is because a large percentage of their electricity-generating stations are larger and capture could be implemented there. The smallest opportunity to reduce $CO_2$ emissions is offered by Wyoming and Minnesota. Finally, on an overall (i.e., from all stationary sources) $CO_2$ reduction basis (shown in Figure 19), Montana could reduce its $CO_2$ emission by about 75% through capture of 90% of the $CO_2$ from its power plants. This is possible because of the small number of point sources in the state and the fact that, while there are not many electricity-generating stations in Montana, they are large. Missouri and North Dakota could potentially capture approximately 70% to 75% of the $CO_2$ produced by implementing 90% $CO_2$ capture from their large generating stations.

The data used to develop the figures discussed in this section (i.e., Figures 13–19) are included in Appendix D.

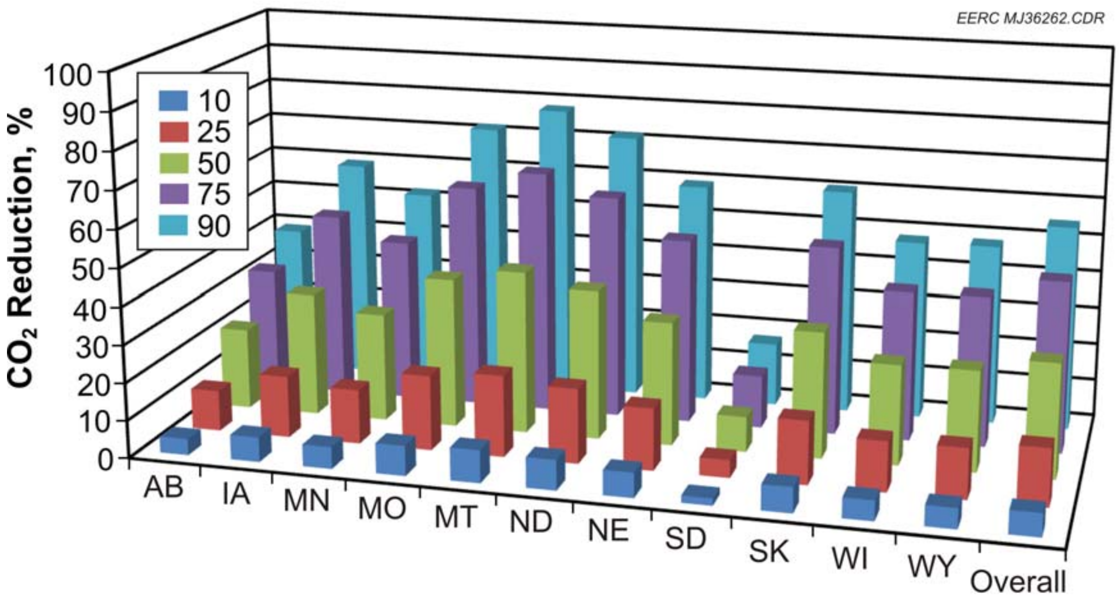


Figure 19. Comparison of the percentage of $CO_2$ reduced from all sources by implementing $CO_2$ capture at the large (100 MW+) electric generating stations for each state/province within the PCOR Partnership region (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

## THE COST OF TRANSPORTING $CO_2$ TO A GEOLOGIC SEQUESTRATION SITE

Transport of large quantities of $CO_2$ captured at a source to a geologic sink for sequestration undoubtedly will be via pipeline. A preliminary network of $CO_2$ pipelines was developed during the final phase of this study for purposes of estimating regional transportation costs only. There are no plans to develop this particular $CO_2$ pipeline network. The original intent was to develop a three-stage pipeline network, with the first lines connecting the gas-processing and ethanol plants to the oil fields where EOR opportunities exist, then adding the electricity-generating facilities and, finally, the spur lines to the brine formations. However, when the maps showing source and geologic sink locations were critically examined, it was apparent that the routes would overlap and that, if pipelines that would carry only $CO_2$ from the ethanol and gas-processing plants were laid in first, they would not be large enough to carry the additional $CO_2$ from the power plants when those streams were available. The prudent choice seemed to be to map out a network with sufficient capacity to carry the $CO_2$ at its maximum expected flow rate to both EOR opportunities and brine formations.

Development of the pipeline network was accomplished on a state-by-state basis. The PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) buffer feature was used to identify the closest geologic sinks to sources in each state. Because the PCOR Partnership region is so large, some of the sources are quite far from the geologic sinks. It was found that the $CO_2$ from sources in the eastern portion of the PCOR Partnership region would be more economically transported to oil fields and brine formations in the Illinois Basin rather than

**Table 10. Geologic Sinks in Closest Proximity to PCOR Partnership $CO_2$ Point Sources**

| State/Province | Geologic Sink |
|---|---|
| Alberta | EOR in Alberta |
| British Columbia[1] | EOR in Alberta or brine formations in British Columbia |
| Iowa | EOR or brine formations in Illinois Basin |
| Manitoba | EOR in western Manitoba or southern Saskatchewan |
| Minnesota | EOR or brine formations in North Dakota |
| Missouri | EOR or brine formations in Illinois Basin |
| Montana[1] | EOR in Montana or North Dakota; brine formations in Montana |
| Nebraska | EOR or brine formations in western Nebraska |
| North Dakota | EOR or brine formations in North Dakota |
| Saskatchewan | EOR in Alberta or southern Saskatchewan |
| South Dakota | EOR in western North Dakota or brine formation in South Dakota |
| Wisconsin | EOR or brine formations in Illinois Basin |
| Wyoming[1] | EOR in Wyoming or brine formation in Montana |

[1] The only point sources considered in these states/provinces were those in the PCOR Partnership portion of the state or province.

to PCOR Partnership regional sinks. Table 10 summarizes the nearest sink areas for the sources in each of the states/provinces.

For each state, a map showing all of the ethanol facilities, gas-processing plants, and power plants larger than 100 MW was generated using the DSS geographic information system (GIS)-mapping capabilities. The relationships between the sources and the nearest geologic sink(s) were noted and potential routes identified. Specific main trunk pipeline routes were determined using a GIS-based model for $CO_2$ pipeline transport that was developed at the Massachusetts Institute of Technology (MIT) (Herzog, 2006; Massachusetts Institute of Technology, 2007). The MIT model calculates pipeline diameter and identifies the least cost path connecting a $CO_2$ source to a given sink. The model implements $1 \times 1$-km obstacle grid layers in which local terrain, crossings, protected areas, and populated places are assigned relative cost factors that are used to determine the least cost route between a single $CO_2$ source and a geologic sink. The cost of any booster stations was not included in the pipeline cost.

To use the model, source and sink locations were selected, and both the mass flow rate of the $CO_2$ stream and a cost of $70,000/in./mi were input (this cost was chosen because it was a "rule-of-thumb" pipeline cost estimate at the time this report was prepared). The mass flow rates that were used were the total $CO_2$ stream produced by a source or group of sources that lay on the trunk route. This was done to ensure that the resulting pipeline network would have additional room for future capture at other industrial sources as it is unlikely that an entire pipeline network would be constructed more than once. The resulting output showed the least cost route and provided metrics for the route that included distance, pipeline diameter, construction cost, and O&M cost. These outputs are summarized on a state-by-state (or province-by-province) basis in Appendix E.

While quite useful, the MIT pipeline-routing model has a few limitations. Pipeline-routing capabilities are limited to the United States; pipeline routes for the Canadian provinces had to be estimated manually. The MIT model will not generate routes for distances less than about 25 mi. Although it takes obstacles into account when determining the least cost route, it does not include the additional costs to cross waterways or run through federal or tribal lands in its cost estimations. Rather, the model uses its default value of $50,000/in./mi for all distances. In an effort to make up for some of the underestimated obstacle crossings and to account for the rapid increase in the costs of steel and labor that will likely continue for the foreseeable future, the pipeline calculations were performed using a cost of $70,000 per in. diameter per mi. O&M costs were calculated to be $5000 per mile, irrespective of pipeline diameter.

Pipelines were not considered if the only $CO_2$ sources feeding the line were a few small ethanol plants as it would not be cost-effective to transport that relatively small quantity of $CO_2$ by pipeline. This occurred in northeastern North Dakota, where two small ethanol plants are located as well as in Alberta where some sources were far from the trunk routes.

Table 11 summarizes the PCOR Partnership regional pipeline network in terms of length, construction, and O&M costs, while Figure 20 shows a map of the preliminary pipeline network. The known routes of existing and planned $CO_2$ pipelines (i.e., the Dakota Gasification Company's pipeline from the Great Plains Synfuels Plant to the Weyburn oil field and the Enhance Energy $CO_2$ pipeline planned for Alberta) were taken into account during the routing exercise. Based on proximity to the various geologic sinks, it would be less costly for the $CO_2$ captured in Wisconsin, Iowa, and Missouri to be transported to coal beds, oil fields, and brine formations in the Illinois Basin. $CO_2$ captured from plants in Nebraska likely would be sequestered in the geologic sinks located southwestern Nebraska. The $CO_2$ captured from plants in the PCOR Partnership portion of Montana, Minnesota, South Dakota, and North Dakota would be transported to western North Dakota for EOR or to the vast brine formations of North and South Dakota. The $CO_2$ captured at the Wyodak electricity-generating campus probably

**Table 11. Regional Pipeline Network Summary[1]**

| State/Province | Length, miles | Construction Cost, $M | O&M Cost, $M/yr |
|---|---|---|---|
| British Columbia[2] | 269 | 143.7 | 1.34 |
| Alberta | 1293 | 1383.3 | 6.46 |
| Saskatchewan | 110 | 128.8 | 0.55 |
| Manitoba | –[3] | – | – |
| Montana[2] | 367 | 532.5 | 1.84 |
| Wyoming[2] | 77 | 46.4 | 0.39 |
| North Dakota | 958 | 1712.0 | 4.79 |
| South Dakota | 915 | 884.0 | 4.58 |
| Nebraska | 1325 | 1639.0 | 6.61 |
| Minnesota | 1363 | 1370.5 | 7.02 |
| Iowa | 1312 | 1299.5 | 6.60 |
| Missouri | 986 | 1498.6 | 4.90 |
| Wisconsin | 871 | 1166.4 | 4.36 |
| Regional Total | 9846 | 11,547.1 | 49.44 |

[1] This summary includes all pipelines of various diameters. Appendix E shows the various pipeline diameters and lengths for each of the states/provinces.
[2] Only includes the pipelines in the PCOR Partnership portion of the state/province.
[3] Not applicable as there are no ethanol plants or electric generating facilities larger than 100 MW.

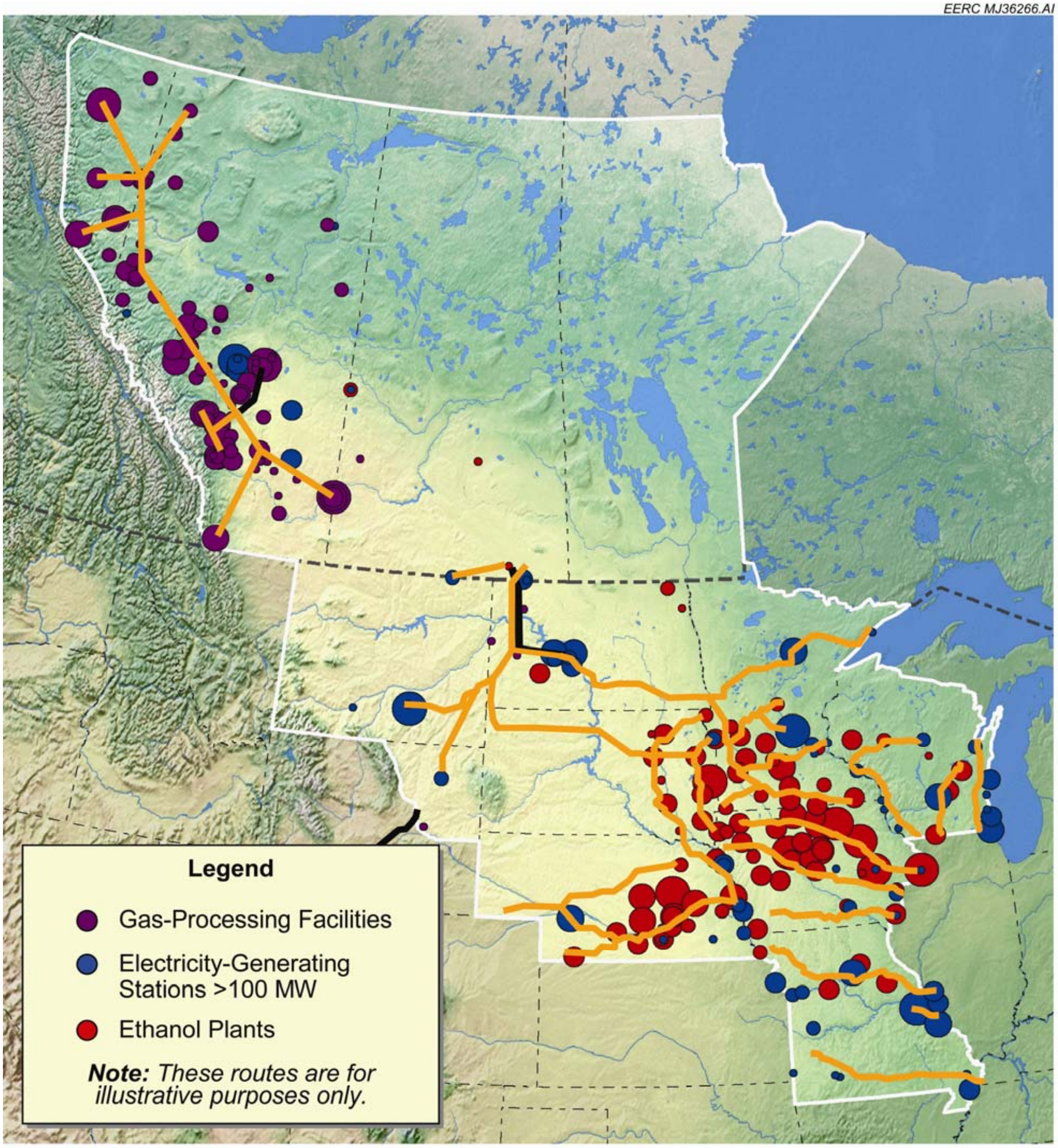


Figure 20. The illustrative PCOR Partnership pipeline network routes. Yellow gold routes show the pipeline network routes calculated during this study. Black lines are existing or planned $CO_2$ pipelines.

would be sequestered in oil fields nearby. $CO_2$ captured in Alberta and Saskatchewan would be used for EOR in those provinces, while the $CO_2$ captured in Manitoba likely would be transported to an oil field in western Manitoba.

The network comprises an estimated total of 9846 mi, which includes both main trunk lines and lines hooking individual sources to the main trunk. A pipeline network of this size will require about $15.5 billion to construct and $49.4 million/yr to operate and maintain. If this construction cost is amortized over 10 payments at 10% interest (the default for the IECM, and therefore, the value used in the levelizing calculations for all of the capture costs), an annual pipeline cost of $2.34 billion (including both construction and O&M costs) is calculated.

Appendix E summarizes the pipelines and shows the routes for each state and province.

## TOTAL COST OF WIDE-SCALE CCS DEPLOYMENT IN THE PCOR PARTNERSHIP REGION

Using the values discussed in the capture from ethanol and gas-processing plants, capture from electricity-generating stations, and pipeline routing sections, the annual cost of various regional CCS scenarios can be estimated. It is not possible to determine which sources would probably capture $CO_2$ and, therefore, which sections of pipeline would be required. Therefore, these estimates assume that capture will take place at all of the ethanol, gas-processing, or electricity-generating facilities and that the entire pipeline network will be needed to transport the $CO_2$ so as to provide the most expensive (i.e., "worst-case") scenario. Table 12 summarizes the estimates and reduction in regional emissions that would result from each of the scenarios.

To more accurately estimate the cost of capturing a ton of $CO_2$, the cost to replace the power lost by installing and operating the capture technology should also be taken into account. The cost of capturing, drying, and compressing the $CO_2$ and replacing the power needed to perform those tasks is called the avoided cost. Using the capture/drying/compression and replacement power cost estimates given in Table 12, avoided costs ranging from $71/ton (for 90% capture from the power plants) to $77/ton (for 10% capture) can be calculated. Total costs that include the cost of the pipeline network range from $78/ton (at the 90% capture rate) to $144/ton (for 10% capture). When the additional $CO_2$ produced by the ethanol plants and gas-processing facilities is included with the scenario in which 90% of the $CO_2$ from the power plants is captured, the avoided cost drops to $71/ton.

The increase in the generation cost of electricity (COE) caused by capture, compression, and transport of the $CO_2$ was estimated for the entire regional electricity-generating fleet. The estimates, which are summarized in Table 13, show that the regional COE is likely to increase by more than the DOE goal of 20%, although it may not double in cost, depending on the level of capture. The table also shows that the majority of the increase in COE at higher capture levels is caused by capture and compression and that the pipeline network does not contribute as much. Because these values were calculated using global numbers for the entire PCOR Partnership electricity-generating fleet rather than averages of COE calculations for each individual facility,

**Table 12. Annualized Cost of Various CCS Scenarios in the PCOR Partnership Region**

| Source | Emissions, million tons | Annualized Cost,[1] $ billions: Capture/Drying/ Compression | Annualized Cost,[1] $ billions: Pipeline | Annualized Cost,[1] $ billions: Replacement Power[2] | Total Annual Cost, $ billions | Total Cost/ton, $/ton | % Reduction in Regional $CO_2$ Emissions[3] |
|---|---|---|---|---|---|---|---|
| Ethanol Plants, noncombustion | 15.6 | 0.15 | 2.34[4] | NA[5] | 2.49[4] | 10/160[6] | 3 |
| Gas-Processing Plants | 21.1 | 0.25 | 2.34[4] | NA[5] | 2.59[4] | 12/123[6] | 4 |
| Power Plants,[7] 10% | 35.00 | 1.84 | 2.34 | 0.86 | 5.04 | 144 | 6 |
| Power Plants,[7] 25% | 87.48 | 3.85 | 2.34 | 2.24 | 8.43 | 96 | 15 |
| Power Plants,[7] 50% | 174.96 | 7.08 | 2.34 | 4.87 | 14.29 | 82 | 30 |
| Power Plants,[7] 75% | 262.44 | 10.48 | 2.34 | 7.88 | 20.70 | 79 | 45 |
| Power Plants,[7] 90% | 314.92 | 12.47 | 2.34 | 9.87 | 24.68 | 78 | 54 |

[1] Calculated for pipelines and replacement power using Excel PMT function with interest = 10%, ten periods, payment at the beginning of the period. This approach produced the same annualized values as the IECM when comparison calculations were performed. The IECM was used to calculate annualized costs for capture, drying, and compression.
[2] Cost of replacement power was the average of pc and IGCC plants; values taken from Figure 12 and amortized according to footnote “a” of this table.
[3] Total regional emission from industrial point sources is roughly 561,900,000 tons/yr.
[4] It is unlikely that the entire pipeline network would be built out for only the ethanol and gas-processing plants.
[5] Not applicable.
[6] First cost listed is for capture/drying/compression only; second cost includes the cost of the entire pipeline network (not likely for only the ethanol and/or gas-processing plants).
[7] Includes only the power plants >100 MW in size.

**Table 13. Estimated Increases in COE* Due to Capture of $CO_2$**

| Percentage Capture | Increase Caused by Capture and Compression only, % | Increase Caused by Capture, Compression, and Pipeline, % |
|---|---|---|
| 10 | 14.9 | 33.9 |
| 25 | 33.5 | 53.8 |
| 50 | 70.1 | 93.3 |
| 75 | 120.6 | 147.5 |
| 90 | 158.7 | 188.5 |

* Cost of generation of electricity rather than the retail cost of electricity.

they should be used only as relative indicators of COE trends that are possible if CCS were implemented on a wide scale within the region. It should be kept in mind that the cost to generate electricity is only a portion of the retail cost of electricity paid by consumers.

It is important to note that the DOE goal is for capture technology research and development to decrease the cost of these technologies and, therefore, the COE. Future technology improvements have the potential to decrease the capture costs and energy penalties (and associated costs) that were calculated in this report.

## SUMMARY AND CONCLUSIONS

Several conclusions can be drawn regarding the early implementation of $CO_2$ capture and sequestration in the PCOR Partnership region. The reader should keep in mind that 1) this study estimated only the costs associated with capture, drying, compression, and transportation by pipeline to a geologic sink and that injection costs at the sink or any monetary value assigned to the $CO_2$ have **not** been included in the cost or energy estimates, 2) the pipeline network that was developed was only for the purpose of estimating transportation infrastructure costs and is not intended to be an implementable pipeline system, and 3) all values apply only to the portions of the states/provinces that are contained in the PCOR Partnership region.

- Early implementation of CCS in the PCOR Partnership region will probably include capture of $CO_2$ from ethanol facilities and gas-processing facilities as well as from at least some of the electricity-generating stations that produce more than 100 MW of power.

- While many promising capture technologies are under development, the technology that is most likely to be employed for capture at the power plants is chemical absorption. Amine scrubbing will probably be used as it is a commercial (and, therefore, better-defined) technology, although some facilities may choose to apply an ammonia-based scrubbing system to their gas streams.

- Drying and compression of the noncombustion $CO_2$ produced during the fermentation step at ethanol plants will cost an estimated $150 million a year (includes levelized capital cost plus O&M costs). Capture of this $CO_2$ stream would reduce the PCOR Partnership region's point-source emissions by 3%. On a per-ton basis, the regional average cost of drying and compressing the noncombustion $CO_2$ from the ethanol plants is $10/ton. Although on the high end of the range, this cost is similar to compression costs found in the literature that range from \$5.44 to \$10.88/ton $CO_2$. The higher cost is because the streams are often relatively small and unable to take advantage of the economy of large-scale processing.

- As shown in Table 5, capture, drying, and compression of the $CO_2$ produced during combustion at ethanol plants could reduce the PCOR Partnership region's point-source $CO_2$ emissions by 0.2% to 1.8% for capture of 10% to 90%, respectively. The levelized annual cost to capture, dry, and compress this stream would range from \$281 million (for capture of 10% of the $CO_2$) to \$1.1 billion (for capture of 90% of the $CO_2$). On a per-ton basis, costs to capture this $CO_2$ range from \$94/ton for 90% capture at one of the larger ethanol facilities to \$1400/ton for 10% capture at one of the smaller facilities. It is unlikely that this combustion-produced $CO_2$ would be captured at the ethanol facilities because of the cost.

- Drying and compression of the $CO_2$ stream from the PCOR Partnership region's gas-processing facilities will require an expenditure of \$255 million to capture the 21 million tons of $CO_2$ produced each year, or \$12/ton $CO_2$. This accounts for roughly 4% of the region's $CO_2$ emission.

- The minimum cost of using MEA to scrub $CO_2$ from the flue gas produced at a coal-fired power plant, dry it, and compress it is estimated to be \$46/ton to \$49/ton of $CO_2$ for 90% $CO_2$ capture and 50% capture, respectively. Roughly \$2.7 billion would be required annually to capture 10% of the $CO_2$ from the region's electricity-generating facilities. As much as \$22.3 billion annually would be needed to capture 90% of the $CO_2$.

- The replacement power requirement ranged from 1980 to 22,719 MW for 10% to 90% $CO_2$ capture from the power plants, respectively. The replacement power is what would be needed to operate the $CO_2$ capture plants at the electricity-generating stations as well as to capture the $CO_2$ produced by generating the replacement power. The cost of replacement power is estimated to be \$5.8 billion to \$66.7 billion for these same levels of $CO_2$ capture. Amortizing these values results in an annual cost of replacing the power used during capture and compression at power plants of \$860 million to \$9.87 billion.

- $CO_2$ captured from facilities in Wisconsin, Iowa, and Missouri will probably be sequestered in the Illinois Basin as those geologic sinks are located more proximally to the three states. $CO_2$ captured from plants in Nebraska likely would be sequestered in the geologic sinks located in southwestern Nebraska. The $CO_2$ captured from plants in the PCOR Partnership portion of Montana, Minnesota, South Dakota, and North Dakota would be transported to western North Dakota for EOR or to the vast brine formations of North and South Dakota. The $CO_2$ captured at the Wyodak electricity-generating campus probably would be sequestered in oil fields nearby. $CO_2$ captured in British Columbia and Alberta would be used for EOR in Alberta, while the $CO_2$ captured in Saskatchewan likely would be transported to oil fields in that province.

- Pipeline transport of $CO_2$ from the ethanol plants, gas-processing facilities, and electricity-generating facilities larger than 100 MW to the geologic sinks will add \$15.5 billion to the cost of CCS infrastructure in the region, or \$2.34 billion per year.

The total cost of capture, drying/compression, and pipeline transportation within the PCOR Partnership region ranges from $5.08 billion/year for the $CO_2$ produced at the gas-processing plants and during fermentation at the ethanol plants (i.e., the sources most likely to be among the first to apply CCS in the PCOR Partnership region) to $29.76 billion/yr for capture from all of the sources discussed in this report that are considered to make reasonable economic sense (the ethanol plants' fermentation $CO_2$, the gas-processing $CO_2$, and 90% of the $CO_2$ produced by the electricity-generating stations of the region that are larger than 100 MW). These two scenarios would reduce the region's point-source $CO_2$ emissions by 7% and 61%, respectively. On a per-ton basis, the scenario in which the ethanol plants' fermentation $CO_2$, the $CO_2$ from the gas-processing plants, and 90% of the $CO_2$ produced by the power plants is captured, dried and compressed, and transported by a pipeline network is $71/ton avoided.

The increase in the cost of electricity caused by the capture, compression, and transport of the $CO_2$ is estimated to be 34% to 189%. Maximizing the value-added benefits associated with EOR as a means of $CO_2$ sequestration will help to offset these costs. Gaining experience through large-scale demonstrations and the earliest applications of CCS is likely to reduce the costs, as will improvements in existing capture technologies and development of new capture concepts.

The estimated high cost of the capture, compression, and pipeline network required for effective wide-scale implementation of CCS as a means to reduce $CO_2$ emission illustrates that additional research for cost-effective capture and compression technologies and judicious siting of pipeline networks are needed so that this approach can be implemented with minimal financial hardship on the region's utilities, industries, and consumers.

