Energy Policy and Conservation Report

DRAFT

July 2004

MINNESOTA DEPARTMENT OF COMMERCE

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Dear Colleague:

Every four years, Minnesota Statutes (Minn. Stat. 216C.18) obliges the Department of Commerce to issue a report on energy issues and information for our State. In fulfillment of this statute, we are pleased to offer this DRAFT Energy Policy and Conservation Report.

As you are aware, energy production, delivery and costs are sensitive to a myriad of factors—both within and outside of Minnesota's influences and borders. The "tug and pull" of these factors results in an ever-changing and evolving energy environment.

We have seen the development or focusing of many factors since the last (year 2000) Energy Policy and Conservation Report. Among these are:

- The development of regional electric independent system operators (ISOs) in the United States regulated by the Federal Energy Regulatory Commission and the creation of the Midwest Independent System Operator (MISO) in Minnesota and the Midwest.
- The natural gas surplus or "bubble" experienced in the U.S. for decades is now been used up and supplies of natural gas are regarded as finite resources. As such, certain usages are being more closely scrutinized to ensure that natural gas supplies are used prudently.
- Wind-powered electric generation in Minnesota continues to develop and flourish.
- Minnesota's economy has grown sufficiently to fully utilize any excess capacity in the State's large power facilities since the last large power plant was built. As such, attention is now turning to future "baseload" facility construction.
- Even more than electric generation, Minnesota and the upper Midwest is finding its electric transmission and delivery system constrained. Since generated electricity is useless to customers if it cannot be delivered, transmission is in sharp focus in our State and region.

This report addresses these developments by providing data and information concerning our State's energy usage, needs and policies as well as policies and strategies for meeting upcoming challenges.

If you wish to provide comments on this DRAFT report, you may do so using e-mail, regular mail, or in person at the public hearing. E-mail your comments to quad.report@state.mn.us. You may direct written comments to:

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The Department will hold a public hearing on this DRAFT report in the next few months. If you are interested in attending, please consult our website http://www.commerce.state.mn.us for the date, time and location of the hearing. Thank you for your interest and participation.

TABLE OF CONTENTS

Introduction

Every four years, the Department of Commerce[1] is required by Minnesota Statutes, section 216C.18[2] 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.[3]

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 remain low, compared to the rest of the nation; and
- the environmental impacts of the energy produced and consumed in the state are reduced.

The goal of these guiding principles is to maintain Minnesota's current reliable, low-cost energy in order to promote job growth and economic development, while lowering the environmental impacts of the production, delivery and use of that energy.

Achieving this goal requires weaving seven energy policy strategies that build on many elements in the present electricity system while making important systemic improvements now and in the future. These seven energy policy strategies are:

Energy Policy Strategy No. 1 – Continue the operation of facilities that provide safe, reliable, low-cost power and do not emit air pollution. The Department supported legislation in 2003 to allow additional spent fuel storage at Xcel Energy's Prairie Island nuclear generation facility. Minnesota's utilities project the need for over 4000 megawatts of mostly baseload and some intermediate resources in the next ten years. During this time period, the licenses will expire of both of Xcel Energy's (Xcel) nuclear generation facilities in Minnesota, Prairie Island and Monticello. These facilities combined provide over 1600 megawatts of baseload generation without emitting any air pollution in the state. If the federal Nuclear Regulatory Commission does not re-license these two facilities, Minnesota's baseload needs and air pollution problems will expand significantly.

Energy Policy Strategy No. 2 – Encourage coal-fired power generation facilities to convert to less polluting fuels, or to install state-of-the-art emissions control technologies. The Department, with Governor Pawlenty's leadership, helped to establish a strong and broad coalition of support for Xcel's Metropolitan Emissions Reduction Program. The coalition, including representatives of the legislature, the business community, energy and environmental

[1] Please see Appendix 1 for a description of the Energy Functions within the Department of Commerce.
[2] The text of Minn. Stat. 216C.18 is provided in Appendix 8.
[3] Appendix 2 provides energy data in compliance with Minn. Stat. § 216C.18, subd. 1. Minn. Stat. 216C.18, subd. 1a stipulates that the Minnesota Public Utilities Commission provide a section on such a rate design policy. That section may be found in Appendix 7.

regulators, public health officials, citizens and environmentalists, supported the re-powering with natural gas of two of Xcel's oldest and dirtiest coal plants, and the installation of state-of-the art control technologies on a third.

Energy Policy Strategy No. 3 – Encourage the generation of reasonably priced, environmentally superior electricity from low-polluting or renewable fuels. The Department supported legislation in the 2003 legislature to expand wind development incentives, and to firm up the state's Renewable Energy Objectives (REO). Under the REO, Minnesota's utilities are required to make a good faith effort to have 10 percent of the electricity they provide to Minnesotans come from renewable energy sources by 2015. The Department supported legislation to require utilities to prove to the Public Utilities Commission that utilities are making the required effort, applying performance criteria developed by the Department and adopted by the Commission.

Energy Policy Strategy No. 4 – Enhance the state and region's energy delivery infrastructure to assure reliability and provide access for electricity from low-cost and/or environmentally superior sources. The Department supported the permitting and construction of the new transmission line from the Buffalo Ridge in southwest Minnesota to the twin cities, as well as other transmission line proposals. In addition, the Department advocated strongly at the Public Utilities Commission (Commission) that Minnesota's transmission owning utilities provide a schedule for addressing numerous, identified weaknesses in the state's transmission grid. The Department is also very active in regional reliability discussions, at Midwest Independent System Operator (MISO) – the Department holds a seat on the MISO Advisory Board) – and at the Organization of MISO States meetings.

Energy Policy Strategy No. 5 – Support research, development and deployment of new, environmentally superior energy technologies. The Department supported approximately $20 million in funding for hydrogen research and other renewable energy research and development at the University of Minnesota in the 2003 legislature. The Department is also a leader in the Minnesota Renewable Hydrogen Initiative, a partnership of industry, university, government and non-government organizations, to guide the state's effort to grow and promote Minnesota's renewable hydrogen industry. In addition, the Department is very active on ethanol and biodiesel program developments in the state, especially with regard to the marketing of E85 fuels (E85 is a transportation fuel, containing 85 percent ethanol and 15 percent gasoline).

Energy Policy Strategy No. 6 – Support the state's conservation programs. The Department opposed efforts in the 2003 and 2004 legislative sessions to divert conservation funds for other purposes to ensure that Minnesota's energy conservation efforts do not decrease. The Department also sought and received approval from the Legislative Audit Commission for a program evaluation of Minnesota's Conservation Improvement Plan (CIP) program. CIP is the nation's premier conservation program, resulting in conservation investments totaling approximately $75 million annually in the state. The program audit will ensure that these funds are spent economically and efficiently. The results of the audit should be available by the end of 2004.

Energy Policy Strategy No. 7 – Reduce regulatory and government barriers. The Department believes that state regulatory requirements for new energy infrastructure investments should be sufficient to weed out bad projects from good (or refine projects to improve them), but should not act as a barrier to critical infrastructure investments necessary to providing reliable electric service to Minnesota consumers. The Department advocated for having a single administrative law judge oversee development of a joint administrative record for both Commission and EQB decisions regarding the need and siting of a proposed generation project. Generally, the administrative record is developed separately and in different timeframes for each decision-making body, and usually by different ALJs. Current law allows these proceedings to be combined, but a combined proceeding has been the rare exception rather the rule. The Department will seek other opportunities for efficiencies in regulatory oversight.

Much has been done up through 2003, but there is plenty more to do on all these strategies. However, the Department's primary focus will be on reliability; assuring the state's current and long term energy reliability.

The Department defines reliability as more than just keeping the lights on and preventing large regional blackouts such as the one that affected the Eastern U.S. on August 14, 2003. The Department'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;
- Continue streamlining the state's regulatory review process to increase certainty of obtaining timely decisions;
- Reach out to neighboring states and provinces to create collaborative, multi-jurisdictional solutions to grid operations issues;
- Improve power quality and service standards; and finally
- Allow economic efficiency principles to guide our actions, whenever possible.

Lastly, the last several years have seen increased amounts of renewable energy development in Minnesota, particularly in many of our rural communities. In addition to the reliability benefits gained by diversifying our energy generation mix, renewable energy development can create economic development benefits as well. The Department will continue to work with other state agencies to ensure that the energy needs for the system as a whole are balanced with economic development and other community goals.

Chapter One
SUMMARY OF MAJOR ENERGY LEGISLATION SINCE 2000

Since the last Quad Report in 2000, the Minnesota Legislature has passed two major pieces of energy policy legislation. The 2001 Legislature passed the Minnesota Energy Security and Reliability Act of 2001 ("MESRA" -- Laws of Minnesota 2001, chapter 212). In 2003, the legislature dealt with the issue of continued operation of Xcel Energy's nuclear generation facilities at Prairie Island and Monticello (Laws of Minnesota 2003, special session chapter 11). This chapter will briefly summarize these two pieces of legislation, and the regulatory or administrative actions that have followed from them.

THE MINNESOTA ENERGY SECURITY AND RELIABILITY ACT OF 2001

The Minnesota Energy Security and Reliability Act of 2001 (MESRA) was enacted in response to a Department of Commerce initiative issued in September, 2000 entitled "Keeping the Lights On." MESRA had three key parts:

1. Essential Energy Infrastructure
2. Distributed Energy Resources
3. Other Reliability and Planning Provisions

Essential Energy Infrastructure

MESRA made a number of changes to the procedures by which essential energy infrastructure is planned for and approved, by reforming and recodifying the Power Plant Siting Act (Minn. Stat. 116C.57 et seq); establishing a new statewide transmission planning process (Minn. Stat. 216B.2525); and by making a few minor amendments to the state's Certificate of Need statute (Minn. Stat. 216B.243). Each of these three energy infrastructure changes is discussed below.

Power Plant Siting Act Reform

The 2001 legislature recodified the Power Plant Siting Act, reforming that statute in many respects. The most significant of these reforms involved the interplay between the Public Utilities Commission, which is charged with determining the need for proposed energy projects above a specified capacity, and the Environmental Quality Board (EQB), which is responsible for conducting environmental review of proposed energy projects. Prior to the 2001 session, the EQB found itself bogged down in controversy over whether a proposed transmission project was "needed." Certain projects, because of size, length or capacity thresholds, were not required to receive a certificate of need (CON) from the Commission.

The 2001 legislature amended the CON statute, to decrease the capacity and length criteria for transmission lines for which a CON would be required from the Commission prior to construction. In addition, the legislature specified that when the Commission has issued a CON for a project, the EQB may not consider issues of need in the siting or routing of the project.

Issues of need include: the size, type and timing of the project; alternative system configurations; and voltage. In other words, the EQB may only consider the location of the project, to minimize the environmental impacts of the proposed project.

