2011 Updated Facility Design Prevention of Significant Deterioration Air Quality Construction Permit Application Supplement Greenhouse Gases Best Available Control Technology Analysis Source ID No. 1890231

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Prepared For

Abengoa Bioenergy Biomass of Kansas, LLC
Hugoton, Kansas

WLA Project No. 165-009

May 2011

Revision No. 0

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May 25, 2011

Kansas Department of Health and Environment
Bureau of Air and Radiation
Attn: Terry Tavener
1000 SW Jackson Street, Suite 310
Topeka, Kansas 66612-1366

Re: 2011 Updated Facility Design
Prevention of Significant Deterioration Air Quality Construction Permit Application Supplement – Greenhouse Gas Best Available Control Technology Analysis for Abengoa Bioenergy Hybrid of Kansas, Hugoton, Kansas, Source ID No. 1890231
WLA Project No. 165-009

Dear Mr. Tavener:

On behalf of Abengoa Bioenergy Hybrid of Kansas, WLA Consulting, Inc. is submitting three original copies of Greenhouse Gas Best Available Control Technology Analysis for a proposed fuel-grade hybrid ethanol production facility to be located near Hugoton, Kansas.

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Respectfully submitted,

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Section 1.0
PSD Applicability for Greenhouse Gases Summary

1.1 Background

On June 3, 2010, the U.S. Environmental Protection Agency (EPA) issued the final Greenhouse Gas (GHG) Tailoring Rule (75 FR 31514). This rule established the thresholds for GHG emissions that define when permits under the PSD and Title V permit programs are required for new and existing industrial facilities. Without the GHG Tailoring Rule, the thresholds established in the Clean Air Act (CAA) for other pollutants would apply to GHGs. This final rule "tailors" the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits.

Starting in January 2011, only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHGs) would be subject to permitting requirements for their GHG emissions under PSD. For those affected facilities, only GHG emissions increases of 75,000 tons per year (ton/yr) or more of total GHG, on a carbon dioxide equivalent (CO_2e) basis, would need to determine the Best Available Control Technology (BACT) for their GHG emissions.

1.2 PSD Applicability

Abengoa Bioenergy Biomass of Kansas, LLC (ABBK) intends to build and operate a biomass-to-ethanol and biomass-to-energy production facility. This document relies upon information presented in the 2011 updated facility design PSD air quality construction permit application (hereinafter referred to as the "application") for the facility submitted to Kansas Department of Health and Environment (KDHE). Therefore, the facility description and emissions calculations presented in that application are not repeated herein.

According to K.A.R. 28-19-17, *Prevention of Significant Deterioration*, K.A.R. 28-19-200, *General Provisions; Definitions*, and K.A.R. 28-19-300, *Construction Permits and Approvals; Applicability*, the proposed facility is required to obtain a PSD air quality construction permit due to the following:

- The potential to emit (PTE) for the proposed facility equals or exceeds either 25 ton/yr of particulate matter (PM) or 15 ton/yr of PM_{10}; 40 ton/yr of sulfur dioxide (SO_2) or sulfur trioxide (SO_3) or a combination thereof; 100 ton/yr of carbon monoxide (CO); 40 ton/yr of volatile organic compounds (VOC); and 40 ton/yr of oxides of nitrogen (NOx);
- The facility belongs to the following source categories:
    1) Chemical process plant with a Standard Industrial Code (SIC) 2869; and
    2) Fossil fuel boiler totaling more than 250,000,000 Btu/hr with a SIC 4911.
- The facility is a major source of the criteria pollutants: PM/PM_{10}, SO_2, CO, and NOx.

Beginning on January 2, 2011, GHGs are a regulated New Source Review (NSR) pollutant under the PSD permitting program when they are emitted by new sources or modifications in amounts that meet the GHG Tailoring Rule's set of applicability thresholds, which phase in over time. For PSD purposes, GHGs are a single air pollutant defined as the aggregate group of the following six gases:

- carbon dioxide (CO_2)
- nitrous oxide (N_2O)
- methane (CH_4)
- hydrofluorocarbons (HFCs)
- perfluorocarbons (PFCs)
- sulfur hexafluoride (SF_6)

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its global warming potential (GWP). The GWP used for calculating CO_2e are from 40 CFR Part 98 Table A-1 of the Greenhouse Gas Reporting Program (GHGRP). The GHG emissions on both a mass basis and CO_2e basis from ABBK are detailed in Table 1-1.

Table 1–1
Summary of GHG Emissions for Abengoa Bioenergy Biomass of Kansas, LLC
(units in tons per year)

Emission Point ID	Source Description	CO_2	CH_4		N_2O		SF_6		Total GHG Mass-Based Emissions	Total CO_2e-Based Emissions
			Actual	CO_2e	Actual	CO_2e	Actual	CO_2e		
EP-02000	Fugitive Leaks	0.0065	0	0	0	0	0	0	0.0065	0.0065
EP-06001	Firewater Pump Engine	119.30	0.004	0.07	0.0002	0.07	0	0	119.30	119.44
EP-08000	High Voltage Circuit Breakers Fugitive Leaks	0	0	0	0	0	0.00021	4.9	0.00021	4.9
EP-09001	Biogas Flare	20,166	0.005	0.10	0.0001	0.03	0	0	20,166.006	20,166.13
EP-18185	EH Fermentation CO_2 Scrubber	88,356.9	0	0	0	0	0	0	88,356.90	88,356.90
EP-20001	Biomass-Fired Stoker Boiler #1	472,118	155	3,246	20	6,288	0	0	472,293	481,652
Total									**580,840**	**590,204**

1. The GWP for each of the GHGs are:

GHG	GWP
Carbon Dioxide (CO_2)	1
Nitrous Oxide (N_2O)	310
Methane (CH_4)	21
Sulfur Hexafluoride (SF_6)	23,900

2. Short tons (2,000 lbs), not long or metric tons are used in PSD applicability calculations in accordance with the GHG Tailoring Rule.

PSD applies to the GHG emissions from a new source if both of the following are true:

1. Not considering its emissions of GHGs, the new source is considered a major source under the PSD permit program and is required to obtain a PSD permit (called an "anyway source"), and
2. The potential emissions of GHGs from the new source would be equal to or greater than 75,000 ton/yr on a CO_2e basis.

Because ABBK's proposed facility will meet both of the PSD applicability criteria for new sources for GHGs, the facility must meet the requirements of the GHG Tailoring Rule beginning January 2, 2011. Specifically, the PSD permit must contain emissions limitations based on application of BACT for GHGs.

Section 2.0
Best Available Control Technology Analysis

2.1 Best Available Control Technology Requirements

As described in Section 1.0, the proposed facility is subject to PSD review as a new major source for GHGs. The CAA and corresponding implementing regulations require that a permitting authority conduct a BACT analysis on a case-by-case basis, and the permitting authority must evaluate the amount of emissions reductions that each available emissions-reducing technology or technique would achieve, as well as the energy, environmental, economic and other costs associated with each technology or technique. Based on this assessment, the permitting authority must establish a numeric emissions limitation that reflects the maximum degree of reduction achievable for each pollutant subject to BACT through the application of the selected technology or technique. However, if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement.

EPA has recommended that permitting authorities continue to use the Agency's five-step "top-down" BACT process to determine BACT for GHGs. However, EPA provided additional guidance for GHG BACT analysis when evaluating emissions from bioenergy production. Further, EPA proposed on March 11, 2011 to defer for a period of three years, GHG permitting requirements for carbon dioxide (CO_2) emissions from biomass-fired and other biogenic sources. This proposed deferral will allow EPA to conduct a detailed examination of the science associated with CO_2 emissions from bioenergy and other biogenic stationary sources. EPA expects the final action on the proposed deferral rule to take effect in the July 2011 timeframe, and until that time, the determination of BACT is still to be made on a case-by-case basis by the permitting authority, KDHE.

A summary of the units subject to GHG BACT and the BACT requirements for the units are presented in Table 2-1. This section is organized by emission unit and then pollutant. When appropriate, emission units with similar characteristics and BACT applicability are grouped together.

Table 2–1
Summary of Emission Units Subject to GHG BACT and PSD-BACT Limits

Stack ID	Equipment/Process	Proposed BACT Emission Limit(s)	BACT Device(s) or Operational Limitation(s)
EP-08000	HV Circuit Breakers	4.9 short tons CO_2e/yr	State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection to maintain fugitive SF_6 emissions below 0.5% (by weight); implementation of an LDAR program; and density monitor alarm set to 4 psi drop.
EP-20001	Biomass-Fired Stoker Boiler #1	0.32 lb CO_2e/lb steam produced	Restriction of the fuel type to biomass that is otherwise considered to have low to no economic value or benefit, and/or is a lower impacting crops; and lower GHG-emitting processes and practices through an energy-efficient design, incorporating cogeneration, process integration, combustion of co-products, heat recovery and operational and maintenance monitoring.
EP-18185	EH Fermentation CO_2 Scrubber	5.89 lb CO_2e/gal etoh produced	Monitoring enzymatic hydrolysis process efficiency, incorporating monitoring CO_2 production during fermentation, energy efficient heat integration, water recycling, and co-product production.
EP-09001	Biogas Flare	10,170 lb CO_2e/hr and 20,166 short tons CO_2e/yr	Restriction of the fuel type to primarily biogas and pipeline-grade natural gas in the pilot; implementation of an LDAR program; and the use the most efficient flare that can perform to the specification required by the facility's process.
EP-06001	Firewater Pump Engine	480 lb CO_2e/hr and 24.0 short tons CO_2e/yr (Non-Emergency Basis)	Fuel-efficient NFPA-20 certified firewater pump engine (20.3±5% gal/hr fuel consumption limit for a 460 Hp engine with a rated speed of 1760 rpm and an EPA Tier 3 emission rating).

2.2 BACT Methodology

BACT is an emissions limitation based on the maximum degree of reduction that is achievable for each pollutant subject to regulation under the CAA which would be emitted from any major emitting facility, on a case-by-case basis, taking into account technical feasibility, energy, environmental, and economic impacts.

The "top-down" BACT evaluation process requires that all technically feasible control technologies be ranked in descending order of control efficiencies. The most effective technology is selected as BACT unless the applicant demonstrates that energy, environmental and/or economic impacts justify a conclusion that the most effective technology is not "achievable". In this case, the next most effective technology is analyzed until the top performing "achievable" technology is identified.

The BACT analyses presented in this application generally conform to the EPA guidelines. The five steps of the "top-down" BACT evaluation procedure are as follows:

Step 1. Identify all available control options with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.

Step 2. Eliminate technically infeasible or unavailable technology options. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 3. Rank remaining control technologies in order of decreasing effectiveness. This includes:

- control effectiveness (percent pollutant removed);
- expected emission reduction (ton/yr);
- energy impacts (Btu, kW-hr);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness and incremental cost effectiveness).

Step 4. Evaluate most effective controls and document results. A case-by-case evaluation of energy, environmental, and economic impacts is performed for each remaining control technology.

Step 5. Select the most effective control that has acceptable energy, environmental, and economic impacts.

The BACT analysis guidance provided within the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* document was followed during the preparation of this BACT analysis. When necessary and as relevant information was available, the EPA's *1990 Draft New Source Review Workshop Manual* and EPA's **R**ACT/**B**ACT/**L**AER **C**learinghouse (RBLC), as well as GHG Control Measures White Papers published by EPA and recently published GHG BACT analyses for similar sources were relied upon.

2.3 High Voltage Circuit Breakers Equipment Leaks BACT Analysis

2.3.1 Source Emissions

There will be one high voltage circuit breaker, rated at 125 kilovolts (kV) utilized at the facility. The circuit breaker will use a sulfur hexafluoride (SF_6) dielectric, with the circuit breaker containing 82 pounds of SF_6 in an enclosed-pressure system.[1] Circuit breakers do not emit SF_6 directly, but according to an EPA investigation, *SF_6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emissions Source,* there is a potential for fugitive emissions (i.e. equipment leaks).

2.3.2 GHG BACT Review

Sulfur hexafluoride, a gaseous dielectric used in the breakers, is a highly potent greenhouse gas, with a "global warming potential" over a 100-year period that is 23,900 times greater than CO_2. Leakage is expected to be minimal, and is expected to occur only as a result of circuit interruption and at extremely low temperatures. Further, industry standards recommend that new equipment be built to low leakage limits (the International Electrotechnical Commission (IEC) standard for new equipment leakage is 0.5% per year).[2] Nevertheless, given SF_6's high global warming potential, even small amounts of leakage can be significant and should be considered for purposes of a GHG BACT analysis. The following presents the GHG BACT analysis for this source.

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[1] Alstom USA Inc., *Instruction Manual-Type HGF 1012/1014*, HG12IM, Revision 0, Part 1, Page 10, 19.
[2] U.S. EPA, J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting), *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, June 2006, first published in Proceedings of the 2006 IEEE Power Engineering Society General Meeting, Montreal, Quebec, Canada, June 2006 (available at: www.epa.gov/electricpower-sf6/documents/leakrates_circuitbreakers.pdf).

2.3.2.1 *Identify Available Control Options*

The following control options have been identified and considered in determining BACT:

- Use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions;
- Substitution of another, non-greenhouse-gas substance for SF_6 such as the use of a non-SF_6 dielectric oil or compressed air (air blast) circuit breaker as the dielectric material in the breakers; and
- Use an emerging technology to replace SF_6 with a material that has similar dielectric and arc-quenching properties, but without the drawbacks of oil and air-blast breakers.
- Develop and implement a Leak Detection and Repair (LDAR) program, similar to NSPS, Subpart VVa (40 CFR §60.480a through §60.489a), and modified to be source- and pollutant-type specific.

2.3.2.2 *Eliminate Technically Infeasible Control Options*

The use state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the proposed control option. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. The best modern equipment can be guaranteed to leak at a rate of no more than 0.5% per year by weight. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when SF_6 (by weight) has leaked from the breaker. This type of technology is feasible for use and is the baseline established for this BACT analysis.

One alternative to SF_6 would be the use of a dielectric oil or compressed air (air blast) circuit breaker, which historically were used in high-voltage installations prior to the development of SF_6 breakers. This type of technology is feasible for use here, although SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities. The main drawback to oil and air-blast breakers are that these type of breakers require significantly

larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers.

The technical feasibility of emerging technologies alternatives to SF_6 was evaluated. According to the most recent report released by the EPA SF_6 Partnership, "[n]o clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[3] Research and development efforts have focused on finding substitutes for SF_6 that have comparable insulating and arc quenching properties in high-voltage applications.[4] While some progress has reportedly been made using mixtures of SF_6 and other inert gases (e.g., nitrogen or helium) in lower-voltage applications, most studies have concluded, "that there is no replacement gas immediately available to use as an SF_6 substitute"[5] for high-voltage applications. Therefore, the alternative to use an emerging technology to replace SF_6 was determined to be technically infeasible.

2.3.2.3 *Rank Technically Feasible Control Options*

Table 2-2 presents the ranked technically feasible control options.

Table 2–2
Ranked Control Options for High Voltage Circuit Breakers Equipment Leaks

Rank	Control Technology	Emission Rate (short tons CO_2e/year)	Emissions Reduction (short tons CO_2e/year)
1	Oil/air-blast circuit breakers	0	4.9
2	State-of-the-art enclosed-pressure SF_6 circuit breakers	4.9	N/A
3	LDAR	N/A	N/A

Note 1: Implementation of the LDAR program will not generate emissions, nor will it control emissions beyond the baseline. The LDAR program is used to monitor equipment leaks for repair.

[3] U.S. EPA, *SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*, December 2008, Page 1 (available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf).
[4] U.S. Climate Change Technology Program, Technology Options for the Near and Long Term, § 4.3.5, *Electric Power System and Magnesium: Substitutes for SF_6*, November 2003, Page 185 (available at: www.climatetechnology.gov/library/2003/tech-options/tech-options-4-3-5.pdf)
[5] Siemens Power Transmission & Distribution, Inc., Siemens TechTopics No. 53, *Use of SF6 Gas in Medium Voltage Switchgear*, June 3, 2005, Page 3 (available at: www.energy.siemens.com/cms/us/US_Products/CustomerSupport/TechTopicsApplicationNotes/Documents/TechTopics53Rev0.pdf).

2.3.2.4 *Evaluate Technically Feasible Control Options*

The energy, environmental and economic impacts associated with using the oil/air-blast breakers were considered. Oil/air-blast breakers would require additional land to be devoted to the facility's design, would generate additional noise, and would increase the risks of accidental releases of dielectric fluid and/or associated fires. By contrast, according to the National Institute for Standards and Technology, SF_6 "offers significant savings in land use, is aesthetically acceptable, has relatively low radio and audible noise emissions, and enables substations to be installed in populated areas close to the loads."[6] Therefore, oil/air-blast breakers do not surpass the choice of SF_6 breakers because of their adverse environmental impacts. Further, the EPA has recognized SF_6 as the preferred dielectric choice for circuit breakers, gas-insulated substations, and other switchgear used in the transmission system to manage the high voltages and is working with the industry through the SF_6 Emission Reduction Partnership to reduce GHG emissions via cost-effective technologies and practices.

Oil/air-blast breakers are the top-ranked control technology (with essentially no greenhouse gas emissions) when the other impacts (economics, energy, environmental detailed below) are not included in the comparison of the two identified technically feasible control technologies. When economics, energy, environmental are included, the most effective control technology that is technically feasible is the use state-of-the-art enclosed-pressure SF_6 circuit breakers. According to information from circuit breaker manufacturers, this equipment can be guaranteed to achieve a leak rate of 0.5% by year by weight or less. This leak rate meets the current maximum leak rate standard established by the IEC. This leak rate performance can be further enhanced by an alarm system to alert operators to potential leak problems as soon as they occur.

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[6] Christophorou, L.G., J.K. Olthoff and D.S. Green, National Institute of Standards and Technology (NIST), Electricity Division (Electronics and Electrical Engineering Laboratory) and Process Measurements Division (Chemical Science and Technology Laboratory), *NIST Technical Note 1425: Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*, November 1997 (available at: www.epa.gov/electricpower-sf6/documents/new_report_final.pdf).

Although oil/air-blast breakers do not contain SF_6, these breakers were determined to be ranked below SF_6 circuit breakers due to the preferred modern industrial application of state-of-the-art SF_6 technology with leak detection. As stated above, SF_6 has become the predominant insulator and arc quenching substance in circuit breakers today because of its superior capabilities. The use of oil/air-blast breakers would require redesign of the power house at the facility as these types of breakers require significantly larger equipment to replicate the same insulating and arc-quenching capabilities of the SF_6 breakers.

There was one PSD permit identified at the time of this BACT analysis that had completed GHG BACT analysis for a similar type source. The Russell City Energy Center is a proposed natural gas fired combined-cycle power plant that would have a nominal output of 600 Megawatts of electricity (MWe). It is proposed to be located at 3862 Depot Road, near the corner of Depot Road and Cabot Blvd., in Hayward, California. The PSD permit for the Russell City Energy Center was approved by the Bay Area Air Quality Management District on February 3, 2010. The proposed BACT for this facility is similar to the approved BACT for the Russell City Energy Center.

An LDAR program is technically feasible control option for this equipment; therefore, no further evaluation of this control is needed.

2.3.2.5 *Establish BACT*

Based on this top-down analysis, ABBK proposes that GHG BACT for the onsite circuit breakers consist of the following:

- State-of-the-art enclosed-pressure SF_6 circuit breaker with a guaranteed leak rate of 0.5% by weight or less by year;
- Density monitor alarm system; and
- Develop and implement a written LDAR program.

The ABBK facility will require one breaker using 82 lbs of SF_6. At a leak rate of 0.5%, annual SF_6 emissions would be a maximum of 0.41 lbs/year, which would equal approximately 4.9 short tons CO_2e per year.

2.3.2.6 *BACT Compliance*

Fugitive emissions are, by their nature, very difficult to monitor directly as they are not emitted from a discrete emissions point. Fugitive SF_6 emissions can be estimated very accurately, however, by measuring "top-ups", i.e., the replacement of lost SF_6 with new product.[7] It is conservatively assumed that the amount of SF_6 that has leaked and entered the atmosphere is the amount that has to be topped up to maintain a full SF_6 level. Therefore, ABBK proposes that no direct monitoring of SF_6 fugitive emissions be required. In place of direct monitoring, ABBK proposes surrogate monitoring through measuring the amount of SF_6 lost and using a conversion factor to assess annual SF_6 fugitive emissions in terms of CO_2e.

In addition, the effectiveness of the leak-tight closed systems will be enhanced by equipping them with a density alarm that provides a warning when SF_6 has leaked from the breaker. BACT was determined for the Russell City Energy Center project to be state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection and the use of an alarm system to alert controllers when a circuit breaker loses 10% of its SF_6. As established in various EPA publications[8], an SF_6 circuit breaker is classified as leaking if it had documented "top-ups" of SF_6, which occurred after a density alarm sounded, indicating that 10% of the circuit breaker gas volume has been emitted; however, recent industry studies[9] have indicated that the leak monitoring set point of the density alarm may be lowered with a reasonable degree of certainty.

A density monitor is used to monitor for and determine SF_6 leaks by measuring the circuit breaker internal pressure and temperature. The monitor then "compensates" for the difference between the measured

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[7] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, supra note 2, Page 1.
[8] *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source*, supra note 2, Page 1.
[9] Thesen, Sven. Pacific Gas & Electric Co., *PG&E and the New Breaker SF_6 Leak Study,* Page 2 (available at http://www.epa.gov/electricpower-sf6/documents/conf04_thesen_paper.pdf).

temperature and the reference standard of a fully charged breaker defined at installation and calculates the temperature compensated pressure. SF_6 is a real gas, not an ideal gas. A real gas has a pressure-temperature-density relationship described by a curved equation while an ideal gas functions on a straight plane. Because of the pressure-temperature-density relationship, the accuracy of the mechanical monitoring device (density alarm) proposed is impacted by both pressure and temperature changes. The accuracy of the most density monitors is ±2.5% (or 2 psi).[10]

Because of the accuracy limit of the equipment, ABBK will implement a density alarm threshold of 5%. If the density monitor alarm set point drop is 4 psi, this correlates to approximately a 5% decrease in SF_6 mass from the original charge at 80 psig using the known mass of SF_6 at 80 psig and a temperature of 75 °F to calculate the breaker volume. This density monitor alarm threshold is less than the final BACT monitor alarm threshold established for the Russell City Energy Center and is consistent with an EPA Electric Power Systems SF_6 Emission Reduction Partner's (Pacific Gas & Electric Co.), new circuit breakers' density monitor alarm threshold. In the event of an alarm, ABBK will investigate the event and take any necessary corrective action to address any problems. The density alarm threshold of 5% is an alarm threshold value only.

ABBK also proposes to develop and implement a written LDAR program modified from the requirements of 40 CFR Part 60, Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006, to be source- and pollutant-type specific.

ABBK will provide construction specifications, operation and maintenance records, and other record keeping documents to KDHE upon request to demonstrate compliance with BACT. ABBK will also provide a copy of the

[10] *PG&E and the New Breaker SF_6 Leak Study*, Page 3

LDAR program and documentation regarding observations and/or repairs made in accordance with the LDAR program to KDHE upon request to demonstrate compliance with BACT.

2.4 Cogeneration Biomass-Fired Boiler BACT Analysis

2.4.1 Source Emissions

The cogeneration plant will employ one water-cooled vibrating grate (stoker) boiler. The boiler will be capable of producing 325,000 pounds per hour of 920 pound-force per square inch gauge (psig) /750 °F steam. The high pressure steam supplies a single condensing-extraction steam turbine generator nominally rated at 22 Megawatts of electricity (MWe). Electrical power will be supplied to the facility. Power sales to the grid are not foreseen at this time.

Enzymatic hydrolysis process steam is extracted from the turbine at a lower pressure from extraction ports. Boiler feedwater preheater steam and deaeration steam is also extracted from the turbine from extraction ports. Exhaust steam is condensed under vacuum against cooling water in the cooling water tower. The stoker boiler's maximum design heat input is 500 million British thermal units per hour (MMBtu/hr). The stoker boiler is capable of burning a combination of raw biomass (consisting of corn stover, wheat straw, milo (sorghum) stubble, corn stover, switchgrass, and other opportunity feedstocks that are available), enzymatic hydrolysis residuals (including lignin-rich stillage cake and thin stillage syrup), particles collected during biomass grinding, NCG vent streams, wastewater treatment sludge and biogas. Natural gas will be used during start-up periods as required per manufacturer recommendations. The stoker boiler will also be capable of firing on natural gas during normal operations as needed at a limited capacity, as well as firing on a combination of natural gas, liquid fuel (i.e. enzymatic hydrolysis thin stillage syrup) and biogas in the event of a solid fuel failure. The cogeneration process will utilize up to 812 dry tons/day of fuel feedstock.

2.4.2 GHG BACT Review

The biomass-fired stoker boiler is the main source of biogenic GHG emissions (CO_2, CH_4, and N_2O) at the facility. The Table 1-1 details the GHGs emitted from the boiler. The total CO_2-based emissions from the boiler are 481,652 short tons/yr of

CO_2e. This amount of CO_2e-based emissions is over 81% of the total facility-wide CO_2e-based emissions.

CO_2 emissions from the combustion of biomass[11] to produce energy are excluded from the energy related CO_2 emissions reported in Annual Energy Outlook 2010 report published by the U.S. Energy Information Administration, an independent statistical agency of the U.S. Department of Energy (DOE). According to current international convention[12], carbon released through biomass combustion is excluded from reported *energy related* emissions. Analysts have debated whether increased use of biomass energy may result in a decline in terrestrial carbon stocks, leading to a net positive release of carbon rather than the zero net release assumed by its exclusion from reported energy related emissions. For example, the clearing of forests for biofuel crops could result in an initial release of carbon that is not fully recaptured in subsequent use of the land for agriculture.[13] As discussed in detail in the Final Environmental Impact Statement (EIS) for the facility prepared by DOE, "DOE anticipates the biorefinery crop residue demand would have a negligible impact on changes in land use type because there would be no incentive to alter land use type for the purpose of meeting demand."[14] Because the EIS specifically addressed the biomass demands and environmental impacts, the results of the EIS are not restated herein. The EIS concluded that land use impacts from the proposed facility would be small and that biomass removal for the use as fuel would not result in significant adverse impacts.

Additionally, the EIS evaluated the fuel life cycle to determine what the overall GHG emissions impacts would be. The EIS stated that "[a]lthough the Abengoa biorefinery would be a source of greenhouse gas emissions, operation of the Abengoa biorefinery would provide a net reduction in greenhouse gas emissions.

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[11] "Biomass energy," as used in this reference, includes solid, liquid, and gaseous energy produced from organic non-fossil material of biological origin.
[12] Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (available at: www.ipcc-nggip.iges.or.jp/public/2006gl/index.html).
[13] U.S. Energy Information Administration, *Annual Energy Outlook 2010 with Projections to 2035*, Report No. DOE/EIA-0383, May 11, 2010 (available at: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2010).pdf).
[14] U.S. DOE, *Final Environmental Impact Statement for the Proposed Abengoa Biorefinery Project near Hugoton, Stevens County, Kansas*, Report No. DOE/EIS-0407, August 2010, Page 4-6 (available at: http://www.biorefineryprojecteis-abengoa.com/uploads/EIS_0407_F-Chapter4_FEIS.pdf).

The EPA guidance, *PSD and Title V Permitting Guidance for Greenhouse Gases*, published in November 2010 (hereinafter referred to as the "November 2010 EPA GHG Guidance") does not provide any direction for GHG BACT when biomass is used as a fuel. The *Guidance for Determining Best Available Control Technology for Reducing Carbon Dioxide Emissions from Bioenergy Production* (hereinafter referred to as the "March 2011 EPA GHG Bioenergy Guidance"), published by the EPA in March 2011 concurrent with the proposed rule to defer application of the PSD permitting requirements to CO_2 emissions from biologically-based materials does provide recommendations for GHG BACT analyses performed for electricity-generating facilities that would utilize biomass fuels alone in the primary production process. EPA Region 7 has indicated that the GHG analysis completed for the facility in the EIS would not meet the BACT requirements for GHG PSD and that the biomass-boiler must go through the "top-down" BACT process to determine BACT for GHGs.[15]

To complete the GHG BACT analysis for the biomass-fired stoker boiler, KDHE recommended that the *March 2011 EPA GHG Bioenergy Guidance* be utilized. The following presents the GHG BACT analysis for this source.

2.4.2.1 *Identify Available Control Options*

Based on the March 2011 EPA GHG Bioenergy Guidance, the options listed as Step 1 of a "top-down" BACT analysis for GHG may be limited to (1) utilization of biomass fuel alone, (2) energy efficiency improvements, and (3) carbon capture and sequestration.

The following control options have been identified and considered in determining BACT:

- Use of low-carbon and carbon neutral fuels;
  - Corn stover
  - Wheat straw
  - Milo stubble
  - Wood chips/wood residues

[15] KDHE, Electronic Mail from Terry Tavener, November 5, 2010.

  - Switchgrass
  - Other opportunity agricultural residues and energy crops
  - Enzymatic hydrolysis residuals
- Use of lower GHG-emitting processes and practices through an energy-efficient design;
  - Cogeneration
  - Process integration and combustion of process co-products
  - Heat recovery
  - Boiler operational monitoring
  - Boiler maintenance
- Carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration");
- Carbon capture for beneficial uses; and
- Combination of these control options.

There are two broad strategies for reducing GHG emissions from the boiler at the proposed facility. The first is to minimize the production of GHG through the use of low-carbon and carbon neutral fuels and through the use of lower GHG-emitting processes and practices. As discussed in detail in the EIS, the proposed facility will provide a net reduction in GHG emissions because of the fuel selected and the long-term land use benefits. Additionally, the lower GHG-emitting processes and practices require less fuel for process heat, which directly impacts the amount of GHG produced. Establishing an aggressive basis for energy recovery and process efficiency will reduce GHG production. The implementation of the use of low-carbon and carbon neutral fuels and the use of lower GHG-emitting processes and practices are an integral part of the facility's design and are considered the baseline for this BACT analysis.

The second strategy for reducing GHG emissions is carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration") or carbon capture for beneficial uses. These control options are evaluated in

this BACT analysis as additional control options in addition to the baseline control options that are already included in the facility's design.

2.4.2.2 *Eliminate Technically Infeasible Control Options*

There were three main options identified for control of CO_2 emissions from the boiler: 1) low-carbon and carbon neutral fuels; 2) lower GHG-emitting processes and practices through an energy-efficient design; and 3) CCS and/or carbon capture for beneficial uses.

Table 2-3 summarizes the technical feasibility/infeasibility determination discussed in this section.

Table 2–3
GHG BACT Control Technology Technical Feasibility/Infeasibility Determination Summary for the Biomass-Fired Boiler

Potentially Available Control Option	Determination Result	Determination Reason
Fuel Type Restriction to Low-Carbon and Carbon Neutral Fuels	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Lower GHG-Emitting Processes and Practices Through an Energy Efficient Design	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Capture Using Pre-combustion Capture	Technically Infeasible	Technology would redefine the project.
Carbon Capture Using Oxygen-fired Combustion	Technically Infeasible	Technology would redefine the project.
Carbon Capture Using Post-Combustion Capture	Technically Feasible	Chemical absorption has been the most widely used method of commercial CO_2 capture and is the primary CO_2 capture technology further analyzed.
Carbon Transportation	Technically Feasible	Technical issues can be addressed through modern pipeline construction and maintenance practices.
Carbon Storage through Geologic Sequestration	Technically Feasible	In Kansas, geologic sequestration of CO_2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil and natural gas reservoirs, oil- and gas-rich organic shales, and basalt
Carbon Storage through Terrestrial Sequestration	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.

Table 2–3
GHG BACT Control Technology Technical Feasibility/Infeasibility Determination Summary for the Biomass-Fired Boiler

Potentially Available Control Option	Determination Result	Determination Reason
Carbon Beneficial Uses	Technically Feasible	The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization.
Combination of These Control Options	Technically Feasible	See reasons above.

The following discusses each of these control options.

Fuel Type Restriction (Low-Carbon and Carbon Neutral Fuels)

Numerous fuels are available for use in the boiler based on the proposed boiler design. The primary fuel initially to be used is corn stover. Other opportunity feedstocks that may be used if available include wheat straw, milo stubble and waste wood chips. Mixed warm season grasses such as switchgrass is a long-term feedstock that the facility plans to transition to as it's primarily fuel. By the year 2018, ABBK anticipates approximately 240,000 acres (970 square kilometers) of mixed warm season grasses will supply approximately 1,900 dry tons (1,700 metric tons) per day, which equates to 75% of the feedstock demand.

