September 2010

AN INVESTIGATION TO EXPLORE THE POTENTIAL FOR GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE PRODUCED BY WISCONSIN'S ELECTRICITY GENERATION FLEET

FINAL REPORT

DOCKET 5-EI-145

Table of Contents

1. EXECUTIVE SUMMARY 4
2. BACKGROUND / CONTEXT 6
2.1 Background on Docket 6
2.2 Background on Wisconsin's Task Force on Global Warming 6
2.3 Context 7
3. THE CARBON SEQUESTRATION STUDY GROUP / PROCESS 9
4. CARBON CAPTURE, TRANSPORT AND STORAGE – OVERVIEW 9
4.1 CO_2 Capture 9
4.2 CO_2 Transport 11
4.3 CO_2 Storage 11
5. LEGAL ISSUES FOR CO_2 CAPTURE, TRANSPORT AND STORAGE 19
5.1 CO_2 Capture Legal Issues 19
5.2 CO_2 Transport and Electric Transmission Legal Issues 19
5.2.1 Pipelines 20
5.2.2 Container Transport 20
5.2.3 Electric Transmission 21
5.3 CO_2 Storage 21
5.3.1 Injection Well Regulation 22
5.3.2 New Class of UIC Wells 22
5.3.3 No Prescriptive Standards 22
5.3.4 Property Damage and Liability Issues 23
6. THREE PLAUSIBLE SCENARIOS FOR WISCONSIN 23
6.1 Scenario 1: Capture CO_2 in Wisconsin, Transport CO_2 to Storage Site Outside Wisconsin 25
6.1.1. Overview 25
6.1.2. Capabilities and Limitations 26
6.1.3. Route Scenarios 26
6.1.4. Mainline Pump Stations 27
6.1.5. Material and Construction Costs 29
6.1.6. Financial Capital Analysis 30
6.2. Scenario 2: Capture and Store CO_2 Outside Wisconsin, Transport SNG to Wisconsin 32
6.2.1. Overview 32
6.2.2 Capabilities / Limitations 33
6.2.3 Economic Cost / Benefit 34
6.2.3.1. Plant Equipment Required 34
6.2.3.2. Infrastructure Required 35
6.2.3.3. Performance Comparison – Fuel Use 35
6.2.3.4. Performance Comparison –Emissions 36
6.2.4. Emerging Technology 37
6.3. Scenario 3: Capture and Store CO_2 outside Wisconsin, Transmit Electricity to Wisconsin 37
6.3.1. Overview 37
6.3.2. Basis of Costs for Power Plant 38
6.3.3. Basis for Assumed Power Plant Location 40
6.3.3.1. MISO Footprint for Generation Site 40

6.3.3.2. Geological Sequestration Opportunities 42
6.3.3.3. Composite of Sequestration and Transmission Upgrades 45
6.3.4. Basis of Analysis 48
6.3.4.1. Fuel Costs 48
6.3.4.2. Transmission Costs 48
6.3.4.3. Pipeline Costs 49
6.3.4.4. Estimation of the EOR Value of the CO_2 (Option 1 only) 49
6.3.5. Total Costs 51
7. NEXT STEPS: CCS POLICY CONSIDERATIONS 52

APPENDIX A: WISCONSIN CARBON SEQUESTRATION STUDY GROUP MEMBERS 54
APPENDIX B: FACT SHEETS ON PLEASANT PRAIRIE 56
APPENDIX C: ADDITIONAL INFORMATION FOR SCENARIO 1 58
APPENDIX D: ADDITIONAL INFORMATION FOR SCENARIO 2 61

List of Figures

FIGURE 4.1: Freshwater Aquifers of Southeast Wisconsin 16
FIGURE 4.2: Midcontinent Rift System 17
FIGURE 4.3: Bayfield Group Thickness near Minnesota/Wisconsin Border 18
FIGURE 6.1: MISO Planning Map 41
FIGURE 6.2: Joint Coordinated System Plan (JCSP) System Overlay (Conceptual) 42
FIGURE 6.3: Target CO_2 Sequestration Areas 44
FIGURE 6.4: Overlay: Geological Sequestration Locations and Transmission Expansion 45
FIGURE 6.5: Schematic of Differences between Option 1 and Option 2 47

List of Tables

TABLE 6.1: Three CO_2 Pipeline Options 27
TABLE 6.2: Mainline Booster Pump Station Cost 28
TABLE 6.3: Pump Station CO_2 Impact 28
TABLE 6.4: Potential Volatility in Price/Ton for Steel Pipe 29
TABLE 6.5: Estimated Construction Costs per Mile to Construct a New CO_2 Pipeline 29
TABLE 6.6: Total Cost to Construct Pipelines 30
TABLE 6.7: Anticipated O&M Costs for Pipelines (2008 Dollars) 30
TABLE 6.8: Total Estimated Cost per Ton CO_2 Values 32
TABLE 6.9: Generation Options 2025 39
TABLE 6.10: Fuel Costs Differential Analysis 48
TABLE 6.11: Value of CO_2 in EOR Applications 51
TABLE 6.12: Total Costs 52

1. EXECUTIVE SUMMARY

Based on recommendations contained in the Interim Report of the Governor's Task Force on Global Warming (February 2008), the Public Service Commission of Wisconsin and the Wisconsin Department of Natural Resources formed a Study Group to explore the potential for geologic sequestration of carbon dioxide produced by Wisconsin's electricity generation fleet. This technical report is the final work product of the Study Group.

Wisconsin currently relies on coal for roughly 38% of the state's installed electric generating capacity and 66% of actual generation. Coal has historically been an abundant and inexpensive fuel for electric generation, but it also emits more carbon dioxide per unit of electricity than any other fuel in common use. New regulations limiting greenhouse gas emissions appear to be inevitable, and these regulations could radically change the economics of coal-fired electric generation unless the associated carbon dioxide emissions are reduced.

Carbon capture and sequestration (CCS) refers to the process of capturing carbon dioxide from large stationary sources that would otherwise release it to the atmosphere and securely storing, or sequestering, the carbon dioxide underground. CCS is a three-step strategy for reducing anthropogenic emissions of carbon dioxide that requires: 1) the deployment of carbon dioxide capture technologies at power plants or large industrial sources; 2) infrastructure to transport the captured carbon dioxide; and, 3) suitable geological reservoirs for storage.

The Study Group found that several promising technologies are being developed and tested for capturing carbon dioxide emissions from power plants. Carbon dioxide can be captured either pre- or post-combustion – depending on the type of power plant – and compressed for transport and disposal. The technology that is closest to commercial deployment is pre-combustion capture from an integrated coal gasification combined cycle (IGCC) power plant. Post-combustion capture in conventional, coal-fired plants or natural gas combined cycle (NGCC) power plants has moved from laboratory testing to field testing, but the first full-scale commercial applications are not expected for several years. The Study Group also found that long-distance transport of carbon dioxide is a proven, viable option with over 3,000 miles of pipeline already in use for this purpose nationwide.

Researchers have identified several types of geologic formations that potentially have the necessary attributes for long-term storage of carbon dioxide: depleted oil and gas reservoirs, saline aquifers, coal beds, and basalt. Based on information available today, Wisconsin does not appear to have any suitable geologic formations of these types. There is one formation in Wisconsin called the Midcontinent Rift System that cannot be completely dismissed as a potential carbon dioxide storage site because it has not been fully characterized, but currently available data suggest that there is only a very small probability that it contains the necessary attributes. Wisconsin may benefit long-term from the further exploration and development of carbon dioxide (CO_2) storage in the area; however, it is not a short-(2 to 5 years) or mid-term (5 to 20 years) possibility. The opportunities closest to the major baseload power plants in Wisconsin are the oil and gas fields, coal seams, and deep saline aquifers found in relatively uniform layers across a wide area of Illinois, Indiana, and Kentucky in the geological feature known as the Illinois Basin. While other opportunities may be present in the Upper Midwest, including oil and gas fields in the northwestern part of Michigan's lower peninsula,

the Illinois Basin is one of the most promising areas in the world for geological storage and has been the subject of large scale experiments through the Midwest Geological Sequestration Consortium, the FutureGen project, and a number of private proposals.

Deployment of CCS technologies will potentially be shaped by a variety of environmental regulatory requirements and other legal considerations. On some issues, such as those relating to pipeline safety, well-established and workable regulations already exist. But for a number of other issues, notably that relating to property damage and liability, a legal framework is only just beginning to develop. Wisconsin will need to take a holistic approach to the development/adoption of a regulatory scheme for CCS that addresses the public/private interests involved and that will allow Wisconsin to work effectively and efficiently with adjacent states to implement proposed projects.

Most of the CCS research to date inherently assumes that carbon dioxide will be stored in close proximity to where it is captured. But because geologic storage of carbon dioxide in Wisconsin does not appear to be feasible, the Study Group concluded that electric providers in Wisconsin would have to explore alternative strategies if they are to make use of CCS technologies. The Study Group identified at least three plausible scenarios by which this could happen. Each scenario represents a different kind of opportunity with distinct advantages and disadvantages. It is critically important to understand that these scenarios are <u>not</u> mutually exclusive; all three scenarios could be realized simultaneously. The purpose of this report is not to facilitate a side-by-side comparison of the three scenarios, precisely because there is no need to choose the one "best" option at this time. Each may prove to be the best option at some place and time under specific circumstances. Scenarios explored by the Study Group include:

> **Scenario 1:** Carbon dioxide is captured from existing coal-fired power plants in Wisconsin and transported via pipeline to a suitable geological storage site in an adjacent state.
>
> **Scenario 2:** CCS technology is used in an adjacent state at a facility that converts coal into synthetic natural gas (SNG), a lower carbon energy source. The SNG is then transported in existing natural gas pipelines to Wisconsin and combusted for electricity at existing or new gas-fired power plants.
>
> **Scenario 3:** Carbon dioxide is captured from a new or existing coal-fired power plant in another adjacent state, and the electricity is transported to Wisconsin via expanded electrical transmission infrastructure.

Although the Study Group focused almost exclusively on technical issues associated with the three scenarios, a few simple policy recommendations can be made at this time. These recommendations reflect the fact that Wisconsin may eventually benefit from one or more of the alternative approaches described in this report, but the state will almost certainly not be on the early, cutting edge of CCS deployment. First, the Study Group recommends that Wisconsin officials support continued federal funding of CCS demonstration projects in other states. Second, the Study Group recommends that state officials continue to collaborate with the federal government and other states on legal, regulatory, and technological issues, where such collaboration is appropriate and advantageous to Wisconsin. For example, the Study Group suggests that Wisconsin should join the Midwest Geological Sequestration Consortium and participate in the Midwestern Governors Association's new Regional CCS Task Force.

2. BACKGROUND / CONTEXT

2.1 Background on Docket

On April 3, 2008 the Public Service Commission of Wisconsin (PSCW) opened Docket 5-EI-145 to commence an *Investigation to Explore the Potential for Geologic Carbon Sequestration for Carbon Dioxide Produced by Wisconsin's Electricity Generation Fleet*. The impetus for this docket was a recommendation made by the Governor's Task Force on Global Warming that the PSCW and the Department of Natural Resources (WDNR) should form a Carbon Capture and Sequestration (CCS) Study Group to evaluate the technical and economic potential and infrastructure requirements for CCS deployment in Wisconsin. The Task Force further recommended that the CCS Study Group should convene by July 31, 2008 to move this investigation forward as soon as possible.

2.2 Background on Wisconsin's Task Force on Global Warming

Wisconsin's Task Force on Global Warming was created by Governor Jim Doyle, pursuant to Executive Order 191 on April 5, 2007. The mission of the Task Force was to:

- Present viable, actionable policy recommendations to the Governor to reduce greenhouse gas emissions in Wisconsin and make Wisconsin a leader in implementation of global warming solutions.

- Advise the Governor on the ongoing opportunities to address global warming locally, while growing our state's economy, creating new jobs, and utilizing an appropriate mix of fuels and technologies in Wisconsin's energy and transportation portfolios.

- Identify specific short-term and long-term goals for reductions in greenhouse gas emissions in Wisconsin that are, at a minimum, consistent with Wisconsin's proportionate share of reductions that are needed to occur worldwide to minimize the impacts of global warming.

The Task Force consisted of a diverse membership representing a cross-section of Wisconsin's economy and its communities.[1] All meetings of the Task Force and its work groups were open to the public. Two public input sessions were held at four locations around the state to receive comments and suggestions from the public. Many members of the public commented on the Task Force's work at these sessions and throughout the process via email. All documents related to the Task Force's work were available via a web site, including agendas, meeting notes, proposed policy drafts, public comments and many reference documents and studies provided to the Task Force members during this process.[2]

In February 2008, the Task Force issued an *Interim Report* to the Governor describing its progress and making eleven important early action recommendations that were approved unanimously by all

[1] A complete list of Task Force members is available at http://dnr.wi.gov/environmentprotect/gtfgw/members.html.
[2] Refer to http://dnr.wi.gov/air/aq/global/climatechange/GTFGW.html.

Task Force members.[3] One of those eleven early action recommendations was the previously mentioned recommendation to form a CCS Study Group and produce this report that explores the possibilities, costs and technical feasibility of geologic carbon sequestration for Wisconsin's coal fleet of electric generation. [4]

2.3 Context

Wisconsin currently relies on coal as an essential fuel for our existing fleet of electric generation units. As of June 2009, 38% of the state's installed electric generating capacity (8,423 MW) used coal as a primary fuel. In 2008, Wisconsin electric providers used 25 million tons of coal at 15 different power plants to produce roughly 66% of the electric power they generated (44.9 million MWh).[5] Given that Wisconsin has no coal resources of its own and imports all of the coal it uses, Wisconsin is significantly more coal-dependent than the United States as a whole. Coal provided the fuel for 48% of our nation's electric generation in 2008.[6]

There are many reasons why coal has been and continues to be such an important part of our electric energy supply. The United States has domestic reserves of recoverable coal that are estimated to be large enough to last nearly 230 years at our current domestic production rates, though global reserves could expire 100 years sooner at current global production rates .[7] Coal-fired boilers are a proven and time-tested technology, and the infrastructure and supply chains for delivering coal to power plants around the country are well-established. Huge capital investments have been made in coal over the past century, and many coal-fired power plants that are 50 years old or older are still reliably generating electricity. Finally, coal-fired electric generation is currently one of the cheapest options for utility-scale electric power in terms of total production costs.

But coal-fired electric generation has disadvantages as well. One of those disadvantages is that coal-fired power plants emit more CO_2 per unit of generated electricity than any of the other generation technologies in common use today. Carbon dioxide is one of several known greenhouse gases (GHG) that contribute to global warming and health concerns. In fact, power plants are the largest source of GHG in Wisconsin and nationally, responsible for more than 30% of total emissions.[8]

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[3] The Task Force's *Final Report*, which was issued in July 2008, includes the 11 recommendations from the *Interim Report* as well as 52 other recommendations. The *Final Report* is available at http://dnr.wi.gov/air/aq/global/climatechange/GTFGW.html.

[4] Based on the Task Force recommendation and the charge given to the CCS Study Group, this report is limited in scope to processes and technologies that result in *geologic* sequestration of CO_2. Throughout the remainder of this report, references to CCS processes or technologies are meant to refer only to options relevant to geologic sequestration. Other high volume sequestration options are being researched and developed, including mineral carbonation and biological sequestration, but those alternatives are beyond the scope of this report.

[5] Data in this paragraph are extracted from the PSCW's Wisconsin Generation database (unpublished) and *2009 Wisconsin Energy Statistics*, published by the Wisconsin Office of Energy Independence and available at http://energyindependence.wi.gov/category.asp?linkcatid=2847&linkid=1451&locid=160. The cited figures for capacity and generation include power plants operated by Wisconsin electric utilities, electric cooperatives, non-utility generators, and merchant generators including out-of-state units registered for compliance with Wisconsin's Renewable Portfolio Standards law (§196.378, Wis. Stats.).

[6] Based on official statistics from the U.S. Department of Energy's Energy Information Administration available at http://www.eia.doe.gov/cneaf/electricity/epa/epates.html.

[7] Refer to Table 10 in the *International Energy Outlook: 2010*, DOE/EIA-0484 (2010), published by the Energy Information Administration and available at http://www.eia.doe.gov/oiaf/ieo/pdf/0484(2010).pdf.

[8] For Wisconsin data refer to *Wisconsin Greenhouse Gas Emissions Inventory and Projections* (AM-393-2008, June 2007), prepared for WDNR and the Governor's Task Force on Global Warming by World Resources Institute and

GHG emissions are currently unregulated in Wisconsin and most of the United States, which means that there is no *immediate* cost associated with emitting CO_2, but that is likely to change for some large emission sources as soon as January 2011.[9] If it happens, the economics of coal-fired electric generation may also change.

The current situation in the European Union's GHG cap and trade program (called the Emissions Trading Scheme or EU ETS) offers one example of what could happen if CO_2 emissions become fully regulated in the U.S. Throughout 2010, the cost to buy an allowance to emit one metric ton of GHG in the EU ETS has averaged between $16.50 and $22.00, despite a generally weak economy and great uncertainty about long-term emission reduction requirements.[10] Closer to home, analyses of a proposed U.S. cap and trade law approved by the U.S. House of Representatives in June 2009 anticipated that GHG allowance prices would range between $13 and $19 per metric ton in the year 2015.[11] Despite the fact that we do not today have any federal, regional or state regulations limiting GHG emissions in Wisconsin, the PSCW has considered it prudent to monetize carbon in various reports and analyses, and it is expected to do so for the foreseeable future. For example, in its most recent *Strategic Energy Assessment,* the PSCW considered scenarios where CO_2 emissions in 2015 were monetized at values between $10 per ton and $26 per ton.[12]

Wisconsin utilities are looking at the likelihood of a future price for GHG emissions and wondering how they will be able to make use of their existing infrastructure and the huge capital investments they've already made in coal-fired power plants. Other than reducing their use of coal, they only have two real options. The first is to make their power plants more efficient at turning coal into electricity, and the second is to employ new technologies designed to eliminate or minimize GHG emissions from coal combustion.

This second option brings us to the topic at hand: carbon capture and sequestration. There is tremendous interest around the world in exploring ways to capture carbon dioxide associated with the use of coal and prevent the emission of CO_2 to the atmosphere. This report will explain some of the carbon capture technologies under consideration. Once the CO_2 is captured, the most promising short-term solution is to store or sequester the CO_2 in geologic reservoirs that will prevent its emission to the atmosphere for hundreds of years, if not longer.

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available at http://dnr.wi.gov/air/aq/global/climatechange/GTFGW.html. For national data, refer to *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008* (EPA 430-R-10-006), published by the U.S. Environmental Protection Agency and available at http://epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Report.pdf.

[9] On December 7, 2009, in response to the United States Supreme Court's decision in *Massachusetts v. EPA*, USEPA published a final determination that GHG emissions endanger public health and welfare. Based on that determination, the Clean Air Act requires USEPA to regulate GHG emissions. USEPA has promulgated rules that will phase in permitting and emission control requirements for major stationary sources over a several-year period beginning in January 2011, but those rules are being challenged in court.

[10] These values are based on historic trading data for futures contracts, and August 2010 currency exchange rates.

[11] Refer to page 13 of the Congressional Budget Office Cost Estimate Report on HR 2454 at http://www.cbo.gov/ftpdocs/102xx/doc10262/hr2454.pdf (June 5, 2009) and page 3 (the fourth slide) of the USEPA presentation, "EPA Analysis of the American Clean Energy and Security Act of 2009 H.R. 2454 in the *111th Congress"* (June 23, 2009) at http://www.epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf.

[12] The cited allowance prices would represent a substantial increase, perhaps on the order of 50% or more in some cases, to the operating costs of coal-fired power plants. And if allowance prices increase with time, as expected, a tipping point could eventually be reached where coal loses its low-cost advantage.

CCS is an emerging area of research and development. It holds great promise for allowing continued use of coal in a "carbon constrained" world where a cost is attached to CO_2 emissions. But there are currently no full-scale CCS power plants anywhere in the world and there are many areas of uncertainty within this evolving technology. This report aims to explore some of those questions and prepare Wisconsin utilities and regulators to make informed, prudent decisions as CCS technologies and/or GHG regulations develop.