In addition, MESRA provided for expedited and local permitting processes for projects that have historically not been overly contentious, such as small generation facilities; natural gas generation facilities; transmission lines between 100 and 200 kilovolts; transmission line upgrades along existing transmission rights of way; and transmission lines of between 200 and 300 kilovolts less than 10 miles in length.

In response to these statutory changes, the EQB initiated two administrative rulemakings. The Board acted to revise its general power plant siting rules (Minnesota Rules, chapter 4400); this rulemaking was completed in early 2003. The other rulemaking (Minnesota Rules, chapter 4410) was initiated to specify the entity responsible for gathering the information on the potential environmental impacts of a proposed project, along with alternatives to the project, in a CON proceeding before for the Public Utilities Commission. That rulemaking was completed as of November 12, 2003, and the Board designated itself as the entity responsible for gathering that information. A general discussion of review and siting for large energy facilities may be found in Appendix 5.

State Transmission Planning

Prior to 2001, utilities planned for transmission upgrades among themselves, without public or regulatory input into that planning process. MESRA created a state transmission planning process, in which each transmission owning utility in the state is required to:

- identify and address inadequacies in the utility's transmission system;
- solicit public input from the public and local governments on those inadequacies; and
- file a plan with the Minnesota Public Utilities Commission by November 1 of each odd numbered year.

Under the statute, a transmission-owning utility could propose to have the Commission "certify" a project, and add that project to the Commission's "List of Priority Projects." The effect of having a projected certified and listed is that such a project does not need a separate CON from the Commission. The Commission is to make decisions on which projects to certify as priority projects by June of the following year.

The Commission adopted rules for the state transmission plan process in June 2003. The Commission has received two sets of submissions under this statute, one in 2001, and one in 2003 (as mentioned above). The most recent plan[4] (filed on November 3, 2003) was submitted

[4] A copy of this plan can be viewed or downloaded at http://www.minnelectrans.com/.

jointly by the Minnesota utilities subject to the planning requirement, and was approved by the Commission on May 27, 2004.

No utility has requested certification of a proposed project under the statute in either the 2001 or 2003 submission. From informed comments made to the Department, the consensus of the transmission owning utilities is that the new certification process could actually more onerous than the single-project certificate of need process. The showing required for certification is the same under either process, but other aspects of the single-project CON process has thus far made that process preferable to utilities.

Even so, the planning process has been noteworthy, in a couple of respects. First, the transmission owning utilities actively worked to make their planning process open to public scrutiny and comment. The utilities divided the state into six planning zones, and held at least one open, public planning meeting in each zone. The other interesting aspect of the 2003 filing was that, although the utilities identified dozens of "inadequacies" in the state's transmission system, the utilities did not include a proposal to address any of these inadequacies. However, the Commission, at the Department's request, has ordered utilities to provide a schedule for addressing those system inadequacies.

Certificate of Need Reform

In addition to the changes to the CON statute discussed previously, MESRA made three other changes to the CON statute:

- it allowed for a consolidated proceeding for determining the need for a generation facility and any transmission lines directly associated with the proposed facility;

- it made minor amendments to the need criteria to be applied by the Commission, in determining if a project is needed; and

- it expanded the list of projects which are exempt from the CON requirements, to include projects to an existing generating facility to increase its efficiency, as long as the capacity of the facility is not increased by more than 10 percent or 100 megawatts, whichever is greater.

Distributed Energy Resources

Distributed energy resources refers both to *demand side* technologies, such as conservation improvements, and *supply side* technologies, such as small "distributed" generation facilities are installed on or in close proximity to load, and some distance from central station generation facilities and the electric grid. Distributed energy resources are important resources for a number of policy and technical reasons, including their ability to improve the operation and reliability of the electricity delivery system. MESRA included a number of reforms to promote the deployment of distributed energy resources.

Public buildings conservation

MESRA established a goal of achieving 30 percent savings in new and existing public buildings throughout the state (Minn. Stat. 16B.32 and 16B.325). The legislation directed the Departments of Administration and Commerce to develop a conservation benchmark for all public buildings and to establish guidelines for designing new buildings.

The Departments of Administration and Commerce refer to this initiative as the B3 project – "Buildings, Benchmarks and Beyond." On January 15, 2003, the agencies released the initial version of these guidelines. Developed by a consortium of state agencies, institutions of higher learning and county government – led by the Departments of Administration and Commerce – these guidelines will be applied to all new buildings receiving funding from the State of Minnesota after January 1, 2004. The next task to be undertaken will be to collect building profile and energy usage data on Minnesota's 10,000-plus buildings.

Conservation improvement plan (CIP) reforms

MESRA made changes to the CIP program (Minn. Stat. 216B.241) that should result in more energy conservation than in the past. These changes include: (1) increased the spending required for conservation programs by municipal utilities and cooperative electric associations to the same level required of investor-owned utilities; (2) increased the focus of all CIP spending on programs that actually reduce energy use; and (3) established consistent statewide reporting and program evaluation to allow assessment of statewide progress and evaluation of the effectiveness of conservation programs.

Distributed generation

MESRA included a number of provisions to encourage small supply-side resources, generically referred to as distributed generation.[5] The purpose of these provisions was to:

- provide cost savings and reliability benefits to customers;
- enhance both the reliability of electric service and economic efficiency in the production and consumption of electricity; and
- promote the use of distributed resources in order to provide electric system benefits during periods of capacity constraints.

[5] "Distributed generation" under MESRA means small generation facilities "fueled by natural gas or a renewable fuel, or another similarly clean fuel or combination of fuels, of no more than ten megawatts of interconnected capacity."

To achieve these goals MESRA directed the Commission to develop and issue by order generic standards for utility tariffs for interconnection and operation of distributed generation facilities (Minn. Stat. 216B.1611). The Commission asked the Department of Commerce to organize and lead two distributed generation work groups:

- a technical work group to make recommendations to the Commission regarding uniform interconnection guidelines for distributed generation;

- a rate work group to develop guidelines to ensure that prices for electric services provided by the electric utility are reasonable and nondiscriminatory while prices charged for power provided by the generator to the utility reflect the value of power.

The Department has submitted the reports of these two workgroups, and parties are awaiting further Commission action.

In addition, MESRA required each utility to:

- implement tariffs consistent with standards issued by the Commission;

- to maintain records and file reports annually regarding applications for interconnection of distributed generation on the utility's system;

- allow customers the opportunity to determine that a portion of the energy supplied to them would be generated by distributed generation (Minn. Stat. 216B.169); and

- use 5 percent of the utility's required CIP spending to underwrite the costs of distributed generation projects, to the extent that cost-effective projects are available in the service territory of the utility (Minn. Stat. 216B.2411).[6]

Renewable Energy

The 2001 Legislature included several provisions in MESRA 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). The REO applies to each utility responsible for procuring energy to serve Minnesota retail electric consumers. Essentially, the REO requires each of these utilities to make a good faith effort to ensure that at least one percent of the energy the utility provides to Minnesota consumers is generated by an eligible renewable energy source by 2005, and to increase this amount to 10 percent by 2015.

MESRA also required each utility to give their customers the option to purchase some or all of the customer's electricity needs from energy generated by renewable sources ("green pricing" -- Minn. Stat. 216B.169). Rates charged for green power offerings must be based on the difference

[6] This provision was amended in 2003 to authorize (rather than require) use of 5 percent of a utility's required CIP spending only if the utility is meeting certain specified renewable energy goals.

between the cost of the renewable energy and the same amount of nonrenewable energy. Utilities may generate their own renewable energy or purchase credits from a renewable energy provider certified by the Minnesota Public Utilities Commission, if the Commission establishes the credit program.

Other Reliability and Planning Provisions

Distribution Reliability Standards

MESRA required the Commission to adopt safety, reliability, and service quality performance and reporting standards for investor-owned electric utilities (Minn. Stat. 216B.81). The statute requires cooperative and municipal utilities to adopt their own standards subsequently, which are to be as consistent as possible with the Commission's standards. The standards must specify:

1. average call center response time;
2. customer disconnection rate;
3. meter-reading frequency;
4. complaint resolution response time;
5. service extension request response time;
6. recording of service and circuit interrupter data;
7. summary reporting;
8. historical reliability performance reporting;
9. notices of interruptions of bulk power supply facilities and other interruptions of power; and
10. customer complaints.

The Commission conducted a rulemaking to develop these standards, and the new rules went into effect January 28, 2003 (Minn. Rules, chapter 7826). The rules require utilities to file an annual reliability report, an annual safety report and an annual service quality report. These three reports should contain information necessary for the Commission to assess each utility's performance in the areas of safety, reliability and service quality.

These utility distribution reliability reports have begun to be filed with the Commission. Three significant difficulties are apparent. First, the filings are of varying quality and accuracy. Each utility identifies, collects, and records service interruptions somewhat differently and each utility has its own method to normalize their reliability data for the effects of severe weather, among other things. Second, there is no framework for examining the reasonableness and appropriateness of a utility's proposed goals. For various reasons, the historical reliability data filed by the utilities does not necessarily provide an accurate picture of the actual level of service quality being provided, particularly with respect to the reliability indices identified in the rules. Given the uncertainty of the data, it cannot reliably be used as a base case for either a qualitative or quantitative comparison among utilities. Third, the rules do not contain any ability to impose terms, conditions and penalties upon a utility that does not meet the service quality standards.

Despite these failings, the ability to record and report distribution-level reliability data accurately, set appropriate reliability goals and improve service performance should increase with each annual filing. The utilities have either recently implemented new reliability tracking systems to comply with the rules, or they soon will be implementing new reliability tracking systems. These tracking systems will improve the accuracy and consistency of the data, and should allow for useful comparisons of a utility's performance from year-to-year.

Preventative Maintenance Authority

MESRA gave the Commission the explicit authority to require investor-owned utilities to "make adequate infrastructure investments and undertake sufficient preventative maintenance with regard to generation, transmission, and distribution facilities" (Minn. Stat. 216B.79). This authority has not yet been exercised by the Commission, and it does not extend to municipal or cooperative electric utilities.

State Energy Plan

MESRA required the Department of Commerce to:

> prepare a state energy planning report and submit it to the legislature by December 15, 2001 and update the report by December 15, 2002. The report must identify important trends and issues in energy consumption, supply, technologies, conservation, environmental effects, and economics, and must recommend energy goals relating to the energy needs of the state. The report must recommend goals for the role of energy conservation, utilization of renewable energy resources, deployment of distributed generation resources, other modern energy technologies, and traditional energy technologies, and affordability of energy services for all Minnesotans (Laws of Minnesota 2001, chapter 212, article 7, section 35).