Other process residuals and by-products that are produced at the facility such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup), particles collected during biomass grinding, non-condensable gas (NCG) vent streams, and wastewater treatment sludge and biogas will also be combusted in the boiler. Natural gas will be used during start-up periods as required per manufacturer's recommendations.

Table 2-4 presents the primary proposed fuel types and approximate carbon content for each. Due to the facility's design, only the primary fuels were included in Table 2-4.

Table 2–4
Primary Proposed Fuel Types for the Biomass-Fired Boiler and Approximate Carbon Content

Feedstock	Ultimate Analysis Carbon Content (wt% dry basis)
Corn Stover	40.7%
Wheat Straw	46.6% ±2.8
Milo Stubble	46.1% ±1.8
Switchgrass	46.6%
EH Lignin-Rich Stillage	48.2%
EH Thin Stillage Syrup	35.0%

Note 1: ABBK provided carbon content values for agricultural residues feedstocks. The variation in carbon content is dependent on the amount of ash in the fuel sample, which is further related to the harvesting technique. For the PTE calculations, the carbon content weight percent dry basis used is the projected overall average for the site-specific feedstock.

It should be noted that agricultural residues typically contain very similar amounts of carbon, with wood having a slightly higher content of carbon and enzymatic hydrolysis residuals having a slightly lower content of carbon.

The boiler will not be able to burn the other process residuals and by-products individually and these supplemental fuels are fed to the boiler to either: 1) increase the overall efficiency of the facility's processes; or 2) combust by-products that would otherwise require off-site disposal. Because the primary fuel(s) will be blended during combustion with supplemental fuels, the nominal fuel blend and worst-case fuel blends were reviewed. Table 2-5 presents the CO_2 emission rates for the proposed fuel blends compared to other common fossil fuels used for electricity generation.

Table 2–5
CO_2 Emission Rates for the Proposed Fuel Blends in the Biomass-Fired Boiler Compared to Other Common Fossil Fuels Used for Electricity Generation

Fuels	Emission Factors (lb/MMBtu)		
	CO_2	CH_4	N_2O
PROPOSED FUEL BLENDS			
Nominal TYPICAL Fuel Blend – Corn Stover: 185.3 dry ton/day – EH Lignin-Rich Stillage: 320.6 dry ton/day – EH Thin Stillage Syrup: 209.5dry ton/day – Biogas: 52.7 dry ton/day	216.00	0.071	0.009
Maximum WORST CASE Fuel Blend – Corn Stover: 109.3 dry ton/day – EH Lignin-Rich Stillage: 384.7 dry ton/day – EH Thin Stillage Syrup: 251.4 dry ton/day – Biogas: 63.2 dry ton/day	215.54	0.071	0.009
COMMON FOSSIL FUELS USED FOR ELECTRICITY GENERATION			
Natural Gas	117.00	0.002	0.0002
Distillate Fuel Oil (#1, #2 and #4)	161.30	0.007	0.001
Electric Power (Coal Combustion)	208.26	0.002	0.004

Note 1: Fossil fuel emissions factors obtained from the California Climate Action Registry, General Reporting Protocol, Version 3.1, January 2009, Tables C.7 and C.8.

The DOE[16, 17] and IPCC[18,] have established that non-fossil fuel-based electricity generation (including both biomass and biogas) is assumed to yield no net emissions of CO_2 (i.e. these fuels are carbon neutral) because of the sequestration of biomass during the planting cycle. Other carbon reporting protocols, such as the California Climate Action Registry's (CCR), *General Reporting Protocol*, specifically state that CO_2 emissions from burning wood, wood waste and biogas are considered biogenic and

[16] Under the carbon accounting protocol of the IPCC, use of biomass fuels for energy does not add to the net amount of carbon in the atmosphere. Multiple DOE laboratories including the National Renewable Energy Laboratory (NREL) and the National Energy Technology Laboratory (NETL), recognize and follow the IPCC carbon accounting protocol.
[17] *Technical Guidelines, Voluntary Reporting of Greenhouse Gases (1605(b)) Program*, Office of Policy and International Affairs, U.S. Department of Energy, January 2007, Page 51 (available at: http://www.pi.energy.gov/documents/January2007_1605bTechnicalGuidelines(1).pdf)
[18] National Greenhouse Gas Inventories Program, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds), *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry and Other Land Use* (available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html)

should not be included as a direct stationary emissions in CO_2 inventories. Therefore, the proposed primary fuels are presented in this BACT as carbon neutral fuels. The natural gas used for the start-up of the boiler is a low carbon fuel as illustrated in Table 2-5.

BACT based on this control option is the use of biomass as a primary feedstock that is otherwise considered to have low to no economic value or benefit (i.e. crop residuals and waste wood); and/or is a lower impacting crops (i.e. mixed warm season grasses such as switchgrass). BACT based on this control option is also limiting the boiler to using natural gas for start-up. This control option is technically feasible for the biomass-fired boiler, is an inherent part of the facility's design, and is considered a baseline control option.

Lower GHG-emitting Processes and Practices Through an Energy-Efficient Design

There are numerous strategies for achieving a highly energy efficient design of a new condensing-extraction steam turbine electrical power generation facility. Energy efficiency in the overall design of the power production process reduces the parasitic load, which in turn requires less fuel for process heat to generate the same amount of electricity, which directly impacts the amount of GHG emissions from the facility. All identified strategies (i.e. control options) listed in this section are technically feasible for application to the biomass-fired boiler, as well as related processes, and all are an inherent part of the facility's design.

- Cogeneration as a CO_2 Reduction Strategy – Cogeneration is the simultaneous production of electric power and thermal energy from a single fuel. The reduction in CO_2 emissions from employing cogeneration comes from the reduced fuel use at electric utility power plants; thus, the amount of CO_2 reduction is dependent upon the type of electric utility power generation displaced. The use of the direct-fired boiler system in which biomass feedstocks are burned directly will produce steam. This steam drives a turbine, which turns a generator that converts the power into electricity. The spent steam from the onsite power plant is then

used in other process areas at the facility and to heat facility buildings, when feasible. Such combined heat and power systems greatly increase overall energy efficiency which has a direct impact on the amount of GHG emissions from the system.

- Process Integration and Combustion of Co-products – ABBK will make use of the most advanced design approaches to integrate the process units and to maximize energy efficiency. Some of the major integration measures of the power generation system with other facility processes include low pressure steam supplied to the enzymatic hydrolysis process and the combustion of process co-products such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup), particles collected during biomass grinding, NCG vent streams, and wastewater treatment sludge and biogas. The largest co-product (on a mass basis and energy basis) is the lignin-rich stillage cake, as detailed in the PTE calculations. The lignin-rich stillage cake adds approximately 210 MMBtu/hr to the total boiler system. The next largest co-product (on a mass basis and energy basis) is the thin stillage syrup, which adds approximately 109 MMBtu/hr. Wastewater treatment will consist of anaerobic treatment followed by aerobic treatment for the purpose of generating a biogas that can be added to the boiler as fuel for an additional 42.30 MMBtu/hr of energy.
- Heat Recovery – Periodically or continuously, some water in the boiler is removed as a means of avoiding the build-up of water impurities in the boiler. The boiler's design includes blowdown waste heat exchangers with raw water makeup. The low pressure boiler feedwater will be preheated with a combination of process waste heat and low pressure steam extraction to improve the power cycle efficiency. Also, process steam condensate is recovered from indirect process steam users and returned to the boiler feedwater system. The process condensate will be cooled with reverse osmosis water, in order to meet the temperature requirements on the condensate polishing resin. The energy is recovered in the reverse osmosis makeup water. Air preheat,

which is a method of recovering heat from the hot exhaust gas of a combustion process by heat exchange with the combustion air before it enters the combustion chamber, will be included in the boiler's design. In addition to process integration techniques to be utilized, the boiler's design includes economizers to improve power cycle.

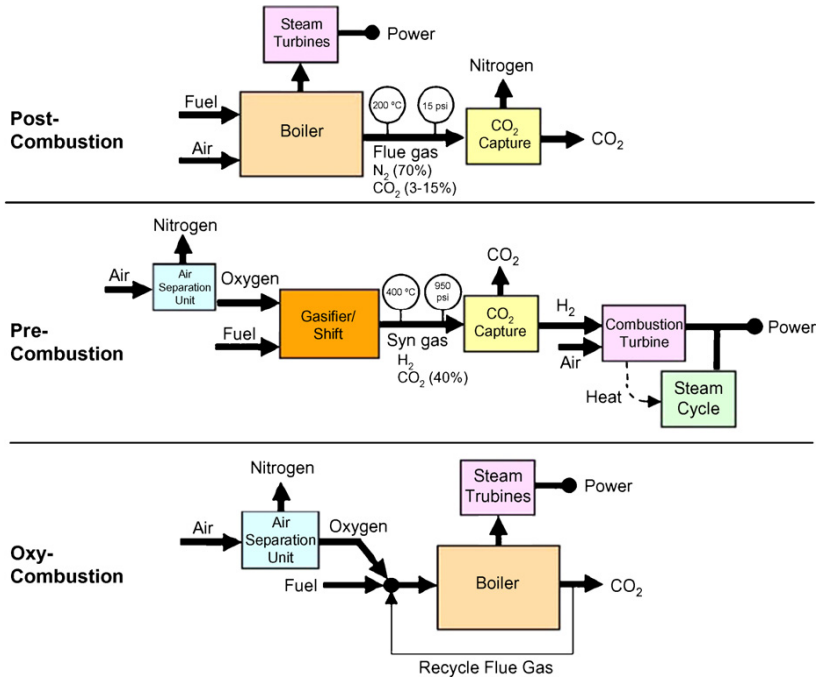
- Boiler Operational Monitoring – Excessive amounts of combustion air used in results in energy inefficient operation because more fuel combustion is required in order to heat the excess air to combustion temperatures. Using state-of-the-art instrumentation for monitoring and controlling the excess air levels in the combustion process, will reduce the heat input by minimizing the amount of combustion air needed for safe and efficient combustion. The boiler's design includes an online stack oxygen analyzer. Oxygen levels will be monitored and the inlet air flow will be adjusted for optimal thermal efficiency within the operating limits of the boiler. Additionally, optimized air/fuel ratios, reduce not only CO_2 emissions but also NOx emissions. The boiler will be equipped with online stack oxygen analyzers as part of the continuous emission monitoring system (CEMS).
- Boiler Maintenance – The boiler will be maintained in accordance with the manufacturer's recommendations. Maintenance of the boiler is performed to increase efficiency, ensure safety and prevent unscheduled shutdowns. Boiler outages for 10 to 14 days each year are planned for scheduled maintenance, cleaning, and "tune-up" to optimize performance.

Carbon Capture

Approaches to CO_2 capture can be divided into three categories: pre-combustion, oxygen-fired combustion, and post-combustion capture. Within these categories are different technologies that can be used.

Figure 2-1 presents block flow diagrams of each of the categories.[19] A description of each method and the different technologies follows.

Figure 2–1
Block Flow Diagrams Illustrating Post-combustion, Pre-combustion, and Oxy-combustion Systems



Pre-combustion capture involves reacting a fuel with oxygen or air, and/or steam to produce a "synthesis gas" or "fuel gas" composed mainly of CO and H_2. The CO is reacted with steam in a catalytic reactor, called a shift converter, to give CO_2 and more H_2. CO_2 is then separated from the gas mixture, usually by a physical or chemical absorption process, resulting in a hydrogen-rich fuel which can be used in many applications, such as a combustion turbine or boiler. This approach would require a complete redesign of the boiler so that they would burn a gaseous fuel. The

[19] Jose´ D. Figueroa (National Energy Technology Laboratory, NETL), Timothy Fout (NETL), Sean Plasynski (NETL), Howard McIlvried (Science Applications International Corporation), Rameshwar D. Srivastava (Science Applications International Corporation), International Journal of Greenhouse Gas Control 2, *Advances in CO_2 Capture Technology—The U.S. Department of Energy's Carbon Sequestration Program*, 2008, first published online September 17, 2007, Page 11 (available at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/CO2%20Capture%20Paper.pdf).

November 2010 EPA GHG guidance states that control technologies with inherently lower polluting processes that would fundamentally redefine the nature of the source do not need to be evaluated.[20] The DOE is proposing to provide federal funding to ABBK to support the final design, construction, and startup of the biomass-to-ethanol and biomass-to-energy production facility. The DOE funding is based on the proposed facility design. ABBK's basic or fundamental business purpose/objective for this project is dependent on the biomass-fired boiler design as proposed. Therefore, pre-combustion as a control technology is technically infeasible.

In the oxygen-fired combustion (oxy-combustion) approach, the biomass is combusted in an enriched oxygen environment resulting in a flue gas that is mainly CO_2 and H_2O. This flue gas stream can be fed directly into a CO_2 compression and dehydration unit. Oxygen-fired combustion is simpler and less chemically intensive than post-combustion CO_2 capture, but is less mature and similarly expensive. Because the boiler is designed to use air for combustion, the use of oxygen would require substantial redesign. As discussed previously, the November 2010 EPA GHG guidance states that control technologies with inherently lower polluting processes that would fundamentally redefine the nature of the source do not need to be evaluated. Therefore, oxy-combustion as a control technology is technically infeasible.

Post-combustion capture methods are applied to conventional combustion processes using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains nearly 80% nitrogen, the CO_2 concentration in the exhaust gases is approximately 10% to 15% depending on the amount of

[20] *PSD and Title V Permitting Guidance for Greenhouse Gases*, supra note13, Page 27.

excess air and the carbon content of the fuel. Additionally, post-combustion capture of CO_2 is a challenging application because:[21]

- The low pressure and dilute concentration dictate a high actual volume of gas to be treated;
- Trace impurities in the flue gas tend to reduce the effectiveness of the CO_2 absorbing processes; and
- Compressing captured CO_2 from atmospheric pressure to pipeline pressure (1,200 to 2,000 psi) represents a large parasitic load.

Post-combustion capture methods require separating the CO_2 from other flue gases because sequestration of combustion gases is not feasible due in part to the cost of gas compression and storage. The most likely options currently identifiable for CO_2 separation and capture include:[22]

- Absorption (chemical and physical)
- Adsorption (physical and chemical)
- Low-temperature distillation (cryogenic separation)
- Gas separation membranes
- Mineralization and biomineralization (carbon calcification)

Chemical absorption has been the most widely used method of commercial CO_2 capture for over 60 years.[23] The main existing commercial applications include enhanced oil recovery (EOR), which involves increasing oil production rates by injecting CO_2 into oil wells. Liquid scrubbing is the most common form of chemical absorption, consisting of two contacting towers (one for CO_2 absorption and one for CO_2 desorption/absorbent regeneration). Chemical absorption is a chemical reaction that forms a loosely bonded intermediate compound. For the CO_2 capture application, a chemical solvent is exposed to the flue gas where it reacts chemically with CO_2 separating it from the other gases. The

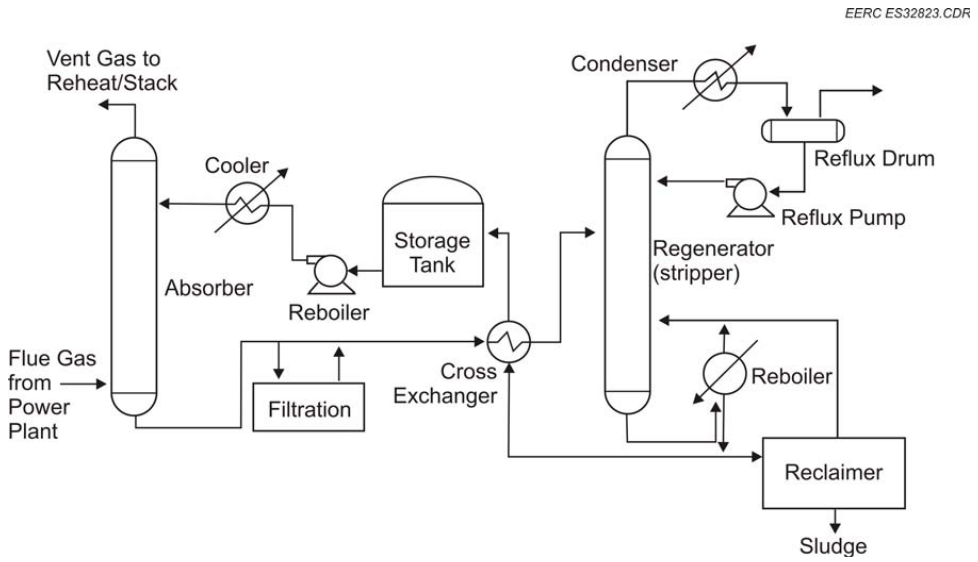
[21] NETL, *Carbon Sequestration, CO_2 Capture* website (available at: http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html).
[22] U.S. DOE, *Carbon Capture Research* website (available at: http://www.fossil.energy.gov/programs/sequestration/capture).
[23] Herzog, H., *An Introduction to CO2 Separation and Capture Technologies,* MIT Energy Laboratory, August 1999 (available at: http://sequestration.mit.edu/pdf/introduction_to_capture.pdf).

intermediate compound is then isolated and heated causing it to break down into separate streams of CO_2 and solvent. The solvent most often used is monoethanolamine (MEA). The primary concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities and high solvent degradation rates due to reactions with SO_2 and NOx. Degradation and oxidation of the solvents over time produces products that are corrosive and may require hazardous material handling procedures. These difficulties can be overcome, and this capture method is technically feasible. Figure 2-2 depicts a generic MEA chemical absorption system (essentially a liquid scrubbing system for CO_2).[24] Other chemical absorption methods are at bench and laboratory scales of development. No CO_2 absorption technology demonstrations, except for liquid scrubbing using alkanolamines for CO_2 removal, have been successfully performed on similar type and sized sources[25].

[24] Energy & Environmental Research Center, University of North Dakota, *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, 2010-EERC-08-15, December 2009.

[25] The PCOR December 2009 report indicated that a technology demonstration project for liquid scrubbing using ammonia as the absorbent was to be conducted at the Basin Electric Power Cooperative for the 125 MW Antelope Valley Power Station. As of December 2010, Basin Electric postponed the CO_2 capture project due to technical, operational, regulatory and financial risks for installing carbon-capture technology at the conventional coal-based power plant. No technology demonstrations have been

Figure 2–2
Generic MEA Chemical Absorption (Liquid Scrubbing) System



Physical absorption processes are commonly used for CO_2 rejection from natural gas and operate at high pressure and low temperature. Use of physical absorption for CO_2 capture from combustion exhaust gas would entail a significant amount of gas compression capacity and a significant energy penalty. This capture method is presumed for the purposes of this analysis to be technically feasible, but because chemical absorption has been commercially demonstrated for CO_2 capture and physical absorption does not offer any capture/control, capital or operating cost benefits, this CO_2 capture technique will not be considered further in this analysis.

Adsorption involves ducting the exhaust gas through a bed of solid material with high surface areas, such as zeolites or activated carbon to adsorb CO_2 while allowing nitrogen and other gases to pass through. Adsorption would require either a high degree of compression or multiple separation steps to produce high CO_2 concentration from exhaust gas. Cryogenic separation is based on solidifying the CO_2 component of the exhaust stream by freezing it to separate it out. Gas separation membranes (or simply membranes) capture CO_2 by separating it from the other exhaust gases using different mechanisms of separation including solution-diffusion and molecular sieving. Mineralization offers a leak-

proof, permanent solution, whereby CO_2 is fixed into a solid matrix of minerals to form thermodynamically stable carbonate minerals. The large volumes of material involved with mineralization present significant challenges for transportation and handling. No large-scale demonstrations of these technologies have been performed on similar exhaust streams. These capture methods are presumed for the purposes of this analysis to be technically feasible, but because these methods have not been commercially demonstrated for CO_2 capture, these CO_2 capture technique will not be considered further in this analysis.

Based on identified post-combustion CO_2 separation and capture methods, the only commercially demonstrated method for similar exhaust streams is chemical absorption (liquid scrubbing employing alkanolamines).

Carbon Transport

Once captured, CO_2 must be transported to a suitable storage site in order to achieve any environmental benefit. CO_2 pipelines are the most prevalent means of bulk CO_2 transport and are a mature market technology in operation today.[26]

Pipeline transportation of CO_2 is typically accomplished with CO_2 that is compressed to its supercritical state, involving pressures of 1,200 to 2,000 psi. In addition, water must be eliminated from CO_2 pipeline systems, as the presence of water results in formation of carbonic acid, which is extremely corrosive to carbon steel pipe. In overall construction, CO_2 pipelines are similar to natural gas pipelines, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. All of these technical issues can be

[26] Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories, Volume 2: Energy, Chapter 5: Carbon Dioxide Transport, Injection and Geological Storage, § 5.4: *CO_2 Transport*, 2006, Page 5.8 (available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_5_Ch5_CCS.pdf).

addressed through modern pipeline construction and maintenance practices.

Carbon Storage

Deploying carbon storage in commercial-scale applications requires adequate geologic formations capable of: 1) sequestering large volumes of CO_2; 2) receiving CO_2 at an efficient and economic rate of injection; and 3) retaining CO_2 safely over extended periods.

In south-central and southwest Kansas, potential geologic sequestration sites within saline aquifers and depleted oil reservoirs within the Ozark Plateau Aquifer System (OPAS) are being studied. Starting in December 2009, the University of Kansas, BEREXO Inc., Bittersweet Energy Inc., the Kansas Geological Survey, and the Kansas State University, began to evaluate potential CO_2 sequestration sites within saline aquifer and depleted oil reservoirs within the OPAS. The study is focusing on the Wellington Field, with evaluation of the CO_2-EOR potential of its Mississippian Chert Reservoir and the sequestration potential in the underlying Cambro-Ordovician Arbuckle Group Saline Reservoir.[27] The purpose of the study is to provide a more detailed analysis of the storage potential of a local area within OPAS (an area covering approximately 17 counties in south-central Kansas) by modeling CO_2 injection within the Arbuckle Group Saline Aquifer and Mississippian Chert Oil Reservoir at Wellington Field (Sumner County, Kansas).

Currently, CO_2 is only captured in Kansas at a few facilities that produce high-purity CO_2.[28] In Kansas, geologic sequestration of CO_2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil and natural gas reservoirs, oil- and gas-rich organic shales, and

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[27] U.S. DOE, National Energy Technology Laboratory, *Modeling CO_2 Sequestration in a Saline Reservoir and Depleted Oil Reservoir to Evaluate The Regional CO_2 Sequestration Potential of The Ozark Plateau Aquifer System, South-Central Kansas*, FE0002056, May 2010 (available at: http://www.netl.doe.gov/publications/factsheets/project/FE0002056.pdf).

[28] Kansas Geological Survey, Geologic Sequestration of Carbon Dioxide in Kansas, Public Information Circular 27, December 2008 (available at: http://www.kgs.ku.edu/Publications/PIC/pic27.html).

basalt (the most problematic because no one knows how much CO_2 the ancient rock--deeply buried in parts of Kansas--can hold). Altogether, researchers estimate Kansas has at least 2.7 to 5.4 billion tons of potential geologic sequestration space, enough to hold almost 70 years worth of the state's stationary CO_2 production.[29] Stevens County, Kansas is located in an area known for oil and gas production, as well as deep saline formations. The proposed facility will be constructed in Section 18, Township 33S, Range 37W. Within this area are the Hugoton Gas Area, Panoma Gas Area and Gentzler oil and gas fields. Table 2-6 summarizes the oil and gas production for the state and county in 2009.[30, 31]

Table 2–6
Summary of Oil and Gas Production in State of Kansas and Stevens County For 2009

Oil Production	Production (bbls)	No. of Wells	Cumulative (bbls)
State-Wide	39,465,916	45,609	6,313,426,149
Stevens County	954,680	153	26,277,308
County Percentage	2.42%	0.34%	0.42%
Gas Production	**Production (mcf)**	**No. of Wells**	**Cumulative (mcf)**
State-Wide	359,713,536	25,836	38,724,276,993
Stevens County	53,957,264	2,196	8,698,699,483
County Percentage	15.00%	8.50%	22.46%

Note 1: Units are barrels (bbls) and million cubic feet (mcf).

In Kansas, concerns have been raised about regulating CO_2-EOR and other geologic sequestration activities and whether the CO_2 would be trapped in these reservoirs or move back to the surface over time. Because Kansas has long been drilled for oil and gas and some areas have been very densely drilled, concerns also exist that CO_2 could move back to the surface through poorly plugged or long-forgotten wells.

According to the Kansas Geological Survey, sequestration in Kansas needs to be studied in more detail to determine if oil and natural gas reservoirs

[29] *Geologic Sequestration of Carbon Dioxide in Kansas*, supra note 27.
[30] Kansas Geological Survey, *State Production and Historical Information* website (available at: http://www.kgs.ku.edu/PRS/petro/state.html).
[31] Kansas Geological Survey, *Stevens County – Oil and Gas Production* website (available at: http://www.kgs.ku.edu/PRS/County/rs/stevens.html).

and coal beds have the capacity to take and hold CO_2. In addition, a variety of legal issues, such as ownership of the underground pore space used for sequestration, would need to be resolved, and a workforce would have to be developed. Ultimately, regulatory decisions, economics, and a well-defined environment for GHG management will highly influence any decisions concerning the feasibility of geologic sequestration.[32]

In addition to the CO_2 storage options already discussed, the other primary storage option available includes using terrestrial applications. Terrestrial sequestration is the enhancement of CO_2 uptake by plants that grow on land and in freshwater and, importantly, the enhancement of carbon storage in soils where it may remain more permanently stored.

In general, croplands store less carbon than grasslands which store less carbon than forests. Grasslands are particularly good at storing carbon in soils because they often have extensive and deep roots. DOE determined in the EIS that "warm season grass production would likely occur on marginal and non-harvested cropland, pasture, and former CRP lands. Bioenergy crops have the potential to reduce atmospheric carbon by building up soil carbon levels, especially when planted on lands where soil carbon levels have been reduced by intensive tillage, such as marginal cropland. In instances where pasture or former CRP lands would be converted to warm season grass production, exchanging one system of perennial vegetation for another would be expected to involve minimal environmental changes, including greenhouse gas emissions. A 2007 study on the Life-Cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types[33] concluded that cellulosic ethanol produced from switchgrass [switchgrass is a type of warm season grass] clearly offers the greatest energy and [greenhouse gas] benefits (by far)."[34]

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[32] *Geologic Sequestration of Carbon Dioxide in Kansas*, supra note 27.
[33] Michael Wang, et. al., Center for Transportation Research, Argonne National Laboratory *Life-Cycle Energy and Greenhouse Gas Emission Impacts of Different Corn Ethanol Plant Types*, first published May 22, 2007 (available at: http://iopscience.iop.org/1748-9326/2/2/024001/pdf/1748-9326_2_2_024001.pdf).
[34] *Final Environmental Impact Statement for the Proposed Abengoa Biorefinery Project near Hugoton, Stevens County, Kansas*, supra note 11, Page 4-30.

Based on these considerations, DOE concluded that in the event warm season grasses were to replace corn stover as the dominant feedstock, the net result to greenhouse emissions would be beneficial. By the year 2018, ABBK anticipates approximately 240,000 acres (970 square kilometers) of mixed warm season grasses will supply approximately 1,900 dry tons (1,700 metric tons) per day, which equates to 75% of the feedstock demand. The change from corn stover to grasses is dependent first on the construction of the facility to generate the crop demand, and second on the negotiation of contracts with local farmers to change their farming practices from corn to grasses. ABBK's long-term operational plan for this facility is based on the feedstock change to mixed warm season grasses.

Terrestrial sequestration provides an opportunity for low-cost CO_2 emissions offsets. Storing carbon in terrestrial ecosystems can be achieved through maintenance of standing aboveground biomass, utilization of aboveground biomass in long-lived products, or protection of carbon (organic and inorganic) compounds present in soils.[35] Because the proposed source consists of a biomass-fired boiler, this type of CO_2 storage is essentially being implemented as part of the facility's design; therefore, terrestrial sequestration is considered a baseline control option.

Carbon Beneficial Uses

In addition to using CO_2 for enhanced oil recovery (EOR), there are many other possible beneficial and revenue-generating uses for captured CO_2 in various stages of development. Technologies are being developed today that synthesize solid materials such as plastics, or carbonates that can be used in cement or glass, from a CO_2 feedstock. There are other technologies under development that do not provide long-term storage of CO_2, but which still could reduce overall GHG emissions by either
1) using CO_2 in a way that displaces the emission of other GHGs, or
2) converting CO_2 into a chemical that can in turn displace the emission of

[35] Gary K. Jacobs, et. al., Oak Ridge National Laboratory, Oak Ridge, TN, *Carbon Sequestration in Terrestrial Ecosystems: A Status Report on R&D Progress*, August 2000 (available at: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/3C1.pdf).

other GHGs. An example of the former is using CO_2 as a refrigerant that substitutes for chemicals currently used in refrigeration that are far more potent greenhouse gases than CO_2, such as hydrofluorocarbons (HFCs). An example of the latter is the wide array of "CO_2-to-fuel" technologies being researched with the goal of producing liquid fuels ranging from methanol or ethanol to gasoline or diesel out of CO_2 and water, along with an energy input (preferably from a CO_2-free source such as solar or wind). Fuels produced from waste CO_2 could displace the use of petroleum-derived fuels, which would result in reduced net GHG emissions.

Some of the better-known types of CO_2-to-fuel technologies are biologically based and use algae and other photosynthetic microorganisms in the conversion of CO_2, water, and sunlight into liquid fuel. A number of different companies are trying to commercialize technologies that use photosynthetic microbes to convert CO_2 to fuel. Some other uses of CO_2 that are being researched do not clearly reduce GHG emissions directly or indirectly, but still provide some other public benefit such as displacing the use of the toxic chemicals or saving water. Examples include using CO_2 as a solvent in place of perchlorethylene for dry cleaning, or using CO_2 as a non-toxic grain silo fumigant.

The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization. They also vary widely in their potential to impact overall GHG emissions. There is a need to better understand the viability of the various technological options for CO_2 use and their potential to incentivize industrial carbon capture and provide substantive GHG emissions reductions.

The majority of CO_2 in the merchant market[36] is used for EOR (approximately 70% to 80%),[37] along with a significant portion used in the

[36] Market in which CO_2 is bought and sold competitively by multiple market participants.

food processing industry. CO_2 currently being utilized that has been separated from flue gas or chemical process streams is generally either captured from relatively pure flue gas streams or from process streams where CO_2 capture and separation is necessitated by a need for product purity (e.g., natural gas pipelines or ammonia production).[38]

For the purposes of this BACT analysis, the feasibility of CO_2 capture, including economic, energy and environmental impacts, must first be established before storage and beneficial use options can be fully explored.

2.4.2.3 *Rank Technically Feasible Control Options*

Table 2-7 presents the ranked technically feasible control options.

Table 2–7
Ranked Control Options for the Biomass-Fired Boiler

Rank	Control Technology	Emission Rate (short tons CO_2/year, excludes CH_4 and N_2O)	Reduction Efficiency	Emissions Reduction (short tons CO_2/year, excludes CH_4 and N_2O)
1	Carbon Capture and Storage (CCS)	~48,000	90%	~433,500
2	Carbon Capture for Beneficial Uses	~48,000	90%	~433,500
3	Baseline (Fuel Type Restriction, Use of Lower GHG-emitting Processes and Practices Through an Energy Efficient Design and Terrestrial Sequestration)	481,652	N/A	N/A

Note 1: CCS and carbon capture for beneficial uses emission rates presented in this table are the emissions rates associated with CO_2 capture only, and do not include the additional emissions generated during CO_2 dehydration, compression, and transport.