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# APPENDIX A

# MODEL SIMULATIONS OF THE CAPTURE OF $CO_2$ FROM ELECTRICITY-GENERATING STATIONS FOR EACH STATE OR PROVINCE WITHIN THE PCOR PARTNERSHIP REGION

## MODEL SIMULATIONS OF THE CAPTURE OF $CO_2$ FROM ELECTRICITY-GENERATING STATIONS FOR EACH STATE OR PROVINCE WITHIN THE PCOR PARTNERSHIP REGION

This appendix presents the results of model simulations that were conducted for each state or province to examine the capture of $CO_2$ from its electricity-generating stations. The technical approach used is presented, followed by the model simulation results for each state or province.

## TECHNICAL APPROACH

The electricity-generating stations were identified in each of the states and provinces of the Plains $CO_2$ Reduction (PCOR) Partnership. Only those stations larger than 100 MW were targeted for $CO_2$ capture. For each of these stations, the $CO_2$ emissions were estimated (tons per year) and the characteristics of the individual generating units were summarized, including information such as the type and size of each boiler, the type of fuel used, and the existence and type of particulate and $SO_2$ control, if any.

The costs associated with $CO_2$ capture include several discrete cost elements. First, the cost of $CO_2$ capture was estimated using a monoethanolamine (MEA) scrubbing system. Costs associated with removal efficiencies of 10%, 25%, 50%, 75%, and 90% were estimated. Second, if a generating unit did not have sulfur control, the cost of incorporating a wet flue gas desulfurization (WFGD) unit was added to the cost of $CO_2$ capture because it was determined that it was more cost-effective to remove the $SO_2$ prior to $CO_2$ capture than to pay the increase in operating costs associated with processing of the $SO_2$-laden gas in the MEA system. This cost penalty is associated with the increase in solvent degradation that occurs in the MEA scrubbing system as a result of the presence of $SO_2$. Lastly, in addition to these operating costs, the costs associated with replacing the power that was consumed as part of the $CO_2$ recovery operations, i.e., replacement power, was also estimated and included in the cost analysis. This cost estimate was based on the use of either scrubbed coal in the existing generation unit or the addition of an integrated gasification combined cycle (IGCC) to generate the replacement power. In both cases, it was assumed that the capture of the additional $CO_2$ that was generated during this additional power production would take place at the capture levels cited above.

The Integrated Environmental Control Model (IECM) was used to estimate the capital and operating costs of the MEA scrubbing system as well as the cost of the WFGD unit. The cost for the replacement of the power that is consumed by $CO_2$ capture was estimated using a combination of sources. For IGCC, the cost range was estimated to be \$2431 to \$3593 per kW. The low end of this range was generated using the IECM while the upper end of the range came from the Excelsior Energy Mesaba Project. The generation of replacement power using scrubbed coal was estimated as \$2279 to \$2726 per kW. The low end of this range came from Energy Information Administration (EIA) assumptions to the Annual Energy Outlook 2008; the upper range was estimated using the IECM.

## PRESENTATION OF MODEL SIMULATION RESULTS

For each state/province, the characteristics of the generating units greater than 100 MW are summarized, and their locations are provided on a map of the state/province. The $CO_2$ emissions from these units are provided, expressed as annual emission rates (i.e., tons per year). The annual quantities of $CO_2$ (tons per year) that are captured are also presented for a range of capture percentages, i.e., 10%, 25%, 50%, 75%, and 90%, and these reductions are also expressed as the percentage of the total $CO_2$ emissions from all of the generating stations (<100 MW as well as >100 MW) and of the total $CO_2$ emissions from all $CO_2$ sources (electricity generation plus all others) within the state/province of interest. The energy penalty associated with the capture of $CO_2$ (MEA scrubber and WFGD unit) is also presented for each level of removal. The penalty is expressed as the percentage of gross output of the generating units. However, the capital cost for providing replacement power is only presented for the 90% removal scenario, without consideration of the additional operating and maintenance costs. Because of the uncertainty associated with this cost element of $CO_2$ capture, the cost of providing this replacement power is assumed to be the average cost of the minimum and maximum replacement costs estimated based on the use of scrubbed coal in the existing generating units or the addition of an IGCC system. Finally, costs for the capture of the $CO_2$ are also provided in terms of $ per ton of $CO_2$ removed as well as the annual levelized cost. These cost estimates include estimates of both capital as well as operating and maintenance costs.

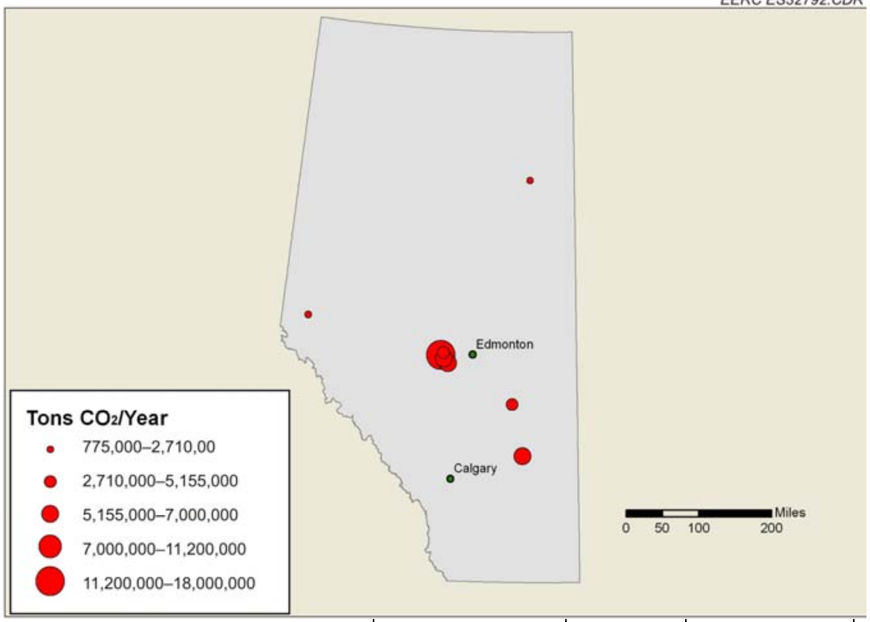
### Alberta

Alberta has 19 electricity-generating stations that emit more than 54,300,000 tons of $CO_2$ annually. Of these stations, eight are larger than 100 MW. These eight generating stations consist of 19 separate generating units, the characteristics of which are summarized in Table A-1 along with a map showing their locations within the province. The units are very similar in that they each burn subbituminous coal in a tangentially fired (T-fired) boiler and have a cold-side electrostatic precipitator (ESP) for particulate matter (PM) control. It was found that most of the units are not equipped with any $SO_x$ control. Therefore, the cost of incorporating a WFGD unit was added to the cost of capturing $CO_2$ for the appropriate amount of flue gas treated to obtain the different $CO_2$ capture rates. The units vary in size from 100 MW (McKay River Power Plant) to the Genesee 3 Station, which has a capacity of 450 MW. The total generation capacity of the units considered for $CO_2$ capture in the Alberta region was 6159 MW. The $CO_2$ generated annually from these 19 units is approximately 45,700,000 tons, which is about 84% of the $CO_2$ generated from all 19 generating stations in Alberta.

The results from the model simulations (Table A-2) show a significant cost and energy penalty for capturing 90% of the $CO_2$ emitted from these units. The energy that would be consumed at this level of capture is 2189 MW, which is 35.5% of the current gross output of these units, as compared to an energy consumption of 243 MW (about 4% of the gross output) at the 10% capture level. At the average projected cost of power replacement, $2936/kW (i.e., the average of the minimum cost projection using scrubbed coal, $2431/kW, and the maximum of using IGCC, $3593/kW), the total cost for power replacement at the 90% capture level is estimated to be about $6.4 billion. Figure A-1 shows the predicted power requirement (expressed as MW) as a function of the percentage of the $CO_2$ that is captured. The figure also shows the total cost of $CO_2$ capture ($ per ton of $CO_2$), again as a function of the percentage of $CO_2$ that is captured. From this graphic, it can be seen that the cost of $CO_2$ capture ($/ton) is relatively high ($94/ton) at low capture rates, i.e., 10%, but drops quickly as the percentage of $CO_2$ captured is increased, leveling off at $51 to $46/ton for 50% to 90% $CO_2$ capture, respectively. This downward trend is observed because of the ability to spread the high capital investment over larger quantities of carbon dioxide increases as the amount of carbon dioxide capture increases. In terms of levelized annual costs, Figure A-1 shows that it increases from $250 M per year (10% $CO_2$ capture) to $1587 M per year (90% $CO_2$ capture).

At the highest rate of capture (90%), there would be an estimated 41,105,000 tons of $CO_2$ captured, or roughly 87% of all the $CO_2$ produced by the 15 electricity-generating stations in Alberta. Given that the total $CO_2$ produced in Alberta is roughly 115,600,000 tons per year, a 90% $CO_2$ capture achieved from the >100 MW electricity-generating stations yields an overall $CO_2$ reduction of 35.5% for the province. As noted above, the total $CO_2$ capture cost required to achieve this reduction would be $1.6 billion annually plus the additional cost of replacing the lost generation capacity.

**Table A-1. Location and Summary of Characteristics of Electricity-Generating Units (>100 MW) in Alberta**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type[2] | Boiler Type[3] | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Sundance Gen Unit 1 | 16,343,514 | 300 | Subbitum. | T-fired | None | C-ESP[4] |
| Sundance Gen Unit 2 | | 300 | Subbitum. | T-fired | None | C-ESP |
| Sundance Gen Unit 3 | | 375 | Subbitum. | T-fired | None | C-ESP |
| Sundance Gen Unit 4 | | 375 | Subbitum. | T-fired | None | C-ESP |
| Sundance Gen Unit 5 | | 375 | Subbitum. | T-fired | None | C-ESP |
| Sundance Gen Unit 6 | | 387 | Subbitum. | T-fired | None | C-ESP |
| Genesee Station 1 | 6,733,497 | 410 | Subbitum. | T-fired | None | ESP |
| Genesee Station 2 | | 410 | Subbitum. | T-fired | None | ESP |
| Genesee Station 3 | | 450 | Subbitum. | T-fired | DFGD[5] | FF[6] |
| Sheerness Gen Station No. 1 | 6,600,745 | 380 | Subbitum. | T-fired | None | C-ESP |
| Sheerness Gen Station No. 1 | | 380 | Subbitum. | T-fired | None | C-ESP |
| Keephills Gen Plant 1 | 5,989,611 | 403 | Subbitum. | T-fired | None | C-ESP |
| Keephills Gen Plant 2 | | 403 | Subbitum. | T-fired | None | C-ESP |
| Battle River Gen Station 1 | 5,155,346 | 148 | Subbitum. | T-fired | None | C-ESP |
| Battle River Gen Station 2 | | 148 | Subbitum. | T-fired | None | C-ESP |
| Battle River Gen Station 3 | | 370 | Subbitum. | T-fired | None | C-ESP |
| Wabamun Gen Plant | 3,165,672 | 300 | Subbitum. | T-fired | None | NA[7] |
| H. R. Milner Gen Station | 959,369 | 145 | Subbitum. | W-fired | None | FF |
| McKay River Power Plant | 775,015 | 100 | Subbitum. | NA | None | NA |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.
[2] Subbituminous coal.
[3] W-fired: wall-fired.
[4] Cold-side ESP.
[5] Dry flue gas desulfurization.
[6] Fabric filter.
[7] Not applicable.

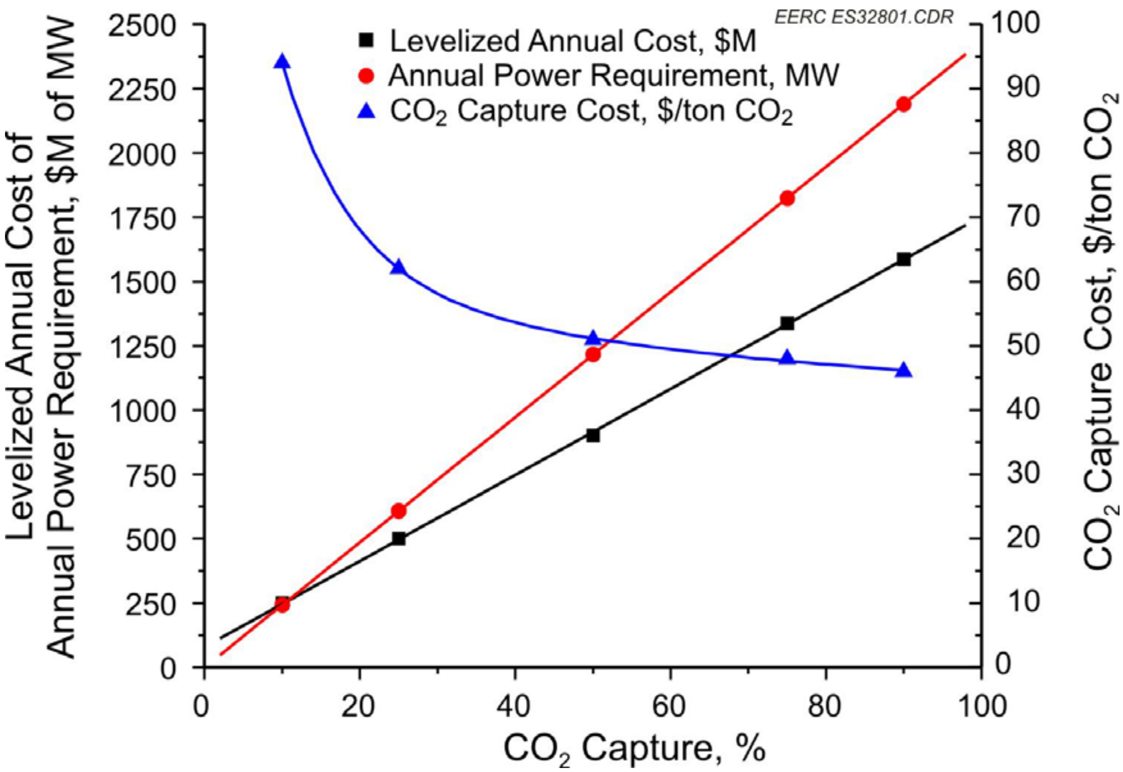



Figure A-1. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Alberta.

**Table A-2. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Alberta**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 45,672,247 tons $CO_2$ emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 4,567,225 | | 11,418,062 | | 22,836,124 | | 31,254,186 | | 41,105,023 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 6159 | | 6159 | | 6159 | | 6159 | | 6159 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 225 | | 562 | | 1125 | | 1687 | | 2025 | |
| WFGD Use, MW | 18 | | 46 | | 91 | | 137 | | 164 | |
| Total Aux Load, MW | 243 | | 608 | | 1216 | | 1824 | | 2189 | |
| % of Gross Output | 3.9 | | 9.9 | | 19.7 | | 29.6 | | 35.5 | |
| Cost of Capture | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 178 | 39 | 206 | 18 | 251 | 11 | 297 | 9 | 325 | 8 |
| Total Levelized Annual Cost[a] | 250 | 94 | 501 | 62 | 903 | 51 | 1338 | 48 | 1587 | 46 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

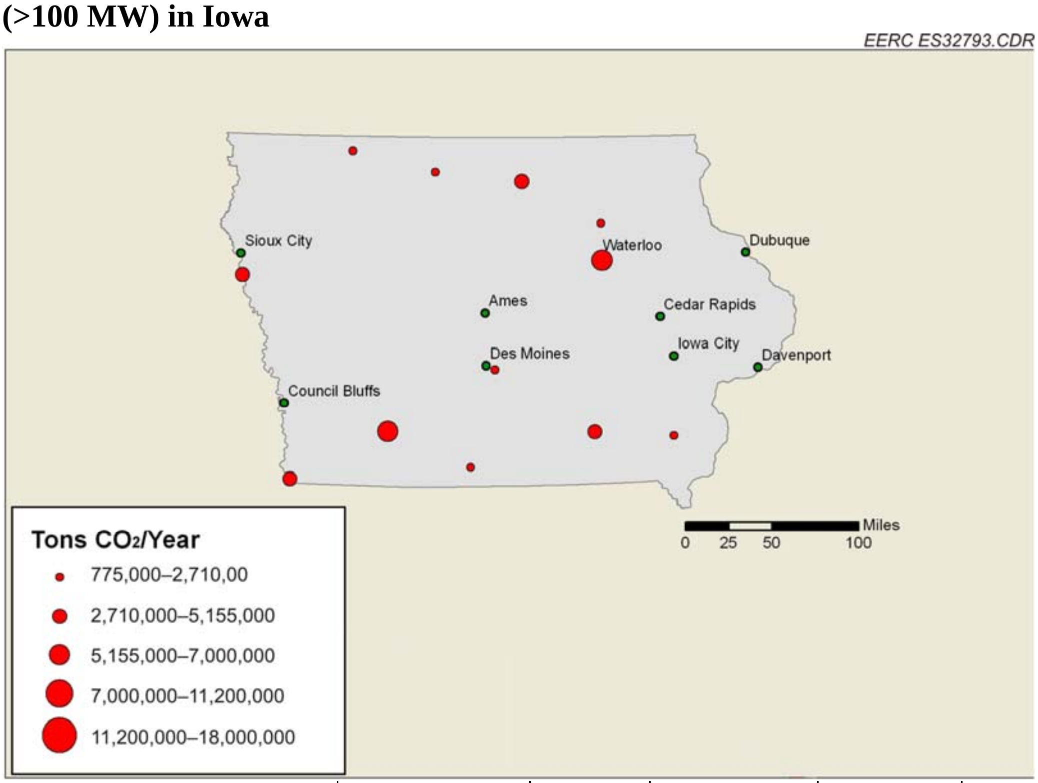
### Iowa

Iowa has 23 electricity-generating stations that emit more than 39,078,000 tons of $CO_2$ annually. Of these 23 stations, 11 are larger than 100 MW. The 11 generating stations consist of 13 separate generating units, the characteristics of which are summarized in Table A-3 along with a map showing their locations within the state. The units are very similar: the primary fuel is subbituminous coal and the boiler is tangentially fired, with a C-ESP for PM control. Most of the units are not equipped with any sort of $SO_x$ control. Therefore, the cost of incorporating a WFGD unit was added to the cost of capturing $CO_2$ for the appropriate amount of flue gas treated to obtain the different $CO_2$ capture rates. The units varied in size from 148 MW (George Neal North 1) to 740 MW (Louisa Station). The total generation capacity of the units considered for $CO_2$ capture is 5165 MW. The $CO_2$ generated from these 13 units totals approximately 36,500,000 tons of $CO_2$ per year, or roughly 93% of the $CO_2$ generated from all 23 generating stations in Iowa (39,078,000 tons per year).

The results from the model simulations (Table A-4) show an energy penalty of as much as 33% for capturing 90% of the $CO_2$ emitted from these electricity-generating units. The cost associated with this energy requirement of 1712 MW (Table A-4) is estimated at about \$5.2 billion (capital costs only), based on the average power cost of \$2936 per kW. The observed trends in the power penalty and cost data, shown in Figure A-2, are similar to what was observed in Alberta, with the highest cost for $CO_2$ capture at the capture level of 10% (i.e., \$86 per ton) followed by a leveling of the costs at \$51 and \$48 per ton for capture rates of 50% and 90%, respectively, and the levelized costs ranging from \$199 million per year (for 10% $CO_2$ capture) to \$1357 million per year (90% capture).

At the highest rate of capture, there would be an estimated 32,867,000 tons of $CO_2$ captured, which is 84% of all the $CO_2$ produced by the 23 electricity-generating stations in Iowa. Given that the total $CO_2$ produced in Iowa is estimated at about 54,600,000 tons per year, a 90% $CO_2$ capture achieved from the >100 MW electricity-generating stations yields an overall $CO_2$ reduction of 60% for the state. The total $CO_2$ capture cost required to achieve this reduction would be about \$1.4 billion annually plus the additional cost of replacing the lost generation capacity.

**Table A-3. Location and Summary of Characteristics of Electricity-Generating Units (>100 MW) in Iowa**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| George Neal North 1 | 7,043,476 | 148 | Subbitum. | Cyclone | None | H-ESP[2] |
| George Neal North 2 | | 350 | Subbitum. | W-fired | None | C-ESP |
| George Neal North 3 | | 550 | Subbitum. | W-fired | None | C-ESP |
| Council Bluffs 3 | 5,786,096 | 725 | Subbitum. | W-fired | None | C-ESP |
| Louisa | 4,846,897 | 740 | Subbitum. | W-fired | None | H-ESP |
| Ottumwa 1 | 4,714,088 | 726 | Subbitum. | T-fired | None | C-ESP |
| George Neal South | 4,673,886 | 650 | Subbitum. | W-fired | None | C-ESP |
| Muscatine | 2,006,515 | 180 | Subbitum. | T-fired | WFGD[3] | C-ESP |
| Lansing 4 | 1,658,922 | 263 | Subbitum. | W-fired | None | ESP |
| Burlington | 1,466,982 | 212 | Subbitum. | T-fired | None | NA |
| Sutherland | 1,394,454 | 157 | Subbitum. | NA | None | NA |
| Prairie Creek | 1,197,431 | 245 | Subbitum. | NA | None | NA |
| Milton L Kapp 2 | 1,188,717 | 219 | Subbitum. | T-fired | None | ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.
[2] Hot-side ESP.
[3] Wet flue gas desulfurization.

**Table A-4. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Iowa**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 36,519,363 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 3, 651,936 | | 9,129,840 | | 18,259,680 | | 27,389,520 | | 32,867,420 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 5165 | | 5165 | | 5165 | | 5165 | | 5165 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 176 | | 441 | | 882 | | 1323 | | 1588 | |
| WFGD Use, MW | 14 | | 35 | | 69 | | 104 | | 124 | |
| Total Aux. Load, MW | 190 | | 476 | | 951 | | 1427 | | 1712 | |
| % of Gross Output | 3.7 | | 9.2 | | 18.4 | | 27.6 | | 33.1 | |
| Cost of Capture | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 115 | 31 | 136 | 15 | 170 | 9 | 205 | 7 | 225 | 7 |
| Total Levelized Annual Cost[a] | 199 | 86 | 418 | 61 | 759 | 51 | 1143 | 49 | 1357 | 48 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

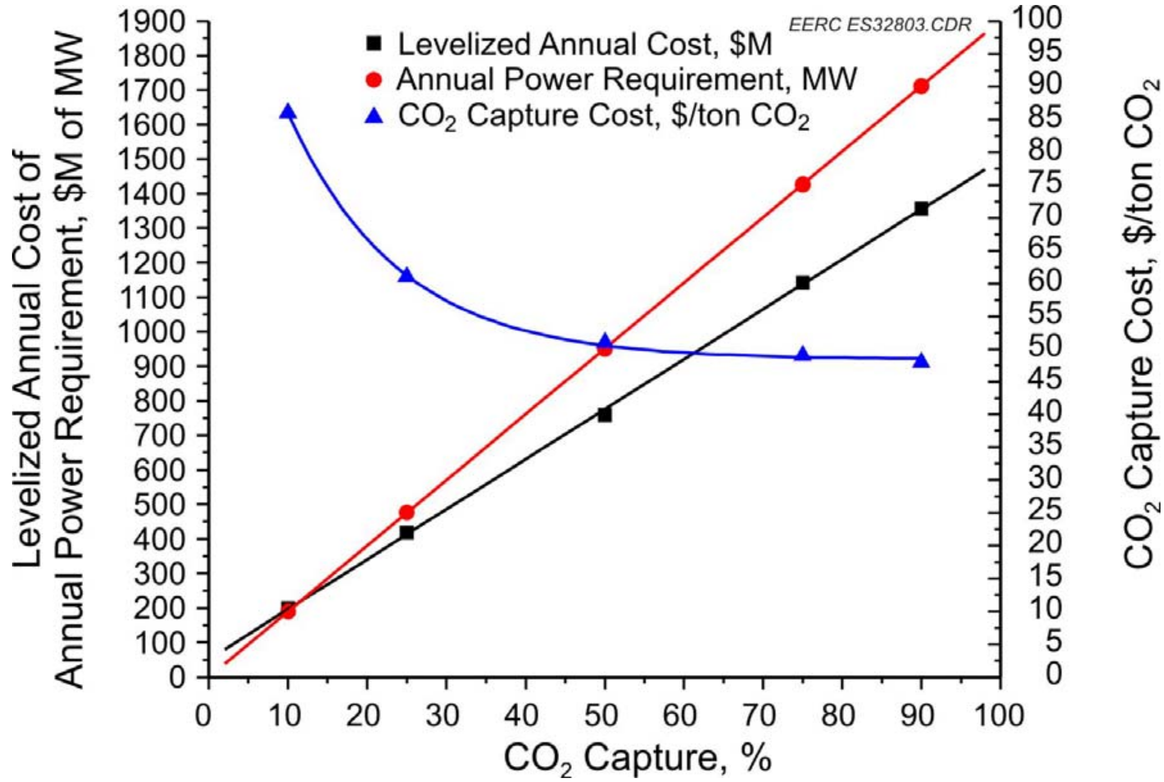



Figure A-2. Results of implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Iowa.