The initial report was issued in January of 2002, and is available on the Department's website.[7] The follow-up report, which contains the policy recommendations of the Department of Commerce under the Ventura Administration, was issued in January of 2003, and is also available electronically.[8]

State Reliability Administrator

MESRA created the position of "Reliability Administrator" within the Department of Commerce to "act as a source of independent expertise and a technical advisor to the commissioner, the commission, the public, and the legislative electric energy task force on issues related to the

[7] www.state.mn.us/mn/externalDocs/Energy_Planning_Report_121602022402_2002PlanningRpt.pdf.
[8] www.me3.org/energyplanupdate2002.pdf.

reliability of the electric system" (Minn. Stat. 216C.052). MESRA requires the Reliability Administrator to:

- model and monitor the use and operation of the energy infrastructure in the state, including generation facilities, transmission lines, natural gas pipelines, and other energy infrastructure;

- develop and present to the commission and parties technical analyses of proposed infrastructure projects, and provide technical advice to the commission; and

- present independent, factual, expert, and technical information on infrastructure proposals and reliability issues at public meetings hosted by the task force, the environmental quality board, the department, or the commission.

The administrator is appointed by the Commissioner of Commerce for a four-year term. The Commissioner is to oversee and direct the administrator's work; review the administrator's expenses; and approve the administrator's budget. To the extent the administrator's expenses are consistent with the budget approved by the commissioner, the Department of Commerce is required to pay expenses incurred by the administrator and assess energy utilities to reimburse Commerce for these expenses (not to exceed $1 million annually for general administrative costs). The statute creating the administrator expires June 30, 2006. Ken Wolf, the current Reliability Administrator was appointed by Commissioner Jim Bernstein in May 2002, for a term that could extend to May 2006.

Major projects of the Reliability Administrator have included:

- facilitating a technical workgroup on distributed generation interconnection standards;

- introductory presentations at the six public meetings on the state transmission planning process;

- facilitating a technical workgroup to establish the scope for an RFP for an engineering consultant to conduct a study of the amount of intermittent electricity resources that could reliably be integrated into Xcel Energy's electric system; and

- planning and convening a symposium on the August 14, 2003 blackout (see appendix 3 for a summary of that symposium).

THE 2003 "PRAIRIE ISLAND 2" BILL

Faced with the prospect of having to shut down and replace Xcel Energy's Prairie Island nuclear generation facility (over 1000 megawatts of baseload generation capacity) for lack of spent nuclear fuel storage capacity, the 2003 legislature responded by passing Laws of Minnesota

2003, special session chapter 11, known to some as the “Prairie Island 2” bill. The legislation consisted of four articles.

Article 1 – Spent Fuel Storage

The first article dealt with the issue of additional spent nuclear fuel storage in the state (Minn. Stat. 116C.83). The 1994 legislature authorized Xcel to fill and place seventeen dry spent fuel casks at Prairie Island but that capacity was only sufficient to allow operation of the facility until 2007. The 2003 legislation authorized sufficient additional dry cask storage at Prairie Island to allow that nuclear generation facility to continue to operate until the end of current licenses in 2013/2014.

In addition, the legislation delegated approval of a future storage facility or dry casks at either the Prairie Island or Monticello nuclear generation facilities from the Minnesota legislature to the Minnesota Public Utilities Commission. Xcel Energy's Monticello nuclear generation facility is expected to run out of spent fuel storage capacity at that facility in 2010. A decision by the Commission on a request to approve additional storage capacity in the state is not effective until the end of the following legislative session, in order to give the legislature an opportunity to review the Commission's decision (pro or con) and to change that decision if the legislature deems necessary. Article 1 also provides for recovery of expenses by Xcel Energy, not to exceed $2.5 million a year, for a settlement with the Mdewakanton Dakota Tribal Council at Prairie Island regarding additional storage at Prairie Island (Minn. Stat. 216B.1645).

Article 2 – Renewable Energy Development

The focus of the second article was on the development of the state's renewable energy resources. The legislature required Xcel Energy to spend at least $16 million on renewable energy development each year that the nuclear facility is in operation and spent nuclear fuel is stored in the state (the "renewable development fund" -- Minn. Stat. 116C.779). In addition, the Legislation passed in 2003 establishes a goal of moving Minnesota towards incorporating hydrogen into its energy mix (MN Session Laws 2003, 1st Special Session, Chapter 11). The legislation:

- ordered Xcel Energy’s ratepayers to fund $10,000,000 for the University of Minnesota Initiative for Renewable Energy and Environment to support basic and applied research and demonstration activities, including hydrogen production and improvements to fuel cell technologies.

- directed the Department of Commerce and the Department of Employment and Economic Development to issue a request for proposals for the construction of a wind-to-hydrogen demonstration project that demonstrates all components of a future hydrogen economy, namely, hydrogen production, storage, and distribution.

- required the Department of Employment and Economic Development to develop a targeted program to promote and encourage hydrogen production.

- required Xcel Energy to transfer roughly $20 million over the next 5 years to the University of Minnesota for the University's Initiative for Renewable Energy and the Environment, for hydrogen and other renewable research and development at the University.

The 2003 legislation also makes 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 requires the utility to invest in another 300 megawatts of wind energy capacity (above the 1994 amounts) by 2010. In addition, the legislation:

- requires the Commission to issue an order by June 2004[9] establishing the criteria and standards by which the Commission will measure an electric utility's efforts to meet the renewable energy objectives to determine whether the utility is making the required good faith effort.

- authorized the Commission to establish a renewable energy credits trading program for the REO, whereby utilities could purchase certified renewable energy credits rather than to generate or procure the renewable energy directly. One workshop on this topic was held in February 2004, with another one slated for June 2004. This work is on-going;

- required each electric utility to report on its plans, activities, and progress with regard to these objectives to the Commission in resource plan filings or in separate reports every two years, whichever is more frequent (previously reporting was only through resource plans); and

- required the Department of Commerce to report to the legislature every odd-numbered year on utilities' progress in increasing the amount of renewable energy provided to retail customers, and make any recommendations for legislative change.

The 2003 legislation increased the amount of small wind energy capacity that can qualify for production incentives (Minn. Stat. 216C.41). The renewable energy production incentive (REPI) provides 1.5 cents per kilowatt-hour produced by eligible facilities. Previously, the REPI was capped at 100 megawatts of small wind energy facilities funded from the State's general fund. That cap was reached by early 2003. The 2003 legislation increased the cap by another 100 megawatts and paid for the REPI increase out of Xcel's renewable development fund (the $16 million required spending referred to above). The second 100 megawatts has also been fully subscribed.

[9] The Commission's order is available at the Commission's website at www.puc.state.mn.us/docs/orders/04-0075.pdf;

Article 3 – Metro Emissions Reduction Program

The third article of the 2003 legislation contained a number of miscellaneous energy provisions, the most important of which facilitated Commission approval of Xcel Energy's Metropolitan Emissions Reduction Program (MERP) proposal: (1) to convert two metro area coal-fired generation facilities to use natural gas, and add significant pollution control technology to a third; and (2) to recover the costs of these projects in a rate rider without having to file for a rate case. The Commission approved this proposal in December, 2003 (more on this proposal can be found in the Key Issues section on environmental protection).

Article 4 – Mesaba Energy Project

The fourth article provided for a number of regulatory incentives for an "innovative energy project" on the Iron Range, which would generate electricity by using "coal as a primary fuel in a highly efficient combined cycle configuration with significantly reduced sulfur dioxide, nitrogen oxide, particulate, and mercury emissions" when compared with traditional technologies. The regulatory incentives include:

- an exemption from demonstrating need for the facility or associated transmission facilities;
- a grant of eminent domain authority for transmission routes approved by the Environmental Quality Board; and
- the possibility of entering into a power purchase agreement with Xcel Energy to provide 450 megawatts of capacity and energy, subject to the approval of the PUC.

The Iron Range project at issue is a 750+ MW generation facility known as the "Mesaba Energy Project" that creates a synthetic gas from coal (coal gasification). It would be located in Hoyt Lakes, Minnesota, on the site of the LTV mining operation.

Chapter Two
POLICY FOCUS ON ELECTRIC RELIABILITY

Reliable electric service is critical for the way we live today. It is essential for work, leisure, and social interaction. Minnesota law requires that energy service be safe, adequate, and reasonably priced, to help fuel Minnesota's economy. The reliability of electric service in Minnesota is one of the Department'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 every moment, there must be enough electric generation and transmission capacity and energy available and balanced *instantaneously* with when the electricity is needed. In other words, the electricity must be generated and transmitted at the same time that a consumer turns on his microwave. Consumers of all types – residential, commercial, industrial – have come to expect and rely on electric utilities to provide that level of reliability.

Failure to maintain instantaneous balance in electric supply and demand will cause disruptions, outages or "reliability events." There are three types of reliability events: a) region-wide, bulk power blackouts; b) localized outages due to problems at the distribution line level; and c) power quality fluctuations. All three of these types of outages were experienced in the August 14, 2003 blackout which affected the east coast and Midwestern U.S., and each will be discussed in this chapter.

In addition, this chapter discusses:

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

This chapter concludes with a discussion of the Department's six policy strategies for maintaining reliable electric service in the state.

Reliability of electric service can be divided into two basic components: adequacy and security. "Adequacy" is the ability of utilities to supply customers' electric service requirements, taking into account scheduled and unscheduled outages. "Security" is defined as the system's ability to withstand sudden unexpected disturbances without collapsing.

RESOURCE ADEQUACY

Rising demand, rising prices, a new energy mix

Minnesota's consumption of electricity is expected to increase at an average rate of about 1.5 percent annually over the next few years, based on the combined projections of all utilities serving Minnesota customers.[10] Since there is not enough excess generating capacity available to meet this increase in demand, significant new generation and transmission facilities will be needed in the near future, to serve the electric needs of the state and the region. Electric utilities engage in resource planning to determine the combination of power plants that most economically meets the increased demand.

The capacity expansion plans of electric utilities indicate that the fuel mix for electric generation will likely change somewhat in the coming years. Natural gas may increase as a source of electricity, although concerns have been raised recently about the extent to which this fuel should be used for this purpose. There are also plans to significantly increase wind generation in the state. In addition, utilities are required by law to make a good faith effort to include electricity generated from renewable sources in their mix of resources used to serve their customers.

As noted above, demand for electricity in our state, and in the Midwest region, continues to increase. As a result of this growing demand for electricity 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 that this new infrastructure is constructed and placed into service in a manner that does not adversely impact the environment, energy costs or other public interests is a challenge that state and regional policy makers must address.