3. THE CARBON SEQUESTRATION STUDY GROUP / PROCESS

The PSCW collaborated with the WDNR to establish and convene a Carbon Sequestration Study Group (the Study Group). Its explicit purpose was to fulfill the CCS recommendations of the Governor's Task Force on Global Warming. The Study Group members are listed in Appendix A with their organizational affiliation.

Because this effort is seen as a natural continuation of the work that was done in preparation of an Integrated Gasification and Combined Cycle (IGCC) Report that was issued in February 2007[13], WDNR Deputy Secretary Al Shea and PSCW Commissioner Mark Meyer volunteered to lead the CCS Study Group just as they had the IGCC study group.

The Study Group conducted its business publicly. All meetings were open to the public, and associated documents were available to the public via the PSCW website. The Study Group met in June 2008, July 2008, March 2009, and October 2009. A draft report was made available for public comment from March 2, 2010 through April 2, 2010. All public comments received by PSCW during that period were reviewed and changes were made to the report where appropriate. This report represents the final work product of the CCS Study Group.

4. CARBON CAPTURE, TRANSPORT AND STORAGE – OVERVIEW

CCS is essentially a three step process. First, CO_2 must be isolated and captured. Second, the captured CO_2 must be compressed and transported to a suitable geologic sequestration site. And third, the CO_2 must be stored in the underground sequestration site. An overview of each step is presented below.

4.1 CO_2 Capture

This section uses the March 2007 Massachusetts Institute of Technology (MIT) report "The Future of Coal" as the primary source for the description of CO_2 capture technologies.

CO_2 capture represents a significant step in pollution control from the combustion of fossil fuels. In the past, the goal of pollution control from fossil fuel combustion was to reduce combustion gasses to CO_2 and H_2O (water vapor). Completely combusting the hydro carbons, removing NOx emissions, and removing non-hydrocarbon emissions (sulfur compounds and metals such as mercury for example) have been the objectives of pollution control programs. Capturing CO_2 emissions is a giant step to reduce combustion emissions to just water vapor and nitrogen (as N_2).

[13] PSC, DNR. Integrated Gasification Combined-Cycle Technology: Costs, Benefits, and Prospects for Future Use in Wisconsin. February 2007. Available online at: http://psc.wi.gov/initiatives/cleanCoal/cleanCoal.htm

CO_2 can be captured either before or after combustion. Post-combustion capture of CO_2 requires that CO_2 be removed from the flue gas. After successfully controlling other pollutants, the flue gas at a pulverized coal plant is a mixture of N_2, CO_2, and water vapor. By chilling the flue gas, CO_2 and water vapor can be separated from the N_2. This is done by chemically absorbing the CO_2 in a cool liquid. Various amine solutions and, more recently, chilled ammonia (like the pilot program at the Pleasant Prairie Power Plant near Racine – please see Appendix B for more information) have been used to condense the CO_2 out of the flue gas. The chilled solution is then warmed, releasing the CO_2 and water. The CO_2 is then dried and compressed to a supercritical liquid that can be put into a pipeline and delivered to a carbon sequestration location where it is pumped, under pressure, deep into geologic structures such as saline aquifers for permanent storage. The CO_2 may also be injected into old oil fields for enhanced oil recovery, or into coal beds that are too deep for economic mining where it displaces methane that can be recovered as natural gas.

A variant of post-combustion CO_2 capture is to fire the pulverized coal boiler with oxygen rather than atmospheric air. This process is known as oxy-firing. Oxy-firing has the advantage that by removing nitrogen (which makes up about 80 percent of atmospheric "air") from the combustion process, the flue gas does not contain any nitrogen compounds. The flue gas is now almost exclusively CO_2 and water vapor. The flue gas can be directly dried (water removal) and the remaining CO_2 can be directly compressed and placed into a pipeline for delivery to a sequestration site.

Chemical absorption requires energy to repeatedly chill the solution. This can be done by using low pressure steam from the boiler, but the diversion of steam does result in less steam being available to generate electricity. This causes the facility to generate less electricity per ton of coal burned compared to a facility that is not capturing CO_2. Additional energy is needed to dry and compress the CO_2. Early studies indicated that the "derate" of a facility may be as much as 30% compared to a facility without CO_2 capture. Recent work with chilled ammonia holds out the promise that the de-rate may be reduced to closer to 10% less electricity generated per ton of coal burned.

Oxy-firing has the advantage that it requires less energy to capture the CO_2 as it need not be separated from the nitrogen compounds in the flue gas. Oxy-firing does require an air separation unit at the facility, as well as more robust boiler design. The air separation unit needed to collect enough pure oxygen to fire the combustion at the boiler needs a lot of the electricity generated at the facility. The parasitic energy consumption of the air separation unit significantly reduces the electricity production put onto the grid. The result is likely to be almost as much of a derate as chilled amine separation from an atmospheric-fired pulverized coal unit.

Pre-combustion capture of CO_2 is an option at an Integrated Gasification Combined Cycle (IGCC) unit. In an IGCC unit, coal is gasified under high pressure and temperatures to create a synthetic gas (syngas). The syngas is primarily CO and hydrogen (H) and some CO_2. The initial CO_2 can be captured at low percentages prior to combustion with very little parasitic energy loss. When the syngas is combusted, the CO is transformed into CO_2. To reduce the CO_2 emissions in the flue gas, the CO needs to be transformed into CO_2 prior to combustion and removed from the syngas. The syngas is passed through a shift reactor. In the shift reactor, the CO_2 in the syngas is reacted with steam over a catalyst to form CO_2 and hydrogen. Because the syngas is still at very high pressure and is very rich in CO_2, a weakly CO_2-binding physical solvent can be used to separate out the CO_2. The CO_2 can now be dried and compressed and placed into a pipeline to be delivered to a

sequestration site. The syngas is now almost pure hydrogen. The hydrogen can be combusted in a combined cycle facility to generate electricity, but the combustion turbine will need to be modified to be capable of burning almost pure hydrogen as a fuel.

4.2 CO_2 Transport

Pressurizing CO_2 for transport is possible, but without actual CO_2 compression transport would become prohibitively expensive for the volumes of greenhouse gases captured from existing or new electric generating facilities.

The Electric Power Research Institute (EPRI) is undertaking research to evaluate the scale, energy requirements, and materials necessities for CO_2 capture, compression and storage. The study will include the resources necessary to make the CO_2 pure enough for injection into an existing pipeline as well as the cost implications and trade-offs with a dedicated pipeline.[14]

Pipeline facilities are the preferred method of transport. As identified by Mr. L. Stephen Melzer,[15] there are three frameworks for pipeline systems:

> **Type I:** Special, Single Use Pipelines (Case-by-Case Specifications for Carried Fluid Composition)
>
> **Type II:** The North American Network; i.e., Multiple Source and User Lines (Strict Specified CO_2 Composition)
>
> **Type III:** Hybrid Lines (Relaxed but Controlled CO_2 Composition)[16]

Most common and in current use today are type II and III pipelines. There are currently over 3,000 miles of major CO_2 pipeline in operation today. Transporting CO_2 is not a new and untested phenomenon. CO_2 pipelines have been in existence for over 35 years. Container transport is also a possibility and is in fact used for CO_2 transport, but is far less efficient and carries higher energy and emissions offset problems when applied in an electric generation setting. For these reasons, the scenario analyses focus primarily on the pipeline method for transporting CO_2.

4.3 CO_2 Storage

For in-depth analysis of geologic storage of CO_2 and a review of the Minnesota Geological Survey's 2008 report, our Study Group turned to University of Wisconsin Geology Professor Alan Carroll. Professor Carroll's overview of various storage types, along with a summary of major conclusions from the Minnesota Geological Survey's 2008 report appears verbatim in this section.

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[14] Compression is estimated to account for one-third to one-fourth of the total energy demand of a CCS system on a power plant, corresponding to an approximate 6% reduction in the plant's net (salable) output. The planned research could reduce this energy drain to 3–4%.

[15] L. Stephen Melzer is a CO_2 consultant with more than 25 years of experience in the oil and gas industry. More information on Mr. Melzer, his consulting business and industry experience can be found on his web site at http://melzerconsulting.com/.

[16] Fundamentals of CO_2 Transport – Building on the Current Infrastructure to Meet the Demands of Widely Deployed Commercial Scale CCS Systems – L. Stephen Melzer, July 11, 2008 presentation.

The majority of the knowledge and technology needed to inject CO_2 into subsurface reservoirs has already been developed, in response to a century of growing global demand for oil and natural gas. The fundamental geologic requirements for either an oil/gas field or a CO_2 injection site are similar, and include: 1) A body of reservoir rock that is capable of receiving and storing fluids; 2) An adjacent seal rock (cap rock) that serves as an impermeable barrier to movement of fluids; and, 3) A geologic structure that juxtaposes the reservoir and seal rocks in a way that inhibits the escape of buoyant fluids to the surface. To these three elements, subsurface storage of CO_2 adds a requirement for sufficient burial depth to maintain CO_2 in a supercritical state and to sequester it away from fresh water aquifers. A commonly accepted minimum depth is 1 km.

A number of different types of CO_2 storage sites have been proposed; each presents its own advantages and disadvantages:[17,18]

• *Depleted oil/gas reservoirs (estimated capacity 12 $GtCO_2$ in oil fields with enhanced oil recovery, 35 $GtCO_2$ in gas fields).* These sites are already well-characterized, can provide secure storage, and offer potential economic offsets in the form of enhanced oil production. However, not all oil fields are suitable for CO_2 storage, and the total available volume of depleted oil fields is unlikely to meet longer-term needs.

• *Saline aquifers (estimated capacity 2730 $GtCO_2$).* These represent a far greater potential reservoir volume than depleted oil and gas fields, and their elevated salinity generally implies good isolation from fresh water aquifers. However, their detailed subsurface geology is not catalogued and extensive exploratory drilling programs would therefore be required. In some cases, the fact that they don't contain oil or gas may indicate a lack of an effective seal.

• *Coal beds (estimated capacity 30 $GtCO_2$)*. It may be possible to retain CO_2 in cleats and on organic matter surfaces in coal beds. In some cases, CO_2 injection may also stimulate production of coal bed methane. The capacity for long-term CO_2 retention and volumetric adequacy are largely unknown, however. CO_2 storage would also preclude future mining of the affected coal.

• *Basalt (estimated capacity 240 $GtCO_2$).* Basalt, a finely crystalline, layered volcanic rock, offers potentially large reservoir volume in fractures and in inter-bedded or subjacent sedimentary layers. It may also form an effective seal to retain injected CO_2. A unique advantage is the presence of reactive ferromagnesian minerals (e.g., olivine) that may form stable compounds with CO_2. Detailed reservoir geology of basaltic intervals is entirely uncharacterized, however, and extensive exploratory drilling would be required.

The geologic storage options that have received the greatest attention (depleted oil and gas fields,

[17] Dooley, J.J., Dahowski, R.T., Davidson, C.L, Wise, M.A., Gupta, N.G., Kim, S.H., and Malone, E.L., 2006. Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change: *Technology Report from the Second Phase of the Global Energy Technology Strategy Program*. Battelle Memorial Institute, 37 p.

[18] Intergovernmental Panel on Climate Change Working Group, 2005. Carbon Dioxide Capture and Storage: *Special Report*, 431 p.

saline aquifers, and coal beds) all tend to be in areas underlain by thick deposits of sedimentary rocks, called sedimentary basins. One such sedimentary basin underlies parts of central and southern Illinois and adjacent states. Due to its great thickness of sedimentary rocks, the Illinois basin offers multiple opportunities for subsurface CO_2 storage in depleted oil fields, saline aquifers, and coal beds. The Paleozoic Mount Simon Formation sandstone, a saline aquifer that extends beneath much of Illinois, has been employed for decades to provide temporary underground storage and retrieval of natural gas. The subsurface geology of the Illinois basin has been thoroughly explored by many previous deep wells, and its potential to receive and retain CO_2 appears to be very good.

Sandstone reservoirs similar to the Mt. Simon Formation in Illinois extend northward beneath much of Wisconsin, but they are much thinner and closer to the surface. The only part of the state where they even approach 1 km depth is in limited areas of southeastern Wisconsin. Furthermore, the entire thickness of Mt. Simon Formation equivalent sandstone and other rocks of similar geologic age in Wisconsin contain fresh water (Figure 4.1). These freshwater aquifers are being heavily exploited as critical municipal water supplies in a number of areas, causing concern about the future viability of this important resource. Mt. Simon equivalents and other freshwater aquifers in Wisconsin therefore are clearly not a practical option for the development of geologic CO_2 storage sites.

Sedimentary rocks of great thickness and depth also exist in northwestern Wisconsin, within a large sedimentary basin called the Midcontinent Rift System (MRS). The MRS system is a huge geologic feature that extends from Lake Superior southwestward into Minnesota, Wisconsin, Iowa, and Kansas (Figure 4.2). Another branch of the MRS extends from Lake Superior southeastward beneath Michigan. The MRS consists up to ~16 km of volcanic rocks (including basalt), overlain by up to ~5 km or more of sedimentary rocks. The volumetric capacity of the MRS therefore could be extremely large, potentially much larger than the Mt. Simon Formation in Illinois. However, unlike the Mt. Simon Formation and other well-explored candidates for geologic CO_2 storage, the MRS is virtually unexplored because it has never produced any commercial amounts of oil or natural gas.

The Minnesota Geological Survey recently conducted a study of the MRS to help evaluate its potential for geologic CO_2 storage.[19] This study was based mostly on previous scientific literature, which consists of outcrop data, geophysical surveys, and a handful of deep wells. The Minnesota study incorporated data from the entire basin (from the Lake Superior region to Kansas). The segment of greatest practical interest to Minnesota straddles the Minnesota/Wisconsin border; the MRS in Wisconsin is therefore in effect a mirror image of the MRS in southeastern Minnesota (Figure 4.3).

The following conclusions are excerpted from the Executive Summary of the Minnesota Geological Survey's 2008 report:

> *The prospective rocks primarily are known with respect to their depth and thickness on the basis of geophysical surveys. These seismic, gravity and magnetic interpretations indicate that sedimentary basins associated with the Midcontinent Rift in Minnesota are to a large degree*

[19] Thorleifson, L.H., 2008. Potential capacity for geologic carbon sequestration in the Midcontinent Rift System of Minnesota: *Minnesota Geological Survey Open File Report* OFR-08-01, 138 p.

associated with depths and volumes that are compatible with sequestration of CO_2. The area where sedimentary rocks are more than 1 km thick, including both the most promising rocks, Bayfield Group sandstones, and overlying rocks that contribute to making up required depth, are presently thought to encompass two north-south belts on either side of the Twin Cities, running from Pine County and Washington County, south to Iowa... Available geophysical information thus indicates that there is sufficient sedimentary rock depth and thickness in the Midcontinent Rift System sedimentary basins in the region for further consideration of sequestration capacity to be warranted.

There is little in available geophysical information, however, that addresses porosity or permeability of these rocks. Although factors other than porosity can affect seismic velocity, the available velocity data from seismic refraction surveys do not look promising, as most values exceed 12,000 ft/sec, which are values higher than those typical of highly porous rock. Nonetheless, further work using new methods, such as velocity or waveform analysis of either existing or, if necessary, new seismic reflection data could be implemented to potentially better address porosity. Another approach might be to use magnetotelluric methods to look for conductive brines in the sedimentary section, which would indirectly indicate porosity, while additional 3D gravity modeling is needed to clarify extent and thickness, using currently available methods and computing power.

Thus while depth and thickness of the rocks are amply demonstrated, required information on porosity and permeability is inadequately established from geophysical surveys, and the same conclusion applies to a review, synthesis, and limited new analyses of their lithostratigraphy, depositional history, physical properties, and hydrogeology. Therefore, these rocks may not be sufficiently well-characterized to permit a fully informed judgment on their suitability as a site for the sequestration of CO_2, but the limited available information indicates that the MRS has attributes that make it far less suitable for sequestration than other sites currently being considered across the country. On the positive side, the MRS contains the only sedimentary rocks in Minnesota that extend to depths required for sequestration, including sandstone bodies that at relatively shallow depths of 2500 ft (762m) or less are known to locally have moderate porosity and permeability. Shale and mudstone intervals are present, which appear to be of sufficiently low matrix permeability to serve as seals. An additional positive attribute is the lack of previous exploration, as reservoirs that have a history of exploration and production tend to have been penetrated by large numbers of often-undocumented drill holes that may not have been properly abandoned, presenting a significant and unquantifiable risk of leakage. These attributes thus suggest that the MRS cannot yet be ruled out as a potential site for deep geologic sequestration of CO_2.

On the negative side, however, the known and inferred properties of the MRS in Minnesota and neighboring areas indicate that there is only a very small probability that it contains the geologic attributes necessary to serve as a site for deep geologic sequestration of CO_2. Geophysical logs of deep exploratory boreholes in Iowa and Wisconsin, petrographic analyses of sandstone in those states as well as Michigan and Minnesota, and the limited number of tests on samples from Minnesota cores as part of this project indicate that sandstone at the depth required for sequestration is relatively low in porosity and permeability. Permeability has been measured to be orders of magnitude too low for sequestration to be viable everywhere it has been tested in the MRS. Furthermore, the MRS is associated with a more complex tectonic history compared to other sites being investigated, and therefore features such as faults and

fractures may play a larger role in site evaluation. For example, low permeability beds in the MRS that are necessary to serve as seals on top of potential CO_2 reservoirs are known to contain fractures with evidence of fluid flow. Fractures associated with faults are believed to serve as conduits for deep MRS groundwater to travel upward across such seals to overlying freshwater aquifers today. Identification and mapping of such features will be a more difficult task compared to the relatively simple structural settings being assessed elsewhere. Thus while much information is available for regions elsewhere in the US, such a body of geologic knowledge does not exist for the Midcontinent Rift. If it is determined that further research is warranted, a comprehensive investigation encompassing geophysical surveys, multiple deep and thoroughly analyzed exploratory boreholes, followed by stratigraphic, structural, tectonic and hydrogeologic interpretation will be necessary to bring the understanding of these rocks up to a level analogous to that presently available for where sequestration is being implemented. Early-phase characterization of the rift thus would require significantly more time and expense than was expended for initial assessments elsewhere.

Similar conclusions are applicable to the "mirror image" portion of the MRS in northwestern Wisconsin. To review this summary, and its applicability to Wisconsin:

1. Rocks of adequate volume and depth for large-scale geologic storage of CO_2 do potentially exist in northwestern Wisconsin. The most prospective interval is the Bayfield Group in Pierce, Dunn, St. Croix, Polk, Barron, and Washburn counties.

2. There are presently very few data on the reservoir properties (porosity, permeability) of these rocks.

3. The reservoir quality data that do exist are not encouraging; they show porosities and permeabilities that are much lower than the minimum for large-scale fluid storage.