[37] Tiina Koljonen, Hanne Siikavirta, Ron Zevenhoven, *CO_2 Capture, Storage and Utilization in Finland*, Project Report, VTT Processes, Systems and Models, August 29, 2002 (available at: www.vtt.fi/inf/julkaisut/muut/2002/co2capt.pdf).
[38] Reed, John, California Carbon Capture and Storage Review Panel, *Technical Advisory Committee Report – Beneficial Use of Carbon Dioxide*, October 4, 2010, Page 1 (available at: http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-10-21/white_papers/Beneficial_Use_of_Carbon_Dioxide.pdf)

The use of low-carbon and carbon neutral fuels, use of aggressive lower GHG-emitting processes and practices through an energy-efficient design to reduce CO_2 emissions, and terrestrial sequestration control options are an inherent part of the facility's design and considered baseline control options. No emissions reduction credit is taken for the implementation of the baseline control options. The baseline presented above represents the design with the highest efficiency improvements limited to the maximum worst-case fuel blend discussed in Section 2.4.2.2. A detailed comparison of the impacts of certain heat recovery strategies on the cogeneration system is presented in Table 2.8. In Table 2.8, the "Base Case" is intended to represent the fully scoped cogeneration system with all heat integration and power cycle heat recovery strategies employed. Case 1 presents the system when the process waste heat integration is not employed, Case 2 presents the system when the boiler feedwater preheaters are not employed, and Case 3 presents the system when the biomass boiler air preheater and economizer are not employed.

Table 2–8
Detailed Comparison of the Impacts of Certain Heat Recovery Strategies on the Cogeneration System

Summary Comparison (Implemented Yes/No)	Base Case (Proposed System)	Case 1	Case 2	Case 3
Biomass Boiler (Fuel Type Restriction)	Yes	Yes	Yes	Yes
Air Preheat	Yes	Yes	Yes	No
Economizer	Yes	Yes	Yes	No
High Pressure Boiler Feedwater Preheater	Yes	Yes	No	No
Low Pressure Boiler Feedwater Preheaters	Yes	Yes	No	No
Process Waste Heat Integration	Yes	No	No	No
Gross Power Production, MWe	21.8	19.3	20.8	20.8
Estimated Net Power to Grid, MWe	2.8	0.3	1.8	1.8
Heat Rate, Btu/kW-hr	21,431.2	24,207.3	23,802.9	27,543.3
Cycle Efficiency, %	15.92%	14.10%	14.33%	12.39%
Overall Efficiency, %	183.6	183.6	183.6	183.6
Boiler Steam Production, lb steam/hr	325,000	325,000	325,000	325,000
CO_2e Production (Maximum WORST CASE Fuel Blend), lb CO_2e/hr	109,966	109,966	116,645	135,165
CO_2e/Steam Ratio (Maximum WORST CASE Fuel Blend), lb CO_2e/lb steam produced	0.34	0.34	0.36	0.42

The technically feasible control options for further controlling CO_2 emissions or reducing overall CO_2 impacts from the biomass-fired stoker

boiler is carbon capture with either long term storage through geologic sequestration or EOR, beneficial use of the CO_2 as a consumer product. For the purposes of this BACT analysis, chemical absorption is assumed to represent the best post-combustion CO_2 capture option that has been commercially demonstrated. The evaluation of the control options in this BACT analysis focuses first on the effectiveness of CO_2 capture, including economic, energy and environmental impacts; and then if CO_2 capture is determined to be cost-effective, storage and beneficial use options will be evaluated.

2.4.2.4 *Evaluate Technically Feasible Control Options*

CCS in biomass-fired power plants may result in net CO_2 removal from the atmosphere. However, biomass plants are typically small (25 to 50 MWe verses 500 to1000 MWe coal power plants). Thus the CCS cost per kW is roughly twice as high as the cost in coal plants.[39] For the purposes of this BACT analysis, the feasibility of CO_2 capture, including economic, energy and environmental impacts will be evaluated first. If CO_2 capture is determined to be cost-effective, storage and beneficial use options will be evaluated. As established above, the only commercially demonstrated post-combustion CO_2 separation and capture method for similar exhaust streams is chemical absorption. The general method involves exposing a gas stream to an aqueous amine solution which reacts with the CO_2 in the gas by an acid-base neutralization reaction to form a soluble carbonate salt.

This reaction is reversible, allowing the CO_2 gas to be liberated by heating in a separate stripping column. Therefore, the major advantage to this technique is that, in the ideal situation, the amine is not consumed and may be continuously recycled through the process. The amine used in this process is most commonly one of several alkanolamines including MEA. The technology was originally developed not for the purpose of carbon sequestration, but in order to "sweeten" natural gas streams by removing

[39] International Energy Agency (IEA), *IEA Energy Technology Essentials, CO_2 Capture and Storage*, ETE01, December 2006, Page 3 (available at: http://www.iea.org/techno/essentials1.pdf).

CO_2. More recently, it was successfully adapted for recovery of CO_2 from flue gas of coal-fired electric power generating plants. Currently, there are three electric power generating stations in the U.S. that capture CO_2 from flue gas and six other major flue gas CO_2 capture facilities worldwide. All nine use MEA as the chemical sorbent.[40]

The disadvantage of the chemical absorption process is that it would consume a significant amount of the energy produced. A typical "energy penalty", which is defined as the percentage of the net power output consumed for the chemical absorption process installed on a conventional coal-fired power plant is between 25% to 37%.[41] This does not include transportation and injection costs, which would increase the economic burden even further. It is expected that the energy penalty for the biomass-fired boiler would be equivalent to that of a coal-fired power plant due to the similar CO_2 concentration in the flue gases.

Certain factors affect the chemical absorption process implementation costs. These factors include the following:

- The primary concerns with MEA and other amine solvents are corrosion in the presence of O_2 and other impurities and high solvent degradation rates due to reactions with SO_2 and NOx. Post-combustion control of SO_2 and NOx before the chemical absorption system can reduce the effects of these pollutants.
- The flue gas should be cooled to around 40 ^oC for the CO_2 absorption to take place. This requires additional cooling water.
- Steam heat is required to heat the solvent to release the CO_2 during regeneration.
- Parasitic power is required for pumping the fluids through the chemical absorption system.

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[40] National Energy Technology Laboratory, *Degradation of Monoethanolamine Used in Carbon Dioxide Capture from Flue Gas of a Coal-fired Electric Power Generating Station* (available at: http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/4b3.pdf)
[41] *Technical Overview of Carbon Dioxide Capture Technologies for Coal-Fired Power Plants*, supra note 18, Page 5.

- Heat exchangers, scrubber towers, absorption towers, and heaters are required for the process.
- Replacement cost of the chemical solvent is high because regeneration is only for a few cycles.
- Degradation and oxidation of the solvents over time produces products that are corrosive and may require hazardous material handling procedures.
- Work to date has used chemical absorption on a small scale or limited applications. Issues involved with scaling up and expanding the existing technology will need to be addressed.
- Reliable operation of packed towers used in chemical absorption systems will need to be demonstrated.

Another shortcoming of the chemical absorption process is that it has a relatively high capital cost. The large size of the major components significantly influences the capital cost. The footprint of the biomass-fired stoker boiler's footprint is expected to increase approximately 60% with the addition of chemical absorption-based CO_2 capture.

Because post-combustion CO_2 capture has not been commercially demonstrated on biomass-fired electricity generating systems, there are no specific reference documents or demonstration projects that can be relied upon. Site-specific cost estimates for the purpose of constructing a commercial scale CO_2 capture system would require significant time and engineering investment, as well as an initial bench-scale/pilot test prior to full scale application. Therefore, for the purposes of this BACT analysis, the Plains CO_2 Reduction (PCOR) Partnership report, *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership (Phase II)* was relied upon for comparison purposes of the estimates CO_2 capture costs presented herein. A copy of the PCOR report has been included in Appendix A.

Although the state of Kansas is not specifically included in the PCOR report, ABBK is a member of the PCOR Partnership and the cost analyses

presented in the report were assumed comparable as the PCOR report included the neighboring states: Missouri and Nebraska. Capture and compression costs and power requirements for ethanol plants, gas-processing plants, and electricity-generating facilities were estimated in the PCOR report 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, which is designed to support a variety of technology assessment and strategic planning activities for the specific fossil fuel-fired power plant types: pulverized coal, natural gas combined-cycle (NGCC), coal-based integrated gasification combined-cycle (IGCC), and oxyfuel combustion.

The results from the IECM simulations conducted for the PCOR report show a significant cost and energy penalty for capturing 90% of the CO_2 emitted from electricity-generating facilities. The PCOR report used a minimum 100 MW limit 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.

For the purposes of the GHG BACT analysis, the data contained in the PCOR report was relied upon to fully demonstrate to KDHE that the cost of add-on CO_2 control at the proposed biomass-to-energy system is not economically feasible. The PCOR report estimated the costs associated with capture, drying and compression separately from the cost of CO_2 transportation by pipeline for sequestration or EOR. Injection costs for sequestration or any monetary value assigned to the CO_2 for EOR have not been included in the cost or energy estimates.[42] Including the cost of

[42] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Pages vi through viii.

replacement power, the per-ton cost associated with CO_2 capture, drying and compression of 90% of the CO_2 produced at the PCOR region's power plants would be $71 per short ton CO_2 avoided.[43] The increase in the cost of producing electricity caused by the capture, compression, and transport of the CO_2 was estimated in the PCOR report to be 159% to 189% with CO_2 capture, drying and compression of 90% of the CO_2 produced.[44]

The nearest commercial CO_2 pipeline terminus is at Guymon, Oklahoma, approximately 40 miles south of the proposed facility at the Mobil Exploration and Producing U.S. Postle Field Unit. ABBK estimated that the capital investment to install a CO_2 pipeline to connect to the Mobil Exploration and Producing U.S. Postle Field Unit would be $35 per linear foot, or $7,392,000, excluding right-of-way acquisitions, surge storage tanks, booster pumps, and operation and maintenance. The preparation of the CO_2 for transport via pipeline will result in additional energy penalties, as well as additional emissions (including CO_2). Because evaluations of the OPAS are ongoing,[45] it has not been fully demonstrated that geologic sequestration in Kansas is technically feasible, therefore, transportation via pipeline for EOR is currently the only commercially demonstrated control option available.

The CO_2 value of $45 per metric ton ($41 per short ton) delivered at pressure to the field is presented as the base case in the NETL report, *Storing CO_2 with Enhanced Oil Recovery*.[46] Other estimates indicate that the CO_2 costs with EOR as low as $10 per short ton. Based on the costs presented in the PCOR report, the per-ton cost associated with CO_2 capture, drying and compression of 90% of the CO_2 produced would be $71 per short ton CO_2 avoided. It is assumed that because the proposed

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[43] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Table 12.
[44] *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, supra note 26, Table 13.
[45] Kansas Geologic Survey, *South-central Kansas CO_2 Project* website (available at: http://www.kgs.ku.edu/PRS/Ozark/index.html).
[46] NETL, *Storing CO_2 with Enhanced Oil Recovery*, DOE/NETL-402/1312/02-07-08, February 7, 2008 (available at: http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf)

biomass-to-energy system will be nominally rated at 22 MW and because the flue gases from biomass combustion will be similar to coal combustion (similar CO_2 concentration, pollutants and control technologies), the PCOR costs are expected to be very conservative costs for CO_2 capture, drying and compression at the proposed facility.

Comparing the CO_2 value of $41 per short ton for EOR to the CO_2 capture cost of $71 per short ton, the implementation of CO_2 capture at the ABBK facility is not cost effective. Further, CO_2 capture would result in significant and adverse energy and environmental impacts due to the following:

- Parasitic consumption of steam and electricity;
- Additional emissions generated during CO_2 dehydration, compression, and transport; and
- Raw material usage for CO_2 capture and processing equipment and construction of a pipeline.

2.4.2.5 *Favorable Environmental Impacts Considerations*

The November 2010 EPA GHG Guidance, states that, "EPA believes that it is appropriate for permitting authorities to account for both existing federal and state policies and their underlying objectives in evaluating the environmental, energy and economic benefits of biomass fuel. Based on these considerations, permitting authorities might determine that, with respect to the biomass component of a facility's fuel stream, certain types of biomass by themselves are BACT for GHGs."[47]

Under the Energy Policy Act of 2005 (EPAct 2005), Congress directed the DOE to carry out a program to demonstrate the commercial application of integrated biorefineries for the production of biofuels, in particular ethanol, from lignocellulosic feedstocks. Accordingly, in February 2006, DOE issued a funding opportunity announcement for the design and construction of commercial-scale integrated biorefineries intended to demonstrate the use of a wide variety of lignocellulosic feedstocks to

[47] *PSD and Title V Permitting Guidance for Greenhouse Gases*, supra note13, Page 9.

produce combinations of liquid transportation fuels (biofuels), bio-based chemicals, substitutes for petroleum-based feedstocks and products, and energy in the form of electricity or useful heat (biopower). In that announcement, DOE also encouraged the use of a wide variety of lignocellulosic feedstocks, but not those biomass components specifically grown for food, and encouraged the use of various technologies to collect and treat the wide variety of biomass feedstocks.

On February 28, 2007, DOE announced the selection of six biorefinery projects for negotiation of financial assistance awards, one of which was the ABBK biomass-to-ethanol and biomass-to-energy production facility. ABBK proposed an innovative approach to biorefinery operations that would involve production of a biofuel and energy that can be used to meet energy needs and displace fossil fuels, such as coal and natural gas. ABBK proposed to locate the facility in Kansas to qualify for state tax credits for the construction of cellulosic ethanol facilities (Kansas Energy Development Act of 2006; Kansas Senate Bill 303), which would make the biorefinery a more viable commercial operation.

2.4.2.6 *Establish BACT*

ABBK proposes that GHG BACT for the biomass-fired stoker boiler consist of the following:

- Restriction of the fuel type to biomass that is otherwise considered to have low to no economic value or benefit (i.e. crop residuals and waste wood); and/or is a lower impacting crops (i.e. mixed warm season grasses such as switchgrass); and
- Use of lower GHG-emitting processes and practices through an energy-efficient design, incorporating cogeneration, process integration, combustion of co-products, heat recovery and operational and maintenance monitoring.

These control options are technically feasible for the biomass-fired stoker boiler and are an inherent part of the facility's design. ABBK proposes that the BACT limit for the biomass-fired stoker boiler be 0.32 lb CO_2e /lb of steam produced.

The proposed BACT limit for the biomass-fired stoker boiler is based on the following:

Steam production rate = 325,000 lb of steam/hr

CO_2e emission rate based on the fuel specifications = 109,965 lb CO_2e/hr

$$CO_2e \text{ BACT Limit} = \frac{109{,}965 \text{ lb } CO_2e \text{ / hr}}{325{,}000 \text{ lb of steam / hr}}$$

$$CO_2e \text{ BACT Limit} = 0.34 \text{ lb } CO_2e \text{ / lb steam produced}$$

2.4.2.7 *BACT Compliance*

ABBK will record the fuel type and quantity combusted in the boiler. Feedstock properties, unburned carbon in ash and sorbent reactivity will be tested weekly. Fuel blends will be reviewed for compliance with the established emission limits prior to combustion and the gas parameters: percent oxygen, flow rate, temperature, and pressure, will be monitored.

The boiler will be equipped with a temperature and pressure compensated steam production flow meter. The flow meter is a requirement of the biomass-fired boiler's performance specification. The cogeneration system (biomass-fired boiler and steam turbine generator) will be subject to a performance test in accordance with ASME PTC-46. The boiler steam flow will be transmitted to the facility distribution control system (DCS) and historized. The boiler's CO_2 emission (lb CO_2/lb steam) will be calculated in the DCS and available for the operator. The boiler steam flow can be verified by measuring the boiler feedwater makeup flow and steam drum blowdown. Both of these streams will be continuously measured and historized.

The BACT limit proposed is based on a "lb CO_2e/lb steam produced" limit instead of the engineering estimate which used "lb CO_2e/MMBtu" because the steam pressure produced will continuously monitored. ABBK proposes that that simplest compliance method be based on steam produced, not the boiler heat input rate. Therefore, all fuel combinations will be reviewed for compliance with the BACT limit prior to combustion

using the fuel specifications (as completed in the potential to emit calculations for the current fuel combinations) and the calculation detailed above. CO_2e-based emissions were determined based on the projected feedstock consumption using emission factors presented in the application. The emission limit is based on a maximum potential to emit, expressed in pounds of CO_2e per pound of steam produced, averaged over 30-day rolling periods.

ABBK will also implement a written preventive maintenance program. ABBK will provide construction specifications, operation and maintenance records, feedstock records, and other record keeping documents to KDHE upon request to demonstrate compliance with BACT.

2.5 Fermentation and Distillation BACT Analysis

2.5.1 Source Description

The CO_2 generated from the biomass co-fermentation process (Area 16000) will be routed through the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185). The rated control efficiency will be equal to or greater than 99 percent. The CO_2 generated from the biomass ethanol recovery process (Area 18000) will be routed through the enzymatic hydrolysis distillation vent scrubber (S-18180). The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency.

The vent streams routed to the scrubber are expected to be saturated with water since the process tanks contain primarily CO_2, other gases (O_2/N_2) and water. These vent streams also are expected to contain trace amounts of contaminants such as ethyl alcohol (ethanol), fuel oils, H_2S, NOx, etc. Table 2-9 presents a comparison of the enzymatic hydrolysis CO_2 scrubber (S-18185) vent stream to a traditional starch fermentation scrubber vent stream.

Table 2–9
Traditional Starch Fermentation Scrubber and Enzymatic Hydrolysis Fermentation Scrubber Vent Stream Comparison

	Typical Starch Fermentation Scrubber (VB 84 MMGPY)		ABBK Scrubber (S-18185) (30 MMGPY)	
	(lb/hr)	(wt.%)	(lb/hr)	(wt.%)
Total	49,199	100.0%	23,424.48	100%
Water	747	1.5%	255.48	1.1%
Alcohol	2	0.004%	1.28	0.005%
By Products	5	0.01%	0.65	0.003%
CO_2	46,993	95.5%	20,387	~88%
Air	1,453	3.0%	2,548	~11%

The enzymatic hydrolysis CO_2 scrubber (S-18185) CO_2 concentration is lower than a typical starch plant, due to the addition of air during fermentation and the unique differences of enzymatic hydrolysis fermentation verses traditional starch fermentation. Additional air is needed for the particular organism used in the enzymatic hydrolysis fermentation process. The typical starch fermentation scrubber information was obtained from the facility's scrubber vendor, Vogelbusch. Vogelbusch engineering data indicates that a typical starch fermentation scrubber will have a CO_2 concentration of 95.5% by weight. Abengoa Bioenergy of Nebraska, LLC has documented it's starch fermentation scrubber's typical CO_2 concentration is greater than 98% by weight.

The scrubber will be packed-tower wet scrubber, which allow for ethanol vapors to be collected in order to produce a higher product yield, and consequently the units control emissions of VOCs, HAPs, organic acids, furfural and higher alcohols. The scrubber systems will recover more than 99% of the ethanol from the vapor stream and return the ethanol to the process downstream. The water from the wet scrubber is pumped back into the process for recycling. The distillation vent scrubber vent feeds into the enzymatic hydrolysis fermentation CO_2 scrubber (S-18185) for further control efficiency.

2.5.2 GHG BACT Review

The total CO_2e-based emissions from the enzymatic hydrolysis production is approximately 88,400 short ton/yr CO_2e. This amount of CO_2e-based emissions is

just over 15% of the total facility-wide CO_2e-based emissions. The following presents the GHG BACT analysis for these sources.

2.5.2.1 *Identify Available Control Options*

The following control options have been identified and considered in determining BACT:

- Monitoring enzymatic hydrolysis process efficiency;
- Carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration")
- Carbon capture for beneficial uses;
- Develop and implement an LDAR program, in accordance with NSPS, Subpart VVa (40 CFR §60.480a through §60.489a), as proposed for the other fugitive HAR pollutants: VOC and HAP; and
- Combination of these control options.

There are two broad strategies for reducing GHG emissions from the scrubber at the proposed facility. The first is to minimize the production of GHG through monitoring enzymatic hydrolysis process efficiency. The enzymatic hydrolysis process efficiency is an integral part of the facility's design and is considered the baseline for this BACT analysis.

The second strategy for reducing GHG emissions is carbon capture and storage ("CCS", also referred to as "carbon capture and sequestration") or carbon capture for beneficial uses. Because of the lower CO_2 concentration in the scrubber vent stream (approximately 88%), the CCS and carbon capture for beneficial uses discussion presented in Section 2.4 is applicable. Although the CO_2 concentration is 88%, this stream is still not considered a "high purity CO_2 Stream" like other traditional starch plant fermentation vent streams, where the CO_2 concentration is greater than 95% and usually 98% to 99% before CO_2 capture is performed for commercial applications.

Implementation of an LDAR program is not intended to control emissions beyond the baseline. The LDAR program is used to monitor equipment

leaks for repair. For the fermentation and distillation operations, CO_2 emissions from equipment leaks were estimated to be less than 1 lb/hr.

2.5.2.2 *Eliminate Technically Infeasible Control Options*

There were two main options identified for control of CO_2 emissions from the scrubber: 1) monitoring enzymatic hydrolysis process efficiency; and 2) CCS and/or carbon capture for beneficial uses.

Table 2-10 summarizes the technical feasibility/infeasibility determination discussed in this section.

Table 2–10
GHG BACT Control Technology Technical Feasibility/Infeasibility Determination Summary for the Fermentation Scrubber

Potentially Available Control Option	Determination Result	Determination Reason
Monitoring Enzymatic Hydrolysis Process Efficiency	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Capture Using Post-Equipment Capture	Technically Feasible	Chemical absorption has been the most widely used method of commercial CO_2 capture and is the primary CO_2 capture technology further analyzed.
Carbon Transportation	Technically Feasible	Technical issues can be addressed through modern pipeline construction and maintenance practices.
Carbon Storage through Geologic Sequestration	Technically Feasible	In Kansas, geologic sequestration of CO_2 may be possible in all five of the geologic formations: deep saline aquifers, coal seams, oil and natural gas reservoirs, oil- and gas-rich organic shales, and basalt
Carbon Storage through Terrestrial Sequestration	Technically Feasible	Inherent part of the facility's design, and considered a baseline control option.
Carbon Beneficial Uses	Technically Feasible	The many different technologies being investigated for the beneficial use of CO_2 vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization.
Combination of These Control Options	Technically Feasible	See reasons above.

The following discusses each of these control options.

Monitoring Enzymatic Hydrolysis Process Efficiency

There are numerous strategies for achieving a highly efficient enzymatic hydrolysis process. All identified strategies (i.e. control options) listed in this section are technically feasible for application to the scrubber, and all are an inherent part of the facility's design.

- CO_2 Production Monitoring During Fermentation – This strategy is the primary GHG BACT control technology option. CO_2 production in fermentation is a function of the yeast and selected micro-organism. A healthy and optimized organism will produce more ethanol and less CO_2.
- Energy Efficient Heat Integration – The enzymatic hydrolysis process is integrated with the cogeneration facility to maximize energy efficiency. This integration is discussed in Section 2.4. Energy efficient heat integration is more important to the boiler GHG than the fermentation scrubber.
- Water Recycling – Process-related water will be recycled whenever possible to reduce the facility's consumption.
- Co-product Production – Valuable co-products will be generated during the enzymatic hydrolysis process. The valuable co-products include products such as enzymatic hydrolysis residuals (including lignin-rich/lignin-lean stillage cake and thin stillage syrup) and wastewater treatment biogas. These products can either be sold as a consumable product or combusted as a supplemental fuel in the biomass-fired boiler.

Carbon Capture

Section 2.4.2.2 details the carbon capture control option technical feasibility determination. The information presented in Section 2.4.2.2 is not repeated herein. For the scrubber, the pre-combustion and oxy-combustion approaches are not applicable. Carbon capture using post-equipment capture is equivalent to post-combustion capture. The only

commercially demonstrated method for similar exhaust streams (i.e. vent streams with low CO_2 concentrations) is chemical absorption.

Carbon Transport and Storage

Section 2.4.2.2 details the carbon transport and storage technical feasibility determination. The information presented in Section 2.4.2.2 is not repeated herein.

Terrestrial sequestration applies to the scrubber because the emissions associated with this scrubber are biogenic CO_2 emissions. Because the proposed source will utilize biomass in the production of ethanol, this type of CO_2 storage is essentially being implemented as part of the facility's design; therefore, terrestrial sequestration is considered a baseline control option.

Carbon Beneficial Uses

Section 2.4.2.2 details the carbon beneficial uses control option technical feasibility determination. The information presented in Section 2.4.2.2 is not repeated herein.

2.5.2.3 Rank Technically Feasible Control Options

Table 2-11 presents the ranked technically feasible control options.

Table 2–11
Ranked Control Options for the Fermentation Scrubber

Rank	Control Technology	Emission Rate (short tons CO_2/year)	Reduction Efficiency	Emissions Reduction (short tons CO_2/year)
1	Carbon Capture and Storage (CCS)	8,800	90%	80,000
2	Carbon Capture for Beneficial Uses	8,800	90%	80,000
3	Baseline (Monitoring Enzymatic Hydrolysis Process Efficiency and Terrestrial Sequestration)	88,360	N/A	N/A
4	LDAR	N/A	N/A	N/A

Note 1: CCS and carbon capture for beneficial uses emission rates presented in this table are the emissions rates associated with CO_2 capture only, and do not include the additional emissions generated during CO_2 dehydration, compression, and transport.
Note 2: Implementation of the LDAR program will not generate emissions, nor will it control emissions beyond the baseline. The LDAR program is used to monitor equipment leaks for repair.

The use of monitoring enzymatic hydrolysis process efficiency to reduce CO_2 emissions and terrestrial sequestration control options are an inherent part of the facility's design and considered baseline control options. No emissions reduction credit is taken for the implementation of the baseline control options. The baseline presented above represents the design with the highest efficiency improvements.

2.5.2.4 *Evaluate Technically Feasible Control Options*

The implementation of CCS and carbon capture for beneficial uses on the fermentation scrubber is similar to the implementation of these control options on the biomass-fired boiler. The lower purity (approximately 88% CO_2 concentration) in the fermentation vent makes these vent streams undesirable for CO_2 processing companies.

Because the largest CO_2 emission sources at the facility are the biomass-fired boiler, the implementation of a CCS control option (excluding terrestrial sequestration) is based on the cost-effectiveness of such a system applied to the boiler. As discussed in detail in Section 2.4, using CCS or carbon beneficial uses to reduce CO_2 emissions from the boiler is technically feasible but would entail significant, adverse economic,

environmental and energy impacts due to increased fuel usage in order to meet the steam and electric load requirements of the CCS systems. Therefore, the use of CCS and carbon beneficial uses technologies were determined not to be cost effective for control of CO_2 from the boiler and subsequently, are not cost effective for the fermentation CO_2 emissions, which are less than 88,360 short ton/yr CO_2e.

An LDAR program is technically feasible control option for this equipment; therefore, no further evaluation of this control is needed.

2.5.2.5 *Establish BACT*

ABBK proposes that GHG BACT for the fermentation scrubber vent stream consist of the following:

- Monitoring enzymatic hydrolysis process efficiency, incorporating the CO_2 production monitoring during fermentation, energy efficient heat integration, water recycling, and co-product production that make the overall process efficient and economical.
- Develop and implement a written LDAR program.

These control options are technically feasible for the enzymatic hydrolysis process and are an inherent part of the facility's design. ABBK proposes that the BACT limit be 5.89 lb CO_2e/gal anhydrous ethanol produced for the enzymatic hydrolysis fermentation CO_2 scrubber stack (EP-18185), averaged over a 30-day rolling period. These proposed emission limit is based on the average continuous flow CO_2 concentrations.

2.5.2.6 *BACT Compliance*

The enzymatic hydrolysis final design has not been established; however, as part of the BACT compliance demonstration, ABBK proposes to complete a Value Engineering Report that will document the enzymatic hydrolysis design parameters and efficiency variables. CO_2e emissions will be determined based on the required stack testing to be completed upon startup. Continuous stack monitoring equipment will be installed to monitor operational indicators and CO_2. Emissions will be averaged over a 30-day rolling period for compliance.

ABBK also proposes to develop and implement a written LDAR program modified from the requirements of 40 CFR Part 60, Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006, to be source- and pollutant-type specific.

ABBK will provide construction specifications, value engineer calculations and analyses, and operation and maintenance records to KDHE upon request to demonstrate compliance with BACT. ABBK will also provide a copy of the LDAR program and documentation regarding observations and/or repairs made in accordance with the LDAR program to KDHE upon request to demonstrate compliance with BACT.

2.6 Flare BACT Analysis

2.6.1 Source Emissions

The facility design will incorporate a flare (EP-09001) for control of process vents flow, biogas and product loadout vapors. The vent streams will normally be vented to the biomass-fired boiler for combustion; however these streams may be vented to the flare as needed for up to 3,960 hours per year.

2.6.2 GHG BACT Review

The flare will have the potential to emit biogenic and anthropogenic GHG emissions (CO_2, CH_4, and N_2O) because it is used to combust process vent streams, biogas, and product loadout vapors. Combustion of the process vent streams, biogas, ethanol, natural gas and gasoline in the flare results in the emissions of NOx, SO_2, CO, VOC, PM/PM_{10}/$PM_{2.5}$ and biogenic and anthropogenic GHG emissions (CO_2, CH_4, and N_2O). Flaring destroys 2,119 lb/hr CH_4 (44,503 lb/hr CO_2e), and generates 10,170 lb/hr CO_2, for a total net reduction of CO_2e equal to 34,333 lb/hr. Total CO_2e emissions from this source (including emissions from natural gas combustion in the flare's pilot) are 10,185 lb/hr. The following presents the GHG BACT analysis for this source.

2.6.2.1 *Identify Available Control Options*

The flare is incorporated in the process design as a type of control technology. Because the combustion of biogas in a flare was selected as BACT for all other NSR pollutants, there was no consideration of other combustion controls performed in this analysis. The following control options have been identified and considered in determining BACT:

- Flare; and
- Develop and implementation of an LDAR program, similar to NSPS, Subpart VVa (40 CFR §60.480a through §60.489a), and modified to be source- and pollutant-type specific.

There are no effective combustion controls to reduce the GHG emissions from flares, and there are currently no available post-combustion controls. The only achievable technological approach to reducing GHG emissions from the flare is to use the most efficient flare that meets the final design requirements.

2.6.2.2 *Eliminate Technically Infeasible Control Options*

There were two options identified for control of CO_2 emissions from the flare: 1) low-carbon fuel; and 2) energy efficient design. The baseline is fuel type restriction and incorporation of energy efficient construction and operation principles into the flare's design. The baseline is the top performing control options identified. The following discusses each of these control options.

Fuel Type Restriction (Low-Carbon Fuel)

The flare will combust biogas as the primary fuel and natural gas in the pilot. Biogas has the lowest direct GHG emissions of all common fuels.[48] Natural gas has the lowest direct GHG emissions of all common fuels, excluding biogas, as discussed in Section 2.5.2.2. Carbon dioxide is a common impurity in natural gas which must be removed to improve the heating value of the gas or to meet pipeline specifications. Pipeline grade

[48] *General Reporting Protocol, Version 3.1*, supra note 39.

natural gas is "sweetened" by the manufacturer and no additional onsite treatment of pipeline grade natural gas will further reduce CO_2.

Energy Efficient Design

There are numerous strategies for achieving a highly energy efficient design of a new flare. Design of the flare is dependent on the final process design of the facility. Specifically, the flare will be equipped with an electric igniter and will be a smoke-less design.

2.6.2.3 Rank Technically Feasible Control Options

The only achievable technological approach to reducing GHG emissions from the flare is to use the most efficient flare that can perform to the specification required by the facility's process. There are no effective combustion or post-combustion controls to reduce the GHG emissions from the 51.10 MMBtu/hr flare.

2.6.2.4 Evaluate Technically Feasible Control Options

As there are no other control technologies to choose from, no additional steps in the top-down BACT analysis are required for the selection of these control technologies as BACT. Also, an LDAR program is technically feasible control option for this equipment; therefore, no further evaluation of this control is needed.

2.6.2.5 Establish BACT

ABBK proposes that GHG BACT for the flare consist of the following:

- Use of lower GHG-emitting processes and practices through an energy-efficient design design, incorporating a fuel efficient flare pilot; and
- Develop and implement a written LDAR program.

ABBK proposes that the process vents flow, biogas flow and product loadout vapors will be inferred based on flow measurements upstream of the flare diverting valve and diverting valve position. ABBK further proposes that the pilot natural gas usage records be based on the vendor

engineering calculations for the pilot's natural gas demand. No additional natural gas monitoring at the flare is proposed.

These control options are technically feasible for the flare and are an inherent part of the facility's design.