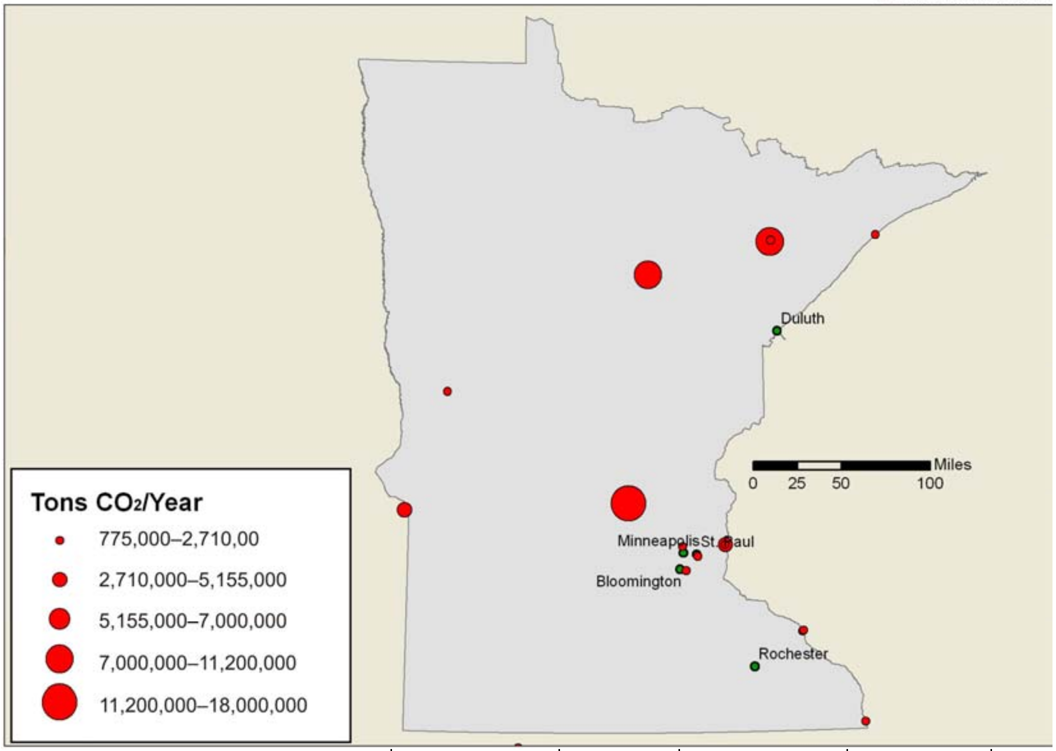
**Minnesota**

Minnesota has 28 electricity-generating stations that emit more than 40,400,000 tons of $CO_2$ annually. Of these 28 stations, eight are larger than 100 MW. The eight generating stations consist of 15 separate generating units, the characteristics of which are summarized in Table A-5 along with a map showing their locations within the state. The units vary in terms of boiler type, size, and existing pollution control equipment. The units all fire a subbituminous coal as the primary fuel and a significant number of the units are equipped with $SO_x$ control. In those instances where there is no $SO_x$ control, a WFGD unit was added to reduce the overall cost of $CO_2$ capture. The generating units vary in size from 100 MW (High Bridge 5) to 900 MW (Sherco 3). The total generation capacity of the units considered for $CO_2$ capture is 5241 MW. The $CO_2$ generated from these 15 units totals approximately 40,200,000 tons of $CO_2$ per year, roughly 99% of the $CO_2$ generated from all 28 generating stations in Minnesota.

The results from the model simulations (Table A-6) show an energy penalty of 34.5% for capturing 90% of the $CO_2$ emitted from these electricity-generating units. The cost associated with this energy requirement of 1808 MW is estimated at roughly \$5.3 billion (capital costs only), based on the average power cost of \$2936 per kW. The predicted trends in the power penalty and cost data (shown in Figure A-3) are similar to what was previously observed for other states/provinces, with the highest cost for $CO_2$ capture at the capture level of 10% (i.e., \$69 per ton) followed by a leveling of the costs at \$44 and \$41 per ton for capture rates of 50% and 90%, respectively, and the levelized costs ranging from \$207 million per year (for 10% $CO_2$ capture) to \$1414 million per year (for 90% capture).

At the highest rate of capture, there would be an estimated 37,660,000 tons of $CO_2$ captured, which is 93% of all the $CO_2$ produced by the 28 electricity-generating stations in Minnesota. Given that the total $CO_2$ produced in Minnesota is estimated at nearly 59,100,000 tons per year, a 90% $CO_2$ capture achieved from the >100 MW electricity-generating stations yields an overall $CO_2$ reduction of nearly 64% for the state. The total $CO_2$ capture cost required to achieve this reduction would be \$1.4 billion annually plus the additional cost of replacing the lost generation capacity.

**Table A-5. Location and Summary of Characteristics of Electricity-Generating Units (>100 MW) in Minnesota**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Sherburne County No. 1 | 18,003,648 | 750 | Subbitum. | T-fired | WFGD | C-ESP |
| Sherburne County No. 2 | | 750 | Subbitum. | T-fired | WFGD | C-ESP |
| Sherburne County No. 3 | | 900 | Subbitum. | W-fired | Dry lime | FF |
| Boswell Energy Center No. 1 | 8,107,209 | 364 | Subbitum. | T-fired | WFGD | C-ESP |
| Boswell Energy Center No. 2 | | 558 | Subbitum. | T-fired | FGD | C-ESP |
| Allen S. King No. 1 | 3,450,149 | 542 | Subbitum. | Cyclone | None | C-ESP |
| Allen S. King No. 2 | 1,856,715 | 230 | Subbitum. | NA | None | NA |
| Black Dog No. 2 | 2,125,518 | 140 | Subbitum. | FBC[2] | None | C-ESP |
| Black Dog No. 3 | | 110 | Subbitum. | W-fired | None | C-ESP |
| Black Dog No. 4 | | 185 | Subbitum. | W-fired | None | C-ESP |
| High Bridge No. 5 | 1,788,938 | 100 | Subbitum. | W-fired | None | C-ESP |
| High Bridge No. 6 | | 156 | Subbitum. | W-fired | None | C-ESP |
| Riverside | 2,257,109 | 216 | Subbitum. | Cyclone | None | C-ESP |
| Taconite Harbor Energy | 1,723,608 | 130 | Subbitum. | NA | None | NA |
| Syl Laskin | 958,729 | 110 | Subbitum. | T-fired | FGD | NA |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.
[2] FBC: fluidized-bed combustor.

**Table A-6. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Minnesota**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 40,272,000 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 4,027,200 | | 10,068,000 | | 20,136,000 | | 30,204,000 | | 36,244,800 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 5241 | | 5241 | | 5241 | | 5241 | | 5241 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 195 | | 488 | | 977 | | 1465 | | 1758 | |
| WFGD Use, MW | 6 | | 14 | | 28 | | 41 | | 50 | |
| Total Aux Load, MW | 201 | | 502 | | 1004 | | 1507 | | 1808 | |
| % of Gross Output | 3.8 | | 9.6 | | 19.2 | | 28.8 | | 34.5 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 82 | 20 | 91 | 9 | 106 | 5 | 121 | 4 | 130 | 3 |
| Total Levelized Annual Cost[a] | 207 | 69 | 435 | 50 | 811 | 44 | 1191 | 42 | 1414 | 41 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

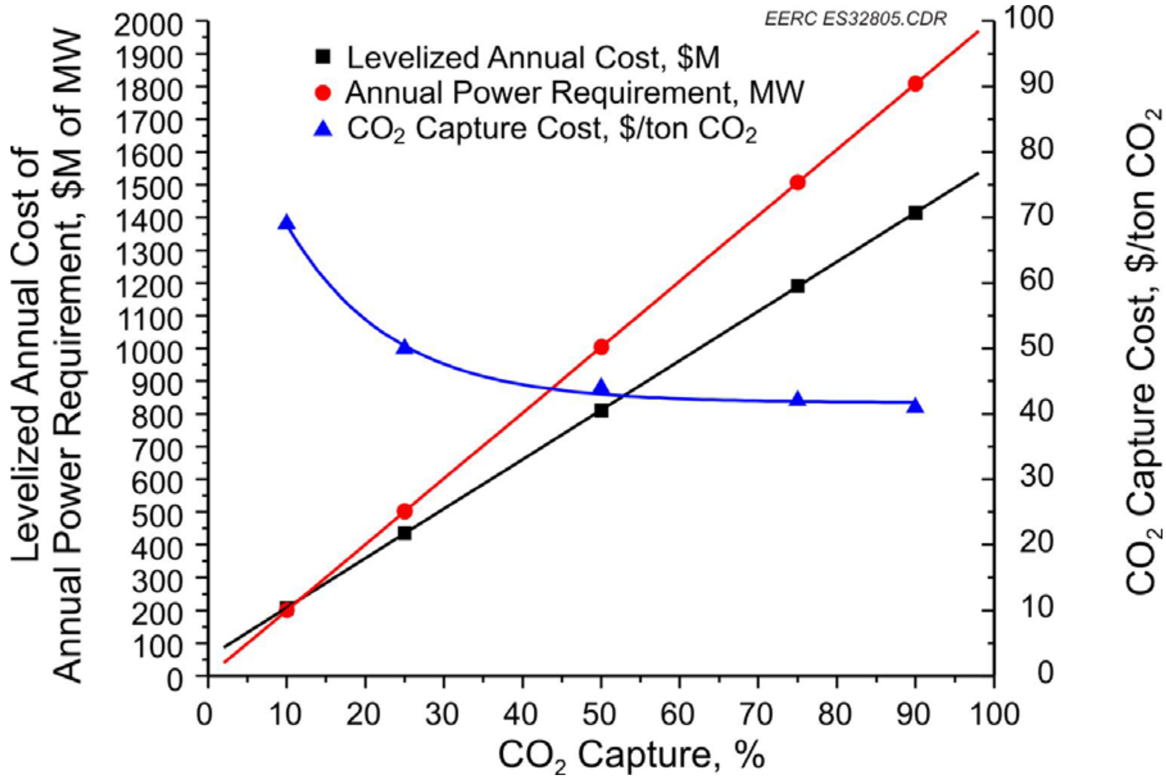



Figure A-3. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Minnesota.

**Missouri**

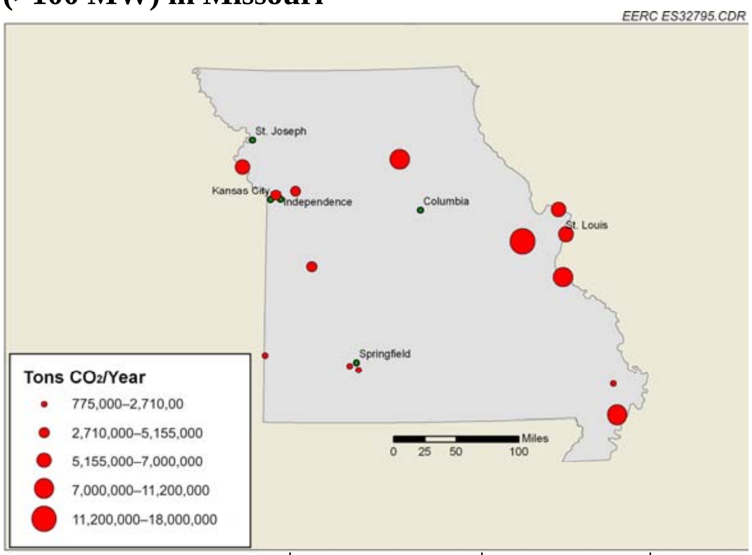
Missouri has 36 electricity-generating stations that emit more than 83,200,000 tons of $CO_2$ annually. Of these 36 stations, 14 are larger than 100 MW. These 14 generating stations consist of 27 separate generating units, the characteristics of which are summarized in Table A-7 along with a map showing their locations within the state.

The units vary in terms of boiler type and size and existing pollution control equipment. The units primarily fire a subbituminous coal as the primary fuel, with three stations burning a bituminous–subbituminous coal blend and one station burning pure bituminous coal. It was found that almost none of the units is equipped with any $SO_x$ control systems. In cases where there is no $SO_x$ control, a WFGD unit was added to reduce the overall cost of $CO_2$ capture. The units vary in size from 105 MW (James River 5) to 670 MW (Latan 1 and Thomas Hill 3). The total generation capacity of the units considered for $CO_2$ capture is 10,836 MW. The $CO_2$ generated from these 27 units totals approximately 79,030,000 tons of $CO_2$ per year, roughly 95% of the $CO_2$ generated from all 36 generating stations in the state (83,200,000 tons per year).

The results from the model simulations are summarized in Table A-8. These results show an energy penalty of 33.5% for capturing 90% of the $CO_2$ emitted from these units. The cost associated with this energy penalty of 3629 MW is estimated to be $10.6 billion (capital costs, only), based on an average power cost of $2936 per kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of $CO_2$ are presented in Figure A-4. The power penalty increases linearly with the percentage of carbon capture, increasing from 403 MW (3.7% of the total output of the units that are >100 MW) to 3629 MW (33.5% of the total output of the units that are >100 MW). This is shown in Figure A-4. The figure also shows that, at the same time, the cost of $CO_2$ capture decreases from $83/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $49 and $46 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $403 million to $2.75 billion.

At the highest rate of capture, there would be approximately 71,124,000 tons of $CO_2$ captured, which is roughly 85% of all the $CO_2$ produced by the 36 electricity-generating stations in Missouri. Given that the total $CO_2$ produced in the state from all sources is 97,600,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 73% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $2.8 billion annually plus the additional cost of replacing the lost generation capacity.

**Table A-7. Location and Summary of Characteristics of Electricity-Generating Units (>100 MW) in Missouri**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Labadie No. 1 | 17,458,154 | 574 | Subbitum. | T-fired | None | C-ESP |
| Labadie No. 2 | | 574 | Subbitum. | T-fired | None | C-ESP |
| Labadie No. 3 | | 621 | Subbitum. | T-fired | None | C-ESP |
| Labadie No. 4 | | 621 | Subbitum. | T-fired | None | C-ESP |
| Thomas Hill No. 1 | 8,692,178 | 180 | Subbitum. | Cyclone | None | C-ESP |
| Thomas Hill No. 2 | | 285 | Subbitum. | Cyclone | None | C-ESP |
| Thomas Hill No. 3 | | 670 | Subbitum. | W-fired | None | C-ESP |
| Rush Island No. 1 | 8,646,702 | 620 | Subbitum. | T-fired | None | C-ESP |
| Rush Island No. 2 | | 620 | Subbitum. | T-fired | None | C-ESP |
| New Madrid No. 1 | 7,757,564 | 600 | Subbitum. | Cyclone | None | C-ESP |
| New Madrid No. 2 | | 600 | Subbitum. | Cyclone | None | C-ESP |
| Meramec No. 1 | 6,628,037 | 138 | Bitum.–Sub. | T-fired | None | C-ESP |
| Meramec No. 2 | | 138 | Bitum.–Sub. | T-fired | None | C-ESP |
| Meramec No. 3 | | 289 | Bitum.–Sub. | F-fired[3] | None | C-ESP |
| Meramec No. 4 | | 360 | Bitum.–Sub. | F-fired | None | C-ESP |
| Sioux No. 1 | 6,273,478 | 550 | Bitum.–Sub. | Cyclone | None | C-ESP |
| Sioux No. 2 | | 550 | Bitum.–Sub. | Cyclone | None | C-ESP |
| Latan No. 1 | 5,397,589 | 670 | Subbitum. | W-fired | None | C-ESP |
| Hawthorn No. 5 | 4,532,076 | 476 | Subbitum. | T-fired | None | C-ESP |
| Montrose No. 1 | 3,803,834 | 170 | Subbitum. | T-fired | None | C-ESP |
| Montrose No. 2 | | 164 | Subbitum. | T-fired | None | C-ESP |
| Montrose No. 3 | | 176 | Subbitum. | T-fired | None | C-ESP |
| Sibley No. 3 | 3,167,591 | 411 | Subbitum. | Cyclone | None | C-ESP |
| Sikeston No. 1 | 2,246,389 | 261 | Subbitum. | W-fired | None | C-ESP |
| James River No. 5 | 1,647,963 | 105 | Bitum.[4] | W-fired | None | C-ESP |
| Asbury No. 1 | 1,604,015 | 213 | Bitum.–Sub. | Cyclone | None | C-ESP |
| Southwest-Springfield | 1,433,865 | 200 | Subbitum. | W-fired | FGD | C-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.
[2] Bitum.–Sub.: mix of bituminous and subbituminous coals.
[3] F-fired: front-fired.
[4] Bitum.: bituminous coal.

**Table A-8. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Missouri**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 79,027,084 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 7,902,708 | | 19,756,771 | | 39,513,542 | | 59,270,313 | | 71,124,375 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 10836 | | 10836 | | 10836 | | 10836 | | 10836 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 372 | | 930 | | 1861 | | 2792 | | 3350 | |
| WFGD Use, MW | 31 | | 78 | | 155 | | 233 | | 279 | |
| Total Aux Load, MW | 403 | | 1008 | | 2016 | | 3024 | | 3629 | |
| % of Gross Output | 3.7 | | 9.3 | | 18.6 | | 27.9 | | 33.5 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 251 | 32 | 298 | 15 | 377 | 10 | 456 | 8 | 503 | 7 |
| Total Levelized Annual Cost | 403 | 83 | 848 | 58 | 1548 | 49 | 2314 | 47 | 2752 | 46 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

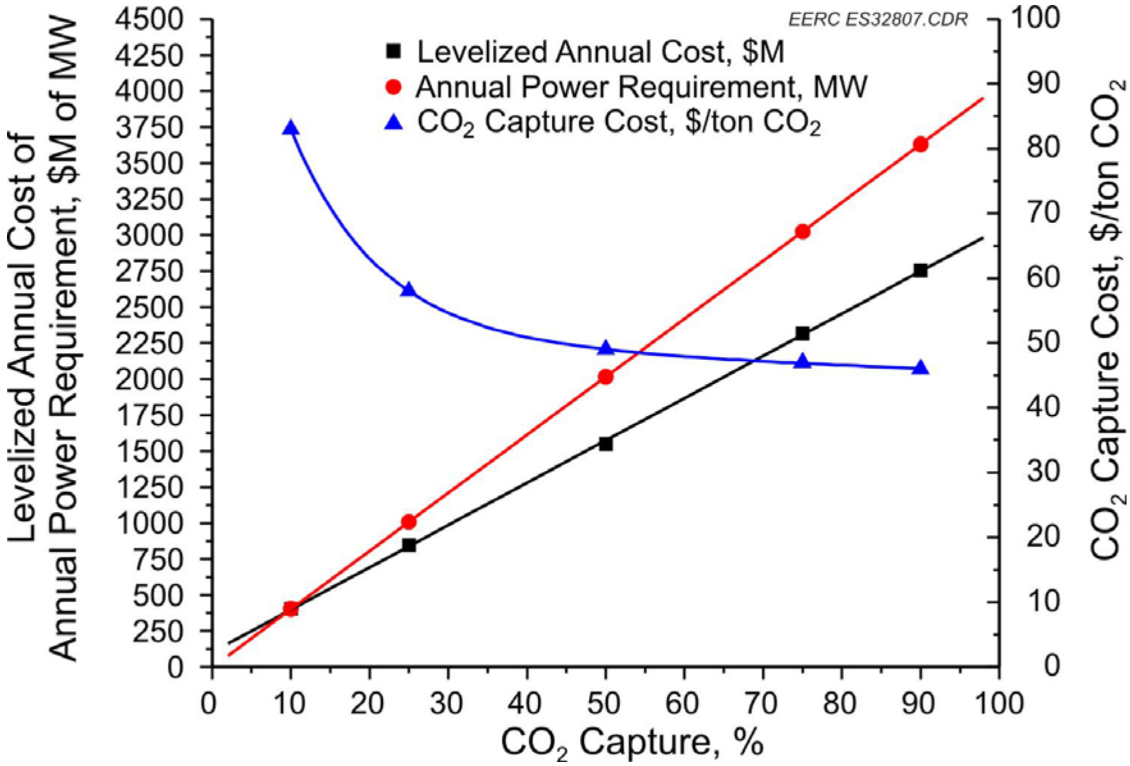



Figure A-4. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Missouri.

### Montana

Only the eastern half of Montana is contained in the PCOR Partnership region. In that area, Montana has six electricity-generating stations that emit more than 20,970,000 tons of $CO_2$ annually. Of these six stations, two are larger than 100 MW: Colstrip and J.E. Corette. The two generating stations consist of five separate generating units, the characteristics of which are summarized in Table A-9 along with a map showing their locations within the state. The units are the same in terms of boiler design and fuel type. All of the units, except the unit at the J.E. Corette Station, are equipped with $SO_x$ control equipment. As such, a WFGD unit was added to this unit to reduce the overall cost of capturing $CO_2$. The units vary in size from 191 MW (J.E. Corette) to 778 MW (Colstrip 3 and 4). The total generation capacity of the units considered for $CO_2$ capture is 2467 MW. The $CO_2$ generated from these five units is approximately 19,152,000 tons of $CO_2$ per year (20,105,280 tons per year), roughly 91% of the $CO_2$ generated from all six generating stations in Montana.

The results from the model simulations are summarized in Table A-10. These results indicate that there is an energy penalty of 34.4% associated with capturing 90% of the $CO_2$ emitted from these units. The cost penalty associated with this energy requirement of 849 MW is estimated at $2.5 billion (capital costs, only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of carbon dioxide are presented in Figure A-5. The power penalty increases linearly with the percentage of carbon capture, increasing from 95 MW (3.9% of the total output of the units that are >100 MW) to 849 MW (34.4% of the total output of the units that are >100 MW).

At the same time, the cost of $CO_2$ capture decreases from $49/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $37 and $36 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $89 to $635 million. It should be noted that the cost of $CO_2$ capture of $36 to $49 per ton of $CO_2$ captured is smaller than in the other states/provinces of the region. This is primarily due to the presence of $SO_2$ control equipment on four of the five units targeted for $CO_2$ capture, which represents about 92% of the total MW output of these five units.

At the highest rate of capture, there would be approximately 18,094,752 tons of $CO_2$ captured, which is roughly 86% of all the $CO_2$ produced by the six electricity-generating stations in Montana. Given that the total $CO_2$ produced in the state from all sources is about 23,700,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 76% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $635 million annually plus the additional cost of replacing the lost generation capacity.

**Table A-9. Location and Summary of Characteristics of Electricity-Generating (>100 MW) Units in Montana**

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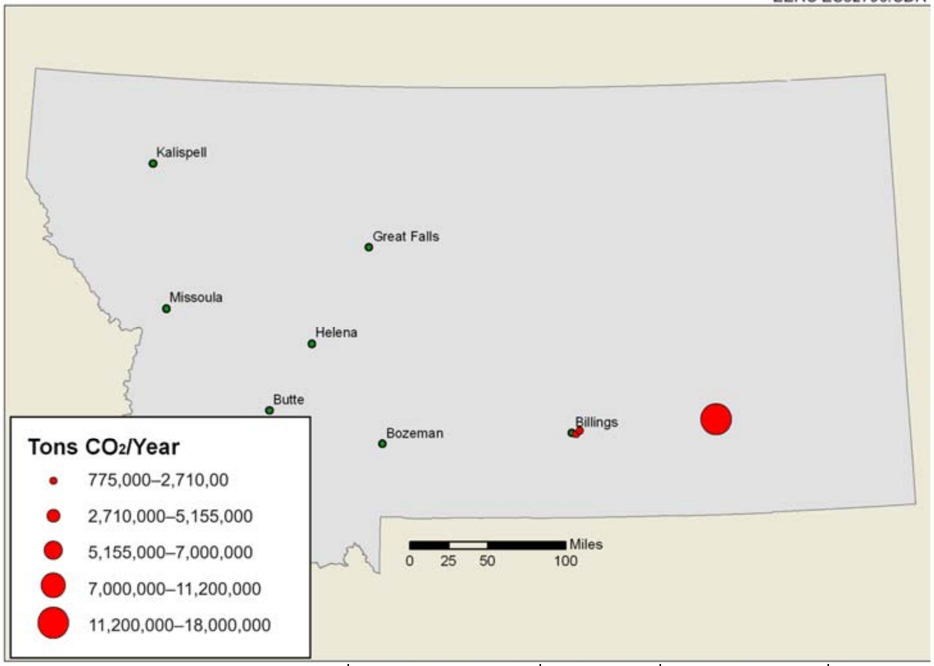



| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Colstrip No. 1 | 17,638,217 | 360 | Subbitum. | T-fired | WFGD | V-Scrub[2] |
| Colstrip No. 2 | | 360 | Subbitum. | T-fired | WFGD | V-Scrub |
| Colstrip No. 3 | | 778 | Subbitum. | T-fired | WFGD | V-Scrub |
| Colstrip No. 4 | | 778 | Subbitum. | T-fired | WFGD | V-Scrub |
| J.E. Corette | 1,514,122 | 191 | Subbitum. | T-fired | None | C-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.
[2] Venturi scrubber.

**Table A-10. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Montana**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 20,979,036 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 2,097,903 | | 5,244,759 | | 10,489,518 | | 15,734,277 | | 18,881,132 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 2467 | | 2467 | | 2467 | | 2467 | | 2467 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 94 | | 234 | | 469 | | 703 | | 843 | |
| WFGD Use, MW | 1 | | 2 | | 3 | | 5 | | 6 | |
| Total Aux Load, MW | 95 | | 236 | | 472 | | 708 | | 849 | |
| % of Gross Output | 3.9 | | 9.6 | | 19.1 | | 28.7 | | 34.4 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 9 | 4 | 10 | 2 | 12 | 1 | 13 | 1 | 14 | 1 |
| Total Levelized Annual Cost | 89 | 49 | 190 | 40 | 362 | 37 | 536 | 36 | 635 | 36 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

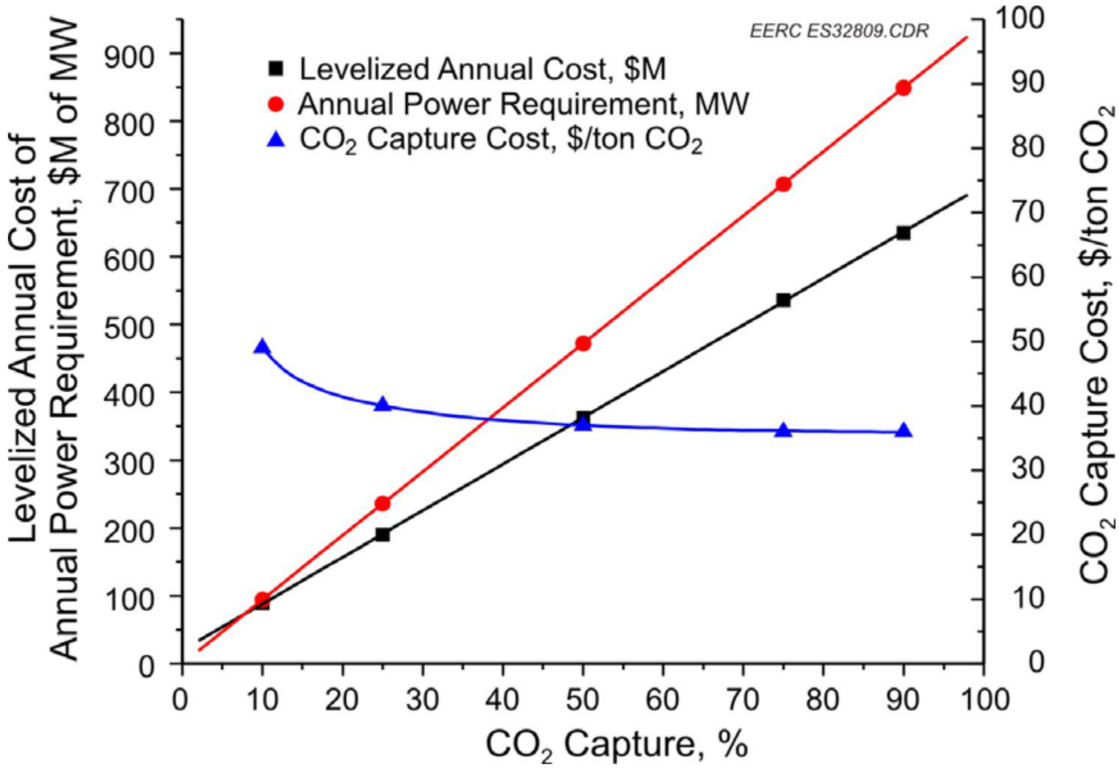



Figure A-5. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Montana.