4. There do appear to be adequate impermeable rocks to act as seals to retain CO_2 in the subsurface.

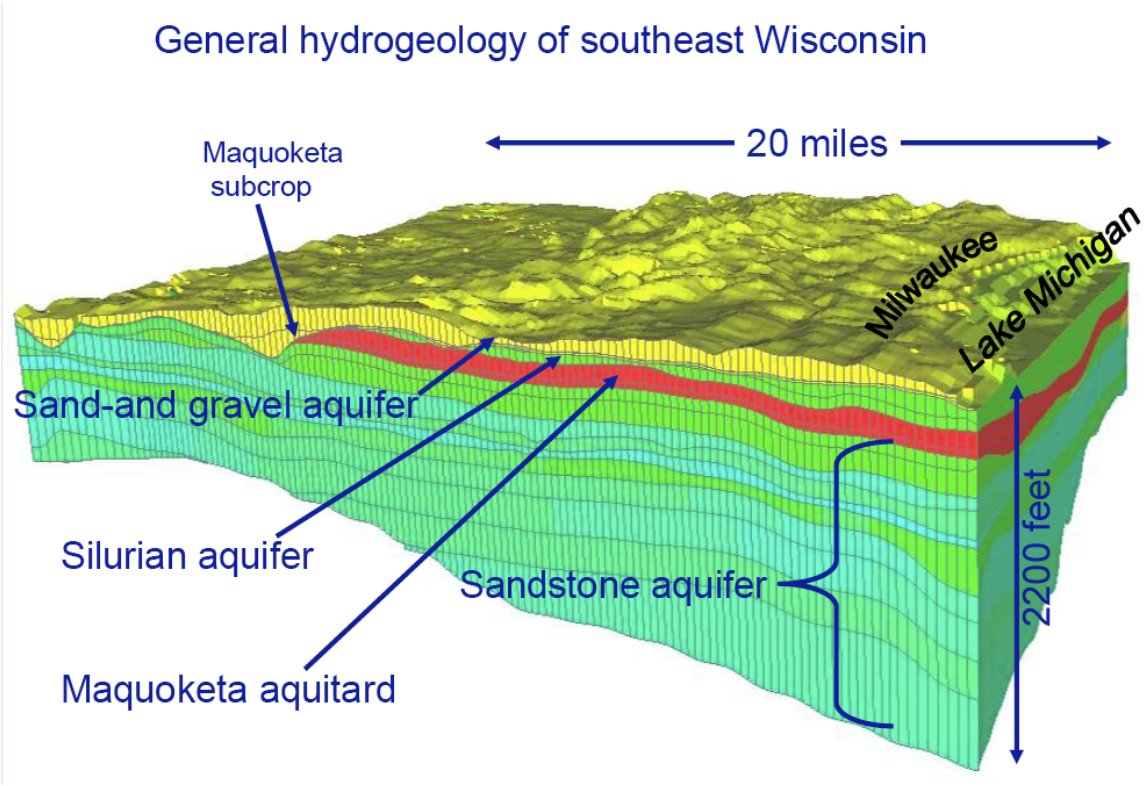
5. The complex geologic structure (especially faulting) of the MRS may pose an unknown risk of leakage of injected fluids.

6. An extensive (and expensive) exploration program would be needed to develop a better understanding of the CO_2 storage potential of the MRS.

Further investigation of the CO_2 storage potential of the MRS would likely proceed as a staged program of progressively increasing costs. The first stages would focus on additional geophysical studies and relatively shallow core drilling. The next stage would involve more intensive 3D seismic surveys and deeper drilling aimed at identifying prospective injection sites. The last stage would involve denser drilling to fully characterize a selected site. The eventual costs of such a program would be relatively high (100s of millions of dollars or more). However, these costs could potentially be viewed as relatively low in comparison to the potential value of large-scale CO_2 storage. Ideally such a project would be conducted jointly by the several states (Minnesota, Wisconsin, Iowa, and Kansas) that might potentially benefit from its findings, rather than any one state alone. Wisconsin may benefit long-term from the further exploration and development of CO_2 storage in the MRS; however, it is not a short- (2 to 5 years) or mid-term (5 to 20 years) possibility.

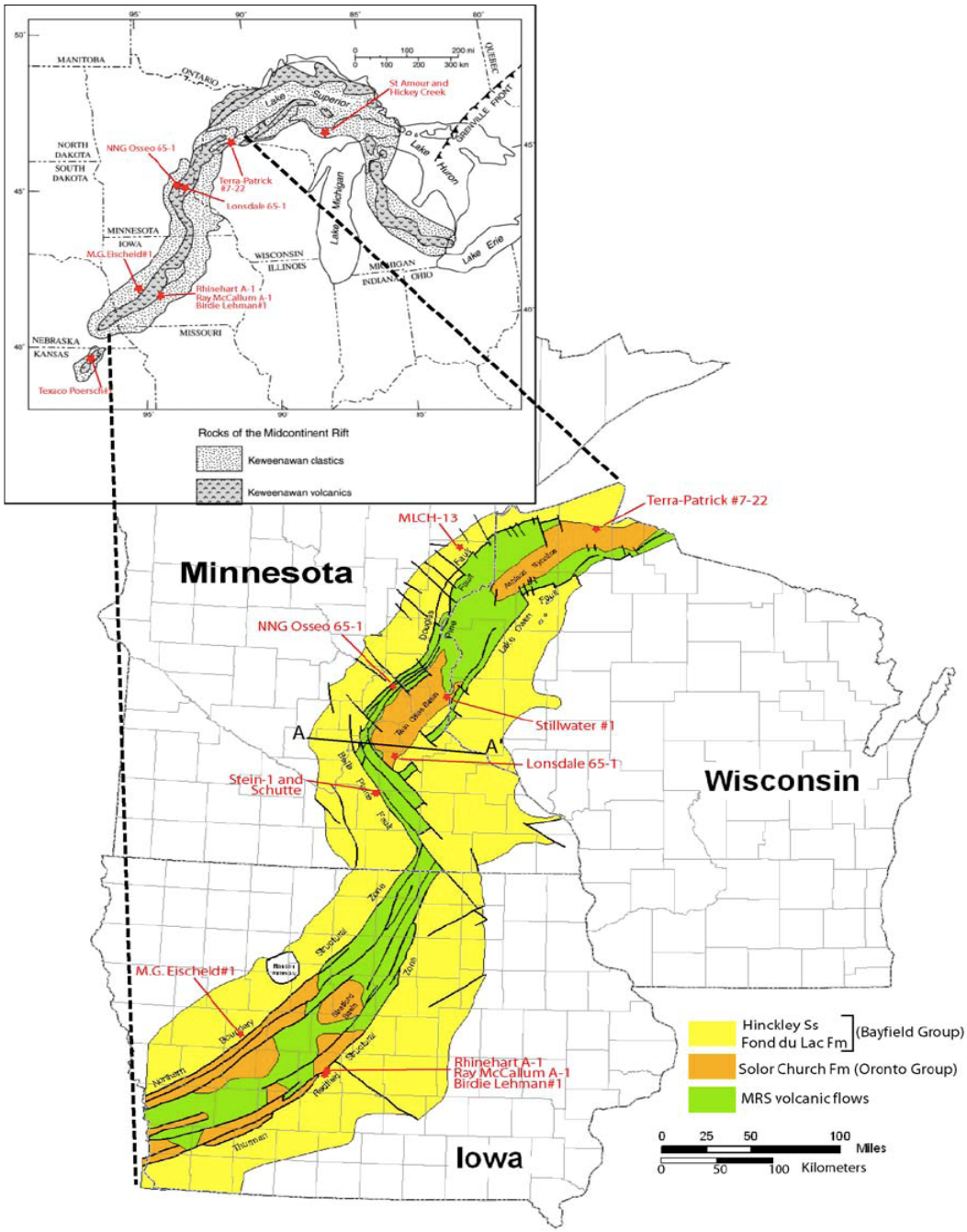
FIGURE 4.1: Freshwater Aquifers of Southeast Wisconsin

Municipal wells extend through essentially the entire thickness of Paleozoic sandstone aquifers, to a depth of ~2200 feet.



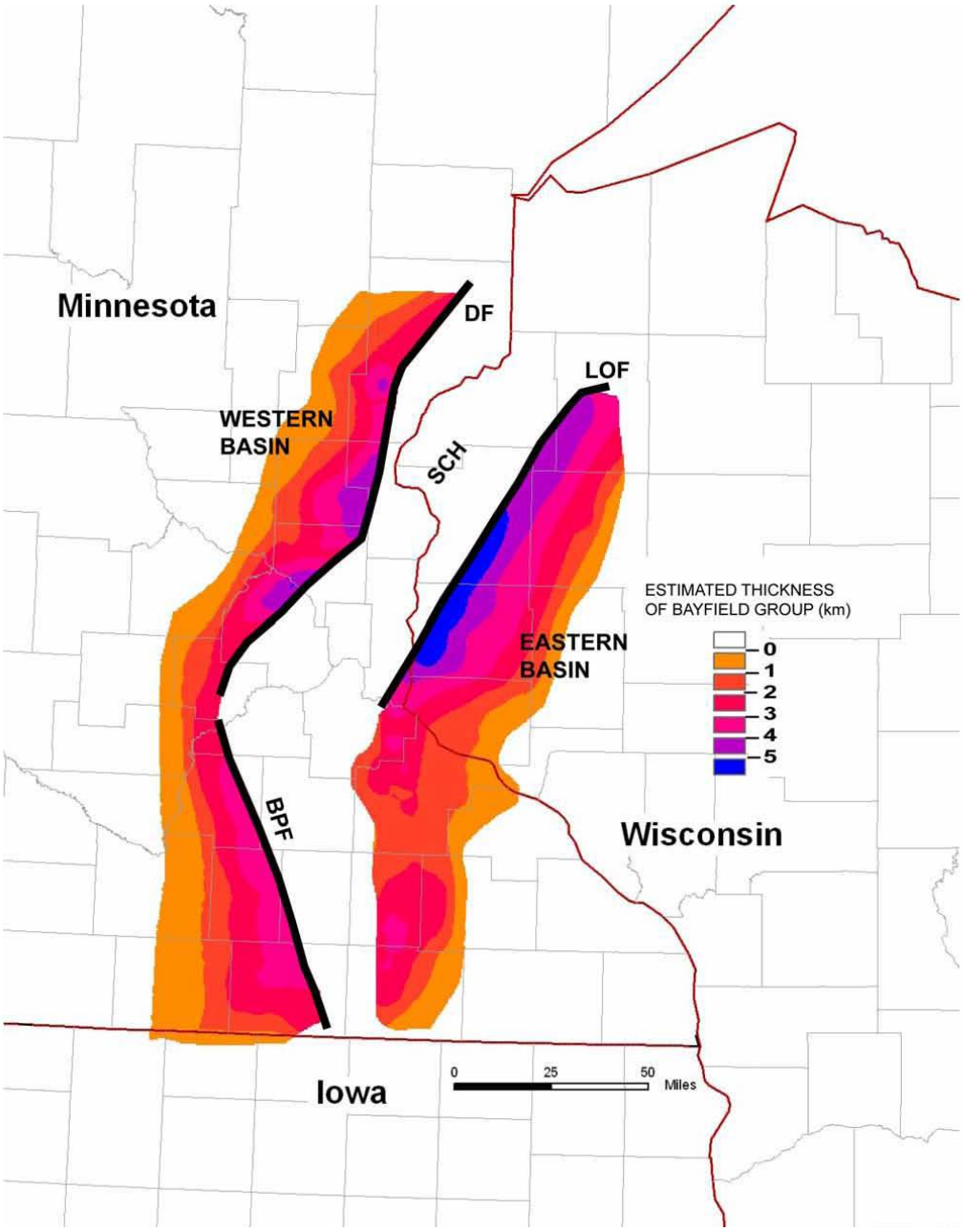
Source: Thorleifson, 2008.

FIGURE 4.2: Midcontinent Rift System



Source: Thorleifson, 2008.

FIGURE 4.3: Bayfield Group Thickness near Minnesota/Wisconsin Border



Source: Thorleifson, 2008. Estimated thickness map for Bayfield Group rocks in Minnesota and Wisconsin, based on three dimensional gravity modeling by Allen (1994).

Along with Professor Carroll's analysis of geologic storage and his examination of the Minnesota Geological Survey's 2008 report, the Study Group also considered research on CO_2 Enhanced Oil Recovery (EOR) Potential presented to the Midwestern Governors Association in June 2009 by Advanced Resources International. The research indicates that eight of the twelve MGA states have

oilfields that are candidates for CO_2 recovery.[20] While Wisconsin is not among these eight potential storage states, neighboring Illinois and Michigan do have EOR potential. The amount of economically recoverable oil in Illinois, according to the draft, is estimated to be between 350 million barrels and nearly two billion barrels, which equates to a CO_2 storage potential of 81 to 433 million tons. Estimates of economically recoverable oil and associated CO_2 storage potential in Michigan are considerably lower but still significant, ranging from 78 to 105 million barrels of oil and 21 to 28 million tons of CO_2. Companies such as Denbury Resources are also considering supplementing their current CO_2 resources with the anthropogenic resources in the region.

5. LEGAL ISSUES FOR CO_2 CAPTURE, TRANSPORT AND STORAGE

This section outlines the current status of regulation both generally with respect to each aspect of CCS, and specifically in Wisconsin, Illinois, and Minnesota. References to Illinois are included because Illinois is identified as a site for geologic sequestration in two of the three scenarios detailed later in this report. References to Minnesota are included because of the potential (currently considered remote) for geologic sequestration of CO_2 in the MRS. In addition, this section reviews the possibilities for the legal treatment of the identified aspects of CCS. A regulatory regime for CCS is still in its nascent stages and will likely change as the technology becomes commercially viable. As CCS gains acceptance, uniform federal standards focused on protecting the environment and promoting public safety should emerge. These standards, similar to many other federal environmental protection and public safety programs, would likely be implemented by state agencies through federally approved partnerships. It is worth noting that states may, in some cases, come up with regulations either sooner or that are more stringent than federal agencies.

It is advisable that Wisconsin take a holistic approach to the development/adoption of a regulatory scheme for CCS in whatever form it appears. Wisconsin will need to develop a regulatory approach that addresses the public/private interests involved and that will allow Wisconsin to work effectively and efficiently with adjacent states to implement proposed projects.

5.1 CO_2 Capture Legal Issues

Carbon capture, federal tax incentives and various regional initiatives have sparked interest in developing capture technology but no regulation exists to govern its use.[21]

5.2 CO_2 Transport and Electric Transmission Legal Issues

The transportation of CO_2, syngas or electrical energy is needed to support the use of electric generation with CCS in Wisconsin. Transporting CO_2 or syngas, via a system of pipelines as explained in Scenarios 1 & 2, has practical and economic advantages over other potential modes to transportation. The transportation of electrical energy may require the construction of additional electric transmission lines.

[20] *CO_2-Enhanced Oil Recovery Potential for the MGA Region*. Robert Ferguson, Advanced Resources International, Inc. June, 2009. Available at: http://www.midwesterngovernors.org/Energy/CO2EORpotential.pdf.
[21] CRS Report for Congress – Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues, April 2007.

5.2.1 Pipelines

Well-established and workable regulations currently exist with respect to CO_2 and syngas pipelines. Prior to construction of either a CO_2 or syngas pipeline, the developer must obtain all permits generally required for pipeline projects with respect to waterways, watershed, wetland and endangered species required by state and federal law. For all pipelines constructed by a Wisconsin utility, the law requires Commission approval of the cost and route.[22] Pipeline common carriers must obtain a certificate of good standing before constructing in Illinois.[23] Pipelines constructed in Minnesota require the Public Utilities Commission's approval.[24]

The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) is the federal agency with jurisdiction over the movement of gas, hazardous liquids and CO_2 by all transportation modes. PHMSA enforces standards for the construction of a new CO_2 or syngas pipeline and the conversion of a steel pipeline not previously used for these purposes.[25] A facility for the interstate transport of both syngas and natural gas also requires the approval of the Federal Energy Regulatory Commission (FERC) prior to construction.[26]

PHMSA regulations for these pipelines also contain detailed operations, maintenance, safety, inspection and reporting requirements.[27] These regulations are implemented both directly by PHMSA and through state approved partnerships. In Illinois and Wisconsin, the Office of Pipeline Safety - Central Region Office is responsible for the regulation of both pipelines.[28] However, Minnesota has primary responsibility for implementing these regulations through an agreement between the PHMSA and the Minnesota Office of Pipeline Safety, within the State Fire Marshal Division of the Minnesota Department of Public Safety.[29]

5.2.2 Container Transport

Transport of CO_2 in containers by road, rail or barge appears impractical considering the volumes anticipated in the scenario projects. However, such modes of transport may be necessary for either a backup system or for smaller scale projects. The transportation of 'bottled' CO_2 is regulated by PHMSA under 49 CFR Parts 171-180. These regulations implement the Federal Hazardous Materials Transportation Law, 49 U.S.C. 5101 et seq., to promote the safe transportation of hazardous materials in commerce. Carbon dioxide appears in the Hazardous Materials Table as a non-flammable gas.[30] Therefore, the transportation in commerce of CO_2 as a gas or refrigerated liquid in cylinders, portable tanks or cargo tank vehicles to a sequestration site would be regulated by PHMSA, subject to all applicable requirements in the U.S. Hazardous Materials Regulations (HMR) including packaging and hazard communication requirements. For a carrier with its principal place of business in Minnesota or that designates Minnesota as its base, the Minnesota

[22] Wis. Admin Code chs. PSC 111 and 112.
[23] IL 220 Ill Comp. Stat. 5/15-401.
[24] Minn. Stat. §§ 216G; Minn. R. ch 7849.
[25] 49 CFR Parts 192 and 195.
[26] 18 CFR §157.
[27] 49 CFR Parts 192 and 195.
[28] http://primis.phmsa.dot.gov/comm/FactSheets/States/IL_State_PL_Safety_Regulatory_Fact_Sheet.htm; http://primis.phmsa.dot.gov/comm/FactSheets/States/WI_State_PL_Safety_Regulatory_Fact_Sheet.htm.
[29] http://primis.phmsa.dot.gov/comm/FactSheets/States/MN_State_PL_Safety_Regulatory_Fact_Sheet.htm; Minn. Stat. §§ 299F and 299J Minn. Reg. Ch 7530.
[30] 49 CFR § 172.101.

Department of Transportation enforces these requirements.[31] To transport CO_2 by truck, drivers must carry a hazardous materials endorsement (HME) on a state-issued commercial drivers license (CDL). This requires following regulations of the issuing state, and the US Transportation Safety Administration.[32]

5.2.3 Electric Transmission

Transmission siting rules and principles are fairly well-established. There is heavy emphasis on state jurisdiction in siting decisions. Prior to construction of a transmission line, the developer must obtain all permits generally required for such projects with respect to waterways, watershed, wetland and endangered species required by state and federal law. For all lines constructed in Wisconsin, the law requires Commission approval of the cost and route.[33] Lines constructed in Illinois require approval by the Illinois Commerce Commission,[34] and lines constructed in Minnesota require the Public Utilities Commission's approval.[35]

Once a project becomes operational, safety is regulated, monitored and enforced by the state in which the project resides.[36] In Wisconsin, utilities (including ATC) must submit a maintenance plan and comply with Commission reliability standards.[37] The Midwest region currently has several planning initiatives underway. The Midwest Independent System Operator (Midwest ISO or MISO) has the Midwest ISO Transmission Expansion Planning process (MTEP). The Organization of MISO States (OMS), through its Cost Allocation and Regional Planning meetings, is exploring the issue of transmission cost allocation. Additionally, the Upper Midwest Transmission Development Initiative (UMTDI) is a cooperative effort among 5 Upper Midwestern states exploring the resolution of previously contentious issues surrounding planning and siting. Given the entirety of these efforts and the recent availability of federal funding for additional research and planning, some of the outstanding transmission issues may be resolved or significantly mitigated in the near future.

5.3 CO_2 Storage

Given that geologic carbon sequestration is an evolving technology, no comprehensive framework currently exists to *specifically* regulate geologic carbon sequestration. The fundamental issues to be addressed include surface ownership issues such as property ownership, sub-surface issues such as pore space ownership and mineral interests, issues of liability, trespass, risk management, long-term oversight, how any regulatory treatment would work in conjunction with existing hazardous waste treatment and groundwater requirements and policy implications regarding the treatment of CO_2 as a commodity or liability.

The U.S. Environmental Protection Agency (USEPA) has jurisdiction under the Safe Drinking Water Act of 1974 (SDWA) to regulate most types of underground injection. Specific regulations are brought together in the Underground Injection Control (UIC) Program, which regulates

[31] Minn. Stat. § 221.0355.
[32] 49 CFR § 1572.
[33] §§196.49 and 196.491, Wis. Stats. and Wis. Adm. Code chs. PSC 112 and 114.
[34] 220 Ill Comp. Stat. §§ 5/8-406 and 5/8-503; 83 Ill. Adm. Code ch. 305.
[35] Minn. Stat. §§ 216B.243 and 216E.02;Minn. R. ch 7849.
[36] http://www.ferc.gov/industries/electric/safety.asp.
[37] Wis. Admin Code § 113.0607.

underground injection in five different classes of injection wells.[38] Property damage and liability issues also factor into the viability of long-term carbon sequestration. Regulation of this aspect of the process has so far been left to the states.