2.6.2.6 *BACT Compliance*

ABBK proposes the use of the top performing control technology to control GHG emissions from the flare. The facility will demonstrate compliance with the BACT limit by recording natural gas fuel usage and using the emissions factors presented in the application to determine resulting CO_2e emissions. Because the natural gas fuel usage can be accurately measured, and the amount of GHG equivalents can be calculated precisely based on well-established emissions factors, no other direct monitoring of GHG emissions is proposed. The emission factors presented in the application will be relied upon to demonstrate compliance with the proposed BACT limit.

ABBK also proposes to develop and implement a written LDAR program modified from the requirements of 40 CFR Part 60, Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006, to be source- and pollutant-type specific.

ABBK will provide construction specifications, operation and maintenance records, and fuel usage records to KDHE upon request to demonstrate compliance with BACT. ABBK will also provide a copy of the LDAR program and documentation regarding observations and/or repairs made in accordance with the LDAR program to KDHE upon request to demonstrate compliance with BACT.

2.7 Firewater Pump Engine

2.7.1 Source Emissions

One 460 horsepower (Hp) (343 kilowatt (kW)) firewater pump engine will be installed at the facility to protect personnel and equipment in the event of a fire. The firewater pump engine will combust diesel fuel and meet the New Source Performance Standard (NSPS) regulation, 40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICEs)*. The emergency engine is assumed to operate less than 100 hours per year for maintenance checks and readiness testing to qualify as emergency engines under NSPS Subpart IIII (40 CFR §60.4211(e)).

2.7.2 GHG BACT Review

The emergency diesel firewater pump engine will have the potential to emit anthropogenic GHG emissions (CO_2, CH_4, and N_2O) because it combusts a hydrocarbon fuel (diesel). The following presents the GHG BACT analysis for this source.

2.7.2.1 Identify Available Control Options

There are no effective combustion controls to reduce the GHG emissions from internal combustion engines, and there are currently no available post-combustion controls. The only achievable technological approach to reducing GHG emissions from the firewater pump engine is to use the most efficient engine that meets the stringent National Fire Protection Association (NFPA) standards for reserve horsepower capacity, engine cranking systems, engine cooling systems, fuel type's instrumentation and control and exhaust systems.

2.7.2.2 Eliminate, Rank and Evaluate Technically Feasible Control Options

The only achievable technological approach to reduce GHG emissions from the firewater pump engine is to select the most fuel-efficient NFPA-20 certified firewater pump engine available.

As there is only one control technology to choose from, no additional steps in the top-down BACT analysis are required for the selection of that

control technology.

2.7.2.3 *Establish BACT*

The firewater pump engine to be selected for use at the facility will be the most fuel-efficient NFPA-20 certified firewater pump engine available. The specific make and model has not been established; however, a review of similar sized engines has indicated that a fuel consumption rate of no more than 20.3±5% gallons per hour is the most efficient rating available for a 460 Hp engine with a rated speed of 1760 rpm and an EPA Tier 3 emission rating.

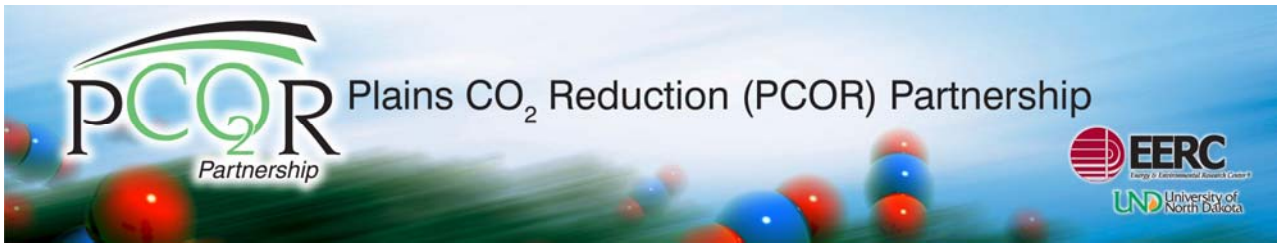
The firewater pump engine may be used for up to 100 hours per year for reliability testing and maintenance purposes. Use of the engine at 20.3±5% gallons of diesel fuel per hour for up to 100 hours per year would result in total GHG emissions from the firewater pump engine of 119.4 short ton/yr CO_2e. ABBK requests that the fuel consumption GHG BACT limit include a 5% variability to allow for selection of the engine with lowest overall EPA Tier 3 emissions at the time of purchase.

2.7.2.4 *BACT Compliance*

The facility will demonstrate compliance with the BACT limit by recording fuel usage and using the emissions factors presented in the application to determine resulting CO_2e emissions. Because fuel usage can be accurately measured, and the amount of GHG equivalents can be calculated precisely based on well-established emissions factors, no other direct monitoring of GHG emissions is proposed. The emission factors presented in the application will be relied upon to demonstrate compliance with the proposed BACT limit. ABBK will provide a copy of the manufacturer's fuel efficiency rating to KDHE upon request to also demonstrate compliance with BACT.

Appendix A

Energy & Environmental Research Center, University of North Dakota, *Regional Emissions and Capture Opportunities Assessment – Plains CO_2 Reduction (PCOR) Partnership Phase II*, 2010-EERC-08-15, December 2009.



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

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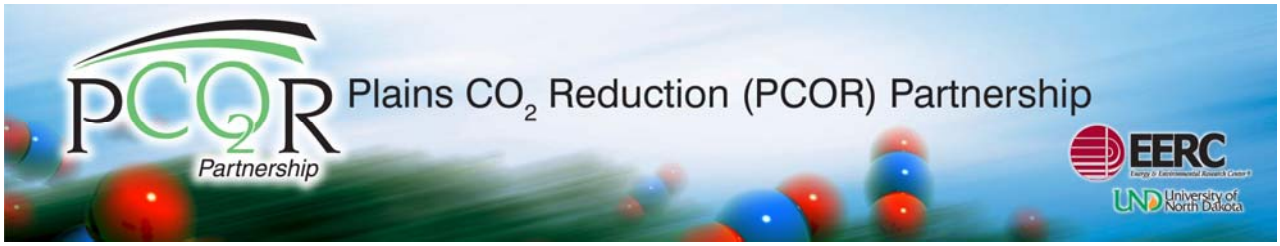

REGIONAL EMISSIONS AND CAPTURE OPPORTUNITIES ASSESSMENT – PLAINS CO_2 REDUCTION (PCOR) PARTNERSHIP (PHASE II)

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December 2009

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.

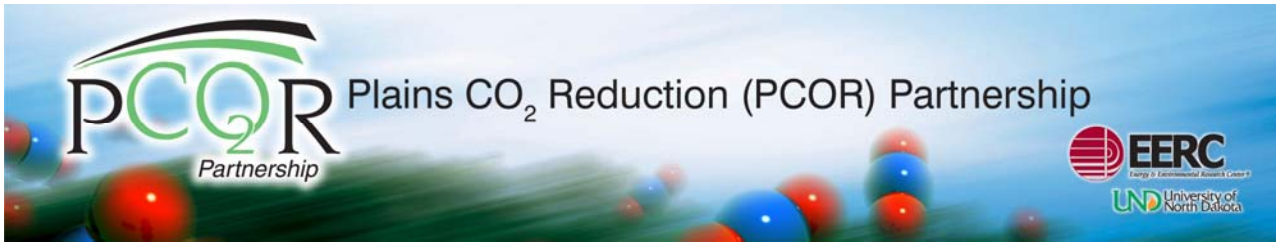
The route and cost of a regional pipeline network needed for early implementation of carbon capture were estimated using a pipeline-routing model developed by the Massachusetts Institute of Technology (MIT). The MIT model calculates pipeline diameter and identifies the least-cost path connecting a CO_2 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.

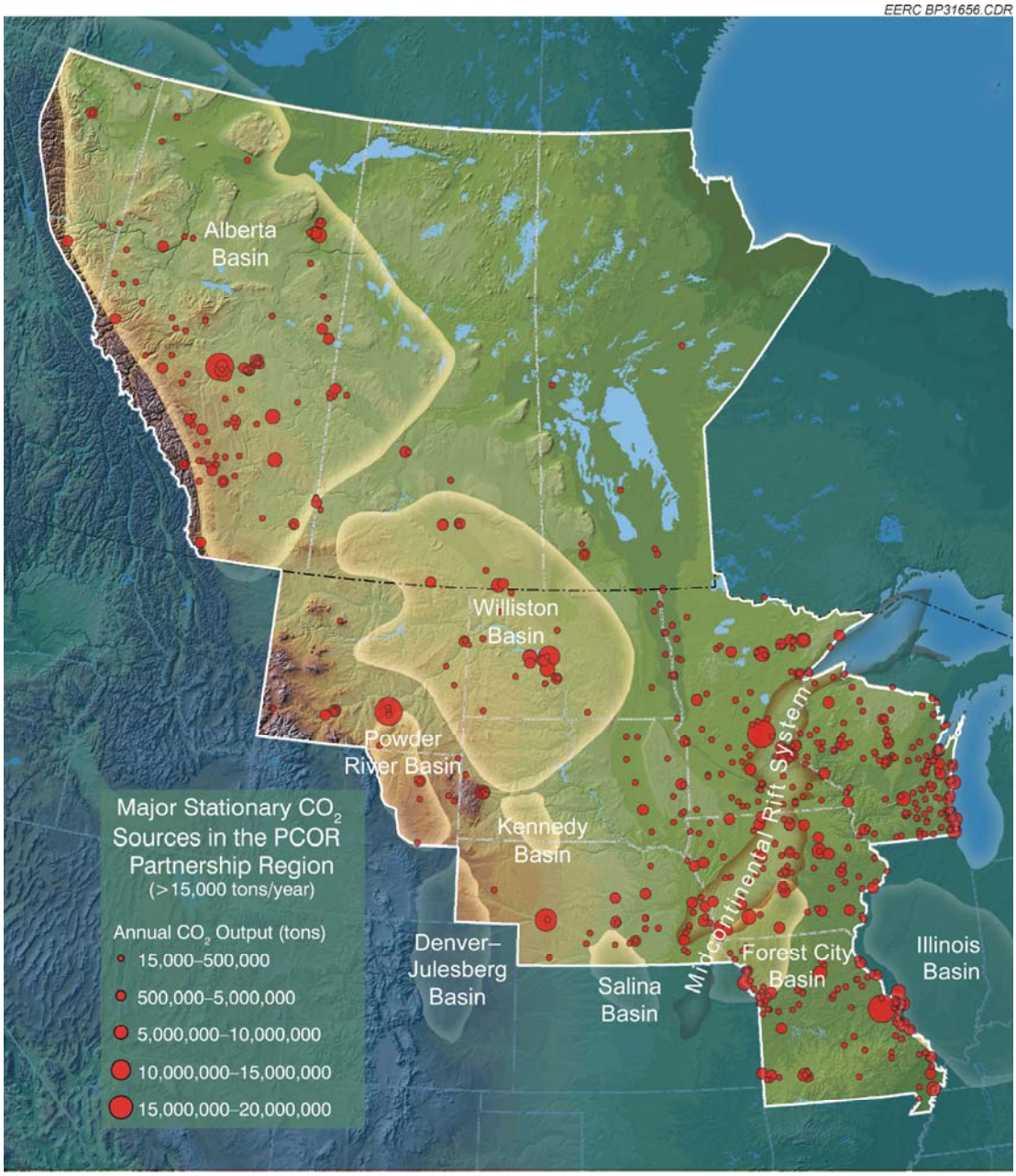

Figure 1. Location and relative output for the PCOR Partnership region's major stationary CO_2 sources.

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.

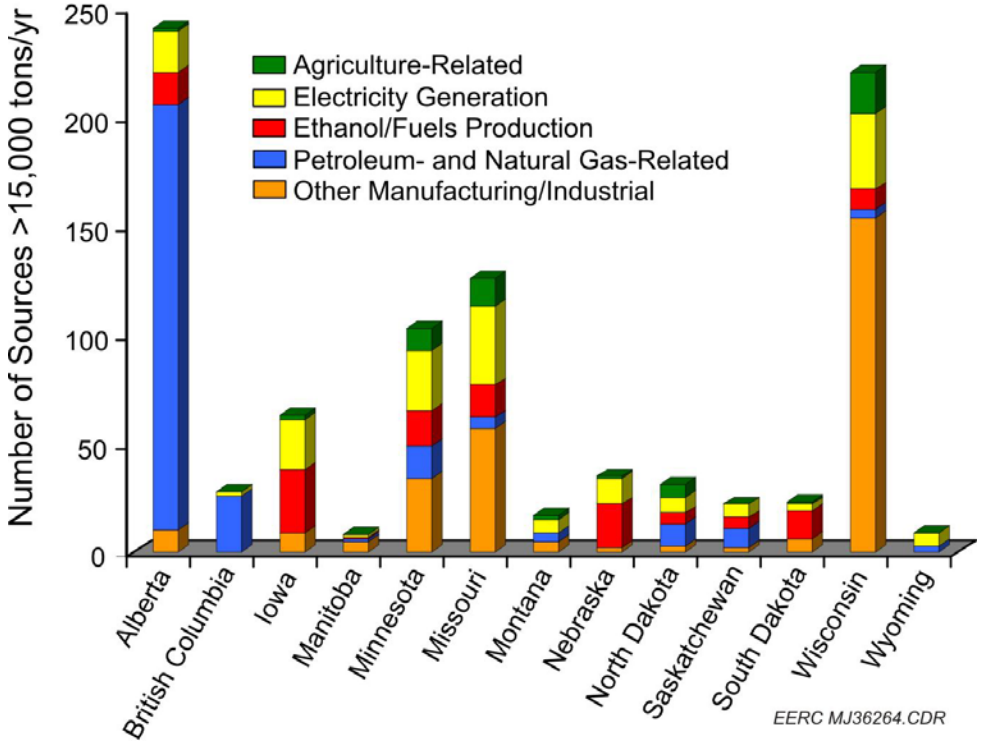

Figure 2. Number of CO_2 sources for each state or province, broken down by major source category (it should be noted that the values for British Columbia, Montana, and Wyoming are only for the portion of the state/province that lies within the PCOR Partnership region and are not necessarily representative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

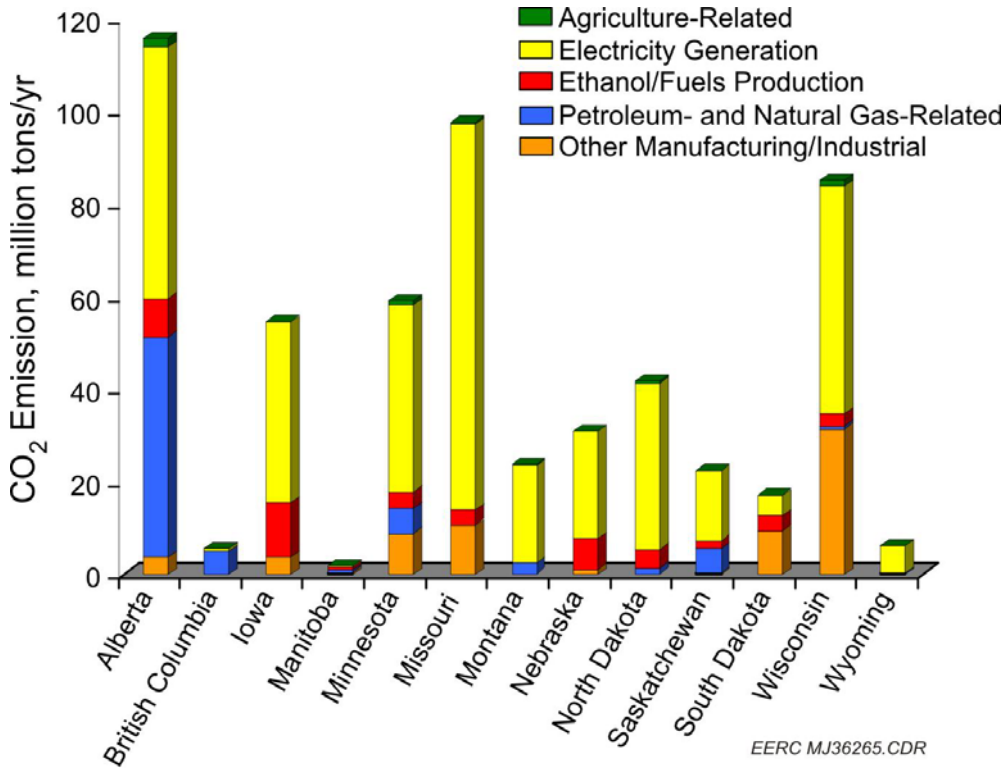

Figure 3. CO_2 emissions for each state or province, broken down by major source category (it should be noted that the values for British Columbia, Montana, and Wyoming are only for the portion of the state/province that lies within the PCOR Partnership region and are not necessarily representative of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

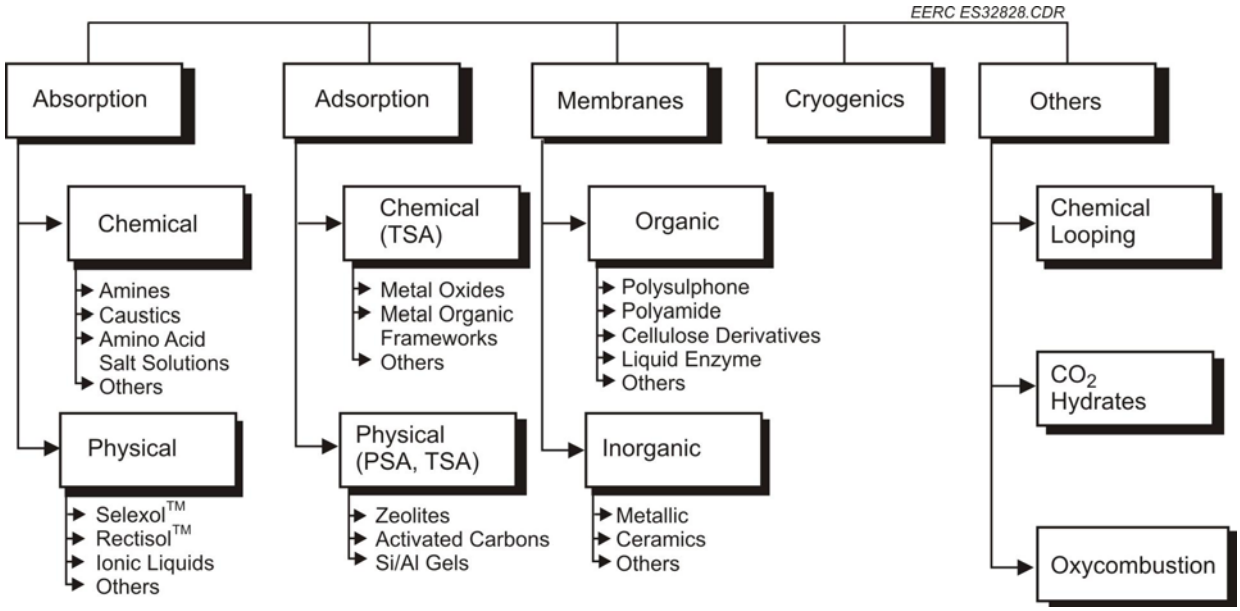

Figure 4. CO_2 capture technology options (PSA = pressure swing adsorption, TSA = temperature swing adsorption).

Table 1. Common Applications for CO_2 Capture Technologies

Technology	Application
Absorption	Commercial plants, mixed-gas streams
	Chemical – fossil fuel-fired systems, e.g., boilers, gas turbines
	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

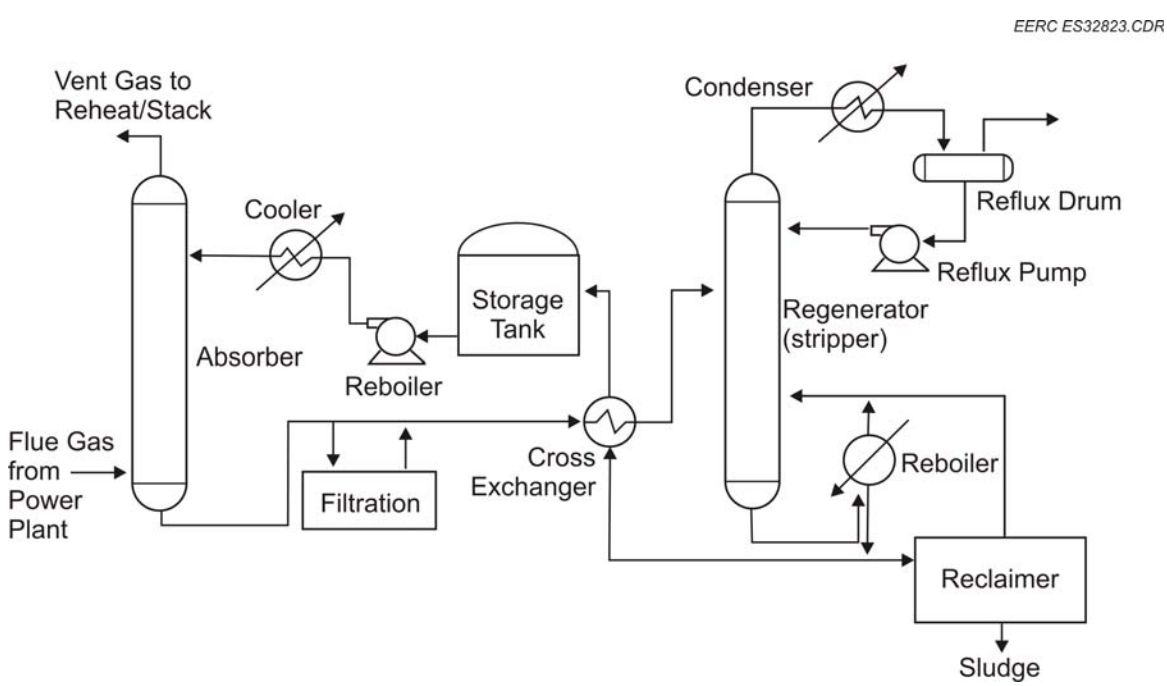

Figure 5. Generic liquid scrubbing system for CO_2 capture.

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.

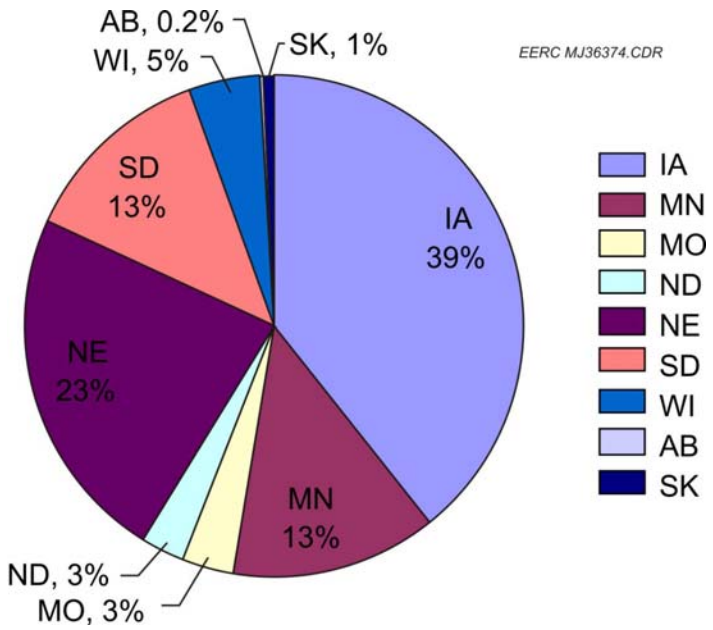

Figure 6. Percentage of CO_2 emissions from ethanol plants contributed by each state/province with at least one ethanol plant that produces >15,000 tons/yr.

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:

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

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.

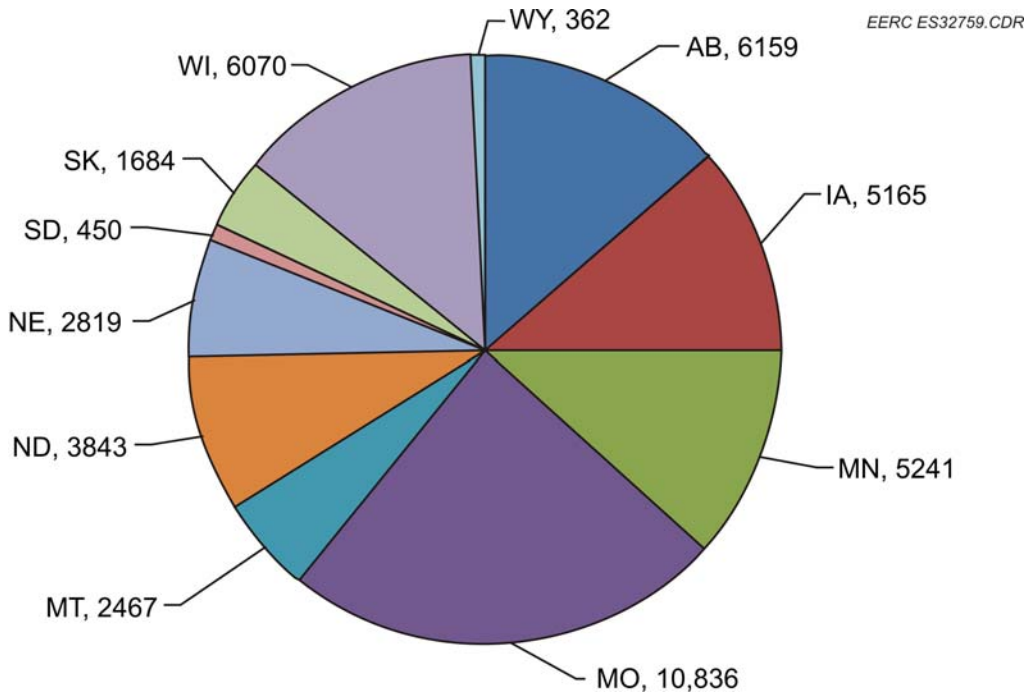

Figure 7. Summary of the total amount of MW considered for CO_2 capture in each state or province. Only the portions of each state/province that lie within the PCOR Partnership region were included.

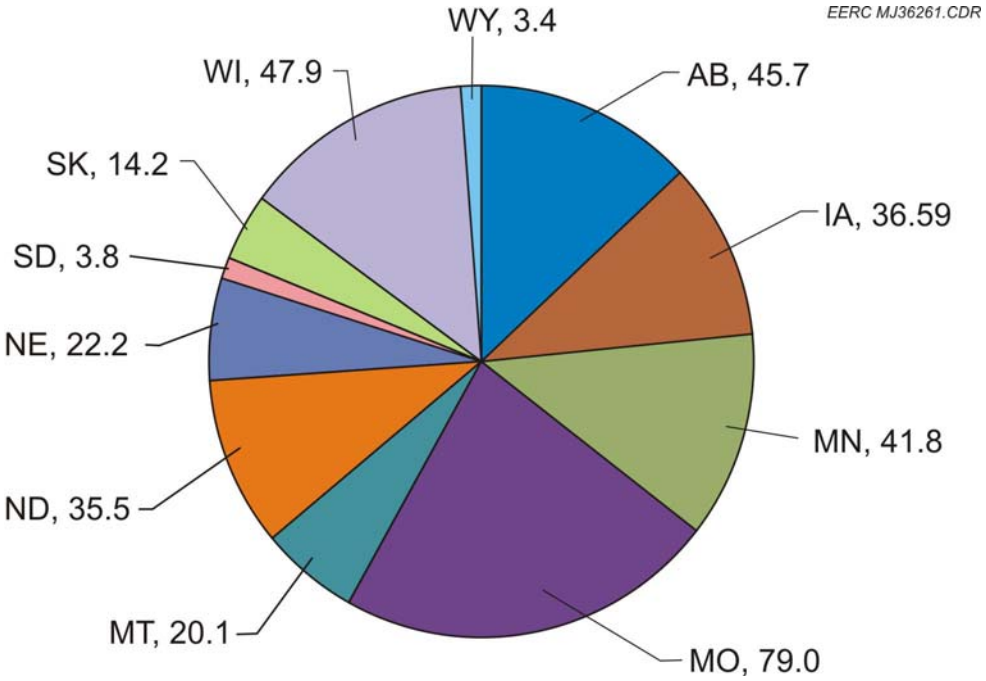

Figure 8. Total amount of CO_2 produced (in MMtons/yr) by electricity-generating stations considered for CO_2 capture on a state/province basis. Only the portions of each state/province that lie within the PCOR Partnership region were included.

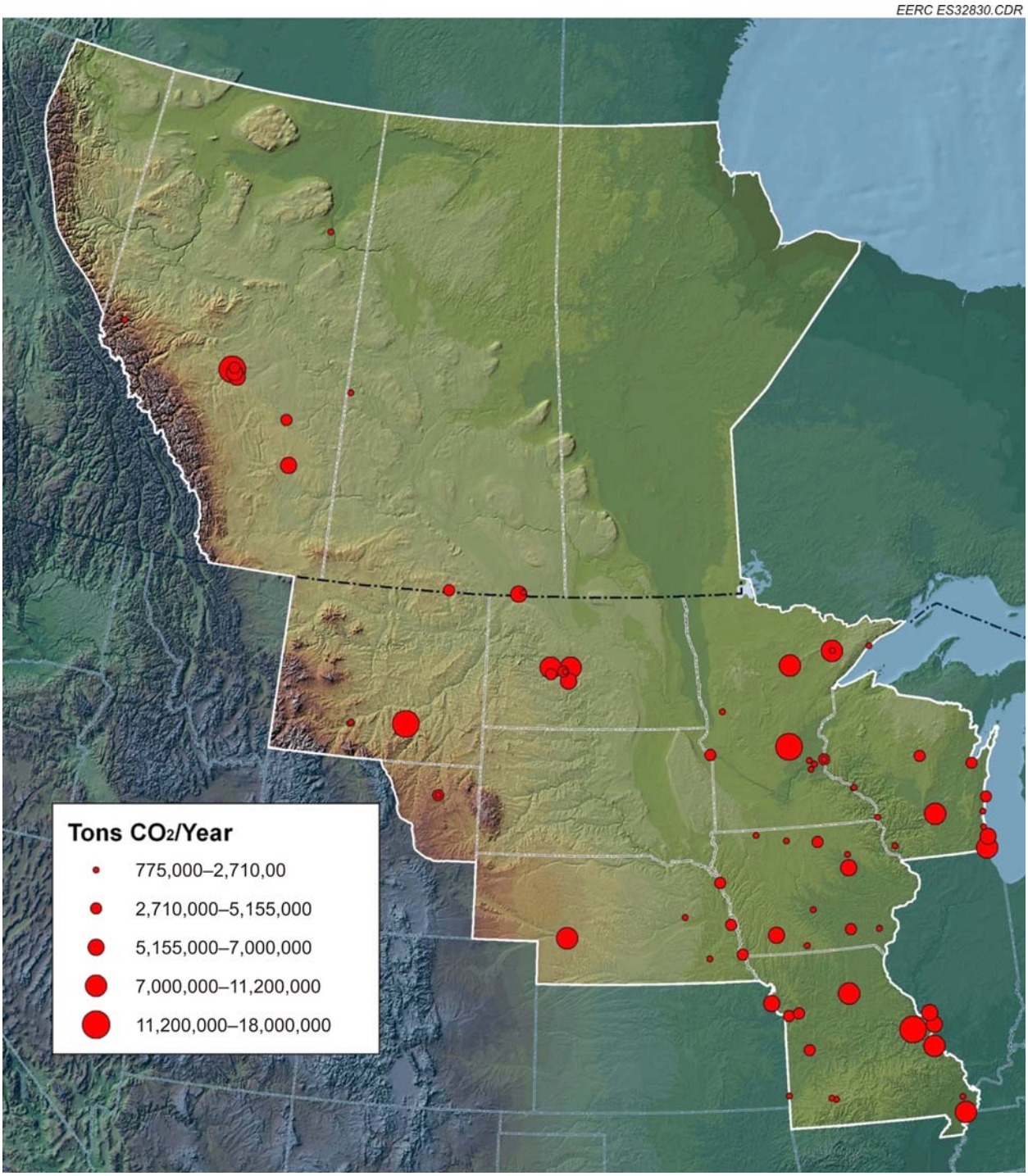

Figure 9. Map showing the location and range of CO_2 emissions of the electricity-generating stations larger than 100 MW in the PCOR Partnership region.

