ENERGY POLICY AND CONSERVATION REPORT

2008

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office of energy security

Minnesota Department of Commerce

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INTRODUCTION

Every four years, the Minnesota Department of Commerce's Office of Energy Security (OES) is required by Minnesota Statutes, section 216C.182 to issue the State Energy Policy and Conservation Report "designed to identify major emerging trends and issues in energy supply, consumption, conservation, and costs." This report—informally referred to as the Quadrennial or "Quad Report"—is published in fulfillment of that requirement. Under Governor Pawlenty's Administration, the guiding principles of Minnesota's energy policy are to ensure that:

- Minnesota has a reliable energy-provision system into the future;
- the state's energy system meets Minnesota's economic needs;
- Minnesota's energy costs are reasonable priced; and
- the environmental impacts of the energy produced and consumed in the state are reduced.

The Office of Energy Security's primary focus will be assuring the state's current and long-term energy reliability. The OES's definition includes the long-term adequacy of supply, security and sufficiency of the transmission grid, and local power quality at the distribution level. As discussed more fully in Chapter Three, this emphasis on reliability will take many forms:

- focus on utility operations, maintenance and system control measures;
- promote greater investments in and upgrades of transmission and distribution infrastructure;
- reach out to neighboring states and provinces to create collaborative, multi-jurisdictional solutions to grid operations issues;
- improve power quality and service standards; and
- allow economic efficiency principles to guide our actions, whenever possible.

Lastly, the past several years have seen increased amounts of renewable energy development in Minnesota, particularly in many of our rural communities. In addition to the security benefits gained by diversifying our energy generation mix, renewable energy development can create local economic development benefits as well.

SUMMARY OF MAJOR ENERGY LEGISLATION SINCE 2004

Since the last Quad Report, the Minnesota Legislature has passed several pieces of energy policy legislation. This chapter will briefly summarize three major pieces of legislation, which the OES is currently in the process of addressing.

A. RENEWABLES PORTFOLIO STANDARD (RPS) (2007 MINNESOTA LAW, CHAPTER 3)[1]

In February 2007, the Minnesota Legislature enacted legislation that created a renewable portfolio standard (RPS) for Xcel Energy, created a separate RPS for other electric utilities,[2] and modified the state's existing non-mandated renewable-energy objective. Electricity eligible for the standards and the objective include: solar, wind and hydroelectric facilities less than 100 megawatts (MW); hydrogen and biomass, which includes landfill gas, anaerobic digestion; and municipal solid waste.[3]

The standard for Xcel Energy requires that eligible renewable electricity account for 30 percent of total retail electricity sales (including sales to retail customers of a distribution utility to which Xcel Energy provides wholesale service) in Minnesota by 2020. Of the 30 percent renewables required of Xcel Energy in 2020, "at least" 25 percent must be generated by wind-energy systems, and "the remaining" 5 percent by other eligible technologies. Wind energy and biomass energy contracted for or purchased by Xcel Energy pursuant to Minn. Stat. §216B.2423 *et seq.* is eligible under the RPS. The RPS schedule for Xcel Energy is as follows:

- 15% by 12/31/2010
- 18% by 12/31/2012
- 25% by 12/31/2016
- 30% by 12/31/2020

The standard for other Minnesota utilities requires that eligible renewable electricity account for 25 percent of retail electricity sales to retail customers (and to retail customers of a distribution utility to which one or more of the utilities provides wholesale service) in Minnesota by 2025. The RPS schedule for other Minnesota utilities is as follows:

- 12% by 12/31/2012
- 17% by 12/31/2016
- 20% by 12/31/2020
- 25% by 12/31/2025

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[1] See http://www.house.leg.state.mn.us/hrd/as/85/as003.html for a detailed summary of 2007 Minnesota Law, Chapter 3.

[2] The following utilities are subject to the statute: Xcel Energy, Minnesota Power, Otter Tail Power, Interstate Power & Light Company, Northwestern Wisconsin Electric Company, Great River Energy, Minnkota Power Cooperative, Dairyland Power Cooperative, Basic Electric Power Cooperative, East River Electric Power Cooperative, L&O Power Cooperative, Southern Minnesota Municipal Power Agency, Western Minnesota Municipal Power Agency/Missouri River Energy Services, Northern Municipal Power Agency, Minnesota Municipal Power Agency, and Central Minnesota Power Agency.

[3] The definition of eligible biomass was refined slightly in 2008 by Senate file 2996 (https://www.revisor.leg.state.mn.us/laws/?id=258&doctype=Chapter&year=2008&type=0) to include the organic components of wastewater effluent and sludge from public treatment plants, with the *exception* of waste sludge incineration.

The February 2007 amendments also modified Minnesota's non-mandated, "good faith" renewable-energy objective. The revised objective, which applies to all utilities, calls for eligible renewables to account for 1 percent of all retail electricity sales in 2005 and 7 percent of all retail sales by 2010. The Minnesota Public Utilities Commission (MPUC) measures utilities' efforts to meet the objective to determine whether utilities are making the required "good faith" effort.[4]

The 2007 legislation required the MPUC to establish a program for tradable RECs by January 1, 2008. The MPUC approved the Midwest Renewable Energy Tracking System (M-RETS) for this purpose in October 2007 and required all utilities to make a substantial and good faith effort to register renewable generation assets by March 1, 2008. The program treats all eligible renewables equally and may not ascribe more or less credit to energy based on the state in which the energy was generated or the technology used to generate the energy. Notably, Xcel Energy may not sell RECs to other Minnesota utilities for RPS-compliance purposes until 2021. In December 2007, the MPUC made certain additional determinations for the operation of the REC trading system, listed below:

- RECs will have a trading lifetime of 4 years according to the year of generation (i.e., all credits generated during 2008, regardless of the month, will expire at the end of 2012).

- The purchase of RECs through M-RETS may be used in utility green pricing programs, subject to the shelf life described above.

- Consistent with M-RETS operating procedures, RECs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)

- The MPUC declined to issue a directive ascribing ownership of RECs where ownership is not addressed in power purchase agreements (PPAs), instead requiring utilities to pursue negotiations and settlements with the owners of generation units.

This docket remains open to address issues not covered during the first phase of rulemaking, as well as future implementation issues that may arise due to changes in national, state, or M-RETS policies and protocols.

[4] In Docket No. E999/CI-04-1616 (https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9BC0C548-1B8D-4FAF-B96F-F97BA88B0ABB}&documentTitle=4872137), the MPUC issued an order clarifying how it will evaluate this "good faith" effort during the years (2006 - 2009) for which no benchmarks are defined by the statute. The order requires utilities to retire renewable energy credits (RECs) equivalent to 1 percent of their annual retail sales for the 2007-2009 compliance years (i.e., the calendar year). In effect, this appears to both establish a mandatory baseline compliance benchmark and allow utilities to bank RECs – subject to the REC trading lifetime – in preparation for meeting the more stringent 7% objective in 2010. It could also be interpreted as setting a precedent for addressing similar issues in future years. Only RECs recorded and tracked through the Midwest Renewable Energy Tracking System (M-RETS) may be used for compliance with the "good faith" objective and future standards.

Utilities are required to file annual compliance reports with the MPUC detailing their retail sales, REC retirements, and REC trading activities. If the MPUC finds a utility is noncompliant, the commission may order the utility to construct facilities, purchase eligible renewable electricity, purchase RECs or engage in other activities to achieve compliance. If a utility fails to comply, the MPUC may impose a financial penalty on the utility in an amount not to exceed the estimated cost of achieving compliance. The penalty may not exceed the lesser of the cost of constructing facilities or purchasing credits and proceeds must be deposited into a special account reserved for energy and conservation improvements. The MPUC may delay or modify a standard as part of an integrated resource planning proceeding under section 216B.2422. The MPUC is authorized to modify or delay the implementation of the standards if the commission determines it is in the public interest to do so.

The 2007 legislation requires utilities subject to section 1 to study and develop plans to enhance the transmission network so that the standards may be met. Utilities are to meet regularly with stakeholders experienced in transmission engineering and renewable energy generation, and are to submit a report to the MPUC by November 1, 2007 that:

- identifies critical issues;
- includes a comprehensive conceptual planning guide and specific transmission line proposals necessary to support the standards; and
- contains a five-year action plan that identifies specific actions that must be taken to implement proposals and further develop transmission plans.

B. NEXT GENERATION ENERGY ACT OF 2007 (2007 MINNESOTA LAW, CHAPTER 136)

On May 25, 2007, Governor Tim Pawlenty signed the Next Generation Energy Act of 2007 ("Next Generation Act"). The Next Generation Act increases energy efficiency, expands community based energy development, and establishes a statewide goal to reduce greenhouse gas emissions and supplements the aggressive 25 x 25 renewable energy standard. The Next Generation Energy Initiative was first announce in December 2006 with the intent to provide more renewable energy, more energy conservation, and less carbon emissions for Minnesota. In conjunction with the Renewable Energy Standard discussed below, the Next Generation Energy Act established nation-leading requirements on Minnesota's electric utilities while ensuring reliability and protecting the cost-competitiveness of Minnesota's electric system.

The Next Generation Act includes:

- **Energy Savings Goals:** The Energy Conservation Policy Goal expands on Minnesota's existing conservation program, consistently ranked in the top five programs in the country. It establishes an energy savings goal for all utilities at 1.5% of annual retail energy sales. The transition from an energy efficiency spending goal will more than double the amount of energy savings achieved by Minnesota's utilities under the previous energy efficiency spending goals. The bill also sets goals to achieve a certain number of high-performance buildings within Minnesota. The state

goal is to achieve certification of 1,000 commercial buildings as ENERGY STAR-labeled, and 100 commercial buildings certified under either the Leadership in Energy and Environmental Design (LEED) or Green Globes guidelines by December 31, 2010.

- **Community Based Energy Development:** The Next Generation Act expands and strengthens Minnesota's commitment to the development of locally-owned renewable energy projects. Previous legislation also increases funding for community energy outreach through Clean Energy Resource Teams (CERTS) throughout the state.

- **Climate Change and Greenhouse Gas Reduction:** According to the National Conference of State Legislators, the Next Generation Act put Minnesota into the top two states (with California) leading the way towards reducing greenhouse gas (GHG) emissions. The bill establishes statewide GHG reduction goals of 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050. The bill also endorses the Governor's Minnesota Climate Change Advisory Group as the entity to develop a comprehensive greenhouse gas emission reduction plan to meet those goals (http://www.mnclimatechange.us/).

- **Next Generation Energy Board** (2007 Minnesota Law, Chapter 57)**:** The board develops next generation energy and biofuels policy, and makes recommendations to the Governor and Legislature about how the state can invest its resources to most efficiently achieve energy independence, agricultural and natural resources sustainability, and rural economic vitality.

On November 6, 2008, the Governor announced $3 million in state grants awarded by the Next Generation Energy Board to accelerate biofuels development. The projects include cellulosic ethanol production, an anaerobic digester technology for hog manure, and using turf grass to produce electricity. A total of 28 proposals were submitted to a technical review committee comprised of staff from the Departments of Agriculture, Natural Resources, Commerce, Employment and Economic Development, and the Pollution Control Agency. As discussed at length in Chapter 3, eight were selected for funding.

C. GREEN SOLUTIONS ACT (2008 MINNESOTA LAW, CHAPTER 340)

As part of the state's effort to adopt and implement a comprehensive plan to reduce greenhouse gas emissions from the electricity generation sector, as required under Minnesota Statutes 2007 Supplement, section 216H.03, the Minnesota Climate Change Advisory Group developed, through an extensive six-month stakeholder process, a list of recommended actions to achieve the state's reduction goals, and submitted it to the 2008 legislature. Among its recommendations was the adoption of a cap and trade program, under which greenhouse gas emissions from individual sources are capped at a level that is reduced over time. Emitters can elect to undertake actions to reduce emissions or, if it is more economical, purchase emissions from other facilities that have reduced their emissions below their cap.

The new act appropriates money for three studies to determine the economic, environmental, and public health impacts of a cap and trade program and to analyze how expenditures from revenues resulting from the allocation of allowances could address those impacts.

The new act also requires a report from the commissioners of Pollution Control and Commerce to the Legislature by January 15, 2009 regarding the status of a model rule establishing a regional cap and trade program under the Midwestern Greenhouse Gas Accord. It specifies that a cap and trade agreement is not effective until approved by a law enacted by the legislature and directs the commissioners of Commerce and/or Pollution Control to arrange three studies to:

- analyze the economic, environmental and public health costs and benefits of the implementation of a cap and trade program;
- estimate the potential revenues from the sale of emissions allowances and how they might be used to mitigate economic impacts of a cap and trade program; and
- analyze options for a decision-making structure and process to allocate expenditures from the revenues that would be realized from an auction of emission allowances.

As stated in the January 15, 2008 report, a stakeholder group was formed – the Greenhouse Gas (GHG) Advisory Group – to help develop specific recommendations for meeting the goals of the Accord. Within the GHG Advisory Group, there are six sub-groups: Model Rule, Scope, Target-setting, Data and Reporting, Modeling, Allowances and Offsets. The GHG Advisory Group and the subgroups began meeting in March 2008. As of February 2009, there have been eight face-to-face meetings of the GHG Advisory Group and numerous conference calls and meetings of the subgroups. The Model Rule sub-group was formed in October 2008 to draft a cap and trade model rule and will begin meetings in January 2009.

The GHG Advisory Group has initiated modeling the potential GHG reductions and economic impacts of a cap and trade program in the Midwest region. Preliminary modeling results should start becoming available in January 2009. However, the final results of the modeling will probably not be available until later in 2009. The MGA staff have been working with Minnesota stakeholders to develop a Minnesota specific study to look deeper into the economic, environmental and health impacts as well as more Minnesota specific information on potential revenue. The scope of that study is not yet final. The Minnesota specific modeling will be performed by the same consultant working on the Midwestern Accord modeling. While some of the Minnesota specific work can begin in parallel with the regional modeling, it is expected that the majority of the Minnesota modeling will follow the Midwestern Accord work. As a result, we do not expect the Minnesota study to be complete until late 2009 or, more likely, later.

Preliminary cap and trade design recommendations were developed in November and December 2008. The preliminary recommendations are consistent with the Minnesota GHG reduction goals under Minnesota Stats. 216H.02 subdivision 1. However, the recommendations are not complete and several significant decisions are still pending. Final recommendations are not expected until the GHG Advisory Group has a chance to review the economic modeling results later in 2009.

ELECTRICITY

Minnesota's economy depends on reliable, reasonably-priced, environmentally sensitive electric service. Consumers of all types—residential, commercial, industrial—have come to expect and rely on electric utilities to provide a high level of reliability and quality of service. As such, the reliability and quality of electric service in Minnesota is among the Office of Energy Security's top priorities.

A key to understanding the difficulty of maintaining the reliability of the electric system is that electricity, unlike natural gas and petroleum, cannot be stored. At any given moment, there must be enough electric generation and transmission capacity and energy available. This energy must instantaneously be balanced when the electricity is needed.

The assessment of reliability discussed in this chapter consists of three sections:

- the long term adequacy of electric supply in Minnesota;
- the transmission system, often referred to as the transmission "grid" or the "bulk power" system; and
- the reliability of and service quality provided by the local retail distribution system, the part of the electricity delivery system that serves end-use customers.

A. RESOURCE ADEQUACY

1. Rising Demand

According to the Annual Energy Outlook 2008 (AEO08),[5] total U.S. electricity sales are forecasted to increase by 29 percent from 3,659 billion kilowatthours (kWh) in 2006 to 4,705 billion in 2030, at an average increase rate of 1.1 percent per year. The relatively slow growth follows the historical trend, with the growth rate slowing in each succeeding decade. Electricity sales, which are strongly affected by economic growth, increase by 39 percent in the high growth forecast case, to 5,089 billion kilowatthours in 2030, but by only 18 percent in the low growth case, to 4,319 billion kilowatthours in 2030. In the reference case, the largest increase is in the commercial sector, at 49 percent from 2006 to 2030 (Figure 60), as service industries continue to drive growth. Electricity demand grows by 27 percent in the residential sector and by only 3 percent in the industrial sector.

As shown in Appendix 1, Figure 2, Minnesota's consumption of electricity demonstrates an increase in both residential and commercial consumption. Figure 2 also illustrates a drop in industrial consumption in 2001 and then slightly increasing since that time. Minnesota is expected to increase at an average rate of about 1.1 percent annually over the next few years, based on the combined projections of all utilities serving Minnesota customers.[6] As discussed below, since there is not enough excess generating capacity available to meet this increase in

[5] See http://www.eia.doe.gov/oiaf/archive/aeo08/electricity.html

[6] A simple trend line estimated that an increase of between 1 and 2 percent will occur annually over the next few years.

demand, new generation and transmission facilities will be needed in the near future to serve the electric needs and the reliability of the regional electricity transmission – both state and region. Electric utilities engage in resource planning to determine the combination of power plants that most economically meets the increased demand.

2. A New Energy Mix

The capacity expansion plans of electric utilities indicate that the fuel mix for electric generation has altered and will continue to change in the coming years. Natural gas may increase as a source of electricity, although recently concerns have been raised about the extent to which electricity justifies this type of fuel usage. There are also plans to significantly increase wind and other renewable generation in the state. With current efforts to relicense and increase the capacity of current facilities, nuclear power will continue to be part of the fuel mix for electric generation.

As noted above, demand for electricity in our state, and in the U.S., continues to increase. As a result of growing demand and limitations due to aging electric infrastructure in the region, additional generation and transmission infrastructure will be needed in both the near and longer term. Ensuring this new infrastructure is constructed and placed into service in a manner that does not materially adversely impact the environment, energy costs or other public interests is a challenge that state and regional policy makers must address.

3. Growth in Demand Greater Than Growth in Supply

Minnesota's utilities are members of the Midwest Reliability Organization (MRO).[7] MRO conducts studies of planned generation resources and transmission system adequacy to ensure it will meet its region's electricity demand. MRO is a member of North American Electric Reliability Corporation (NERC), which collects these regional studies to evaluate the reliability of the interconnected grid as a whole. The generation fuel source mix is made up of fossil/coal, hydroelectric, gas/oil, nuclear, and wind/biomass and other types of renewable energy technologies. This diverse generation mix keeps our power system reliable and economical. The Midwest Reliability Organization (MRO) replaced the Mid-Continent Area Power Pool (MAPP) as a reliability organization within NERC in January 2005.[8]

The United States portion of the MRO region has a peak demand occurring in the summer season. The MRO-U.S. summer peak demand is expected to increase at an average rate of 1.9 percent per year during 2006–2015, a slight decrease from the 2.0 percent predicted last year for the 2005–2014 period.[9] The MRO-U.S. summer reserve is predicted to be between 21 and 17 percent from 2006-2010. However, current planned capacity reported in the MRO-U.S. region is below the MRO's targets for generation adequacy during the 2010–2015 period. Some of the growth in electric demand may be met through energy conservation.

[7] The MRO region covers all or portions of Iowa, Illinois, Minnesota, Nebraska, North and South Dakota, Michigan, Montana, Wisconsin, and the Canadian provinces of Manitoba and Saskatchewan.
[8] MAPP continues to exist as a regional transmission group with a Regional Transmission Committee (RTC) and a Generation Reserve Sharing Pool (GRSP).
[9] See http://www.midwestreliability.org/03_reliability/assessments/2006_Ten-Year_Reliability_Assessment.pdf

Conservation programs are in place to help manage load growth in Minnesota. Compared with new generation resources, these programs reduce the demand for electricity. However, the OES expects that growth in the demand for electricity in Minnesota will outstrip the contribution of conservation towards balancing supply and demand in the state in a cost-effective manner. Moreover, the pressure that demand growth places on utilities is not even. Some utilities may have greater needs for new electric infrastructure, due to the fact that their electric demand or "load" is growing faster than the loads of other providers.

4. Need for Base Load Resources

In Minnesota, no base load plants (facilities that constantly run to serve the steady level of ongoing electric demand) have been built since the 1980s. There have been a number of capacity additions since 2000. However, the majority of the additions are small oil/gas, diesel or wind units installed by municipal utilities, electric cooperatives and Investor Owned Utilities (IOUs). Only six combustion generation projects greater than 50 megawatt facilities (excluding wind) have been installed since 2000. The facilities are:

TABLE 1

UTILITY-OWNED ELECTRIC GENERATION GREATER THAN 50 MW INSTALLED SINCE 2000

		Plant Profile			
			Capacity		
		Unit Type	Summer (MW)	Winter (MW)	Year Installed
Great River Energy	Lakefield Junction				
	Martin County, MN				
	Unit 1	Gas Turbine	85.000	97.000	2001
	Unit 2	Gas Turbine	84.000	97.000	2001
	Unit 3	Gas Turbine	83.000	94.000	2001
	Unit 4	Gas Turbine	82.000	95.000	2001
	Unit 5	Gas Turbine	84.000	97.000	2001
	Unit 6	Gas Turbine	86.000	95.000	2001
Great River Energy	Pleasant Valley Station				
	Mower County, MN				
	Unit 11	Gas Turbine	150.000	172.000	2001
	Unit 12	Gas Turbine	150.000	167.000	2001
	Unit 13	Gas Turbine	121.000	128.000	2002
Xcel Energy	Angus Anson				
	Minnehaha County, SD				
	Unit 4	Gas Turbine	158.400	180.000	2005
Xcel Energy	Black Dog Steam				
	Dakota County, MN				
	Unit 5	Gas Turbine	195.000	205.000	2002

TABLE 1 Continued

UTILITY-OWNED ELECTRIC GENERATION GREATER THAN 50 MW INSTALLED SINCE 2000

		Plant Profile			
			Capacity		
		Unit Type	Summer (MW)	Winter (MW)	Year Installed
Xcel Energy	Blue Lake Gas Turbine Scott County, MN				
	Unit 7	Gas Turbine	158.830	163.770	2005
	Unit 8	Gas Turbine	156.970	161.660	2005

As shown above, the installed capacity are gas turbine, which are either peaking facilities (plants used only in times of highest demand, such as a hot summer day) or intermediate facilities (facilities that are more expensive to operate than base load plants, but less expensive than peaking plants—used when all available base load resources have been "dispatched").

The operating licenses of both Monticello and Prairie Island facilities are scheduled to expire in 2010 for Monticello and in 2013/2014 for the Prairie Island units. However, Xcel Energy has filed for re-licensing for both facilities. The Monticello application was filed with the Nuclear Regulatory Commission (NRC) in March 2005 and a renewed license was issued in November 2006. The Prairie Island application was filed in April 2008 and an NRC decision is schedule for October 2010. Additionally, both of the facilities have filed Certificate of Need with the Minnesota Public Utilities Commission for increasing ("uprate") generation capacity: 71 MW increase for Monticello and 164 MW for Prairie Island. If re-licensing for these facilities had expired, the base load resource problem would have needed to be expanded by another 1600 megawatts. Nuclear power is and will continue to be an important part of the fuel mix for electric generation in Minnesota.

Capacity additions require advanced planning. In general, base load and intermediate resources are more difficult for utilities to build than peaking or intermittent resources because base load and intermediate resources are more expensive to construct, and generally have greater environmental impacts. Minnesota Rules parts 7843.0100-7843.0600 require electric utilities to file proposed integrated resource plans (IRP) every two years which presents the utility's 15 year demand forecast and the utility's proposed capacity additions to meet the forecasted demand. There are a number of IRPs that have been filed with the Minnesota Public Utilities Commission

or are scheduled to be filed during 2009.[10] It is important to note that while capacity planning is performed by the individual utilities, the OES is now in the process of preparing the first statewide resource plan as required by 2007 Minnesota Law, Chapter 136, Article 4, section 16.