5.3.1 Injection Well Regulation

According to the USEPA, the injection of CO_2 for underground storage meets the definition of "underground injection" in section 1421(d)(1) of the SDWA. The UIC program currently applies to a variety of underground injection activities, including the underground injection of CO_2 for purposes of enhanced oil recovery. In the summer of 2008 the agency proposed regulations for permitting sequestration projects for the sole purpose of carbon storage. While maintaining the current Class II well regulations related to the use of CO_2 for EOR, the proposed regulations would create a new Class VI UIC well. This proposal addresses broad issues raised by large commercial carbon sequestration operations including: 1) site selection criteria; 2) monitoring for subsurface migration; 3) injection well design standards; 4) conditions attaching to any abandonment of the site; and, 5) standards for halting CO_2 injection if a loss of containment should occur.[39]

States are allowed to assume primary responsibility for implementing the UIC requirements within their boundaries, as long as the state program is consistent with USEPA regulations and has received USEPA approval. The scenarios described in this report focus on the use of sequestration sites in Illinois and Minnesota. In Illinois the Illinois DNR and Illinois EPA administer different aspects of the UIC program.[40] In Minnesota, the USEPA administers the program from its Region 5 office.[41]

5.3.2 New Class of UIC Wells

The UIC program is designed to protect drinking water aquifers from industrial injection of fluids into deep geologic formations for purposes such as enhanced oil or gas recovery. CO_2 storage presents special challenges as it is buoyant, can be corrosive, and would be spread over a large area and held indefinitely. Therefore, USEPA proposes a new Class VI well specific to storage.

5.3.3 No Prescriptive Standards

USEPA proposes performance-based standards, as opposed to prescriptive requirements. In general, an injection and operations plan must be included with the application that demonstrates drinking water would be protected. The permit holder would have to monitor and periodically report back to USEPA to ensure that model predictions as to the size of the CO_2 plume and injection pressures prove true. Permittees would be required to demonstrate financial responsibility for post-injection

[38] 40 CFR Parts 144-148.
[39] 73 FR pages 43492-43541; National Energy Technology Lab (NETL) Carbon Sequestration FAQ: http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carbon-seq.html and "EPA To Develop Regulations for Geologic Sequestration of Carbon Dioxide" press release: http://yosemite.epa.gov/opa/admpress.nsf/eebfaebc1afd883d85257355005afd19/84bd1ef19c00eb7a85257371006b6a21!OpenDocument.
[40] 62 Ill. Adm. Code Part 240 and 35 Ill. Adm. Code Part 704.
[41] The Region 5 USEPA web page: http://www.epa.gov/region5/water/uic/uicpartners.htm. It is not known at the time of publication which agencies will take responsibility for administering the new Class VI wells if the proposed rule is promulgated.

site care for 50 years; that time period could be shorter or longer, depending on the residual risk to drinking water aquifers based on monitoring data.

5.3.4 Property Damage and Liability Issues

A March 2009 report by the Midwestern Governors Association (MGA) examined the liability and financial responsibility issues associated with long-term geologic carbon storage that are currently of greatest concern.[42] As one might expect based on the preceding discussion, the principal source of long-term liability is groundwater contamination and other hazards that may result from leaking or seeping CO_2. Of lesser concern is the possibility that storage projects might induce seismic activity or somehow harm human health in ways not currently understood. Project developers could potentially be subject to many different types of challenges, according to the MGA report:

> *Geologic storage projects may be subject to liability under common law, contractual requirements, and jurisdictional and federal statutes (e.g., the Underground Injection Control (UIC) program under the Safe Drinking Water Act – SDWA, Resource Conservation and Recovery Act – RCRA, and Comprehensive Environmental Response, Compensation, and Liability Act – CERCLA). Geologic storage projects may be subject to tortious liability that would stem from a project adversely impacting other interests and would be brought under four different common law doctrines: nuisance, trespass..., strict liability, or negligence. Contractual liability would stem from an operator or other responsible entity breaching contractual obligations (e.g., failure to contain CO_2 after receiving carbon credits for containment).*

The MGA report notes that "these potential sources of liability should not pose a significant risk in sites with proper site selection, characterization, operation, closure, and management." Nevertheless, potential CCS project developers interviewed by MGA staff identified long-term liability as one of the main factors creating the uncertainty that makes it difficult for them to acquire financing.

6. THREE PLAUSIBLE SCENARIOS FOR WISCONSIN

Although there appears to be no suitable geologic carbon sequestration sites in Wisconsin, it may yet be possible for electric utilities, cooperatives, and merchant power plants in Wisconsin to identify other geologic carbon sequestration opportunities and locations in nearby states. The Study Group identified at least three plausible scenarios by which this could happen. Each scenario, which will be detailed below, represents a different kind of opportunity with distinct advantages and disadvantages.

The first scenario is one in which multiple existing coal-fired power plants located in Wisconsin are assumed to have installed the necessary equipment to capture and compress most of the CO_2 that they would otherwise emit. The captured CO_2 would then be transported via new dedicated pipelines to a suitable geologic sequestration site in another state. The principal advantage of this

[42] *Toolkit for Carbon Capture and Storage: Statutory and Regulatory Issues*, prepared by Great Plains Institute for the Midwestern Governors Association Renewable Electricity and Advanced Coal with Carbon Capture and Storage Advisory Group, March 2009. Available at http://www.midwesterngovernors.org/Energy/Toolkit.pdf.

scenario compared to the others is that it might allow the existing coal-fired power plants that currently provide more than 60% of Wisconsin's electricity to remain in service and be cost-competitive even after greenhouse gas regulations are adopted. One of the disadvantages of this approach is that CO_2 capture and compression would reduce the net electrical output of these existing power plants, perhaps to the point where new capacity is needed.

Under the second scenario, we assume that a coal gasification facility is built at or near a geologic sequestration site in another state. At the facility, coal is converted to synthetic natural gas. As part of this process, roughly half of the carbon in the coal is captured as CO_2 and sequestered while the rest remains in the synthetic natural gas that is placed into a natural gas pipeline. This synthetic natural gas could then be used at existing or new gas-fired power plants in Wisconsin. The principal advantage of the second scenario is that it might allow for the continued and perhaps increased use of efficient gas-fired combined cycle power plants with decreased greenhouse gas emissions, possibly even with an attendant decrease in coal-fired generation. One of the disadvantages of this approach is that it does nothing to prolong the lives of Wisconsin's coal-fired power plants and thereby protect those investments from becoming stranded assets.

Finally, in the third scenario, we simply assume that a generating facility is built at or near a suitable geologic sequestration site in another state, and the electric power is transmitted to Wisconsin via new transmission lines to a Wisconsin utility or cooperative. The principal advantage of this scenario is that it may prove to be the least expensive option per unit of delivered electricity. One of the disadvantages is that it does not help extend the life or maintain the cost competitiveness of any of Wisconsin's existing fossil fuel power plants.

It is critically important to understand that these scenarios are <u>not</u> mutually exclusive; all three scenarios could be realized simultaneously. The purpose of this report is not to facilitate a side-by-side comparison of the three scenarios, precisely because there is no need to choose the one "best" option at this time (or perhaps ever). Each may prove to be the best option at some place and time under specific circumstances. Some of the variables that might potentially influence which options, if any, will be suitable for a given circumstance include:

- Peak demand for electricity – if peak demand increases, options that increase total installed generating capacity may be of more value, all else being equal, than options that make use of existing generating capacity;

- Natural gas prices – this variable will dictate the value of synthesis gas and thus the economic viability of any coal gasification plant as in scenario 2, and it could also influence whether carbon capture retrofits at coal-fired power plants are economical when compared to fuel-switching options;

- Oil prices – this variable influences the value of CO_2 for enhanced oil recovery applications, which is an option for geologic sequestration in some but not all locations;

- Steel prices – although this variable can influence the costs of any of the options, it greatly influences the cost of constructing a CO_2 pipeline as in the first scenario;

- Transmission constraints – the costs and benefits of the third scenario are largely dependent on whether new transmission lines are required;

- Regulations limiting greenhouse gas emissions – future regulations may intentionally or unintentionally favor specific applications of carbon capture and sequestration technology;[43] and,

- Space limitations – some existing power plants may not have the physical space necessary to install carbon capture equipment.

6.1 Scenario 1: Capture CO_2 in Wisconsin, Transport CO_2 to Storage Site Outside Wisconsin

6.1.1. Overview

CO_2 capture at existing coal-fired electric generating units (EGUs) and the subsequent transport of the CO_2 to storage sites capable of indefinite storage (sequestration) is an important scenario to be explored in determining the impacts and overall feasibility of reducing GHG emissions from major sources. The Study Group focused primarily on the component of direct sequestration, which is the transport of CO_2 via pipeline from the source. A detailed evaluation is performed for the capture and transport of CO_2 from large existing single point sources. Other alternatives were identified and evaluated on a qualitative basis.

Scenario 1 focuses on capturing CO_2 from existing coal-fired facilities and transporting it through a pipeline network. This exploration evaluates various pipeline network alternatives for transport, including existing pipeline networks such as natural gas, petroleum and petroleum-derived liquids, as well as the development of a dedicated CO_2 pipeline network. For the purposes of this scenario, it is assumed that pipeline technology for CO_2 transport is mature, stemming from its use since the 1970's for EOR and in other industries. It is also assumed that the capture technology can be retrofitted to existing power plants and is capable of capturing 90% of the CO_2 from the flue gas. The CO_2 will be injected into the pipeline on a continuous basis with little to no storage capability assumed at the individual facilities.

Storage technology is also addressed separately in the report although various storage locations are discussed in terms of a destination for the pipeline scenarios. Based on previous and on-going studies, it does not appear that there are any suitable sites for CO_2 sequestration in Wisconsin. Therefore the study focuses on transporting CO_2 via an interstate pipeline from Wisconsin power plant facilities to the Illinois basin for indefinite storage. (Another potentially viable option, not analyzed herein, would be to transport the CO_2 to oil and gas fields in the northwestern part of Michigan's Lower Peninsula, for EOR purposes. This would probably require a pipeline of comparable length, assuming the pipeline did not cross Lake Michigan, and therefore would not significantly alter the calculations of pipeline costs that follow.)

[43] For example, a bill approved by the U.S. House of Representatives in June 2009 would provide incentives for specified carbon capture demonstration projects at power plants. These incentives would only be available to generating units rated at 200 MW or more and only if the unit derives at least half its energy from coal or petroleum coke. Furthermore, incentives for the first 6000 MW of demonstration projects would be greater than for later projects.

The sources of CO_2 for the purposes of this pipeline network study are those generated by the larger coal-fired EGU facilities located in Wisconsin. The plants in question have CO_2 mass emission rates greater than 1,000,000 tons annually. Coal-fired EGUs in construction or expected to be commercial prior to the end of 2009 were included in the network analysis and conceptual design.

6.1.2. Capabilities and Limitations

This section of the report discusses engineering alternatives for the design and construction of a pipeline system to transport liquid CO_2. Tonnages of CO_2 generated from coal-fired power plants will be gathered at several points along the pipeline and transported to a final sequestration site in central Illinois, in or near Crawford County.

Various design and routing scenarios are initially discussed. Further analysis is then conducted into the most plausible of the scenarios. Routing and right-of-way (ROW) considerations are outlined and the sensitivity of material costs is identified. Design specifics and references to federal regulations are made where appropriate. Mainline booster pumps are stationed at intervals along the pipeline to maintain minimum required pressures, which is detailed. Economic considerations are also explored, ranging from steel pipe and fitting material costs, to construction and operation and maintenance (O&M) projections.

6.1.3. Route Scenarios

Wisconsin's public utilities own and operate coal-fired power plants situated throughout Wisconsin. Transporting quantities of CO_2 generated by these power plants through an existing natural gas or liquids pipeline is the best option, but not feasible due to batching requirements when mixing products. Furthermore, there are pipeline pressure and diameter limitations of the existing infrastructure since CO_2 is transported at pressures in excess of 2,000 psi. Finally, existing pipelines in the Midwest are nearly 100% scheduled, so little excess capacity exists.

The most practical option would be to construct a new dedicated pipeline capable of operating at a pressure of at least 2,000 psi for transporting CO_2. The primary obstacles for this option are securing permits and ROW, along with the large amount of capital required.

Thirteen plants were considered for this carbon capture study. Based on their proximity to each other, three routes or lines were explored: an eastern line, a southern line and a western line. A CO_2 threshold of 30 million tons per year (1.4 billion ft^3/day) was established based on loads attainable on two of these routes. This is achievable with either the eastern or southern line based on the number of plants and the cumulative volume of CO_2 emitted by plants on each respective line. The maximum tonnage available for the western line is 15 million tons per year.[44] The eastern, western and southern line options, the mileage of the line, and the power plants feeding the CO_2 are listed in Table 6.1 below. Maps depicting the proposed routes for each main pipeline are in Appendix C of this document.

The Southern Line consists of two branch lines connecting power plants from central and eastern Wisconsin. The two branch lines eventually merge into a 30" trunk line that travels south along Lake Michigan's western shore to the Illinois Basin. The Eastern Line consists of a branch line

[44] To put these volumes in perspective, consider that the maximum flow capacity found anywhere on North America's current CO_2 pipeline system is 24 million tons per year. Two separate pipelines operate at that capacity.

originating from northeastern Wisconsin that collects CO_2 from power plants located further south along the Michigan shoreline. The branch lines eventually form two 20" trunk lines traveling south along Lake Michigan's western shore into the Illinois Basin. The Western Line consists of two 20" branch lines connecting power plants on the western side of the state and merging into a 30" trunk line traveling southwest through Wisconsin to the Illinois Basin.

TABLE 6.1: Three CO_2 Pipeline Options

	Eastern Line – 30 Mil. Tons/Yr	**Southern Line – 30 Mil. Tons/Yr**	**Western Line – 15 Mil. Tons/Yr**
Length	400 miles	370 miles	700 miles
Plants	Pulliam, Edgewater, Valley, Oak Creek, Pleasant Prairie	Columbia, Oak Creek, Pleasant Prairie	Weston, Alma / Madgett, Genoa, Nelson Dewey

The eastern line was selected as a good compromise for further analysis based on the route mileage and number of plants along its route, while fulfilling the maximum flow capacity requirements.

Two options were analyzed for the eastern line: a single 30" diameter pipeline, or two 20" diameter pipelines running in parallel. A single 30" diameter pipeline would cost less, but closer analysis reveals pipe wall thickness issues and yield strength complications along with potential welding challenges. Two 20" diameter paralleling pipelines would cost more, but would more closely meet all design and operating requirements. Each 20" line would operate at 2,160 psi to meet the operating pressure limitations specified in American National Standards Institute - Standard 900 (ANSI 900). Higher pressures would require ANSI 1500 fittings, costly and impractical for this project. The federal regulations that would govern design, construction, O&M, and pipeline integrity management of the proposed CO_2 pipeline are found in 49 CFR Part 195.

6.1.4. Mainline Pump Stations

Due to the high pipeline operating pressure, pump stations spaced along each 20" mainline are required. Each 20" mainline with a maximum allowable operating pressure (MAOP) of 2,160 psi will undergo a pressure drop of 12 psi/mile. The minimum pressure desired along each mainline is 1,440 psi. With a starting pressure of 2,160 psi, mainline booster pumps will be required at 70 mile intervals, per each mainline. Table 6.2 estimates the booster pump installation cost.

TABLE 6.2: Mainline Booster Pump Station Cost

Diameter	# of Pump Stations	HP per Mile	Miles Between Stations	HP per Station	Total HP	Total Electrical Load (Kilowatts)	Est. Cost
2 x 20”	12	85	70	6,000	72,000	53,690	$ 72,000,000
1 x 30”	3	45	160	7,200	21,600	16,107	$ 21,600,000

In addition to the capital and O&M costs associated with the mainline booster pump stations, there is also an accompanying CO_2 emissions impact. Given that generating facilities will likely be carbon-constrained in the future, it is important to analyze the CO_2 impact in tandem with capital and O&M costs. Each booster pump station represents an electrical load that is served from the electrical network or grid. Table 6.2 lists the estimated pump station electrical requirements in terms of horsepower and associated electric power (kilowatt) requirements for each pipeline scenario.

In order to determine the CO_2 impact or footprint, annual output emission rates were obtained from the Emissions & Generation Resource Integrated Database (eGRID), a comprehensive inventory of environmental attributes of electric power systems created by the Environmental Protection Agency.[45] eGRID is based on available plant-specific data for all U.S. electricity generating plants that provide power to the electric grid and report data to the U.S. government.

Midwest Reliability Organization (Eastern) annual output emissions rates were used as default factors for estimating the CO_2 emissions from electricity use when developing the pump station carbon footprint. In Table 6.3, the CO_2 output emission rate of 1,834.72 lbs per MWh was converted to tons per MWh and multiplied by the total pump station electrical load to yield a CO_2 footprint for each pipeline configuration. A 90% capacity factor was applied to the pump stations to account for maintenance outages and periods of reduced flow.

TABLE 6.3: Pump Station CO_2 Impact

Pipeline Configuration	Total Pump Station Electrical Load (MW)	Carbon Dioxide (Tons/MWh)	Estimated Pump Station Carbon Footprint (Tons/Year)
(2) 20" Lines	53.69	0.917	388,152
(1) 30" Line	16.107	0.917	116,447

[45] Environmental Protection Agency, Clean Energy Resources – eGRID. Located online at the USEPA web site: http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

6.1.5. Material and Construction Costs

Material cost estimates are highly volatile due to the cost of steel, which provides a challenge in forecasting line pipe prices.

Table 6.4 compares pipe costs from a 2005 report issued by Midwest Geological Sequestration Consortium versus pipe purchase costs for more recent installations performed by IBS' engineering group.[46] This table is intended *only to demonstrate* the potential upswing in capital that could be required to secure line pipe for a CO_2 pipeline project of this magnitude and may not necessarily reflect actual market conditions today. Furthermore, a reduction in pipe price will likely be realized for 400 miles of product run versus shorter distance laterals of up to 20 miles in product run length.

TABLE 6.4: Potential Volatility in Price/Ton for Steel Pipe

Pipe Diameter	400 Mile (Tons Pipe)	$/Ton (2004)	Pipe Cost (2004)		2007/2008 Project Pipe Size	$/Ton for Year
18"	98,679	$1,135	$111,960,000		2007 – 14" lateral	~1,050
20"	110,000	$1,250	$137,520,000		2007 – 16" lateral	~1,200
22"	121,234	$1,134	$137,520,000		2007 – 20" lateral	~1,400
24"	136,086	$1,444	$196,560,000		2008 – 24" line pipe	~3,900
30"	164,571	$1,684	$277,200,000			

The estimated total construction costs are found in Table 6.5. ROW costs are again referenced from the 2005 report and do not include provisions for condemnation or securing ROW through the major metropolitan areas of Chicago and Milwaukee. In routing of a new CO_2 pipeline, all efforts should be made to avoid environmentally sensitive and urban areas by utilizing existing pipeline or other utility ROW.

TABLE 6.5: Estimated Construction Costs per Mile to Construct a New CO_2 Pipeline

Construction Costs Per Mile - 2004 Numbers					
Pipe Diameter	ROW (Costs)	Materials	Construction	Services	Total
18"	$67,000	$311,000	$306,000	$96,000	$713,000
20"	$67,000	$382,000	$336,000	$102,000	$820,000
22"	$67,000	$460,000	$366,000	$107,000	$933,000
24"	$67,000	$546,000	$396,000	$121,000	$1,063,000
30"	$67,000	$770,000	$486,000	$181,000	$1,437,000

[46] 2004 Regional Carbon Sequestration Partnerships Annual Review Meeting in Pittsburgh, PA, November 2004. *An Assessment of Geological Carbon Sequestration Options in the Illinois Basin: Year One* by R.J. Finley. Available at: http://sequestration.org/publish/yr1_nov04.pdf. A research update presentation was given to the Work Group in July, 2008 by Finley.

Materials costs were derived largely from pipe pricing in Table 6.4. Construction pricing for an actual future project may require additional hidden inflation factors, such as per diem and stipulated work week agreements. Services include construction inspection and other third party entities, such as surveying.

The estimated total costs are outlined in Table 6.6, merging data from the previous tables. For comparison, a 2007 Transmission Pipeline Project in Midwestern U.S. (85 miles of 30" pipeline and 30 miles of 20" pipeline) cost $275,000,000.