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.

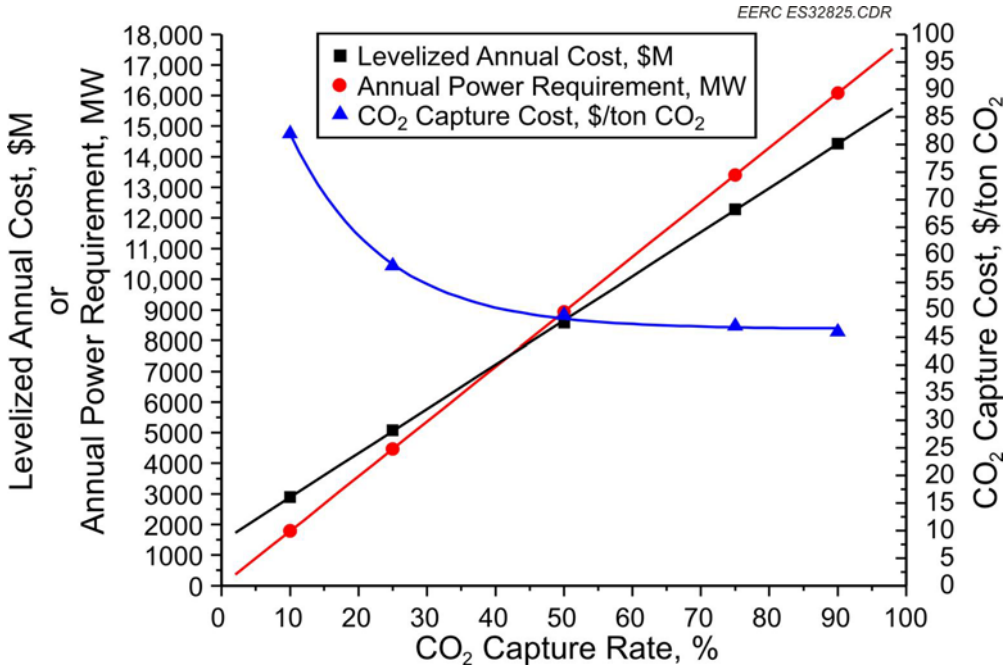

Figure 10. Graphical summary of the costs and energy penalty associated with implementation of CO_2 capture at electricity-generating stations larger than 100 MW in the PCOR Partnership region.

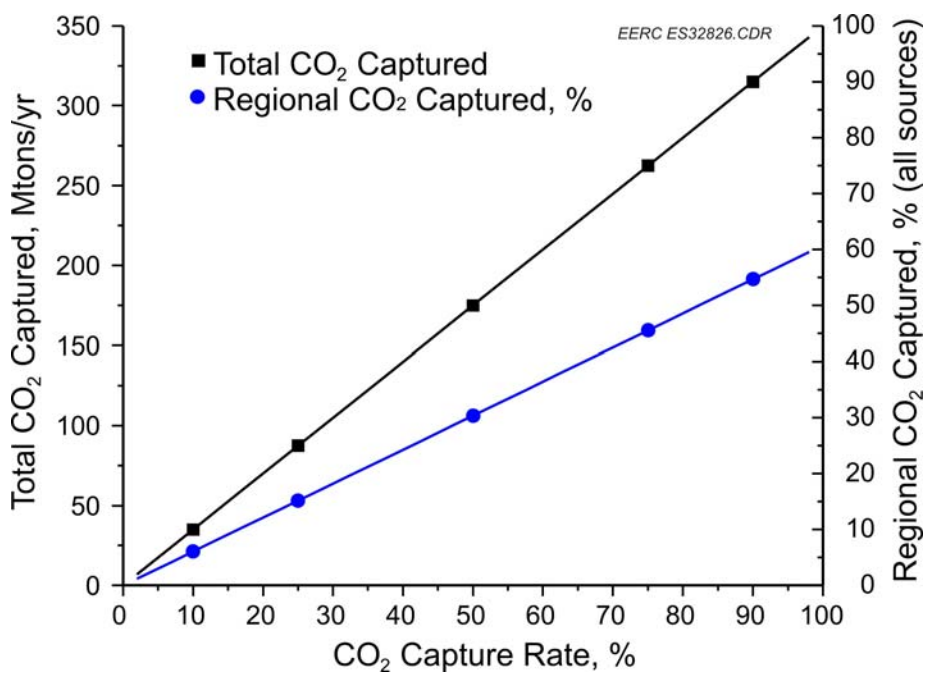

Figure 11. Total CO_2 captured from all electric generation stations larger than 100 MW in the PCOR Partnership region.

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.

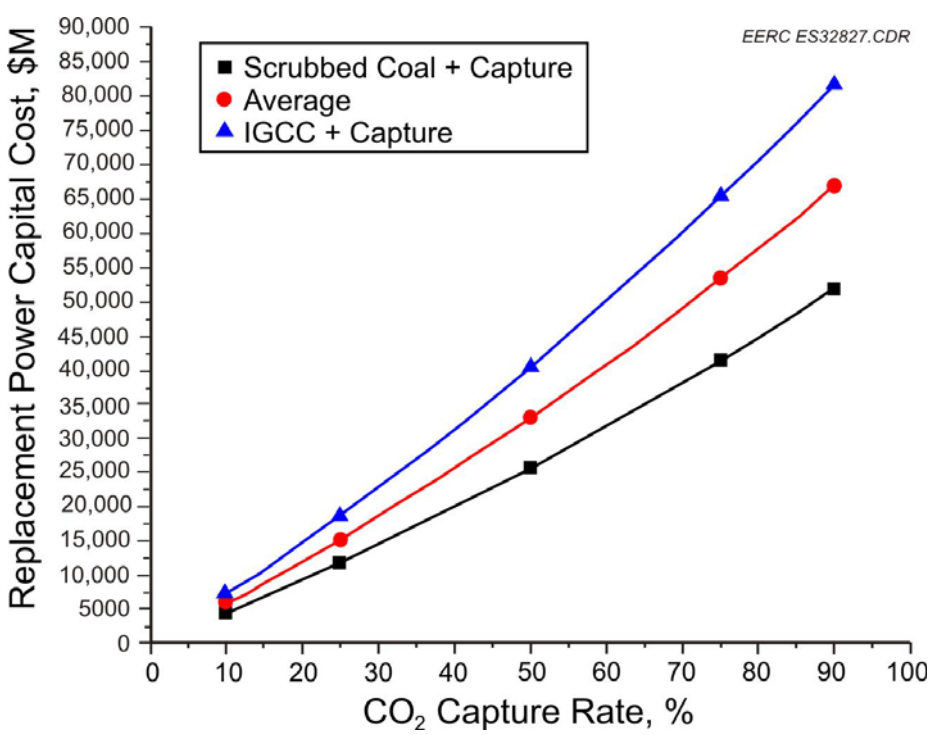

Figure 12. Replacement power capital cost as a function of CO_2 capture rate for two power generation methods and their average.

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.

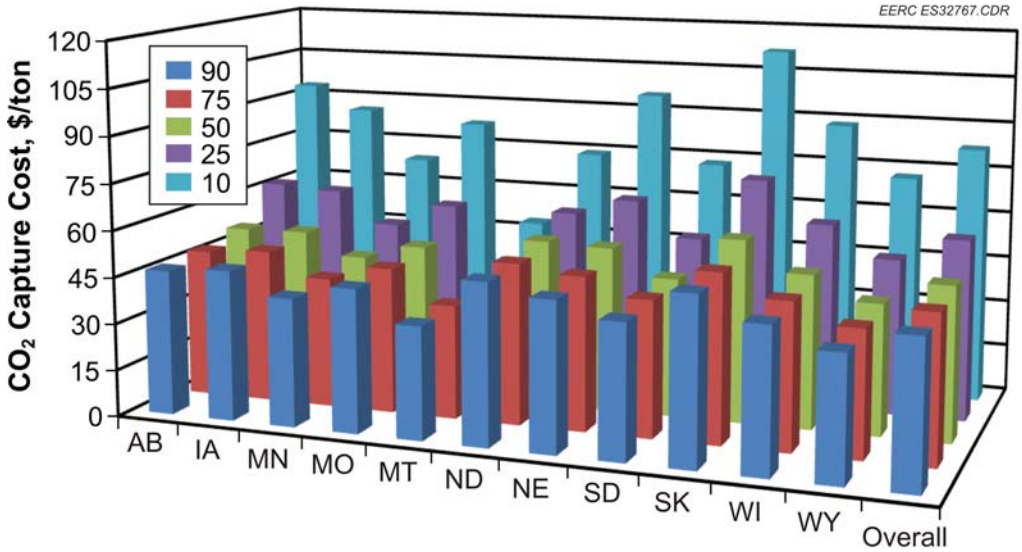

Figure 13. Comparison of CO_2 capture cost for all of the states/provinces in the PCOR Partnership region on a dollars-per-ton-CO_2-captured basis for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership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

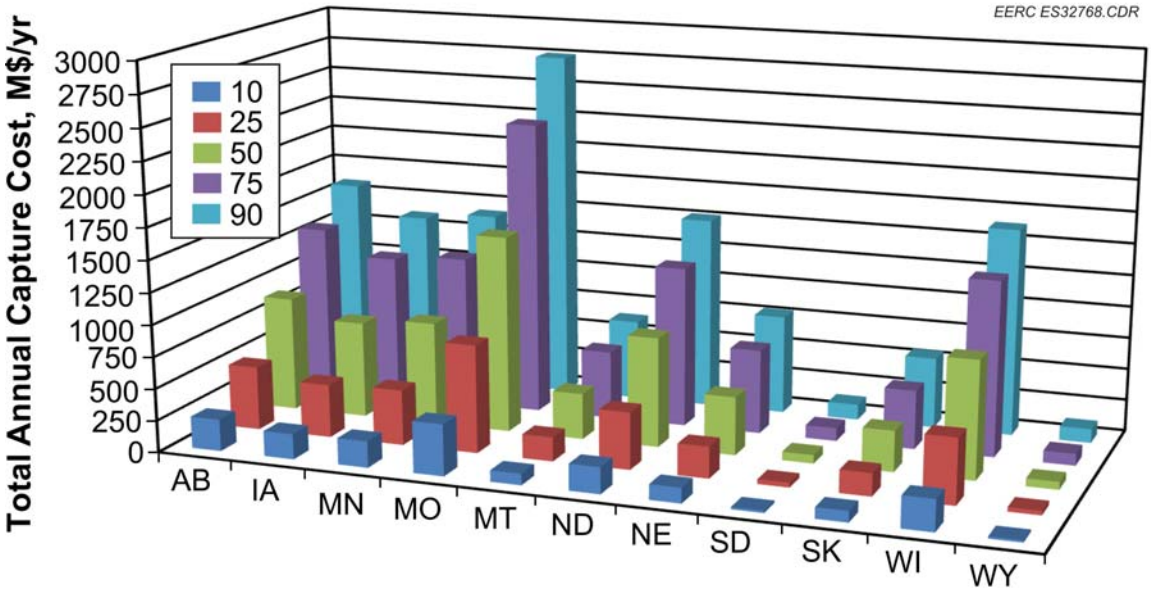

Figure 14. Comparison of total annual CO_2 capture cost for all of the states/provinces in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire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

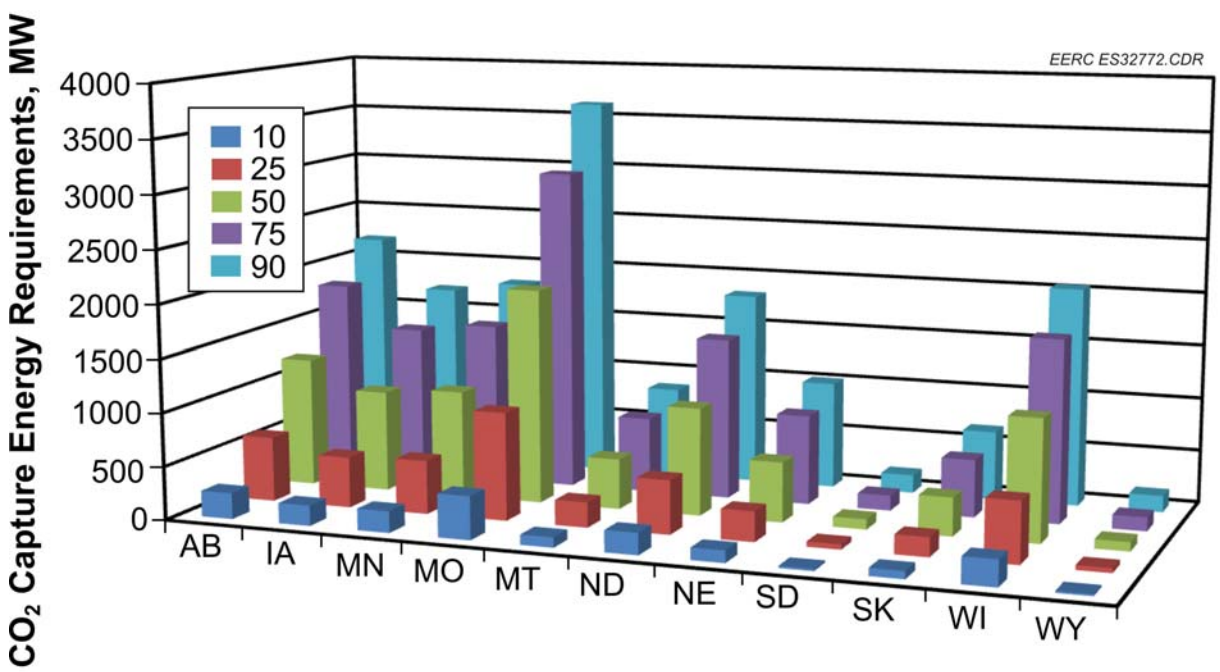

Figure 15. A comparison of the energy required for CO_2 capture in each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the entire state).

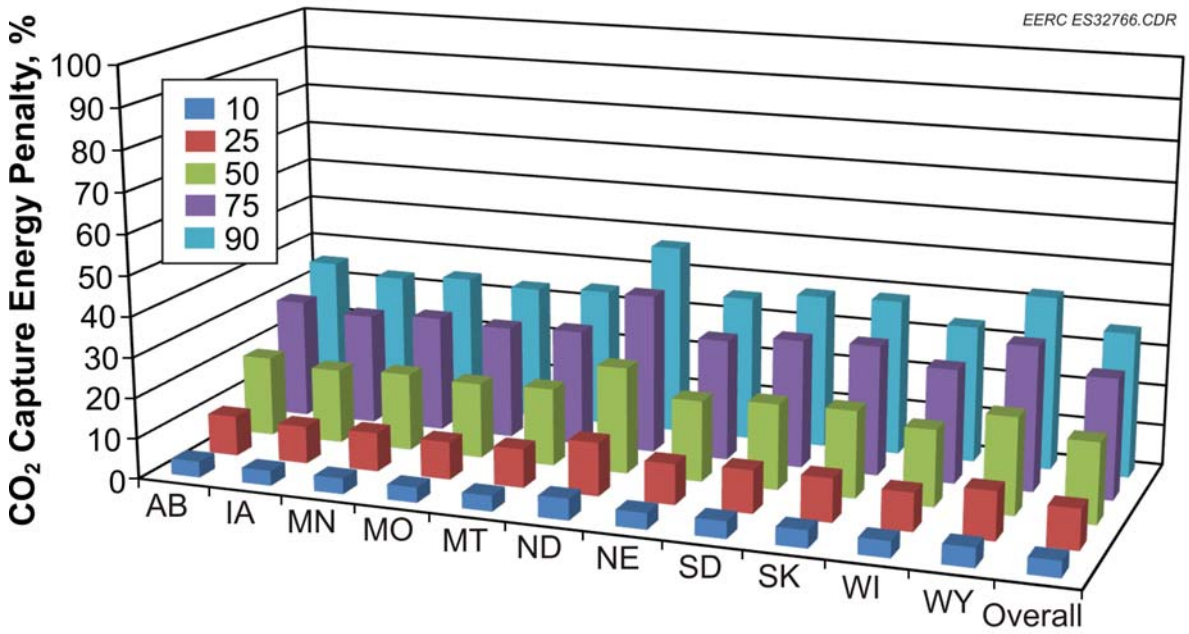

Figure 16. A comparison of the energy penalties incurred during CO_2 capture for each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than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

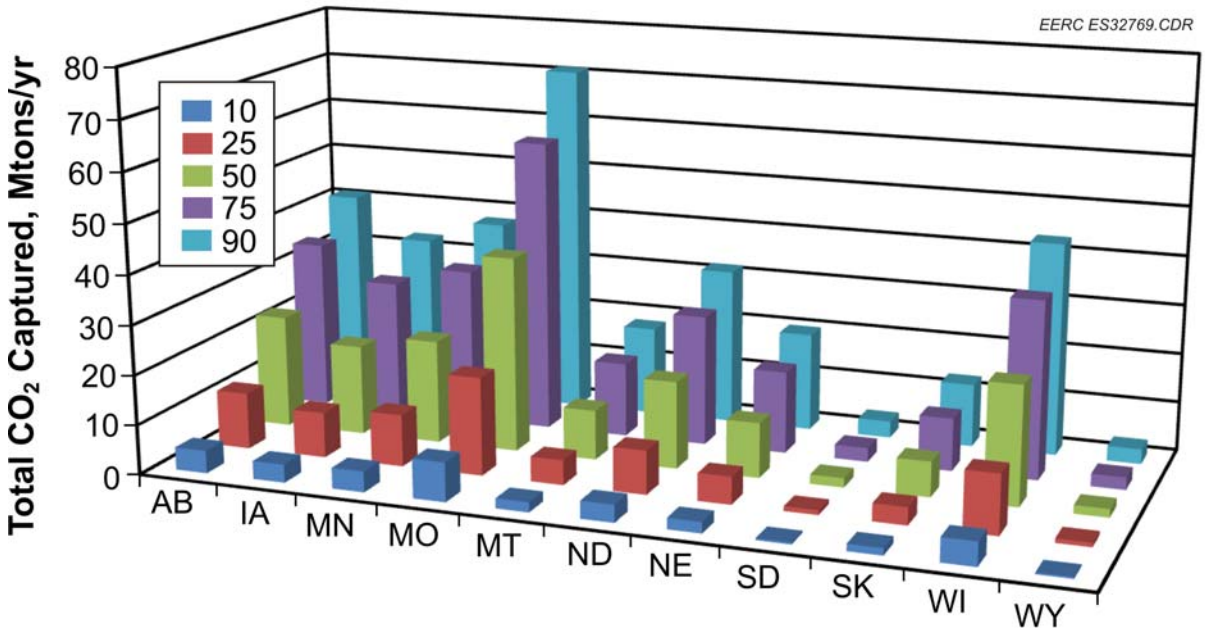

Figure 17. Comparison of the total amount of CO_2 that could be captured for each state/province in the PCOR Partnership region for various capture rates (it should be noted that values for Montana and Wyoming only reflect the portions of the states that lie within the PCOR Partnership rather than the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

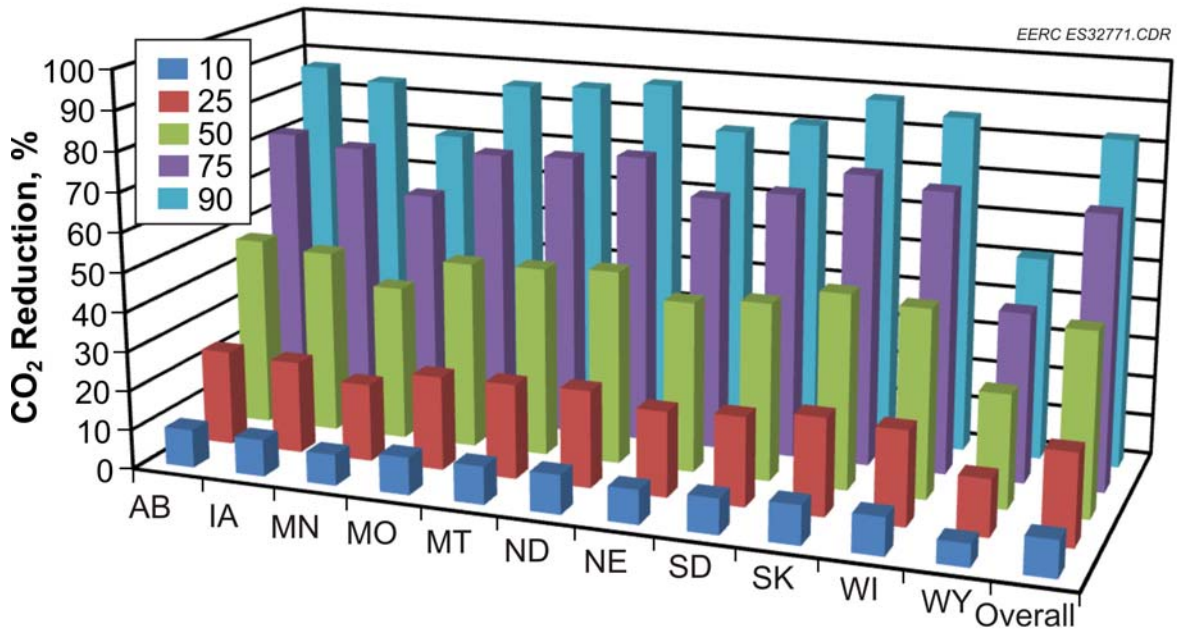

Figure 18. Comparison of the percentage of CO_2 reduced from all electricity-generating stations in each state/province in the PCOR Partnership region when CO_2 capture is implemented at the large (100 MW+) electricity-generating stations (it should be noted that values for Montana and Wyoming only reflect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

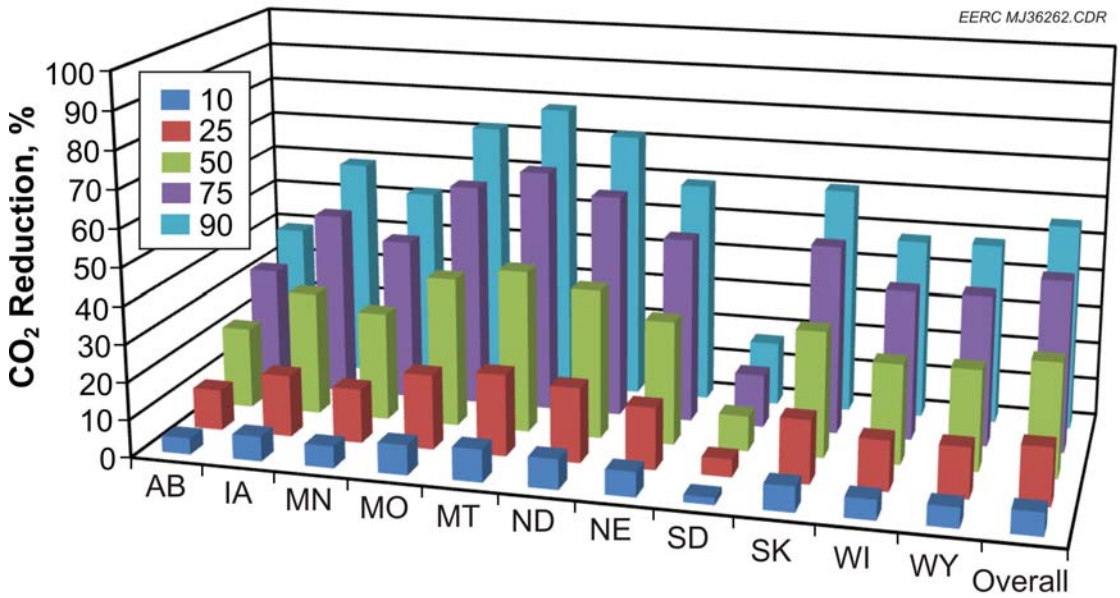

Figure 19. Comparison of the percentage of CO_2 reduced from all sources by implementing CO_2 capture at the large (100 MW+) electric generating stations for each state/province within the PCOR Partnership region (it should be noted that values for Montana and Wyoming only reflect the portions of the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

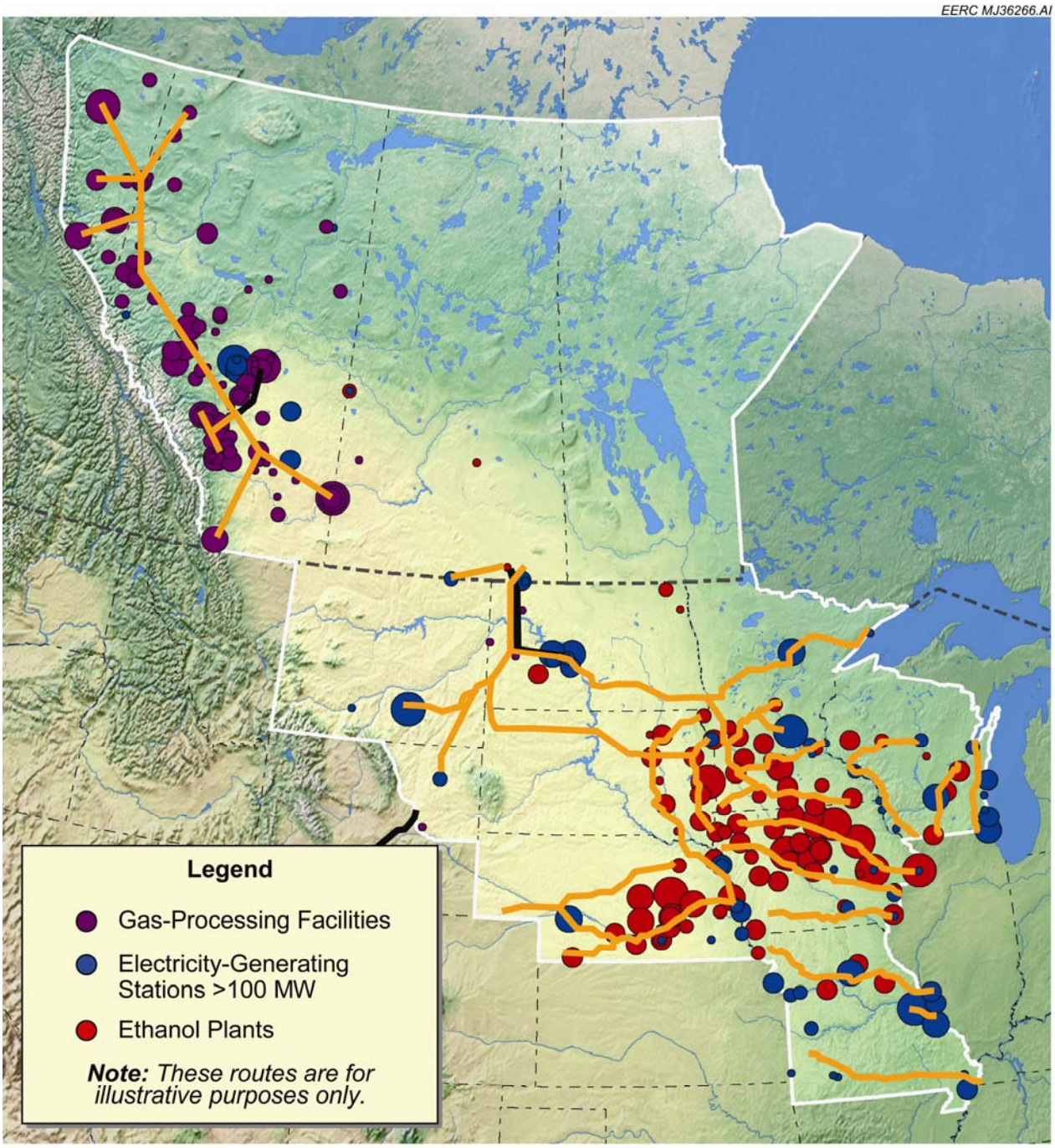

Figure 20. The illustrative PCOR Partnership pipeline network routes. Yellow gold routes show the pipeline network routes calculated during this study. Black lines are existing or planned CO_2 pipelines.

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

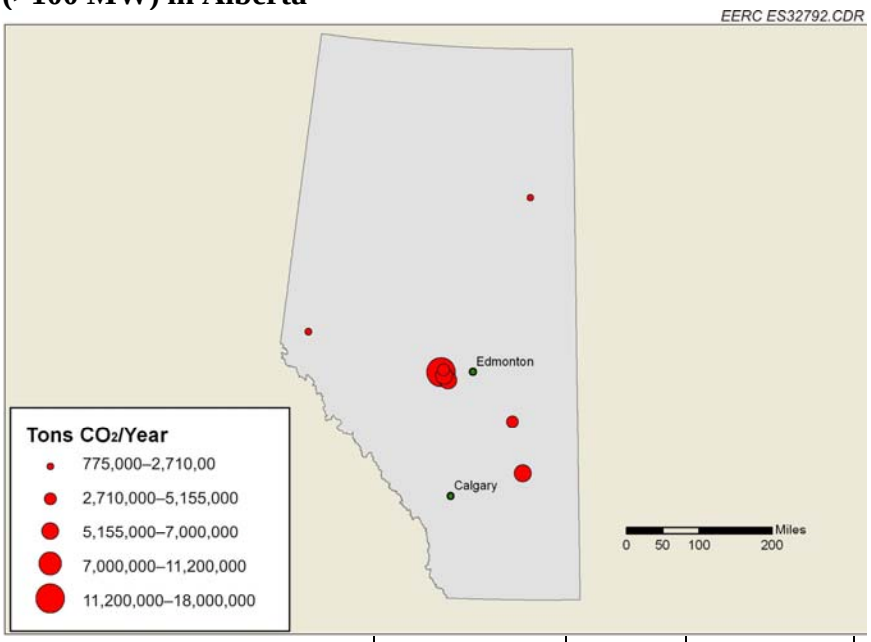
Alberta has 19 electricity-generating stations that emit more than 54,300,000 tons of CO_2 annually. Of these stations, eight are larger than 100 MW. These eight generating stations consist of 19 separate generating units, the characteristics of which are summarized in Table A-1 along with a map showing 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.

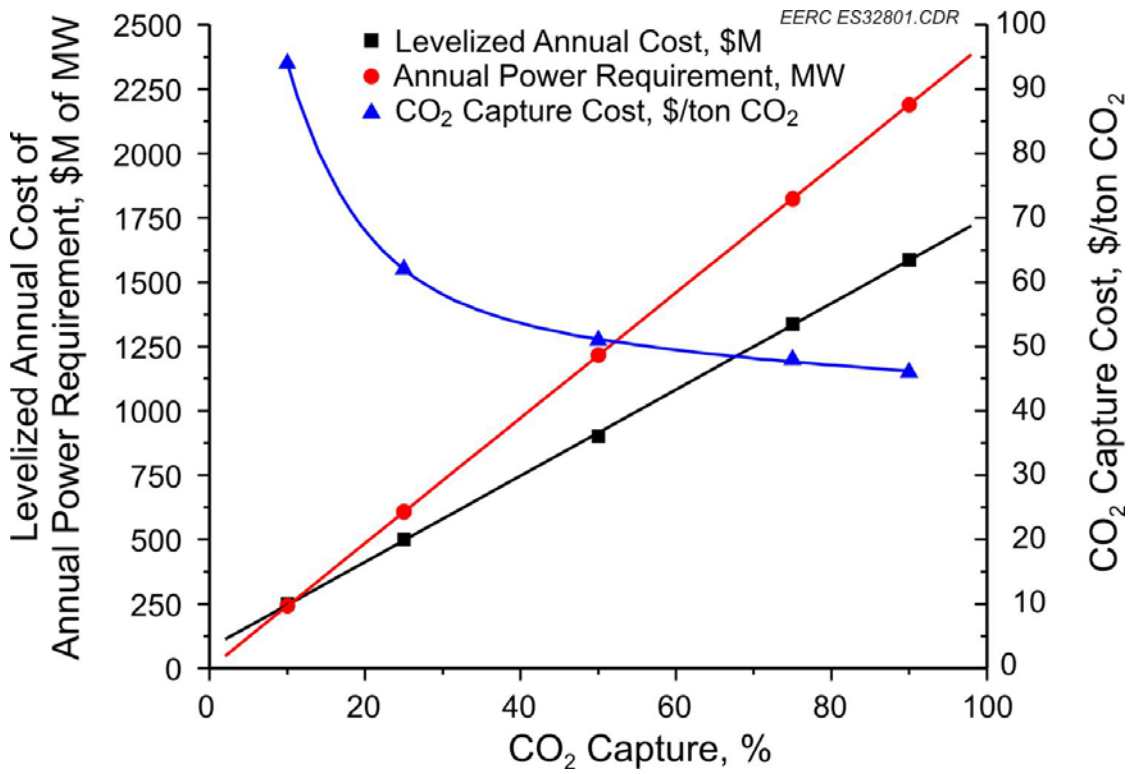


Figure A-1. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Alberta.