5. Increased Reliance on Natural Gas Generation

All of the new combustion generation resource additions referred to above are natural gas turbines that are fueled by natural gas. According to the EIA, summer capacity from natural gas has increased from 5 percent of the total electric capacity in 1990 to 23.6 percent of the total electric capacity in 2005. Natural gas generation facilities have long been a small part of Minnesota's supply mix, and have traditionally relied on the summer surplus of natural gas pipeline capacity that is available since most consumer furnaces are not being used to heat homes and businesses. However, the state's usage of natural gas-fueled generation is increasing. These upward trends are a result of natural gas existing superior to coal and nuclear fuel in overall environmental impacts, and that natural gas plants can be constructed more quickly. Natural gas-fired generation allows facilities to start up and shut down more quickly and easily than other types of facilities. However, only a limited number of natural gas generation facilities can be added to the existing natural gas pipeline infrastructure without appropriate pipeline upgrades to handle the additional capacity and line pressure needs of gas fueled electric generation.

B. TRANSMISSION INFRASTRUCTURE

Minnesota's transmission system – the high voltage power lines that transmit electric energy from generation plants to local load and among utilities to ensure a high degree of reliability – is part of an overall regional transmission grid operated on a coordinated basis with other interconnected transmission systems throughout the Upper Midwest and Eastern United States and Canada. Historically designed to reliably deliver power to electric load centers such as the Twin Cities metropolitan area, Duluth, Mankato, Rochester and St. Cloud, and to interconnect utilities for reliability reasons, the transmission grid is now relied on more heavily. It acts as a regional "highway" providing the physical link between sellers and buyers, facilitates an ever-increasing amount of transactions among an increasing number of market participants, and over increasing distances. At the same time, it continues to serve a critical reliability role.

Transmission is in the spotlight on a state/regional/national basis for three reasons:

(1) Transmission has not been built or upgraded for decades, thus, we've outgrown our grid,
(2) There are a number of electric transmission constraints, and
(3) With states enacting Renewable Energy Standards, the need for transmission to deliver renewable energy is immediate.

[10] Xcel Energy's IRP (Docket No. E002/RP-07-1572) was filed in December 2007 and the parties (including the OES) have filed comments with the Minnesota Public Utilities Commission. Four electric utilities (Dairyland Electric Cooperative (Docket No. ET3/RP-08-0113), Great River Energy (Docket No. ET2/RP-08-0784), Basin Electric (ET6125/RP-08-0846) and Minnesota Municipal Power Agency (MMPA) (Docket No. ET6133/RP-08-0927))filed IRPs with the Commission in 2008. Interstate Power and Light Company, Missouri River, Otter Tail Power Company, South Minnesota Municipal Power Agency (SMMPA), Minnesota Power and Minnkota Power Cooperatives are scheduled to file IPRs in 2009.

1. Transmission Construction and Upgrades

The 2005 Biennial Transmission Projects Report identifies more than 75 areas where additional transmission infrastructure will be needed in the next ten years to address a growing demand for power including more renewable energy.[11] A number of significant studies have recently been completed and others are presently underway to determine the best manner in which to address Minnesota's need for new transmission.

As discussed below, the Midwest Independent System Operator's (MISO) primary function is to monitor the bulk power transmission system and develop policies and procedures that ensure every electric industry participant has access to the transmission system, and that transmission lines are used to minimize congestion and maintain system reliability. Several Minnesota electric utilities have contracts with MISO to conduct facility studies identifying their transmission needs and potential solutions. The table below identifies the most recent studies and provides a link to the Minnesota-related reports.

TABLE 2

MISO
OASIS Studies Page
Facility Studies[12]

Path	Season - Year	Study Number	Date Posted	Links to Comments
OTP - OTP	10/1/2008 - 6/1/2069	F075 (A411)	2/4/2009	FS Report - XEL
GRE - NSP	10/1/2008 - 1/1/2034	F068 (A356)	2/2/2009	Final FS Report
			6/4/2008	Addendum to SIS
WAUE - NSP	6/1/2009 - 6/1/2029	F069 (A345)	6/4/2008	Addendum to SIS
GRE - NSP	1/1/2009 - 1/1/2029	F070 (A346)	1/15/2009	Final FS Report
			6/4/2008	Addendum to SIS
GRE-GRE	5/1/2008 - 5/1/2025	F060 (A310)	11/1/2007	Final FS Report
ALTW - GRE	1/1/2007 - 1/1/2022	F064 (A317)	10/2/2007	Final FS Report
OTP - Multiple	1/1/2010 - 1/1/2037	F066 (A190)	9/8/2008	FS Report - XEL
			8/9/2007	FS Report - OTP
MP - MP	5/1/2007-5/1/2008	F058	11/30/2006	Draft FS Report
GRE - GRE	6/1/2009-1/1/2028	F059	8/18/2006	Final FS Report
Multiple involving NSP, OTP, GRE, ALTW and WAPA	2006 and beyond	F056	6/6/2006	Draft Final FS Report
OTP - OTP	10/1/03-12/31/29	F054	3/17/2006	Final FS Report

[11] See the "2005 Minnesota Biennial Transmission Project Report" at http://www.minnelectrans.com/2005 Minnesota Biennial Report.pdf

[12] See https://oasis.midwestiso.org/documents/miso/Transmission Service Planning - FaS Reports.htm

TABLE 2 (Continued)

Path	Season - Year	Study Number	Date Posted	Links to Comments
NSP - NSP	05/01/06-05/01/26	F043	10/14/2005	Final FS Report
MP - GREC	04/01/05-05/01/05	F040	5/10/2005	Facility Study Report
NSP - GRE	09/01/04-09/01/19	F019	11/8/2004	Phase 1 Facility Study_Final Report
NSP - NSP	04/01/05-11/01/05	F036	11/10/2004	Phase 1 Facility Study Final Report
GRE - GRE	10/01/03-10/01/33	F018	9/20/2004	Final Report
MP - GRE	2004	F033	7/6/2004	F033 Facility Study

The above list reports are voluminous and identify numerous, multiple transmission options for Minnesota electric utilities both individual and in concert with other utilities. Needless to say, there will be a large number of route permits and certificate of need applications that will be filed to expand the transmission grid now and into the future. It is a busy time for Minnesota utilities, and for the Public Utilities Commission, the Minnesota Office of Energy Security, local officials, and the general public.

2. Electric Transmission Constraints

As a rule, large electric generators and consumers of electricity typically are not located in the same place. In order for the power to be delivered from the place of generation to the place of consumption, transmission line pathways must be developed. Eventually, transmission constraints, or bottlenecks, develop in areas where a transmission line delivers the maximum level of power that it can safely and reliably carry. Bottlenecks limit energy transactions. In turn, this may lead to higher energy costs. More importantly, such transmission constraints can threaten system reliability.

Many major transmission lines into and out of Minnesota are nearing or at operational limits that could affect reliability. For example, the major transmission lines from Minnesota into Wisconsin currently operate at reliability limits during summer peak times to satisfy power requirements in the region. The transmission system may not, without future upgrades or new additions, support additional generation from Canada.

3. Renewable Development Constraints

Minnesota has a tremendous capacity for renewable energy development, especially its wind energy resources. As of 2008, Minnesota has over 1,754 megawatts of wind energy capacity installed. Xcel Energy alone owns or purchases roughly 1200 megawatts of wind energy capacity in Minnesota. Xcel is expected to purchase an additional 2,000 – 3,000 megawatts in the region by 2020 to satisfy its need under Minnesota's and neighboring states' Renewable Energy Standard requirements or goals.

However, transmission has been a major factor limiting further development in the southwest portion of the state. As discussed below, Xcel Energy is in the process of siting the three major transmission projects, which are designed to cross the southern part of Minnesota to bring wind generated electric power from the Southwest Minnesota area to major Metro-area markets.

The development of further wind (or renewable) generation will be stymied without sufficient transmission capacity to bring that energy to load centers, where it can be used to serve consumer needs. Continued expansion of the wind energy resource in Minnesota will require additional transmission capacity. As policy makers struggle with how best to encourage renewable energy development in the state, they should keep in mind that transmission capacity, not production subsidies, tax credits or mandates, may be the limiting factor for that development.

4. Potential Electric Transmission Solutions

One obvious way to alleviate constraints on the power system would be to construct additional transmission lines and facilities and upgrade existing power lines. In a recent filing to the Commission, Minnesota's transmission owning entities identified inadequacies in the state's transmission infrastructure which need to be addressed to ensure reliable service to Minnesota consumers. The OES is actively encouraging those utilities to follow through in fixing these identified inadequacies in a timely manner.

As mentioned above, transmission has been a major factor limiting further development in the southwest portion of the state. Xcel Energy is in the process of siting a major high voltage transmission line in the Buffalo Ridge area. While this project will help to mitigate the area's transmission constraint, additional transmission will be necessary to continue to develop this resource. One of the three major transmission projects in CAPX2020 is designed to cross the southern part of Minnesota to bring wind generated electric power from the Buffalo Ridge area to the major consuming markets, including the Minneapolis/St. Paul metro area.

To help meet state Renewable Energy Standard goals before new transmission lines become available, state legislation in 2007 required a statewide study of dispersed renewable generation potential to identify locations in the transmission grid where a total of 1200 MW of relatively-small renewable energy projects could be operated with little or no change to the existing infrastructure. For the purposes of the study, dispersed renewable energy projects are wind, solar and biomass projects that will generate between 10 and 40 MW of power.

An analytic team led by staff from the Department of Commerce Office of Energy Security and Great River Energy in collaboration with the Minnesota electric utilities and with the Midwest Independent System Operator (MISO) is conducting the two-year Dispersed Renewable Generation Study. A technical review committee (TRC) of national, regional and state technical experts representing the national energy laboratories, MISO, wind and community energy advocates and Minnesota's utilities is guiding and reviewing the work of the analytic team.

On June 16, 2008 the Minnesota Department of Commerce Office of Energy Security released the results of the first phase of the study. The Phase I study goal was to identify locations in the transmission grid where a total of 600 MW of relatively-small sized renewable energy projects could be operated with little or no changes required to the existing infrastructure. For Phase I of the study, the analytic team generated the first state-wide models of Minnesota's entire electrical system including higher and lower voltage lines, and developed new methodologies to identify potential opportunities for dispersed renewable generation. The potential locations studied were based on public input, regional availability of renewable resources, current dispersed generation in the MISO queue, and access to existing transmission.

Phase II of the study began in October of 2008. The goal of Phase II is to identify locations for an additional 600 MW of dispersed renewable energy. A report on the results of Phase II is due by September 15, 2009.

Due to the intermittency of the wind resource, wind energy, by itself, cannot be relied upon for baseload or peaking purposes because it cannot be "dispatched" (turned on or off as needed). However, this drawback can be mitigated by being matched with another type of generation resource that has the ability to "follow" the wind energy (turned on or up when the wind is not blowing, turned off or down when wind energy is being generated).

In addition, a variety of demand-side options can also be used to address system congestion. Reduced consumption of electricity through energy conservation practices is the least cost, most effective and efficient tool that electricity consumers can practice. This helps manage and/or reduce the demand for the use of transmission facilities. Timing electricity use so that consumers' demand for electricity is spread throughout a 24-hour period, avoiding so-called "peak" consumption times during the day can also help alleviate constraints.

5. MISO

As mentioned above, the day-to-day operation of the electricity system is conducted by the individual utilities and the regional reliability entity, the Midwest Independent System Operator (MISO).

After receiving approval from the Commission, Minnesota's four investor-owned utilities (Xcel, Minnesota Power, Otter Tail Power Company, and Interstate Power and Light) joined MISO, and transferred functional control (but not ownership) of their transmission facilities to MISO. As an "independent system operator," MISO's operations and activities are subject to the approval of the Federal Energy Regulatory Commission (FERC).

MISO's primary function is to monitor the bulk power transmission system and the open-access electricity "market" and develop policies and procedures that ensure every electric industry participant has access to the transmission system, and that transmission lines are used to maximize efficiency, minimize congestion and maintain system reliability.

A potential issue arises from the fact that utilities in MISO operate under a different protocol than utilities that are not MISO members. As a result, there are "seams" between members and non-member utilities. A "seam" is defined as an intersection of entities operating under different market rules and designs and other regional practices that inhibit or preclude the ability to transact capacity and/or energy efficiently across the intersection.

In the past, the OES has worked closely with MAPP and Minnesota members. The OES is now also actively engaged in numerous MISO stakeholder groups including holding a seat on the MISO Advisory committee and being an associate member of the Organization of MISO States. The MISO Advisory committee advises the MISO Board of Directors on key operational and organization issues.

C. ELECTRICITY DISTRIBUTION AND SERVICE QUALITY

If the transmission system is analogous to the interstate highway system whose focus is on moving electricity efficiently and reliably, the local electric distribution system can be thought of as local streets and roads whose focus is on distributing quality electric service to retail customers. The number and frequency of distribution level service quality disturbances or "outages" is much greater than outages in the transmission system, but distribution outages typically affect fewer customers than transmission outages. Accordingly, distribution reliability is an important part of overall electric service quality.

Efforts to address distribution issues tend to focus more clearly on an individual utility rather than an interconnected system. Minnesota has been addressing the specific issues of customer service quality and customer outages through industry-wide rule-making and proceedings related to specific utilities. The utilities currently file service quality metrics for Commission approval on an annual basis.

In an effort that goes well beyond the requirements of these rules, the OES and the Office of the Attorney General negotiated with Xcel to gain a number of significant service quality remedies above and beyond what Xcel must do under the Commission's rules, such as:

- pay customer refunds totaling $1 million to those who experienced the longest outages during the time period of the investigation;
- increased spending on maintenance items such as tree trimming and cable replacement;
- file a revised service quality plan, in the form of a Commission-approved customer tariff, which includes strict and well-defined service quality standards with noncompliance payments in the millions of dollars for such areas as:
    - customer complaints,
    - number of outages per customer,
    - length of outages per customer,
    - customer call response time, and
    - natural gas leak response time.
- submit to an independent review of Xcel's new customer outage system currently being developed to be certain that concerns raised in the investigation are addressed;
- agree to a number of customer communication and reporting provisions.

The settlement, approved with modifications by the Commission, is the strongest customer service program in Minnesota and, to our knowledge, the region.

D. CONCLUSIONS

As mentioned in the introduction, the continuing reliability and quality of electric service is one of the guiding principles of Minnesota's energy policy and is among the OES's top priorities in the coming years. Accordingly, the OES, in concert with other state agencies and interested persons, seeks to preserve and enhance the reliability and quality of the electric system in Minnesota. As we move forward, the operators of the electricity system need to ensure that operations, maintenance and system control measures are demonstrably adequate. Next, as the OES is currently analyzing, the planning for new generation resources must be reviewed and evaluated by the combined resource needs of all of Minnesota utilities together in order to get "the big picture." Additionally, there must be continued focus and investment in the transmission infrastructure so that it will be able to handle peak demands and permit the economic and physical flow of power from where it is generated to where it is needed. Finally, reasonably-priced, reliable power is critical to Minnesota's economic well being. Yet, the economics of energy policy often gets subsumed by other important policy goals such as local economic development. It is important that policymakers and regulators making decisions understand the economic consequences of their actions and, perhaps take a larger, longer-term view of things. The cost of policies that differ from a basic approach of ensuring reliable power in a least-cost manner should be reasonably known so decisions to pursue such policies are fully informed.

PORTFOLIO DIVERSIFICATION—RENEWABLE AND MODERN ENERGY TECHNOLOGIES

It is common knowledge within the investment community that the best financial portfolios are those that balance risk and don't put all resources in one investment product. Similarly, the electric portfolio can be seen as being made more reliable and perhaps less prone to price volatility by ensuring a healthy mix of traditional and less traditional technologies. In addition, energy efficiency and conservation, discussed in the next chapter, are also an important part of the electricity portfolio because energy saved is energy that never needs to be produced.

Traditional non-renewable fuels for the generation of electricity include nuclear, coal, petroleum, and natural gas. These fuels continue to provide the vast majority of our energy today. Supplies of non-renewable fuels are finite. Renewable energy technologies, on the other hand, could be considered infinite. A rule of thumb in defining a renewable fuel is that its source can replenish itself within a human generation—on the order of 25 years. An additional desirable characteristic of many forms of renewable energy are that they are highly biodegradable and have very low toxicity. For example, wind and solar energy are considered infinitely renewable, and hydro and biomass resources take only months or years to replenish the energy source. Other fuels that are considered renewable are in fact, waste fuel sources. For example, mixed municipal solid waste is from a waste stream that is a mixture of household and construction products.

What is most significant about renewable energy technologies is that many of them have evolved from the research phase to market readiness. For example, wind energy, although limited by its intermittent nature, has evolved to the point where the price of electricity generated by wind is competitive with other forms of electricity on the market today. As discussed below, the Minnesota Office of Energy Security is expanding its role to promote more and different energies by focusing its research efforts and allotting grants to projects designed to implement new technologies.

A. RENEWABLE ENERGY

In addition to wind power, the price of other renewable energy has declined significantly, with re-powering existing hydro facilities and biomass co-firing also showing prices that are competitive with new natural gas and coal technologies. As the cost of electricity generated using traditional fuels increases, either due to increased fuel prices (natural gas, in particular) or increased emissions control measures, prices for renewable energy will continue to become more attractive.

B. RENEWABLE ENERGY POLICIES AND PROGRAMS

Recognizing the importance of diversifying its electricity portfolio, Minnesota has a number of state programs and policies to encourage renewable energy development. The OES is involved in the implementation of renewable energy policies such as the Renewable Energy Standard (25

percent renewable electricity goal by 2025), green pricing (renewable electricity choice options), and the development of a regional certification, tracking, and trading mechanism for renewable energy, in collaboration with other Midwestern stakeholders.

1. Evolution from the Renewable Energy Objectives to the Renewable Energy Standards

The 2001 legislature included several provisions to promote the development and use of renewable energy in Minnesota. The most significant of these provisions is the Renewable Energy Objective (REO—Minn. Stat. §216B.1691). As originally enacted, the REO required each of these utilities to make a good faith effort to ensure that at least one percent of the energy the utility provided to Minnesota consumers was generated by an eligible renewable energy source by 2005, and to increase this amount to 10 percent by 2015.

The 2003 legislation amended the statute to make the renewable energy objective a requirement for Xcel (rather than a "good faith" objective) above the renewable capacity mandated in the 1994 legislation (825 megawatts of wind, 125 megawatts of biomass), and required the utility to invest in another 300 megawatts of wind energy capacity (above the 1994 amounts) by 2010. In addition, the legislation required the Commission to establish criteria and standards to measure an electric utility's efforts to meet the renewable energy objectives to determine whether the utility is making the required good faith effort and authorized the Commission to establish a renewable energy credits trading program for the REO, whereby utilities could purchase certified renewable energy credits rather than generate or procure the renewable energy directly.

In February 2007, Minnesota enacted legislation that:

- created a renewable energy standard (RES) beginning in 2010;
- modified the state's existing non-mandated renewable-energy objective;
- required the MPUC to establish a trading system for renewable credits; and
- amended the definition of "eligible energy technology."[13]

By 2010, a utility should make a good faith effort to generate or procure 7 percent of its retail electric sales from an eligible energy technology. The standard for Xcel Energy requires that eligible renewable electricity account for 30 percent of total retail electricity sales (including sales to retail customers of a distribution utility to which Xcel Energy provides wholesale service) in Minnesota by 2020. Of the 30 percent renewable energy required of Xcel Energy in 2020, "at least" 25 percent must be generated by wind-energy systems, and "the remaining" 5 percent by other eligible technologies. The standard for other Minnesota utilities requires that eligible renewable electricity account for 25 percent of retail electricity sales to retail customers (and to retail customers of a distribution utility to which one or more of the utilities provides wholesale service) in Minnesota by 2025. The RES schedules are as follows:

[13] The definition is "electricity generated by solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass, which includes landfill gas, anaerobic digestion, and municipal solid waste."

Xcel Energy	Other Minnesota Utilities
15% by 12/31/2010	12% by 12/31/2012
18% by 12/31/2012	17% by 12/31/2016
25% by 12/31/2016	20% by 12/31/2020
30% by 12/31/2020	25% by 12/31/2025

The 2007 legislation required the MPUC to establish a program for tradable RECs by January 1, 2008. The MPUC approved the Midwest Renewable Energy Tracking System (M-RETS) for this purpose in October 2007 and required all utilities to make a substantial and good faith effort to register renewable generation assets by March 1, 2008. The program treats all eligible renewable energy equally and may not ascribe more or less credit to energy based on the state in which the energy was generated or the technology used to generate the energy. Notably, Xcel Energy may not sell RECs to other Minnesota utilities for RES-compliance purposes until 2021. In December 2007 (in Docket E-999/CI-04-1616), the MPUC made certain additional determinations for the operation of the REC trading system.[14] This docket remains open to address issues not covered during the first phase of rulemaking, as well as future implementation issues that may arise due to changes in national, state, or M-RETS policies and protocols. M-RET is operational. Early in 2009, the OES will provide a separate report to the Minnesota Legislature summarizing utility compliance with the Minnesota Renewable Energy, Minn. Stat. §216B.1691.

2. Clean Energy Resource Teams (CERTs)

CERTs is an innovative partnership between the state Office of Energy Security, University of Minnesota Regional Sustainable Development Partnerships, Minnesota Project, Green Institute, and Southwest Regional Development Commission. The program gives citizens a voice in the energy planning process by connecting them with the technical resources to identify and implement community-scale renewable energy and energy efficiency projects (see: www.cleanenergyresourceteams.org).

CERTs was established in 2003 with an initial grant from the Minnesota Legislative and Citizens Commission on Minnesota Resources. FY 2008 and 2009 funding comes from the Renewable Energy Development Fund (see Laws of Minnesota 2007 Chapter 57, Sec. 3, Subd 6(2), and Subd. 25) and several foundations. There are six greater Minnesota regional teams and a Twin Cities metropolitan area network. Teams are comprised of interested community, industry and government stakeholders. Each region meets regularly to educate themselves about energy

[14] In the Docket E-999/CI-04-1616, the MPUC made the below listed determinates:

- RECs will have a trading lifetime of 4 years according to the year of generation (i.e., all credits generated during 2008, regardless of the month, will expire at the end of 2012).
- The purchase of RECs through M-RETS may be used in utility green pricing programs, subject to the shelf life described above.
- Consistent with M-RETS operating procedures, RECs must remain "whole" and may not be disaggregated into separate environmental commodities (e.g., carbon emission credits)
- The MPUC declined to issue a directive ascribing ownership of RECs where ownership is not addressed in power purchase agreements (PPAs), instead requiring utilities to pursue negotiations and settlements with the owners of generation units.

issues, planning, and technology and then develops a plan to implement specific energy efficiency and renewable projects based on their priorities. The State Energy Office within the Office of Energy Security uses federal funding to support the CERTs teams with project related costs.

CERTs provides technical and grant support for a number of projects. In many instances a small grant is used to leverage additional funding. A representative sample of the over 70 recent projects CERTs has been involved with include:

- Solar project at the ARTech School in Northfield, MN, which resulted in 2,500 kWh energy offset/year.
- Solar project with the Two Harbors High School which effectively offsets over 3,500 kWh/year.
- Installation of a 20 kW wind turbine in Park Rapids, MN which provides over 25,000 kWh of energy/year.
- Installation of 200 CFL light bulbs on the White Earth Reservation, which will save nearly 10,000 kWh of energy per 7 year life of each lamp.
- Exploring wind development and energy efficient retrofit potential for Arctic Cat in Thief River Falls.
- Installation of a solar array at the North Shore Community Charter School in Duluth and development of a solar curriculum package.
- Assistance to the Rural Renewal Energy Alliance in Pine River who manufacturers and installs solar heating systems for low-income families.
- Assisted West Central Telephone Company in implementing renewable energy technologies which lead to a research grant from Xcel Energy.
- Partnership with the Southwest Initiative Foundation to organize statewide events focused on distributed generation and the Youth Energy Summit.