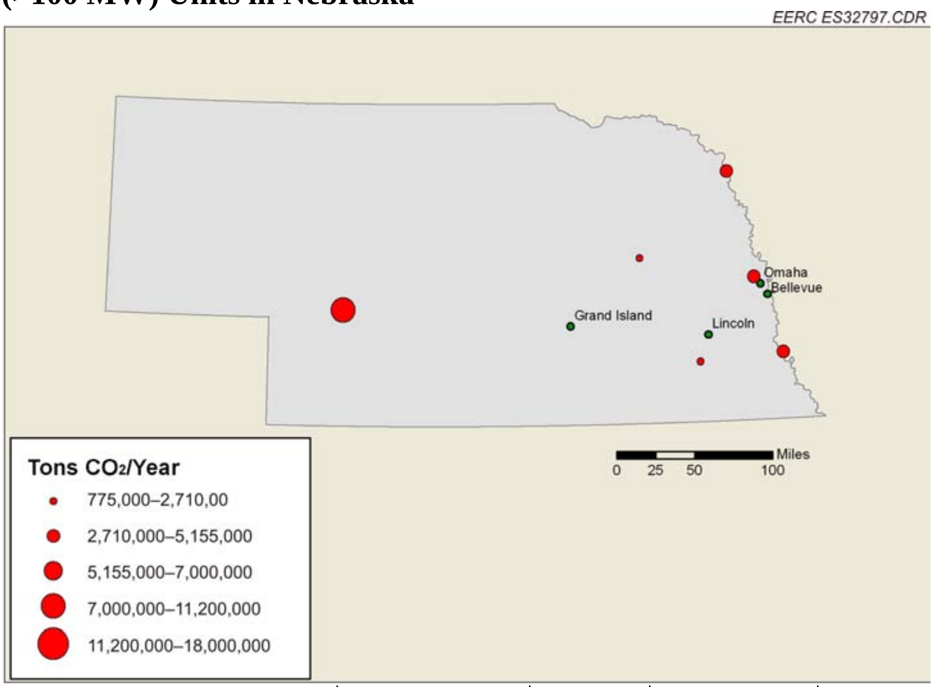
**Nebraska**

Nebraska has 12 electricity-generating stations that emit approximately 23,300,000 tons of $CO_2$ annually. Of these 12 stations, five are larger than 100 MW. The five generating stations consist of ten separate generating units, the characteristics of which are summarized in Table A-11 along with a map showing their locations within the state. None of the units is equipped with $SO_x$ control equipment, requiring the addition of WFGD to each of the units to reduce the overall cost of $CO_2$ capture. The units in Nebraska vary in size from 100 MW (North Omaha 2 and 3) to 711 MW (Gerald Gentleman Station 1). The total power generation capacity of the units considered for $CO_2$ capture in the state of Nebraska was 2819 MW. The $CO_2$ generated from these ten units totals approximately 22,753,000 original tons of $CO_2$ per year, or roughly 86% of the $CO_2$ generated from all 12 generating stations in the state.

The results from the model simulations are summarized in Table A-12. These results indicate that there is an energy penalty of 35.9% associated with capturing 90% of the $CO_2$ emitted from these units. The cost associated with this energy penalty of 1012 MW is estimated to be approximately $3.0 billion (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of $CO_2$ are presented in Figure A-6. The power penalty increases linearly with the percentage of carbon capture, increasing from 113 MW (4.0% of the total output of the units that are >100 MW) to 1012 MW (35.9% of the total output of the units that are >100 MW). At the same time, the cost of $CO_2$ capture decreases from $96/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $49 and $48 per ton of $CO_2$ captured for capture rates of 75% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $119 (10% capture) to $784 million (90% capture).

At the highest rate of capture, there would be approximately 19,990,000 tons of $CO_2$ captured, which is roughly 85% of all the $CO_2$ produced by the 12 electricity-generating stations in Nebraska. Given that the total $CO_2$ produced in the state from all sources is 30,990,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 64.5% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $784 million annually plus the additional cost of replacing the lost generation capacity.

**Table A-11. Location and Summary of Characteristics of Electricity-Generating (>100 MW) Units in Nebraska**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Gerald Gentleman Station No. 1 | 11,192,809 | 711 | Subbitum. | Dry bottom | None | H-ESP |
| Gerald Gentleman Station No. 2 | | 654 | Subbitum. | Dry bottom | None | NA |
| Nebraska City No. 1 | 4,703,184 | 565 | Subbitum. | W-fired | None | C-ESP |
| North Omaha No. 2 | | 100 | Subbitum. | T-fired | None | C-ESP |
| North Omaha No. 3 | | 100 | Subbitum. | T-fired | None | C-ESP |
| North Omaha No. 4 | | 125 | Subbitum. | T-fired | None | C-ESP |
| North Omaha No. 5 | | 200 | Subbitum. | W-fired | None | C-ESP |
| Sheldon No. 1 | 1,895,755 | 119 | Subbitum. | Cyclone | None | H-ESP |
| Sheldon No. 2 | | 136 | Subbitum. | Cyclone | None | H-ESP |
| Platte No. 1 | 895,952 | 109 | Subbitum. | T-fired | None | H-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-12. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Nebraska**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 22,211,654 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 2,221,165 | | 5,552,914 | | 11,105,827 | | 16,658,741 | | 19,990,481 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 2819 | | 2819 | | 2819 | | 2819 | | 2819 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 104 | | 259 | | 518 | | 776 | | 932 | |
| WFGD Use, MW | 9 | | 22 | | 44 | | 67 | | 80 | |
| Total Aux Load, MW | 113 | | 281 | | 562 | | 843 | | 1012 | |
| % of Gross Output | 4.0 | | 10.0 | | 19.9 | | 29.9 | | 35.9 | |
| Cost of Capture | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ | $M/yr | $/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 93 | 42 | 107 | 19 | 130 | 12 | 153 | 9 | 167 | 8 |
| Total Levelized Annual Cost[a] | 119 | 96 | 247 | 64 | 458 | 53 | 664 | 49 | 784 | 48 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

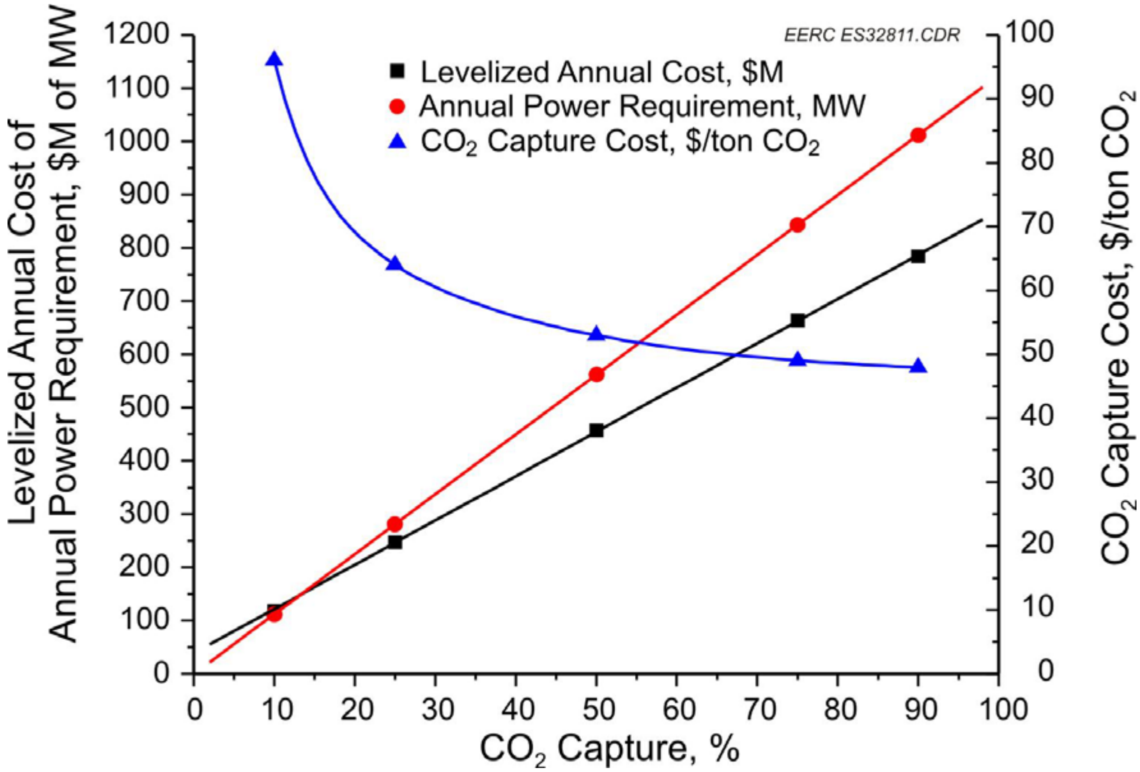



Figure A-6. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Nebraska.

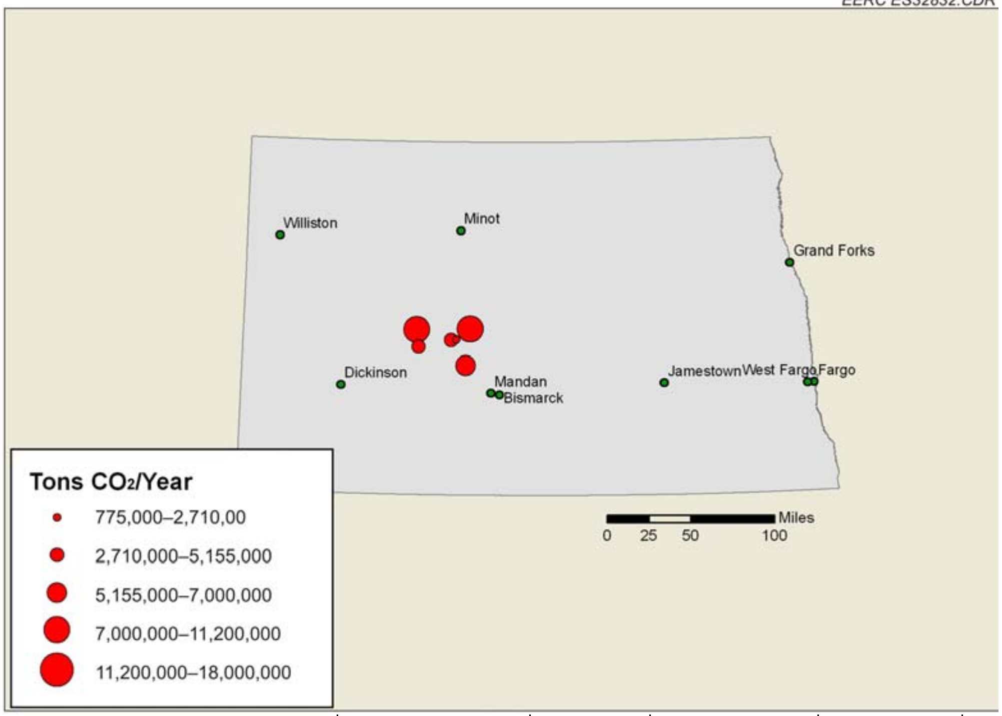
**North Dakota**

North Dakota has seven electricity-generating stations that emit approximately 35,950,000 tons of $CO_2$ annually. Of these seven stations, six are larger than 100 MW. The six generating stations consist of ten separate generating units, the characteristics of which are summarized in Table A-13 along with a map showing their locations within the state. In those instances where a generating unit has no $SO_x$ control, a WFGD unit was added to reduce the overall cost of $CO_2$ capture. Compared to the other states and provinces in the PCOR partnership region, the electricity-generating units in North Dakota are different in that they burn lignite rather than subbituminous or bituminous coal. The units in North Dakota vary in size from 140 MW (Stanton 1) to 547 MW (Coal Creek Unit 2). The total generation capacity of the units considered for $CO_2$ capture in the state of North Dakota was 3843 MW. The $CO_2$ generated from these ten units is approximately 35,274,145 tons of $CO_2$ per year, roughly 98% of the $CO_2$ generated from all seven generating stations in North Dakota.

The results from the model simulations are summarized in Table A-14. These results indicate that there is an energy penalty of 47.2% associated with capturing 90% of the $CO_2$ emitted from these units. This is one of the highest energy penalties of all of the states and provinces and is due largely to the fuel that is burned in these units. Lignite produces more $CO_2$ per Btu of coal, contains more moisture, and generates a larger volume of flue gas. These factors, combined with the unit configurations, result in a high energy penalty for the MEA $CO_2$ absorption system. The cost penalty associated with this energy requirement of 1815 MW is estimated at approximately $5.3 billion (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of $CO_2$ is presented in Figure A-7. The power penalty increases linearly with the percentage of carbon capture, increasing from 202 MW (5.3% of the total output of the units that are >100 MW) to 1815 MW (47.2% of the total output of the units that are >100 MW). At the same time, the cost of $CO_2$ capture decreases from $74/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $52 and $51 per ton of $CO_2$ captured for capture rates of 75% and 90%, respectively while the levelized annual cost, not including the cost of replacement power, increases from $206 million (10% capture) to $1.52 billion (90% capture).

At the highest rate of capture, there would be approximately 31,700,000 tons of $CO_2$ captured, which is roughly 88% of all the $CO_2$ produced by the seven electricity-generating stations in North Dakota. Given that the total $CO_2$ produced in the state from all sources is about 41,800,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 76% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $1.52 billion annually, plus the additional cost of replacing the lost generation capacity.

**Table A-13. Location and Summary of Characteristics of Electricity-Generating (>100 MW) in North Dakota**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Coal Creek No. 1 | 11,094,478 | 506 | Lignite | T-fired | WFGD | ESP |
| Coal Creek No. 2 | | 547 | Lignite | T-fired | WFGD | ESP |
| Antelope Valley B1 | 8,696,067 | 435 | Lignite | T-fired | DFGD | FF |
| Antelope Valley B2 | | 435 | Lignite | T-fired | DFGD | FF |
| Milton R. Young B1 | 5,862,979 | 235 | Lignite | Cyclone | None | ESP |
| Milton R. Young B2 | | 439 | Lignite | Cyclone | WFGD | ESP |
| Leland Olds No. 1 | 4,808,205 | 216 | Lignite | W-fired | None | ESP |
| Leland Olds No. 2 | | 440 | Lignite | Cyclone | None | ESP |
| Coyote | 3,658,089 | 450 | Lignite | Cyclone | DFGD | FF |
| Stanton No. 1 | 1,338,838 | 140 | Lignite | W-fired | None | ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-14. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in North Dakota**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 35,274,145 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 3,527,415 | | 8,818,536 | | 17,637,073 | | 26,455,609 | | 31,746,733 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 3843 | | 3843 | | 3843 | | 3843 | | 3843 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 197 | | 492 | | 985 | | 1477 | | 1772 | |
| WFGD Use, MW | 5 | | 12 | | 24 | | 36 | | 43 | |
| Total Aux Load, MW | 202 | | 504 | | 1008 | | 1512 | | 1815 | |
| % of Gross Output | 5.3 | | 13.1 | | 26.2 | | 39.3 | | 47.2 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 57 | 16 | 67 | 8 | 83 | 5 | 100 | 4 | 110 | 3 |
| Total Levelized Annual Cost[a] | 206 | 74 | 447 | 58 | 863 | 54 | 1264 | 52 | 1519 | 51 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

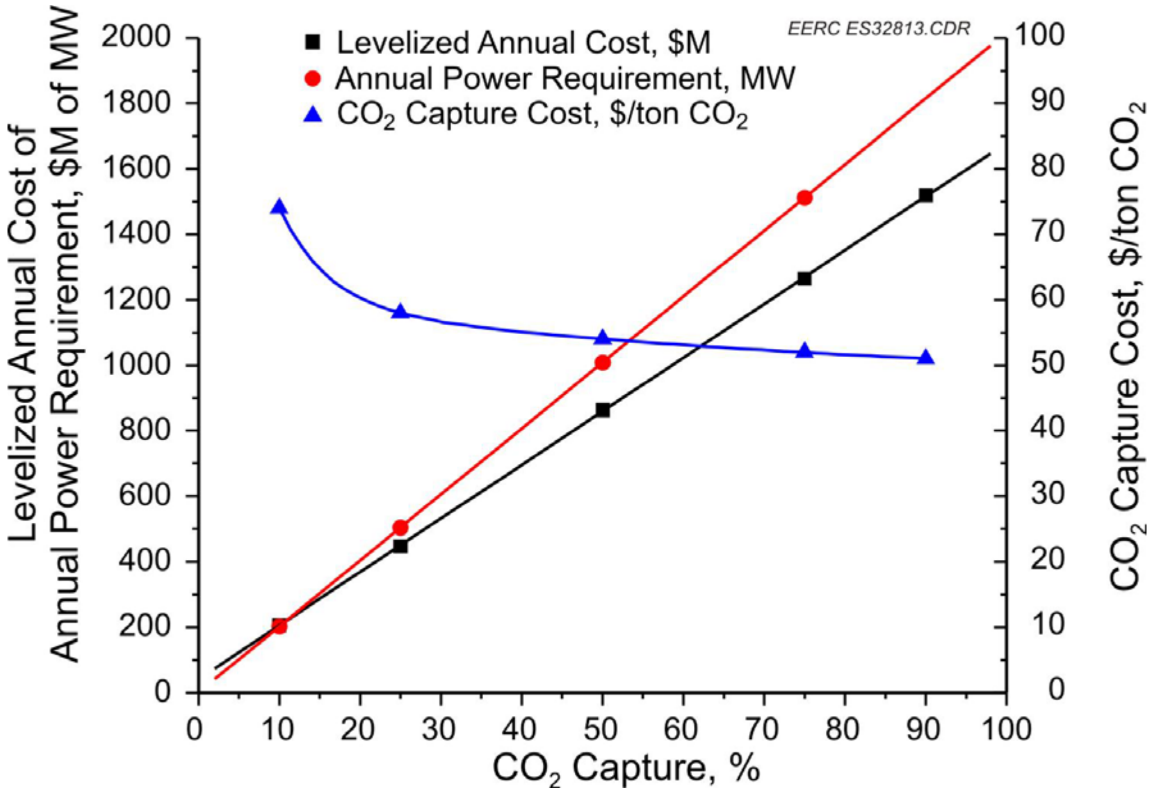



Figure A-7. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in North Dakota.

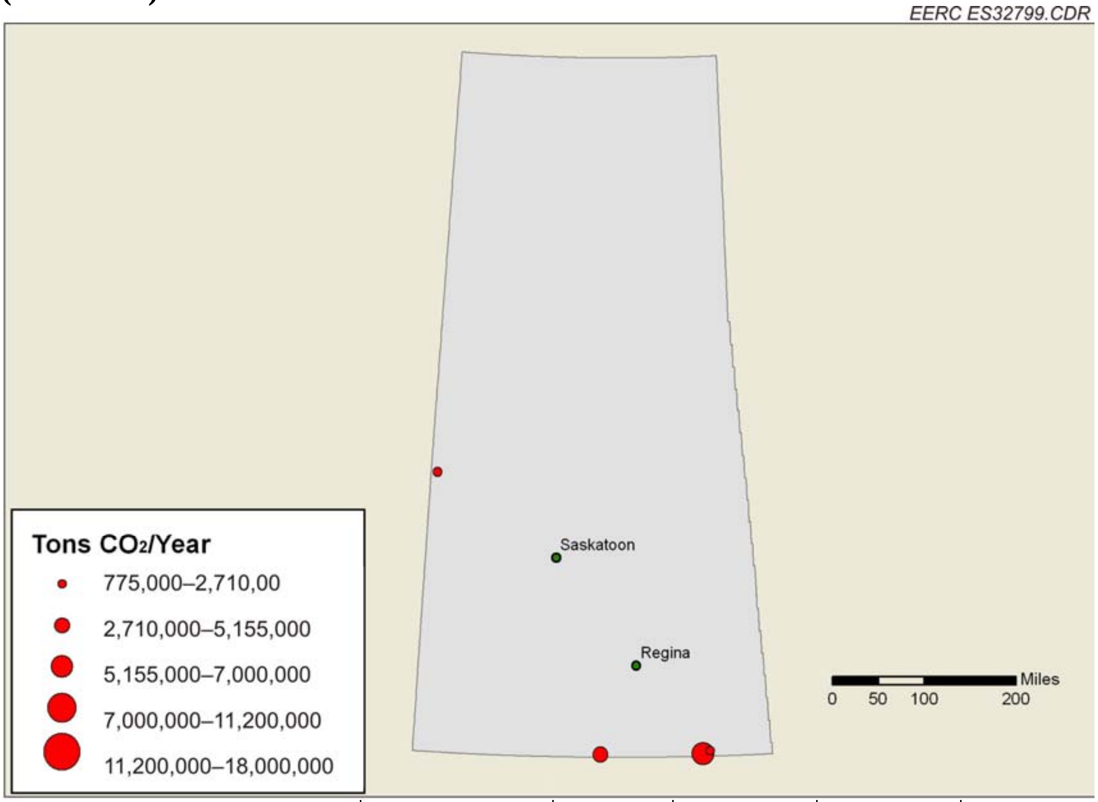
**Saskatchewan**

Saskatchewan contains six electricity-generating stations that emit approximately 15,100,000 tons of $CO_2$ annually. Of these six stations, four are larger than 100 MW and consist of eight separate generating units, the characteristics of which are summarized in Table A-15 along with a map showing their locations within the province. In cases where there is no $SO_x$ control, WFGD was added to reduce the overall cost of $CO_2$ capture. Electricity-generating stations in Saskatchewan, similar to those in North Dakota, burn lignite rather than subbituminous and bituminous coal. The units in Saskatchewan vary in size from 100 MW (Meridian) to 293 MW (Boundary Dam Station 6). The total generation capacity of the units considered for $CO_2$ capture in the province of Saskatchewan is 1684 MW. The $CO_2$ generated from these eight generating units is approximately 14,200,000 tons of $CO_2$ per year, roughly 94% of the $CO_2$ generated from all six generating stations in the province.

The results from the model simulations are summarized in Table A-16. These results indicate that there is an energy penalty of 38.5% associated with capturing 90% of the $CO_2$ emitted from these units. This energy penalty is similar to that predicted for North Dakota, reflecting the unique characteristics of lignite coal as it relates to carbon dioxide generation and capture. The cost associated with this energy requirement of 648 MW is estimated at approximately $1.9 billion (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of carbon dioxide is presented in Figure A-8. The power penalty increases linearly with the percentage of carbon capture, increasing from 72 MW (4.3% of the total output of the units that are >100 MW) to 648 MW (38.5% of the total output of the units that are >100 MW). At the same time, the cost of $CO_2$ capture decreases from $112/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $59 and $53 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $87 million (10% capture) to $558 million (90% capture).

At the highest rate of capture, there would be approximately 12,800,000 tons of $CO_2$ captured, which is roughly 88.2% of all the $CO_2$ produced by the six electricity-generating stations in Saskatchewan. Given that the total $CO_2$ produced in the province from all sources is 22,400,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 57% for the entire province. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $558 million annually, plus the additional cost of replacing the lost generation capacity.

**Table A-15. Location and Summary of Characteristics of Electricity-Generating (>100 MW) Units in Saskatchewan**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Boundary Dam Station No. 3 | 6,570,850 | 150 | Lignite | T-fired | None | C-ESP |
| Boundary Dam Station No. 4 | | 150 | Lignite | T-fired | None | C-ESP |
| Boundary Dam Station No. 5 | | 150 | Lignite | T-fired | None | C-ESP |
| Boundary Dam Station No. 6 | | 293 | Lignite | T-fired | None | C-ESP |
| Poplar River Station No. 1 | 4,401,400 | 281 | Lignite | T-fired | None | C-ESP |
| Poplar River Station No. 2 | | 281 | Lignite | W-fired | None | C-ESP |
| Shand Power Station | 2,226,250 | 279 | Lignite | W-fired | None | C-ESP |
| Meridian Generating Facility | 843,997 | 100 | Lignite | NA | None | C-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-16. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Saskatchewan**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 14,230,697 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 1,423,070 | | 3,557,674 | | 7,115,349 | | 10,673,023 | | 12,807,627 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 1684 | | 1684 | | 1684 | | 1684 | | 1684 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 66 | | 166 | | 332 | | 497 | | 597 | |
| WFGD Use, MW | 6 | | 14 | | 28 | | 43 | | 51 | |
| Total Aux Load, MW | 72 | | 180 | | 360 | | 540 | | 648 | |
| % of Gross Output | 4.3 | | 10.7 | | 21.4 | | 32.1 | | 38.5 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 73 | 51 | 82 | 23 | 96 | 13 | 110 | 10 | 119 | 9 |
| Total Levelized Annual Cost[a] | 87 | 112 | 179 | 73 | 321 | 59 | 463 | 54 | 558 | 53 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

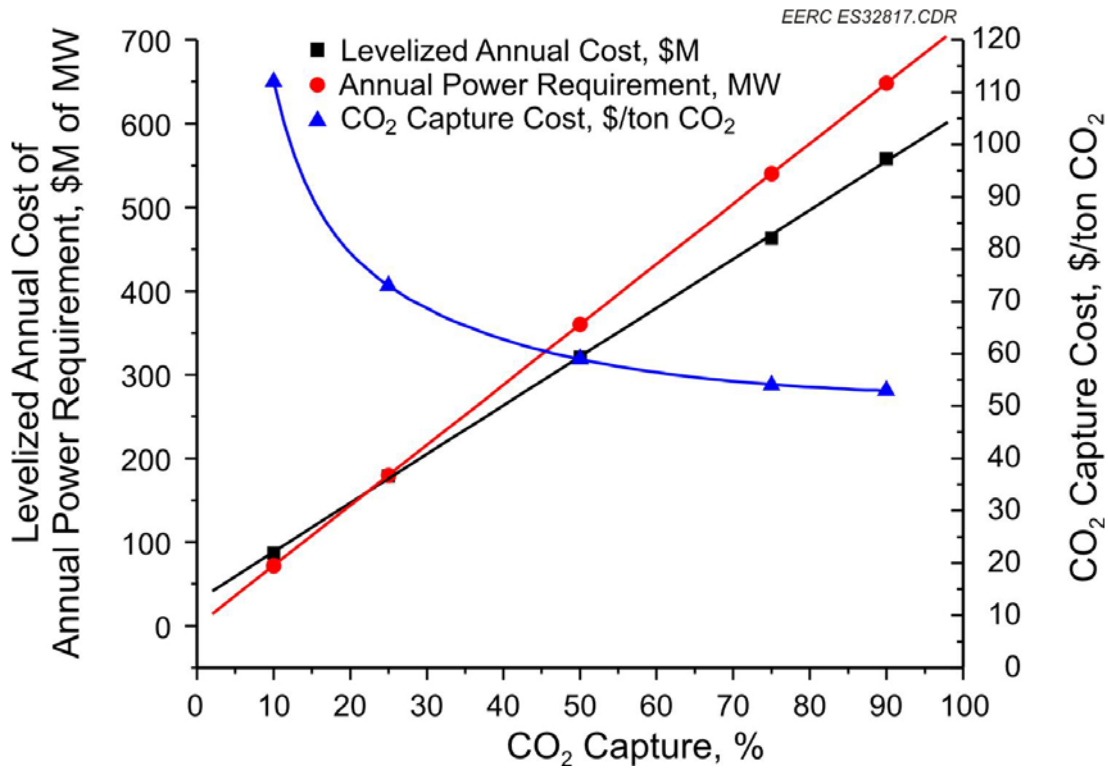



Figure A-8. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Saskatchewan.