Growth in Demand Greater Than Growth in Supply

Minnesota's utilities are members of the Mid-Continent Area Power Pool (MAPP), an organization created to ensure reliability of electric service in the region. Currently, all companies that own or use electric generation and transmission facilities in Minnesota, North Dakota, South Dakota, Nebraska, Missouri, Manitoba and parts of Wisconsin, Iowa and Montana belong to the MAPP. MAPP was formed in 1972 as one of the ten "regional reliability councils" created by the electric industry after a massive blackout in 1968. MAPP is a voluntary organization that establishes standards and practices for reliability of electric service, under the national umbrella organization for the regional reliability organizations, the North American Electric Reliability Council.

The United States portion of the MAPP region has a peak demand occurring in the summer season. In its Ten-Year Reliability Assessment, released in September 2003, MAPP estimated that the region's summer reserve margin would be 21.9 percent in 2003, well above the MAPP-designated reserve requirement of 15 percent.[11] However, MAPP projects the summer reserve

[10] A simple trend line estimates that the increase will be between 1 and 2 percent annually over the next few years.
[11] A reserve margin is a measure of the system's generating capability above the amount required to meet peak load requirement.

margin to decline to 9.3 percent by 2012 as the region's increasing power needs absorb the current surplus power. Some, but not nearly all, of this growth in electric demand may be met through energy conservation. Conservation programs are an important tool to manage load growth in Minnesota. The programs reduce the demand for electricity and require less lead-time for implementation compared with new generation resources. However, the Department 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, such as Great River Energy and Xcel Energy, will likely 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.

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 proposed for construction and none have been built since the 1980s. In fact, only three non-mandated combustion generation projects greater than 50 MW have obtained all necessary permits and completed constructed in the past five years.[12] These three projects 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"). Another three generation projects, none of which are base load plants, either recently obtained the necessary permits or are expected to do so soon.[13] Finally, there is one additional generation project, proposed as an intermediate facility, that is in the middle of the process of seeking the necessary permits.[14] As provided in their integrated resource plans and other filings, Minnesota's utilities project a need for additional base load generation capacity of 2730 megawatts by 2015 and another 1285 megawatts of intermediate generation capacity by that time. Note that these projections do not include the possible need for replacing the capacity and energy currently provided by Xcel Energy's Prairie Island and Monticello nuclear generation facilities. The operating licenses of both Monticello and Prairie Island facilities expire during this planning period (2010 for Monticello and 2013/2014 for the Prairie Island units). If these facilities are not re-licensed by the federal Nuclear Regulatory Commission, the baseload resource problem expands by another 1600 megawatts. Baseload and intermediate resources are more difficult for utilities to build than peaking or intermittent resources, in that baseload and intermediate resources are more expensive to construct, and generally have greater environmental impacts.

[12] Specifically, Xcel Energy's Black Dog addition, Great River Energy's Pleasant Valley station, and Great River Energy's Lakefield Junction station.
[13] Specifically, Minnesota Municipal Power Agency's Faribault Energy Park, Trimont Wind I's wind farm (under sale to Great River Energy), and Xcel Energy's Blue Lake addition.
[14] Specifically, Calpine Corporation's Mankato Energy Center (part of which is under contract to Xcel Energy).

Increased reliance on natural gas generation

All of the new combustion generation resource additions referred to above (both completed and proposed) are fueled by natural gas. 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 beyond those "summer peak" applications. The reasons for this upward trend in the use of natural gas are that natural gas is superior to coal and nuclear fuel in its overall environmental impacts, and that natural gas plants can be constructed more quickly. Natural gas-fired generation is also more nimble in that the facility can be started up or shut down quicker and easier 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 significant upgrades to the pipeline system.

SECURITY OF THE TRANSMISSION SYSTEM

The nation's bulk power system is like the interstate highway system, carrying the majority of the power from generators to load centers (where the customers are). Like the interstate highway system, the nation's bulk power electrical system has evolved into an interconnected transmission grid. In most instances, the interconnected nature of the transmission grid is a benefit because interconnection allows regions to import solutions to their supply needs and to lower overall costs by accessing cheaper generation in neighboring regions. This exchange of power allows for more efficient use of the electric system overall. However, the transmission line that allows a region to import a solution may also allow that region to export a problem.

Lack of Investment in Transmission Infrastructure

The most significant electricity issue currently facing the state is that of ensuring that Minnesota consumers continue to enjoy the benefits of a reliable electric transmission infrastructure capable of providing those consumers with access to low-priced generation. The increase in wholesale electricity marketplace activity since 1996 has resulted in a significant decrease in the amount of transmission capacity that is available to move power over the regional, interconnected transmission grid. While the amount of new generation capacity constructed in the United States has increased, the amount of transmission capacity available to transport that power has not grown to accommodate new demands on the transmission system. Investment in the transmission system in 1999 was less than one-half the investment in 1979 even while peak demand for electricity grew and is expected to continue growing.

In Minnesota, utilities have not generally proposed the construction of new major transmission capacity, preferring instead to purchase energy from the grid, or to build natural gas peaking or intermediate plants. Given the congestion of the transmission system into and out of Minnesota, these options may not be as available to utilities as they have been.

Only one large transmission line has been proposed and approved in the recent past. That project is an Xcel Energy transmission project to provide an outlet in southwestern Minnesota for wind generation from the Buffalo Ridge (near the cities of Benson and Pipestone). The transmission would allow Xcel Energy to satisfy the wind energy mandates imposed on the utility by the 1994 legislature. The project has been approved by the Commission and Xcel is currently in the process of procuring a route permit from the Minnesota Environmental Quality Board.

Electric Transmission Constraints

As a rule, large electric generators and consumers of electricity generally 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, preferred transmission line pathways must be developed. Eventually, transmission constraints, or bottlenecks, develop in those areas where a transmission line delivers the maximum level of power that it can safely and reliably carry. Bottlenecks limit energy transactions. This, in turn, 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 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. In addition, the transmission system cannot, without future upgrades or new additions, support additional generation from Canada.

One Minnesota utility has found it necessary to build peaking capacity to meet its expected load as a result of the increasingly constrained transmission system. The utility found that, due to transmission constraints, it could not transmit the power it could acquire from generation facilities located elsewhere to where in was needed to meet the summer demand of its consumers.

Renewable development constrained

Minnesota has a tremendous capacity for renewable energy development, especially its wind energy resources. Currently, Minnesota has over 550 megawatts of wind energy capacity installed. That number could increase by up to 6 times over the next decade, to something approaching 3000 megawatts.

However, that development will be stymied without sufficient transmission capacity to bring that energy to load centers, where it can be used to serve consumer needs. The capacity of the line proposed by Xcel Energy to deliver wind energy generated in southwestern Minnesota to the Twin Cities is completely subscribed to carry wind energy currently under contract to Xcel to fulfill a portion of its wind mandate. Expansion of the wind energy resource in southwestern Minnesota, as with other parts of the state, 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.

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 26 inadequacies in the state's transmission infrastructure which need to be addressed to ensure reliable service to Minnesota consumers. The Department is actively encouraging those utilities to follow through in fixing these identified inadequacies in a timely manner.

A less obvious option is the construction of relatively small-scale, distributed or dispersed generation resources in strategic locations. "DG" facilities, as these are often referred to, can potentially be used to reduce the strains on transmission lines at heavily used locations and to relieve system congestion. As mentioned in Chapter 2, on August 20, 2001, in response to a change in Minnesota law (Minnesota Statute 216B.1611, subdivision 2), the Commission initiated a proceeding to establish generic standards for utility tariffs for interconnection and operation of distributed generation facilities of 10 megawatts or less. In its initial Order on this issue, the Commission stated:

> Most electricity is generated at large power plants, then transmitted long distances to where it is needed. This arrangement has resulted from the economies of scale in generation, especially for plants driven by fossil fuels or nuclear fission. "Distributed generation," in contrast, refers to the practice of generating electricity close to where it is needed, in plants designed to meet only the local need. Interest in distributed generation has grown as the cost advantage of large generating plants over small generating plants has declined, and as the demands on the transmission system have increased.
>
> Many benefits have been attributed to distributed generation. It may reduce the need for long-distance transmission of electricity. That is, an electric system with a lot of distributed generation may be able to operate with fewer resources devoted to transmission than can a system of the same size with little distributed generation. An electric system with a lot of distributed generation may be more reliable as well. The use of many small generators instead of a few large generators suggests that the failure of any one generator would affect a smaller portion of the utility's customers. Similarly, a reduced reliance on long-distance transmission suggests that a transmission line failure would affect fewer customers. For a customer, having a back-up generator may provide some protection against any type of electric system failure. Finally, facilitating privately-owned distributed generation may

> make it easier for customers to adopt a means of generating electricity – such as solar power – that better reflect their values and preferences.

The Commission, subsequent to this Order, asked the Department to form two work groups, one on DG technical interconnection standards, the other on DG rate issues. The Department did so, and submitted the recommendations of the work groups to the Commission. Once the Commission acts on these recommendations to establish standards, each utility under its jurisdiction is to file specific distributed generation tariffs for its system. (Xcel Energy already has a distributed generation tariff for small facilities, but the company would need to modify its filing to conform to the generic standards set by the Commission.)

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 costly, most effective and efficient tool that all electricity consumers can practice to manage 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.

MAPP & MISO Issues

Day-to-day operation of the electricity system is conducted by the individual utilities and the regional reliability entities, MAPP (Mid-Continent Area Power Pool) and MISO.

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

MISO's primary function is to monitor the bulk power transmission system and to develop policies and procedures that ensure that every electric industry participant has access to the transmission system, and that transmission lines are used in a way that minimizes congestion and maintains system reliability.

MISO has a much larger geographical footprint than MAPP, but not every MAPP member belongs to MISO. MISO members include utilities with more than 100,000 miles of transmission lines covering 1.1 million square miles from Manitoba, Canada, to Kentucky. In many respects, MISO covers two disparate regions. The eastern half of MISO is made up of densely populated states, many of which have deregulated their electric industries. The western half, of which Minnesota is a part, is composed of sparsely populated states that for the most part continue to comprehensively regulate their electric utilities. There is a great deal of overlap between the western territory served by MISO and MAPP, although many MAPP members are

not members of MISO. The differences in membership, organizational structure and mission between MAPP and MISO create a tension that must be managed so as to not allow these differences to pose reliability or other problems for Minnesota consumers.

Another potential problem arises from the fact that utilities in MISO operate under a different protocol compared to utilities that are not MISO members. As a result of this disparity, there are "seams" between members and non-member utilities. A "seam" is defined as a barrier resulting from differences in market rules and designs and other regional practices that inhibit or preclude the ability to transact capacity and/or energy.

For many years now, the Department has worked closely with MAPP and its Minnesota members. The Department 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. Minnesota holds its seat on the Advisory committee until 2005.