CERTs holds regularly scheduled forums, workshops and conferences that provide opportunities for legislators, regulators, business owners and citizens to meet and share energy efficiency and clean energy experiences from across Minnesota.

3. Green Pricing

Minnesota's voluntary green pricing program gives consumers the option of purchasing renewable energy beyond the minimum standard set by the state. By paying a premium on their electricity bill, consumers support increased development of renewable energy projects and reduce their reliance on fossil fuels. Increased use of renewable energy sources also benefits the local economy and improves Minnesota's energy security.

The Office of Energy Security regulates green pricing programs in the state to protect consumer interests. Renewable energy procured on behalf of green pricing customers cannot be sold twice or counted toward any state's Renewable Energy Standard. Utilities must report on renewable energy procured for green pricing customers to verify that green pricing sales do not exceed

green pricing generation. Starting with fiscal year 2009, utilities will record renewable energy credits for green pricing generation in the Midwest Renewable Energy Tracking System (MRETS) to verify compliance.

From July 1, 2007–June 30, 2008, electric utility green pricing programs in Minnesota sold 181,550 megawatt-hours of renewable electricity, a 28% increase over the previous fiscal year.

4. Renewable Energy Tradable Credits

The Renewable Energy Objective (216B.1691) and Green Pricing (216B.169) create the possibility of a market for renewable energy. Under the notion of Renewable Energy Tradable Credits, electricity from renewable sources may be treated as a separate electricity commodity with additional value attributes. Many renewable energy contracts between electric utilities and energy producers now contain language specifying the ownership of the renewable or green attributes, commonly called renewable credits or "green credits." These green credits could potentially be used for green pricing programs and renewable energy objectives or for emissions credits in pollution reduction markets.

5. Net Metering

Net metering is a state policy that allows small renewable electric generators to offset consumption at the retail rate. All electric utilities in the state are required to offer a net metering option to their customers. Minnesota was the first of 40 states to enact net metering (MN Statute 216B.164 and MN Rule 7835). In 2006, there were 190 net metered facilities (less than 40 kilowatt capacity) in Minnesota. Of those 190 facilities, 134 were small wind turbines and 56 were solar photovoltaic systems.

6. Wind Energy

Wind energy technologies that generate electricity have become the most visible form of renewable energy in Minnesota. Minnesota has a significant wind resource, especially in the area commonly known as the Buffalo Ridge in the very southwestern part of Minnesota. In the southeastern part of the state, in Mower County, the combination of a good wind resource and access to the existing transmission grid has led to a rapidly increasing level of wind development activity.

Transmission has been a major factor limiting further development in the southwest portion of the state. Xcel Energy is in the process of siting a major high voltage transmission line in the Buffalo Ridge area. While this project will help to mitigate the area's transmission constraint, additional transmission will be necessary to continue to develop this resource. As discussed earlier, one of the three major transmission projects in CAPX2020 is designed to cross the southern part of Minnesota to bring wind generated electric power from the Buffalo Ridge area to the major consuming markets, including the Minneapolis/St. Paul metro area.

To help meet state Renewable Energy Standard goals before new transmission lines become available, state legislation in 2007 required a statewide study of dispersed renewable generation potential to identify locations in the transmission grid where a total of 1200 MW of relatively-small renewable energy projects could be operated with little or no change to the existing infrastructure. For the purposes of the study, dispersed renewable energy projects are wind, solar and biomass projects that will generate between 10 and 40 MW of power.

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Phase II of the study began in October of 2008. The goal of Phase II is to identify locations for an additional 600 MW of dispersed renewable energy. A report on the results of Phase II is due by September 15, 2009.

Due to the intermittency of the wind resource, wind energy, by itself, cannot be relied upon for baseload or peaking purposes because it cannot be “dispatched” (turned on or off as needed). However, this drawback can be mitigated by being matched with another type of generation resource that has the ability to “follow” the wind energy (turned on or up when the wind is not blowing, turned off or down when wind energy is being generated).

Xcel owns or purchases power generated by roughly 1200 megawatts of wind energy capacity in Minnesota. Xcel is expected to purchase an additional 2,000 – 3,000 megawatts in the region by 2020 to satisfy its need under Minnesota’s and neighboring states’ Renewable Energy Standard requirements or goals. In total, this amount would represent over 20 percent of its total generation capacity. In 2004, Xcel commissioned an independent study of the costs of managing this amount of wind on their system. The results of this study led to a larger, statewide wind integration study completed in 2006 showing that the integration of wind power into the generation mix at a regional level to meet 20 percent of Minnesota’s electric consumption need would result in a negligible incremental reliability cost.

As reported in the 2004 Quadrennial Report, in 2003, the OES received funding through the Legislative Commission on Minnesota Resources to offer rebates for community wind energy projects. Following a strong response to a request for proposals, the following two community wind projects were chosen and completed in 2005:

- Carleton College installed a 1.65 MW wind turbine. The project was completed in 2004. The turbine is estimated to produce 4.5 million kilowatt-hours of electricity per year; and

- University of Minnesota West Central Research and Outreach Center (U of MN WCROC) installed a 1.65 MW wind turbine which provides the campus with 5.6 million kilowatt hours of energy annually--more than half of its annual electricity requirement. Of equal or greater interest is the wind turbine's potential to generate additional energy sources and to provide a platform for research in areas of stored wind energy with hydrogen, fuel mixing, and value-added products such as wind-produced fertilizer.

Individual turbine projects cost more than traditionally fueled generating facilities per kilowatt to install but the upfront capital investment can be recovered in less than 10 years in a large part of Minnesota, depending on the wind resource, utility buyback rate, and the extent of transmission constraints.

In 2005, the OES received an additional $400,000 to implement an additional phase of the Community Wind Energy Rebate Program. The purpose of the program is to showcase and demonstrate innovative community wind projects. After a competitive bid process, funding is reserved for two additional projects including:

- Community Wind Initiative, collaboration between the Rural Minnesota Energy Board (RMEB) and the Metropolitan Energy Policy Coalition (MEPC). RMEB has identified Lyon County Landfill as a viable site for up to three large scale turbines. The Lyon County site is studying the viability of utilizing methane recapture at the landfill to generate electricity as well. The addition of the turbines to the site increases the overall project viability and reduces the interconnection costs for both projects.

- Community Winds of Winona County is developing two (2) one megawatt wind turbines in Altura, Minnesota.

Each project has $200,000 reserved under this program.

Minnesota has long been a national leader in promoting locally owned wind development. In 2005, Minnesota's legislature directed utilities to create a tariff for Community-Based Energy Development (C-BED) projects. In November of 2005, Governor Pawlenty established a C-BED goal of an additional 800 megawatts (MW) of locally owned wind projects by 2010. There has been a significant growth in the contribution from C-BED projects between 2007 and 2008.

Table 3
C-BED Project

	December 31 2007	December 31, 2008
MN Total Installed Wind	1,298 MW	1,627 MW
Installed C-BED	2.5 MW	119.5 MW
Total MN Community Wind	324 MW	450 MW

Thus, as a result of the hard work of community leaders, project developers, and utilities, nearly a third of new wind capacity installed in 2008 was community owned.[15]

7. Wind Monitoring Program

In 1982 the OES began the Wind Resource Assessment Program (WRAP) to systematically measure and map the state's wind resources. The 14th edition of the WRAP Report, published in 2002, provides summary wind speed and directional data for each site that the OES monitored. In 2005 the OES commissioned detailed wind maps generated with sophisticated modeling techniques by WindLogics. The new wind maps cover all regions of the state at a higher resolution than previous wind maps using a meso-scale weather model that incorporates long term weather data and satellite measurements.

C. BIOMASS ENERGY

Biomass is a large and varied category of renewable energy, loosely defined as direct derivatives from plant and animal products or by-products. This category can encompass everything from trees, vegetation and agricultural products, to manure, and wastewater. Biomass energy production can be generally divided into three categories: combustion, digestion, and decay.

1. Biomass Combustion

Biomass combustion consists of the direct combustion of the biomass product or a derivative of the product to produce heat, which is used directly or for producing electricity. The most common example of a biomass combustion facility is a fireplace.

Currently nearly all commercial biomass combustion facilities in Minnesota use waste products—waste logging, manufacturing, or trimming residues. The cheapest methods for using biomass are for direct heating, often via a boiler, or for co-firing in an existing fossil fuel plant. The biomass can also be gasified then combusted, using techniques similar to coal gasification. Saint Paul's 33 Megawatts District Energy Heating and Cooling System is an example of a high efficiency biomass project that uses urban waste wood.

[15] Information regarding C-BED installation is updated quarterly on our website at: http://www.state.mn.us/mn/externalDocs/Commerce/CBED_Projects_Report_121107120316_UtilityC-BEDProjects.pdf

2. Biomass Digestion

Biomass can be anaerobically digested to produce biogas, a combination of methane, carbon dioxide, and trace gases. The biogas can then be used for heating, producing electricity, or both. Anaerobic digestion of animal manures, waste water effluent, or food wastes is most common.

A previous OES study found that on-farm manure digester systems are generally limited to dairy farms with 400 cows or more; this size allows for economically producing electricity without additional funding sources. However, smaller sizes may be feasible for heat recovery only, especially when a covered lagoon is being installed for manure management. Swine digesters require very large sized farms greater than 10,000 swine to begin considering electricity generation. However, it is possible to produce methane for its heating value on smaller swine farms. Since there are many transaction costs associated with generating electricity in small-sized systems, it may not be worth the complexity of interconnection and additional costs to set up manure digester systems in such circumstances. Manure digesters may be a good compromise alternative where regulations, permitting, or neighbor objections pose difficulties for a new or expanded farm operation.

Mixed waste digesters can incorporate manure, food processing waste, or other digester-suitable material. A possible benefit of digesters for large facilities is that they can reduce the load on municipal wastewater treatment facilities. Wastewater treatment facilities can sometimes be retrofitted to capture methane to heat the digester and/or facility, and sometimes generate additional electricity.

As shown in the table below, there are five OES on-farm anaerobic digestion grant projects scheduled in 2008.

OES 2008 On-Farm Anaerobic Digestion Grant Projects

Est. KWh	**Facility**	**Grant**	**herd size and total project cost**
1,965,000	Daley Farms Digester LLP (with GHD)	$250,000.00	1000 head project $1,267,000 total cost
13,297,680	Riverview Dairy of MN, LLP	$225,000.00	7,400 head $4,873,000 total cost.
2,061,519	Diamond K Feeds, LLP	$250,000.00	950 (expanding to 2000 head) $2,062,000 total cost
13,297,680	West River Dairy, LLP	$225,000.00	6600 head project $4,873,000 total cost
262,800	Jer-Lindy Farms	$48,500.00	200 head project $540,000 total cost
30,884,679	Total kWh anticipated	$998,500.00	

3. Biomass Decay

Biomass Decay

Landfill gas (LFG) is a waste fuel from the decay of municipal solid waste (MSW). MSW in Minnesota is estimated to contain approximately 60 percent biomass in paper and organic materials.[16] LFG is defined by Minnesota Statute 216B.2422, subd. 1 as a "renewable energy." By 2010, Minnesota utilities are encouraged to generate one percent of electricity from biomass (LFG).[17] According to the Minnesota Pollution Control Agency, there are seven landfill gas-to-electricity recovery projects in Minnesota totaling 26.2 megawatts.[18] The facilities are:

Table 4
2006 Minnesota LFG Operations[19]

Facility	Electricity
1. Pine Bend	12.0 MW
2. Burnsville	4.2 MW
3. Elk River	4.3 MW
4. WDE	0.2 MW
5. Anoka-Ramsey/Planergy	1.5 MW
6. Spruce Ridge	2.4 MW
7. East Central SLF	1.6 MW
Total	26.2 MW

In addition, the Minnesota Pollution Control Agency plans to issue a request for proposals for landfill gas to electricity projects at the Louisville Landfill in Shakopee and the Woodlake Landfill in Medina.

The EPA Landfill Methane Outreach Program (LMOP) estimates there is a potential electric production from LFG in Minnesota of approximately 45 MW with 10 MW from 11 closed landfills and 11 MW from 9 open landfills in addition to the 26.2 MW from established LFG facilities. However, other landfills in Minnesota may be good candidates for heat or electricity generation. Heat recovery is generally the most cost-effective method. Many landfills have to collect and flare methane emissions and capturing this resource for heating or electricity production can make both good energy policy and economic sense.

D. SOLAR ENERGY

Solar energy can be used for producing heat and electricity in Minnesota. A common misconception is that the amount of sunlight received in an area is based on temperature. In reality, Minnesota has a significant solar resource. In fact, it is about the same as Houston, Texas. As a recognized leader in renewable energy development, Minnesota continues to grow

[16] See "Statewide MSW Composition Study" March 2000, Solid Waste Management Coordinating Board.
[17] Minnesota Statute 216B.1691, subd.2.
[18] www.cleanenergyresourceteams.org/files/CERTs_presntations_Landfill_Gas_2.pdf
[19] EPA Landfill Methane Outreach Program, Landfill Database http://www.epa.gov/lmop/proj/xls/lmopdatamn.xls

its solar resource for the benefit of Minnesota's economy, environment, and energy security. To this end, the Office of Energy Security administers several solar initiatives, including a solar rebate program (for both solar electric and solar thermal) and a new solar hot air grant program for low income households.

1. Solar Rebate Program

The solar rebate program is supported by the Minnesota legislature and funded through Xcel Energy's Renewable Development Fund. Between 2002 and 2006 approximately $1 million was spent to encourage 500 kilowatts (131 installations) of grid-connected solar-electric systems. During the first two years, there were few applicants to the program; by 2006, however, the program's popularity grew as applicants fully reserved available funds. For fiscal years 2008 and 2009 an additional $1.2 million was allocated for solar electric and solar hot water. These funds were fully reserved six months prior to the end of the funding cycle.

2. Solar Electric Rebate

Minnesota achieved a milestone of more than one megawatt of solar photovoltaics in the summer of 2008. Minnesota's Solar Electric Rebate programs are responsible for most of this development, along with federal investment tax credits (now extended through Dec 31, 2016). The $1.1 million Solar Electric Rebate Program for FY 08/09 will result in an additional 150 installations receiving $2,000 per kilowatt rebates for grid-connected solar electric installations of up to 10 kilowatts. The average total cost of a solar photovoltaic system under the program was $9,774 per kilowatt. The last year of the program was limited to professional installations (by licensed contractors and professional engineers) in an effort to support better performing systems and workforce development. In addition, program guidelines were revised this year to offer additional incentives ($2,250 per kilowatt) to applicants who choose North American Board of Energy Practitioners (NABCEP) Solar PV Certified installers. Minnesota is one of a number of states whose programs recognize the value of NABCEP certification. NABCEP certified installers have signed a code of ethics, met specific standards of experience and training, and passed a four hour exam. This voluntary certification helps protect consumers and enhances the solar profession by promoting training and regular continuing education. The number of certified installers in Minnesota climbed from four to fourteen between 2006 and 2008.

3. Solar Hot Air

The Renewable Energy Equipment Grant is a new program to assist low income households with their heating needs through the use of renewable energy technologies, including solar hot air panels. The grant program, created by the Minnesota State Legislature and administered by OES, is open to clients of the low income weatherization program and will make solar an option for a greater number of Minnesotans. The hot air panel systems (many of which are manufactured in Minnesota) mount on the exterior of buildings and circulate air heated by the sun to offset a portion of the energy used by a traditional heating system. Relatively inexpensive to install and operate, the panels will help families realize long-term financial benefits through energy cost reductions of 20-25%.

4. Solar in the Cities

OES is a partner in the Minneapolis Saint Paul "Solar in the Cities" initiative. *Solar in the Cities* is supported by the U.S. Department of Energy's Solar America Initiative which promotes solar photovoltaics, a type of solar electricity viable in Minnesota, to be cost-competitive by 2015. As part of this effort, OES has committed to working with other Minnesota organizations on a strategic planning process to mainstream solar technologies in the coming decade.

5. Solar Hot Water Rebate

The residential Minnesota Solar Hot Water Rebate (launched July 2008) promotes investment in solar domestic hot water systems, with state matching funds of up to $2,500 for a single family home and up to $10,000 for multi-family dwellings. One innovative feature of the program is the requirement that energy efficiency standards be met through a hot water energy audit as part of the process, thus maximizing the benefits of the solar hot water system. The rebate program was preceded by solar thermal training co-sponsored by OES and four Minnesota electric utilities. One hundred twenty people attended the training which was open to plumbing and mechanical contractors--trades that are well-positioned to fold solar thermal technologies into their business operations. Several building authority officials attended as well. The $100,000 program was fully reserved after five months.

E. HYDROELECTRIC ENERGY

Minnesota has approximately 195 megawatts of hydroelectric generation located within the state, the largest being Minnesota Power's Thompson Dam at 75 megawatts. Minnesota also imports a significant amount of hydroelectric power from Manitoba, Canada.

While the ability to add more hydroelectric facilities depends on the flows of water and surrounding terrain, certain niche opportunities may exist for hydroelectric expansion. A 1996 assessment report released by the U.S. Department of Energy lists 40 sites in Minnesota with an additional 137 megawatts of hydropower potential: 12 upgrades to existing power generation sites (72 megawatts), 21 additions to existing dam sites with no power generation (51 megawatts), and 7 undeveloped sites (14 megawatts). Minnesota offers a production incentive for certain hydroelectric facilities. Redwood Falls and Blue Earth County are currently receiving the state hydroelectric production incentive for having refurbished their facilities.

F. NEXT GENERATION ENERGY BOARD

The Next Generation Energy Board was established by Governor Pawlenty as part of the Next Generation Energy Act of 2007. The board develops next generation energy and biofuels policy, and makes recommendations to the Governor and Legislature about how the state can invest its resources to most efficiently achieve energy independence, agricultural and natural resources sustainability, and rural economic vitality. As a result of the establishment of the Next Generation Energy Board, more funds are available to accelerate the renewable energy projects and advance biofuels in Minnesota. Recently, Governor Tim Pawlenty announcement that eight projects will receive nearly $3 million in state grants awarded by the Next Generation Energy

Board. “Emerging technologies are dramatically changing the way we produce and use energy,” Governor Pawlenty said. “These grants are part of our broader effort to Americanize and improve our energy sources and position Minnesota for economic growth.”

A total of 28 proposals were submitted to a technical review committee comprised of staff from the Departments of Agriculture, Natural Resources, Commerce, Employment and Economic Development and the Pollution Control Agency. After ranking the projects, eight were selected for funding. The eight projects are:

1. **Central Minnesota Ethanol Partnership, Little Falls - $910,000**
   The development of Minnesota's first commercial scale cellulosic ethanol plant is closer to reality because of this joint venture between the Central Minnesota Ethanol Cooperative, SunOpta BioProcess, and Bell Independent Power Corporation. The grant will fund the final stage of a study to determine the feasibility of building a commercial scale cellulosic ethanol plant that would be co-located with the existing Central Minnesota corn ethanol plant.

2. **Chippewa Valley Ethanol Company, Benson - $700,000**
   This project will introduce new technology that will allow the Chippewa Valley Ethanol Company facility to use farm or woodland biomass to power plant operations, replacing up to 90 percent of its current dependence on natural gas. The technology will also allow the facility to eventually transition from corn-based ethanol production to cellulosic ethanol production. Demonstrating the feasibility of this technology is a critical step in making biomass gasification a commercial reality.

3. **Rick Neuvirth Farm, Elkton - $220,000**
   Anaerobic digester technology uses methane gas produced from manure or other waste materials to generate electricity. This technology helps livestock facilities meet their energy needs and reduce operating costs while improving air quality and reducing odors. Anaerobic digester technology has proven to be very successful on dairy farms, but it has yet to be implemented in swine operations in Minnesota. Mr. Neuvirth, a hog producer, plans to use anaerobic digester technology on his swine operation, generating electricity to meet nearly 100 percent of his farm's energy needs.

4. **Northern Excellence Seed, Williams - $200,000**
   This seed company's project will demonstrate the viability of burning waste biomass such as grasses to produce electricity, which will bring the state closer to commercializing small-scale gasification technology and use of turf grass biomass to produce electricity.

5. **Minnesota Valley Alfalfa Producers, Raymond - $400,000**
   One of the challenges facing biomass-to-energy technology is how to efficiently store and transport various raw materials such as crop waste, grasses and woodland biomass. This farmer-owned cooperative will demonstrate a promising approach

called "pelletizing," in which a variety of biomass materials are processed into uniform sized pellets that can be more easily stored and transported.

6. **University of Minnesota Department of Forestry, St. Paul - $100,000**
The U of M will study the sustainability of the state's approximately 16 million acres of forests. As the demand for woody biomass increases, the study will provide key information for public officials and private investors about the supply of woody biomass in order to ensure sound policy and investment decisions.

7. **Central Lakes College Ag Center, Wadena - $100,000**
The project will provide significant insight into the production feasibility and energy content of five perennial energy crops, including four native prairie plants. The project is a partnership between a MnSCU campus, local farmers and University of Minnesota faculty in evaluating switch grass, intermediate wheatgrass, Survivor false indigo, prairie cord grass and miscanthus. The project will demonstrate best-management practices for growing and harvesting the grasses for use as cellulosic energy crops.

8. **University of Minnesota, Morris - $50,000**
The University of Minnesota, Morris is in the process of installing a biomass gasifier to serve as the campus heating plant and help reduce campus energy costs. This project will lead to the development of a contract with a biomass producer and establish a model for biomass production.

G. DIESEL GENERATORS

Diesel fuel is used in peaking diesel generators that account for more than 1,600 megawatts of peaking capacity in Minnesota, which approaches the combined capacity of the Prairie Island and Monticello nuclear power plants. Diesel generators have a low installed cost, high operating costs, low permitting requirements, and do not operate many hours of the year. However, they do operate primarily during periods of high summer demand and can be an air emissions concern. Many of these plants are older and can have locally high emissions.

To reduce emissions and produce renewable energy, diesel generators, for example, can use percentage blends of biodiesel. Using higher blends of biodiesel (greater than 20 percent) is being investigated for compatibility with various types and generations of generators (older generators may not have certain parts that are compatible for long-term use of biodiesel). Using biodiesel in these generators may be a low-cost method of reducing many air emissions, but further demonstration and research in a larger number of generator types may be necessary. Although more research is needed on nitrogen oxide (NOx) biodiesel emissions, biodiesel does significantly reduce hydrocarbon (HC) emissions. NOx and HC are both precursors to ground-level ozone formation.

1. UMN Biodiesel Generator Testing

The University of Minnesota Center for Diesel Research (CDR) performs both laboratory and field demonstration tests of diesel electric generator performance and emissions when using biodiesel blended fuel. The CDR has five current projects underway testing biodiesel.

2. The Zoo School Field Test

Based on lab test results among other findings, better fuel economy and reductions in particulate emissions of up to 30 percent and NOx reductions of up to 19 percent, a B20 biodiesel blend combined with supplemental charge air-cooling was demonstrated on a standby generator at the School of Environmental Studies at the Minnesota Zoo (hence, the name “Zoo School”) in Apple Valley. Specifically, the field test compared the emissions, particulate and gaseous, from a 3406 Caterpillar engine operated on regular Diesel Fuel and on B20. The B20 used was a blend of 20% Soy Diesel (soy methyl ester) and 80% of the same regular diesel used as a "baseline" for the testing. Tests were conducted at two different intake air temperatures and two different loads. The field study portion of the project, titled "Improving Air Quality by Using Biodiesel in Generators," is complete

3. VW TDi Testing Resumes

A new Euro IV compliant VW TDi engine has been installed on a regenerative DC dynamometer test stand and emissions testing has begun. This work follows a significant assortment of tests conducted on a 1999 TDi VW engine. Those tests included running a synthetic Fischer-Tropsch fuel and 100% RME Biodiesel looking at the emissions effects of fuel, especially nanoparticle emissions and looking at the effects of lubricating oils on nanoparticle emissions with this engine.