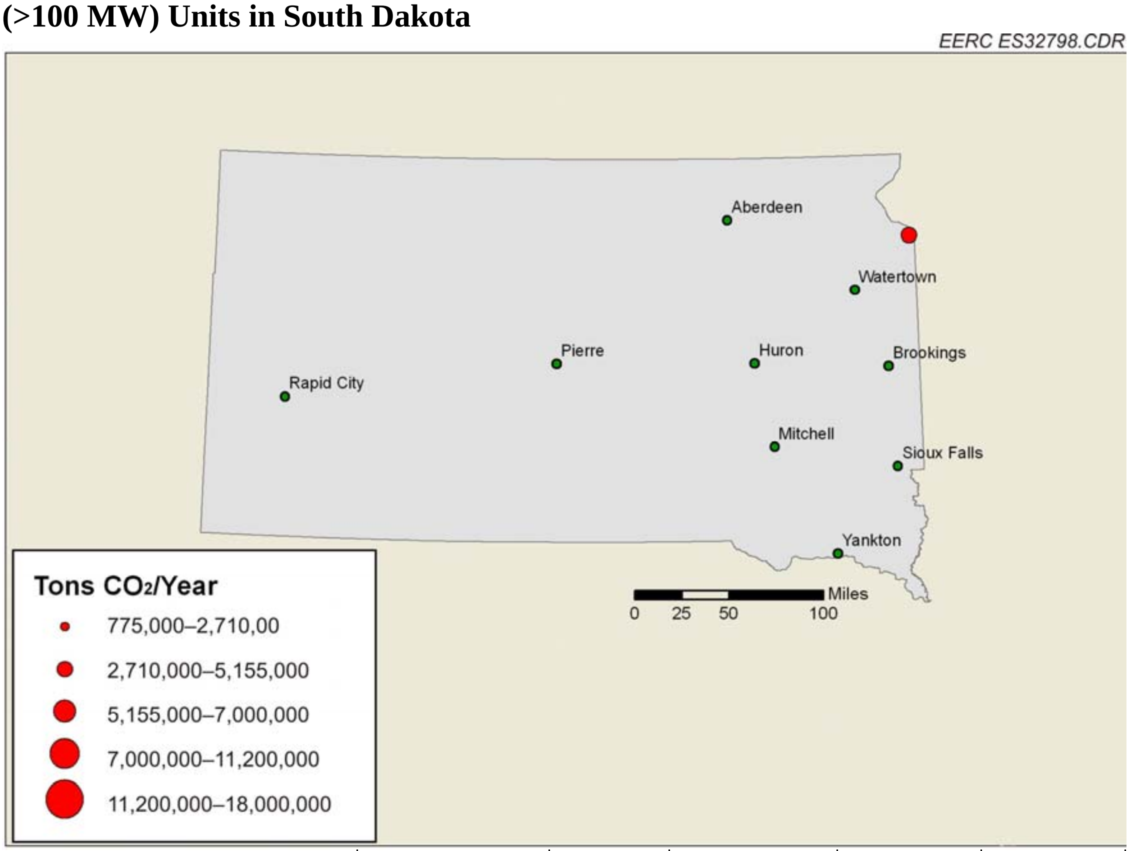
**South Dakota**

South Dakota contains three electricity-generating stations that emit approximately 4,160,000 tons of $CO_2$ annually. Of these three stations, one is larger than 100 MW. This generating station is known as the Big Stone Station and is located on the border of South Dakota and Minnesota. The unit has a 450-MW capacity and is equipped with a cyclone boiler with a C-ESP for PM control. The unit is not equipped with $SO_x$ control, and therefore, WFGD was added to reduce the overall cost of $CO_2$ capture. The characteristics of this unit are presented in Table A-17 along with a map showing its location within the state. The $CO_2$ generated from the Big Stone Station is approximately 3,780,000 tons per year, roughly 91% of the $CO_2$ generated from all three generating stations in the state.

The results from the model simulation are summarized in Table A-18. These results indicate that there is an energy penalty of 38% associated with capturing 90% of the $CO_2$ emitted from this unit. The cost penalty associated with this energy requirement of 171 MW is estimated at approximately $502 million (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of $CO_2$ are presented in Figure A-9. The power penalty increases linearly with the percentage of carbon capture, increasing from 19 MW (4.2% of the total output of the station) to 171 MW (38% of the total output of the station). At the same time, the cost of $CO_2$ capture decreases from $73/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $45 and $43 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $17 million (10% capture) to $122 million (90% capture).

At the highest rate of capture, there would be approximately 3,375,000 tons of $CO_2$ captured, which is roughly 81% of all the $CO_2$ produced by the three electricity-generating stations in South Dakota. Given that the total $CO_2$ produced in the state from all sources is about 17,200,000 tons per year, capturing 90% of the Big Stone Station's $CO_2$ would yield an overall $CO_2$ reduction of nearly 20% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $122 million annually, plus the additional cost of replacing the lost generation capacity.

**Table A-17. Location and Summary of Characteristics of Electricity-Generating (>100 MW) Units in South Dakota**




| Unit ID | $CO_2$ Emissions, tons/year | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Big Stone | 3,784,492 | 450 | Subbitum. | Cyclone | None | C-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-18. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in South Dakota**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 35,274,145 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 3,527,415 | | 8,818,536 | | 17,637,073 | | 26,455,609 | | 31,746,733 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 3843 | | 3843 | | 3843 | | 3843 | | 3843 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 197 | | 492 | | 985 | | 1477 | | 1772 | |
| WFGD Use, MW | 5 | | 12 | | 24 | | 36 | | 43 | |
| Total Aux Load, MW | 202 | | 504 | | 1008 | | 1512 | | 1815 | |
| % of Gross Output | 5.3 | | 13.1 | | 26.2 | | 39.3 | | 47.2 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 57 | 16 | 67 | 8 | 83 | 5 | 100 | 4 | 110 | 3 |
| Total Levelized Annual Cost[a] | 206 | 74 | 447 | 58 | 863 | 54 | 1264 | 52 | 1519 | 51 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

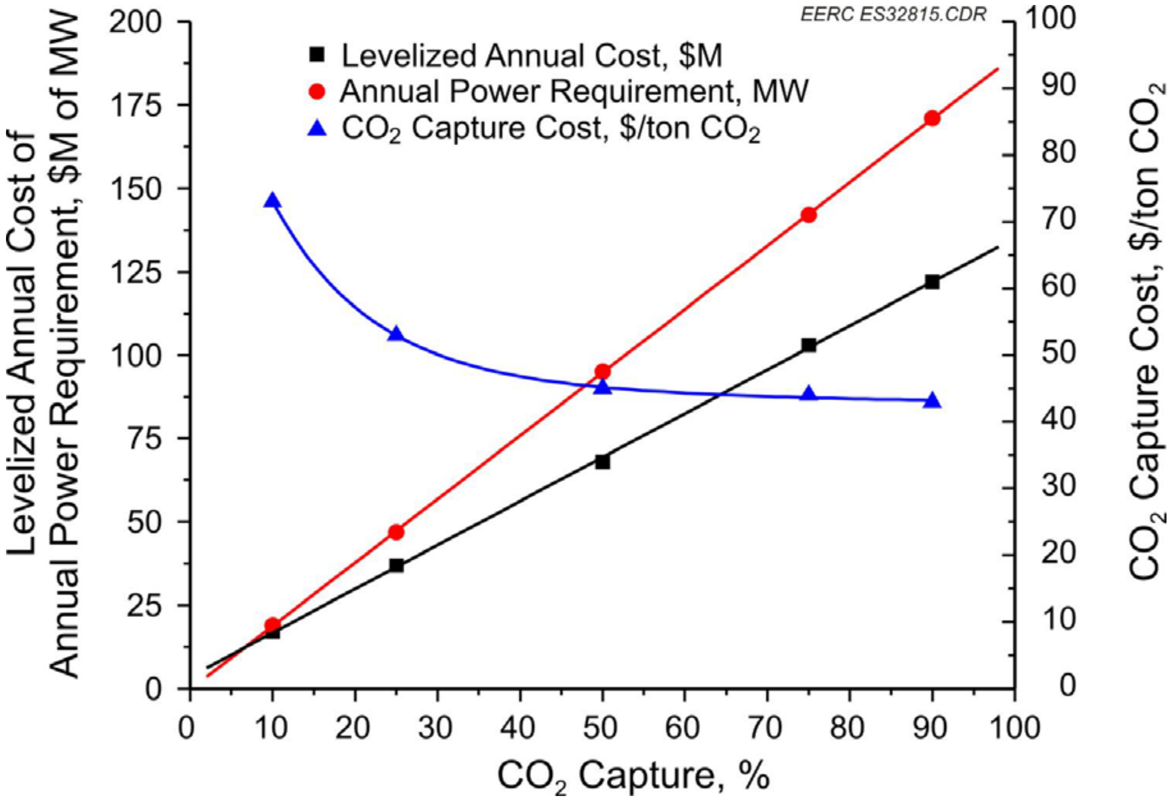



Figure A-9. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in South Dakota.

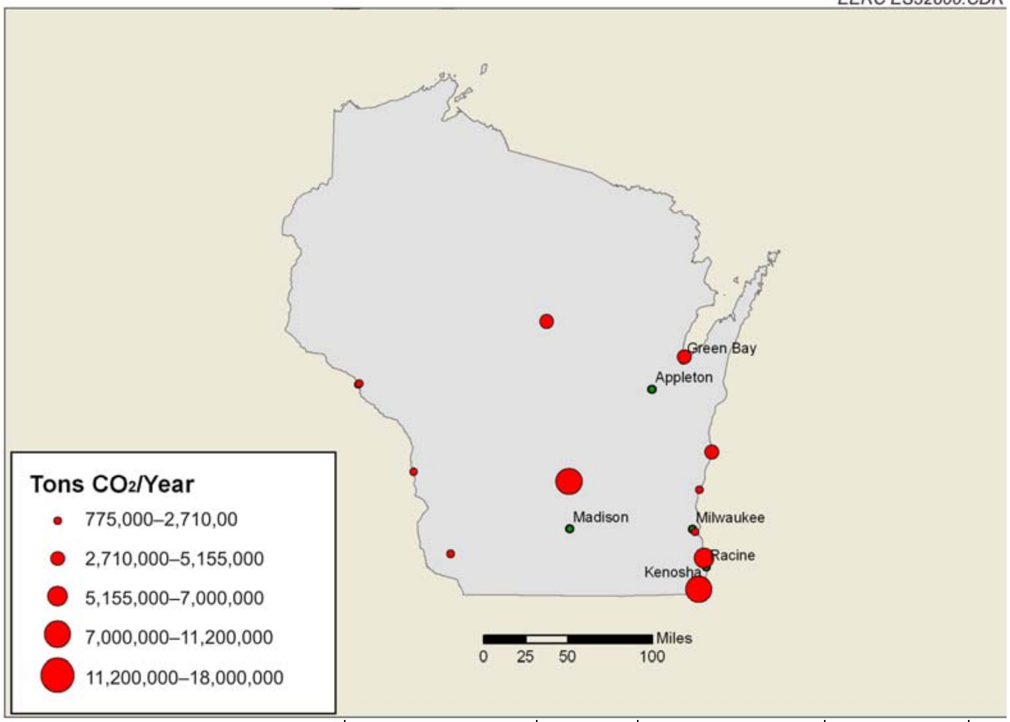
**Wisconsin**

Wisconsin has 35 electricity-generating stations that emit approximately 49,200,000 tons of $CO_2$ nnually. Of these 35 stations, 12 are larger than 100 MW. These 12 generating stations consist of 20 separate generating units, the characteristics of which are summarized in Table A-19 along with a map showing their location within the state. In cases where there is no $SO_x$ control, WFGD was added to reduce the overall cost of $CO_2$ capture. The electricity-generating stations in Wisconsin use either subbituminous or bituminous coals or blends of these coals. These units vary in size from 100 MW (Alma) to 1234 MW (Pleasant Prairie Station Units 1 and 2). The total generation capacity of the units considered for $CO_2$ capture is 6070 MW. The $CO_2$ generated from these 20 units totals approximately 47,900,000 tons of $CO_2$ per year, roughly 97% of the $CO_2$ generated from all 35 generating stations in Wisconsin.

The results from the model simulations are summarized in Table A-20. These results indicate that there is an energy penalty of 33.7% associated with capturing 90% of the $CO_2$ emitted from these units. The cost penalty associated with this energy requirement of 2048 MW is estimated to be approximately $6.0 billion (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of $CO_2$ are presented in Figure A-10. The power penalty increases linearly with the percentage of carbon capture, increasing from 243 MW (4.0% of the total output of the units that are >100 MW) to 2048 MW (33.7% of the total output of the units that are >100 MW). At the same time, the cost of $CO_2$ capture decreases from $88/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $49 and $45 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $245 million (10% capture) to $1.6 billion (90% capture).

At the highest rate of capture, there would be approximately 43,100,000 tons of $CO_2$ captured, which is roughly 88% of all the $CO_2$ produced by the 35 electricity-generating stations in Wisconsin. Given that the total $CO_2$ produced in the state from all sources is 85,100,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 51% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $1.6 billion annually, plus the additional cost of replacing the lost generation capacity.

**Table A-19. Location and Summary of Characteristics of Electricity-Generating Units (>100 MW) in Wisconsin**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type[2] | Boiler Type[3] | $SO_2$ Control | PM Control[4] |
|---|---|---|---|---|---|---|
| Pleasant Prairie No. 1 | 9,078,811 | 617 | Subbitum. | W-fired | None | C-ESP |
| Pleasant Prairie No. 2 | | 617 | Subbitum. | W-fired | None | C-ESP |
| Columbia No. 1 | 7,912,253 | 512 | Subbitum. | T-fired | None | H-ESP |
| Columbia No. 2 | | 511 | Subbitum. | T-fired | None | C-ESP |
| South Oak Creek No. 5 | 6,505,811 | 275 | Bitum.–Sub. | W-fired | None | C-ESP |
| South Oak Creek No. 6 | | 275 | Bitum.–Sub. | W-fired | None | C-ESP |
| South Oak Creek No. 7 | | 318 | Bitum.–Sub. | T-fired | None | C-ESP |
| South Oak Creek No. 8 | | 314 | Bitum.–Sub. | T-fired | None | C-ESP |
| Edgewater No. 4 | 5,103,545 | 330 | Subbitum. | Cyclone | None | C-ESP |
| Edgewater No. 5 | | 380 | Subbitum. | W-fired | None | C-ESP |
| Weston No. 3 | 4,795,936 | 350 | Subbitum. | T-fired | None | H-ESP |
| Pulliam No. 8 | 2,988,738 | 136 | Subbitum. | W-fired | None | C-ESP |
| J.P. Madgett | 2,712,763 | 387 | Subbitum. | W-fired | None | H-ESP |
| Genoa | 2,292,069 | 346 | Bitum. | T-fired | None | C-ESP |
| Valley No. 1 | 1,938,648 | 136 | Bitum. | F-fired | None | FF |
| Valley No. 3 | | 136 | Bitum. | F-fired | None | FF |
| Nelson Dewey No. 1 | 1,796,376 | 100 | Bitum.–Sub. | Cyclone | None | H-ESP |
| Nelson Dewey No. 2 | | 100 | Bitum.–Sub. | Cyclone | None | H-ESP |
| Port Washington | 1,057,002 | 130 | Bitum. | NA[5] | None | NA |
| Alma | 813,275 | 100 | Subbitum. | NA | None | NA |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-20. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Wisconsin**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 47,909,654 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 4,790,965 | | 11,977,414 | | 23,954,827 | | 35,932,241 | | 43,118,689 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 6070 | | 6070 | | 6070 | | 6070 | | 6070 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 224 | | 525 | | 1050 | | 1574 | | 1889 | |
| WFGD Use, MW | 19 | | 44 | | 88 | | 132 | | 158 | |
| Total Aux Load, MW | 243 | | 569 | | 1138 | | 1706 | | 2048 | |
| % of Gross Output | 4.0 | | 9.4 | | 18.7 | | 28.1 | | 33.7 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 179 | 37 | 207 | 17 | 254 | 11 | 301 | 8 | 329 | 8 |
| Total Levelized Annual Cost[a] | 245 | 88 | 512 | 60 | 924 | 49 | 1374 | 47 | 1632 | 45 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

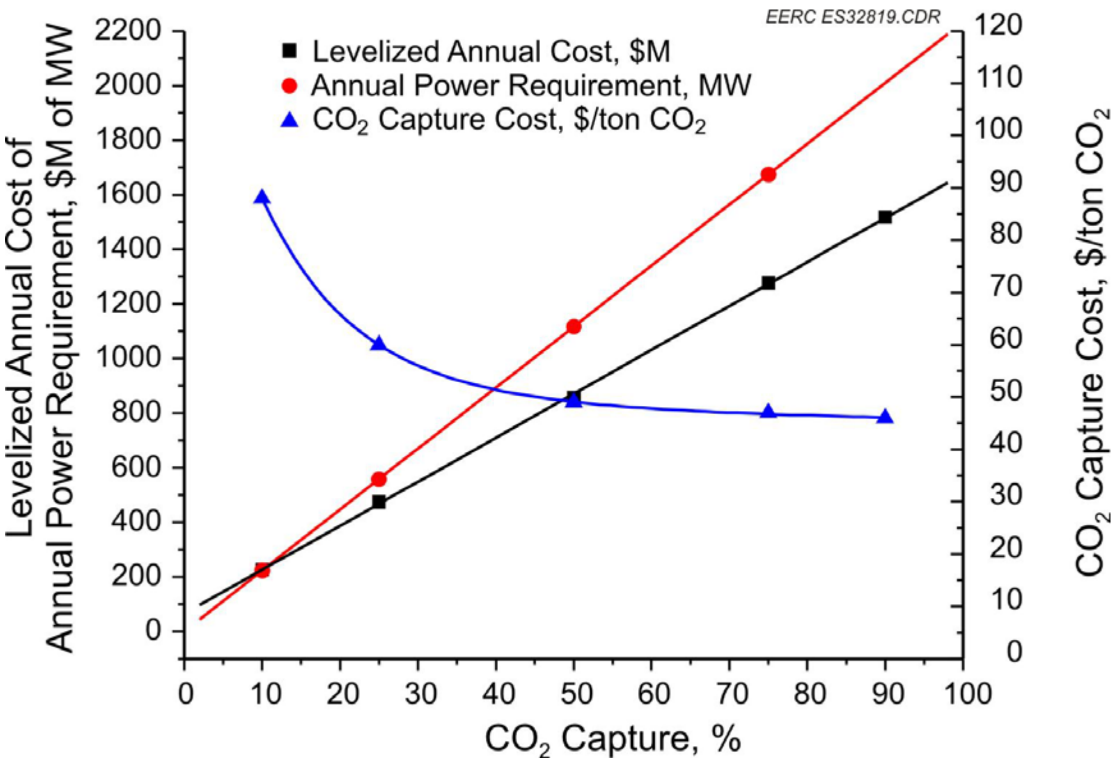



Figure A-10. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Wisconsin.

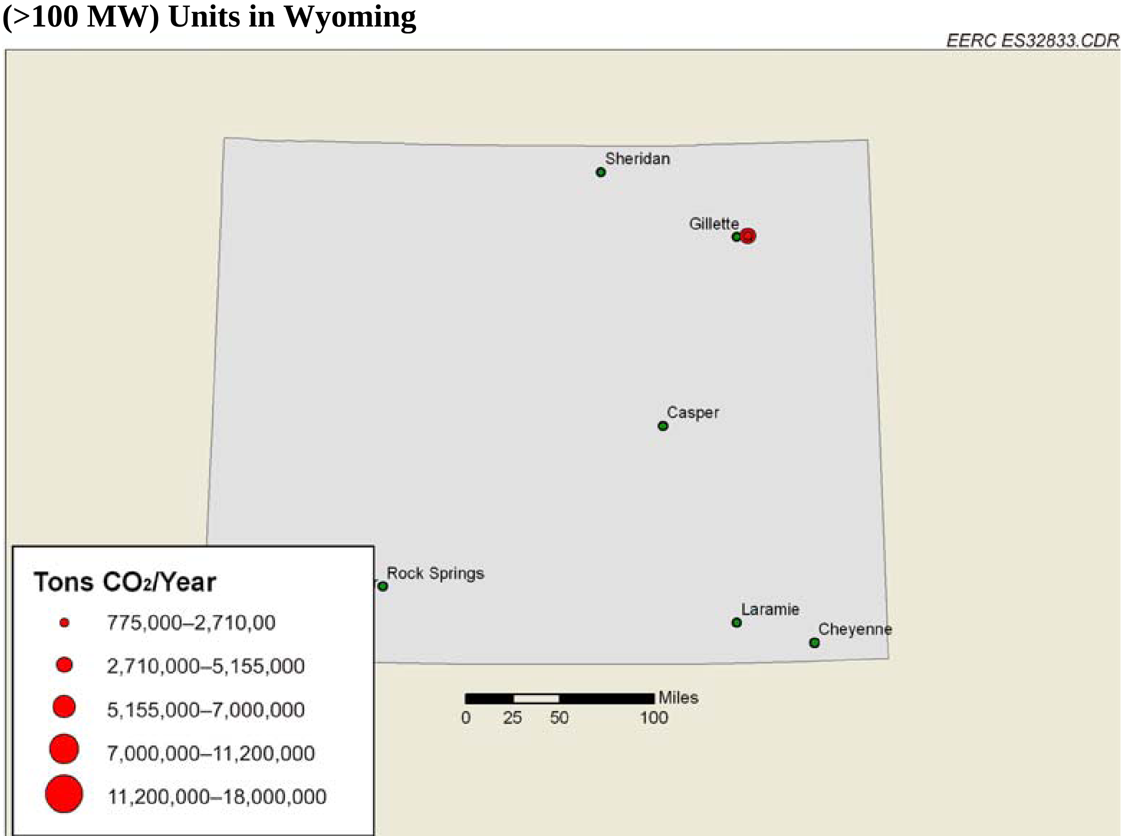
**Wyoming**

The PCOR Partnership region contains only a small portion of Wyoming. This portion of the state has six electricity-generating stations that emit approximately 5,900,000 tons of $CO_2$ annually. Of these six stations, only one is larger than 100 MW. This generating station is known as the Wyodak Station and is located just east of Gillette, Wyoming. The 362-MW unit has a wall-fired boiler that is equipped with a C-ESP for PM control and a dry scrubber for $SO_x$. The characteristics of the Wyodak Station are summarized in Table A-21 along with a map showing its location within the state. The $CO_2$ generated from the Wyodak Station is approximately 3,371,000 tons per year, approximately 57% of the $CO_2$ generated from all six generating stations in the part of Wyoming that is in the PCOR Partnership region.

The results from the model simulations are summarized in Table A-22. These results indicate that there is an energy penalty of 42.8% associated with capturing 90% of the $CO_2$ emitted from this unit. The cost penalty associated with this energy requirement of 155 MW is estimated to be approximately $455 million (capital costs only), based on an average power cost of $2936/kW. The predicted trends in the power penalty and cost of $CO_2$ capture as a function of the capture percentage of carbon dioxide are presented in Figure A-11. The power penalty increases linearly with the percentage of carbon capture, increasing from 17 MW (4.7% of the total output of the units that are >100 MW) to 155 MW (42.8% of the total output of the unit). At the same time, the cost of $CO_2$ capture decreases from $72/ton of $CO_2$ captured (10% $CO_2$ capture rate) to between $42 and $39 per ton of $CO_2$ captured for capture rates of 50% and 90%, respectively, while the levelized annual cost, not including the cost of replacement power, increases from $16 million (10% capture) to $110 million (90% capture).

At the highest rate of capture, there would be approximately 3,030,000 tons of $CO_2$ captured, which is roughly 51% of all the $CO_2$ produced by the six electricity-generating stations in the PCOR Partnership region of Wyoming. Given that the total $CO_2$ produced in the PCOR Partnership region of the state from all sources is 6,260,000 tons per year, a 90% $CO_2$ capture rate for electricity-generating stations >100 MW yields an overall $CO_2$ reduction of 48% for the entire state. As noted above, the cost of achieving this $CO_2$ capture is estimated to be approximately $110 million annually, plus the additional cost of replacing the lost generation capacity.

**Table A-21. Location and Summary of Characteristics of Electricity-Generating (>100 MW) Units in Wyoming**




| Unit ID | $CO_2$ Emissions, tons/year[1] | Unit Size, MW | Fuel Type | Boiler Type | $SO_2$ Control | PM Control |
|---|---|---|---|---|---|---|
| Wyodak | 3,370,621 | 362 | Subbitum. | W-fired | None | C-ESP |

[1] As shown in the PCOR Partnership Decision Support System (DSS, © 2007 EERC Foundation) from estimations and actual reporting data.