TABLE 6.6: Total Cost to Construct Pipelines

Pipeline Options	Booster Pump Station Costs	Pipeline Construction Costs	Total Construction Costs
East Line (two 20" lines)	$ 72,000,000	$ 656,000,000	$ 728,000,000
East Line (one 30" line)	$ 21,600,000	$ 574,800,000	$ 596,400,000
South Line	$ 21,600,000	$ 531,690,000	$ 553,290,000
West Line	$ 50,000,000	$1,005,000,000	$1,055,000,000

Ongoing O&M yearly costs will be required. Estimates for pipeline, booster pumps and power are tabulated in Table 6.7 based on the following assumptions:

1. Pipeline - $ 667/inch diameter/miles/year
2. Pump station - $ 50/HP/year
3. Power costs - $ 360/HP/year

TABLE 6.7: Anticipated O&M Costs for Pipelines (2008 Dollars)

Pipeline Options	Pipeline O&M (per year)	Pump Station O&M (per year)	O&M Power (per year)	Total (per year)
East Line (two 20" lines)	$ 10,672,000	$ 3,600,000	$ 25,920,000	$ 40,192,000
East Line (one 30" line)	$ 8,004,000	$ 1,080,000	$ 7,776,000	$ 16,860,000
South Line	$ 7,403,000	$ 1,080,000	$ 7,776,000	$ 16,259,000
West Line	$ 12,673,000	$ 2,500,000	$ 18,000,000	$ 33,173,000

6.1.6. Financial Capital Analysis

Given the high-level nature of the analysis, simple economic carrying charge methodology was applied to estimate the cost of raising and maintaining the financial capital associated with the

project. This approach is often used in engineering-economic analyses and provides a reasonable first-cut estimate of the financial cost of carrying an asset.

The key components and assumptions of the analysis are:

The utility's capital structure (i.e., its mix of debt and equity)	50% debt and 50% equity
The returns on the debt and equity securities	debt return = 6.06% and equity return = 10.75%
The effective corporate tax rate	40%
The asset depreciation rate	3.0% (which is roughly equivalent to a 30-year expected asset life)

With the before-tax return on equity calculated, the rate of return on the project can also be calculated.

Equity: Percentage of capital structure x 0.1075/ (1-0.40) = 50% x 17.9% = 9%

Debt: Percentage of capital structure x 6.06% = 50% x 6.06% = 3.0%

Rate of Return: equity return component + debt return component = 9.0% + 3.0% = 12.0% which can be rounded to 12%

This represents the return **on** capital. Ratepayers, though, must also pay the utility back for the principal it invested in the project. This is the purpose of the annual depreciation expense. It is the return **of** capital. As noted above, a 3% annual asset depreciation rate is assumed.

The economic carrying charge can now be calculated by adding the rate of return of 12%, and the annual depreciation rate of 3% to produce an economic carrying charge rate of 15%. This analysis suggests that for every $1 million of capital costs we incur for a carbon sequestration project, we incur annual costs of $150,000 (*i.e.*, $1,000,000 x 15%).

Therefore, the simple economic carrying charge methodology applied to the 30" Eastern line yields a yearly revenue requirement based on the following cost components:

Capital Expenditure x 15%	$ 89,460,000
Annual O&M	$ 16,860,000
Annual Revenue Requirement	**$106,320,000**

For 30,000,000 tons of CO_2, the equivalent first year rate is estimated at $ 3.54 per ton. Table 6.8 lists the total annual cost on a per ton basis for each of the pipeline scenarios evaluated.

TABLE 6.8: Total Estimated Cost per Ton CO_2 Values

Pipeline Options	Estimated Installation Cost	Estimated O&M Costs Per Year	15% Capital Revenue Requirement Amount & O&M Cost (per year)	Tonnage Of CO_2 Transported	Total Annual Cost Per Ton CO_2 Transported
East Line (two 20" lines)	$ 728,000,000	$ 40,192,000	$ 149,392,000	30,000,000	$ 4.98
East Line (one 30" line)	$ 596,400,000	$ 16,860,000	$ 106,320,000	30,000,000	$ 3.54
South Line	$ 553,290,000	$ 16,259,000	$ 99,252,500	30,000,000	$ 3.31
West Line	$1,055,000,000	$ 33,173,000	$ 191,423,000	15,000,000	$ 12.76

6.2. Scenario 2: Capture and Store CO_2 Outside Wisconsin, Transport SNG to Wisconsin

6.2.1. Overview

An alternative application of CCS of relevance to the electrical sector in Wisconsin is the production of SNG from coal in Illinois and distribution to Wisconsin using existing natural gas pipelines. This application, when coupled with longer term contracts and potentially less volatile prices for natural gas, may allow existing NGCC facilities in Wisconsin an opportunity to increase their hours of dispatch and produce an amount of energy equivalent to that of a new 1,000 MW coal plant. Since these units are the most efficient fossil fired generation units in Wisconsin, an increase in their hours of dispatch would produce additional electrical energy in Wisconsin with significantly lower carbon dioxide emissions than conventional coal plants.

SNG is indistinguishable from conventional natural gas and is compatible with existing natural gas pipelines, storage infrastructure, and end usage. In this scenario, CCS is used in Illinois at a synthetic natural gas production facility to reduce the carbon content of coal to the carbon content of natural gas; a reduction of about 50% on an energy basis. An identical process has been operating since 2000 at the Great Plains Synfuels plant in North Dakota which converts lignite coal into SNG and stores the carbon dioxide liberated in the process at an oil field in Weyburn, Saskatchewan. A number of SNG facilities have been proposed in Illinois in recent years. One such facility – the proposed Secure Energy Inc. SNG plant in Decatur – obtained an air permit in 2007 but has not yet commenced operation.

The full fuel-cycle greenhouse gas emissions from SNG production with CCS are comparable to traditional natural gas production, while without CCS the lifecycle emissions of SNG are up to 175% higher than conventional natural gas.[47] Thus, the consumption of SNG, produced from coal with CCS in Illinois, at a natural gas power plant in Wisconsin may combine the greenhouse gas profile of natural gas electrical production with price and supply stability. The high efficiency of

[47] MIT Future of Coal, Appendix 3F, 2007.

NGCC power plants and the reduced carbon content of SNG produced with CCS results in net greenhouse gas emissions approximately 1/3 to 1/4 of those from pulverized coal plants. Since the CCS would be implemented at the SNG facility in Illinois, the costs associated with piping carbon dioxide from Wisconsin to Illinois are avoided.

The timeline for deploying CCS in the production of SNG is likely to be earlier than the timeline for constructing an IGCC power plant with CCS in Wisconsin (with a carbon dioxide pipeline to Illinois) or in Illinois (with an electrical transmission line to Wisconsin). The availability of SNG for lowering greenhouse gas emissions from the electrical sector in Wisconsin is mostly dependent on the development of SNG facilities in Illinois with CCS because existing NGCC plants and natural gas pipeline infrastructure in Wisconsin could be used to reduce baseload coal generation if SNG was used to increase the dispatch of these NGCC plants. A number of recent projects and proposals in the Illinois basin, including a U.S. Department of Energy (DOE) Phase 3 large-scale injection CCS project in Decatur, Illinois and Duke Energy's IGCC power plant under construction in Edwardsport, Indiana, are indications that state, federal and private investment in CCS in the Illinois Basin are accelerating. The DOE Phase 3 project in Decatur is especially significant because it is projected to begin injecting 1 million metric tons of CO_2 from an ethanol plant in February, 2011 and is located 2,000 feet from the Secure Energy SNG plant mentioned previously. Nevertheless, significant regulatory and economic barriers remain in the near future for any commercial applications of CCS that would benefit Wisconsin. The ultimate timeline is driven more by the pace of federal action on carbon regulation, as well as federal investments in CCS such as the recently-announced resurrection of the FutureGen project in Illinois.

The cost of using SNG to lower greenhouse gas emissions in Wisconsin is dependent both on the cost of the SNG delivered to NGCC facilities as well as the market prices for electrical energy during the non-peak hours when these facilities would be available for additional dispatch. Proposed SNG projects in the Illinois Basin have offered to sell SNG through long-term fixed price contracts that will depend on the capital costs of the facility, the costs of coal, and other market considerations. Long-term fixed price contracts for SNG, however, are significantly different from the current fuel procurement process at NGCC facilities in Wisconsin because the ultimate source of the energy has price stability and supply characteristics that are established by mine mouth coal rather than by existing natural gas markets.

In order to assess the advantages and disadvantages of using an out-of-state SNG plant to fuel new or existing NGCC plants generating power in Wisconsin, a comparison was done between this approach and the alternative of installing an IGCC plant in Wisconsin.

6.2.2 Capabilities / Limitations

An attempt was made to compare the SNG/NGCC combination with the IGCC alternative on the basis of both cost and performance. A number of relatively recent studies are available that provide estimates of the cost and performance of IGCC plants, with a smaller number of studies available that provide this information for SNG plants. However, the Study Group was unable to locate any single study that provides this information for both of these options. As a result, available cost estimates for the two technologies were developed at different times, using different assumptions. Given the rapid changes in plant construction costs in recent years, the Study Group concluded that a cost estimate for an IGCC plant from one study could not be reliably compared with a cost estimate for an SNG plant from a different study. As a result, the discussion below will address the

factors that will drive the capital costs of the plant options, but will not attempt to compare the costs of the options on a quantitative basis.

In order to compare performance between the two alternatives, data from the following studies were used:

- National Energy Technology Laboratory (NETL), *Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity*, Revision 1, August 2007 ("NETL study"); and,

- University of Kentucky, *Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal*, July 2007 ("Kentucky study").

The NETL study provides performance information for several different IGCC plant configurations, both with and without carbon capture. The study also provides performance information for an NGCC plant. The Kentucky study provides performance information for an SNG plant, with and without carbon capture. The NETL study is based on the use of Illinois No. 6 bituminous coal, while the carbon capture SNG case in the Kentucky study is based on relatively similar Eastern Kentucky bituminous coal. The IGCC plant configuration in the NETL study using a General Electric gasifier is similar to the single-stage quench gasifier configuration of the SNG plant in the Kentucky study. Therefore, the following combination of results from the two studies will provide a basis for comparing the performance of the two alternatives within this report:

- SNG/NGCC Combination – SNG plant with carbon capture (Case 2) from Kentucky study supplying fuel to NGCC plant without carbon capture (Case 13) from NETL study; and,

- IGCC Alternative – IGCC plant using General Electric gasifier, with carbon capture (Case 2) from NETL study.

In the case of the SNG/NGCC combination, a number of calculations were required to combine the results of SNG and NGCC performance estimates. The results of the comparison are described in the text below, and the calculation details are shown in Appendix D.

6.2.3 Economic Cost / Benefit

There are several ways to compare the SNG/NGCC combination against an IGCC alternative in terms of cost components. The alternatives require different plant equipment, infrastructure and have different performance cost components with regards to emissions and fuel inputs. A discussion of these likenesses or differences follows in this section.

6.2.3.1. Plant Equipment Required

The capital cost differential between the alternatives will depend on differences in the equipment that must be installed under each alternative. Currently-proposed SNG and IGCC plants use similar gasifiers as the starting point in their processes. Sometimes referred to as "steam-oxygen gasifiers,"

these units react coal with steam and with oxygen from an air separation unit to produce a syngas consisting primarily of carbon monoxide (CO), with a smaller percentage of hydrogen (H_2). In an IGCC plant without carbon capture, this low-BTU syngas is utilized directly in the combustion turbine of a combined cycle unit. In an SNG plant and an IGCC plant with carbon capture, a portion of the CO in the syngas must be converted to H_2 by reacting it with water in a water-gas shift (WGS) reaction ($CO + H_2O \text{--->} H_2 + CO_2$). In the case of the IGCC plant, the goal is to convert as much CO to H_2 as practicable. In the case of the SNG plant, the percentage of H_2 in the syngas is increased to a ratio of 3 moles of H_2 to 1 mole of CO. The CO_2 in the gas exiting the WGS reactor is then removed and compressed for transportation to the sequestration site. Following CO_2 separation, the syngas, consisting almost entirely of H_2 in the case of the IGCC plant, is combusted in the combustion turbine of a combined cycle unit. In the SNG plant, the syngas, consisting of a mixture of CO and H_2, is reacted in a methanation reaction ($CO + 3H_2 \text{--->} CH_4 + H_2O$) to produce methane ($CH_4$) and water. The water is condensed out of the gas stream exiting the methanation reactor and the CH_4 is compressed and sent to the natural gas pipeline.

Both the gasification process and the methanation process (in the case of the SNG plant) release heat that is recovered by producing steam. In the SNG plant, the steam is utilized in a dedicated steam turbine generator. In the IGCC plant, the steam is utilized in the steam turbine of the combined cycle power block.

The power block portion of the IGCC plant is similar to the NGCC plant. As noted above, the IGCC plant will have a larger steam turbine generator to utilize steam produced in the gasification process. Since the IGCC plant will burn hydrogen rather than methane, minor modifications to the combustion turbine may be required.

6.2.3.2. Infrastructure Required

The primary advantage of the SNG/NGCC plant combination is its ability to utilize existing transportation infrastructure. While upgrades may be necessary in some cases, this combination would utilize the existing natural gas pipeline infrastructure to transport fuel from the SNG plant in Illinois to the NGCC plant in Wisconsin. The IGCC plant, on the other hand, would require the construction of a dedicated CO_2 pipeline from the plant to a sequestration site in Illinois. It may also require upgrades to the rail transportation system to deliver coal to the plant.

6.2.3.3. Performance Comparison – Fuel Use

Fuel use for each of the alternatives was compared on the basis of net heat rate. In the case of the SNG/NGCC combination, the SNG plant is a net producer of electricity, so the net electrical output of the SNG plant, as well as that of the NGCC plant, was considered in determining the effective net heat rate of the system. As detailed in Appendix D, the results are as follows:

	Heat Rate (BTU/kWh)
SNG/NGCC Combination	11,215
IGCC Alternative	10,505

The higher heat for the SNG/NGCC combination results primarily from the conversion of syngas to methane in the SNG plant. The methanation reaction is exothermic, releasing a significant amount of the chemical energy in the CO and H_2 supplied to the methanation reactor in the form of heat. While this heat is recovered as steam and used in a steam turbine generator, this is a less-efficient way to utilize the chemical energy in the syngas, compared to high temperature combustion in the IGCC plant's combustion turbine.

While the SNG/NGCC plant would require more coal to produce electricity, this disadvantage would potentially be offset by the lower price for coal used by the SNG plant. Since it is assumed that the SNG plant would be located near a coal supply source, the transportation component of the delivered cost of fuel would be lower for the SNG plant than for the IGCC plant.

6.2.3.4. Performance Comparison –Emissions

An IGCC plant will likely hold a primary advantage over the SNG/NGCC combinations when comparing emissions. As detailed in Appendix D, the total CO_2 emissions for each of the alternatives are as follows:

	CO_2 Emissions (lbs/MWh)
SNG/NGCC Combination	813
IGCC Alternative	206

While significantly higher than the IGCC, the emissions of the SNG/NGCC combination are significantly lower than the emissions from an IGCC or other coal plant without carbon capture. For example, without carbon capture, the IGCC configuration used in the comparison has a CO_2 emission rate of 1,755 lbs/MWh.

It would be possible to further reduce the CO_2 emissions for the SNG/NGCC combination by capturing CO_2 from the NGCC plant and piping it to a sequestration site. Alternatively, instead of producing SNG, the gasification plant in Illinois could produce hydrogen (similar to the IGCC plant with carbon capture), and the hydrogen could be piped to Wisconsin for use in the NGCC plant. However, either of these approaches would negate the primary advantage of the SNG/NGCC combination, which is the ability to utilize coal to generate electricity in Wisconsin with reduced CO_2 emissions, and without the need to construct a new pipeline between Wisconsin and Illinois.

6.2.4. Emerging Technology

There are a number of technologies in development that offer the potential to improve the efficiency and reduce the capital cost of producing SNG compared to the current steam-oxygen gasification process used in the above comparison. Two possibilities are described briefly as follows:

In a process called Catalytic Gasification, coal and steam in the presence of a catalyst are reacted at a relatively low temperature in a fluidized bed reactor to directly produce methane. The catalyst is separated from the ash discharged from the reactor and recycled back to the reactor. No air separation unit, WGS reactor, or methanation reactor is required. A catalytic gasification process was pilot-tested by Exxon in the 1970s. A company called GreatPoint Energy is currently attempting to commercialize a proprietary version of this technology which they call hydromethanation.

Another emerging technology reacts hydrogen and coal to directly produce methane. This process is called Hydrogasification. A portion of the methane is sent to a methane-steam reformer, which performs what is essentially the reverse of the methanation reaction described above to produce additional hydrogen to continue the process. Similar to catalytic gasification, no air separation unit, WGS reactor, or methanation reactor is required to produce SNG using this process. A German company, Rheinbraun AG, pilot-tested a hydrogasification plant in the 1970s. Arizona Public Service was recently awarded a grant by DOE to test an updated version of this technology.

6.3. Scenario 3: Capture and Store CO_2 outside Wisconsin, Transmit Electricity to Wisconsin

6.3.1. Overview

Scenario 3 places a new 1000 MW power plant in an area outside of Wisconsin that is located closer to a coal fuel supply and at or near a subsurface saline aquifer or similar sink suitable for carbon dioxide sequestration. The costs would be paid for, and benefits would be utilized by, Wisconsin electricity users. The major difference this scenario presents is that a major pipeline investment would not be necessary to transport carbon dioxide from Wisconsin, but investments would be needed in the transmission infrastructure to transmit the electricity. We are not suggesting that a “dedicated” line would connect this unit to a Wisconsin interconnection point, but rather, the unit would be connected to the transmission grid and improvements necessary to ensure deliverability would be included in the overall scenario costs. Because a specific location for the unit has not been proposed and because of the many approved and proposed improvements associated with the Midwest ISO Transmission Expansion Plan (MTEP), it is difficult to assign specific costs to transmission improvements that would be necessary. As a result of our inability to assign direct transmission costs, we have agreed that 20 percent of the overall plant costs are a reasonable assumption.

Based on the above, the primary economic benefits associated with this scenario (compared to Scenario 1) include:

- Lower delivered fuel costs;
- Economic value of CO_2 in EOR applications; and,

- New generation would increase total available generating capacity, while retrofitting carbon capture technology on existing units would lead to a derate of those units and reduce total available generating capacity.

6.3.2. Basis of Costs for Power Plant

In November 2008, EPRI issued a report as a public domain document that can be used for comparative studies of the central station generation technology options that will be widely utilized to meet future generation needs.[48] This report provides cost estimates (See Table 6.9) for eight (8) generation technologies: nuclear, supercritical pulverized coal (SCPC), circulating fluidized bed (CFB), IGCC, NGCC, wind, dedicated small biomass (biomass CFB), and solar thermal trough (Solar). In the report, the cost estimates are provided for both the near term (2015) and longer term (2025); however, only 2025 cost estimates appear in Table 6.9. The cost of the technologies were estimated on a generic (non-site specific) basis and represent an average over a range of fuel types, regions of the country, etc., and further cost adjustments would need to be performed to verify any analysis based on these numbers. Cost and performance estimates were provided for the PC and IGCC technologies with and without carbon capture in 2025. For both of these technologies, the report also provides an estimate assuming technology advancements (cost and performance enhancements) between now and 2025. This will provide a range of costs to bracket the potential cost implications of CO_2 capture with these technologies.

The EPRI report is based on a nominal unit size of 550-750 MWe which is lower than the assumed size of 1000 MW. For the purposes of this analysis, no adjustments for the improved economy of scale were assumed. As noted below, the cost basis is generalized for the country as a whole, and any adjustment for economy of scale is within the same range of the adjustments for site specific cost drivers.

Note from EPRI Report: Cost and performance estimates are idealized for representative generating units and have been normalized where possible to produce a consistent database. Estimates are not intended to apply to specific energy companies at specific sites since site-specific and company-specific conditions can vary substantially.

[48] *Program on Technology Innovation: Integrated Generation Technology Options.* EPRI, November 2008.