4. Exhaust After Treatment Testing and Development

A variety of recent tests have been conducted to help a customer develop diesel exhaust aftertreatment systems. DOC's (Diesel Oxidation Catalysts), DPF's (Diesel Particulate Filters) and Lean NOx Catalysts have been tested over a variety of steady state and transient cycles. Particulate and gaseous emissions data are recorded.

5. The Effects of Lubricating Oils on Nanoparticles

Work is just beginning on several projects that will investigate the effects of lubricating oil formulation on exhaust nanoparticle (nuclei mode particle) emissions.

6. "Pseudo" FTP Test Cycle

The CDR has successfully implemented a test cycle that mimics the FTP (Federal Test Procedure) heavy-duty transient cycle but does not include any of the motored portions of the cycle. When the actual cycle calls for the engine to be motored, a no load condition is applied. The cycle is 1200 seconds long and preliminary results of NOx data show good correlation with

the actual test cycle. The CDR was able to measure raw gaseous emissions during the cycle and those values are integrated to give average brake specific values for the cycle. A post consent decree Cummins ISM engine is currently installed on the test stand capable of running this cycle.

H. OTHER ENERGY TECHNOLOGIES

This discussion of fuel sources focuses on fuels and technologies that show efficiency or emissions improvements over traditional generating sources or pertinent to policy issues in Minnesota.

1. Combined Heat and Power

Despite some barriers to CHP projects, such as the cost of standby power, there are several exciting projects moving forward in the state. One innovative CHP project is Koda Energy, a partnership between the Shakopee Mdewakanton Sioux Community and Rahr Malting Co., facilitated by Xcel Energy, to build and operate a CHP plant fueled by agricultural byproducts and grown energy crops. Koda is also exploring options for burning native prairie plants and biosolids. In January 2009, Koda Energy will start up the boilers in the new CHP biomass facility located on the Rahr Malting campus in Shakopee. The plant will generate electricity and heat using agricultural byproducts from the malting process, waste trees and eventually biomass energy crops. Experts from the University of Minnesota are assisting with identifying appropriate sites in the area for a new type of crop--energy crops such as native grasses or other plants that could be harvested, dried and burned inside the plant to turn its gigantic turbine blades. They also are identifying the co-benefits these crops would provide, such as prevention of agricultural runoff, so benefits could be bundled to increase their value and attract farmers to invest in energy crops.

Electrical power generated by the facility, expected to average 18,130 kW (gross), with net power generated at approximately 19.5 kW, will be used by Koda Energy and sold onto the grid initially. Rahr Malting will also use waste heat from the generation in their malting process. Waste from malting and food processing will be used primarily to generate electricity. Other raw materials like wood chips, biosolids, and switch grass will also be burned. Agreements are already in place between Koda Energy and General Mills which will provide oat hulls from the processing of cereals like Cheerios from the Coon Rapids facility. Other contracts for additional raw materials are being negotiated.

Another biomass CHP project, at Northern Excellence Seed, a producer-owned grass seed company in Williams, Minnesota, has temporarily stalled to sort through options for interconnection. Northern Excellence Seed is in the process of installing a first of its kind, 100-kilowatt gasifier capable of burning seed chaff and straw that hasn't been pelletized. This project is facing the particularly difficult challenge likely to confront any new CHP technologies in Minnesota – how a company can afford to pay for the power it will need during the time when a brand new energy technology (serial number 1) is being installed, set up and optimized. Northern Excellence Seed needs the ability to use the utility's generation resources on a "firm" basis while their new system gets set up, tested and optimized, which for a new technology can

easily take a full year. Once the CHP system is performing to specification, Northern Excellence Seed will have performance data to base future power need decisions, which should be considerably less than during the testing and optimization period needed for new technologies.

The cost of standby power to a customer depends on their needs. If a customer only wants the ability to sell their power to the utility, they do not pay for the utility's generation. However, some customers, such as Northern Excellence Seed, need the ability to use the utility's generation resources on a "firm" basis – i.e., they need access to power, possibly during their own peak and their utility's peak time, until their own generation technology is fully installed and optimized. Customers like Northern Excellence Seed are required to pay for that service the same as other customers. These rates can be almost as much as the full prices of electric service because a utility has to build the required amount of energy into its planning process.

The Minnesota Public Utilities Commission (PUC) addressed this issue in the Distributed Generation (DG) workgroup. The PUC determined that DG customers must pay for the costs they impose on the electric utility system to ensure that other customers did not have to subsidize DG customers. Because the PUC has recently ruled on this issue, attempting to address service rates for DG projects through the PUC may not an effective option. But there are other alternatives for promoting CHP. One promising alternative is output-based regulations (OBR), which encourage efficiency and renewable energy as air pollution control measures. OBR establishes performance criteria that allow efficiency and renewable energy to compete on equal footing with other methods of reducing emissions, such as combustion and add-on controls.

Traditionally, boilers and power generators have been regulated on an input basis, with emission limits established on a unit of pollutant emitted per unit of fuel input basis (e.g., pounds per million British thermal units [lb/MMBtu]). This approach relies on the application of pollution control devices to reduce emissions and does not explicitly recognize the efficiency of the process in converting fuel input into a useful output. Establishing emission limits on an output basis—units of pollutant per unit of useful output (e.g., pounds per megawatt-hour [lb/MWh])—recognizes efficiency improvements as pollution prevention. Several states, including Connecticut, Massachusetts, and Indiana, have used OBR for certain particulate emissions.[20]

Northern Excellence Seed and company's like it that are pursuing CHP have another option. Rather than use the electricity they generate, they can sell it through a power purchase agreement to a generation utility and continue to purchase all of the electricity they use from their local

[20]Connecticut has promulgated an OBR for nitrogen oxides (NO_x), particulate matter, carbon monoxide, and carbon dioxide (CO_2) from small distributed generators (less than 15 megawatts [MW] capacity), including CHP. The regulation values the efficiency of CHP based on the emissions that are avoided by not having separate electric and thermal generation. Indiana has created a set-aside of allowance allocations for energy efficiency and renewable energy in its NO_x trading program. Indiana allocates 1,103 tons of NO_x allowances each year for projects that reduce the consumption of electricity or energy other than electricity, or generate electricity using renewable energy. Massachusetts has used OBR in its NO_x cap-and-trade program to allocate emission allowances to affected sources (generators greater than 25 MW). This approach provides a significant economic incentive for CHP within the emissions cap. Massachusetts also has a multi-pollutant emission regulation (DOC) (NO_x, sulfur dioxide, mercury, CO_2) for existing power plants, which uses an output-based format for conventional emission limits.

utility. The difference in price can be considerable. A company typically pays about eight cents per kilowatt for their firm electric service but is lucky to get half that amount for the electricity that it sells.

Other updates on other CHP projects include: Minnesota Power is trying to allow more steam to be routed through its turbines via steam efficiency improvements. The New Ulm Public Utilities Commission is studying upgrades and biomass fuel for its existing district heating system. The Metropolitan Council (Met Council) has implemented fluidized bed incineration at the Metro Plant. Met Council also completed a study of heat recovery potential in 2008 and plans to install a non-condensing auxiliary turbine/generator, hopefully in the next two years. A new heat exchanger at Met Council's Seneca (Eagan) plant was already installed to recover heat from the discharge water of the incinerator scrubbers.

2. Coal Gasification

Modern coal plants have significantly fewer emissions than older plants due to advanced technologies and more stringent emissions reduction equipment. However, even new coal-fired electric generating plants produce emissions.

Integrated Gasification Combined Cycle (IGCC) technology has significant potential for reducing the emissions from coal fired electric generation. The unique technology is the "integrated gasification," while the "combined-cycle" portion is a conventional method of increasing efficiencies commonly used with natural gas. In coal gasification, coal is pulverized to a fine powder and then combusted with reactant gases rather than burned whole. The gasification process captures emissions before they are burned rather than filtering them afterward. The size of IGCC plants that have been tested range from approximately:

- 100 megawatts for the Pinon Pine project in Nevada;
- 250 megawatts for the Tampa Electric project in Florida; and
- 262 megawatts for the Wabash River project in Indiana.

A fourth demonstration project of approximately 540 megawatts is currently underway in Kentucky.

The heart of gasification-based systems is the gasifier. A gasifier converts the coal feedstock into gaseous components by applying heat under pressure in the presence of steam. The gaseous mixture is call syngas. Syngas is primarily hydrogen, carbon monoxide and other gaseous constituents, the proportions of which can vary, depending on the conditions in the gasifier and the type of feedstock. The syngas is cleaned of hydrogen sulfide, ammonia and particulate matter and is burned as fuel in a combustion turbine, much like natural gas, i.e. "integrated gasification." The combustion turbine drives an electric generator. Hot air from the combustion turbine is channeled back to the gasifier or the air separation unit, while exhaust heat from the combustion turbine is recovered and used to boil water, creating steam for a steam turbine-generator. This technology is known as "combined cycle" (see below).

The syngas can also be used as chemical "building blocks" to produce a broad range of liquid or gaseous fuels and chemicals or as a source for hydrogen that can be separated from the gas stream and used as a fuel.

3. Combined Cycle

Currently, only natural gas is widely used in a combined cycle power technology. The use of these two types of turbines—a combustion turbine and a steam turbine—in combination, known as a "combined cycle," is one reason why coal gasification-based power systems currently in existence can achieve higher power generation efficiencies than a conventional coal plant. Present gasification-based systems operate at efficiencies of around 45 percent. By contrast, a conventional coal-based boiler plant employs only a steam turbine-generator and is typically limited to 33–38 percent efficiencies.

4. Hydrogen and Fuels Cell

Hydrogen and the hydrogen economy have received a lot of attention recently. Hydrogen and its use in fuel cells, for example, represent a revolution in energy production and use. As discussed in more detail below, fuel cells can be used to make electricity and heat to operate our vehicles and buildings. Fuel cells use a chemical reaction rather than a combustion reaction and are more efficient than generation from combustion sources and have nearly no pollution.

Hydrogen is an energy carrier, not an energy source. As such, it is the only concept available today that could potentially be used to "store" electricity. Many other fuels can be converted to hydrogen but hydrogen itself does not occur naturally in a usable form. The hydrogen can be derived from renewable (electrolysis using renewable energy, biomass, ethanol, algae, etc.) or non-renewable sources (coal, petroleum, natural gas, methanol, propane, etc.). Because hydrogen can be derived from both nonrenewable and renewable energy sources, it can be tailored to a given state's or region's strengths.

The OES is one of the founding members of the Minnesota Renewable Hydrogen Initiative, a growing partnership of more than 200 industry, university, government and non-profit organizations. The Initiative is working to promote the production and use of hydrogen and fuel cells in Minnesota and help develop associated jobs and businesses. The Initiative has set a goal of becoming a national leader in renewable hydrogen production by the year 2010. Additionally, the OES has provided grants for fuel cell installations in Uninterruptible Power Systems applications in the telecommunications industry. This project will demonstrate fuel cells in a cost-competitive application.

5. Fuel Cells

Fuel cells are an important enabling technology for the hydrogen economy and have the potential to revolutionize the way we power our nation, offering a cleaner, more-efficient alternative for heating, electricity, and transportation. Fuel cells are being developed to power passenger

vehicles, commercial buildings, homes, and even small devices such as laptop computers and cell phones. The largest near-term market for fuel cells will most likely be in these small devices since the cost of electricity from batteries is very high.

A fuel cell is an electrochemical device that uses hydrogen (or a hydrogen-rich fuel such as ethanol or natural gas) and oxygen to create electricity and heat. If pure hydrogen is used as a fuel, fuel cells emit only heat and water as a byproduct. Several fuel cell types are under development, and have a variety of potential applications.

Fuel cells are classified primarily by the kind of electrolyte they employ. The electrolyte determines the kind of chemical reactions that take place in the cell, the kind of catalysts required, the temperature range in which the cell operates, the fuel required, and other factors. These characteristics, in turn, affect the applications for which these cells are most suitable. There are several types of fuel cells currently under development, each with its own advantages, limitations, and potential applications. One of the most promising types is the Polymer Electrolyte Membrane fuel cell.

Polymer electrolyte membrane (PEM) fuel cells, also called proton exchange membrane fuel cells, deliver high power density and offer the advantages of low weight and volume, compared to other fuel cells. They need only hydrogen, oxygen from the air, and water to operate and do not require corrosive fluids like some fuel cells. They are typically fueled with pure hydrogen supplied from storage tanks or onboard reformers.

PEM fuel cells are used primarily for transportation applications and some stationary applications. Due to their fast startup time and favorable power-to-weight ratio, PEM fuel cells are particularly suitable for use in passenger vehicles, such as cars and buses.

6. A Flexible, Adaptable Energy System

The production of hydrogen from electricity generated by wind turbines or other renewable energy technologies or even ethanol has significant potential in Minnesota. Hydrogen production provides a level of flexibility in that the hydrogen could be used for either vehicle applications or stationary electric power. Electricity stored as hydrogen would yield a smaller amount of energy due to losses in the conversion process, but the flexibility of the fuel and the ability to deliver the energy during periods that maximize the economics could overcome some, if not all of these losses. Wind-to-hydrogen plants could serve the hydrogen needs of small communities, or they could be used to firm up wind capacity so as to relieve constraints on our electrical transmission grid.

7. End-Users of Hydrogen in Minnesota

Within Minnesota, Flint Hills Resources (formerly Koch Petroleum Group) and Ashland Oil may be the largest users of hydrogen, employed in the refining process and to make fertilizers, but they are also hydrogen producers. In addition, most power plants use hydrogen for cooling their electrical generation equipment, and powdered metal plants are a growing market, where

hydrogen takes the place of dissociated ammonia in the metal coating process. Renewably produced hydrogen could also be used in the manufacture of anhydrous ammonia, a process that currently uses large quantities of hydrogen produced through the steam reformation of natural gas.

8. Laying the Foundation for Hydrogen in Minnesota

Minnesota has a significant presence in the fuel cell component supplier industry. Minnesota companies such as 3M, Tescom, Entegris, and Donaldson provide membranes, sub-assemblies and control systems used by a variety of PEM fuel cell manufacturers. Cummins Power is actively pursuing development of solid oxide fuel cells. Companies such as Praxair, Flint Hills Resources, and Marathon Ashland Petroleum have significant experience with handling hydrogen and fueling infrastructure. Given that the economic viability of renewable hydrogen is largely dependant upon the cost effectiveness of producing renewable fuels and power, the state's strength in the renewable biofuels and wind power provides competitive advantage in the pursuit of renewable hydrogen.

As discussed in Chapter 1, the Minnesota Legislature has provided funding sources to the University of Minnesota Initiative for Renewable Energy and Environment to support basic and applied research on hydrogen production, as well as funding to match federal and private investments in three multi-fuel hydrogen refueling stations in Moorhead, Alexandria and the Twin Cities. The Governor's Clean Energy Technology Collaborative is developing a clean energy technology roadmap and includes renewable hydrogen and fuel cells as a part of that roadmap. This integration enables a system-wide approach to development of renewable hydrogen, and demonstrates the interdependence of multiple technologies and resources required to most cost-effectively meet the states renewable energy and hydrogen goals. The 2007 legislature appropriated $750,000 to prepare the hydrogen road map and for grants. Should the incorporation of hydrogen into the clean energy technology roadmap succeed, the $750,000 will be available for grants.

NATURAL GAS

Recent price volatility in energy markets is demonstrated in the existing natural gas market and the extreme natural gas price fluctuations. Natural gas prices continue to reflect a delicate balance of supply and demand. Despite a small decline in 2006, basic consumption (demand) is projected to increase in the near term. Moreover, conventional natural gas production as well as natural gas imports continue to decrease. Although natural gas is still considered one of the cleanest burning fuels, it can no longer be taken for granted as a low-cost, unlimited resource. The role of natural gas is a matter of national energy debate.

As the future of natural gas is considered, there are issues that warrant focus. Those issues can be categorized into four general areas:

- Increasing Demand
- Supply Availability
- Availability of Transportation Capacity
- Increasing Prices and Volatility

Each is discussed below.

A. DEMAND - CHANGING CONSUMPTION PATTERNS

Natural gas consumption in the residential and commercial sectors is influenced primarily by weather. If winters are mild, weather-related consumption normally is less; if winters are severe, weather-related consumption is higher. However, natural gas consumption is also affected by the general level of economic activity, and the relative prices of natural gas and alternative fuels. Although total overall consumption of natural gas declined in 2006, consumption (demand) is projected to increase in the near term.

Statewide, Minnesotans consumed a total of 240.82 billion cubic feet of natural gas in 2006. The 2006 consumption level is lower than prior years and represents a decrease of 18.7 billion cubic feet (or approximate 7 percent) from 2001 consumption of 259.56 billion cubic feet. While somewhat less than previous years, it is consistent with the overall national consumption between 2005 and 2006. As noted above, consumption is affected by a number of factors.

As shown in Appendix 1, Figure 4, there are two notable consumption trends. First, more natural gas is being used for electric generation. During the energy crisis in the middle and late 1970s, use of natural gas for electric generation declined sharply. Recently, however, natural gas has been used at significantly higher rates to generate electricity. While this upward trend is only slightly evident in this chart, the increase will be more noticeable starting in 2007 as recently approved natural-gas facilities go online in Minnesota. One of the basic reasons for turning to natural gas as a fuel source for electricity is that gas-fired plants have fewer harmful environmental effects than other traditional fossil fuels such as coal or fuel oil. The other notable consumption trend is residential consumption. As shown in Appendix 1, Figure 5, after removing the effects of weather, residential consumption per customer of natural gas has declined 161.6

thousand cubic feet per year in 1965 to 98.8 thousand cubic feet per year in 2006 (or approximately 39 percent over the last 43 years). One of the reasons for this trend is the increased efficiency of household gas-fueled appliances as well as the construction of energy-efficient new housing as specified by building code requirements.

On a national level, total demand for natural gas has been growing since 1949 with consumption of 4.971 trillion cubic feet (Tcf) to 21.66 Tcf in 2006. [21] National consumption shows a decrease of a 1.6 percent (from 22.01 Tcf to 21.66 Tcf) between 2005 and 2006. Residential natural gas consumption has grown from 993 billion cubic feet in 1949 to 4.37 Tcf and 4,724 in 2006 and 2007. Commercial consumption of natural gas has grown from 0.39 Tcf in 1949 to 2.83 Tcf in 2006. EIA's 2008 Annual Energy Outlook projects that natural gas consumption will increase to 23.8 Tcf until 2016 and then decline to 22.7 trillion cubic feet (Tcf) by 2030.[22]

According to the U.S. Energy Information Administration (EIA), the largest potential near-future increase in the use of natural gas will come from electric generation. (This trend is only starting to be evident in Minnesota, as shown in Figure 4 of Appendix 1, which includes data through 2006.) At a national level, natural gas consumption for electricity generation increased from 5.38 trillion cubic feet in 2001 to 6.24 Tcf in 2006, an average annual growth rate of approximately 3.2 percent.[23] The project path of natural gas consumption depends almost entirely on the amount consumed in the electric power sector.

New natural gas-fired peaking and intermediate generation plants compete with local distribution companies (LDCs) for natural gas during the traditional storage summer refill season, thus further impacting the volatility of natural gas prices during this period. One way of limiting the demand for natural gas (and electricity) is to utilize energy conservation programs and to implement renewable technologies when possible. With the uncertainty and volatility of natural gas prices, conservation programs are excellent ways of slowing increasing demand by reducing a customer's usage, which in turn reduces the customer's energy bill.

B. SUPPLY AVAILABILITY

No discussion regarding the growth in demand of natural gas would be complete without a corresponding discussion of the supply of natural gas. It is important to note that Minnesota has no native source of natural gas supplies. Therefore, Minnesota utilities must obtain natural gas predominately from the natural gas fields in Kansas, Oklahoma, Texas, and Alberta, Canada.

Nationally, the demand for natural gas is increasing and natural gas is critical to the U.S. economy and security as a fuel source for both residential home heating, industrial processing and electric generation. Thus, more attention will continue to be focused on potential sources of natural gas supplies to meet such demand. As of 2006, the EIA states there is 1,532.8 Tcf of technically recoverable U.S. (domestic) natural gas resources waiting to be tapped.[24] The natural

[21] http://www.eia.doe.gov/oiaf/archive/aeo08/excel/figure73_data.xls
[22] http://www.eia.doe.gov/oiaf/archive/aeo08/excel/figure72_data.xls
[23] http://www.eia.doe.gov/oiaf/archive/aeo08/excel/figure72_data.xls
[24] http://www.eia.doe.gov/emeu/aer/txt/ptb0401.html

gas reserve additions reflect an expected increase in exploratory and developmental drilling especially from unconventional sources.[25]

According to EIA's AEO 2008, total U.S. natural gas production grows modestly in the reference case, from 18.5 Tcf in 2006 to 19.4 Tcf in 2030, as depletion of the onshore lower 48 conventional resource base is offset by increased production from unconventional sources. Offshore production increases from 3.0 Tcf in 2006 to 4.5 Tcf in 2017, then declines to 3.5 Tcf in 2030. Production in shallow waters declines slowly through 2030. Production in deeper waters rises to 3.0 Tcf in 2019 and then declines through 2030.

While unconventional natural gas production is a large percent of total production and is projected to increase in the future, U.S. output is not sufficient by itself to meet U.S. natural gas demand. The nation has historically imported significant amounts of natural gas supplies from Canada. However, net U.S. imports of natural gas from Canada are projected to decline, and net imports of liquefied natural gas (LNG) were projected to grow, from 2006 through 2030.[26] The EIA AEO 2004 identified two possible supply sources may be available in the near term to mitigate the decline in historic Canadian imports. The first is the construction of a pipeline to move natural gas from the MacKenzie Delta in Canada's Northwest Territories into Alberta. The second is increased use of imported (LNG).[27]

However, recently reported costs for development of the Mackenzie Delta natural gas pipeline, including development costs for the three anchor natural gas fields, increased substantially. Therefore, the pipeline is not expected to be built with natural gas prices at the levels projected in the AEO2008 reference case. Canada still is expected to export natural gas to the United States in the reference case, however, with U.S. net imports from Canada declining from 3.2 trillion cubic feet in 2006 to 0.9 trillion cubic feet in 2030. Natural gas prices in the reference case are adequate to support that level of imports despite the absence of the Mackenzie Delta pipeline.

In the AEO2008 projections, most of the expected growth in U.S. natural gas imports is in the form of LNG. The total capacity of U.S. LNG receiving terminals increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the reference case (with no further increase through 2030), and net LNG imports grow from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030 (Figure 82). Net U.S. imports of LNG are expected to vary considerably from year to year, depending on both the level of U.S. natural gas prices and whether those prices are higher or lower than prices elsewhere in the world. Higher prices overseas are expected to reduce U.S. LNG imports, while lower prices overseas are expected to increase U.S. imports. Although LNG imports were limited in the spring and early summer of 2008 due to higher international natural gas prices, LNG imports will continue to be part of the U.S. natural gas supply portfolio.