**Table A-22. Summary of $CO_2$ Capture Costs for >100 MW Electricity-Generating Stations in Wyoming**

| Carbon Capture, % | 10 | | 25 | | 50 | | 75 | | 90 | |
|---|---|---|---|---|---|---|---|---|---|---|
| 3,371,000 tons of carbon dioxide emissions per year for units of >100 MW | | | | | | | | | | |
| $CO_2$ Captured | | | | | | | | | | |
| tons per year | 337,100 | | 842,750 | | 1,685,500 | | 2,528,250 | | 3,033,900 | |
| Energy Assessment | | | | | | | | | | |
| Gross Electrical Output, MW | 362 | | 362 | | 362 | | 362 | | 362 | |
| Auxiliary Load, MW | | | | | | | | | | |
| Amine Scrubber, MW | 16 | | 40 | | 79 | | 119 | | 143 | |
| WFGD Use, MW | 1 | | 3 | | 7 | | 10 | | 12 | |
| Total Aux Load, MW | 17 | | 43 | | 86 | | 129 | | 155 | |
| % of Gross Output | 4.7 | | 11.9 | | 23.8 | | 35.6 | | 42.8 | |
| Cost of Capture | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ | \$M/yr | \$/ton $CO_2$ |
| Annual Cost $SO_2$ Removal | 10 | 29 | 12 | 14 | 15 | 9 | 19 | 7 | 21 | 7 |
| Total Levelized Annual Cost[a] | 16 | 72 | 34 | 50 | 61 | 42 | 93 | 40 | 110 | 39 |

[a] Includes the costs associated with both $SO_2$ and $CO_2$ removal.

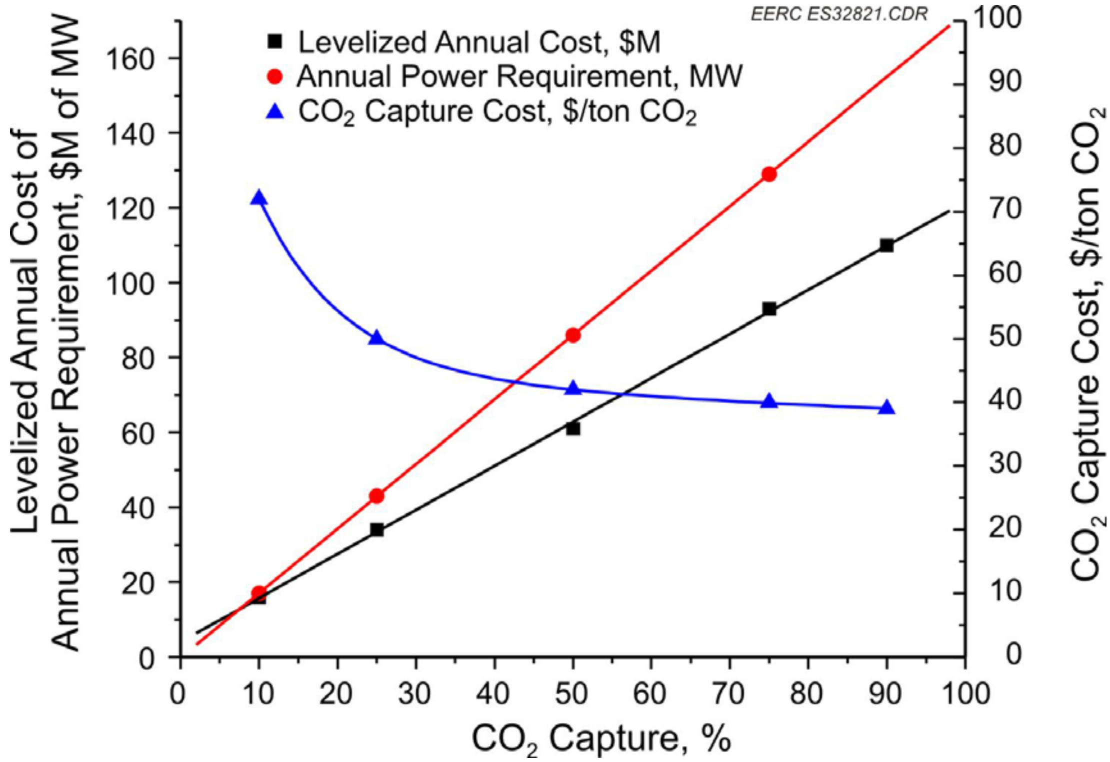



Figure A-11. Results from implementing $CO_2$ capture on electricity-generating units larger than 100 MW in Wyoming.

# APPENDIX B

# PROCEDURES USED TO ESTIMATE CAPTURE, DRYING, AND COMPRESSION COSTS AT ETHANOL PLANTS AND ELECTRICITY-GENERATING FACILITIES

# PROCEDURES USED TO ESTIMATE CAPTURE, DRYING, AND COMPRESSION COSTS AT ETHANOL PLANTS AND ELECTRICITY-GENERATING FACILITIES

## PROCEDURE USED TO ESTIMATE THE COST AND POWER REQUIREMENTS FOR CAPTURING, DRYING, AND COMPRESSING $CO_2$ PRODUCED DURING NATURAL GAS COMBUSTION

1. The annual combustion carbon dioxide ($CO_2$) emissions for the desired plant were obtained from the Plains $CO_2$ Reduction (PCOR) Partnership master source spreadsheet.

2. The Integrated Environmental Control Model (IECM) was configured.

   - The IECM session was begun by configuring the plant to be a combustion turbine producing the amount of $CO_2$ obtained in Step 1. To determine the $CO_2$ production estimated by the IECM, the "Get Results–Power Block–Flue Gas" tab was checked, and the quantity of $CO_2$ in the flue gas was noted. The "Get Results–Overall Plant–Plant Performance" tab provided the number of operating hours per year. Multiplying of the $CO_2$ quantity in the flue gas by the operating hours per year produced an annual $CO_2$ production rate.

   - If the IECM-estimated $CO_2$ quantity was too large, the number of turbines was changed in the "Set Parameters–Power Block–Gas Turbine" tab to one turbine. On the same tab, the turbine inlet temperature was adjusted until it produced the correct amount of $CO_2$ (or got as close as possible to the desired value).

   - Once the plant was set up without capture, capture capability was added to it on the "Configure Plant" tab. None of the other settings were changed.

   - The product pressure was set to 2500 psig on the "Set Parameters–$CO_2$ Capture–Amine System–Storage" tab. On the "Set Parameters–$CO_2$ Capture–$CO_2$ Transport–Config" sheet, the minimum possible total pipeline length of 0.6214 mi was entered.

3. The costs associated with $CO_2$ transport and storage were subtracted from the total variable costs on the "Get Results–$CO_2$ Capture–O&M (operation and maintenance) Cost" tab. This resulted in a calculation of the total variable cost for the capture plant only. Dividing this number by the total variable cost for everything determined the percentage associated with the capture plant. The fixed costs were multiplied by this percentage to get the total fixed costs for the capture plant. Adding the total variable cost for the capture plant to the total fixed costs for the capture plant produced the total annual O&M costs associated with capturing, drying, and compressing the $CO_2$ (but not for transporting or storing it).

4. The annual O&M cost on the "Get Results–$CO_2$ Capture–Amine System–Total Cost" tab was replaced with the one calculated in Step 3. This value was added to the annual capital cost to arrive at the total annual costs. Dividing this value by the number of tons of $CO_2$/yr that were

removed (which was found on the Amine System Cost Factors tab) resulted in a dollars-per-ton $CO_2$ value.

5. To calculate the energy used by the capture plant, all of the energy values from the "Get Results–$CO_2$ Capture–Cost Factors" tab were summed. The sum was divided by the tons of $CO_2$ removed/yr and then multiplied by the number of hours per year that the plant operated (found above the emission rate on the tab). This calculation resulted in a value for the energy required to capture, dry, and compress a ton of $CO_2$ per year.

6. Changing the amount of capture at the plant (i.e., 10%, 35%, 50%, etc.) was accomplished by changing the flue gas bypass control on the "Set Parameters–$CO_2$ Capture–Amine System–Config" tab to "Bypass." The box next to "Overall $CO_2$ Removal Efficiency" was unchecked, and the percentage of the desired capture rate was entered. The default IECM value is 90% capture of the $CO_2$.

## PROCEDURE USED TO ESTIMATE THE COST AND POWER REQUIREMENTS FOR CAPTURING, DRYING, AND COMPRESSING $CO_2$ PRODUCED DURING COAL COMBUSTION

1. The annual combustion $CO_2$ emissions for the desired plant, as well as the fuel type, were obtained from the PCOR Partnership master source spreadsheet. Absent specific information regarding coal type, it was assumed that subbituminous coal from the Wyoming Powder River Basin was used.

2. The IECM was configured.

   - The IECM session was begun by configuring the plant to be a combustion boiler. The $NO_x$, $SO_x$, and mercury control buttons were set to "none," and particulate control was set to cold-side electrostatic precipitator (C-ESP). Before configuring the plant to enable $CO_2$ capture, the plant was set up to produce the amount of $CO_2$ obtained in Step 1.

   - In the "Set Parameters–Fuel–Properties" menu, the fuel was set to the correct one and the "Use This Fuel" button was clicked. A review of the "Get Results–Stack–Flue Gas" tab showed the quantity of $CO_2$ the IECM predicted that the plant would produce per hour. Multiplying this value by the number of hours per year that the plant operated (found in the "Get Results–Overall Plant–Plant Performance" tab) gave a yearly $CO_2$ emission rate.

   - The box next to the gross electrical output on the "Set Parameters–Base Plant–Performance" tab was unchecked and changed to match the plant output. In the case of a coal-fired ethanol plant, the value was changed to the minimum possible so as to produce as small a stream as possible.

   - Amine capture capabilities were added on the "Configure Plant" tab.

- On the “Set Parameters–$CO_2$ Capture–Amine System–Config” tab, the flue gas bypass control was changed to “Bypass.” The box next to “Overall $CO_2$ Removal Efficiency” was unchecked. The bypass was set to a percentage that produced the correct amount of $CO_2$ for a given source.

- The product pressure was set to 2500 psig on the “Set Parameters–$CO_2$ Capture–Amine System–Storage” tab. On the “Set Parameters–$CO_2$ Capture–$CO_2$ Transport–Config” sheet, the minimum total pipeline length of 0.6214 mi was entered.

3. The costs associated with $CO_2$ transport and storage were subtracted from the total variable costs on the “Get Results–$CO_2$ Capture–O&M Cost” tab. This resulted in a calculation of the total variable cost for the capture plant only. Dividing this number by the total variable cost for everything determined the percentage associated with the capture plant only. Fixed costs were multiplied by this percentage to get the total fixed costs for the capture plant. Adding the total variable cost for the capture plant to the total fixed costs for the capture plant produced the total annual O&M costs associated with capturing, drying, and compressing the $CO_2$ (but not transporting or storing it).

4. On the “Get Results–$CO_2$ Capture–Amine System–Total Cost” tab, the annual O&M cost was replaced with the one calculated in Step 5. This value was added to the annual capital cost to determine the total annual cost. The total annual cost was divided by the number of tons of $CO_2$/yr that were removed (this is on the Amine System Cost Factors tab) to get a dollars-per-ton $CO_2$ value.

5. The energy used by the capture plant was calculated by summing all of the energy values on the “Get Results–$CO_2$ Capture–Amine System–Misc” tab. The sum was divided by the quantity (in tons) of $CO_2$ removed/yr and multiplied by the number of hours per year that the plant operated. This produced the energy required to capture, dry, and compress a ton of $CO_2$ per year.

6. Changing the amount of capture at the plant (i.e., to 10%, 35%, 50%, etc.) was accomplished by changing the flue gas bypass control on the “Set Parameters–$CO_2$ Capture–Amine System–Config” tab to “Bypass.” The box next to “Overall $CO_2$ Removal Efficiency” was unchecked, and the percentage of the desired capture rate was entered. The default IECM value is 90% capture of the $CO_2$.

   In the case of combustion at an ethanol plant, a particular emission rate is desired and the specific required bypass rate must be determined through a ratio of the desired emission rate to the total rate shown by the IECM, as follows:

$$\frac{\text{IECM Predicted Quantity}}{0.9} = \frac{\text{Desired Quantity}}{x}$$

   and solving for x.

## PROCEDURE USED TO ESTIMATE THE COST AND POWER REQUIREMENTS FOR DRYING AND COMPRESSION OF THE $CO_2$ PRODUCED DURING GAS PROCESSING OR THE ETHANOL FERMENTATION PROCESS

1. The annual noncombustion (i.e., fermentation) $CO_2$ emissions for the desired ethanol plant were obtained from the PCOR Partnership master source spreadsheet.

2. The IECM was configured.

    - The IECM session was begun by configuring the plant to be a combustion turbine with an amine system.

    - The product pressure was set at 2500 psig on the "Set Parameters–$CO_2$ Capture–Amine System–Storage" tab.

    - The "Get Results–$CO_2$ Capture–Amine System–Cost Factors" sheet was viewed to see how much $CO_2$ the IECM predicted was being captured. The IECM default bypass shows 90% capture of the plant's emissions. A ratio was used to determine the amount of bypass needed to obtain the correct size $CO_2$ stream. The following equation was solved for x, the overall plant capture rate:

    $$\frac{\text{IECM Predicted Quantity}}{0.9} = \frac{\text{Desired Quantity}}{x}$$

    - On the "Set Parameters–$CO_2$ Capture–Amine System–Config" tab, the flue gas bypass control was changed to "Bypass." The box next to "Overall $CO_2$ Removal Efficiency" was unchecked, and the overall plant capture rate that was calculated was input as a percentage.

3. The drying and compression unit cost on the "Get Results–$CO_2$ Capture–Amine System–Capital Cost" tab was divided by the total process facilities capital cost to determine the percentage of capital cost that was associated with drying and compression.

4. All of the energy used at the plant (shown on the "Get Results–$CO_2$ Capture–Amine System–Cost Factors" tab) was summed. The percentage that was associated with the $CO_2$ compression was determined by dividing the "$CO_2$ Compression Energy" value by the total.

5. The "Electricity" cost from the "Get Results–$CO_2$ Capture–Amine System–O&M Cost" tab was multiplied by the percentage from Step 4 to get a cost for electricity required to run the $CO_2$ drying and compression unit. The $CO_2$ drying and compression cost was divided by the total variable cost to get a percentage, which was multiplied by the total fixed costs to calculate the fixed costs associated with running the $CO_2$ drying and compression unit. The drying and compression electricity cost was added to the drying and compression fixed costs to arrive at the total annual drying and compression O&M costs.

6. The total levelized annual cost on the "Get Results–$CO_2$ Capture–Amine System–Total Cost" tab was multiplied by the percentage from Step 3 to give the annual capital costs associated with drying and compression of the $CO_2$ stream. This value was added to the annual O&M costs calculated in Step 5 to get the total annual costs, which was divided by the number of tons $CO_2$/yr to get a dollar-per-ton $CO_2$ value.

7. The unit compression energy was calculated by the IECM and was found on the "Set Parameters–$CO_2$ Capture–Amine System–Storage" tab.

# APPENDIX C

# COMPARISON OF COSTS AND ADDITIONAL ELECTRICAL REQUIREMENTS FOR $CO_2$ CAPTURE FROM ETHANOL PLANTS

## COMPARISON OF COSTS AND ADDITIONAL ELECTRICAL REQUIREMENTS FOR $CO_2$ CAPTURE FROM ETHANOL PLANTS

The following abbreviations will be used in this appendix:

IA = Iowa
MB = Manitoba
MN = Minnesota
MO = Missouri
ND = North Dakota
NE = Nebraska
SD = South Dakota
WI = Wisconsin
AB = Alberta
SK = Saskatchewan

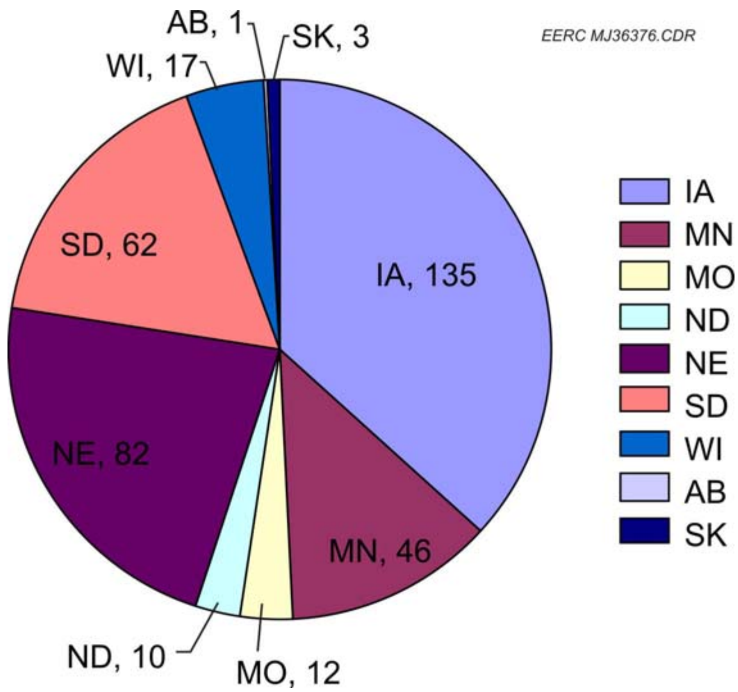



Figure C-1. Additional electrical capacity (MW) needed to capture fermentation $CO_2$ and 10% of combustion $CO_2$ at the region's ethanol plants.

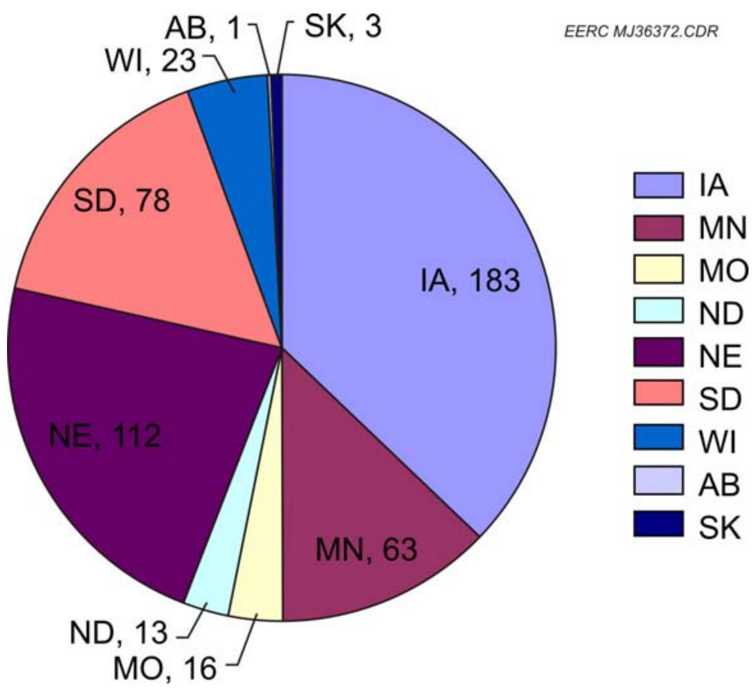



Figure C-2. Additional electrical capacity (MW) needed to capture fermentation $CO_2$ and 25% of combustion $CO_2$ at the region's ethanol plants.

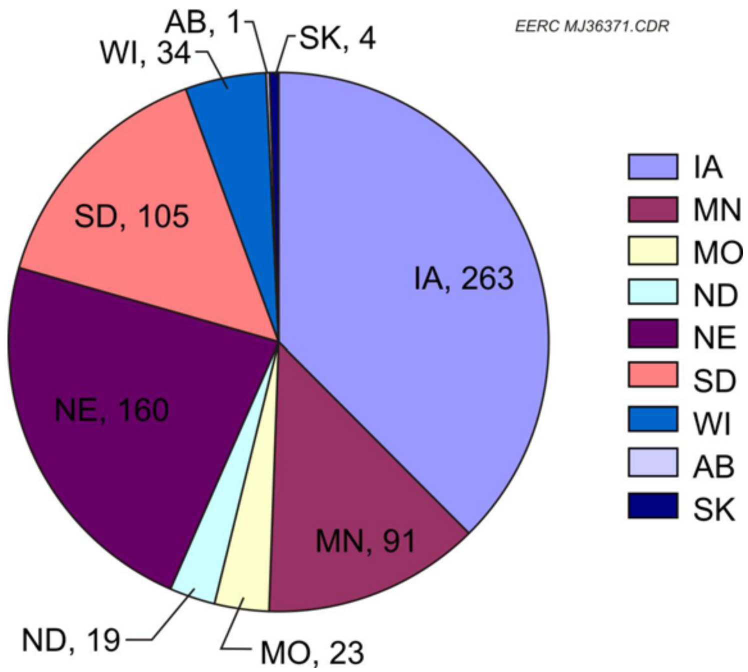



Figure C-3. Additional electrical capacity (MW) needed to capture fermentation $CO_2$ and 50% of combustion $CO_2$ at the region's ethanol plants.

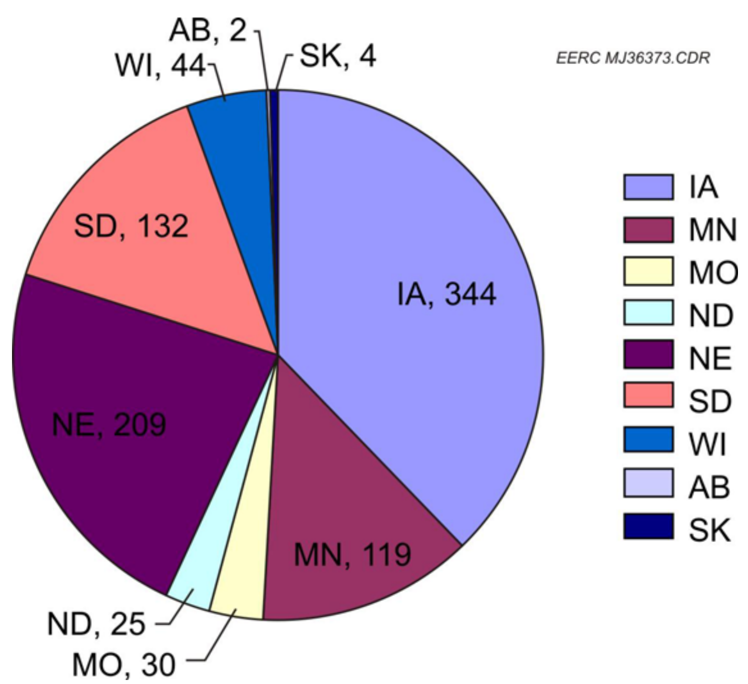



Figure C-4. Additional electrical capacity (MW) needed to capture fermentation $CO_2$ and 75% of combustion $CO_2$ at the region's ethanol plants.

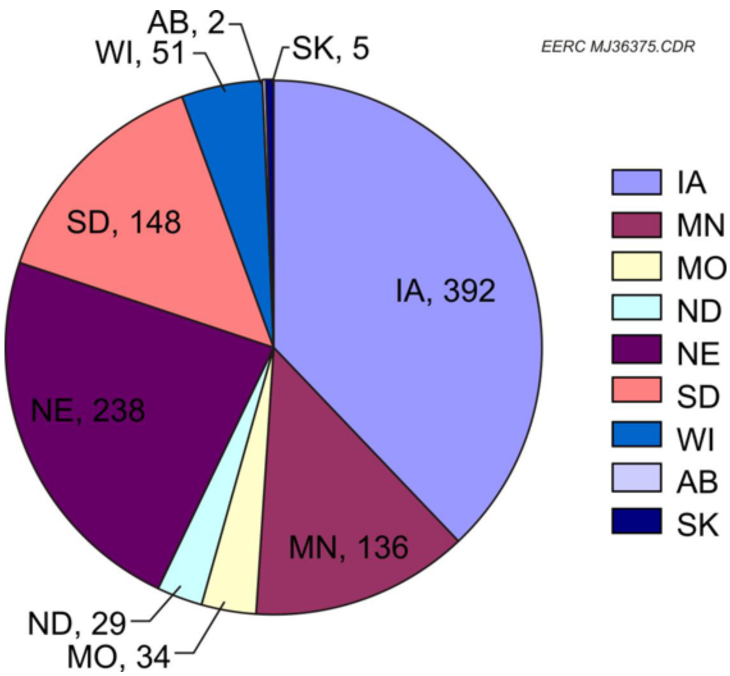



Figure C-5. Additional electrical capacity (MW) needed to capture fermentation $CO_2$ and 90% of combustion $CO_2$ at the region's ethanol plants.

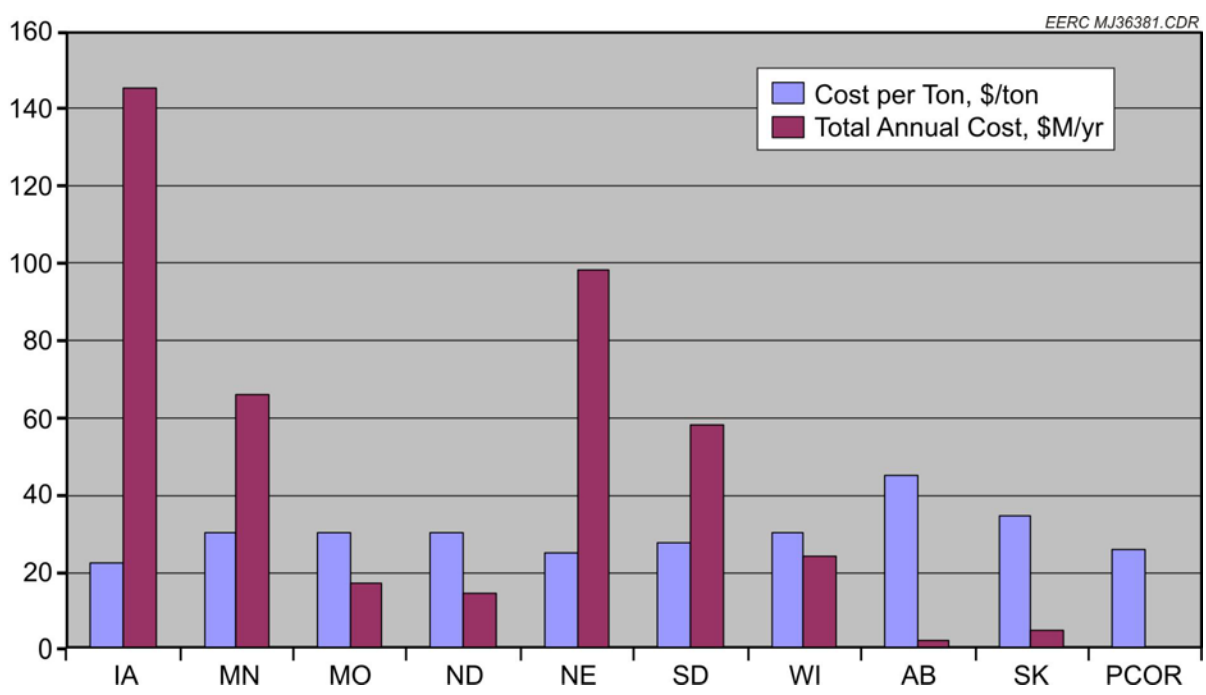



Figure C-6. The cost of capture of fermentation $CO_2$ and 10% of combustion $CO_2$ produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $477.5 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states and provinces.