ELECTRICITY DISTRIBUTION

If the transmission system is analogous to the interstate highway system, the local electric distribution system can be thought of as local streets and roads, distributing electricity to retail customers. The number and frequency of distribution level reliability disturbances or "outages" is much greater than outages in the transmission system, but distribution outages typically affect fewer customers than transmission outages that often affect a larger area. From the perspective of the customer who loses electric service, the distinction as to whether the service interruption is a transmission or distribution outage is immaterial. Accordingly, distribution reliability is an important part of overall electric service reliability.

Efforts to address distribution reliability 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 rulemakings and through proceedings related to specific utilities. (See Chapter Two for a discussion of the Commission's safety, reliability, and service quality standards for distribution utilities, Minnesota Rules, chapter 7826.)

In addition, in an effort that goes well beyond the requirements of these rules, the Department 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 customers who experienced the longest outages during the time period of the investigation.

- Increased spending on maintenance items such as tree trimming and cable replacement in the amount of $15-20 million by January 1, 2005 (the lack of tree trimming maintenance was a key contributing factor of the August 14th blackout).

- 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:

  1. customer complaints,
  2. number of outages per customer,
  3. length of outages per customer,
  4. customer call response time, and
  5. 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. It will be reviewed after two years of implementation, to be fine-tuned and strengthened if needed.

Power Quality Fluctuations

Today's economy, and certainly tomorrow's digital economy, is heavily reliant on technology using microprocessors that create smart devices that automatically provide needed services and information. The problem created by microprocessors is that the "quality" of the electricity provided must be raised -- unprotected microprocessors demand "near-perfect power" to function properly. A similar need for perfection exists in other infrastructures, where existing and future advanced systems are predicated on the perfect functioning of today's communications, transportation, and financial services. "Power quality" in this instance refers to the technical characteristics of the electricity provided. Examples of power quality problems include minuscule power interruptions and voltage fluctuations. The same electrical disturbances that were previously unnoticeable on mechanical equipment can severely upset high-tech equipment operations.

The traditional level of power quality is not sufficient for the "digital society" of tomorrow. In many industrial and highly sensitive computerized applications, there is a need for an increase in power quality from today's outage/availability average of about 99.0 percent (approximately 8 hours of outage per year or "two nines" of reliability) to 99.9999 percent (approximately 32 seconds of outage per year or "six nines" of reliability). Such near-perfect power is needed for error-free operation of the microprocessor chips finding their way into just about everything, including billions of embedded applications. Thus, even when there is no failure of the electric

lines, a voltage fluctuation over those lines that go into an end-use appliance can have adverse consequences for the consumer, especially when that electrified appliance is a computer or sensitive digital equipment.

The problem of power quality may be huge. In its 2003 "Electricity Sector Framework for the Future" report, the Electric Power Research Institute estimates that these minuscule fluctuations in power quality may potentially cost upwards of $100 billion annually in the U.S., or an additional cost of 50 cents for each dollar spent on electricity. If that figure is anywhere close to true, that is a staggering sum.

STATE POLICY ON ELECTRIC RELIABILITY

As mentioned in the introduction, the continuing reliability of electric service is one of the guiding principles of Minnesota's energy policy and is one of the Department's top priorities in the coming years. Accordingly, the Department, in concert with other state agencies and interested persons, will seek to preserve and enhance the reliability of the electric system in Minnesota through pursuit of the following six reliability strategies.

Reliability Strategy No. 1: Increased Focus on Utility Operations, Maintenance and System Control Measures

As the August 14th 2003 blackout demonstrated, the operators of the electricity system need to ensure that their operations, maintenance and system control measures are demonstrably adequate. Such an undertaking has three parts. One part focuses on the day-to-day operations and maintenance procedures of a utility. Inadequate tree trimming — a maintenance issue — was a key cause of the August 14th blackout. The second part is control measures that monitor the operations of the transmission system. Again, a contributing factor to the August 14th blackout was computer outages that prevented the utility from understanding what was happening on the transmission system and reacting to the contingencies in time for the necessary actions to be taken.

The third part deals with communications between the entities responsible for the grid, be it among utilities, among independent transmission system operators or between independent transmission system operators and utilities. The need for constant instantaneous balance between the generation of electricity and its use requires constant communication to keep the system operating smoothly.

Minnesota should expect each transmission owner to comply with all national, regional, state and industry operation and maintenance standards. Some form of annual certification from the utilities to the state would help ensure that each of the three parts is adequately being addressed.

Reliability Strategy No. 2: Encouraging Infrastructure Investment

A strong, interconnected transmission bulk power grid enhances reliability. It provides the capacity to handle peak demands and permits the economic and physical flow of power from where it is generated to where it is needed. Unfortunately, investment in transmission has been lagging, thereby threatening the reliability of the state's and the nation's transmission system.

As noted above, Minnesota's transmission utilities have identified at least 26 inadequacies in the transmission infrastructure needed to serve Minnesota customers. The Department will be working very hard to ensure that those inadequacies are addressed in a timely fashion. In addition, as mentioned previously, new legislation passed in 2001 gives the Commission the authority to require public utilities to make infrastructure investments if necessary for the provision of adequate, reliable electric service. This explicit authority, which many believe was implicit in the Commission's authority already, has not yet been used, but the Department will not hesitate to call on the Commission to use that authority if reliability to Minnesota consumers appears to become compromised.

Reliability Strategy No. 3: Encouraging Multi-State Solutions

Many forms of infrastructure, such as transportation, communications and fuel pipelines, have slowly evolved from being local in scale to become regional and then national and international networks. The electric grid has followed a similar pattern. Federal regulatory interests are advancing that evolution, moving determinedly toward a policy framework intended to lessen individual states' roles in the administration of a wholesale electric marketplace.

These factors have dramatically changed the traditional integrated utility model. Due to continuing growth in electricity demand and the opportunity to purchase lower cost power over the grid, interstate power delivery has become a key strategy used by the state's utilities. Minnesota's interconnections provide significant reliability and economic benefits to Minnesota electric utilities and their customers. It allows for:

- sharing of reserve generation capacity thereby avoiding the costs and impacts of generation facility construction;

- improved reliability by providing for a larger pool of resources for purchasing power at lower costs when unforeseen events occur; and

- access to more sources of economic wholesale energy.

Most Minnesota utilities rely on electricity generated outside of Minnesota to meet their customers' needs. Several municipal utilities receive power from regional and federal agencies whose sources are as far away as Wyoming. In some manner, all Minnesota utilities use the regional grid to import power at various times, to varying degrees and from diverse resources. Thus, regional, interstate transmission lines and multi-state arrangements benefit Minnesotans.

Though the trend toward increased interstate electricity commerce provides the benefits noted above, questions arise in the wake of cascading power outages as to whether a highly integrated grid is less reliable than smaller, less connected systems that meet local needs with local generation. The answers to these questions are not simple. For example, local generation would need to have backup systems to continue to meet electricity demands when any part of the local system fails or is taken down for maintenance. Such backup systems would be very expensive and may be problematic to build if only local sources of supply to meet Minnesota needs are allowed. Moreover, the move to construct such a system would take an untold amount of time and resources.

In many respects, however, the "local generation to meet local needs" question has already been answered. As noted above, Minnesota's utilities, with the support and concurrence of Minnesota's regulators, have constructed their electric systems in such a way as to connect the state electrically to all of its neighboring states and provincial jurisdictions in the north central U.S. and central Canada. Additionally, most of Minnesota's major utilities serve customers in adjacent states as well as Minnesota. As a result, Minnesota's utilities must work with multiple state regulatory jurisdictions, and Minnesota policy makers cannot readily act in isolation.

Most of the states in the MAPP region, including Minnesota, continue to comprehensively regulate their electric utilities, to ensure reliable electric service within pre-determined utility service territories – the traditional regulatory model for electric utilities. However, each state applies that model in its own way. While the electricity policies of the states in the MAPP region vary, all states have the common objective of ensuring that utilities provide reliable, reasonably priced electricity to consumers. Achieving these objectives is critical to supporting sustainable economic growth. While it is likely that states in our region will continue to focus principally on individual state needs, the arena in which the regional transmission grid is planned, expanded and operated has broadened. Thus, state regulators and policy makers must develop knowledge and practices that can support regional grid development in the collective public interest.

In doing so, states whose utilities are members of MISO have an opportunity to preserve their right to manage grid enhancement issues in a way that recognizes each state's unique characteristics and substantial historical investments. The Organization of MISO States (OMS) is the primary avenue to do this. The OMS is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the MISO. The purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, the FERC, other relevant government entities, and state commissions as appropriate. The OMS has a broad and complex mission focusing on the development of a cost-effective, economically efficient Regional Transmission Organization in the Midwest by working with both the MISO and FERC. However, there is still a need to preserve a focus on the distinct characteristics of the upper Midwest through common dialogue, beginning with Minnesota's neighboring jurisdictions. These deliberations should identify and consider opportunities and strategies for enhancing

reliability – both supply adequacy and security – in an economic and environmentally beneficial manner. The Department will continue to work to ensure that Minnesota will be a leader in this discussion.

Reliability Strategy No. 4: Realigning and Integrating Regulatory Review

Electric utilities wishing to build infrastructure in Minnesota face a series of disconnected proceedings in front of multiple state agencies, reviewing sometimes redundant information. State regulatory requirements should be sufficient to weed out bad projects from good (or refine projects to improve them), but should not act as a barrier to critical infrastructure investments necessary to providing reliable electric service to Minnesota consumers.

In Minnesota, planning for new generation resources to meet the demands of Minnesota electricity consumers is performed through Integrated Resource Planning on a utility-specific basis. Each state-regulated electric utility in this state is required to file an Integrated Resource Plan for approval on a biennial basis that projects the future resource needs over a fifteen year planning horizon. New generation resources as well as proposals to reduce and manage demand for electricity are analyzed together to develop a plan for meeting the utility customers' needs. However, there is no mechanism for reviewing and evaluating the combined resource needs of all of Minnesota utilities together in order to get "the big picture," something policy makers have been clamoring for.

Such a mechanism exists for transmission infrastructure needs. Minnesota recently established a "State Transmission Plan" process. Every two years, all of the transmission-owning utilities are required to identify inadequacies in the transmission system serving Minnesota consumers. These inadequacies and proposed solutions are then discussed in public meetings around the state and ultimately submitted to the Commission for review. From this process, the state gets a somewhat global view of the state of the Minnesota transmission system.

Once planned for, most projects to build or enhance the electricity infrastructure, whether it is a transmission line or new generation facility, are scrutinized by at least three different state agencies: the Department, the Environmental Quality Board and finally the Commission.[15]

Such a project will generally need a Certificate of Need (CON) from the Commission. This process begins with an application for a CON, and a technical/policy review of the proposal by the Department. Parties then advocate before the Commission as to whether the project is "needed" (including a review of the environmental impacts of the project conducted by the EQB). In this process, alternatives to the proposed project are considered, including conservation and renewable alternatives.