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[25] Unconventionally reservoired deposits (continuous-type accumulations) are geographically extensive subsurface accumulations of crude oil or natural gas that generally lack well-defined hydrocarbon/water contacts. Examples include coalbed methane, "tight gas," and self-sourced oil- and gas-shale reservoirs.

[26] http://www.eia.doe.gov/oiaf/archive/aeo08/gas.html

[27] LNG is natural gas in a liquid state maintained at a temperature of –260° Fahrenheit. Once the imported LNG is returned to its gaseous state it is transported through high pressure pipelines to local/regional markets. Imported LNG comes from an increasing number of countries including Algeria, Malaysia, Australia, and Trinidad and Tobago.

The largest primary source natural gas expansion came to light after the AEO 2008 was published. The recent increases in supply came from across the Lower 48 States. But, more than half of the increase in natural gas production between the first quarter of 2007 and the first quarter of 2008 came from Texas, where supplies grew by an exceptionally high 15 percent. Other contributing regions included Wyoming with growth of 9 percent, Oklahoma with 6 percent growth, and Louisiana with 4 percent growth. Even production from the offshore Gulf of Mexico, which had been declining for years, increased 2 percent from first-quarter 2007 to first-quarter 2008. The start-up last year of production from the deepwater Independence Hub, with wells in 9,000 feet of water, alone added about 1 percent to Lower 48 States production. Production in the rest of the States as a group has increased by 8 percent. High and increasing natural gas prices have spurred more natural gas drilling and the trend to move from drilling simpler vertical wells to horizontal wells.[28] Horizontal drilling is fast becoming the primary method used to produce gas from geologic formations like shale. Drilling and completing a horizontal well through shale has required improved technology, but these wells have become essential to the rapid economic development of unconventional resources in the United States.[29]

In sum, it appears there are adequate supplies available to meet projected demand, at least for some time beyond the 2030 forecast. The real question then becomes the price at which such supplies are available.

C. AVAILABILITY OF TRANSPORTATION CAPACITY

There are four major pipelines that serve Minnesota, but the vast majority of transportation of natural gas is provided by Northern Natural Gas (NNG), which delivers approximately 84 percent of the natural gas consumed in Minnesota in 2002. There are two operational intrastate pipelines: the Minnesota Intrastate Pipeline Company (MIPC) and the Hutchinson Utilities Commission (HUC) pipeline.

It is logical to assume that future projected consumption and prices will be impacted by the capacity (physical pipeline size) limits of Minnesota pipelines. Currently, Minnesota is served by four interstate pipelines and two intrastate pipelines. The MIPC and HUC pipelines are the two intrastate pipelines and both are reported to be fully subscribed. The interstate pipelines[30] include the Great Lakes Gas Transmission pipeline, the Viking Gas Transmission pipeline and the Northern Natural Gas Company (NNG) pipeline. The Great Lakes Gas Transmission pipeline has capacity available for any increased natural gas consumption that would occur in the

[28] One indicator of the transition from conventional to unconventional production is the number of rigs drilling "horizontal wells." In the late 1990s, about 40 drilling rigs, or 6%, were drilling horizontally. As of May 2008, the number of rigs drilling horizontal wells has grown to 519 rigs, or 28% of the total. Horizontal wells don't simply go straight down, but also have one or more horizontal sections. In the Barnett Shale, the wells go down about a mile and a half, make a turn and go horizontally about a mile, running through the rocks that hold natural gas.

[29] http://tonto.eia.doe.gov/energy_in_brief/natural_gas_production.cfm

[30] Interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC). At first, that new investment would be charged only to the customers using the new pipeline capacity. Then, in order to incorporate the new investment costs into the overall rates, the pipeline company would have to file a rate case. When this step is completed, the price charged to all customers reflects the increased costs. In contrast, natural gas pipelines located wholly within the state (or intrastate pipelines) are rate regulated by the Commission with larger pipelines requiring a CON prior to initial construction.

northern half of Minnesota. As for the Viking Gas Transmission pipeline, which is already operating at full capacity, any increases in year-round demand would require additional pipeline related construction. However, the largest pipeline, NNG, is expanding to meet increase the demand.

Specifically, NNG's Northern Lights project (FERC CP06-403) is a multi-phased pipeline expansion designed to increase capacity in the company Market Area, in which Minnesota is its largest customer. The first phase of construction was completed on October 31, 2007, and the facilities were placed in service on November 1, 2007. The project's incremental gas volumes are 374,225 thousand cubic feet (Mcf) for peak-day delivery. A small part of the project was recently complete on November 1, 2008. The project consisted of construction of 58 miles of mainline, 28 miles of branch line and 12 new town border stations and modification to 31 town border stations. NNG is now in the next phase of the Northern Lights projects (FERC CP09-11), which is designed to increase capacity in its Market through 2026. The latest phases will result in estimated incremental firm winter capacity of approximately 135,000 Mcf/day by winter 2010.

NNG's expansion represents a significant new investment in infrastructure, which required long-term commitments/contracts by Minnesota utilities that were executed prior to construction. Below is a summary of investment NNG has made or plans to make on its Northern Lights project:

Table 5
Northern Lights Capital Expenditures
(Minnesota)

Year	Investment
Prior to 2006	$ 6.1 million
2007	$99.8 million
2008	$ 8.4 million
2009 (forecasted)	$75.0 million
2010/2011(forecasted)	$25.4 million
Total	$214.7 million

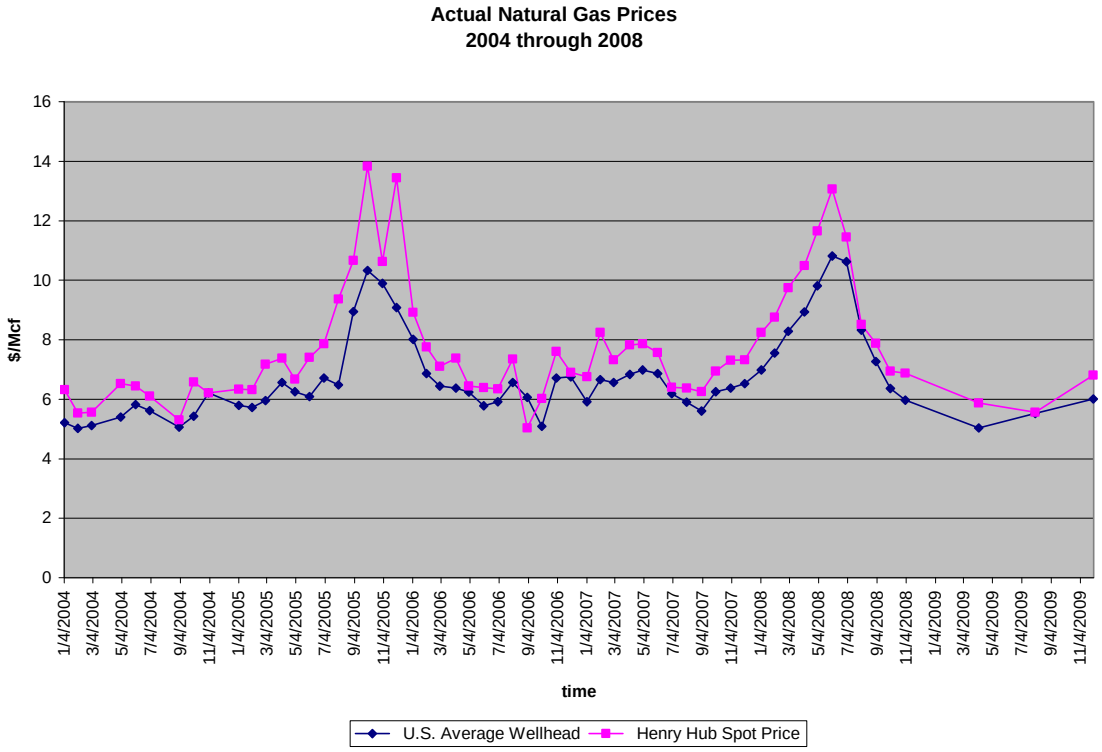
With NNG's recent and planned expansions of approximately $214.7 million, Minnesota's delivery infrastructure is being redeveloped and improved to meet energy demands now and into the future.

D. INCREASING PRICES & PRICE VOLATILITY

In June 2008 published AEO2008 reference case, lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu ($5.99 per thousand cubic feet) in 2016 and then rise to $7.22 per million Btu ($7.43 per thousand cubic feet) in 2030. The natural gas prices in the reference case were determined largely by the cost of supplying natural gas from the remaining U.S. and Canadian resource base. In the future, however, the U.S. natural gas market

is expected to become more integrated with natural gas markets worldwide, as a result of increased U.S. access to, and reliance on, LNG supplies from foreign sources. As a consequence, international market conditions will have a stronger influence on domestic natural gas prices in the United States, causing even greater uncertainty in future U.S. natural gas prices than would be the case if the United States relied exclusively on natural gas supplies from North America.

The June 2008 is based on data available through December 2007 and does not reflect the dramatic price volatility experienced in 2008. The below table shows actual wellhead and spot prices through November 2008:[31]



The first high price spikes occurred in the fall of 2005 in the aftermath of Hurricanes Rita and Katrina during which there was significant infrastructure damage. The fall 2005 retreated from the record levels in February 2006 after record warm temperatures in January 2006. The second noticeable price increase occurs in the spring and early summer of 2008. This increase occurred when four factors came together:

1. Colder that normal April weather;
2. Shut down of the Independence Hub between April and June;
3. A weak U.S. dollar; and
4. Record level oil prices.

[31] http://tonto.eia.doe.gov/cfapps/STEO_Query/steotables.cfm?tableNumber=16&periodType=Monthly&startYear=2004&startMonth=1&startMonthChanged=false&startQuarterChanged=false&endYear=2009&endMonth=12&endMonthChanged=false&endQuarterChanged=false&noScroll=false&loa

The colder than normal April weather put pressure on national storage after the traditional heating season. At the same, a leak at one of the major hub in the Gulf of Mexico, the Independence, was shut down production of approximately 1 billion cubic feet (Bcf) per day which historically was put into storage. A weak U.S. dollar and oil prices reaching all time record level along with the competing demand for electric generation and winter storage, natural gas price increase to level only seen in the fall of 2005. As shown above, the 2008 high prices occurred during the spring and not during the winter when demand for natural gas for home heating is the strongest. The natural gas fell as the price of oil decreased, the dollar gained strength and winter storage injection proceeding at the 5 year historic average. Prices through November and December 2008 have been moderated by declining industrial demand due to the economic slow down.

Local Distribution Companies (LDCs) are now using financial tools to combat price volatility. There are a variety of financial tools that can be used to stabilize prices for the end-use customer. One way price stabilization is achieved is by entering into financial futures contracts and options through an exchange (i.e., NYMEX). Financial tools also can involve entering into physical hedges with suppliers and other third-parties. The purpose of these tools, whether considered to be future contracts or physical hedges, is to obtain guaranteed supplies at a pre-set price. Thus, LDCs use these tools to mitigate price risk and volatility. Several Minnesota utilities have received Commission approval to recover the costs of such financial tools and are now using the tools in managing their gas supply portfolio.

In conclusion, the overall domestic demand for natural gas continues to grow and has the potential to outpace the domestic supply. Domestic supplies have relied on Canadian imports, but as Canadian imports decline, there is a need to develop an overall infrastructure to import and use LNG and to further develop unconventional supplies. While the pipeline infrastructure is aging in general, Minnesota has been the recipient of signification investment by NNG to improve and expand interstate pipeline capacity. As long as demand increases and supplies remain tight, the price for natural gas will be higher than in the past and will continue to be volatile.

TRANSPORTATION FUELS

Minnesotans consumed a total of 130.1 million barrels[32] (5,464 million gallons) or the equivalent of 701 trillion BTUs[33] of total petroleum products in 2006. Total petroleum products include: asphalt and road oil, aviation fuel, distillate fuel, jet fuel (all types), kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel. Motor gasoline accounted for 2.7 billion gallons of the 2002 total, an increase of approximate 100 million gallons over 2002 consumption. Since Minnesota has no oil reserves, Minnesota imports all of its petroleum products in the form of crude oil or finished product, which is valued at over $16.7 billion, each year.[34]

A. OVERVIEW

In 2006, Minnesotans used about 84 percent of all petroleum products for air, land, and water transportation. These products include asphalt and road oil as well as actual fuels like diesel, jet fuel, and motor gasoline. Most agricultural use of petroleum falls under the transportation category. Commercial, electric utility, industrial, and institutional space heating and processing uses accounted for about nine percent of petroleum products. In 2000, about 16 percent of Minnesota households currently use either fuel oil or propane for their heating source. This use constituted about 9 percent of the total petroleum products used.

Most petroleum products enter and leave Minnesota by pipeline. Some are transported by barge, rail, ship, or truck. All but a small portion of the United States' imported Canadian crude oil and liquid petroleum gases (LPG) pass through Minnesota on their way to other parts of the Midwest, Eastern Canada, and New England.

Refined petroleum products are available in Minnesota through area refineries or via pipelines. Electric utility and other industrial customers then use barge, rail or trucks to transport the finished products to their individual locations. Smaller volume customers, such as farms, homes, and gas stations, receive their petroleum products via truck delivery.

The price of petroleum products is largely comprised of the basic cost of crude oil and assessed taxes. World political and economic market forces primarily determine the cost of crude oil. Federal and state governments assess taxes on petroleum products.

Many factors influence the other aspects of the price of finished petroleum products. Some price changes are due to supply and demand imbalances. For example, supply shortages sometimes occur due to maintenance, damage on the pipelines or at refineries or increased consumption in developing markets, such as India and China. Since each petroleum product needs to be stored individually, some supply shortages result from simple logistical problems associated with coordinating production and storage to meet current and future demand.

[32] http://www.eia.doe.gov/emeu/states/sep_sum/html/pdf/sum_use_tot.pdf
[33] http://www.eia.doe.gov/emeu/states/sep_sum/html/pdf/sum_btu_tot.pdf
[34] http://www.eia.doe.gov/emeu/states/sep_sum/html/pdf/sum_ex_tot.pdf

Higher than expected demand for a particular product can also create temporary shortages that lead to higher prices. Very cold weather increases the heating use of propane products and very wet or very dry weather increases the agricultural use of petroleum products.

Activity in the commodities market can further influence price changes. Spikes or sudden drops in prices are sometimes the markets' response to perceptions of future supply and demand imbalances. Most recently, the cost per barrel of oil reached a peak price around the $147 per barrel mark in July 2008 before declining below $50 per barrel in December 2008. This translated into higher prices at the gas pump, in many cases, at or above $4 per gallon during early summer 2008. Consumption has been impacted by this increase in price. Thus, data trends become more important information for planning purposes than specific numbers on specific dates.

B. FUTURE TRENDS

The EIA's press release announcing the Annual Energy Outlook 2009 (AEO2009), dated December 2008, stated "For the first time in more than 20 years, the new *AEO* reference case projects virtually no growth in U.S. oil consumption, reflecting the combined effect of recently enacted corporate average fuel economy standards, requirements for increased use of renewable fuels, and an assumed rebound in oil prices as the world economy recovers.[35]

Residential, commercial and industrial uses of petroleum products for non-transportation purposes have been steady or declining in the past several years and the trend is expected to continue. The transportation sector, which consumes nearly two-thirds of all petroleum products, has shown steadily increasing levels of consumption. This increase continued until prices recently reached the $4 per gallon level, which appears to be significant enough to encourage consumers to consider altering transportation behavior.

One factor that impacts the price of petroleum products is supply. Crude oil is necessary for the production of petroleum products. The world's annual supply of crude oil depends on the interplay of many complex factors including demand, weather, politics, technology, and economics. In 2005, the world currently uses approximately 85 million barrels of crude oil per day.[36] Scientists estimate that ongoing natural processes create new crude oil at the rate of 7 million barrels per year. These numbers indicate an eventual depletion of the available crude oil, although it may be possible to find or manufacture new sources and substitutes for these products.

As with natural gas and electricity, the available infrastructure also has a large impact on petroleum prices. Currently, demand is beginning to exceed ocean-shipping capacity and is approaching the capacity of some pipelines. Furthermore, the cost of developing new crude oil wells is increasing. New wells are in less accessible locations. Higher prices for petroleum, however, allow development of lower grades of crude that were previously too costly to produce. However, with the 2008 global recession and the reduced crude prices, exploration and drilling may diminish accordingly.

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[35] http://www.eia.doe.gov/oiaf/aeo/

[36] EIA at: Total World Petroleum Consumption

Four other trends may impact the price of petroleum products. First, in the 1990s, crude oil and refined petroleum product, like natural gas, became publicly traded commodities on world mercantile exchanges. During times of actual or perceived supply disruptions or shortages, prices now fluctuate more erratically. Second, nearly every major international oil company and most independent marketers are forming E-commerce sites to trade commodities independently. Their effect on energy prices and supply will depend largely on which sites survive. Third, petroleum refiners have significantly changed their operations in the 1990s. They have reduced refining costs by moving toward just-in-time production. Storage is now more in the control of independent terminal and pipeline operators. Finally, international demand has increased due to the expansion of overseas markets, particularly in India and China.

In 2007, the United States imported more than 58 percent of its petroleum resources, either in the form of crude oil or refined products. U.S. crude oil imports have declined from 62 percent in 2002 and 60 percent in 2006. About half of these imports came from the Western Hemisphere (North, South and Central America and the Caribbean) during 2006.[37] Much of the crude oil that is fed into refineries in Minnesota is delivered by pipelines from Canada. However, since political pressures in all oil producing areas impact the market, the fact that Minnesota does not receive a large percentage of its crude oil feedstock from areas such as Mexico, Venezuela, Nigeria, and the Middle East does not mean that Minnesotans are insulated from price fluctuations due to political and economic unrest in those areas.

C. RELIABILITY ISSUES

The increasing reliability issues that result from problems with the supply infrastructure will continue to be a challenge for the industry throughout the country.

1. Refinery Operating Practices

Inventories of petroleum products are often maintained on a "just in time" basis. That is, refineries are operated at or near the lower operational inventories for all products. This results in a market that is not as capable of adjusting to significant changes in demand. Some areas of the state are more adversely affected during these times of product shortfalls. Low inventories often cause price increases, as retailers are forced to try to curb demand in order to have sufficient product to get through these periods.

2. Regulation Changes Regarding Commercial Drivers' Hours of Service

The Federal Motor Carriers Safety Administration recently changed rules concerning the maximum number of hours that commercial drivers who deliver petroleum products may operate a vehicle. The change requires all drivers to account for the amount of time that they are actually waiting for product to be loaded in their vehicle towards their hours of service allotment.

During periods of high demand for all petroleum products, which includes home heating fuels such as propane and fuel oil, long truck-filling wait times may cause drivers to approach their maximum hours of service without satisfying the demand for those fuels. Fuel suppliers may

[37] http://tonto.eia.doe.gov/energy_in_brief/foreign_oil_dependence.cfm

choose to have additional drivers on hand to satisfy these periods of peak demand, although employing additional drivers may lead to increases in delivered fuel prices. In times of extreme hardship, Minnesota's Governor has the authority to extend drivers' allowed hours of service.

3. Seasonal Demand Fluctuations

September is typically seen as the end of the driving season and demand for petroleum products generally declines. Petroleum refineries in the U.S. tend to choose September or later winter months where there is a lower than normal demand for products as the time to schedule routine maintenance for critical equipment, known as refinery turnaround.

Scarce petroleum inventory issues introduce increased price uncertainty and less supply resilience into the market. There is less flexibility in the supply chain to buffer the market from supply disruptions such as refinery fires or even routine maintenance. Where these events used to cause regional disruptions in supply and price, they now cause upward price pressures on all areas of the country, not just those affected by infrastructure changes. These factors, combined with the ongoing political unrest in many petroleum exporting countries, underscore the importance of diversifying transportation fuels supplies in order to decrease Minnesota's dependence on factors outside the state's control.

D. RENEWABLE TRANSPORTATION FUELS

Minnesota leads the nation in use of cleaner, alternative fuels. For more than a decade Minnesota's fueling stations have been required to sell E10, a blend of 10% ethanol with gasoline for use in gasoline powered engines. In 2005, Governor Pawlenty signed legislation requiring all of Minnesota's gasoline to be blended with 20 percent ethanol under certain conditions, and in 2007, the Governor signed into law the petroleum replacement promotion goal (239.7911) requiring that at least 20 percent of the liquid fuel sold in the state is derived from renewable sources by December 31, 2015; and at least 25 percent of the liquid fuel sold in the state is derived from renewable sources by December 31, 2025. In preparation, the state commissioned a number of tests to determine the effects that an increase in the ethanol blend would have on engines and parts. The drivability and compatibility tests found that motor vehicles operating on a 20-percent blend of ethanol fuel performed as well as those running on E10 ethanol or gasoline. The tests also found that using the higher E20 ethanol blends did not cause significant problems for a wide range of materials, including metals, plastics, rubbers and fuel pumps used in vehicle fuel systems. The E20 requirement will take effect in 2013 unless ethanol has already replaced 20 percent of the state's motor vehicle fuel use by 2010 or EPA fails to approve a 211 (f)(4) waiver of the federal Clean Air Act.

1. Ethanol

Ethanol is an alternative fuel made from a variety of plant-based feedstocks collectively known as "biomass." Fuel ethanol contains the same chemical compound as beverage alcohol. It is produced by fermenting sugar from starch crops such as corn or found in plants like sugar cane. Ethanol can also be made from cellulosic materials, such as grass, wood, crop residues, or newspapers. It is typically blended up to 10 percent with gasoline (E10) for use in conventional

vehicles. Ethanol is also available in other blends of 85 percent ethanol and 15 percent gasoline. Known as E85, it can be used in fuel flex vehicles (FFVs). FFVs are being manufactured by most of the major vehicle manufacturers and are designed to operate on gasoline, E85 or a combination of the two fuels. Based on registration records, there were approximately 175,000 flex fuel vehicles registered in Minnesota in 2008. Ethanol or gasoline can be blended in any combination in an FFV.

Since 1998, approximately $11 million has been invested in making Minnesota an international leader in E85 development.[38] In 2007, the Minnesota Legislature approved $2.25 million for an FY08/09 biofuels program for fueling stations installing mid-blend biodiesel (B10-B20) and E85. As the close of the program nears the funding has resulted in 44 projects with 20 more pending.

In 1997, there were approximately 7 E85 fueling stations in Minnesota. At the beginning of 2004, there was a total of 285 E85 fueling station in the United States. As of November 2008, Minnesota led the nation with over 350 E85 fueling stations, which accounts for approximately one quarter of all E85 fueling stations nationwide. In 2007 (the latest year with complete annual data), Minnesota sold over 21 million gallons of E85. This represents an increase of more than 18.8 million gallons (or approximately 725 percent) from the 2004 total E85 sales of 2.5 million gallons. Demand for mid ethanol blends has grown substantially, and some Minnesota service stations are installing blending pumps that can provide various ethanol blends of ethanol, such as E50, E40, E30, and E20, for use in FFVs.

With data through October, the monthly 2008 E85 prices ranged from $2.22 per gallon to $3.19 per gallon, averaging $2.75 per gallon, which is $0.60 per gallon or 21 percent less than 87 octane (E10) gasoline. However, ethanol has lower energy content than gasoline and E85 vehicles average fuel economy is about 15 percent less, which varies depending on the model and driving habits. Drivers' fuel economy can fluctuate by 10 percent or more based on driving habits alone—rapid starts, idling, vehicle contents, etc. It is important to note that E85 does reduce pollution on a per mile basis compared to gasoline, even with its decreased fuel economy. E85 also supports economic development by partially keeping energy expenditures in Minnesota.