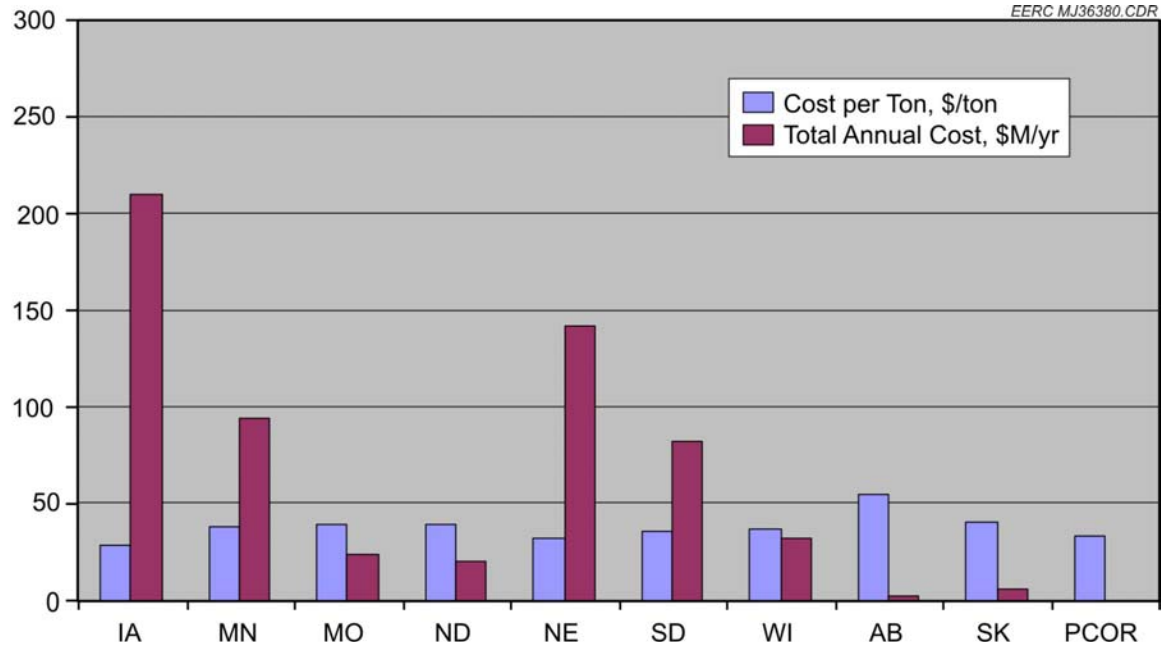



Figure C-7. The cost of capture of fermentation $CO_2$ and 25% of combustion $CO_2$ produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $696 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states and provinces.

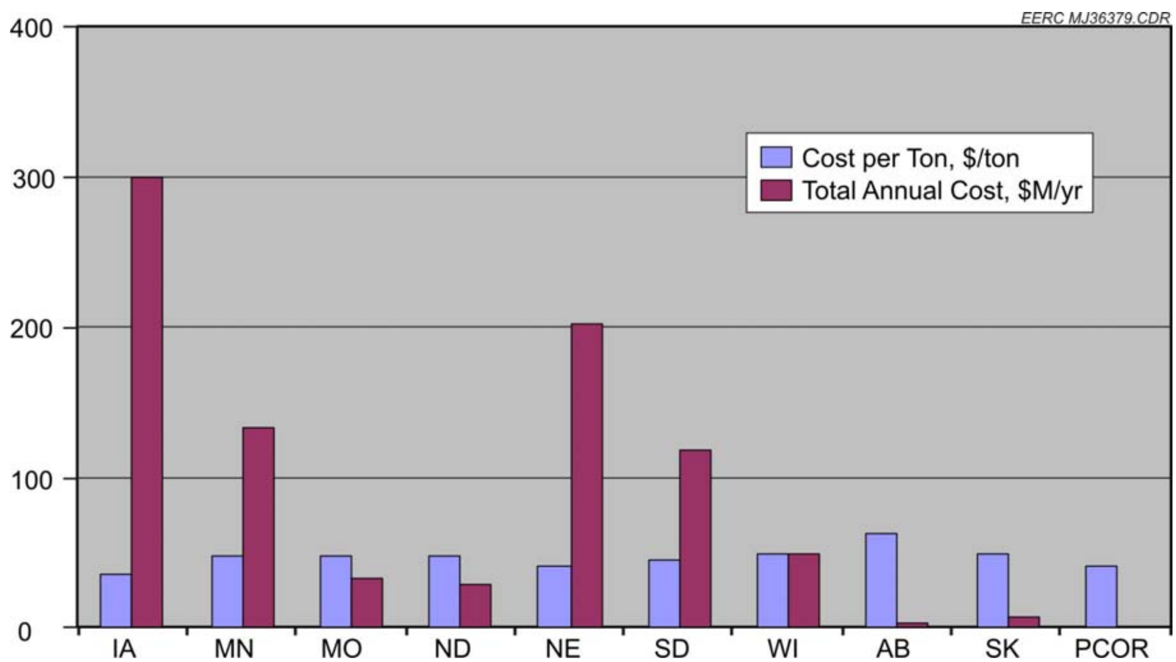



Figure C-8. The cost of capture of fermentation $CO_2$ and 50% of combustion $CO_2$ produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $990.6 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states and provinces.

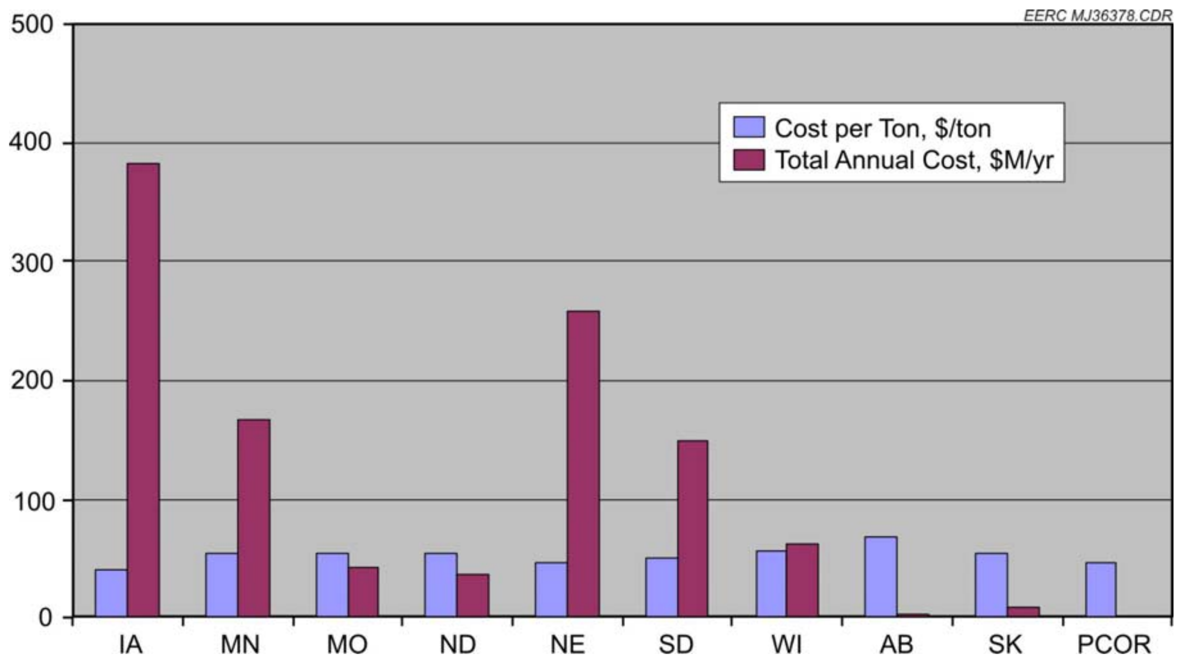



Figure C-9. The cost of capture of fermentation $CO_2$ and 75% of combustion $CO_2$ produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $1259.5 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states and provinces.

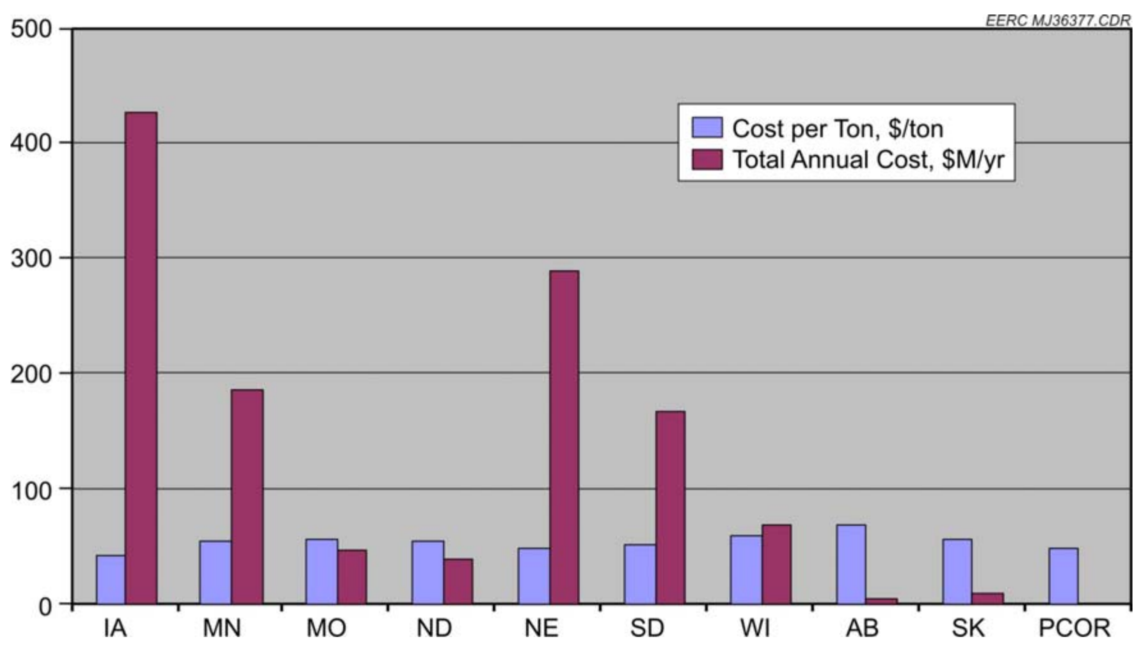



Figure C-10. The cost of capture of fermentation $CO_2$ and 90% of combustion $CO_2$ produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $1412.7 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states and provinces.

# APPENDIX D

# DATA USED TO GENERATE CHARTS SUMMARIZING $CO_2$ CAPTURE AT ELECTRICITY-GENERATING FACILITIES

**Table D-1. Capture Power Requirement as a Percentage of Gross Electrical Output for the Electricity-Generating Stations Producing at Least 100 MW**

| State/Province | Gross Output | Capture Power Requirement, Percentage of Gross Output | | | | |
|---|---|---|---|---|---|---|
| | | 10 | 25 | 50 | 75 | 90 |
| Alberta | 6159 | 3.9 | 9.9 | 19.7 | 29.6 | 35.5 |
| Iowa | 5165 | 3.7 | 9.2 | 18.4 | 27.6 | 33.2 |
| Minnesota | 5241 | 3.8 | 9.6 | 19.2 | 28.7 | 34.5 |
| Missouri | 10,836 | 3.7 | 9.3 | 18.6 | 27.9 | 33.5 |
| Montana | 2467 | 3.8 | 9.6 | 19.1 | 28.7 | 34.4 |
| Nebraska | 2819 | 4.0 | 10.0 | 19.9 | 29.9 | 35.9 |
| North Dakota | 3843 | 5.2 | 13.1 | 26.2 | 39.4 | 47.2 |
| Saskatchewan | 1684 | 4.3 | 10.7 | 21.4 | 32.1 | 38.5 |
| South Dakota | 450 | 4.2 | 10.5 | 21.1 | 31.6 | 38.0 |
| Wisconsin | 6070 | 4.0 | 9.4 | 18.7 | 28.1 | 33.7 |
| Wyoming | 362 | 4.7 | 11.9 | 23.7 | 35.6 | 42.7 |
| Overall | 45,096 | 4.0 | 9.9 | 19.8 | 29.6 | 35.6 |
| Average | – | 4.1 | 10.3 | 20.6 | 30.8 | 37.0 |

**Table D-2. Cost of $CO_2$ Capture at the PCOR Partnership Regional Electricity-Generating Stations Producing at Least 100 MW**

| State/Province | Capture Cost, \$/ton $CO_2$ Captured | | | | |
|---|---|---|---|---|---|
| | 10 | 25 | 50 | 75 | 90 |
| Alberta | 94 | 62 | 51 | 48 | 46 |
| Iowa | 86 | 61 | 51 | 49 | 48 |
| Minnesota | 69 | 50 | 44 | 42 | 41 |
| Missouri | 83 | 58 | 49 | 47 | 46 |
| Montana | 49 | 40 | 37 | 36 | 36 |
| Nebraska | 96 | 64 | 53 | 49 | 48 |
| North Dakota | 74 | 58 | 54 | 52 | 51 |
| Saskatchewan | 112 | 73 | 59 | 54 | 53 |
| South Dakota | 73 | 53 | 45 | 44 | 43 |
| Wisconsin | 88 | 60 | 49 | 47 | 45 |
| Wyoming | 72 | 50 | 42 | 40 | 39 |
| Overall | 83 | 58 | 49 | 47 | 46 |
| Average | 81 | 57 | 48 | 46 | 45 |

**Table D-3. Levelized Annual Capture Cost for PCOR Partnership Regional Electricity-Generating Stations Producing at Least 100 MW**

| | Levelized Annual Capture Cost, $M/yr | | | | |
|---|---|---|---|---|---|
| State/Province | 10 | 25 | 50 | 75 | 90 |
| Alberta | 250 | 501 | 903 | 1338 | 1587 |
| Iowa | 199 | 418 | 759 | 1143 | 1357 |
| Minnesota | 207 | 435 | 811 | 1191 | 1414 |
| Missouri | 403 | 848 | 1548 | 2314 | 2752 |
| Montana | 89 | 190 | 362 | 536 | 635 |
| Nebraska | 119 | 247 | 458 | 664 | 784 |
| North Dakota | 206 | 447 | 863 | 1264 | 1519 |
| Saskatchewan | 87 | 179 | 321 | 463 | 558 |
| South Dakota | 17 | 37 | 68 | 103 | 122 |
| Wisconsin | 245 | 512 | 924 | 1374 | 1632 |
| Wyoming | 16 | 34 | 61 | 93 | 110 |
| Overall | 1838 | 3847 | 7079 | 10,483 | 12,468 |

**Table D-4. Quantity of $CO_2$ Captured at the PCOR Partnership Region's Electricity-Generating Stations Producing at Least 100 MW**

| | | | Total $CO_2$ Captured, Mtons/yr | | | | |
|---|---|---|---|---|---|---|---|
| State/Province | Total $CO_2$ Production, Mtons/yr | $CO_2$ Production from All Electric Stations, Mtons/yr | 10 | 25 | 50 | 75 | 90 |
| Alberta | 105 | 47.4 | 4.57 | 11.42 | 22.84 | 34.25 | 41.11 |
| Iowa | 55.5 | 39.2 | 3.65 | 9.13 | 18.26 | 27.39 | 32.87 |
| Minnesota | 72.3 | 53.3 | 4.18 | 10.46 | 20.92 | 31.38 | 37.66 |
| Missouri | 99.0 | 83.3 | 7.90 | 19.76 | 39.51 | 59.27 | 71.12 |
| Montana | 23.2 | 21.0 | 2.01 | 5.03 | 10.05 | 15.08 | 18.09 |
| Nebraska | 33.7 | 25.8 | 2.22 | 5.55 | 11.11 | 16.66 | 19.99 |
| North Dakota | 44.3 | 36.0 | 3.55 | 8.82 | 17.64 | 26.46 | 31.75 |
| Saskatchewan | 21.2 | 14.5 | 1.42 | 3.56 | 7.12 | 10.67 | 12.81 |
| South Dakota | 19.9 | 4.19 | 0.38 | 0.94 | 1.88 | 2.81 | 3.38 |
| Wisconsin | 90.0 | 50.6 | 4.79 | 11.98 | 23.95 | 35.93 | 43.12 |
| Wyoming | 6.29 | 5.91 | 0.34 | 0.84 | 1.69 | 2.53 | 3.03 |
| Overall | 576 | 382 | 35.01 | 87.48 | 174.96 | 262.44 | 314.92 |

**Table D-5. Percentage of Reduction in $CO_2$ Emissions from Electricity-Generating Stations in the PCOR Partnership Region Afforded by $CO_2$ Capture**

| State/Province | $CO_2$ Production from All Electric Stations, Mtons/yr | $CO_2$ Reductions from All Electric Stations, % | | | | |
|---|---|---|---|---|---|---|
| | | 10 | 25 | 50 | 75 | 90 |
| Alberta | 47.4 | 9.64 | 24.1 | 48.2 | 72.3 | 86.7 |
| Iowa | 39.2 | 9.33 | 23.3 | 46.6 | 70.0 | 83.9 |
| Minnesota | 53.3 | 7.86 | 19.6 | 39.3 | 58.9 | 70.7 |
| Missouri | 83.3 | 9.49 | 23.7 | 47.4 | 71.1 | 85.4 |
| Montana | 21.0 | 9.58 | 24.0 | 47.9 | 71.9 | 86.2 |
| Nebraska | 25.8 | 8.61 | 21.5 | 43.1 | 64.6 | 77.5 |
| North Dakota | 36.0 | 9.86 | 24.5 | 49.0 | 73.5 | 88.2 |
| Saskatchewan | 14.5 | 9.80 | 24.5 | 49.0 | 73.5 | 88.2 |
| South Dakota | 4.19 | 8.95 | 22.4 | 44.8 | 67.2 | 80.6 |
| Wisconsin | 50.6 | 9.46 | 23.7 | 47.3 | 71.0 | 85.2 |
| Wyoming | 5.91 | 5.70 | 14.2 | 28.5 | 42.7 | 51.3 |
| Overall | 382 | 9.17 | 22.9 | 45.8 | 68.8 | 82.5 |

**Table D-6. Percentage of Reduction in $CO_2$ Emissions from All Industrial Point Sources in the PCOR Partnership Region Afforded by $CO_2$ Capture**

| State/Province | Total $CO_2$ Production, Mtons/yr | $CO_2$ Reductions from All Sources, % | | | | |
|---|---|---|---|---|---|---|
| | | 10 | 25 | 50 | 75 | 90 |
| Alberta | 105 | 4.35 | 10.9 | 21.7 | 32.6 | 39.1 |
| Iowa | 55.5 | 6.58 | 16.5 | 32.9 | 49.4 | 59.2 |
| Minnesota | 72.3 | 5.79 | 14.5 | 29.0 | 43.4 | 52.1 |
| Missouri | 99.0 | 7.98 | 20.0 | 39.9 | 59.9 | 71.8 |
| Montana | 23.2 | 8.67 | 21.7 | 43.4 | 65.0 | 78.0 |
| Nebraska | 33.7 | 6.59 | 16.5 | 33.0 | 49.4 | 59.3 |
| North Dakota | 44.3 | 8.01 | 19.9 | 39.8 | 59.7 | 71.6 |
| Saskatchewan | 21.2 | 6.71 | 16.8 | 33.6 | 50.3 | 60.4 |
| South Dakota | 19.9 | 1.89 | 4.7 | 9.4 | 14.1 | 17.0 |
| Wisconsin | 90.0 | 5.32 | 13.3 | 26.6 | 39.9 | 47.9 |
| Wyoming | 6.29 | 5.35 | 13.4 | 26.8 | 40.2 | 48.2 |
| Overall | 576 | 6.08 | 15.2 | 30.4 | 45.6 | 54.7 |

# APPENDIX E

# SUMMARY OF $CO_2$ PIPELINE ROUTES FOR THE PCOR PARTNERSHIP STATES AND PROVINCES

## SUMMARY OF $CO_2$ PIPELINE ROUTES FOR THE PCOR PARTNERSHIP STATES AND PROVINCES

### ALBERTA

**Table E-1. Summary of $CO_2$ Pipelines in Alberta[1]**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M[2] Cost, $millions/yr |
|---|---|---|---|
| 178 | 36 | 448.2 | 0.89 |
| 44 | 30 | 91.7 | 0.22 |
| 88 | 20 | 123.8 | 0.44 |
| 209 | 16 | 234.1 | 1.04 |
| 312 | 12 | 262.1 | 1.56 |
| 211 | 8 | 118.2 | 1.06 |
| 251 | 6 | 105.3 | 1.25 |
| **1293** | **–** | **1383.3** | **6.46** |

[1] Totals are in bolded text.
[2] Operation and maintenance.


Figure E-1. Map showing pipeline routes in Alberta.

## BRITISH COLUMBIA

**Table E-2. Summary of $CO_2$ Pipelines in British Columbia[1]**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 50 | 12 | 42.0 | 0.25 |
| 70 | 8 | 39.2 | 0.35 |
| 149 | 6 | 62.5 | 0.74 |
| **269** | **–** | **143.7** | **1.34** |

[1] Totals are in bolded text.


Figure E-2. Map showing pipeline routes in British Columbia.

## IOWA

**Table E-2. Summary of $CO_2$ Pipelines in Iowa**[1]

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 220 | 24 | 369.6 | 1.1 |
| 291 | 20 | 406.7 | 1.5 |
| 201 | 16 | 225.1 | 1.0 |
| 191 | 12 | 160.4 | 1.0 |
| 53 | 8 | 29.7 | 0.3 |
| 59 | 6 | 24.8 | 0.3 |
| 297 | 4 | 83.2 | 1.5 |
| **1312** | **–** | **1299.5** | **6.6** |

[1] Totals are in bolded text.

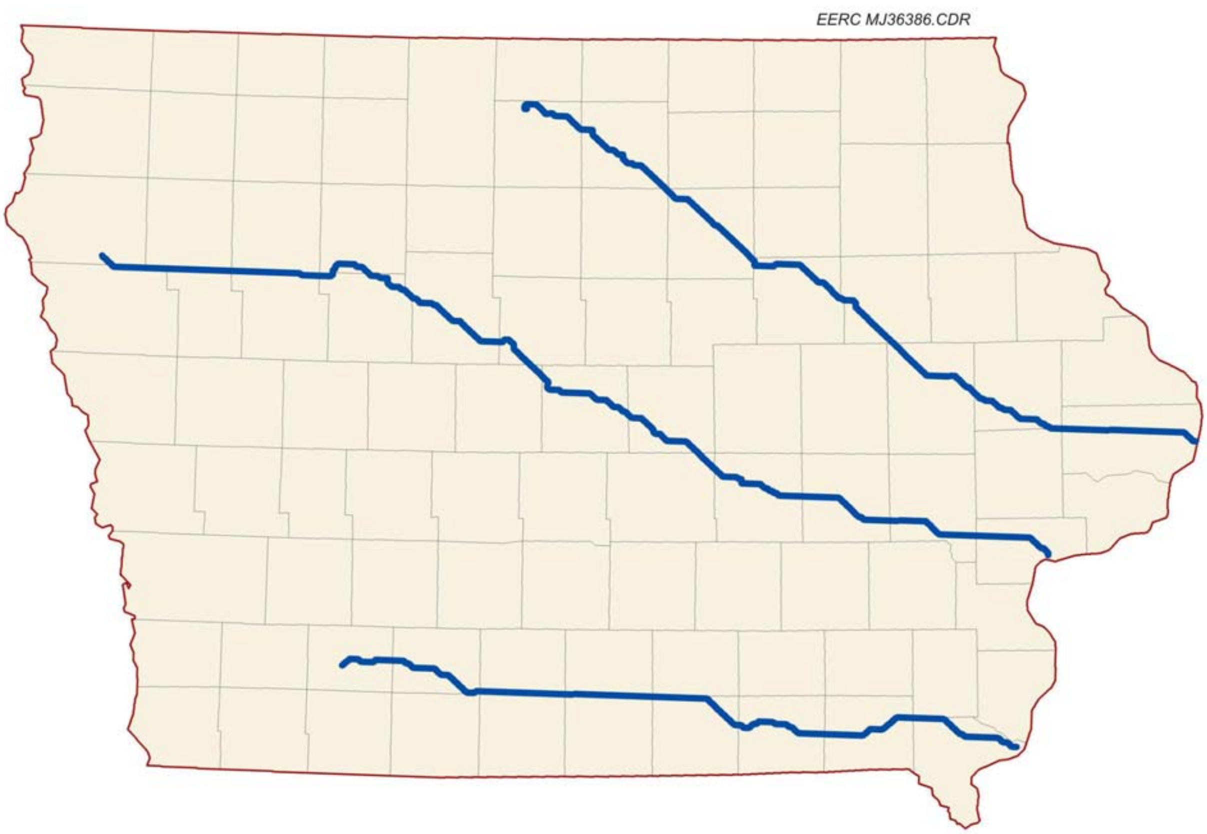



Figure E-3. Map showing pipeline routes in Iowa.

## MANITOBA

There are no ethanol plants, gas-processing plants, or electricity-generating stations at least 100 MW in size in Manitoba.