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.

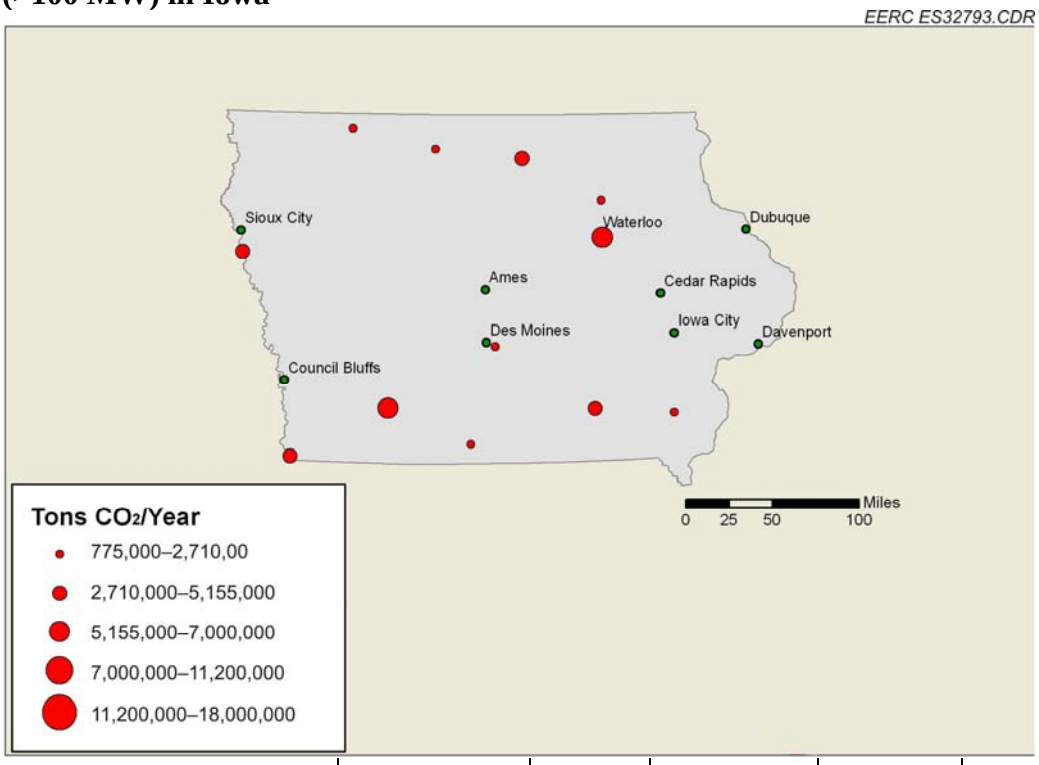
Iowa

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.

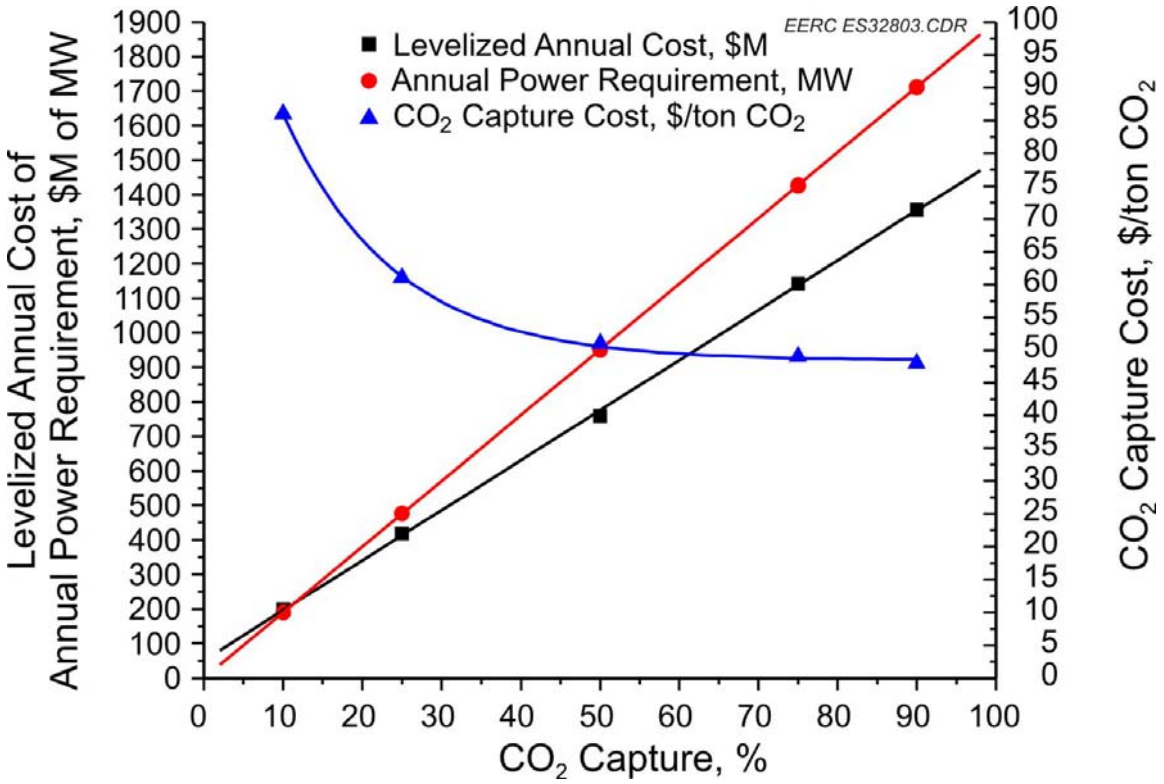


Figure A-2. Results of implementing CO_2 capture on electricity-generating units larger than 100 MW in Iowa.

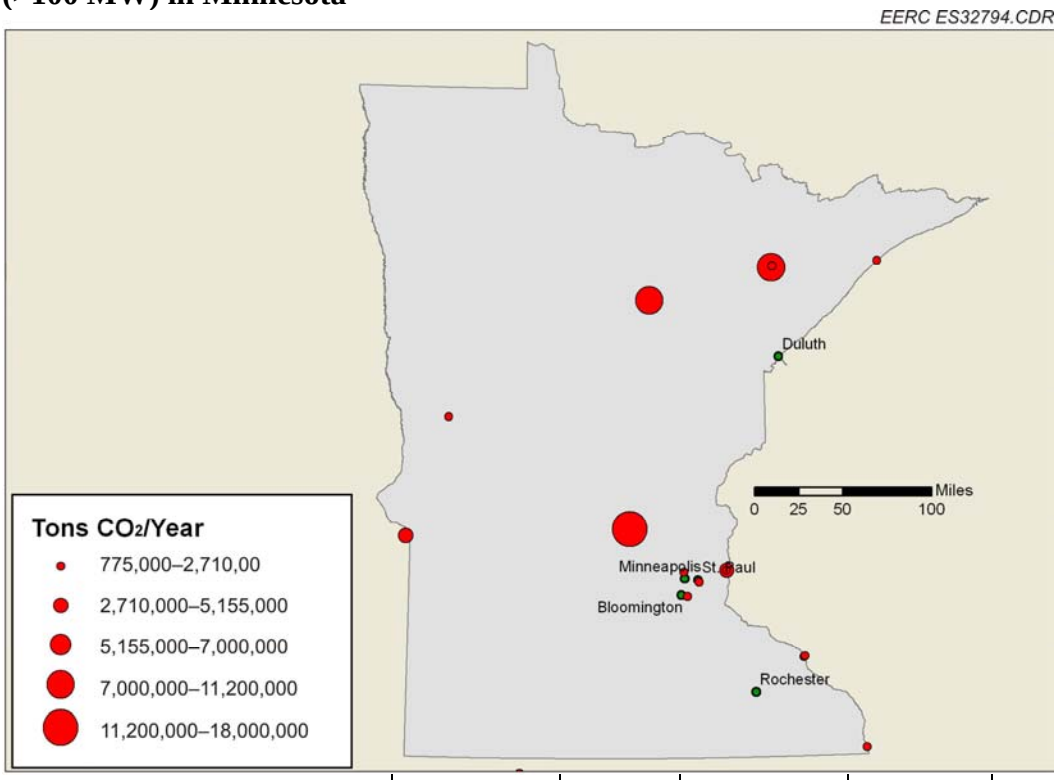
Minnesota

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.

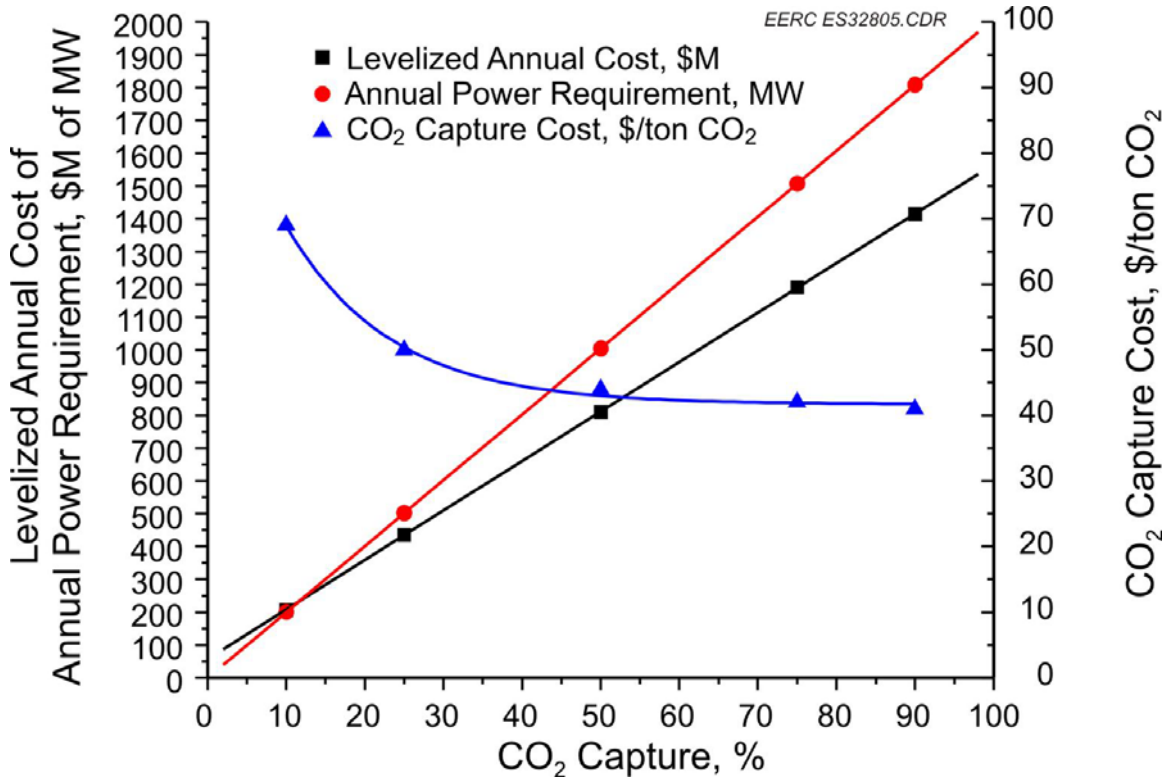


Figure A-3. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Minnesota.

Missouri

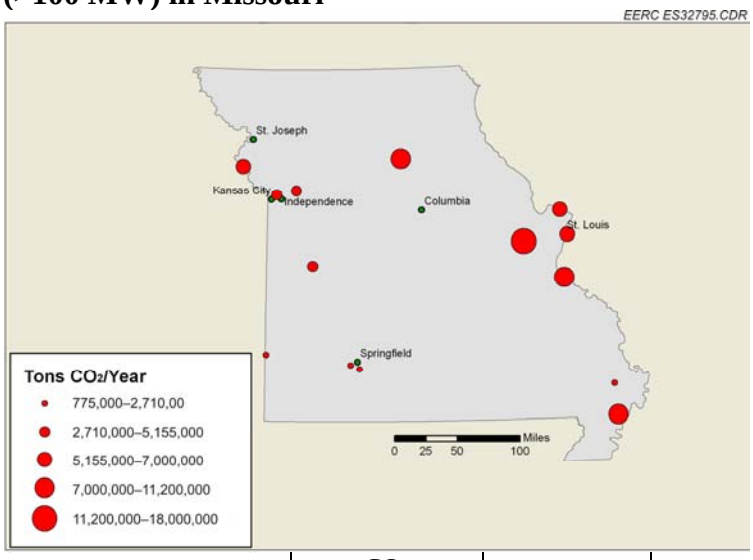
Missouri has 36 electricity-generating stations that emit more than 83,200,000 tons of CO_2 annually. Of these 36 stations, 14 are larger than 100 MW. These 14 generating stations consist of 27 separate generating units, the characteristics of which are summarized in Table A-7 along with a map showing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

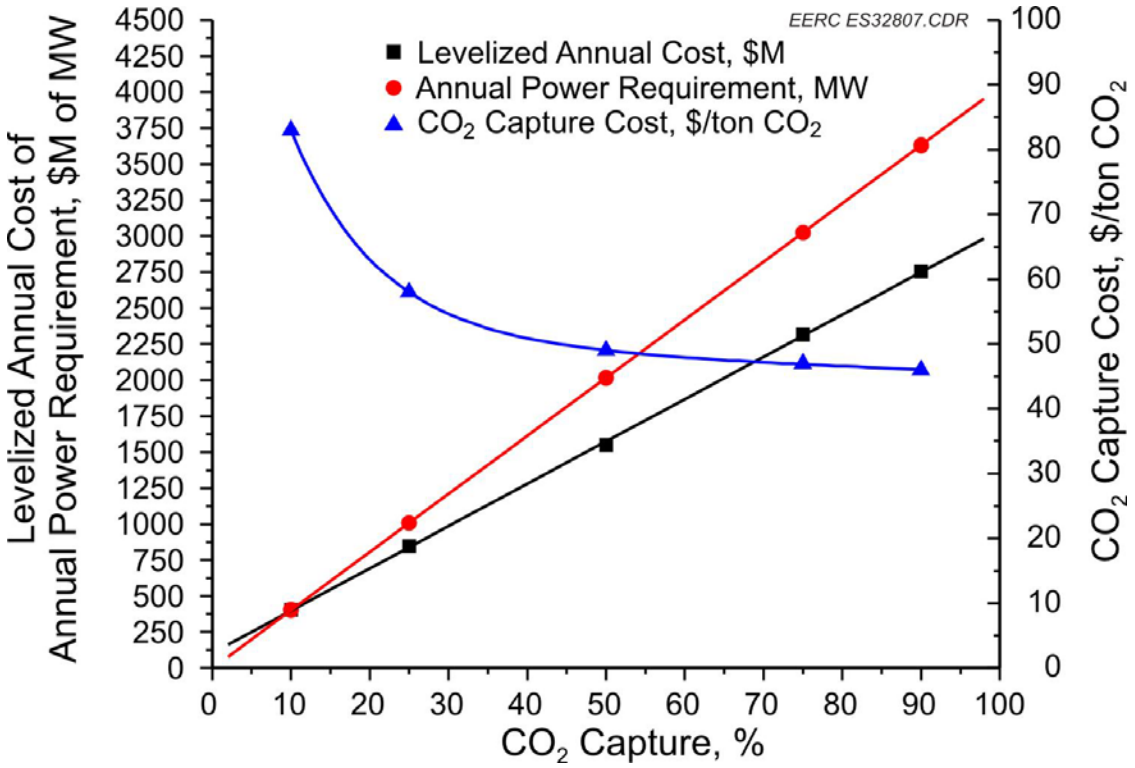


Figure A-4. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Missouri.

Montana

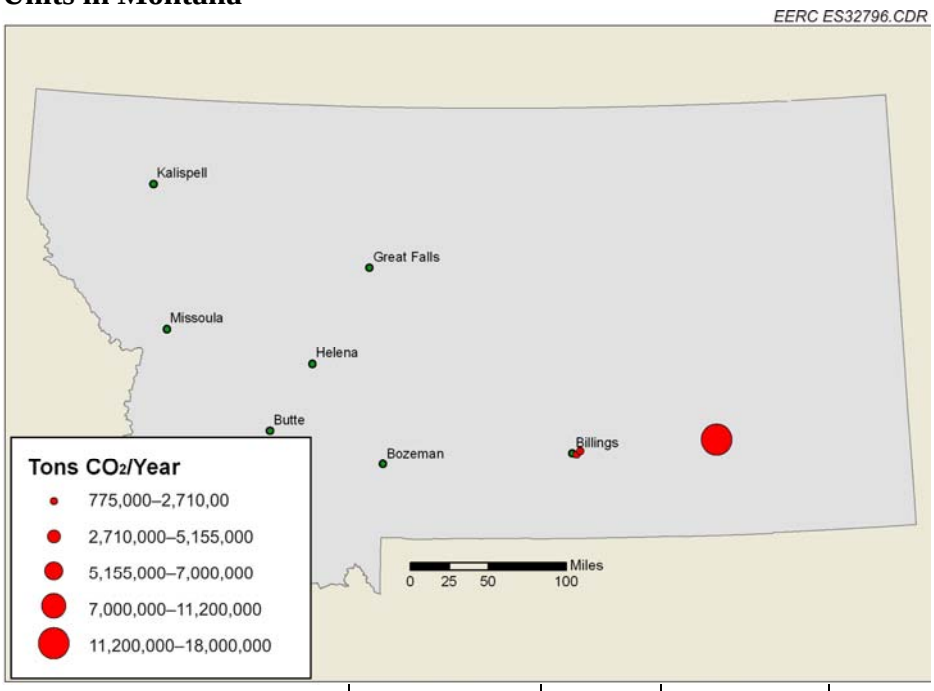
Only the eastern half of Montana is contained in the PCOR Partnership region. In that area, Montana has six electricity-generating stations that emit more than 20,970,000 tons of CO_2 annually. Of these six stations, two are larger than 100 MW: Colstrip and J.E. Corette. The two generating stations consist 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



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.

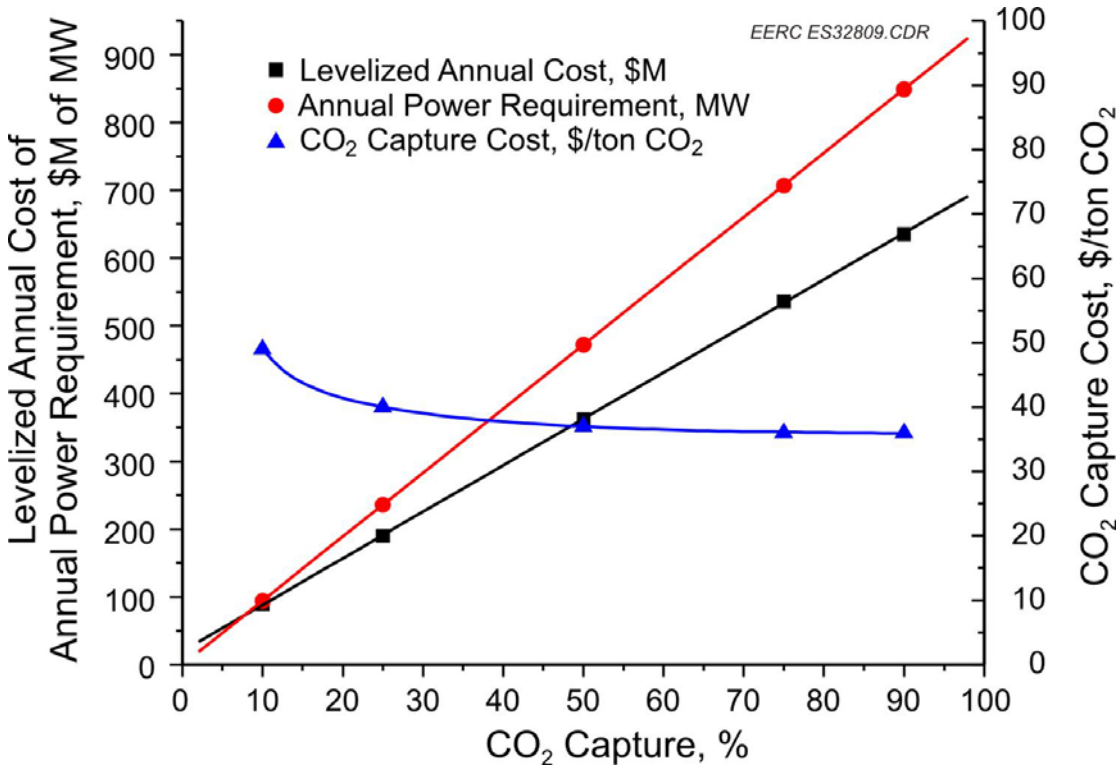


Figure A-5. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Montana.

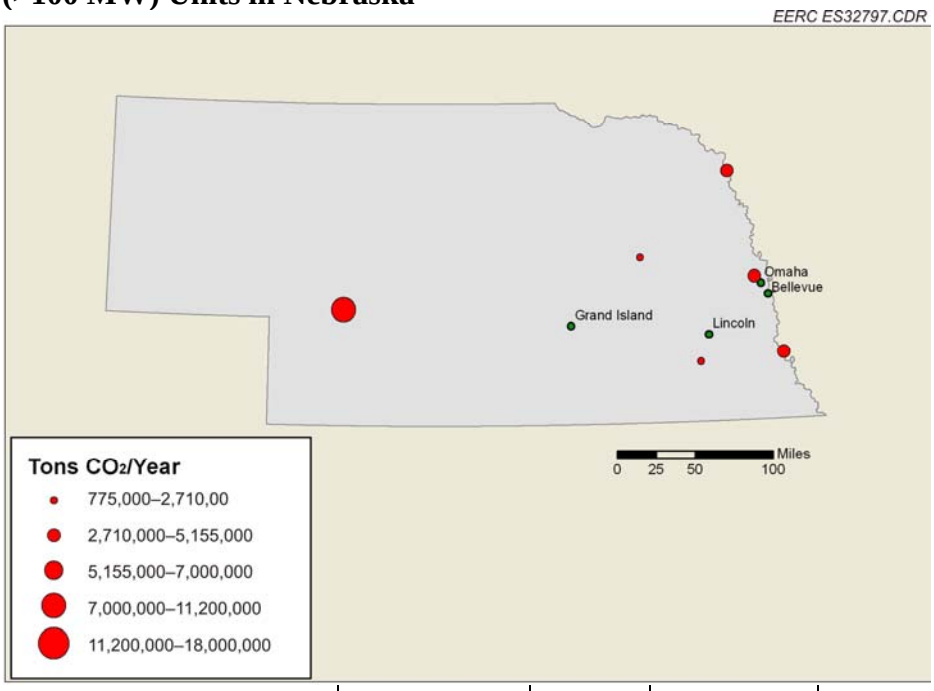
Nebraska

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.

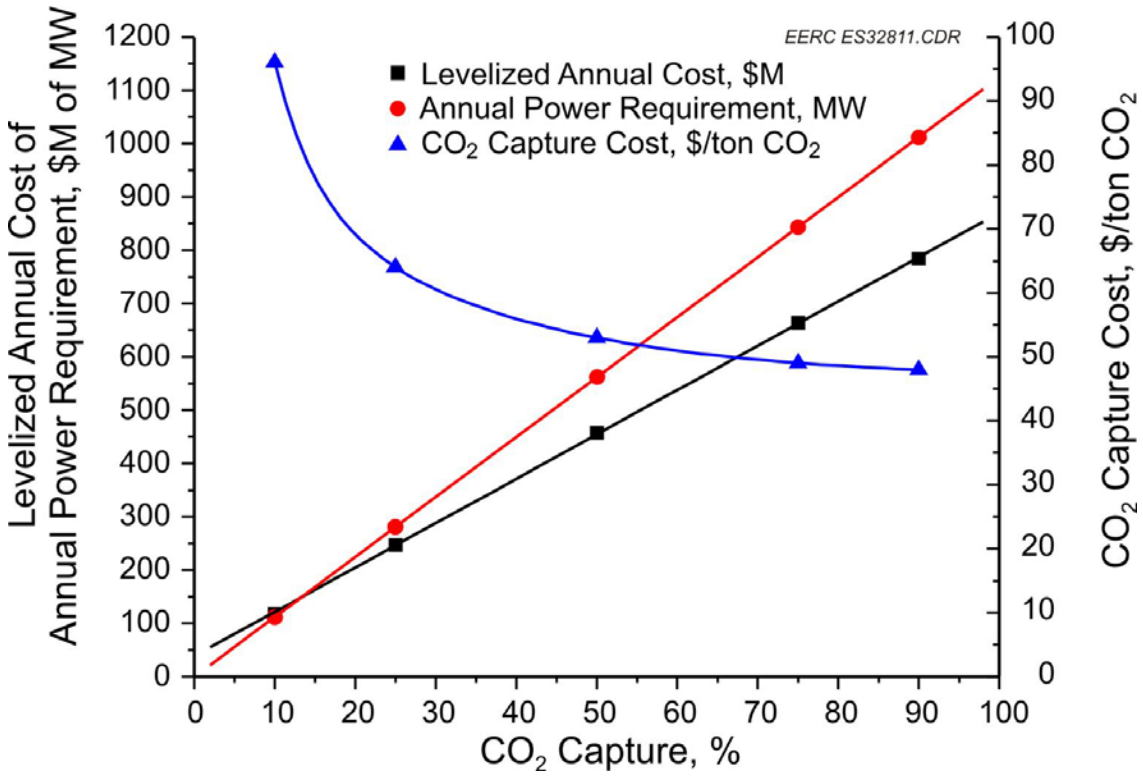


Figure A-6. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Nebraska.

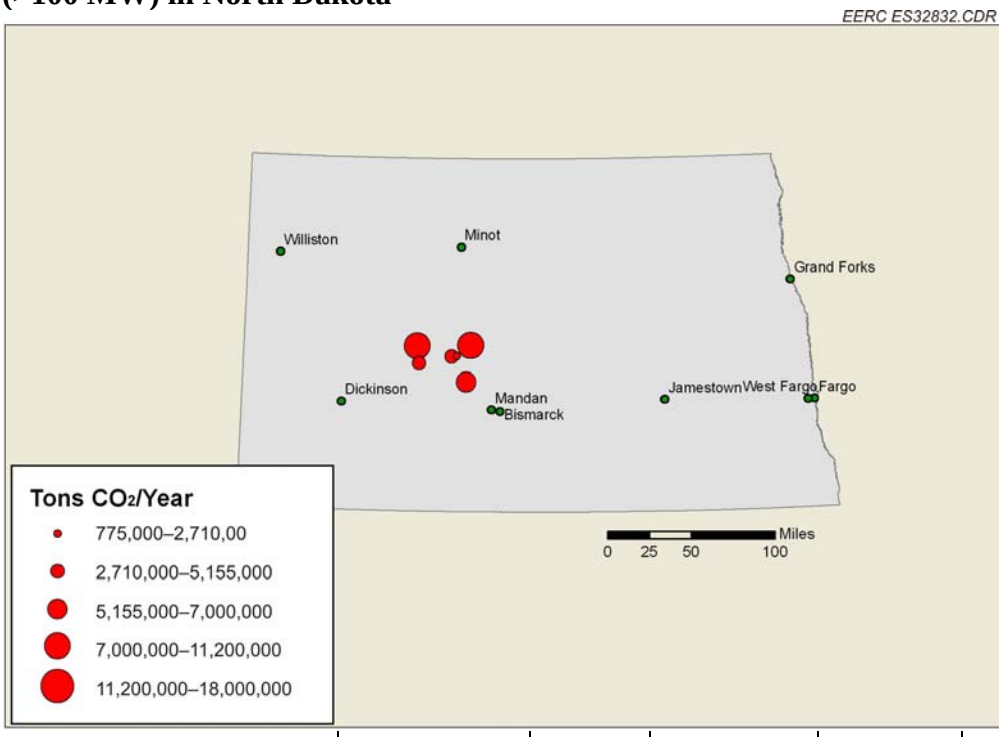
North Dakota

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.

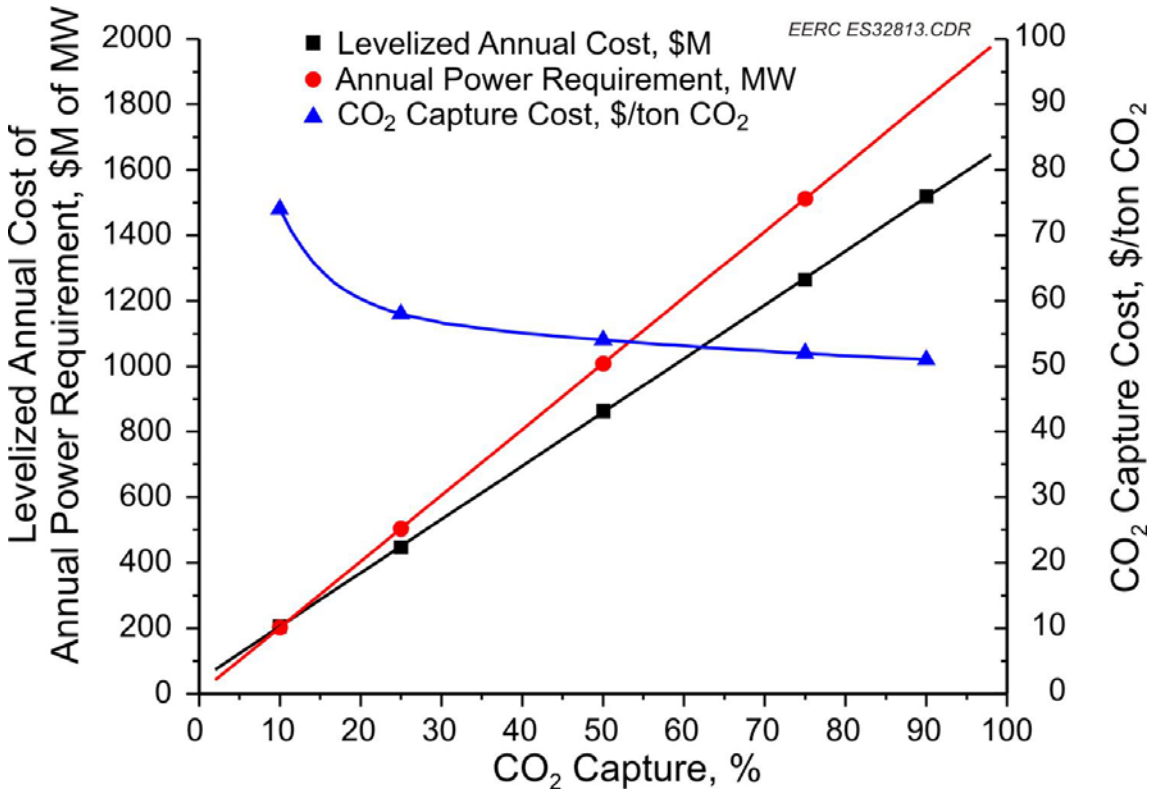


Figure A-7. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in North Dakota.