Since 2005, 6 new ethanol plants have been built with a combined production capacity of 323 million gallons. As of August 2008, Minnesota had 17 ethanol plants with a production capacity of 847 million gallons.[39] This represents an increase of 524 million gallons (or approximately 161 percent) in production capacity over less than a three year period.

Contrary to popular misconception, producing ethanol does not consume more energy than it yields. An energy balance of exactly one would indicate that it takes exactly as much energy to produce an energy product as is available from its use. According to the United States Department of Agriculture (USDA), Economic Research Service Report number 814, entitled "Estimating The Net Energy Balance Of Corn Ethanol: An Update," corn ethanol is energy efficient, as indicated by an energy ratio of 1.34; that is, for every Btu dedicated to producing

[38] To date, approximately 20% of this total has been state-funded with the remainder contributed by station owners, Minnesota Corn Growers, U.S. Department of Energy, automakers, foundations and nonprofits.
[39] http://www.mda.state.mn.us/renewable/ethanol/capacities.htm

ethanol, there is a 34-percent energy gain. A similar study done in 1995 indicated only a 1.24 energy ratio. The increase is accounted for by an increase in corn yields and greater efficiencies in the ethanol production process. As a result, energy efficiency in the production of ethanol is increasing. The concept of "input efficiencies for fossil energy sources" was introduced as a component of the study. This was meant to account for the fossil energy used to extract, transport and manufacture the raw material (crude oil) into the final energy product (gasoline). According to the study, gasoline has an energy ratio of 0.805. In other words, for every unit of energy dedicated to the production of gasoline there is a 19.5 percent energy loss. In short, the finished liquid fuel energy yield for fossil fuel dedicated to the production of ethanol is 1.34 but only 0.805. for gasoline. This equates to a greater net energy yield for ethanol of (1.34/0.74) or 81 percent greater than the comparable yield for gasoline. [40]

2. Biodiesel

Biodiesel is the equivalent of diesel fuel. It is an alternative fuel that can be made from domestic, renewable oils and fats. In Minnesota it is made primarily from soybean oil. Mixtures of biodiesel and petro-diesel are called "biodiesel blends," with B2 being 2 percent biodiesel, and B20 being 20 percent biodiesel. Blends as high as B20 can be used with little or no engine modifications. Biodiesel blends are already used by hundreds of vehicle fleets, including several fleets (Eureka Recycling in St. Paul, U.S. Forest Service in International Falls and the local governments of Minneapolis, Hennepin County and Brooklyn Park,) which are using B5 (5 percent biodiesel) or B20 (20 percent biodiesel) blends voluntarily. Metropolitan Council operates Metro Transit, the transit system in the Twin Cities area. Metro Transit uses B10 and B20 in the summer months.[41]

In 2002, the legislature passed a law requiring that diesel fuel sold in Minnesota must contain at least 2 percent biodiesel (B2). Implementation of the law (Minnesota Statutes 239.77) was September 29, 2005. There are a few exceptions to the requirement, including railroad locomotives, off-road taconite and copper mining equipment and heating equipment motors located at nuclear power plants. In 2007, Governor Tim Pawlenty unveiled a plan for taking the state's biodiesel requirement from the current 2 percent blend in diesel fuel to a 20 percent blend by 2015. This "B20" proposal relates to a statutory goal signed into law during the 2005 session and modified in 2008 to set intermediate blending mandates of B5 by May 1, 2009 and B10 by May 1, 2012.

According to Minnesota Department of Agriculture, in the fall of 2005, Minnesota had three new production facilities that made the state the largest producer of biodiesel in the U.S.[42] The three Minnesota plants and their production capacities were:

- The Farmers Union Marketing and Processing Association (FUMPA) plant in Redwood Falls with 3 million gallons of annual biodiesel production;
- The SoyMor facility in Albert Lea, with production capacity of 30 million gallons annually; and

[40] http://www.mda.state.mn.us/renewable/renewablefuels/balance.htm
[41] http://www.accountability.state.mn.us/Departments/MetCouncil/Goals.htm.
[42] http://www.mnsoybean.org/Biodiesel/MinnesotaBiodieselPlants.cfm

- The Minnesota Soybean Processors (MnSP) plant in Brewster, also with 30 million gallons of annual production capacity.

The SoyMor facility was shut down in March 2008 due to "current biodiesel economics". According to SoyMor's board chair, Gary Pestorious, "We never intended biodiesel plants to run 60 or 70 cent oil. When we invested in it and put the project together it was 20 cents." Pestorious added, when soy oil hit 62 cents a pound, plant officials estimated the company lost $1 per gallon produced. [43]

The Minnesota Biodiesel Task Force was formed in March 2003 to help the state carry out its mandate requiring that nearly all diesel fuel sold in the state contain at least a 2 percent biodiesel blend by September 2005. To help reach an eight million gallon production capacity goal, and ensure a smooth introduction of biodiesel into the marketplace, the Biodiesel Task Force was appointed to advise the Minnesota Department of Agriculture on methods to increase the production and use of biodiesel in Minnesota.

Since then, the Task Force has helped promote and educate possible biodiesel developers, marketers, consumers and manufacturers. During 2008, the Minnesota legislature required the Minnesota Department of Agriculture and the Department of Commerce file a report addressing cold weather biodiesel blends and submit recommendations by February 15, 2009.[44]

3. Propane and Natural Gas

Propane and natural gas (compressed and liquefied) are also options for fueling Minnesota vehicles that feature ultra-low tailpipe emissions. Minnesota Valley Transit Authority operates three natural gas buses and Schwan's Food Services operates nearly allof their vehicles in propane. CenterPoint Energy has a compressed natural gas (CNG) public fueling station in Minneapolis. Although having higher up-front costs, the long-term operating costs are significantly reduced.

4. Hybrid Vehicles

Demand for electric hybrid vehicles, a technology that can significantly increase mileage, has grown dramatically in the last two years. The high price of gasoline and consumer interest in deceasing carbon emissions are the major drivers of the market. Today, despite the higher cost of dual system vehicles, there are over twenty five hybrid electric models on the market, an exponential increase over the three hybrid models that were available just a few years ago.

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[43] http://www.biodieselmagazine.com/article.jsp?article_id=2235

[44] Minnesota Law, Chapter 297, Section 68 [Technical Cold Weather Issues] states:

> The commissioners of agriculture and commerce shall consult with stakeholders who are technical experts in cold weather biodiesel and petroleum diesel issues to consider and make recommendations regarding improvements in the production, blending, handling, and distribution of biodiesel blends to further ensure the performance of these fuels in cold weather. The commissioners shall issue a report on these issues by February 15, 2009, to the chairs and ranking minority members of the legislature with jurisdiction over agriculture and commerce policy and finance.

In 2004, California Car Initiative (CalCars) converted a Toyota Prius hybrid to a plug-in electric vehicle (PHEV), and spawned a national promotional campaign to convince auto manufacturers to manufacture PHEVs. A PHEV is a vehicle technology that is based on hybrid electric vehicles, like the Toyota Prius or other vehicles with hybrid drive trains. PHEVs have larger battery packs than normal hybrids, and these battery packs can be charged either by the vehicle's gasoline engine and regenerative braking system during operation, or from plugging it into an electric outlet when not in operation. In most cases, a standard 110-volt outlet is used to recharge the battery.

PHEV technologies have the potential to greatly reduce gasoline consumption over the already low consumption of a hybrid vehicle, particularly on short, start-and-stop type trips, which are typical of many urban commuter trips. PHEVs also reduce emissions when compared to a typical passenger car. But because PHEVs rely on electricity as a replacement for gasoline, the emissions profile of a PHEV includes emissions associated with the generation of the electricity used to recharge the battery. Because grid electricity today is heavily dependent on coal, a normal hybrid vehicle actually has a slightly better emissions profile than a PHEV, and will continue to have lower emissions until about 50% of the electricity on the grid is generated from zero emission sources according to a Minnesota Pollution Control Agency 2007 report.

There are hundreds of PHEVs on U.S. roads today, of which Minnesota is home to at least ten. Today's PHEVs are customized projects rather than mass produced, many of which have been converted using commercially available after-market conversion kits. But auto manufactures have taken notice, and at least fourteen automotive companies, some of which are new start-ups, are exploring or planning to offer a PHEV models.

In December, 2008 the Chinese battery company, Build Your Dreams Group (BYD) began selling a $22,000 PHEV with a 62-mile battery range to fleet customers in China. BYD hopes to sell 10,000 vehicles in the Chinese market during 2009, and plans enter the European market in 2010, followed by the U.S. market around 2011. A few other companies, such as Aptera with a three-wheel model and Fisker with a pricey, luxury sports car, are currently taking orders for vehicles, which should be in production soon.

The Minnesota Office of Energy Security, through a legislative appropriation, provided funding for the Minnesota Department of Transportation to convert a flex-fuel Ford Escape to a plug-in electric hybrid, a project that is being managed by Minnesota State University at Mankato. It is also providing funding to Minnesota's post secondary automotive engineering programs on a competitive basis for PHEV and other electric vehicle projects so that Minnesota's automotive engineers and technicians can gain experience. In addition, OES provided a grant to HourCar, a non-profit car sharing organization in the Twin Cities that was the first in Minnesota to convert a Prius to a PHEV, for two solar electric recharging stations, one at Mississippi Market in St Paul and the other at the light rail station on 46th Avenue in Minneapolis.

In the 2006 session, the Minnesota Legislature enacted a session law (Chapter 245 Subd. 2) that requires all solicitation documents for the purchase of state owned passenger vehicles and trucks to contain the following language: "It is the intention of the state of Minnesota to begin purchasing plug-in hybrid electric vehicles and neighborhood electric vehicles as soon as they

become commercially available, meet the state's performance specifications, and are priced no more than ten percent above the price for comparable gasoline-powered vehicles. It is the intention of the state to purchase plug-in hybrid electric vehicles and neighborhood electric vehicles whenever practicable after these conditions have been met and as fleet needs dictate for at least five years after these conditions have been met."

The interest in hybrid technology as a way to achieve fuel economy is not limited to gasoline-electric hybrids. A potentially less expensive technology, the hydraulic hybrid, is also making its debut. In 2007, the U.S. Environmental Protection Agency demonstrated a new hydraulic hybrid technology in a UPS delivery vehicle. In laboratory tests, this technology achieved a 60 – 70 percent improvement in fuel economy and 40 percent reduction in emissions over a conventional vehicle. The University of Minnesota's Engineering Research Center for Compact and Efficient Fluid Power has also developed a promising hydraulic technology, which they hope to scale up and demonstrate in Minnesota if funding is available. Larger trucks and buses are the target market for hydraulic hybrids until such time when hydraulic components can be sized appropriately for passenger vehicles.

OTHER KEY ISSUES AND PROGRAMS

In addition to electric reliability, renewable energy development and natural gas availability, there are a number of issues that the OES believes will be critical for policy-makers to be aware of, as they work to ensure Minnesota's energy future. Those issues include:

- Conservation,
- Environmental protection, and
- Affordability.

A. CONSERVATION

The Minnesota Conservation Improvement Program (CIP), first enacted by the Minnesota Legislature in 1982, requires Minnesota natural gas and electric utilities to invest a portion of their revenues in energy efficiency and conservation programs. These programs are intended to incent consumers and businesses to save energy by purchasing energy efficient equipment and/or changing behaviors. Typical conservation improvement programs include furnace rebates, lighting rebates, and building design assistance. Utility CIPs are funded through surcharges added to the electric and natural gas rates charged to utility customers. The Office of Energy Security (OES) in the Minnesota Office of Energy Security provides regulatory oversight over the use of CIP funds.

There are three primary benefits of conservation. First, conservation helps the utilities and their customers avoid the operating costs of providing more electricity and natural gas such as buying fuel and operating and maintaining power plants. Second, conservation helps the utilities and their customers avoid or delay the capital costs of adding new system capacity such as new power plants, transmission lines, natural gas pipelines, and distribution systems. Third, conservation reduces carbon dioxide and other emissions released by burning fossil fuels.

Conservation is a critical part of Minnesota's efforts to meet its residents' energy needs and reduce greenhouse gases. In 2007, Minnesota's utilities devoted approximately $108 million to CIP activities and achieved total annual energy savings of 464,000 MWh of electricity and 1.9 million MCF of natural gas, resulting in approximately 535,000 tons of avoided carbon dioxide emissions. Historically, CIP projects have reduced electricity consumption in Minnesota by approximately 0.8 percent annually out of an estimated growth rate of 2.3 percent without CIP.[45] In 2007, the Minnesota Legislature passed The Next Generation Energy Act (NGEA) of 2007 (Laws of 2007, Chapter 136), which strengthened Minnesota's commitment to energy savings.

Specifically, NGEA established an annual savings goal of 1.5 percent of retail sales for electric and natural gas utilities. Previously the law required that each natural gas and electric utility spend between 0.5 percent and 2.0 percent of its gross operating revenues (GOR) annually on their CIPs. The revised statute added an energy savings goal for each utility equal to 1.5 percent of its average annual retail energy sales in Minnesota, excluding sales to certain facilities that

[45] The 2005 Legislative Auditors Report on the Energy Conservation Improvement Program may be viewed at: http://www.auditor.leg.state.mn.us/Ped/2005/pe0504.htm.

have been granted exemption from CIP charges by the Commissioner of Commerce. The CIP savings goal is related to the broader state goal of reducing per capita fossil fuel use by 15 percent by 2015, and is ultimately an integral part of any effort to reduce statewide CO_2 emissions.

To address the 2007 NGEA requirements, the OES is proceeding in four general areas:

1. **Deemed Savings Database Development -** The OES is assisting utilities in their understanding of what efficiency measures produce the most cost effective energy savings and how to calculate those energy savings in a scientifically accurate manner. The OES has hired an experienced engineering firm to identify, review and assess the assumptions used to determine the energy savings for many standard efficiency measures. The contractor has identified a range of energy savings estimates for each typical conservation improvement measure, many of which are implemented by utilities and energy service companies around the nation. While there is a vast body of energy saving estimates associated with these measures, the estimated energy savings for each measure can vary broadly, depending on climate, facility type, and end use of a measure. This can call into question the validity of the engineering calculations used to determine energy savings, and lead to an array of different energy savings calculations between utilities. The Deemed Savings Database project will assess the methodologies used in determining the energy savings for a number of measures and determine which assumptions and calculations are most reliable for Minnesota utilities to use in their conservation improvement projects. In addition the OES will convene ongoing stakeholder workgroups to revise the calculations as necessary, i.e. to reflect a change in baseline standards, and to add new measures as they become available.

   There is an opportunity for ongoing research to verify the savings associated with measures that are rebated under utility conservation programs. Such an effort could include field monitoring of installed measures in order to provide data on the actual savings of one technology over its standard efficiency counterpart. This type of testing program could also provide savings verification for different conservation strategies and indirect program activities. This program could become a regional or national center for energy efficiency verification that would serve a similar function for conservation programs as the Underwriters Laboratory currently provides for electrical equipment. The primary purpose of this center would be to verify the energy savings assumptions are used to determine the energy savings of measures within a Deemed Savings Database. Such an effort would provide policymakers and state regulators with the assurance that energy savings associated with energy efficiency and conservation programs are realized, and allow their use in regional or national carbon markets.

2. **Measurement and Verification** - The OES continues to work with all utilities to increase Measurement and Verification (M&V) activities. In 2008, the OES established M&V protocols[46] for all utilities, which require that utility projects with first-year savings of 1,000,000 kWh of electricity or 20,000 MCF of natural gas undergo specific M&V activities to ensure that the savings are being realized. The savings levels that trigger M&V requirements were discussed extensively with utility stakeholders and were established at a level that was sufficient to keep M&V costs at a reasonable level relative to the savings achieved. The OES set a guideline that M&V costs should be limited to less than 10 percent of the projects projected first-year savings.

3. **Research and Development -** The NGEA authorized the OES to assess utilities up to $3.6 million annually for research and development projects that further the ability of utilities to reach their 1.5 percent energy conservation goal. Over the last year, OES has met with utilities and other stakeholders to get input on the types of projects that utilities think would be most beneficial to identifying new energy savings programs to assist in meeting the energy conservation goal. OES issued its first request for proposals in April 2008 to fund research into specific types of new conservation measures, including conservation potential assessments, technology pilot projects, and programs targeted at influencing consumer behavior. The OES received a total of 42 proposals with requests for more than $10 million and matching funds of over $5 million. From these projects, the OES selected 10 proposals for $1.65 million in available funding. This new authority provides an ability to fund new projects aimed at assessing assess new promising efficiency technologies and strategies and communicate the results to Minnesota utilities so they can assess the costs and impact that the technology could have if applied in their service territory.

4. **Electric Utility Infrastructure Projects -** An additional area where the OES will be working with utilities and stakeholders is in the evaluation of the energy savings impacts of electric utility infrastructure (EUI) projects. Such an effort will include the development of a reference database of these projects that can be accessed by utilities. Currently there is little guidance available to utilities for quantifying the energy savings associated with EUI projects. This is partly by design: as there is little experience in working with these projects, we did not want to overly restrict utilities, and the engineers that evaluate these projects. Furthermore, these types of projects only apply to the 0.5 percent of energy savings above 1 percent, so the magnitude of savings associated with these project types will be limited, although capturing these savings will be critical for some utilities to meet the full 1.5 percent energy savings goal.

[46] See the Director of the Office of Energy Security's Decision dated July 23, 2008 in Docket No. 06-1591, https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5376649

In sum, the OES strives to ensure that the electricity and natural gas savings reported through CIP are accurate and that programs are operated cost-effectively[47] through the CIP planning and review process.[48] Minnesota's conservation and efficiency programs have been widely heralded in their successes and achievements. In 2008, the American Council for an Energy Efficient Economy, a highly respected research and advocacy organization, ranked Minnesota's utility conservation programs as fourth in the nation in terms of program policies and practices.[49] With the 2007 changes to the CIP statutes discussed above, utilities and OES are challenged to increase the energy and carbon dioxide savings from CIP even further, while still maintaining cost-effective programs.

B. ENERGY INFORMATION CENTER

The Energy Information Center promotes energy efficiency and renewable energy to Minnesota consumers and businesses through contacts by telephone, web site, email, tradeshows, classes and public presentations. Info Center staff have made presentations at various state agencies (e.g. Agriculture, Pollution Control, MnSCU system colleges), as well as at city and county fairs and regional events. Some of the more popular events include Living Green Expo, Minnesota Indoor Air Association Conference, Home and Garden Show, FarmFest, Congregations Caring for Creation with Will Steger and so many others. The Info Center offers dozens of energy conservation publications and distributes more than 138,000 publications and CD-ROMs annually. The Info Center offers CDs for consumers, the building industry, renewable energy and commercial and industrial businesses. Info Center staff is available five days a week to answer consumer and builder questions. In FY 2006, the SEO had nearly 300,000 direct contacts or website visits, and distributed more than 175,000 publications and CDs.

In March 2005, St. Cloud University surveyed consumers to determine conservation actions resulting from contact with the Energy Information Center. Results included:

- 80% of respondents found the SEO information to be easy to understand, accurate, useful, and reliable.
- 53% of respondents acted upon information from the SEO and took action to improve the energy efficiency of their home or business.

[47] Cost-effectiveness in Minnesota CIPs are defined according to four benefit-cost tests: Societal, Ratepayer, Participant, and Utility. More information on these tests is provided in the Legislative Auditor's Report noted above. The OES focuses on the Societal test as a measure of program cost-effectiveness consistent with its mission as a public agency.

[48] Investor-owned utilities are required to file proposed CIP plans, covering one to three years, with the OES. The OES employs a variety of methods and tools to review the plans, and has authority to modify program goals or savings assumptions. Investor-owned utilities also file annual status reports summarizing program performance including custom commercial/industrial projects completed during the year. Since these custom projects typically are quite large, OES typically reviews a selection of these custom projects to ensure that the engineering assumptions and methodologies are sound. The process for regulating cooperative and municipal utility CIPs is similar to the investor-owned utility procedures, though due to their status as non-rate regulated entities, OES's role is more advisory in nature.

[49] See "The 2008 State Energy Efficiency Scorecard" (Washington, DC: American Council for an Energy-Efficient Economy, December 2002), page 2.

C. ENERGY CODE ADVANCEMENT PROJECTS

Minnesota is a national leader in advancing energy efficiency through strong and innovative energy codes. USDOE has been an essential partner in the OES's Energy Code Advancement Projects, providing eight SEP Special Project awards and four Rebuild America awards to implement both the residential and commercial energy codes in Minnesota. The OES works closely with the state Building Codes Division, the Builders Association of Minnesota, the University of Minnesota, engineer and architect associations and other building trade organizations to improve the understanding of and compliance with energy code requirements. This is done through formal continuing education, workshops, and the development of case studies and training materials specifically for home builders.

The Minnesota residential energy code was among the first in the nation to mandate strict air tightness standards. As a result, nearly all new single family homes now built in Minnesota are eligible for the federal energy tax credit.

Additionally, the Minnesota Legislature established a goal of achieving 30 percent savings in existing public buildings throughout the state, known as "Buildings, Benchmarks and Beyond" or "B3." The legislature, in setting this energy savings goal directed the Departments of Administration and Commerce to do two things:

- To undertake energy benchmarking for all public buildings. There are over 5,000 such buildings, so the work is expected to focus on creating and prioritizing a list of poorly performing buildings.
- To create guidelines for designing new buildings, to ensure that the designs of new buildings are not only cost effective and energy efficient, but also beneficial to the environment and to the inhabitants of the building.

As part of the B3 initiative, an interdisciplinary team of local and national experts has developed sustainable building guidelines for the State of Minnesota Departments of Administration and Commerce that will be used on all new state buildings. Benchmarking will identify the energy performance of existing public buildings in order to direct energy conservation improvements where they are most needed and most cost-beneficial.

D. ENVIRONMENTAL PROTECTION

Reliable, reasonably priced energy is necessary to sustain modern life and enable a robust economy. The generation and use of electricity, however, has negative impacts on the environment that must be managed and mitigated. Minnesotans expect a balance between mitigating the environmental impacts of electric generation and the availability of affordable, reliable electric service. The OES is constantly focused on striking the appropriate balance, striving to reduce the emissions intensity of electric generation, as well as overall emissions. That is, to reduce both the total amount of emissions from electric generation, and the emissions per kilowatt-hour consumed in Minnesota.

There are a wide variety of programs and initiatives through which the OES seeks to achieve this goal, including:

- the Renewable Energy Standard;
- the Conservation Improvement Program;
- support for legislation allowing continued operation of Xcel's Prairie Island nuclear generation facility, which is a base load generation resource that emits no air pollution;
- support for Xcel's contract with Manitoba Hydro for 500 megawatts of base load hydropower, another base load resource that emits no air pollution; and
- most significantly, leadership and support for the Metropolitan Emissions Reduction Project (MERP), proposed by Xcel and the Izaak Walton League of America, discussed below.

Metropolitan Emissions Reduction Project (MERP).

Older coal-combustion electric generation facilities contribute a significant portion of the criteria pollutants produced in Minnesota. Three of these coal-fired electric facilities are situated on the banks of the Mississippi and St. Croix rivers within the Twin Cities metropolitan area. In the spring of 2002, Xcel, the owner of the three facilities filed a petition with the MPUC, known as the "Metropolitan Emissions Reduction Project" (MERP), in fulfillment of a voluntary commitment made to the Izaak Walton League, as part of Xcel's merger proceeding before the Commission in 2000.[50] The MPUC ultimately approved this proposal in December 2003. Through out the approval process, the OES provided leadership and support for MERP proposed by Xcel and the Izaak Walton League of America with the goal of striking the appropriate balance, striving to reduce the emissions intensity of electric generation, as well as overall emissions. That is, to reduce both the total amount of emissions from electric generation, and the emissions per kilowatt-hour consumed in Minnesota.