**MINNESOTA**

**Table E-4. Summary of $CO_2$ Pipelines in Minnesota**[1]

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 299 | 30 | 530.2 | 1.49 |
| 107 | 24 | 179.4 | 0.53 |
| 155 | 20 | 217.5 | 0.78 |
| 17 | 16 | 19.0 | 0.09 |
| 233 | 12 | 195.7 | 1.17 |
| 161 | 8 | 90.1 | 0.81 |
| 208 | 6 | 87.4 | 1.04 |
| 183 | 4 | 51.2 | 0.92 |
| **1363** | **–** | **1370.5** | **7.02** |

[1] Totals are in bolded text.

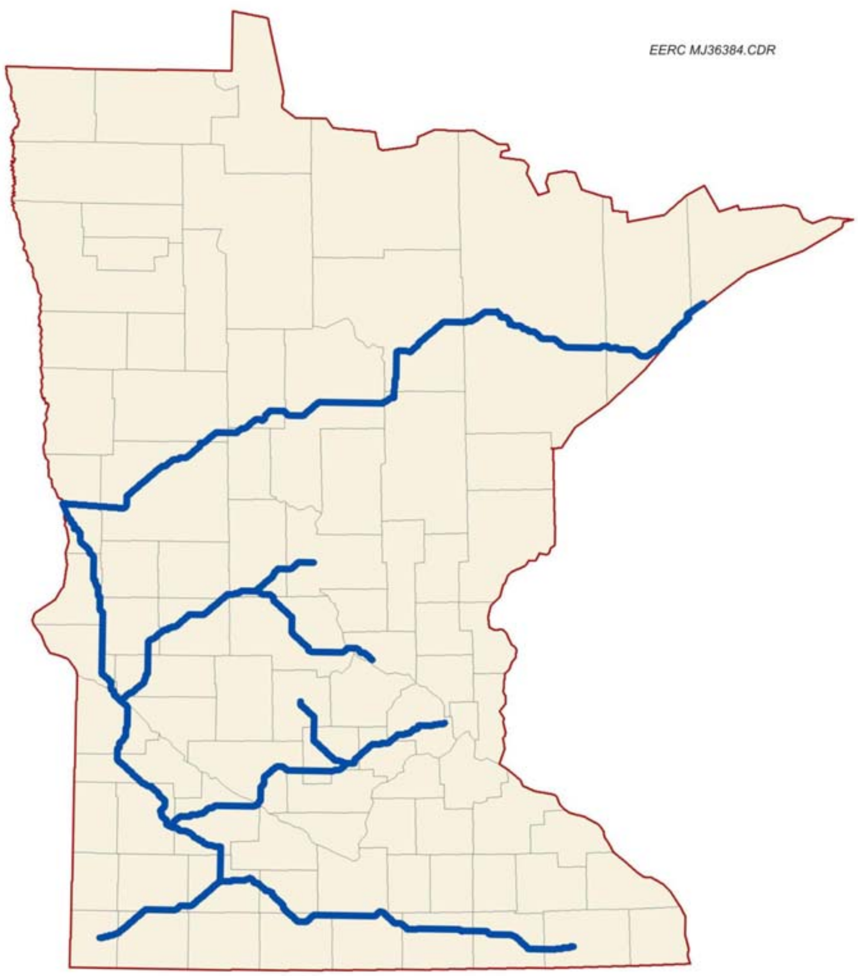



Figure E-4. Map showing pipeline routes in Minnesota.

**MISSOURI**

**Table E-5. Summary of $CO_2$ Pipelines in Missouri**[1]

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 374 | 30 | 785.4 | 1.87 |
| 204 | 24 | 342.7 | 1.02 |
| 76 | 20 | 106.4 | 0.38 |
| 111 | 16 | 124.3 | 0.56 |
| 139 | 12 | 116.8 | 0.70 |
| 82 | 4 | 23.0 | 0.40 |
| **986** | **–** | **1498.6** | **4.93** |

[1] Totals are in bolded text.


Figure E-5. Map showing pipeline routes in Missouri.

## MONTANA

**Table E-6. Summary of $CO_2$ Pipelines in Montana**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 290 | 24 | 486.1 | 1.45 |
| 77 | 12 | 46.4 | 0.39 |
| **367** | **–** | **532.5** | **1.84** |

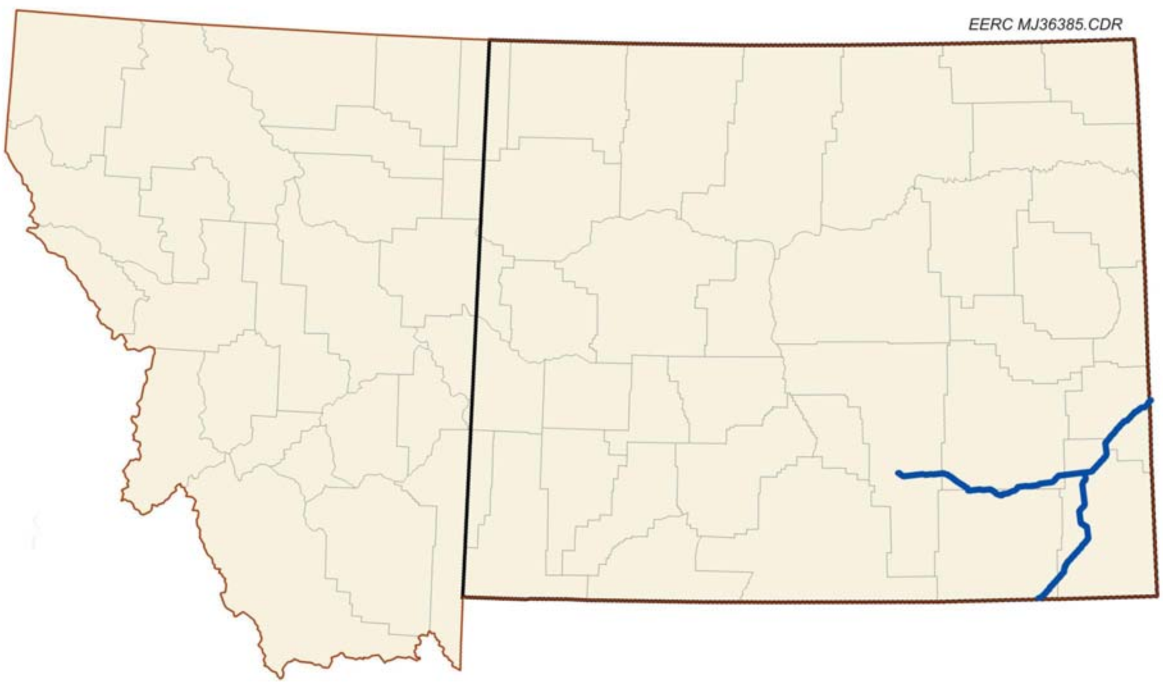



Figure E-6. Map showing pipeline routes in Montana.

## NEBRASKA

**Table E-7. Summary of $CO_2$ Pipelines in Nebraska[1]**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 79 | 30 | 165.9 | 0.39 |
| 623 | 24 | 1046.6 | 3.10 |
| 7 | 20 | 9.8 | 0.04 |
| 60 | 16 | 67.2 | 0.30 |
| 287 | 12 | 241.1 | 1.44 |
| 2 | 8 | 10.6 | 0.01 |
| 171 | 6 | 71.8 | 0.86 |
| 96 | 4 | 26.7 | 0.48 |
| **1325** | **–** | **1639.7** | **6.62** |

[1] Totals are in bolded text.

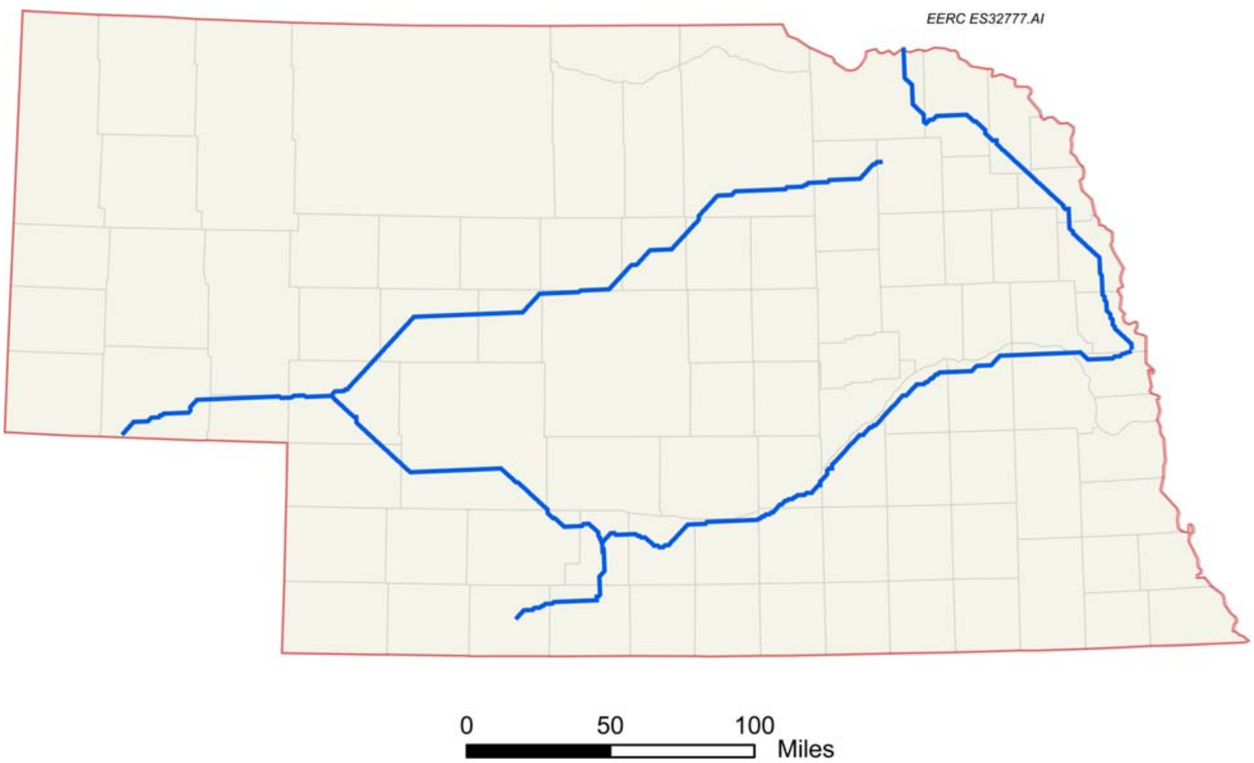



Figure E-7. Map showing pipeline routes in Nebraska.

## NORTH DAKOTA

**Table E-8. Summary of $CO_2$ Pipelines in North Dakota**[1]

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 604 | 30 | 1266 | 3.02 |
| 289 | 20 | 404.8 | 1.45 |
| 10 | 16 | 11.2 | 0.05 |
| 15 | 12 | 12.6 | 0.08 |
| 40 | 6 | 16.8 | 0.20 |
| **958** | – | **1711.4** | **4.79** |

[1] Totals are in bolded text.

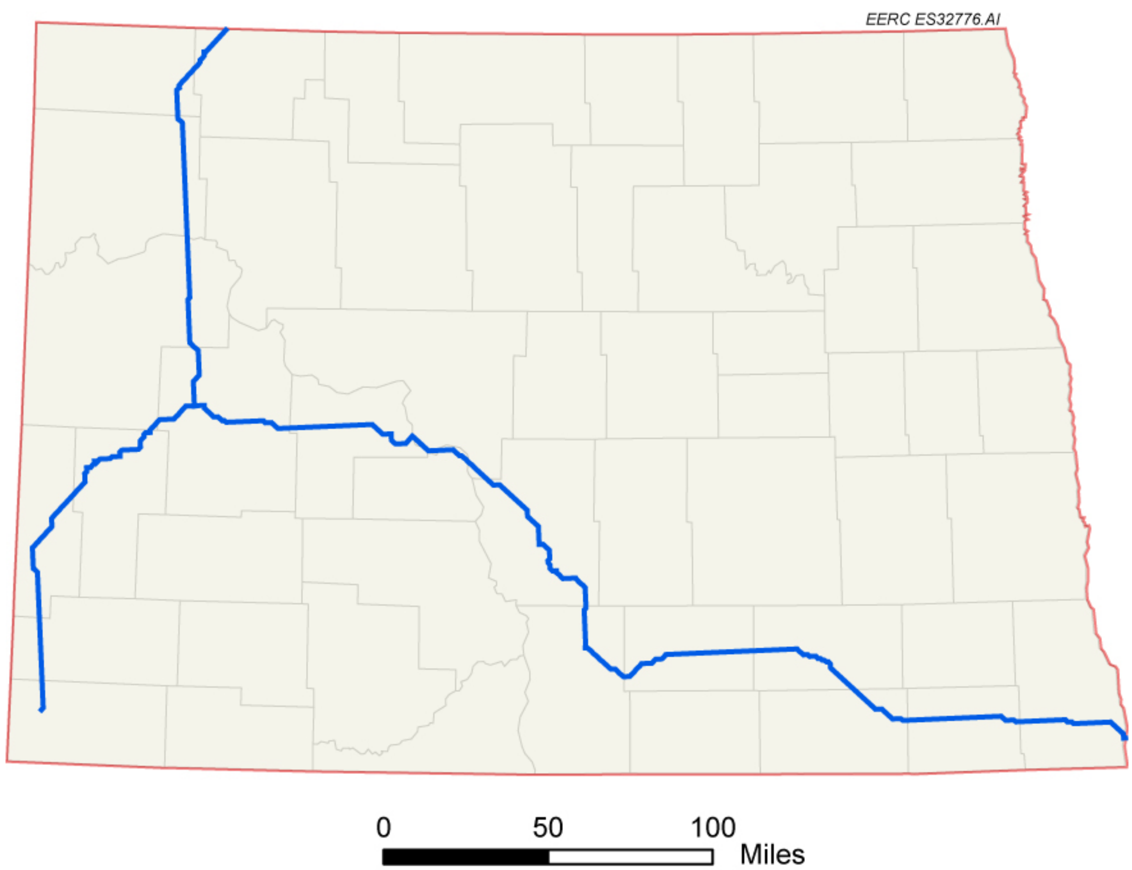



Figure E-8. Map showing pipeline routes in North Dakota.

## SASKATCHEWAN

**Table E-9. Summary of $CO_2$ Pipelines in Saskatchewan[1]**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 20 | 20 | 28.0 | 0.10 |
| 90 | 16 | 100.8 | 0.45 |
| **110** | **–** | **128.8** | **0.55** |

[1] Totals are in bolded text.

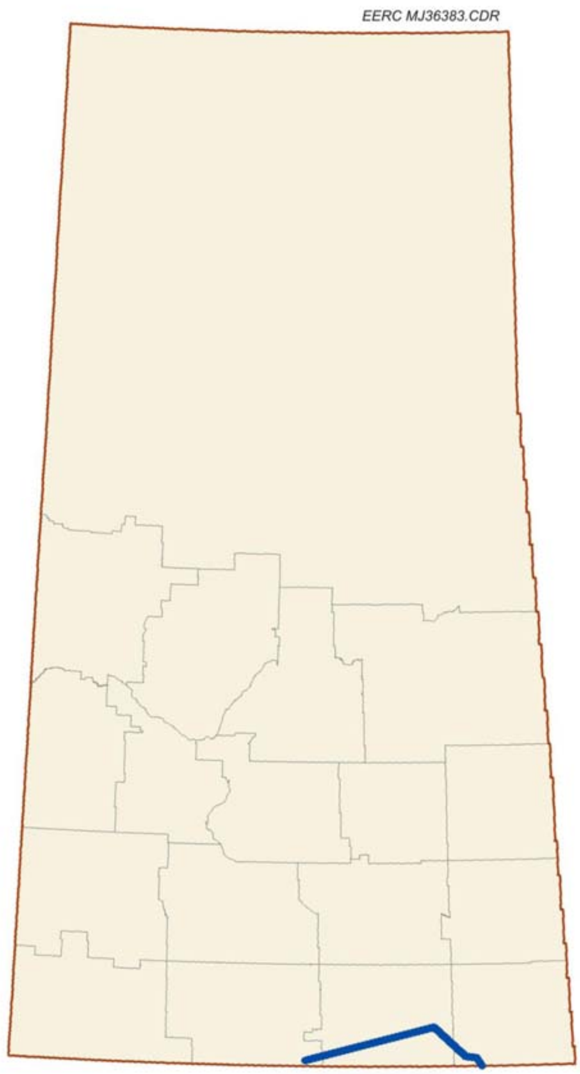



Figure E-9. Map showing pipeline routes in Saskatchewan.

## SOUTH DAKOTA

**Table E-10. Summary of $CO_2$ Pipelines in South Dakota[1]**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 362 | 20 | 506.8 | 1.81 |
| 202 | 16 | 225.8 | 1.01 |
| 21 | 12 | 17.6 | 0.11 |
| 297 | 6 | 124.6 | 1.48 |
| 33 | 4 | 9.2 | 0.17 |
| **915** | **–** | **884.0** | **4.58** |

[1] Totals are in bolded text.

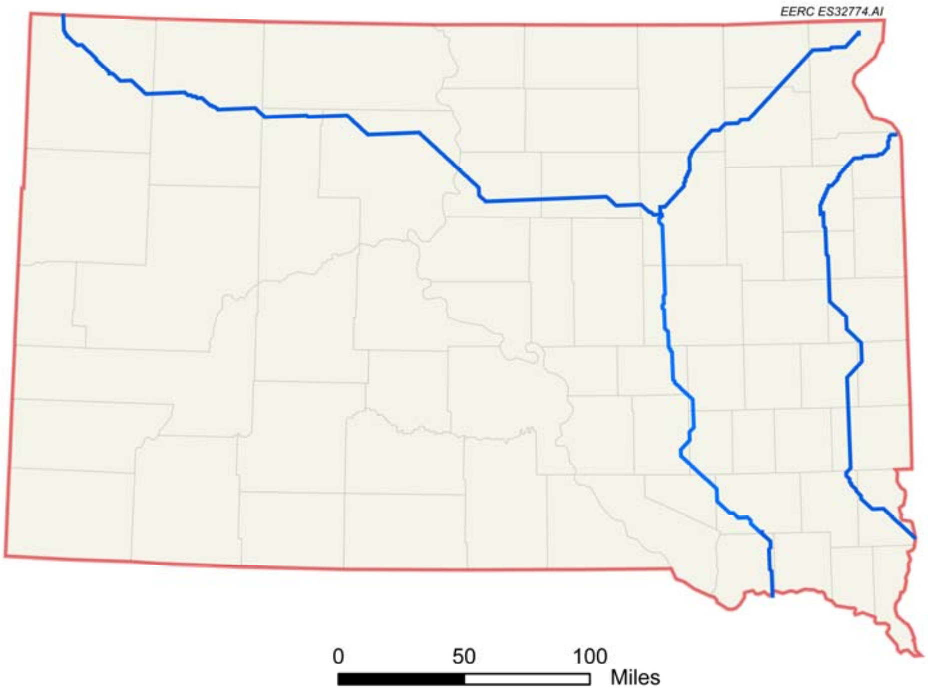



Figure E-10. Map showing pipeline routes in South Dakota.

## WISCONSIN

**Table E-11. Summary of $CO_2$ Pipelines in Wisconsin**[1]

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 165 | 30 | 347.3 | 0.83 |
| 478 | 20 | 669.7 | 2.39 |
| 36 | 16 | 40.3 | 0.18 |
| 64 | 12 | 53.8 | 0.32 |
| 11 | 8 | 6.2 | 0.05 |
| 117 | 6 | 49.1 | 0.59 |
| **871** | **–** | **1166.4** | **4.36** |

[1] Totals are in bolded text.

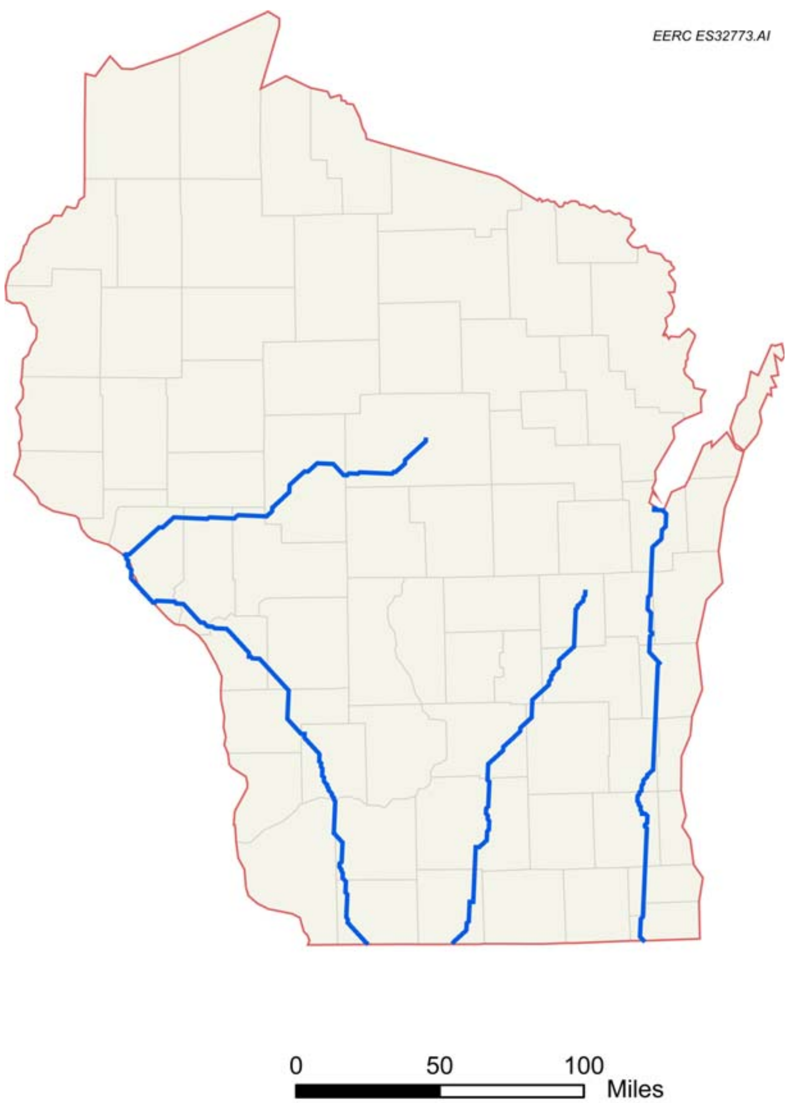



Figure E-11. Map showing pipeline routes in Wisconsin.

**WYOMING**

**Table E-12. Summary of $CO_2$ Pipelines in Wyoming**

| Length, mi | Diameter, in. | Construction Cost, $millions | O&M Cost, $millions/yr |
|---|---|---|---|
| 77 | 12 | 46.4 | 0.385 |

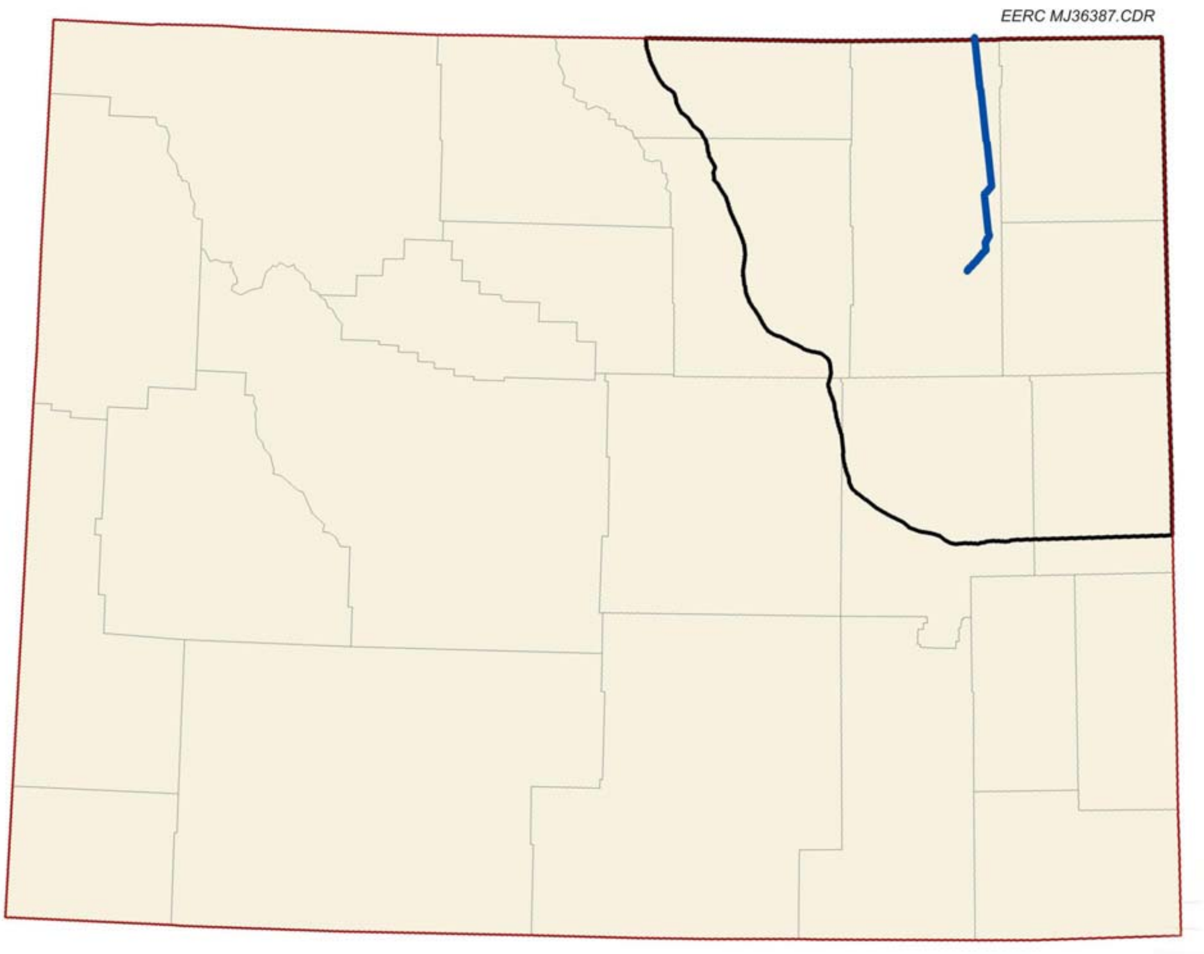



Figure E-12. Map showing pipeline routes in Wyoming.