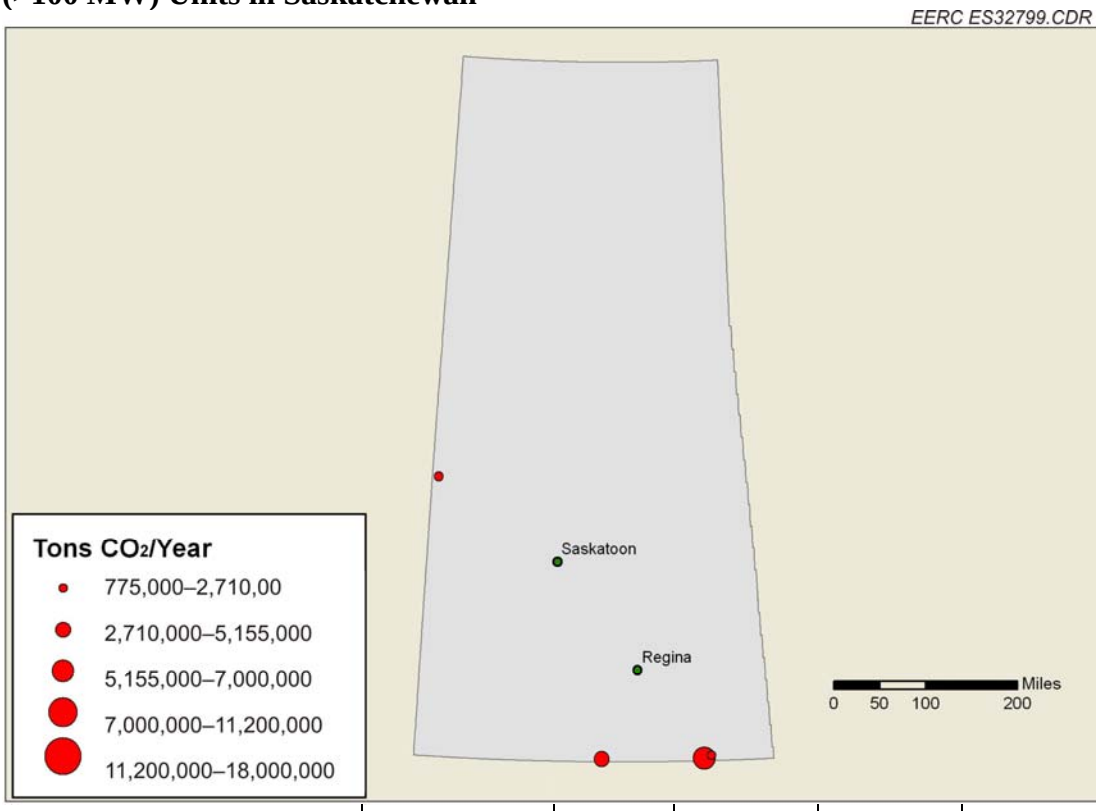
Saskatchewan

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.

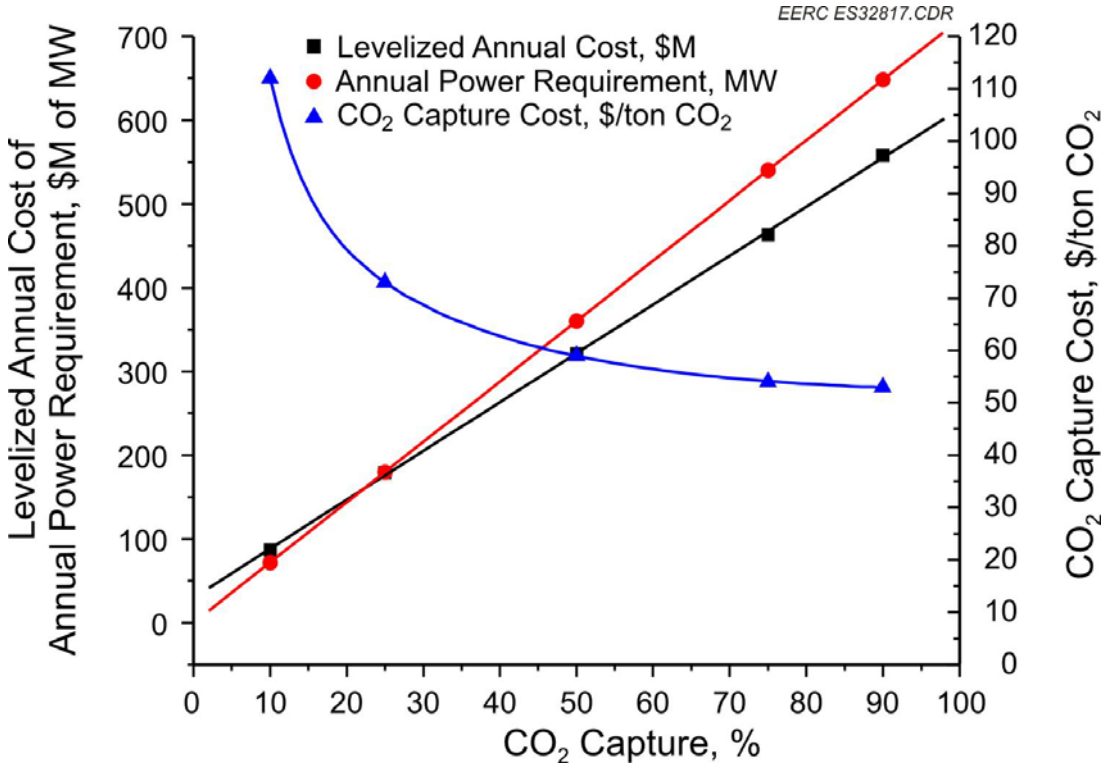


Figure A-8. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Saskatchewan.

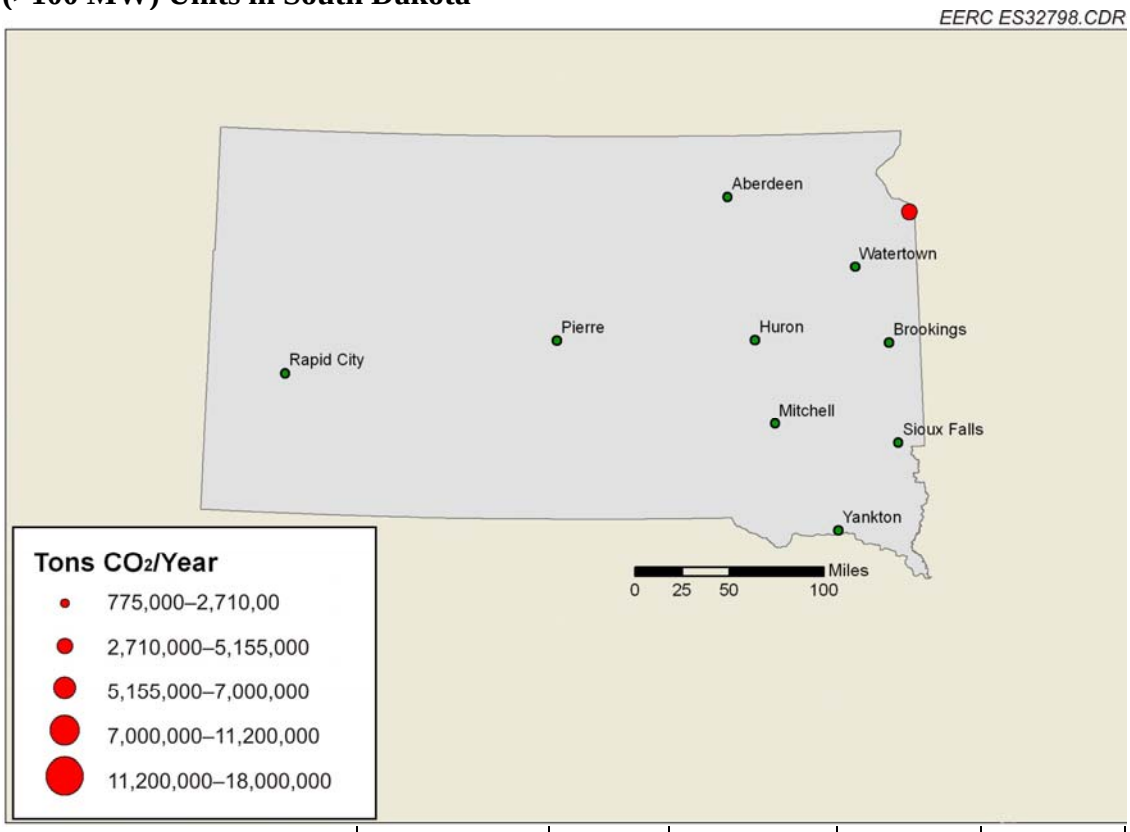
South Dakota

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.

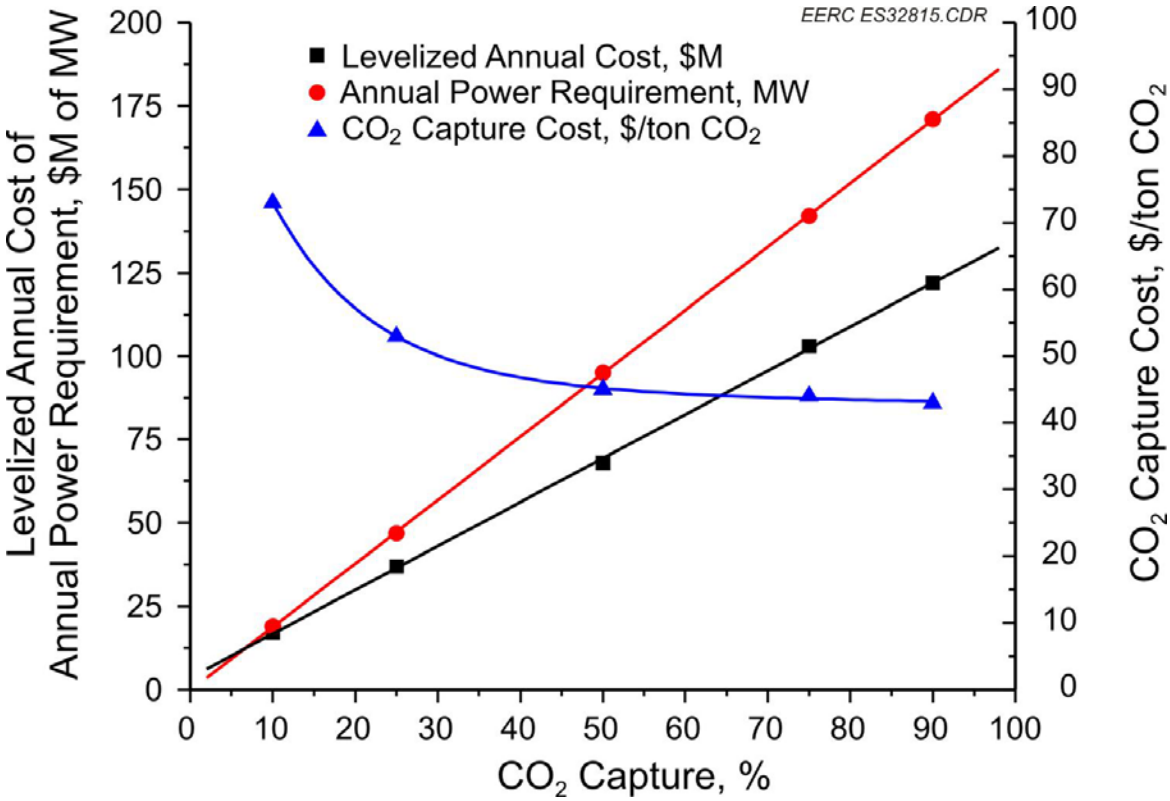


Figure A-9. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in South Dakota.

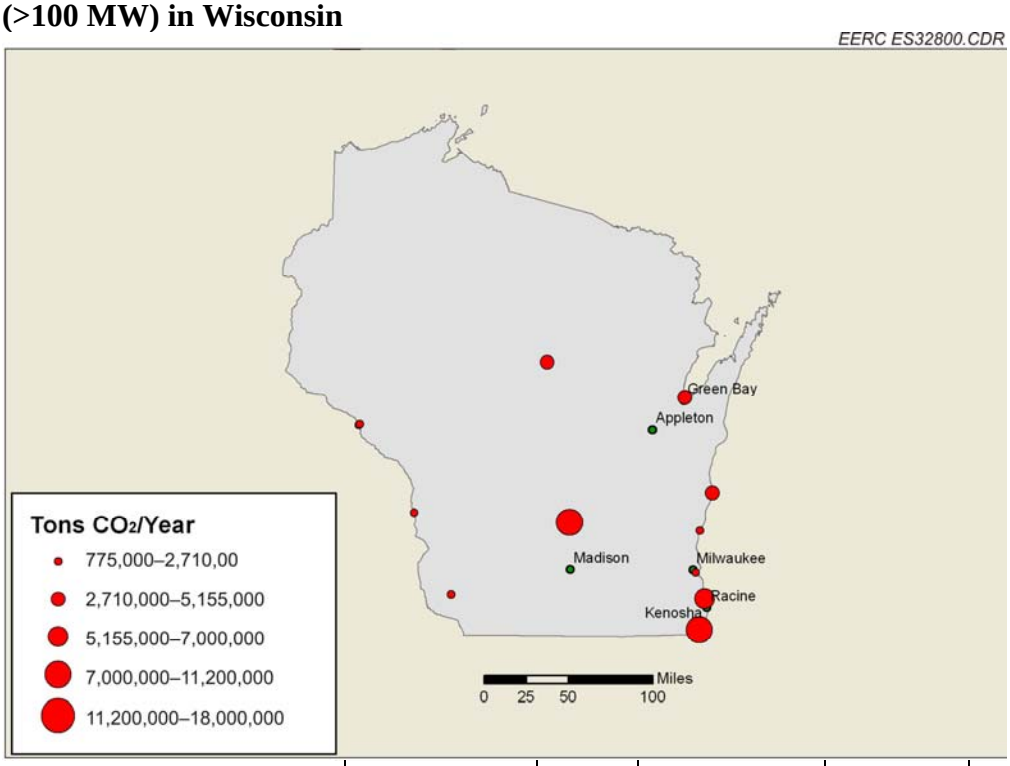
Wisconsin

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.

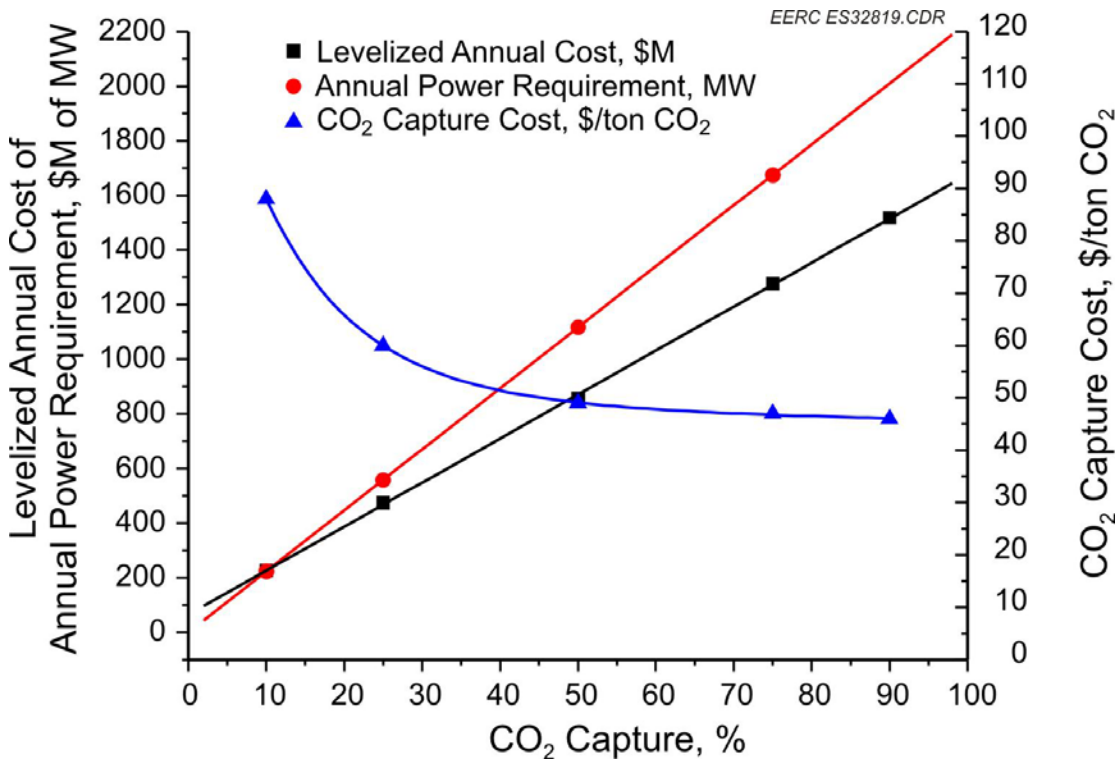


Figure A-10. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Wisconsin.

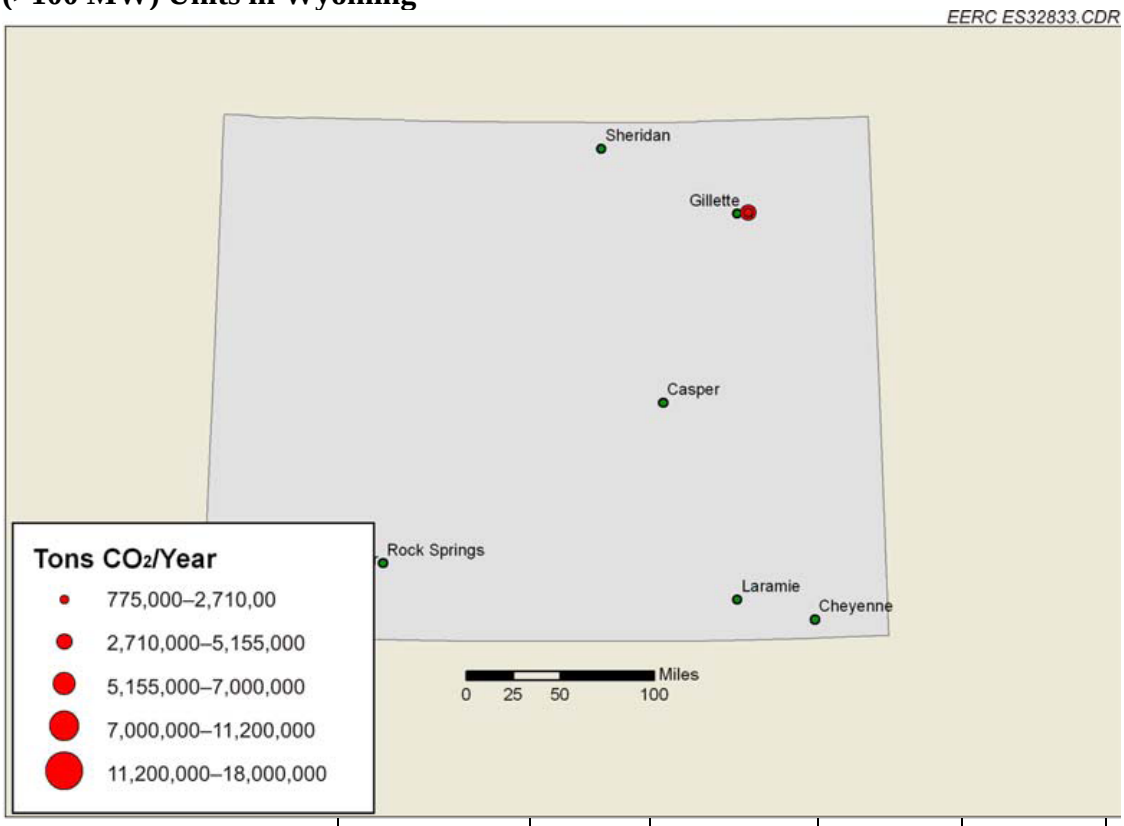
Wyoming

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.

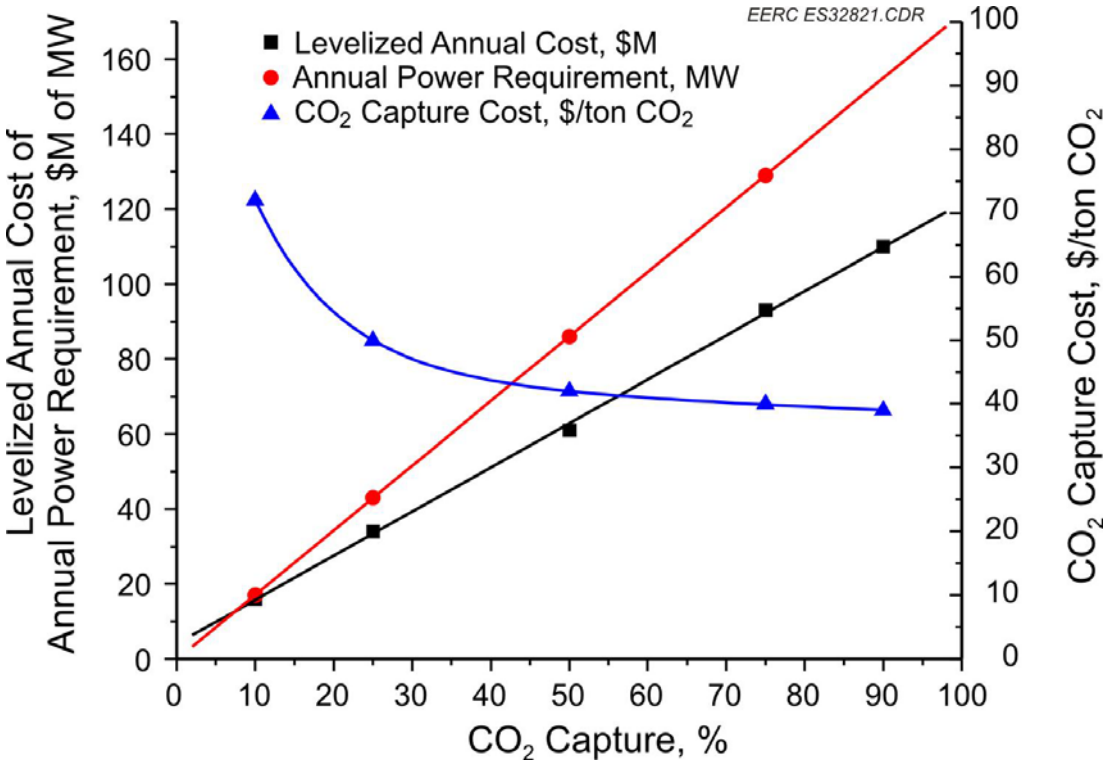


Figure A-11. Results from implementing CO_2 capture on electricity-generating units larger than 100 MW in Wyoming.

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

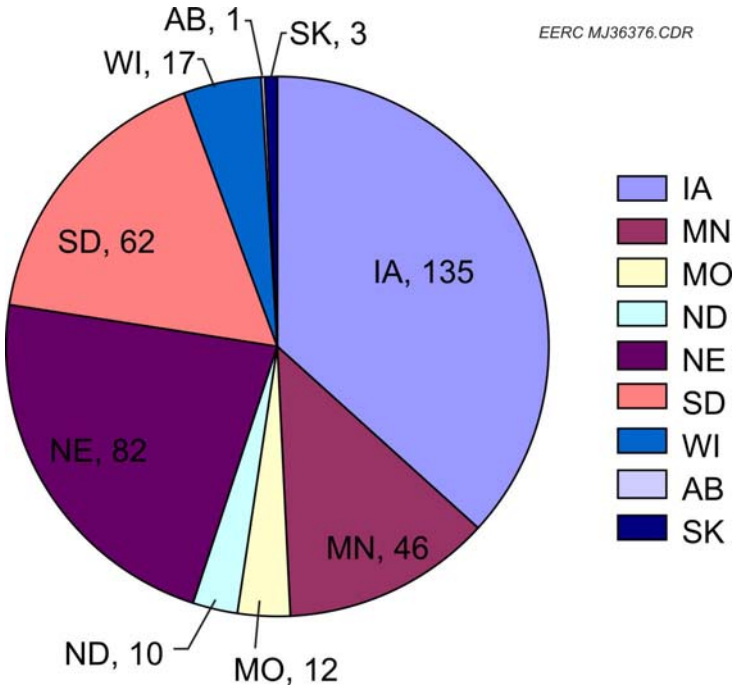


Figure C-1. Additional electrical capacity (MW) needed to capture fermentation CO_2 and 10% of combustion CO_2 at the region's ethanol plants.

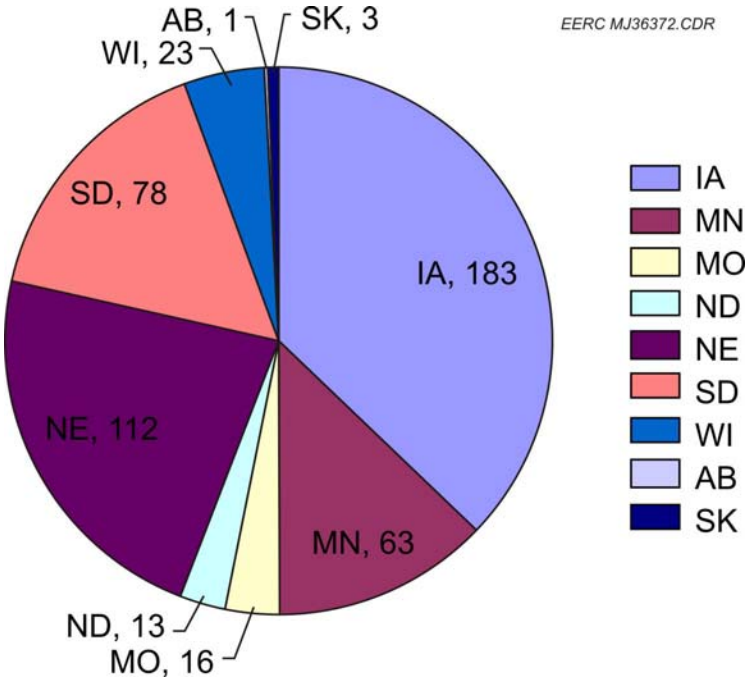


Figure C-2. Additional electrical capacity (MW) needed to capture fermentation CO_2 and 25% of combustion CO_2 at the region's ethanol plants.

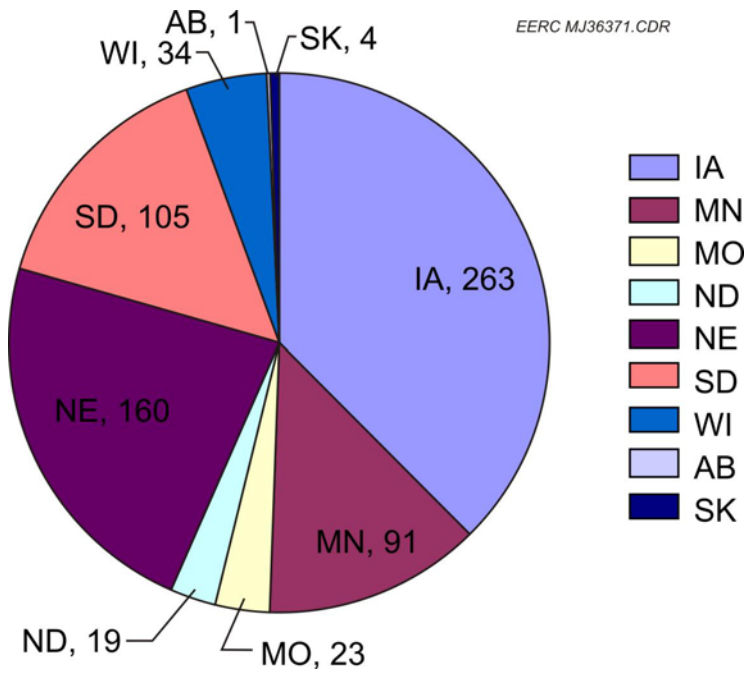


Figure C-3. Additional electrical capacity (MW) needed to capture fermentation CO_2 and 50% of combustion CO_2 at the region's ethanol plants.

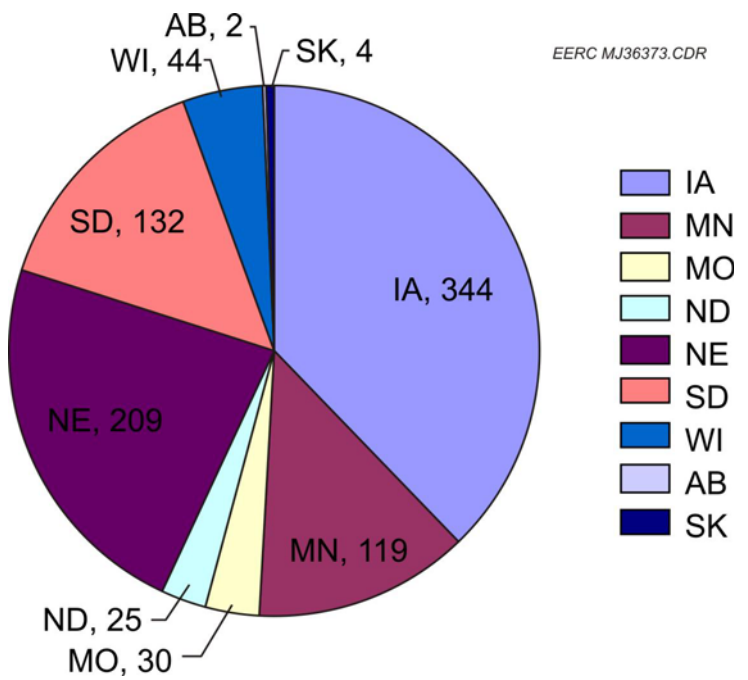


Figure C-4. Additional electrical capacity (MW) needed to capture fermentation CO_2 and 75% of combustion CO_2 at the region's ethanol plants.

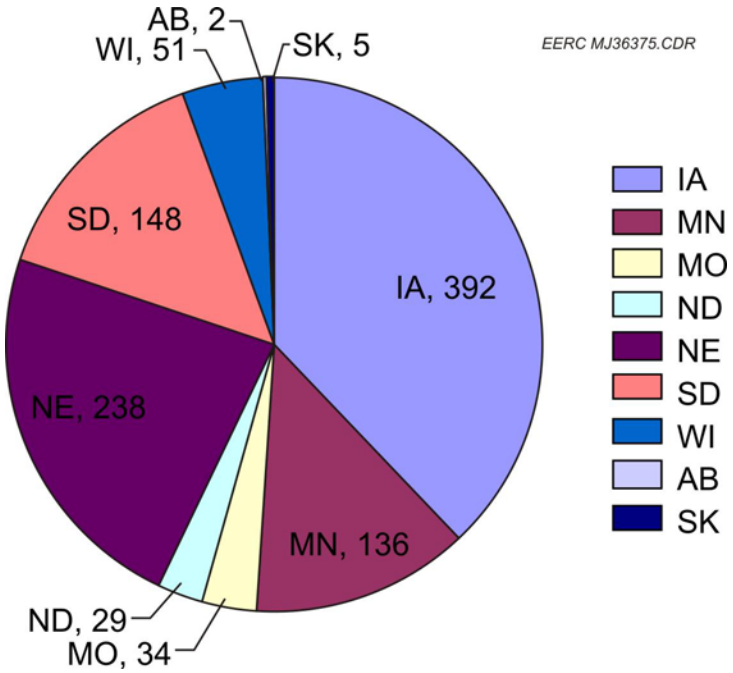


Figure C-5. Additional electrical capacity (MW) needed to capture fermentation CO_2 and 90% of combustion CO_2 at the region's ethanol plants.