MERP is one of the largest energy-related projects ever proposed in Minnesota. Xcel proposed to shut down and dismantle the two coal-fired power plants on the banks of the Mississippi River in the Twin Cities (the Riverside plant in Minneapolis and the High Bridge plant in St. Paul). In their place, Xcel proposed to site natural gas-fired electric generation facilities that will not only replace the power previously generated by Riverside and High Bridge but will increase the capacity by approximately 300 megawatts. MERP also includes the installation of new state-of-the-art pollution control equipment and facility refurbishment at the Allen S. King plant located on the banks of the St. Croix River south of Stillwater. The demolition and construction involved with MERP carries a price of approximately $1 billion. The schedule for the demolition and construction for the three plants (Allen S. King, High Bridge and Riverside, in that order) calls for work to begin late 2004 or early 2005, and be completed by 2010.

[50] Xcel's MERP petition in Docket E002/M-02-633 was enabled by 2003 Minnesota Laws, Special Session Chapter 11, Article 3.

Currently, MERP is on track to meet the proposed 2010 completion date[51]:

- The Allen S. King Plant was the first of the three MERP projects completed. The plant was returned to service in July 2007 and has been regularly dispatched to meet system needs since May 2008.
- The High Bridge combined cycle natural gas facility was the second of the three MERP projects completed and was placed into operation in May 2008, after successfully passing emissions testing.
- The old Riverside coal plant was retired in September 2008. According to Xcel, the new Riverside combined cycle natural gas facility is progressing well and is on scheduled for the May 2009 commercial operation date.

Minnesota is on schedule to meet the 2015 CO2 reduction. MERP is one of the major factors in the reduction of CO2 in Minnesota. In addition to the CO2, MERP will also reduce emissions at the plants significantly by reducing sulfur oxide emissions by 95 percent, nitrogen oxide by 95 percent, particulate matters by 70 percent and mercury emissions to nearly zero. Health authorities have indicated that better air quality in the Twin Cities and in the state should translate into fewer illnesses such as asthma. Moreover, MERP permits maintaining electric generation facilities within the Twin Cities, and continuing to make use of existing electric transmission facilities, ensures that the Twin Cities and the state maintain a reliable electric system. With Governor Pawlenty's leadership, a strong and broad coalition of support including representatives of the legislature, the business community, energy and environmental regulators, public health officials, citizens and environmentalists, the MERP project is the greatest single reduction in emissions in Minnesota history.

E. AFFORDABILITY

For many Minnesota households, energy costs place a severe and continuing stress on the family's budget. Energy costs account for up to 13 percent of a typical low-income household budget as compared to 3 percent for other households. The inability of some households to pay their energy bill results in utilities, focusing their attention and resources on bill collection, disconnection and reconnection activities. The costs of such efforts are typically borne by other ratepayers on the utility's system.

The OES's first line of defense against high energy costs is through its advocacy for low utility rates at the Commission. In nearly every type of proceeding at the Commission, OES analysts are working to reduce the overall costs of the provision of utility service, in order to keep rates affordable for Minnesotans. This advocacy is not only good for individual Minnesota citizens; it is also good for Minnesota's economy.

However, for those individuals that need additional help, assistance for low-income energy consumers is available through federal programs administered by the OES. These programs serve between a quarter and a third of the Minnesota households that are eligible for assistance.

[51] See Xcel's October 1, 2008 MERP update to the MPUC in Docket E002/M-02-633.

Four Minnesota statutes specifically address low-income energy concerns. These statutes mandate programs that include an electric rate discount, affordability program, conservation and energy efficiency services, and protection against utility disconnection during cold-weather months.

1. Low Income Home Energy Assistance Program

Minnesota's Low Income Home Energy Assistance Program (LIHEAP) helps eligible low-income households meet their immediate winter heating needs. LIHEAP is funded by the U.S. Department of Health and Human Services. The OES contracts with 38 local nonprofit organizations, local government organizations, and tribal organizations to provide services to the public.

Households with incomes up to 50 percent of the state median income are eligible for the program. The amount of payment allotted per household is determined by income, household size and fuel type. Households with the lowest incomes and highest bills receive the largest grants. Assistance provided to households is usually in the form of a payment to their energy vendor. Renters may be eligible for the program.

LIHEAP remains dependent on the federal appropriations process for its funding and the amount granted to the program varies from year to year. Although the number of eligible households has risen dramatically, the federal fuel assistance funds have not kept pace.

During the past 22 years, the number of Minnesota households that have received LIHEAP assistance range from a high of 139,573 in FY 1984 (about 21 percent of those eligible) to a low of 81,486 in FY 1998 (about 19 percent of those eligible). In FY 2008, the program served 126,218 Minnesota households with an average bill payment assistance grant of $516 per household.

Additional money is available to households if they have an emergency situation and are in jeopardy of losing their heat. Emergency situations include:

- broken heating equipment that must be fixed or replaced;
- termination of utility service; and
- danger of being without fuel or of having utility service terminated.

Assistance with emergency situations is available 24 hours a day, seven days a week, during the heating season. The local service providers also provide advocacy and referral services throughout the program year.

2. Reach Out For Warmth

Households that have too much income to be eligible for the LIHEAP program, but under 60 percent of the state median income, are eligible for help through the Reach Out for Warmth (ROFW) emergency fuel fund. This fund was established in 1992 by the Minnesota State Legislature. Department staff administers the year-round fund through the same 38 local

energy assistance agencies that deliver LIHEAP services. ROFW is a community-based fuel fund and is supported by individuals, businesses, churches, civic groups, school children, energy vendors, and private foundations. All funds raised locally stay in the area to help local residents and are matched 2 to 1 with federal LIHEAP dollars.

3. Minnesota Weatherization Assistance Program

The OES administers the Weatherization Assistance Program (WAP), which uses U.S. Department of Energy funds to provide energy conservation and efficiency services to income-qualified households.

The Weatherization program offers a long-term solution to reduce the homeowner's annual heating bill by an average of 25 percent. This reduces homeowners' reliance upon other programs, such as LIHEAP, to pay heating bills and frees up dollars in that program to assist other clients.

For the 2008-2009 winter heating season, Minnesota received $9.7 million in WAP funds from the Department of Energy (DOE). In F&2003 over 4300 households were served using both DOE funding and money transferred from LIHEAP's energy conservation option. The WAP uses the same income guidelines as LIHEAP, serving households who are at or below 50 percent of the state median income. More than half the households served have one or more members who are in a priority category (child, elderly or disabled). WAP contracts with 32 local nonprofit and government organizations to provide weatherization and conservation services. Some agencies receive additional funding from outside sources, such as CIP, to serve additional households.

The WAP is unique in that it requires an on-site visit, where an energy auditor can assess the client's home to identify the most necessary and cost-effective improvements.

The Minnesota WAP, which began in 1978, has historically been innovative in its field. It was the first WAP nationally to use blower door and infrared technology to test homes for air leakage and the first to use blown-in sidewall insulation. It has also received national awards for innovative software to determine, measure and report conservation projects.

Services provided by the program include:

- educating participants;
- conducting energy audits to evaluate the home's energy usage;
- installing exterior wall and attic insulation;
- correcting air infiltration and sealing attic bypasses; and
- testing, repairing, or replacing home mechanical systems to ensure efficiency and safety.

4. Minnesota Low Income Statutes

Minn. Stat. §216B.16, subd. 14, requires Xcel to offer a 50 percent discount on the first 300 kilowatt-hours of electric service to residential customers who are receiving federal energy assistance. In years past, this program provided a uniform sum to all eligible customers. In the 2004 session, the legislature authorized the modification of the program to allow for a more targeted approach.

Minn. Stat. §216B.16, Subd. 15 requires that by September 1, 2007, a public utility serving low-income residential ratepayers who use natural gas for heating must file an affordability program with the commission. For purposes of this subdivision, "low-income residential ratepayers" means ratepayers who receive energy assistance from the low-income home energy assistance program (LIHEAP). Any affordability program the commission orders a utility to implement must lower the percentage of income that participating low-income households devote to energy bills, decrease or eliminate participating customer arrears and coordinate the program with other available low-income bill payment assistance and conservation resources. As of 2008, all regulated natural gas utilities have filed for and received MPUC approval of a Gas Affordability Program (GAP).

Minn. Stat. §216B.241, subd. 1a, established the Conservation Improvement Program (CIP). Under this program, certain natural gas and electric companies are required to make investments in conservation and energy efficiency for their residential and non-residential customers. Utilities operating these conservation programs are also required to devote a portion of their CIP spending "to programs that directly address the needs of renters and low-income persons…."

Minnesota's regulated natural gas and electric utilities have complied with the CIP statute by developing conservation projects available only to low-income residential ratepayers. In 2002, for example, low-income energy conservation spending reached nearly $3 million for such projects as water heater replacement, home weatherization and setback thermostat installation.

Minn. Stat. §216B.095 and §216B.097, also known collectively as the Cold Weather Rule, provides protection against disconnection of residential utility service during the cold weather months for any household whose income is less than 50 percent of the state median income and which makes and keeps a bill payment arrangement with their utility company. A utility may not disconnect a household who meets the eligibility criteria of the statute and Minnesota Rules, parts 7820.1800-7820.2300 as interpreted by the Minnesota Public Utilities Commission.

Additional consumer protections can be found in:

1. Minn. Stat. §216B.0975: protecting consumers against disconnections in extreme heat conditions

2. Minn. Stat. §216B.098: providing for budget billing plans; payment agreements for arrearages; protections in undercharge situations; and protections for a residence with medically necessary equipment necessary to sustain life.

5. Other Programs

There are also several smaller programs, the largest of which is the Salvation Army's HeatShare program, operated at the local level by some counties, local social service providers and religious institutions. However, these programs are sporadic in their assistance and are geared almost exclusively at crisis situations.

APPENDIX

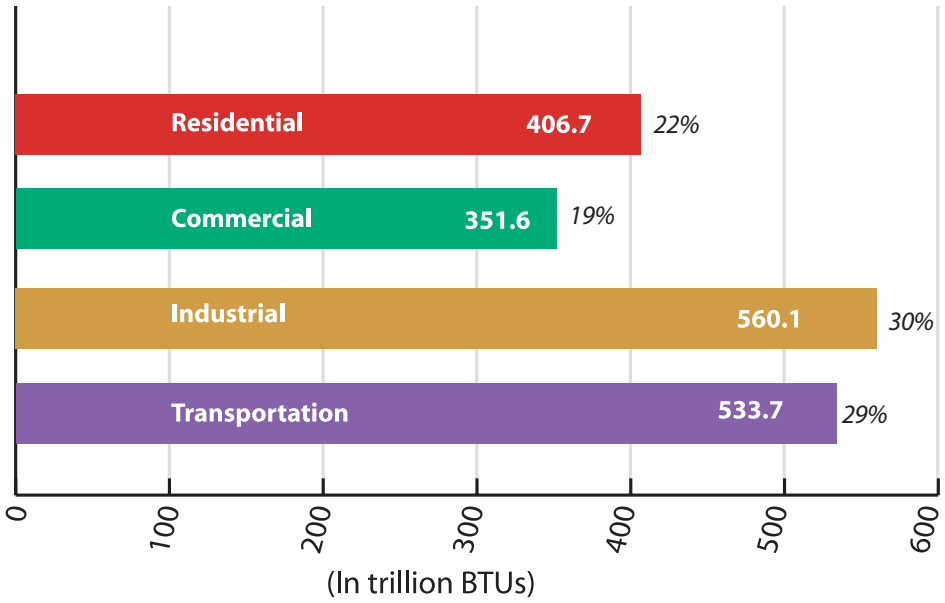
MINNESOTA ENERGY INFORMATION

This data comes primarily from two sources: data collected internally pursuant to Minn. Stat. 216C.17 through the Department of Commerce Regional Energy Information System (REIS), and data obtained through the U.S. Department of Energy's Energy Information Administration (EIA). For each graph, the sources are noted and additional information about the data and assumptions used are included in the appendix. The department sought to provide the most current data available from different sources; hence, data references may cite differing years.**

HOW MUCH ENERGY DOES MINNESOTA USE?

Minnesotans consumed a total of 1,852.2 trillion Btus of energy (electricity, natural gas, petroleum products, coal and biomass) in 2005. (EIA State Energy Data, Table R1. Energy Consumption by Sector, Ranked by State, 2005) Figure 1 shows the relative amounts of energy Minnesotans use for commercial, residential, industrial and transportation purposes.45

Figure 1: Energy End Use in Minnesota, 2005



Source: EIA State Energy Data System (SEDS), Table R1. Energy Consumption by Sector, Ranked by State, 2005

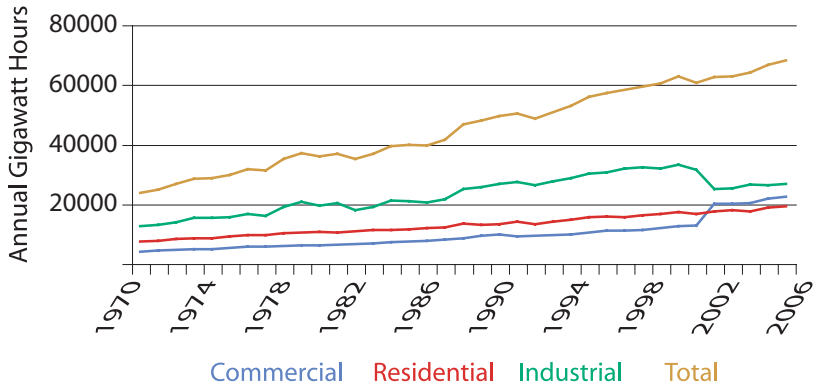
The following sections further explain Minnesota energy use according to fuel type: electricity, natural gas and petroleum products.

ELECTRICITY

Minnesotans consumed a total 68,029 gigawatt-hours of electricity in 2006. Figure 2 shows total electric consumption since 1970 and breaks down that electric consumption into the residential, commercial and industrial customer classes.

This graph illustrates Minnesota's increasing demand for electricity, both overall and in the various sectors. Total demand for electricity has increased an average of 3.1 percent annually over the 1970-2006 period.

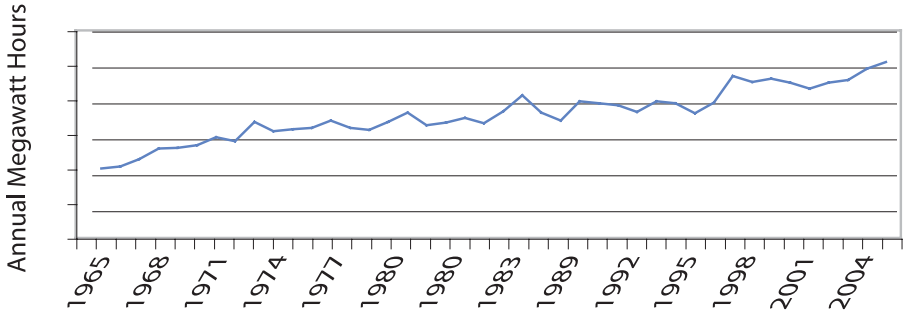
Figure 2: Electric Consumption in Minnesota by Customer Class, 1970–2006



Source: REIS database

Note: Data extracted from REIS and the EIA website reflects 2001 usage. Some of the petroleum, coal, biomass, solar and geothermal data were extracted from EIA's "State Energy Data 2000 Consumption" (http://www.eia.doe.gov/emeu/states/_use_multistate.hyml).

Figure 3: Weather Normalized Electric Consumption per Residential Customer, 1970-2006



Sources: REIS database,
DNR – State Climatologist at http://www.climate.umn.edu

Note: Customer is defined as a residential meter.

Demand by commercial customers has grown the most in that span, increasing 3.8 percent annually. The annual growth rates for residential and industrial customers for the same period, were 2.8 percent and 2.4 percent, respectively.

Many factors influence electricity consumption, including weather, price, population levels and the general economic climate. The data in Figure 2 are not adjusted for these factors. Thus, consumption changes in the different classes can vary significantly in the short term. Industrial consumption, for example, fell by 4.8 percent in 2001, with the economic recession playing a part in that decline.

Minnesota's weather is a major factor in residential use of electricity. Figure 3 shows the electric consumption per residential customer, taking into account differences in weather from year to year. Adjusting the data to account for abnormal weather is called "weather normalization," which provides a way to look at trends in energy use. Normalization removes the effects of increased energy use in hotter summers and colder winters as well as decreased use during milder years. This figure shows a fairly steady increase in electricity used per customer from the mid-

1960s to the present, with a large increase beginning in the late 1990s. These increases appear to stem from greater use of electricity for air conditioning, home computers, and various other electronic appliances.

NATURAL GAS

Minnesotans consumed a total of 240.82 billion cubic feet of natural gas in 2006. Figure 4 shows Min-

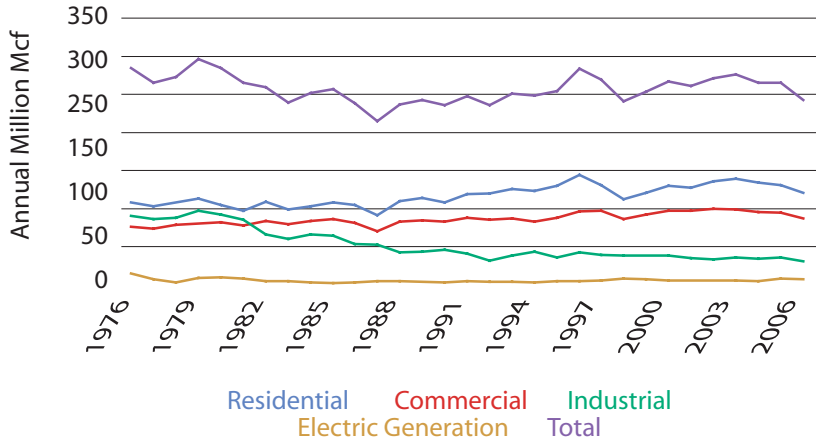
nesota's natural gas consumption by residential, commercial, industrial, electric generation and transportation customers (which includes pipeline operation and, since 1990, natural gas fueled vehicles).

This graph shows two notable consumption trends. First, more natural gas is being used for electric generation. During the energy crisis in the middle and late 1970s, use of natural gas for electric generation declined sharply. Recently, however, natural gas has been used at significantly higher rates to generate electricity. While this upward trend is only slightly evident in this chart, the increase will be more noticeable starting in 2003 as recently approved natural-gas facilities go online in Minnesota. One of the basic reasons for turning to natural gas as a fuel source for electricity is that gas-fired plants have fewer harmful environmental effects than other traditional fossil fuels such as coal or fuel oil.

The second notable consumption trend is residential consumption. Residential consumers' use of natural gas has steadily decreased. Figure 5 shows natural gas use per residential customer after "normalizing" the data for weather fluctuations.

As shown in Figure 5, after removing the effects of weather, residential consumption per customer of natural gas has declined for 161.6 thousand cubic feet per year in 1965 to 98.8 thousand cubic feet per year in 2006 (or approximately 39 percent over the last 43 years). One of the reasons for this trend is the increased efficiency of household gas-fueled appliances as well as the construction of energy-efficient new housing as specified by building code requirements.

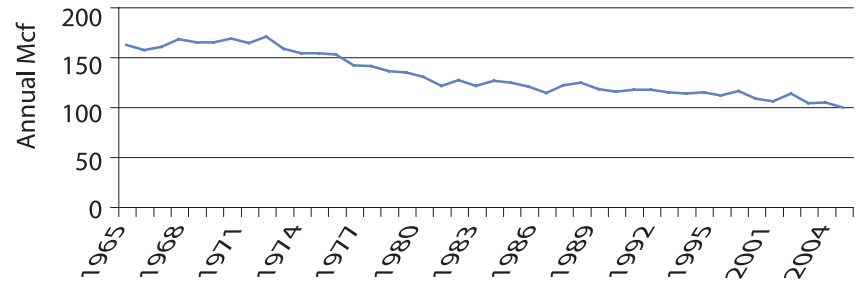
Figure 4: Natural Gas Consumption in Minnesota by Customer Class, 1970–2006



Source: REIS database

Note: Figure 4 shows a total consumption of 333.53 Bcf in 2002. However, "deliveries to transportation," "Company Use" and "Unaccounted For" categories account for the difference of approximately 63.73 Bcf in 2002.

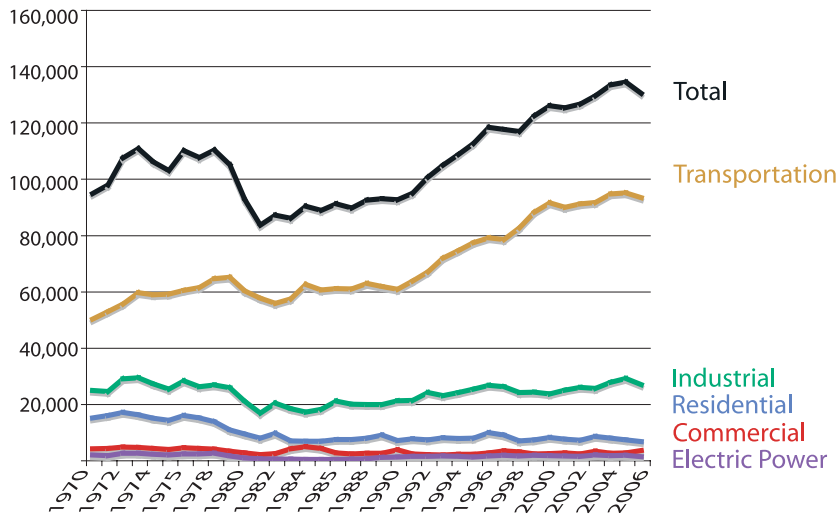
Figure 5: Weather Normalized Natural Gas Consumption per Residential Customer, 1965–2006



Sources: REIS database, DNR – State Climatologist

Note: Customer is defined as a residential meter.

Figure 6: Petroleum Products Consumption in Minnesota by Customer Class, 1970–2005 (millions of gallons annually)



Source-EIA; 1998 data is preliminary.

PETROLEUM

Minnesotans consumed a total of 701 trillion Btus (130,067 thousand gallons) of petroleum products in 2006. Figure 6 shows the total petroleum consumption in Minnesota for the residential, commercial, industrial, transportation, and electric generation customer classes.

In 2006, Minnesotans used about 71.5 percent of all petroleum products for transportation (air, land, and water). This amount includes asphalt and road oil as well as fuels like diesel, jet fuel, and motor gasoline. Most agricultural use of petroleum is also included in the transportation category. About 23.5 percent of petroleum products were used for the commercial, electric utility, industrial, and institutional space heating and processing categories. With about one-fourth of Minnesota households using either fuel oil or propane for heating, residential heating use constituted about 5 percent of the total petroleum products used in 2006.

HOW MUCH DOES MINNESOTA'S ENERGY COST?

Figures 7, 8, and 9 show Minnesota's total real expenditures (adjusted for inflation) on electricity, natural gas, and petroleum. All price and expenditure data in this

Millions $ (2000 Dollars) report has been converted to year 2000 dollar values.