TABLE 6.9: Generation Options 2025

All Costs in Constant December 2007 $	**Efficiency (%)**	**Capacity Factor (%)**	**Capital Cost** (Dec. 2007 $/kW) TCR	**Levelized Cost of Electricity (LCOE)** **(2007 Constant $/MWh)**	**CO_2 Emissions (Metric Tons Per MWh)**	**Sources/Assumptions**
Supercritical Pulverized Coal (SCPC) w/ CO_2 capture	27 12,640	80	4100	98	0.124	Plant size range = about 550–750 MWe. Data represents averages for different types of coals at various regions in USA. A) 12640 – With CO_2 Capture, No cost and performance improvements
Supercritical Pulverized Coal (SCPC) w/ CO_2 capture; with cost and performance improvements	33 10,340	80	3400	83	0.10	Fuel cost = $1.8 / MMBtu. Assumed 90% CO_2 removal will require technology advances over current state of the art. B) 10340 – With CO_2 Capture, with cost and performance improvements
Integrated Gasification Combined Cycle (IGCC) w/ CO_2 capture	31 11,000	80	4000	91	0.10	All efficiencies are based on higher heating value (HHV).
Integrated Gasification Combined Cycle (IGCC) w/ CO_2 capture; with cost and performance improvements	34 10,040	80	3250	77	0.10	Based on EPRI Coal Fleet Program studies and results.
Combustion Turbine Combined Cycle (CTCC) – (Natural Gas @ $8–10/MM Btu)	54	80	820	66-–79	0.35	Plant size = about 800 MW; no CO_2 capture and sequestration. CTCC unit based on GE 7H machine or equivalent by other vendors. Capacity factor represents technology capability. Data represents averages for various regions in USA. All efficiencies are higher heating value (HHV).
Nuclear- Economically Simplified Boiling Water Reactor (ESBWR)	33	90	3380	64	None	Plant size = 1500 MW Nuclear fuel cost: $0.80/MMBtu EPRI TAG® sensitivity studies of all-in costs. Values shown are averages of high and low ends of data range. Data represents averages for various regions in USA.
Wind	N/A	42	1995	71	None	Plant size = 100 MW Based on COE corresponding to 42% capacity factor, consistent with anticipated fleet average. Data represents averages for various regions in USA.
Biomass CFB	28	85	3235	73	0.10	Plant size = 75 MW Assumes 16% improvement in cost associated with lower fuel cost. Net emissions of 0.1 metric tons per MWh are assumed to result from incomplete closure of fuel cycle. Data represents averages for various regions in USA. Efficiency is based on higher heating value (HHV).

The remainder of the analysis for this scenario is based on an assumed 1,000 MW SCPC power plant with CO_2 capture. Operating at an 85% capacity factor, this hypothetical power plant would generate 7,446,000 MWh of electricity per year.

Capital Costs:	1,000 MW * $4,100/kW = $4.1 billion 1,000 MW * $3,400/kW = $3.4 billion with cost improvements
CO_2 Produced:	9,788,214 tons/yr 8,007,131 tons/yr with performance improvements
CO_2 Captured:	8,772,579 tons/yr 7,188,071 tons/yr with performance improvements
CO_2 Emitted:	1,015,634 tons/yr 819,060 tons/yr with performance improvements

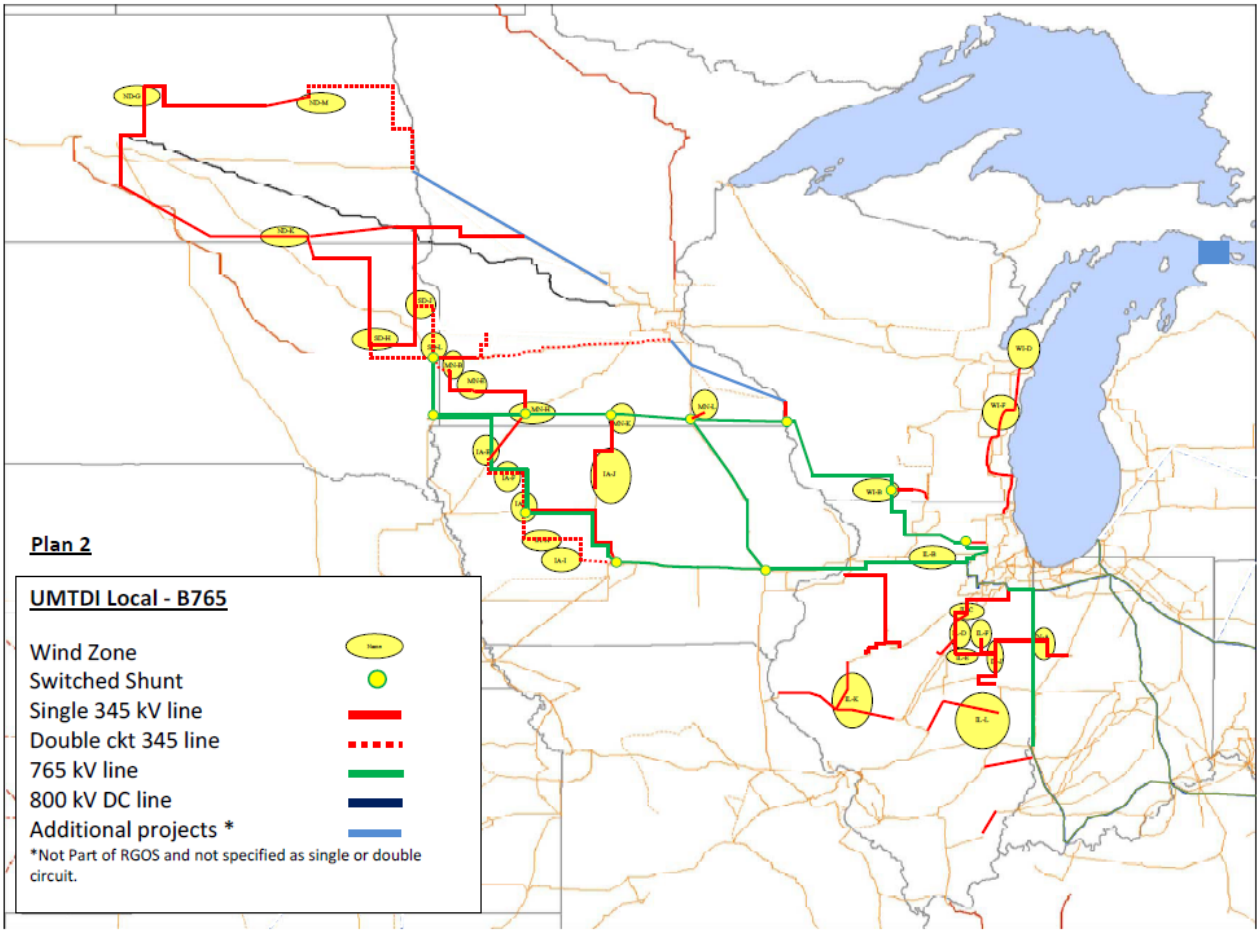
6.3.3. Basis for Assumed Power Plant Location

This scenario assumes that a power plant serving Wisconsin's needs will have to be built within or near the MISO footprint in a location suitable for integration to the regional transmission grid. In addition, this scenario assumes that the best location for the selected power plant will be a location in reasonable proximity to coal supplies and geologic sequestration opportunities that are not available in Wisconsin.

6.3.3.1. MISO Footprint for Generation Site

For the purposes of this analysis, the assumption is that the power plant would be sited in, or near, the MISO footprint. Although there is uncertainty on what the future transmission improvements will be in MISO to address the movement of wind energy, it is illustrative to review options that have been proposed thus far in the planning process and how that relates to potential areas for CO_2 sequestration. In a recent planning update, MISO provided an illustrative map of potential transmission upgrades based on the potential location of wind energy farms. The map provided as Figure 6.1 illustrates the most western wind farm developments and the extension of the transmission system to those areas. As can be seen in this figure, the transmission system may extend into North and South Dakota to capture potential wind generation from that region. This creates the opportunity for a new power plant to be sited closer to sequestration sites in North Dakota, South Dakota, Montana, and Wyoming.

FIGURE 6.1: MISO Planning Map[49]

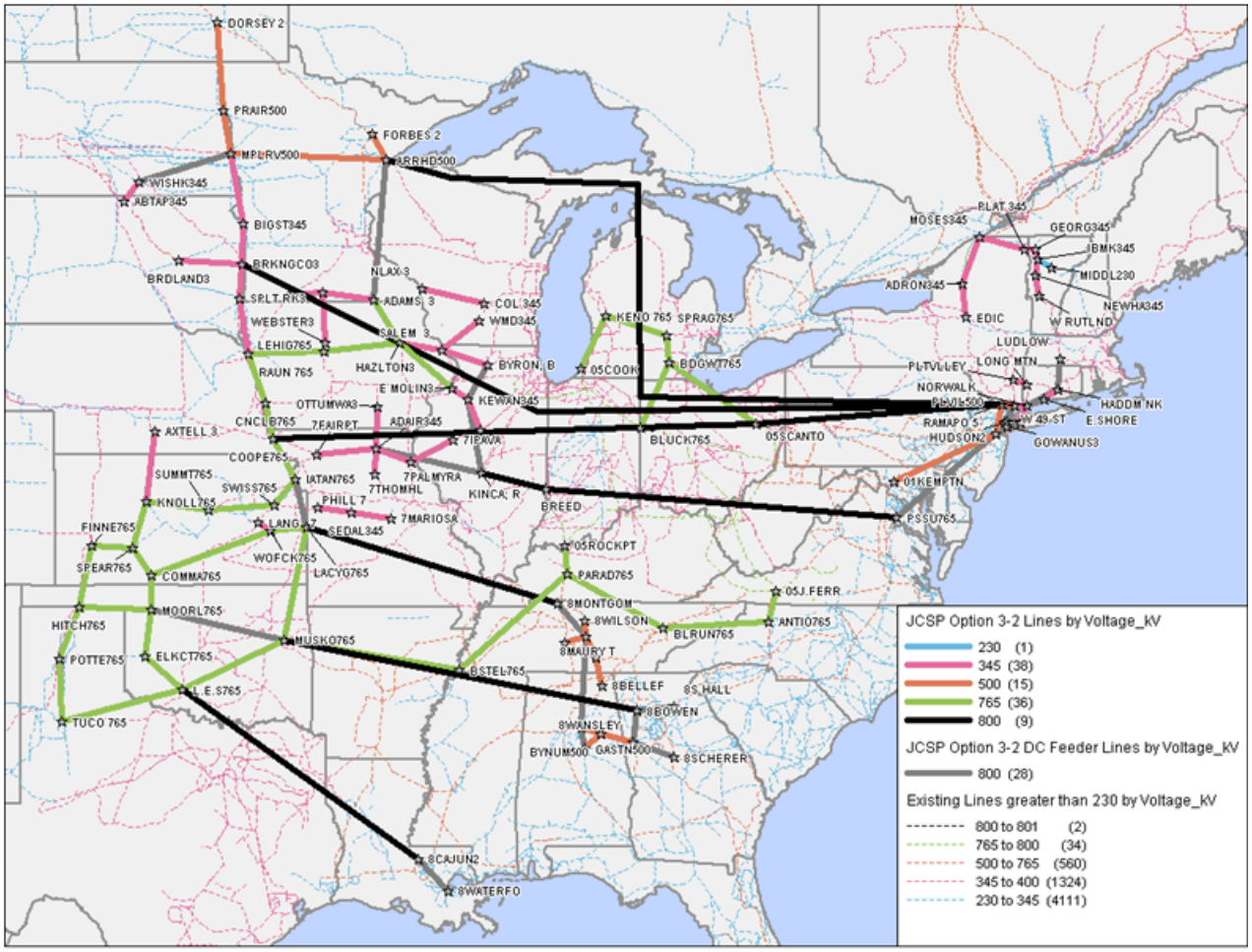


Another perspective on the scope of the transmission system extension to the west can be seen in Figure 6.2. This illustrative map is an outgrowth of the planning efforts being coordinated by DOE with independent system operators to study the impact of a higher wind energy component to the nation's energy supply and is referred to as the Joint Coordinated System Plan (JCSP).[50] As projected in this figure, the transmission system would extend to Kansas and Oklahoma which could provide an opportunity for siting a new power plant near EOR opportunities for sequestration in those states.

[49] Refer to *Regional Generation Outlet Study, Phase I Executive Summary Report*, December 2009. Available at http://www.midwestmarket.org/publish/Document/13b9ea_1265d1d192a_-7c300a48324a?rev=1. The map used here for illustrative purposes shows just one of several scenarios analyzed in the study.

[50] Map is part of the JCSP effort. Source: Joint Coordinated System Plan and Regional Generation Outlet Study Overview, Feb. 2009. MISO. Available online at: http://www.misostates.org/Carp2MoellerJCSPRGOSUpdate.pdf.

FIGURE 6.2: Joint Coordinated System Plan (JCSP) System Overlay (Conceptual): 20% Wind Energy Scenario



Source: Original map from Joint Coordinated System Plan '08. *Joint Coordinated System Plan '08*. Retrieved May 3, 2010, from http://www.jcspstudy.org

6.3.3.2. Geological Sequestration Opportunities

The DOE National Energy Technology Lab has produced a summary of the geological opportunities for CO_2 sequestration, referred to as ATLAS II.[51] In that document, the areas of the country that have opportunities for geological sequestration have been identified with many of the better opportunities validated through follow-up studies. The DOE report summarizes the opportunities as:

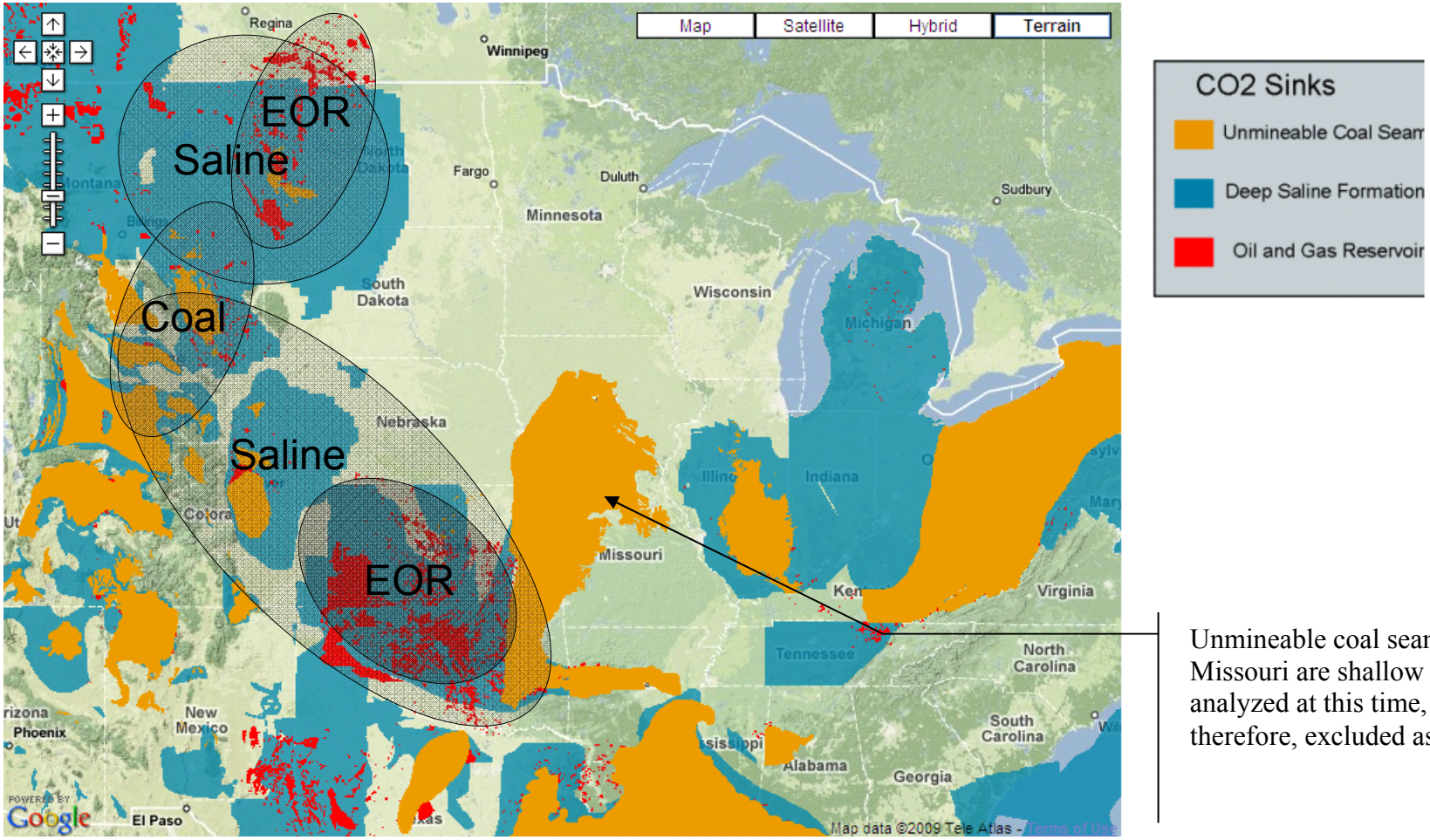
1. Enhanced Oil Recovery;
2. Coal Bed Methane;
3. Saline Aquifers;
4. Unmineable Coal Seams (methane recovery opportunity is limited); and,
5. Shale formations.

[51] *Carbon Sequestration Atlas of the United States and Canada*. DOE / NETL 2008.

This report is not intended to be a complete analysis of the opportunity, but to illustrate where the opportunities may exist.

Along those lines, the areas in and near the MISO footprint where CO_2 sequestration opportunities exist are shown in Figure 6.3. Identified on the map are the general areas where CO_2 sequestration opportunities exist in the form of EOR, coal bed methane recovery, saline aquifers and unmineable coal seams.

FIGURE 6.3: Target CO_2 Sequestration Areas



Unmineable coal seams in Iowa and Missouri are shallow and not fully analyzed at this time, and are, therefore, excluded as target areas.

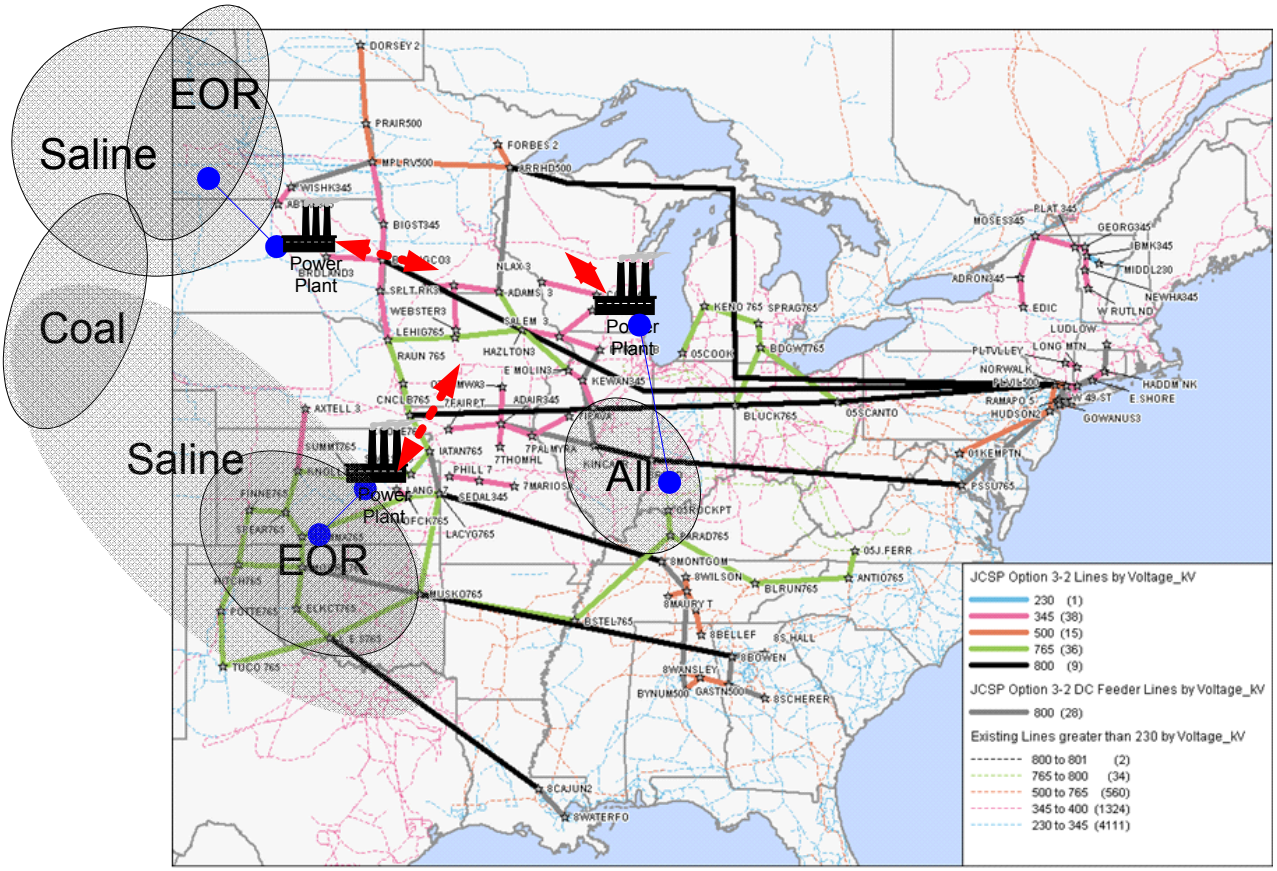
Source: "Natcarb Sinks Map - Atlas 2008." *NETL: NatCarb.* Web. 3 May 2010. http://geoportal.kgs.ku.edu/natcarb.