If the Commission issues a CON, the utility must usually then apply to the EQB for a site permit for a transmission line or power plant. During the actual siting process additional, more detailed environmental review of the project is performed by EQB, including an additional analysis of

[15] A more detailed discussion of the regulatory process is found in Appendix 5.

alternatives to the project. Power plants also need an emissions permit from the Minnesota Pollution Control Agency, and usually a water consumption permit from the Minnesota Department of Natural Resources. Permits and approvals from other federal, state and local entities may also be required.

Running this gauntlet of agencies and procedures can easily take two to three years. The length and complexity of the regulatory process must be addressed. There is significant overlap in the substantive review of projects. For example, energy conservation is potentially reviewed in three separate proceedings: resource planning, CON, and the conservation improvement plan (CIP) process.[16] Renewable energy achievements are reviewed in two proceedings, resource planning and CON.

These redundancies have the effect of increasing the regulatory burden on the utility and regulatory agencies. Simultaneously the redundancies decrease the effectiveness of the conservation goals established in resource planning by potentially reducing their importance. In addition, these redundancies potentially act as barriers to the construction of projects that are needed to enhance the overall reliability of the electricity grid. Ideally, determinations by the Commission in the resource planning process should guide subsequent processes such as CIP and CON.

The Department will seek to have these processes re-aligned and integrated, to reduce the overall regulatory burden on project developers, state agencies and others who participate in Commission and Board proceedings, without reducing necessary input from, and notice to, the public. An example of this initiative is the Department's advocacy for a single administrative law judge to oversee development of a joint administrative record for both Commission and EQB decisions regarding the need and siting of a proposed generation project. Generally, the administrative record is developed separately for each decision-making body, and usually by different ALJs. Current law allows these proceedings to be combined, but a combined proceeding has been the rare exception rather the rule.

Reliability Strategy No. 5: Developing Power Quality Standards

Minnesota's present electric delivery infrastructure, like most systems around the country, is not very well equipped to handle the power quality demands of high-end digital customers. Further, the system would be hard pressed to support levels of security, quality, reliability, and availability needed for economic prosperity into the future while under continued stress. The existing infrastructure is vulnerable to human error, natural disasters, and intentional physical and cyber attacks. Appropriate use of emerging technologies may be able to address these issues to some extent. Building reasonable distributed generation proposals into the consideration of alternatives to new transmission infrastructure may be an appropriate method for locating strategic sites.

[16] CIP is a program to implement a statutory requirement that electric and gas utilities spend a specified percentage of their gross operating revenues on conservation programs and activities.

The cost of power quality interruptions for Minnesota has not been quantified in an independent, authoritative study. Although the problem is certain to exist, the degree of attention it deserves cannot be fully ascertained because the cost the problem represents is unknown. Minnesota consumers expect that their electricity service will meet their needs both for general purposes such as lighting and for more highly technical needs. There is a need to ensure that electric power is adequate to meet the increasingly sophisticated energy needs of consumers. The Department will seek to develop information about the costs Minnesotans incur due to power quality fluctuations, and if necessary, to develop standards or other strategies to ensure that Minnesota consumers have the benefit of the power quality they need to conduct their business.

Reliability Strategy No. 6: Letting Economic Efficiency Guide Energy Policy

Low-cost, reliable power is critical to Minnesota's economic well-being. Yet, the economics of energy policy often gets subsumed by other, albeit important policy goals such as local economic development. To address the reliability threats to the electricity system 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. That is, the cost of policies that differ from a basic approach of ensuring reliable power in a least-cost manner should be reasonably known so that decisions to pursue such policies are fully informed.

This information is critical because the more energy dollars that are diverted into projects based upon non-economic criteria, the more expensive basic electric service becomes. In addition, other problems may go unsolved due to the lack of funding. Funding for transmission infrastructure has been at reduced levels recently. Partly, this reduction is due to the fact that decisions by utilities, independent power producers, policy makers and others have diverted significant funds to generation projects that were justified on factors other than least cost, economic criteria. Such diversions are not a "free lunch" – they result in intended and unintended costs on the electric system. These costs show up in two areas. First, more expensive generation is constructed, since the generation projects have not been selected on a least cost basis. Second, these more expensive projects displace other energy projects that might have been more "needed" to solve reliability issues, locally or in the region. Thus the result of the lack of focus on least cost planning principles is that the costs of electricity in the region is higher than it might otherwise be, and that the overall reliability of the system is lower than it otherwise could be.

To raise the overall reliability and reduce the cost of the electric system, economic efficiency needs to play a greater role in decisions. One example is the optimal level of conservation a utility should achieve. Establishing better ties between the level of conservation determined in resource planning and in other proceedings would improve economic efficiency. Using this approach would make the least cost level of conservation the standard, rather than resetting the level of conservation in every proceeding.

Chapter Three
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 that 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 an electron saved is an electron that never needed to be produced.

Traditional non-renewable fuels for the generation of electricity include nuclear, coal, petroleum, and natural gas. These fuels 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. 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 hypothetical research to market ready resources. 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.

RENEWABLE ENERGY

Besides the price of wind energy becoming competitive, 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 costs 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.

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.
(See Appendix 2 for an overview table of these programs).

Renewable Energy Objective

Described more fully in Chapter Two, the Renewable Energy Objective (Minnesota Statute 216B.1691) requires each electric utility to make a good faith effort to generate or procure renewable energy so that 10 percent of the energy provided to retail customers in Minnesota by 2015 is generated by eligible renewable technologies. The term "eligible energy technology" is defined as an energy technology that generates electricity from the specified renewable energy sources (solar, wind, hydroelectric with a capacity of less than 60 MW, or biomass) that was not mandated by state law or Commission order prior to August 1, 2001. In other words, the renewable energy that Xcel Energy developed to fulfill the mandates from the 1994 legislation authorizing dry cask storage of spent nuclear fuel at Prairie Island does not count toward Xcel's REO.

Green Pricing

Green pricing is a voluntary customer choice program that allows electricity consumers to purchase "green" electricity, generally at a higher price than the service based on the utility's portfolio of resources to meet customers' needs. All Minnesota electric utilities are required to provide this option to customers. Customers may or may not choose to purchase "green" power to increase renewable energy use.

Under these programs, the electric utility procures renewable electricity on behalf of customers who purchase it to support cleaner energy sources. If demand for energy under a utility's "green" pricing programs grows, the utility procures more renewable energy for these interested customers. A benefit of a green pricing program is that the electric utility can generally offer the power at a much lower price than an individual customer could obtain by installing and operating a renewable energy system.

From July 1, 2002 - June 30, 2003, electric utility green pricing programs in Minnesota sold 24,703 MWh of renewable electricity. Over 25 MW of renewable energy have been certified for use in green pricing programs, with 14 MW added in 2003 alone.

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.

Net Metering

Net metering is a state policy that allows small renewable electric generators to offset their consumption at the retail rate. All electric utilities in the state are required to offer a net metering option to their customers. Minnesota was one of the first of 37 states to enact net metering (MN Statute 216B.164 and MN Rule 7835). In 2003 there were 105 net metered wind facilities (less than 40 kilowatt capacity) in Minnesota, an estimated 1.5 MW of wind energy capacity that generated 663,000 kilowatt-hours of electricity in excess of what they consumed. The efficiencies of these small machines is much lower than larger turbines due to design, technology, and installation techniques but they can produce enough electricity to offset up to the equivalent power of 5 or 6 homes when the wind blows at average speeds. There were also twenty four solar energy facilities which generated no excess electricity.

(LEFT) 10-kW net metered wind turbine at Macalester College in St. Paul (Source: Minnesota Public Radio, Mary Losure)
(RIGHT) 35-kW net metered refurbished wind turbine near Glenwood (Source: Carl Nelson)

**SIDEBAR: CLEAN ENERGY RESOURCE TEAMS (CERTS)
In 2002, the Legislative Commission on Minnesota Resources provided funding for the creation of Clean Energy Resource Teams (CERTs). The CERTs teams are designed to give citizens a voice in local energy planning by bringing together interested community, industry and government stakeholders to:

- Develop a common level of understanding on energy issues and technologies;
- Complete an inventory of available energy resources;

- Develop energy action plans that prioritize cost and community effective energy efficiency and renewable energy projects; and
- Work to implement those projects to the extent possible in each region.

The Department is working closely with the Minnesota Project and the University of Minnesota Regional Sustainable Development Partnerships to implement CERTs.
END SIDEBAR**

Wind Energy

Wind energy technologies that generate electricity have become the most visible form of renewable energy in Minnesota. Minnesota has a very significant wind resource, especially in the part of the state that experiences the greatest consistent wind speeds, the area commonly known as the Buffalo Ridge in very southwestern part of Minnesota. The only major drawback of wind energy from an energy standpoint is that the wind energy is an intermittent resource – the wind does not blow, or blow consistently, throughout the day or throughout the year. As a result, wind energy, by itself, cannot be relied upon for baseload or peaking purposes – 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). Because wind may be considered essentially a "free" fuel and emits no pollutants or other emissions, wind can provide Minnesotans with clean, reasonably priced electricity, provided, however, that sufficient transmission capacity exists to bring the wind-generated electricity from sparsely populated areas to population centers, where the wind can be used.[17]

The economics for large wind farms are very competitive, with contracts being executed for a price as low as 2.5 cents/kWh in good wind resource areas (including federal tax credit and depreciation, but no state incentives). Individual turbine projects cost more than traditionally fueled generating facilities per kWh 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.

Wind turbine technology is getting more efficient. For example, annual capacity factors exceeding 40 percent are being experienced at a number of southeast Minnesota monitoring sites with moderate wind speeds. Standard wind turbine sizes are now exceeding 1.5 megawatts, twice what it was five years ago. Larger turbines tend to produce electricity more efficiently than small turbines.

As turbine towers become taller (260 feet is now the standard height), areas north and east of the Buffalo Ridge are becoming viable sites for large wind farms. Individual turbines and wind farms are already moving into Mower, Dodge, Rice, and Stevens counties. Further expansion

[17] The costs associated with wind-generated electricity are generally made up of: 1) the capital costs of the wind turbines; 2) the costs associated with siting, constructing, interconnecting and maintaining the turbines and appurtenant facilities; 3) managing intermittency through load following and other techniques; and 4) the costs of transmitting the electricity to where it can be used.

will be dependent on the price offered by utilities, which is a function of the utilities' avoided costs and the need for electricity. Transmission has also been a 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.