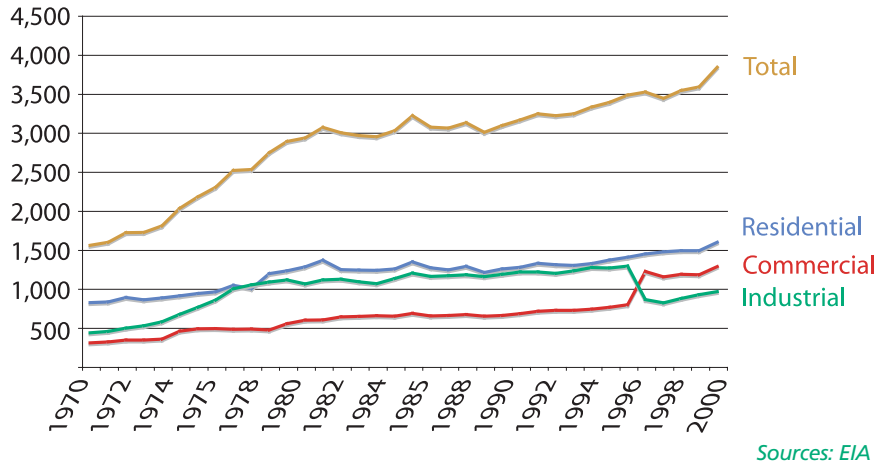
In 2005, Minnesotans spent about $3.8 billion on electricity, $3.0 billion on natural gas and $9.4 billion on petroleum products.

Historically, Minnesota has enjoyed low electric prices compared with other parts of the country. Figure 10 shows the average price that residential, commercial and industrial customers paid for electricity in 2005 in Minnesota and the corresponding national average prices. This table shows that the electric rates paid by Minnesota

commercial Commercial customers ranked 15th lowest nationally in 2005 (they were 19th lowest in 2000). For Minnesota industrial customers, electric rates were 22nd lowest nationally in 2005 (30th lowest in 2000), while the rates for Minnesota residential customers ranked 20th lowest in 2005 (they were 21st in 2000).

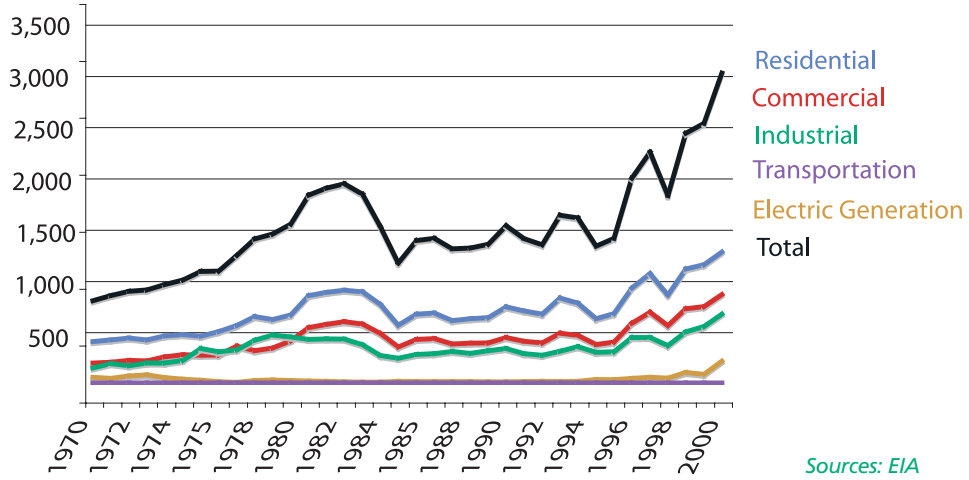
One of the most significant factors affecting the price of electricity is the availability of power, or generating capacity. The increasing demand for electricity has put pressure on the existing generation capacity. Utilities in Minnesota are in the process of adding more capacity to portions of the electric system. The sizes and types of new generation facilities will determine the actual affect on the relative prices of Minnesota electricity.

Figure 7: Annual Real Expenditures on Electricity in Minnesota by Customer Class



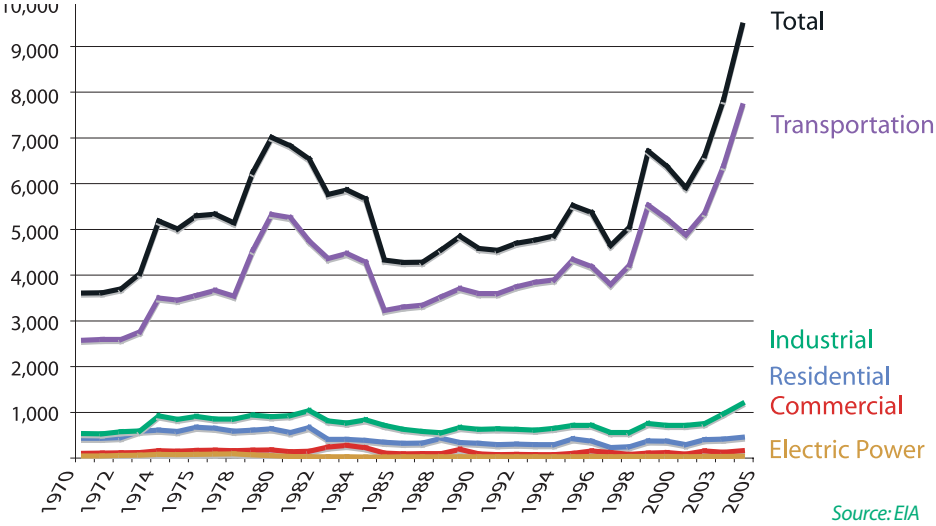
Sources: EIA

Figure 8: Annual Real Expenditures on Natural Gas in Minnesota by Customner Class 1970–2005



Sources: EIA

Figure 9: Annual Real Expenditures on Petroleum Products in Minnesota by Customer Class 1970–2005



Source: EIA

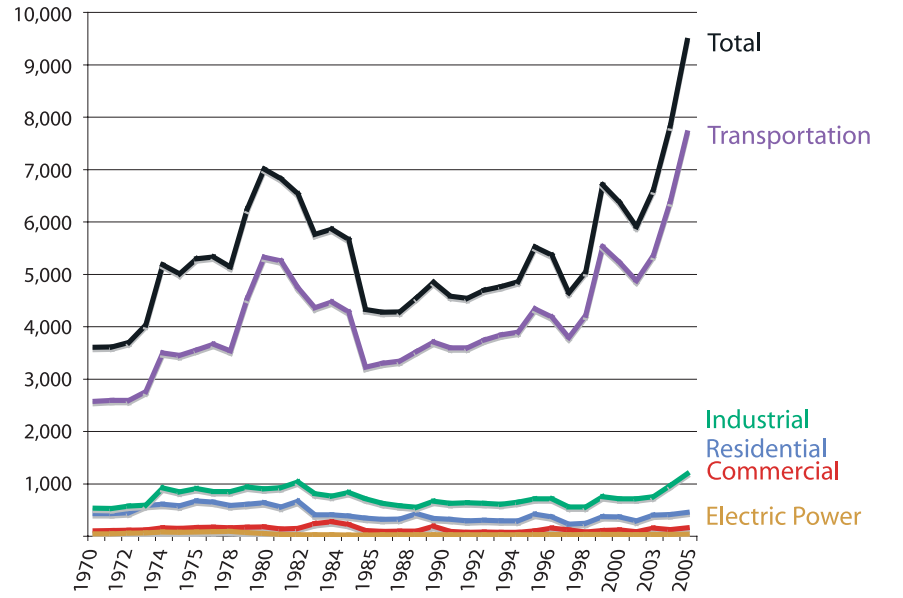
Figure 10: 2005 Minnesota Electric Prices Relative to Prices in Other States (¢/kWh)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota Price	9.93¢	10.04¢	8.39¢
Minnesota Rank*	23rd	14th	13th
Average U.S. Price	9.92¢	10.96¢	9.07¢
Highest Price	24.30¢	24.57¢	15.82¢
Lowest Price	3.97¢	4.92¢	2.59¢

** The rank is from the lowest cost state to the highest cost state. For example, a rank of 24 means that 23 other states have lower costs.*

Source: EIA

Figure 11: Real Prices for Natural Gas in Minnesota by Customer Class, 1970–2005



Sources: EIA

Figure 12: 2005 Minnesota Natural Gas Prices Relative to Prices in Other States

(Dollars per Thousand Cubic-Feet)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	$9.93	$10.04	$8.39
Minnesota rank	23rd	14th	13th
Average U.S. price	$9.92	$10.96	$9.07
Highest price	$24.30	$24.557	$15.82
Lowest Price	$3.97	$4.92	$2.59

Source: EIA

Figure 11 shows Minnesota's natural gas prices for the residential, commercial, industrial and electric generation customer classes.

Minnesota customers have historically enjoyed very low natural gas prices compared with prices paid by consumers in other states. Figure 12 below shows this comparison for residential, commercial and industrial customers.

A major reason Minnesota enjoys comparatively lower prices is that interstate pipelines bring gas to the state from various and competing natural gas production areas in Canada and the southern U.S. Minnesota utilities have, therefore, been able to purchase gas at relatively "good' prices due to competition between Canadian and U.S. natural gas production areas and relative price dif

Figure 13 shows the Minnesota prices for the most commonly used petroleum products: distillate fuel (diesel and heating fuel), jet fuel, liquid petroleum gases, and motor gasoline.

The prices that Minnesotans pay for petroleum products are largely based on the price of crude oil plus the assessed taxes. World political and economic market forces primarily determine the cost of the crude oil price. Federal and state governments assess taxes on petroleum products.

The price of finished petroleum products is influenced by several factors. Sometimes price changes are due to supply and demand imbalances. For example, supply shortages can occur due to maintenance or damage on pipelines or at refineries. Also, since each petroleum product needs to be stored separately, some supply imbalances

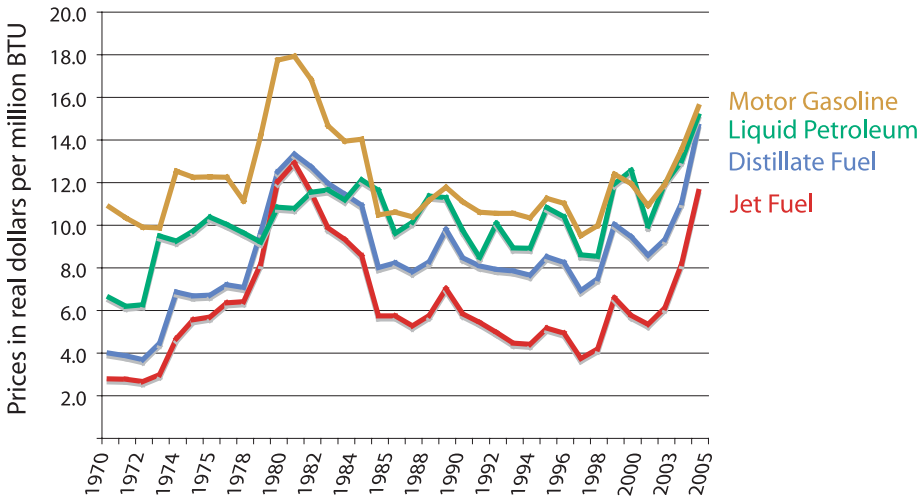
result from simple logistical problems with coordinating production and storage to meet current and future demand.

Unexpected demand for a particular product can also create temporary shortages that lead to higher prices. For instance, very cold weather increases the use of propane products for space heating and very wet or very dry weather increases or decreases the agricultural use of petroleum products.

Activity in the commodities market can further influence price. Unexpected spikes or sudden drops in prices are sometimes the markets' response to perceptions of future supply and demand imbalances. Thus, data trends typically provide more reliable information for planning than specific numbers on specific dates.

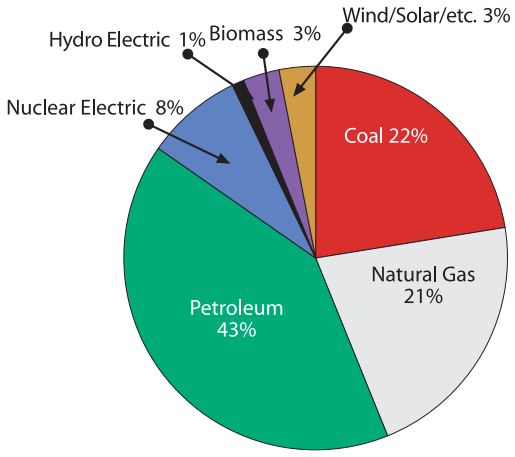
The U.S. Department of Energy estimates that the price that consumers pay at the pump can be generally broken down as follows: 46 percent crude oil; 26 percent federal and state taxes; 19 percent refining costs; and 9 percent distribution, marketing, and retail station costs and profits.

Figure 13: Real Prices for Petroleum Products in Minnesota, 1970–2005



Source: EIA

Figure 14: Total Inputs Used to Produce All Energy Consumed in Minnesota, 2006



Sources: EIA

Note: Biomass includes wood and RDF (refuse-derived fuel), which is fuel generated by burning waste products.

WHERE DO MINNESOTAN'S GET THEIR ENERGY?

In 2005, Minnesota required a total of 1,852.2 trillion Btus of energy to produce all of the energy consumed in the state. This number is greater than the total consumption figure because it also includes the losses that occur in the production and transmission of electricity. Figure 14 shows the types and relative amounts of fuel used to produce the energy consumed in Minnesota.

ELECTRICITY

There are three distinct steps to providing electricity to the customer: generation, transmission, and distribution.

Step 1 Generation: Electricity is produced at generating stations or power plants that are usually located in relatively remote areas, using a variety of fuels.50 Most generation facilities in Minnesota are owned by electric utilities with a small amount owned by independent power producers or private industrial entities. Federal regulators have taken steps to decrease price regulation and allow more competition in the wholesale market for electric generation (sales between providers), and many states have allowed generation owners other than utilities to sell power directly to consumers. In Minnesota generation remains largely state regulated and utilities are required to provide safe, reasonably priced, reliable service to customers.

Step 2 Transmission: Electric energy is transported from the generating stations to the load centers (areas where much electricity is used, like cities) via high-voltage transmission lines. The U.S. portion of the North American integrated grid of electric transmission lines is regulated by the Federal Energy Regulatory Commission (FERC), and operation of the grid is subject to the constant review of independent system operators, such as the Midwest Independent System Operator (MISO) which controls the grid in our region of the U.S. Some large industrial users receive electricity directly from transmission lines.

Step 3 Distribution: Most consumers are served by lower-voltage distribution lines, which carry electricity from the transmission lines to homes and businesses.

Each electric utility in Minnesota has exclusive rights and the responsibility to serve all consumers in a geographic area established (and occasionally modified) according to state law. Three types of utilities serve electric consumers in Minnesota.

First, investor-owned utilities (IOUs) are rate-regulated by the state and

are allowed to recover all prudently incurred costs of providing electricity to consumers. Second, distribution electric cooperative associations are member/consumer-owned and are regulated by their elected boards unless they choose to become subject to the regulation of the Minnesota Public Utilities Commission. Distribution cooperatives, in turn, are served by Generation and Transmission cooperatives that procure and transmit power for their member distribution cooperatives. Third, many municipalities in Minnesota receive their electricity from municipal utilities, which are governed by city officials. Municipal utilities can either generate their own electricity or purchase

it on contract through a Municipal Power Agency or other utility. Figure 15 illustrates the portion of the state each utility type serves.

The electricity consumed by Minnesota customers is generated from a variety of fuels.

Figure 16 shows the amount of electricity generated by source for plants in Minnesota. Information about the fuel inputs of electricity consumer in Minnesota but generated elsewhere is not included. Also, generation purchased in contracts from marketers and utilities without Minnesota service territory are not included in this data, since the fuel source is not always known in such contracts.

NATURAL GAS

The natural gas industry also follows three steps in providing the product, natural gas, to the customer: production, transportation and local distribution.

Step 1: The production areas for natural gas consumed in Minnesota are in both Canada and the southern and western U.S. The production process and the wholesale price of Minnesota's natural gas supplies are completely deregulated.

Step 2: Natural gas is transported from the production areas to local distribution companies through an international grid of large pipelines. These transportation pipelines are regulated in the U.S. by the Federal Energy Regulatory Commission (FERC). The three main interstate pipelines that serve Minnesota customers are the Northern Natural Gas Company (Northern) pipeline, which provides approximately 68 percent of the total natural gas transportation capacity used by Minnesota customers; the Viking Gas Transmission Company (Viking) pipeline, which provides approximately 8 percent of the total pipeline capacity; and the Great Lakes Gas Transmission Company (Great Lakes) pipeline, which provides less than 1 percent of the natural gas pipeline capacity used in the state. The remaining pipeline capacity in Minnesota is composed of three pipelines that combined represent less than 1 percent of transportation capacity and peak shaving and on-line storage facilities.

Northern transports gas from the Hugoton basin, which is located primarily in the Kansas and Oklahoma area, as well as the Permian, Anadarko, and Gulf Coast basins, which are all located in Texas. Viking and Great Lakes pipelines have gathering facilities in the Alberta basin (in the Canadian provinces of Alberta and British Columbia). Newly constructed interstate pipes provide greater access to Minnesota of Rocky Mountain gas supplies than in the past.

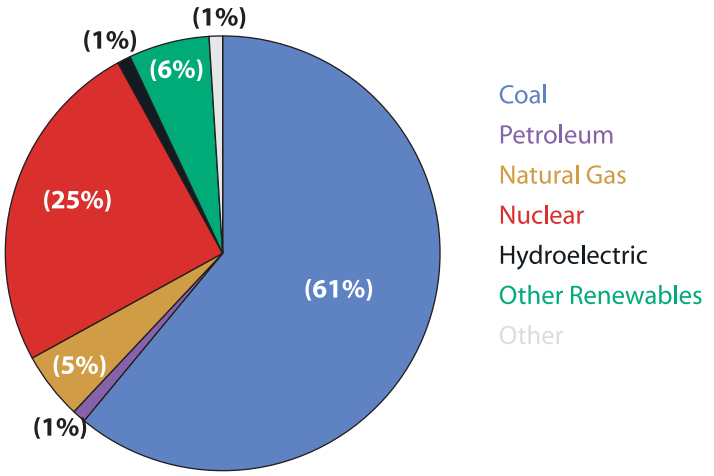
Figure 15: Percentage of Customers and Load Served by Different Electric Utility Types in 2006

Type of Entity	# Customers	% Total Customers	Total GWh	% Total GWh
IOU, Regulated	1,435,389	57%	44,884	66%
Cooperative	733,784	29%	13,306	20%
Municipal	355,257	14%	9839	14%

Source: REIS

Figure 16: 2001 Electric Generation by Fuel Imput

(Megawatt Hours)



Source: REIS

Figure 17: Percentage of Customers and Volume Served by Natural Gas Utilities in 2006.

Type of Entity	# Customers	Percent of Total Customers	Total Mcf	% Total Mcf
IOU, regulated	1,452,681	94.7	225,291,743	93.6
Municipal	77,858	5.1	15,175,391	6.3
Private, unregulated	3,478	0.2	353,950	0.1

Source: REIS

Since interstate pipeline capacity is available to all shippers on a nondiscriminatory basis, prices are set by negotiations between suppliers and buyers.

Step 3: Delivery of natural gas to end-use customers is completed by the companies that build and maintain the smaller pipeline infrastructure that runs from the large interstate pipelines to the customers. These firms are called local distribution companies, or LDCs. There are six investor-owned LDCs in Minnesota that are regulated by the state. The department reviews the LDCs' gas costs to ensure that they are reasonable and makes recommendations to the Commission, which has the final authority to allow (or disallow) gas costs to be recovered from Minnesota ratepayers.

In addition to the six regulated LDCs, there are 20 municipal LDCs that are under local control. There are also a few privately owned LDCs that do not serve sufficient numbers of customers to justify state regulation per Minn. Stat. 216B.02, subd. 4 and 216B.16, subd. 12. Figure 17 illustrates the portion of Minnesota's gas consumers served by each utility type.

Unlike electric companies, natural gas companies do not have assigned service territories. However, once an LDC has established the infrastructure to serve an area, in order to avoid duplication of facilities, it effectively becomes the infrastructure to deliver natural gas to low density populations located long distances from major pipelines hinders further development.

PETROLEUM

In 2007, the United States imports more than 58 percent of its petroleum resources, either in the form of crude oil or refined products. U.S. crude oil imports have declined from 62 percent in 2002 and 60 percent in 2006. About half of these imports came from the Western Hemisphere (North, South and Central America and the Caribbean) during 2006. (http://tonto.eia.doe.gov/energy_in_brief/foreign_oil_dependence.cfm)

Minnesota has no indigenous oil reserves. All of the oil used in the state must be imported. Most petroleum products enter and leave Minnesota by pipeline. Some are transported by barge, rail, ship, or truck. Most of the United States' imported Canadian crude oil and liquid petroleum gases (LPG) pass through Minnesota on their way to other parts of the Midwest, Eastern Canada, and New England.

Minnesota customers are provided refined petroleum products through area refineries or pipelines. Electric utility and other industrial customers use barge, rail or trucks to transport the finished products from these services to their individual locations. Smaller-volume customers, such as farms, homes, and gas stations, receive their petroleum products via truck delivery.

Residential, commercial and industrial use of petroleum products for non-transportation purposes has been steady or declining in the past

several years. That trend is expected to continue. The transportation sector, which accounts for nearly two-thirds of all petroleum consumption, has seen steadily increasing levels of demand.

One factor that impacts the price of petroleum products is supply. Crude oil is necessary for the production of petroleum products. The world's annual supply of crude oil depends on the interplay of many complex factors including demand, weather, politics, technology, and economics. In 2005, the world currently uses approximately 84 thousand million barrels of crude oil per day. (See EIA at: Total World Petroleum Consumption.) Scientists estimate that ongoing natural processes create new crude oil at the rate of 7 million barrels per year. These numbers indicate an eventual depletion of the available crude oil, although it may be possible to find or manufacture new sources and substitutes for these products.

As with natural gas and electricity, the available infrastructure also has a large impact on petroleum prices. Currently, demand is beginning to exceed ocean shipping capacity and is approaching the capacity of some pipelines. Furthermore, the cost of developing new crude oil wells is increasing. New wells, for example, are in less accessible locations. Higher prices for petroleum, however, allow development of lower grades of crude that were previously too costly to exploit.

Three other trends may impact the price of petroleum products. First, in the 1990s, crude oil and refined petroleum product, like natural gas, became publicly traded commodities on world mercantile exchanges. During times of actual or perceived supply disruptions or shortages, prices now fluctuate more erratically. Second, nearly every major international oil company and most independent marketers are forming E-commerce sites to trade commodities independently. Their effect on energy prices and supply will depend largely on which sites survive. Third, petroleum refiners have significantly changed their operations in the 1990s. They have reduced refining costs by moving toward just-in-time production. Storage is now more in the control of independent terminal and pipeline operators.

CHANGING IMPORTS NEEDS

In 2007 the United States met over 58 percent of its crude oil needs with imports. Much of the crude oil that is fed into refineries in Minnesota is delivered by pipelines from Canada. EIA projects that the U.S. dependence on foreign petroleum is expected to decline in the next two decades. (See EIA, How dependent are we on foreign oil? May 2008.) The fact that Minnesota does not receive a large percentage of its crude oil feed stocks from areas such as Mexico, Venezuela, Nigeria, and the Middle East does not mean that Minnesotans are insulated from the political and economic unrest that has affected those areas. Events in these places affect the world market, which influences Minnesota prices. However, the Commission's recent decisions in Docket Nos. PL9/CN-07-464 and PL9/CN-07-465 granted Enbridge Energy Limited Partnership the required "Certificates of Need" to expand its current oil pipelines and provides Minnesota with potentially greater future access to the oil reserve in Canada.

RELIABILITY ISSUES

The reliability issues that result from problems with the supply infrastructure will continue to be a challenge for the industry throughout the country.

Petroleum products suppliers often operate with only a thin margin between current demand and inventories. In other words, suppliers tend to shy away from "stockpiling" reserves of petroleum products. This results in a market that is not capable of drawing upon instantly available reserves in order to adjust to significant changes in demand.