Disclaimer: This map was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference therein to any specific sites, or service by trade name, trademark, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions expressed therein do not necessarily state or reflect those of the United States Government or any agency thereof.

6.3.3.3. Composite of Sequestration and Transmission Upgrades

In Figure 6.4, the potential areas for CO_2 sequestration are superimposed onto the transmission planning map associated with the JCSP study. If the power plant was sited on the farthest western edge of the expanded transmission system that location would still require some pipeline installation to move the CO_2 to the sequestration site. For the purposes of this analysis, it was also assumed that some transmission upgrades would be necessary to fully integrate the plant into the MISO grid. Based on this compromise location, there would be a need for the installation of some CO_2 pipeline infrastructure and some transmission upgrades to connect to the grid. Other factors would need to be included in a comprehensive power plant siting effort including water supply, railroad infrastructure, etc., and are beyond the scope of this study.

FIGURE 6.4: Overlay: Geological Sequestration Locations and Transmission Expansion



Source: Original map from Joint Coordinated System Plan '08. *Joint Coordinated System Plan '08*. Retrieved May 3, 2010, from http://www.jcspstudy.org/. Superimposed carbon sinks from "Natcarb Sinks Map - Atlas 2008." *NETL: NatCarb.*

A more detailed siting effort may result in a shift of where the power plant site would be located that would either increase the pipeline distance and reduce the transmission upgrade, or the reverse. As such, there would be cost changes that would partially or completely offset the change in location.

By choosing a western location, the power plant will be closer to the Wyoming Powder River Basin (PRB) with a subsequent reduction in the cost of fuel. Another economically important attribute of a western location is that it could be located in reasonable proximity to large oil and gas fields that are amenable to the use of huge volumes of CO_2 for EOR. The presumption for this option is that EOR may make sense for early adopters of CO_2 capture technologies (pioneer plants), and that it may dramatically help the economics of such projects. A plant located in Illinois would have access to Illinois Basin coal that might similarly reduce fuel costs, but this location might have substantially less potential for EOR. For example, the previously mentioned DOE Atlas II document estimates that Illinois has less than one-sixth the CO_2 storage potential of Wyoming in oil and gas reservoirs.

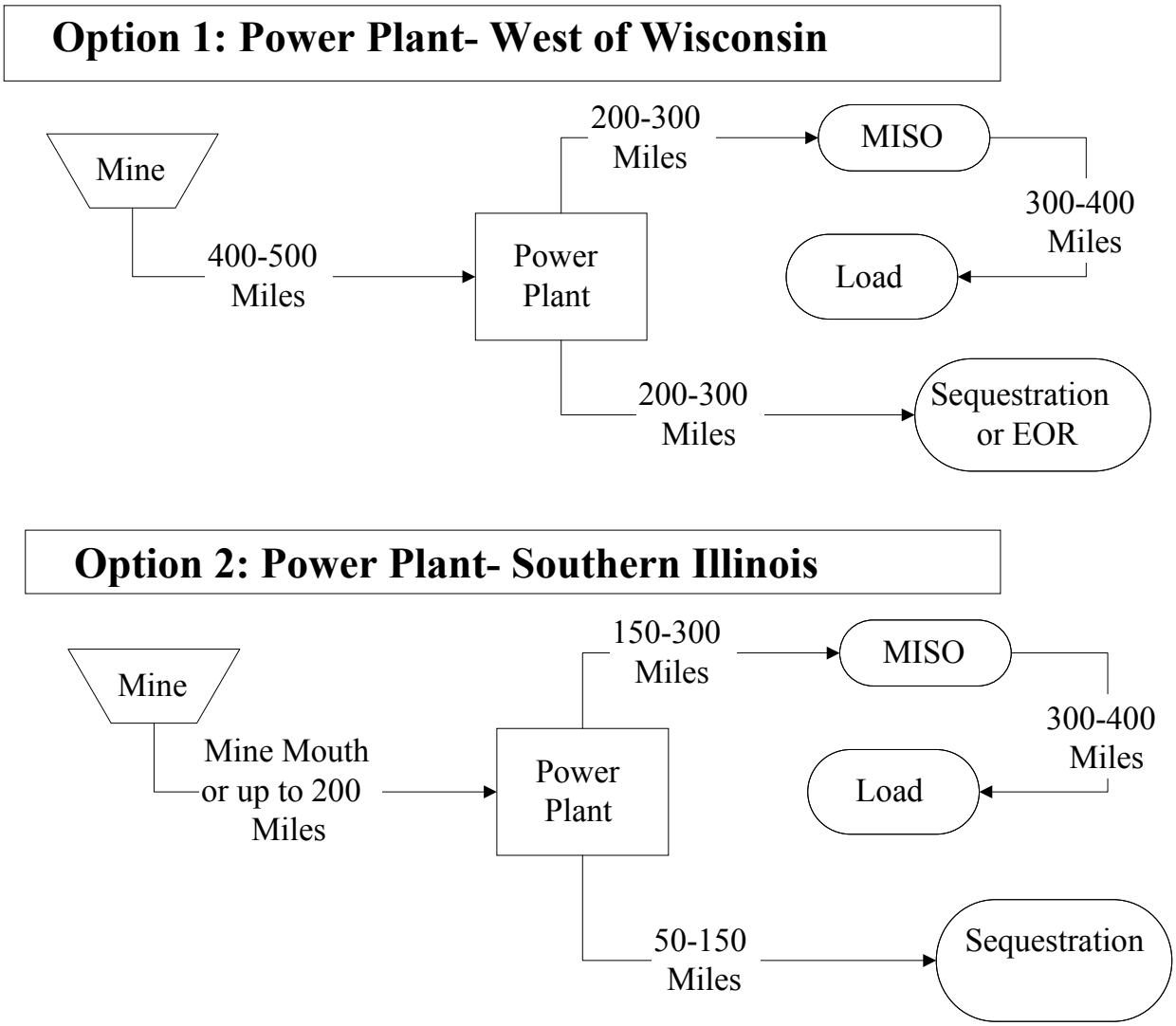
To simplify the remainder of the analysis, the following high-level assumptions were made:

1. MISO will complete a build out of the transmission system, mostly to the west and primarily to incorporate more wind energy facilities. In general, this expanded Midwestern grid would also have sufficient capacity to accommodate a new baseload power plant with CCS. However, a new *western* power plant would still require 200 to 300 miles of incremental transmission to interconnect to that grid while a *southern Illinois* power plant would require 150 to 300 miles of incremental transmission to interconnect.
2. Siting compromises on a western power plant (water, rail, and transmission) would necessitate that an EOR sequestration site would be remote from the power plant (but assumed to be within 200 to 300 miles), whereas a southern Illinois plant would be 50-150 miles from a non-EOR sequestration site.
3. The western site location would require the transportation of coal 400 to 500 miles, while the Illinois location would be within 200 miles of the coal mine.
4. Transmission congestion charges were beyond the scope of this analysis and were not included.

The key differences between the two options are shown in the schematic (Figure 6.5), and can be summarized as:

- Differences in delivered fuel cost (based on coal source and rail miles);
- Differences in transmission cost (based on line miles); and,
- Differences in CO_2 transport cost (based on pipeline miles and EOR options).

FIGURE 6.5: Schematic of Differences between Option 1 and Option 2



6.3.4. Basis of Analysis

The remaining analysis is based on the key differences between Options 1 and 2, i.e. a new power plant "out west" versus one sited in Illinois. This high level analysis is based on simplifying assumptions about the key cost differentials which are:

1. Fuel Cost (Transportation) (annual);
2. Transmission (capital);
3. CO_2 Pipeline (annual); and,
4. Enhanced Oil Recovery (annual).

6.3.4.1. Fuel Costs

The economic analysis of fuel costs in Table 6.10 assumes that Option 1 (a power plant west of Wisconsin) will burn PRB coal and Option 2 (a power plant in southern Illinois) will burn Illinois Basin coal.

TABLE 6.10: Fuel Costs Differential Analysis

	Option A - Western Site	**Option B - Illinois Site**
Capacity (MW)	1,000	1,000
Capacity Factor	85%	85%
Electricity Generated (kWh/yr)	7,446,000,000	7,446,000,000
Average Heat Rate (Btu/kWh)[52]	11,490	11,490
Delivered Cost of Coal ($/MMBtu)[53]	$1.02	$1.69
Annual Fuel Cost ($/yr)[54]	$87,498,961	$145,007,695
Present Value, 30 years at 9.0%	$898,934,058	$1,489,758,891

6.3.4.2. Transmission Costs

Because of the uncertainty associated with the location of the power plants relative to existing transmission infrastructure, this analysis estimates that the transmission upgrades will be equal to 20% of the assumed capital costs of the generating facility for either site location option.

Transmission Costs: 0.20 * $4.1 billion = $820,000,000 high-end estimate
0.20 * $3.4 billion = $680,000,000 low-end estimate

[52] Average of two possible heat rate values cited in the EPRI report for an advanced SCPC power plant with carbon capture.
[53] Based on average weekly coal commodity spot prices in October and November 2009. Illinois site is assumed to be a mine mouth power plant with no rail costs.
[54] Annual Fuel Cost = Electricity Generated (kWh/yr) * Heat Rate (Btu/kWh) * Delivered Cost of Coal ($/MMBtu) * (1 MMBtu/1,000,000 Btu).

The validity of this estimate can be checked by comparing it to a value based on the JCSP assumption of $4,000,000 per mile for 200 miles of incremental transmission, i.e. a value of $800,000,000. The 20% estimate appears to be reasonable.

6.3.4.3. Pipeline Costs

This analysis will assume the need to construct a dedicated 250 mile CO_2 pipeline for Option 1 and a 100 mile pipeline for Option 2. The estimates for construction costs will use the same assumptions that were used in Scenario 1.

As described in Scenario 1, two 20" diameter parallel pipelines would have adequate capacity to transport 30 million tons of CO_2 per year. Since we have already demonstrated that the hypothetical power plant for Scenario 3 would capture less than 10 million tons of CO_2 per year, this analysis will assume that a single 20" diameter pipeline would be adequate.

Option 1: 250 miles, requiring 3 booster pump stations

Pipeline construction = $820,000/mile * 250 miles = $205,000,000
Pump station construction = 3 stations * 6,000 HP/station * $1000/HP = $18,000,000
Carrying costs = 0.15 * capital = 0.15 * $223,000,000 = $33,450,000/year
Pipeline O&M = $667/inch diameter/mile/year * 20" * 250 miles = $3,335,000/year
Pump station O&M = $50/HP/year * 18,000 HP = $900,000/year
Pump station power = $360/HP/year * 18,000 HP = $6,480,000/year
Annual cost = $33,450,000 + $3,335,000 + $900,000 + $6,480,000 = $44,165,000

Option 2: 100 miles, requiring 1 booster pump station

Pipeline construction = $820,000/mile * 100 miles = $82,000,000
Pump station construction = 1 station* 6,000 HP/station * $1,000/HP = $6,000,000
Carrying costs = 0.15 * capital = 0.15 * $88,000,000 = $13,200,000
Pipeline O&M = $667/inch diameter/mile/year * 20" * 100 miles = $1,334,000/year
Pump station O&M = $50/HP/year * 6,000 HP = $300,000/year
Pump station power = $360/HP/year * 6,000 HP = $2,160,000/year
Annual cost = $13,200,000 + $1,334,000 + $300,000 + $2,160,000 = $16,994,000

This analysis does not account for the potential for considerably lower construction costs in the more rural areas of the western states and fewer land owners to deal with on ROW issues, compared to the assumptions used in Scenario 1.

6.3.4.4. Estimation of the EOR Value of the CO_2 (Option 1 only)

This analysis assumes that the pipeline built under Option 1 will transport captured CO_2 to an EOR site, while the pipeline built for Option 2 transports CO_2 to an unmineable coal seam or saline aquifer. Without question, it would be technically feasible to construct a CO_2 pipeline from southern Illinois to an EOR site, but this analysis assumes otherwise in part to demonstrate how the EOR value of CO_2 dramatically changes the value proposition for CO_2 capture.

Several DOE studies have been performed to estimate the opportunity for the use of CO_2 in EOR applications. Some of these studies discuss the value of CO_2 in current EOR applications in the lower 48 states. The key drivers in establishing the amount paid for the CO_2 from the oil developer's perspective are the future value of a barrel of oil and the rate of recovery of oil per unit of CO_2 injected. Five to ten years ago, a common industry number for the long term future price of oil was $25 per barrel. Obviously, that industry perspective has changed over the last few years, but there is still very significant uncertainty. The amount of oil recovered per unit of CO_2 injected is also very uncertain, especially where little or no actual field experience has been obtained.

Values of $0.65 to $1.20 per MCF of CO_2 were noted as a common range for current CO_2 EOR applications.[55] For this analysis a value of around $0.65 was used which equated CO_2 per MCF to 2.25% of the value at $30 per barrel of oil.[56] A higher value would be justified if the recovery of oil rate is expected to be higher or is fairly certain based on experience, a higher future value of oil is assumed, or government incentives are provided to extract the oil.

The other major factor influencing the value of the CO_2 injected is the rate of oil recovery. Industry values between 4 and 10 MCF were noted in one reference, and a broader range of 2 to 12 MCF was noted in another. For this analysis a value of 6 MCF of CO_2 per barrel of oil recovered was assumed.

The estimate of the present value is provided in Table 6.11 utilizing these assumed values.

[55] DOE-Office of Fossil Energy "*Undeveloped Domestic Oil Resources*: *The Foundation for Increasing Oil Production and a Viable Domestic Oil Industry", February 2006.*
U.S. Department of Energy/Office of Fossil Energy Project Facts: "Recovering "Stranded Oil" Can Substantially Add to U.S. Oil Supplies, Six Reports Examine Basin-Oriented Strategies For Increasing Domestic Oil Production".
[56] As noted, oil prices are volatile. In this scenario as in the previous two scenarios, the calculations are based on assumptions that the Study Group considered reasonable at the time the calculations were made. All calculations in this report are provided for illustrative purposes only, and cannot be viewed as predictive of revenues or costs for actual future projects.

TABLE 6.11: Value of CO_2 in EOR Applications

Economic Value of Enhanced Oil Recovery		
Basis: Oil Recovery Rate of 1 Barrel per 6 MCF of CO_2		
Assumed value of oil: $30		
CO_2 Captured	7,980,325	tons per year
CO_2 Captured	137,261,589	MCF per year
Oil Recovery Rate	6	MCF CO_2 per barrel of oil
Oil Recovery	22,876,932	barrels of oil
Oil Value	30	$ / barrel
CO_2 value per MCF	2.25%	of value of oil
Annual EOR Revenue	$92,651,573	$ per year
Present Value	$951,870,205	30 years at 9% risk adjustment
Present Value	$950,000,000	rounded
	$11.61	$ per ton of CO_2
	$0.68	per MCF of CO_2
	9%	PV factor
	30	years

Notes:

- 17.2 MCF per ton of CO_2.
- Range of values for oil recovery is between 4 and 10 MCF per barrel of oil.
- Range of values for CO_2 costs is driven by acquisition cost balanced by project risk. A range of values between $0.65 and $1.20 has been reported.
- Assumes selection of a sequestration site capable of producing the full amount of oil specified in the table.

6.3.5. Total Costs

The costs of each option are summarized in Table 6.12. The figures for power plant construction and transmission are an average of the high and low values previously cited.

TABLE 6.12: Total Costs

Option	Construction		Total
	Power Plant	Transmission	
A	$3,750,000,000	$750,000,000	$4,500,000,000
B	$3,750,000,000	$750,000,000	$4,500,000,000

Option	Annual Operation			Total
	Fuel	Pipeline	EOR Value	
A	$87,500,000	$44,165,000	($92,651,573)	$39,013,427
B	$145,000,000	$16,994,000	0	$161,994,000

7. NEXT STEPS: CCS POLICY CONSIDERATIONS

In exploring or pursuing any CCS opportunities outlined in this report or otherwise, it will be important for policymakers to identify policy options to assist the development and implementation of those opportunities. Among the policy options to consider when investigating CCS opportunities are legislative and regulatory options that facilitate the process for getting CCS projects approved and constructed. The IGCC report that was published by WDNR and PSCW in February 2007 contained a range of policy options that could potentially be implemented in Wisconsin to promote that specific pre-combustion CCS technology. Some of those policy options have already been fully or partially implemented, while others have not. The CCS Study Group did not explicitly revisit or revise those recommendations. Although that report is now more than three years old and the issues are rapidly evolving, there may be merit in implementing more of the policy options contained in that report.

Considering not just IGCC but all of the CCS technologies more broadly, in order to realize their full potential we need to consider both technology policy and regulatory policy. Technology policies will drive the research, development, and demonstration of CCS. Regulatory policies will shape the deployment of the technology. Wisconsin could and should have a role, albeit a limited role focused on collaboration with other governments, in both areas of policy development.

Financial incentives are the most important technology policy instruments to support research, development, and demonstration of CCS. For example, the post-combustion carbon capture demonstration at We Energies' Pleasant Prairie Power Plant in southeast Wisconsin was funded in part by a grant from DOE. In 2009, DOE awarded $3.4 billion in additional, new financial support for CCS research, development, and demonstration. Wisconsin can recognize the potential long-term benefits to the state of CCS demonstration projects in other states and support continued federal funding of those projects.

The most challenging legal and regulatory issues associated with CCS concern long-term geologic storage. Because Wisconsin does not have any known geologic formations that might be suitable for long-term storage of CO_2, it makes no sense for Wisconsin to be in the forefront in resolving those legal and regulatory issues. This does not mean that Wisconsin will have or should have no role, because we recognize that Wisconsin sources of CO_2 could someday be directly or indirectly affected by how the legal issues are resolved in other jurisdictions.

Considering the secondary role that Wisconsin is likely to have in terms of either technology or regulatory policy, a prudent approach toward "next steps" might be for the State to continue its collaboration with the federal government and especially with other states, carefully choosing when and how to be involved in order to protect our long-term interests.

Under the auspices of the Regional Carbon Sequestration Partnerships established by DOE, Wisconsin currently is a member of the Plains CO_2 Reduction Partnership (PCOR).[57] Wisconsin is the eastern-most state in PCOR, and the options for geologic storage of CO_2 within the PCOR territory are all in the western states. So one of the options the state could consider is whether to pursue membership in the Midwest Geological Sequestration Consortium (MGSC) in addition to PCOR membership. This was one of the policy options presented in the 2007 IGCC report published by PSCW and WDNR, and it is still relevant today. The MGSC territory covers Illinois and parts of Indiana and Kentucky. As we have seen in Scenario 1 of this report, Wisconsin sources may someday be piping CO_2 to those states for geologic storage. Given that possibility, it may be prudent to partner with those states as they demonstrate technologies and develop policies.

Finally, the Midwestern Governors Association (MGA) has adopted a resolution that would commit the member states to working together on a phased approach toward commercial deployment of CCS, with the first phase focused on states that have geologic storage potential and better access to existing and proposed CO_2 pipelines, and the second phase focusing on the remaining states (including Wisconsin) after 2020. The MGA resolution would also establish a regional CCS task force, in which Wisconsin officials would participate. The MGA task force could provide another excellent vehicle for Wisconsin to engage in the policy debate in collaboration with some of the states that will be on the leading edge.