**SIDEBAR: Community Wind Rebate
In 2003 the Department of Commerce received U.S. Department of Energy 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 that will be completed by June 2005:

Carleton College and Northfield Public Schools (joint application) proposed installing two 1.65 MW wind turbines (3.3 MW total)

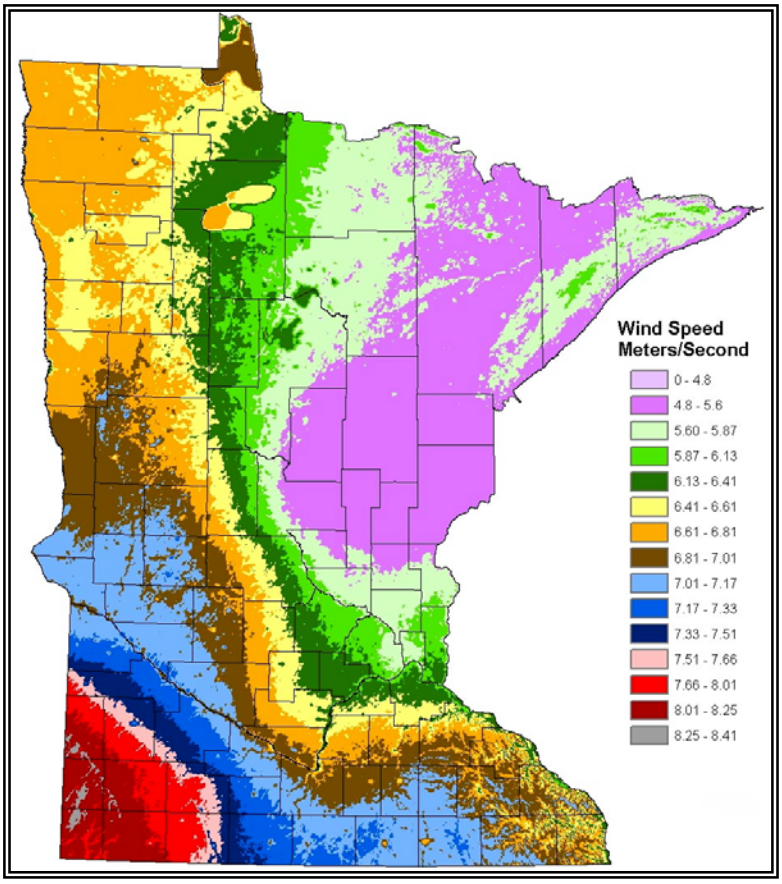
University of Minnesota-Morris West Central Research and Outreach Center proposed installing two 0.95 MW wind turbines (1.9 MW total)
END SIDEBAR**

Xcel Energy has roughly 500 megawatts (MW) of wind energy capacity installed, and is expected to install an additional 1,000 MW over the next several years. In total, this amount would represent over 15 percent of its total generation capacity. An independent wind intermittency study is currently being conducted about the costs of managing this amount of wind on their system. The study should be available by fall of 2004.

Minnesota's local wind market is active, as evidenced by the response to a $21 million solicitation for renewable energy and energy efficiency projects under a U.S Department of Agriculture program. Over $7.9 million was awarded to 35 wind projects nationally, 21 of which were in Minnesota. Four million dollars was awarded to Minnesota representing over 50 percent of the wind-related funding.

Wind Production Incentive

The Minnesota Wind Production Incentive provides 1.5 cents/kWh to qualifying small energy projects less than 2 MW in size. Currently 200 MW are subscribed or queued in the program with an additional 52 MW on a waiting list. Since its inception in 1997, nearly $10.4 million has been paid to wind energy producers under this program through June 2004.



Minnesota State Wind Incentive Program

Wind resource map of Minnesota showing average annual wind speeds at 70 meters above ground level.

	Projects (#)	Enrolled (MW)	Operating (MW)	2003 Electricity (MWh)
First 100 MW[18]	102	100	100	186,874
Second 100 MW[19]	26	100	29.6	6,651
Waiting List	36	52	na	na

Wind Monitoring Program

The Department of Commerce has been actively involved in statewide wind resource monitoring since 1982. This program collects and tabulates various wind speeds around the State. The Department also uses the data to generate statewide maps of the wind resource, providing a graphical representation of the potential that exists for wind development throughout the state. The current map was developed using Geographic Information Systems (GIS) and wind-flow modeling software programs. The highest data confidence exists in the western and southern parts of the state due to the large number of monitoring towers. The Department is working to expand wind monitoring in the other parts of Minnesota to determine wind speeds more accurately in these regions. Such information is crucial for identifying potential wind energy areas in Minnesota.

[18] The money for this part of the incentive program comes from the state's General Fund.
[19] The money for this part of the incentive program comes from Xcel Energy's Renewable Development Fund.

Biomass Energy

Biomass is a large and varied category of renewable energy, loosely defined as direct derivatives from plant and perhaps 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.

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 MW District Energy Heating and Cooling System is an example of a high efficiency biomass project that uses urban waste wood.

**SIDEBAR: District Energy in Saint Paul
District Energy in downtown Saint Paul is an example of a renewable-fueled combined heating, cooling, and power facility. The energy system used by District energy is 80 percent fueled by urban waste wood but can also use natural gas, coal, and oil. Their facilities provide:

- Heating for approximately 155 buildings and 300 homes representing over 27 million square feet of building space, including the State Capitol;
- Cooling for more than 60 buildings representing over 10 million square feet of building space;
- Electricity generation of 33 MW of capacity.

END SIDEBAR**

**SIDEBAR: Little Falls Ethanol Plant Biomass Project
Sebesta Blomberg & Associates received $2 million through the U.S Department of Agriculture 2002 energy solicitation to implement a biomass cogeneration demonstration project at the Central Minnesota Ethanol Coop in Little Falls. The project is designed to use wood waste, primarily sawdust from local sawmills. Using gasification and thermal oxidation of sawdust the project is expected to supply all of the thermal energy needs of the plant for both process steam and drying of the distiller's dried grains. The project is expected to be on line in the first quarter of 2005. If successful, this project could improve ethanol operations by reducing operating costs, environmental emissions, fossil fuel consumption, and increasing facility revenue by creating co-product streams of heat, electricity, and liquid fuels. The project is also intended to create a modular design for biomass cogeneration that could be replicated at other ethanol plants across Minnesota.
END SIDEBAR**

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 are most common. The Haubenschild Family farm at Princeton, Minnesota, using dairy manure, is a well-documented case study of a dairy operation generating electricity, heat, and value-added fertilizer from the enhanced manure resource.

A Department study in 2003 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. 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. However, 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.

**SIDEBAR: Wastewater Treatment Facility Upgrades

Rochester Public Utilities

The Rochester Public Utilities Wastewater Treatment Facility generates biogas as a major byproduct of its wastewater treatment process and in 1980 installed two 400 kW generators that can supply 25 percent of the summer electricity load. Recently, Rochester upgraded to two 1,000 kW turbocharged engines that will increase both the size and efficiency of the electric generation. In addition, the new configuration will include a combined heat and power design to use the waste heat from the electricity generation to heat the anaerobic digester and increase biogas production by 25 percent.

Albert Lea Public Utilities

The Albert Lea Public Utilities Wastewater Treatment facility was recently retrofitted to capture methane gas to generate electricity using four combustion microturbines. Previously it used the methane in a boiler to generate heat for the digester facility or burned the methane in an

atmospheric flare. It is expected that the facility will generate and offset 800,000 kWh/yr of usage at the plant, or equal to the electricity consumption of about 100 average Minnesota homes.
END SIDEBAR**

Biomass Decay

Landfill gas 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) ("Statewide MSW Composition Study" March 2000, Solid Waste Management Coordinating Board). There are currently four landfill gas-to-electricity recovery projects in Minnesota totaling 24.2 MW. The US EPA's Landfill Methane Outreach Program (LMOP) estimates that 25 other landfills in MN 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.

Hydroelectric Energy

Minnesota has approximately 195 MW of hydroelectric generation located within the state, the largest being Minnesota Power's Thompson Dam at 75 MW. 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 MW of hydropower potential: 12 upgrades to existing power generation sites (72 MW), 21 additions to existing dam sites with no power generation (51 MW), and 7 undeveloped sites (14 MW). 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.

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, solar energy resource quality depends on naturally occurring cloud cover as well as air clarity. As a consequence, Minnesota has better solar resources than Houston, Texas and almost as good resources as Jacksonville, Florida.

Solar heat generation is more cost effective than solar electricity installations, although not necessarily more common. Simply designing or positioning a home or building and its windows to use some of the sun's passive solar gain can offset annual heating needs up to 35 percent. Solar thermal applications can also heat pools, pre-heat building indoor ventilation air, actively heat buildings, and heat domestic hot water.

Solar electric systems are not currently cost-effective for utility applications or strict cost-effective requirements. However, some consumers are exploring and using solar. A 34 kilowatt (kW) system was recently installed in Minneapolis and is the largest system in the five-state region. Solar electricity may also be used in the future during high-cost, high-demand time periods for electric utilities.

1 kW met metered dual axis tracking solar system located at Dodge Nature Center, West St. Paul, MN
Source: Dodge Nature Center

**SIDE BAR: Minnesota Solar Rebate Program
The Minnesota Solar Rebate Program is operated by the Department of Commerce with funding from Xcel Energy's Renewable Development Fund.

The program leverages 80 percent cost-sharing by participants. To date, the 46 participants have increased the amount of grid-connected solar electricity in Minnesota over 100 percent in less than two years. The solar rebate program is one tool that will be used in the federal Million Solar Roofs Initiative.
END SIDEBAR**

**SIDEBAR: Minnesota Million Solar Roofs Initiative
The Department coordinates the Minnesota Million Solar Roofs Initiative using federal funding chosen in a competitive process by the U.S. Department of Energy. The Minnesota Million Solar Roofs Initiative is a state chapter of the federal Million Solar Roofs Initiative which seeks to:

- encourage and document 500 installations by 2010 in Minnesota;
- educate consumers, builders, installers, utilities, and code officials about solar technologies;
- reduce the barriers and transaction costs associated with installing solar technologies; and

- emphasize broad stakeholder participation by consumers, utilities, government, and business.

END SIDEBAR**

Biofuels

Biofuels for non-transportation uses generally consist of biodiesel and vegetable oils. Biodiesel fuel has become well known in Minnesota's transportation sector, but it can also be used as a fuel for generating heat or electricity. Biodiesel can be used in a boiler or furnace as a fuel oil replacement, electric diesel generator, and, along with vegetable oils, in a combustion turbine.

Diesel Generators

Diesel fuel is used in peaking diesel generators that account for more than 1,600 MW 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.