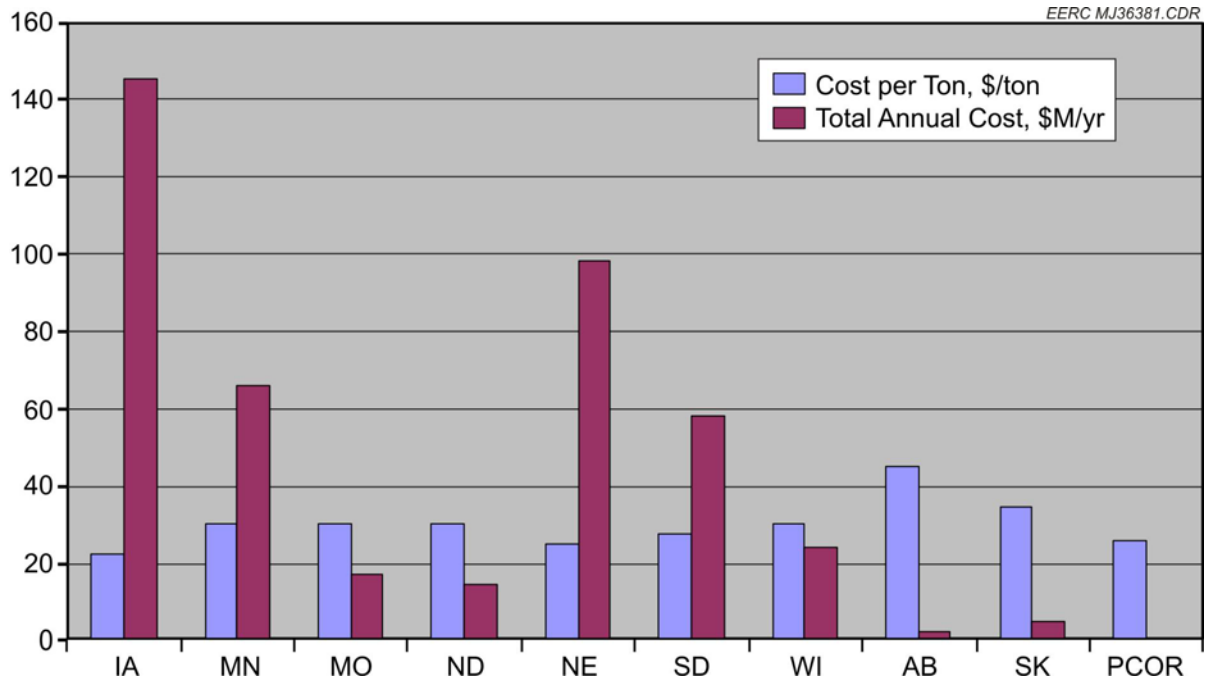


Figure C-6. The cost of capture of fermentation CO_2 and 10% of combustion CO_2 produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $477.5 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the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

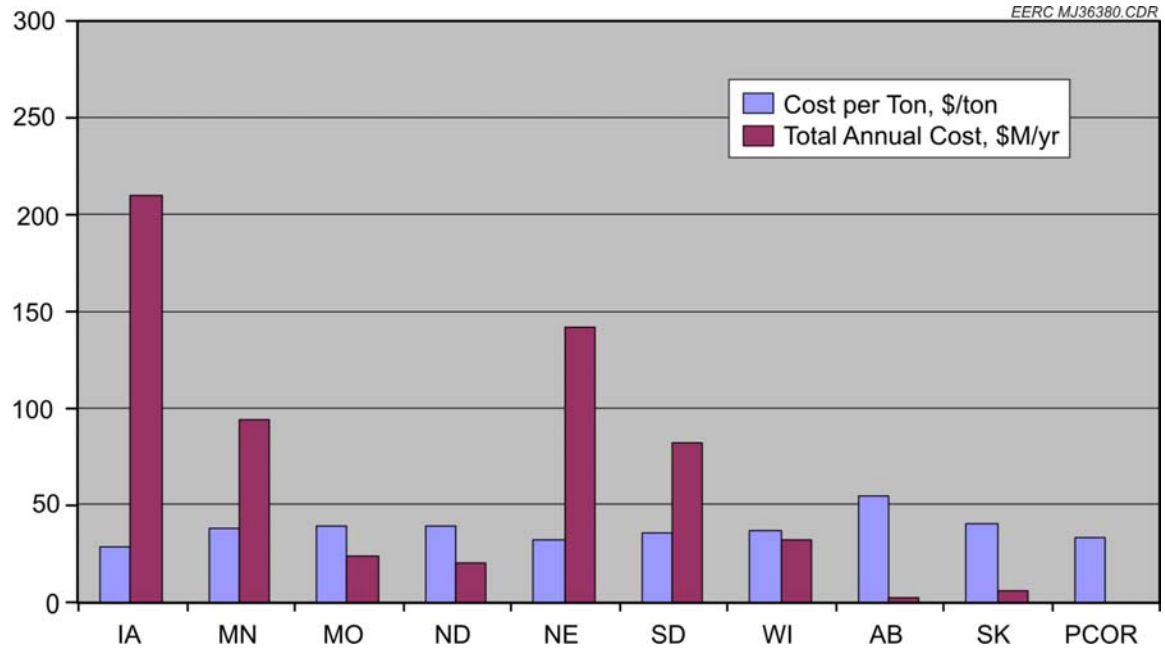


Figure C-7. The cost of capture of fermentation CO_2 and 25% of combustion CO_2 produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $696 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the states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

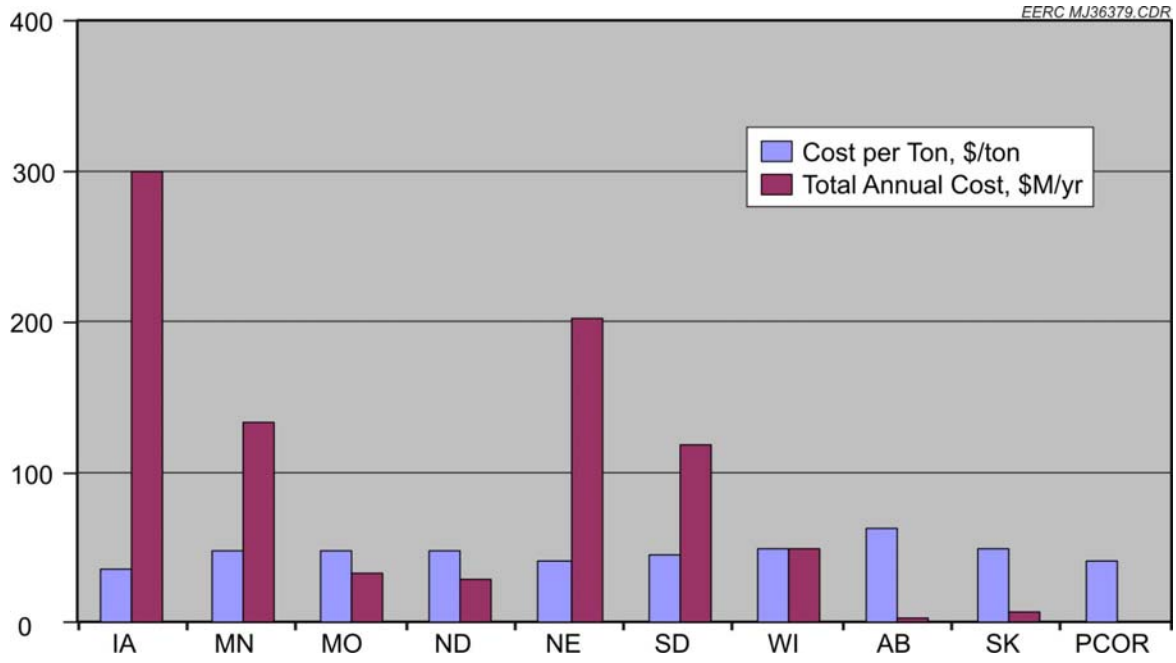


Figure C-8. The cost of capture of fermentation CO_2 and 50% of combustion CO_2 produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $990.6 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the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

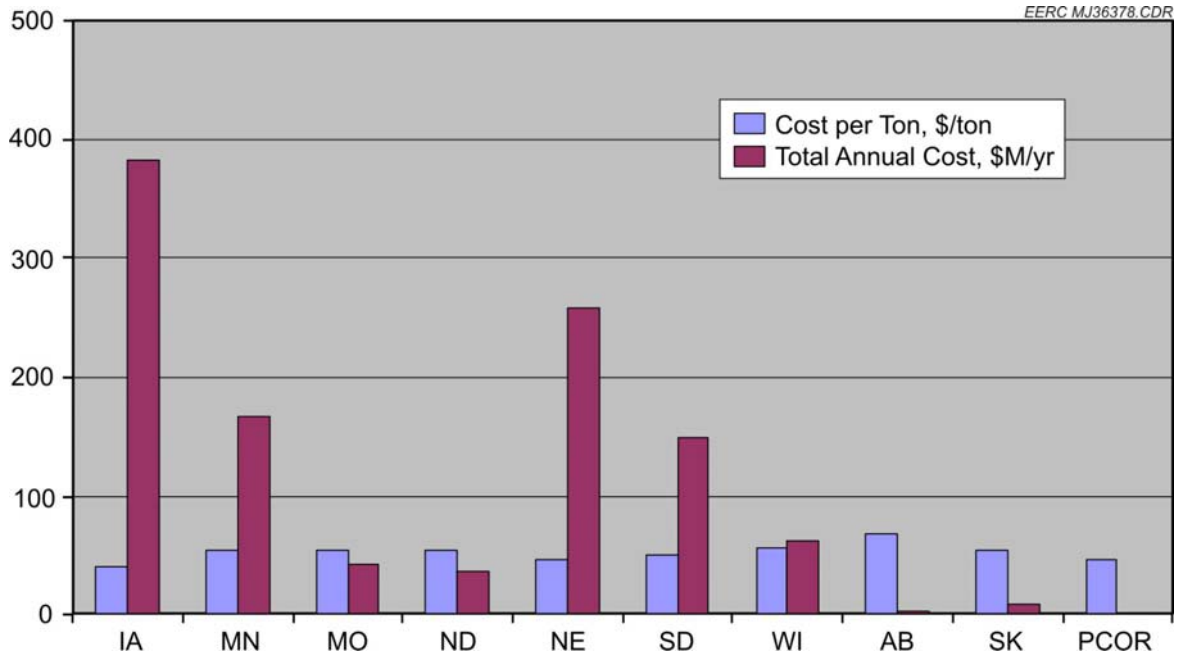


Figure C-9. The cost of capture of fermentation CO_2 and 75% of combustion CO_2 produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $1259.5 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the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

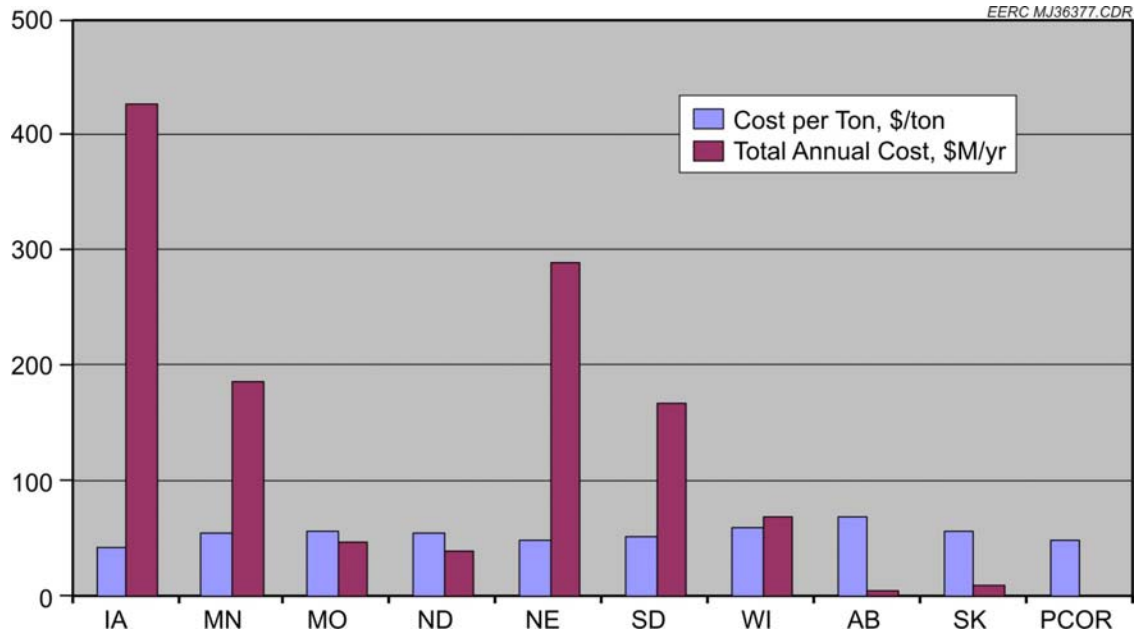


Figure C-10. The cost of capture of fermentation CO_2 and 90% of combustion CO_2 produced at the PCOR Partnership region's ethanol plants. The regional total annual cost of $1412.7 million/yr is not shown because its magnitude would compress the chart, making it difficult to see differences between the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

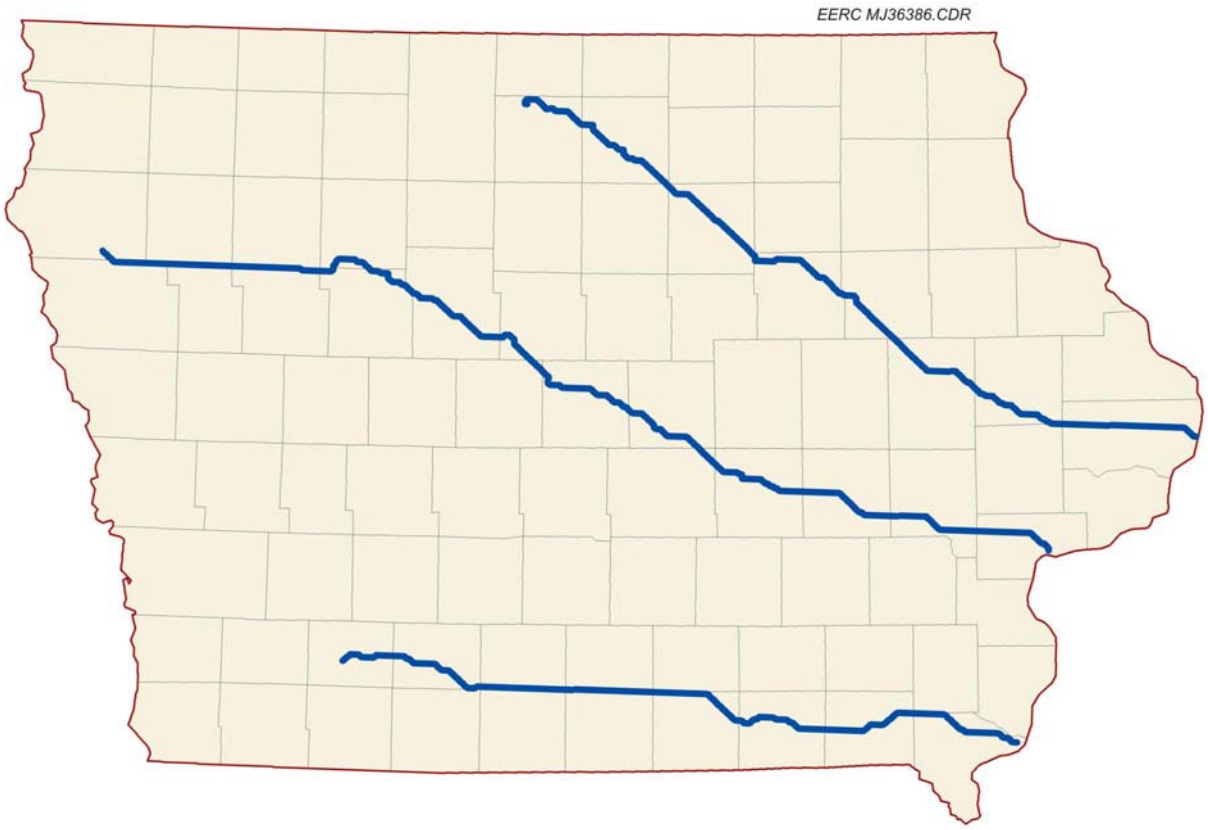


Figure E-3. Map showing pipeline routes in Iowa.

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**

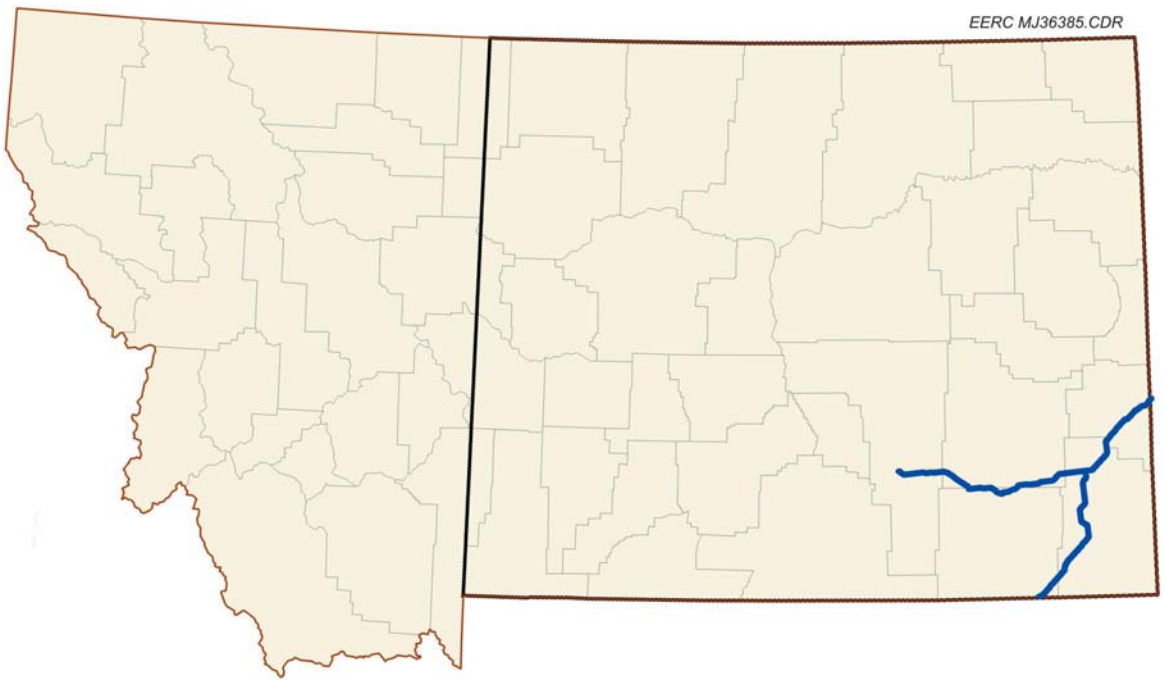


Figure E-6. Map showing pipeline routes in Montana.

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.

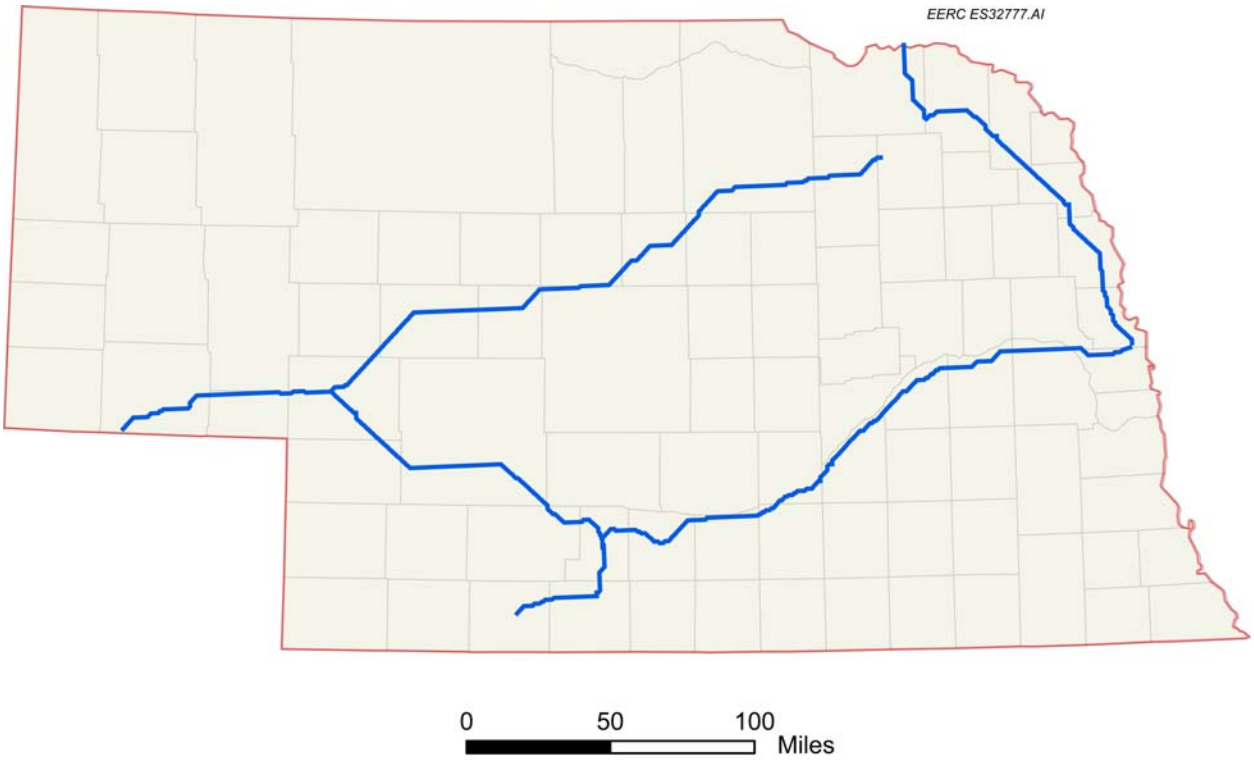


Figure E-7. Map showing pipeline routes in Nebraska.

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.

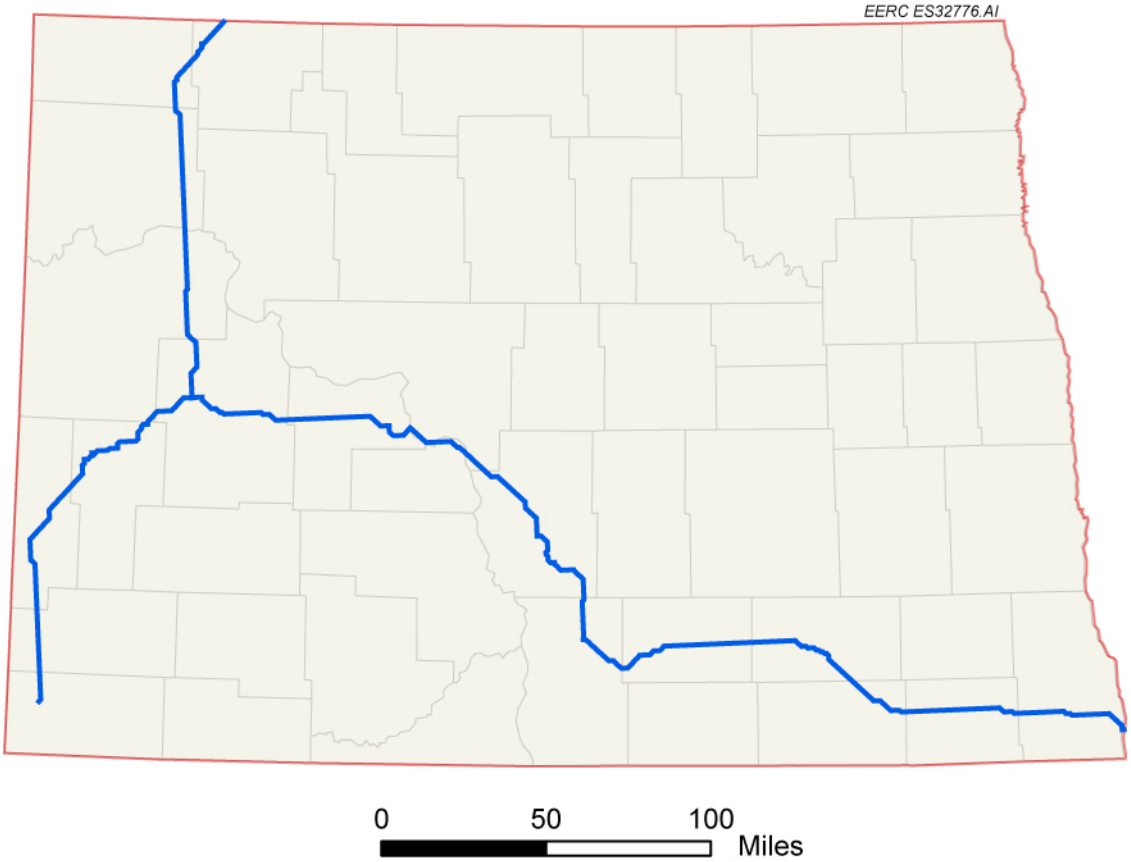


Figure E-8. Map showing pipeline routes in North Dakota.

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.

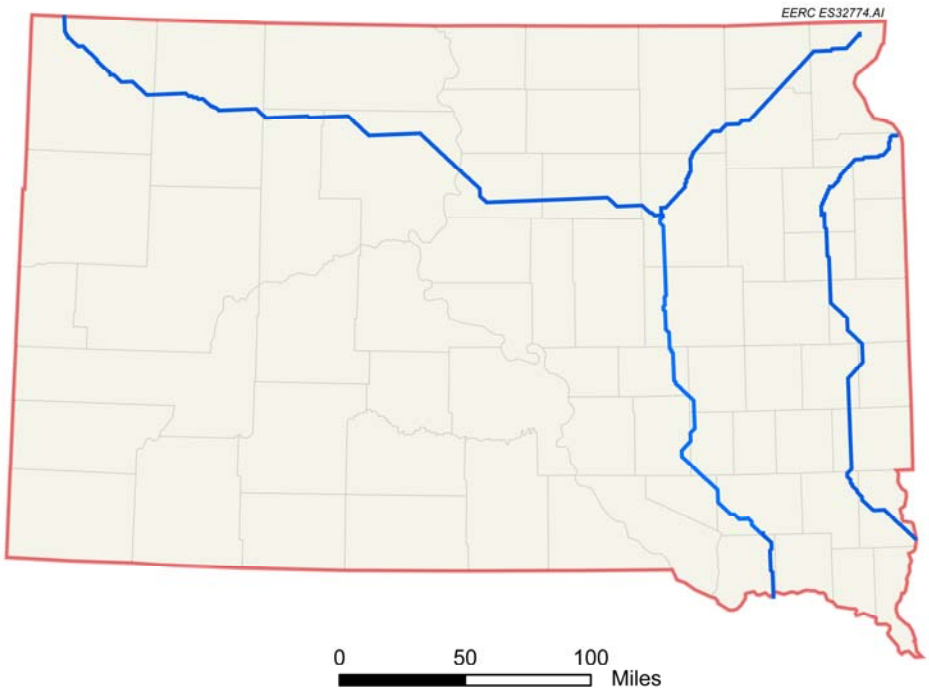


Figure E-10. Map showing pipeline routes in South Dakota.

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.

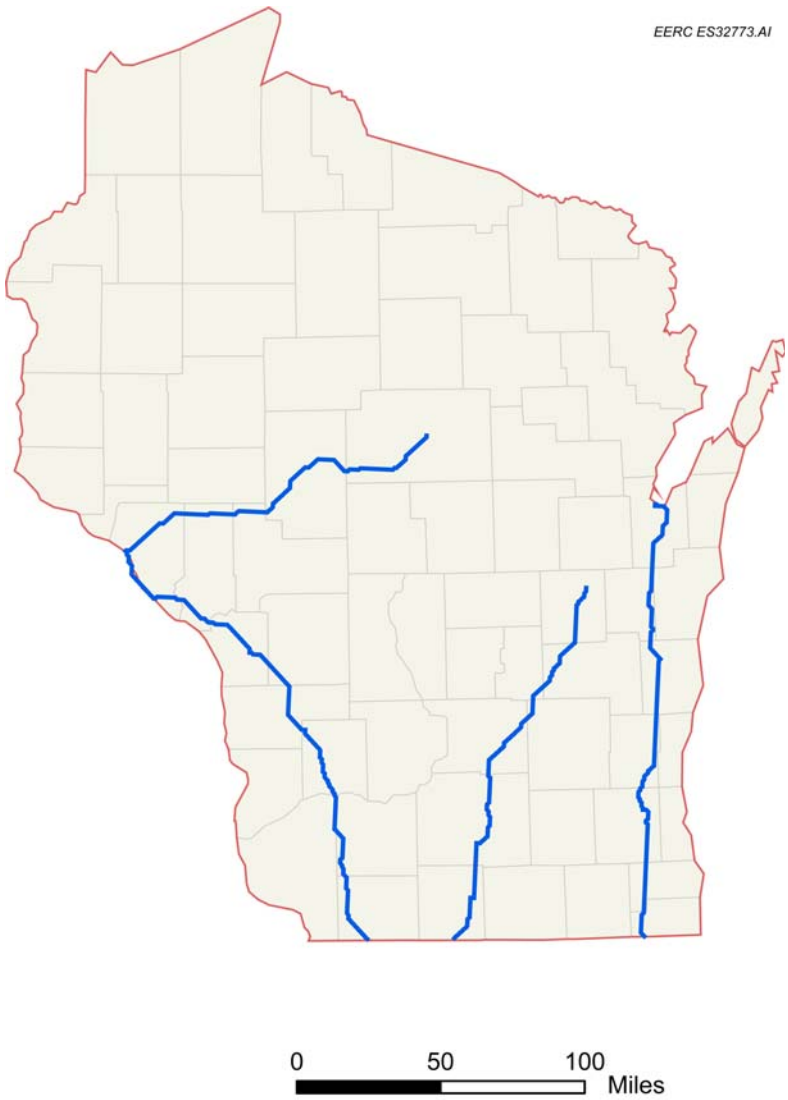


Figure E-11. Map showing pipeline routes in Wisconsin.

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

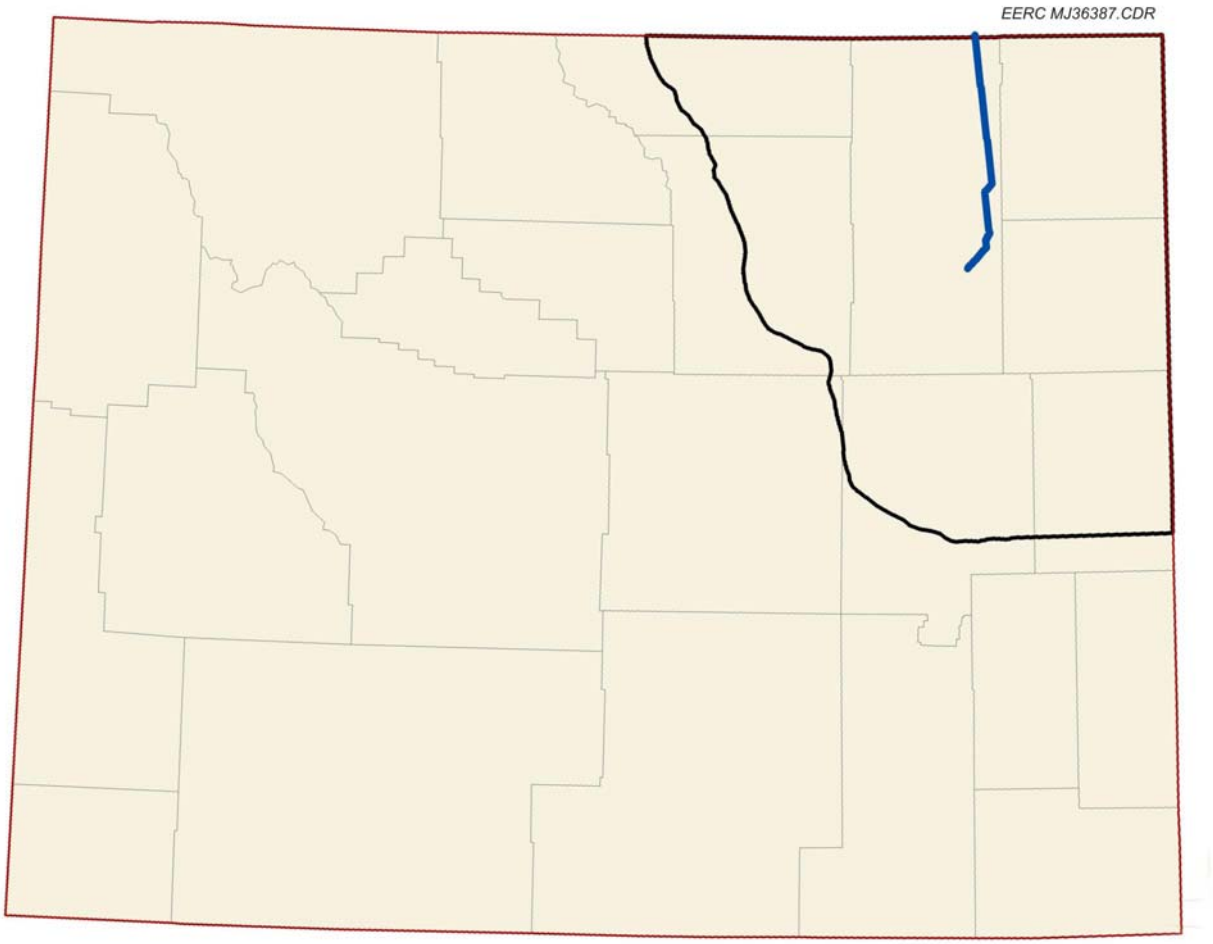


Figure E-12. Map showing pipeline routes in Wyoming.