[57] The Plains CO_2 Reduction (PCOR) Partnership, Wisconsin Carbon Sequestration Briefing, July 11, 2008.

APPENDIX A: WISCONSIN CARBON SEQUESTRATION STUDY GROUP MEMBERS

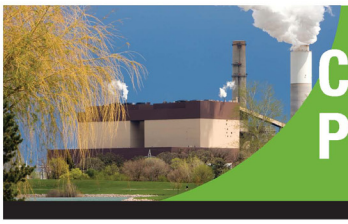
Organization	Member
Public Service Commission of WI (PSCW)	Mark Meyer, Chair Commissioner
PSCW	Chela O'Connor, Coordinator Executive Assistant to Commissioner Meyer
PSCW	John Shenot Policy Advisor
Wisconsin Department of Natural Resources (WDNR)	Al Shea Deputy Secretary
Clean Wisconsin	Pete Taglia Staff Scientist
Dairyland	Don Huff Director of Environmental Services
Energy Center of Wisconsin	Steve Kihm Senior Project Manager – Research
Chicago Council on Global Affairs	Steve Brick Senior Fellow on Energy and Climate
MEUW	David Benforado Executive Director

Organization	Member
MGE	Scott Neitzel VP- Energy Supply
University of Wisconsin	Alan Carroll Professor, Dept. of Geology and Geophysics
Utility Workers Coalition	Steve McFarlane Chair (and President of Operating Engineers Local 310)
WEPCO	Kris McKinney Manager of Environmental Policy
WIEG	Todd Stuart Executive Director
WPL	Scott Smith Director of Regulatory Affairs
WPPI	Andy Kellen Assistant VP – Power Supply Resources
WPSC	Jay Van Campenhout Project Director – Environmental Retrofits
Xcel	David Donovan Manager of Regulatory Policy

Additional PSCW Staff Support was provided by:

- Scot Cullen
- Dennis Koepke
- Mike Newmark
- Lisa Stefanik

APPENDIX B: FACT SHEETS ON PLEASANT PRAIRIE



Carbon Capture Process

ALSTOM
we energies
EPRI ELECTRIC POWER RESEARCH INSTITUTE

Commitment to Technology

The Pleasant Prairie Power Plant, located in the village of Pleasant Prairie in southeast Wisconsin, is hosting a demonstration project of new chilled ammonia technology that aims to achieve a highly efficient capture rate of carbon dioxide (CO_2) emissions from a coal-fueled generating facility.

Partners

- Alstom Power Inc., a leading power equipment supplier in the world, technology developer and operator
- Electric Power Research Institute (EPRI), the project supporter and research arm of the electric power industry
- We Energies, the carbon capture project host

Project Summary

Using less than one percent of the flue gas from one boiler unit, Alstom Power Inc. will operate the carbon capture technology with a patented process invented by Eli Gal, an individual who licensed Alstom Power Inc. as the exclusive, worldwide licensee.

- The project is the first-of-its-kind in the United States.
- This process will have high efficiency CO_2 capture.

Timeline

The construction of the carbon capture facility is complete. The project will be operated by Alstom for about one year. During this time, EPRI will conduct an extensive test program to collect data and evaluate technology performance. Results of the demonstration project are anticipated to be published mid-2009.

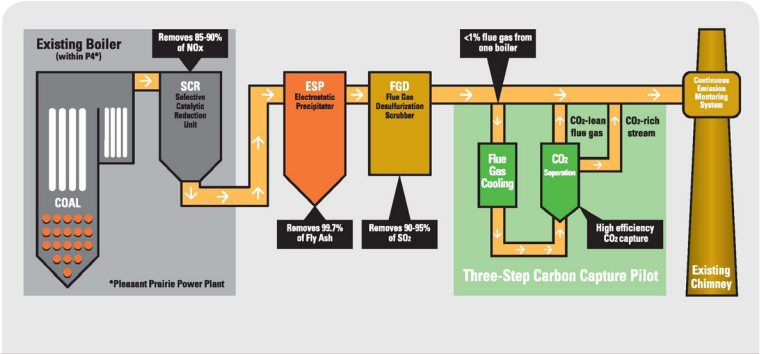
Carbon Capture Process

The carbon capture technology is a three-step process. It begins with the cooling and conditioning of the flue gas from the boiler and existing air quality control system. The flue gas then proceeds to the CO_2 absorber where the carbon dioxide is absorbed through contact with an ammonium carbonate solution. The solution containing the absorbed CO_2 is then pumped to a regeneration system. As this solution is heated under pressure, the absorption process is reversed and pure CO_2 is recovered. The solution with CO_2 removed is recycled back to the CO_2 absorber while the pure CO_2 from the regenerator is further compressed for eventual disposal underground.

Anticipated Project Outcomes

The use of this new technology has the potential to dramatically reduce the cost of removing CO_2 from pulverized coal (PC) power plants.

Note: Almost all current analyses show a PC plant with carbon capture sequestration (CCS) is less expensive than an integrated gasification combined cycle (IGCC) plant with CCS.



Source: Appendix B fact sheets provided for this report courtesy of We Energies.

APPENDIX B: FACT SHEETS ON PLEASANT PRAIRIE (CONTINUED)

CHILLED AMMONIA POST-COMBUSTION

We Energies Pleasant Prairie Field Pilot

The Chilled Ammonia CO2 capture pilot at the We Energies power plant in Pleasant Prairie, Wisconsin, USA, went into operation in July 2008. The pilot, designed to capture 15 000 metric tonnes of CO2 per year, has already logged more than 4 000 hours of operation, and is currently in 24 x 7 operations. It is on target to achieve all objectives, including 90% capture of CO2 in continuous operation at full load.

Alstom is responsible for the construction, operation and maintenance of the carbon capture facility. The key objective of this project is to demonstrate full system operation on actual flue gas and prove the design concept feasibility, in support of larger scale demonstrations.

The results obtained from this pilot have already resulted in several improvements to the process. Parametric and long-term testing will continue throughout 2009 and approval has been obtained to extend the pilot testing until March 2010. The Electric Power Research Institute (EPRI), supported by a collaboration of 37 US and international utilities, participates in the project.

At a glance

Location:
Pleasant Prairie, Wisconsin, USA

Customer:
We Energies

Process:
PC boiler combusting low sulphur sub-bituminous coal

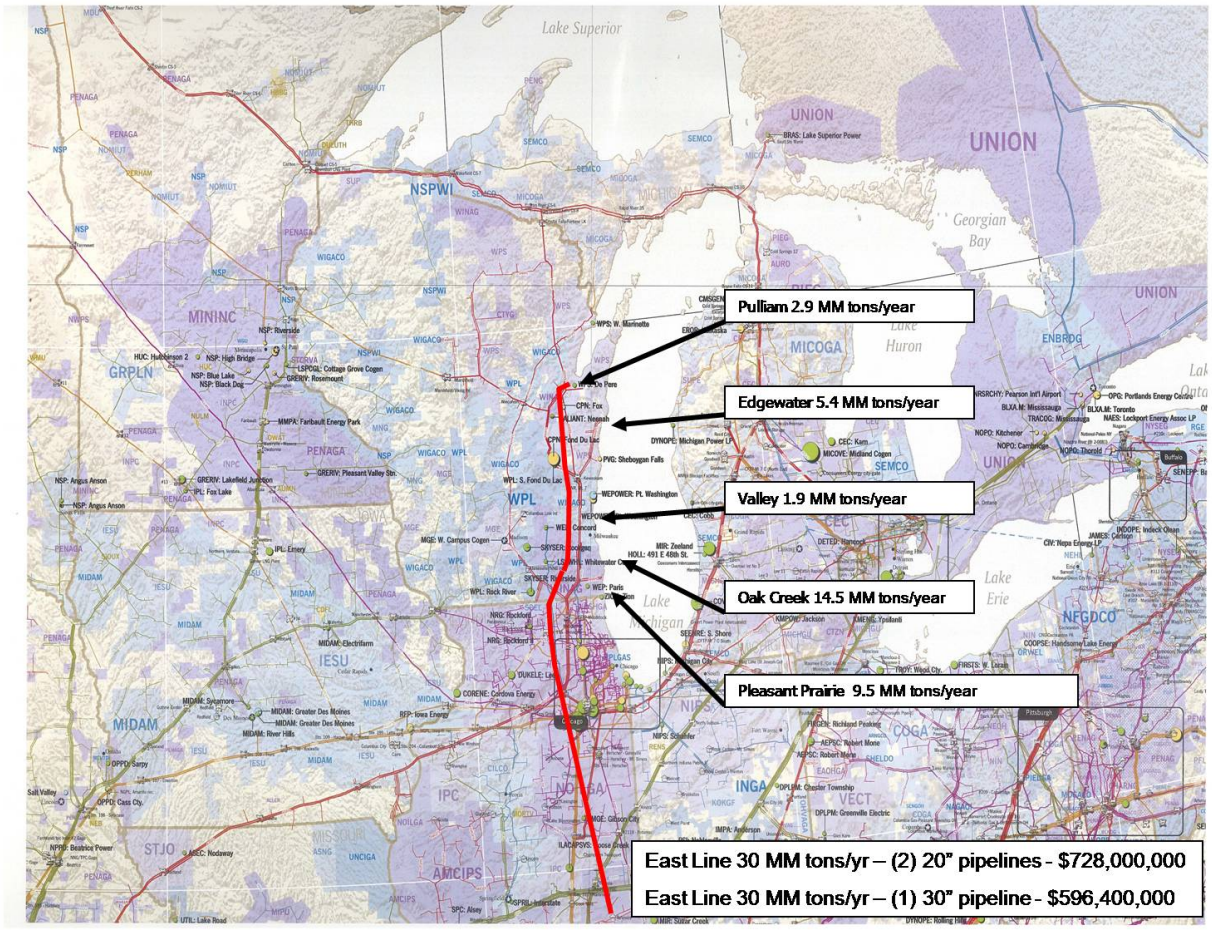
Capture Technology:
Chilled Ammonia Post-Combustion

CO2 Capture Capacity:
15,000 metric tonnes per year

Commissioning:
July 2008

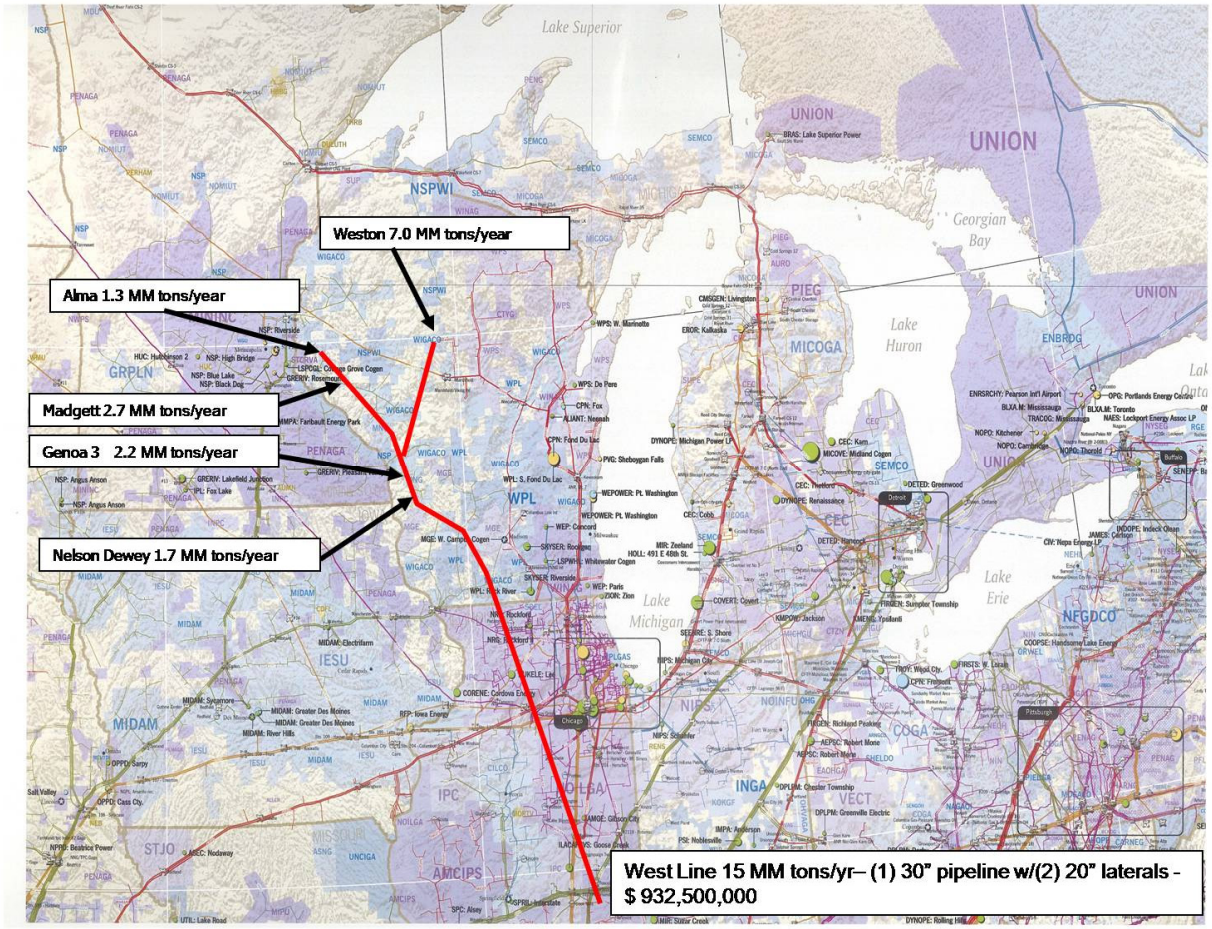
APPENDIX C: ADDITIONAL INFORMATION FOR SCENARIO 1

Maps in this appendix depict potential East, West and South main pipeline routes from sites in Wisconsin to surrounding states.



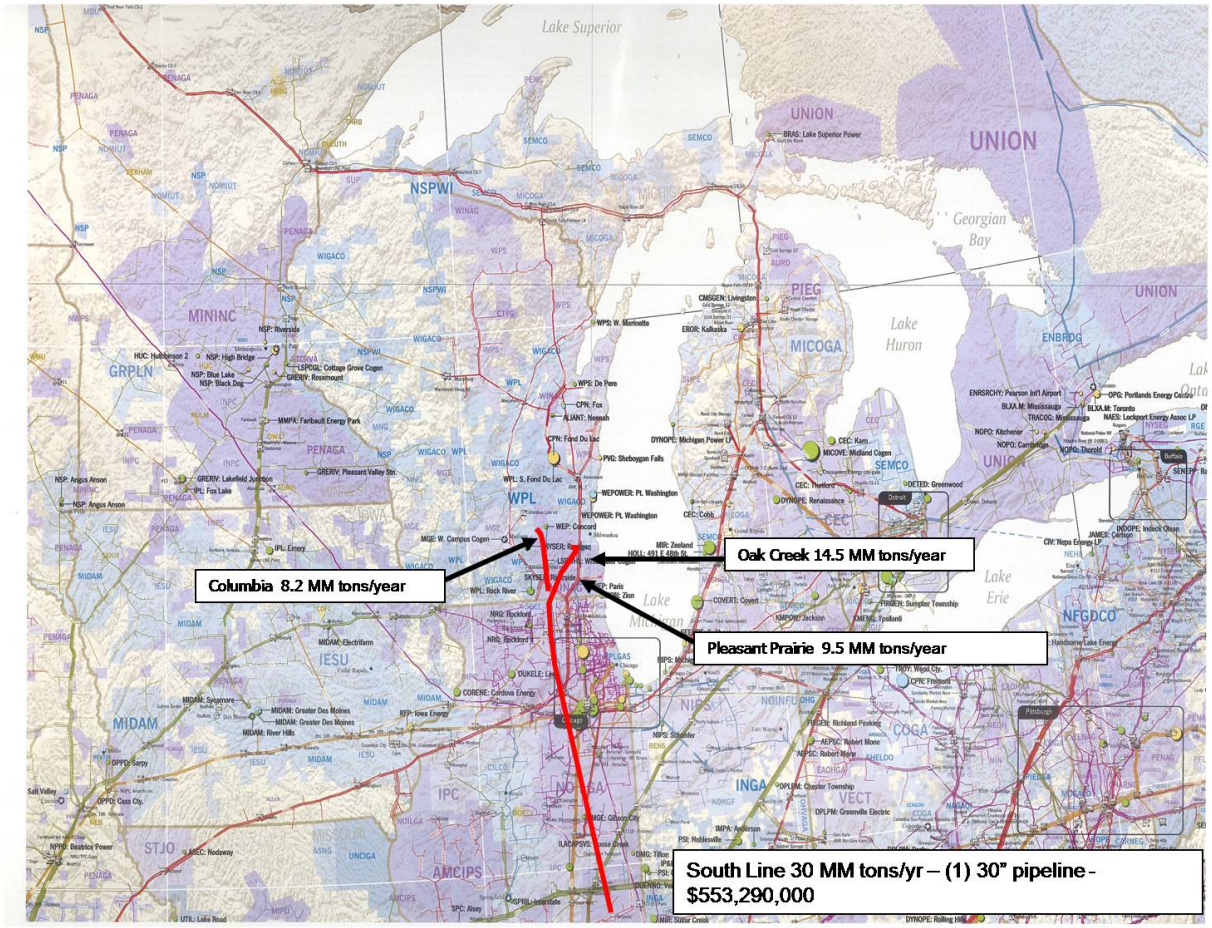
Source: Platts North American Natural Gas System Map

APPENDIX C: ADDITIONAL INFORMATION FOR SCENARIO 1 (Continued)



Source: Platts North American Natural Gas System Map

APPENDIX C: ADDITIONAL INFORMATION FOR SCENARIO 1 (Continued)



Source: Platts North American Natural Gas System Map

APPENDIX D: ADDITIONAL INFORMATION FOR SCENARIO 2

Scenario 2: Capture and Store CO2 Outside Wisconsin; Transport SNG to Wisconsin
Cost and Performance Evaluation
Calculation Appendix

CALCULATION FOR COAL AND GAS PLANTS

Data From NETL Report (Reference 1)

NETL Case Number	Technology	Type	CO2 Capture?	Net Output (MW)	Heat Rate (BTU/kWh)	CO_2 Emissions (lb/MWh)	Source of Data in Reference (1)
2	IGCC	GE	Yes	556	10,505	206	Exhibits 3-34 (p. 130), 3-35 (p. 131), 3-38 (p. 133)
13	NGCC		No	560	6,719	797	Exhibits 5-7 (p. 445), 5-8 (p. 446), 5-9 (p. 447)

CALCULATION FOR SNG / NGCC COMBINATION

Values from Kentucky Report (Reference 2)

Table 19, Case 2 (p. 44)	
Gas Produced (MMBtu/day)	71,736
Coal Used (MMBtu/day)	121,885
Net Power Produced (MW)	8
CO2 Released (tons/day)	165

Calculated Values for SNG Production

Values per MMBtu of Gas Production	
Gas Produced (MMBtu)	1.00
Coal Used (MMBtu)	1.70
Net Power Produced (MWh)	0.0027
CO2 Released (lbs)	4.60

APPENDIX D: ADDITIONAL INFORMATION FOR SCENARIO 2 (Continued)

Calculated Values for Combined SNG Production and NGCC Generation

	Hourly Performance									Total (SNG + NGCC) Performance	
	NGCC			SNG			SNG + NGCC				
	Generation (MWh)	Fuel Use (MMBtu)	CO2 Released (lbs)	Net Generation (MWh)	(Coal) Fuel Use (MMBtu)	CO2 Released (lbs)	Net Generation (MWh)	(Coal) Fuel Use (MMBtu)	CO2 Released (lbs)	Heat Rate (BTU/kWh)	CO2 Released (lbs/MWh)
SNG + NGCC, no CO2 Capture	560	3,765	446,607	10	6,397	17,320	570	6,397	463,927	11,214	813

References:

(1) National Energy Technology Laboratory, Cost and Performance Baseline for Fossil Energy Plants (Rev. 1), August 2007

(2) University of Kentucky, Technologies for Producing Transportation Fuels, Chemicals, Synthetic Natural Gas and Electricity from the Gasification of Kentucky Coal, July 2007