**SIDEBAR: UMN Biodiesel Generator Testing
The University of Minnesota Center for Diesel Research performed both laboratory and field demonstration tests of diesel electric generator performance and emissions when using biodiesel blended fuel.

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 in Apple Valley. Emissions reductions comparable to laboratory demonstration results were measured in the Zoo field test.
END SIDEBAR**

GSHPs reduce the need for non-renewable heating sources but are most cost- and energy-effective where natural gas service is unavailable and/or where electric or propane heat is currently being used. GSHPs are also most cost-effective in commercial, industrial, and

institutional facilities, but are more common in the residential sector due to longer payback acceptance. Several Minnesota electric utilities offer small rebates or electric rates for GSHPs.

OTHER ENERGY TECHNOLOGIES

This discussion of non-renewable fuel sources (nuclear, coal, natural gas) focuses on fuels and technologies that show efficiency or emissions improvements over traditional generating sources or pertinent to policy issues in Minnesota.

Ground Source Heat Pumps

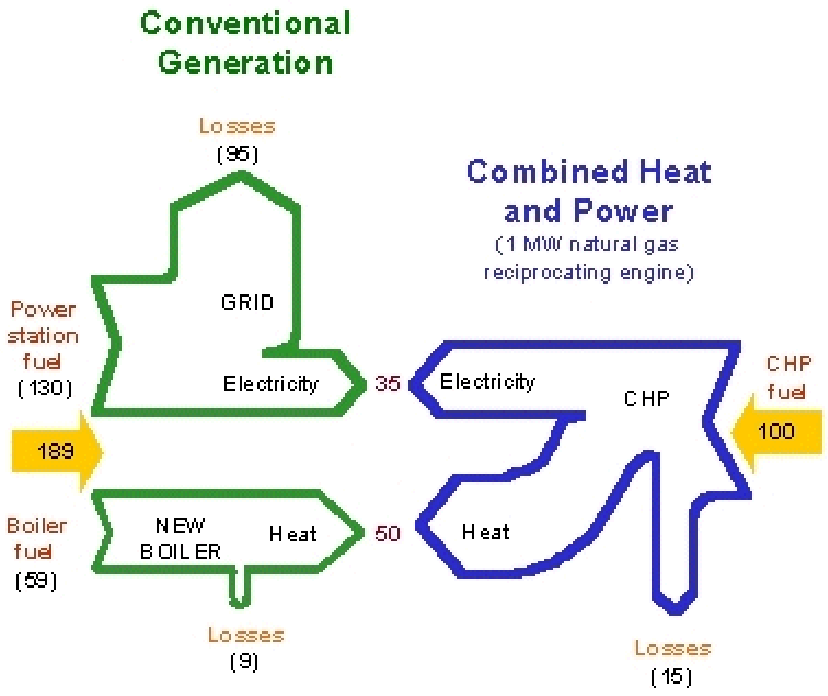
Ground source heat pumps (GSHP) use the latent heat of the earth to heat and cool a building. The most common construction is a series of buried coils or wells that have a liquid solution flowing through closed piping. Transferring the constant 55 degree (F) temperature of the earth from a depth of 10 feet or more into a thermal-exchange system reduces the need for heating in the winter and cooling in the summer, since the building air can be heated or cooled more efficiently than using outdoor air temperatures as a starting point.

Source: Geothermal Heat Pump Consortium (EPS graphic found at http://www.geoexchange.org/illustrations/graphics.htm)

Combined Heat and Power

Combined heat and power, the generation of electricity and use of waste heat from the process, is not a new concept. Thomas Edison's first electrical plants were designed to take advantage of the waste heat from the generation process.

Figure 20



Source: U.S. Department of Energy CHP Systems for buildings Program website, http://www.bchp.org/public.basic.html

Combined heat and power (CHP) is a term that refers to the use of so called "waste heat" from the generation of electricity.

A business using a CHP system essentially gets "more miles per gallon" and more for its money. Many businesses use both boiler system and electricity to supply the building's energy needs, with only 30 to 40 percent efficiency. When CHP is used, both heat and power needs are met with one energy supply source at up to 90 percent efficiency.

Innovations in electric power generation are helping more businesses and organizations consider CHP. Advances in microturbines and natural gas reciprocating engines have expanded CHP opportunities for smaller facilities. Thermally activated technologies have advanced to use waste heat for both heating and cooling applications such as building air conditioning or chilled water supply. While eliminating the need for traditional utility service for a location is unlikely, in some systems the electricity generated by the customer can become a value-added byproduct that can be sold back to the utility or used on site, substantially improving the economics of a CHP system.

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 do 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 are range from approximately:

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

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

The Mesaba Coal Gasification Project

As noted iv Chapter 2, an IGCC plant is currently being proposed for Minnesota's Iron Range. The size proposed for this plant is larger than the IGCC plants currently in existence. The Mesaba project is reportedly seeking to be designated the FutureGen project.

A capital construction cost comparison of electric generating technologies from the Public Utilities Commission Metropolitan Emissions Reduction Proposal briefing estimated the following capital costs:

IGCC plant: $1.6 to $1.8 million per megawatt (MW)
New Coal plant: $1.5 to $1.8 million per MW
New Natural Gas plant: $0.7 to $0.8 million per MW

Gasification Technology

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.

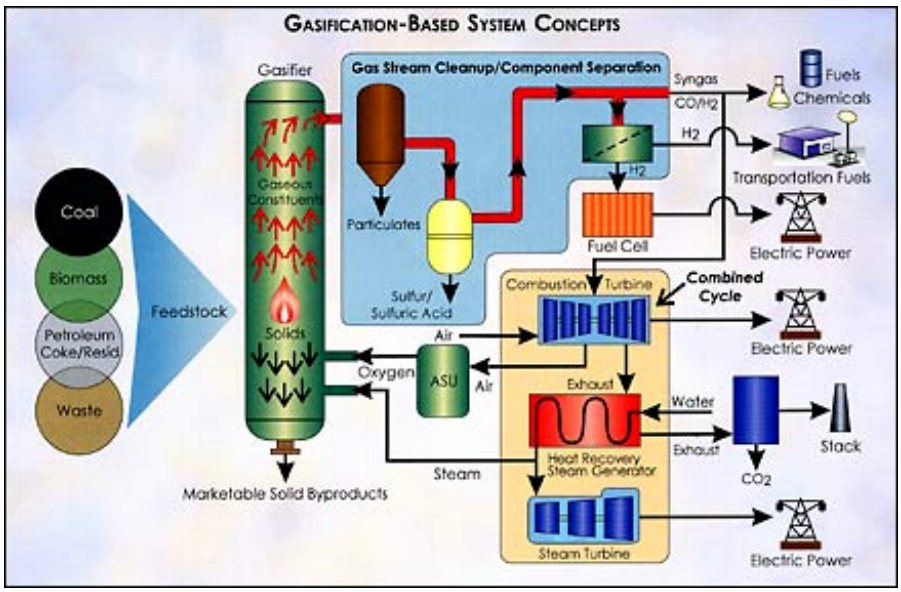
Syngas is primarily hydrogen, carbon monoxide and other gaseous constituents, the proportions of which can vary, depending on the conditions in the gasifier and the type of feedstock. The syngas is cleaned of hydrogen sulfide, ammonia and particulate matter and is burned as fuel in a

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.

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.



Source: U.S. Department of Energy, Office of Fossil Energy

How Gasification Power Plants Work

The US Department of Energy has initiated a program called FutureGen, in which the Department is offering $1 billion for the development and construction of a zero emissions coal gasification generation facility. In order to be emissions-free, the FutureGen facility must be able to sequester the carbon dioxide created by the combustion process. *Carbon sequestration* is a method of capturing and permanently isolating carbon dioxide (CO_2) emitted from the IGCC

process in an effort to prevent global climate change. When oxygen is used in the IGCC gasifier (rather than air), the CO_2 produced is in a concentrated gas stream. This process makes it much easier and less costly to separate and capture the CO_2. Once the CO_2 is captured, it can be sequestered - that is, prevented from escaping to the atmosphere and contributing to the "greenhouse effect."

Hydrogen & Fuels Cells

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.

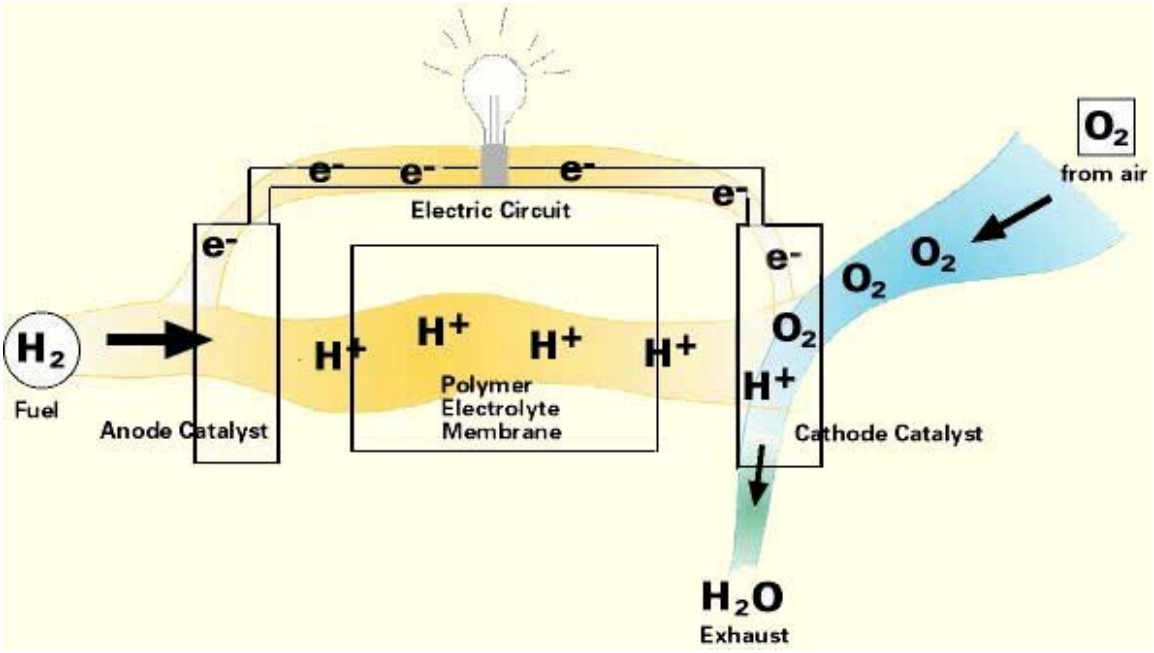
Hydrogen is an energy carrier, not an energy source. As such, it is the only concept available today that could potentially be used to "store" electricity. Many other fuels can be converted to hydrogen but hydrogen itself does not occur naturally in a usable form. The hydrogen can be derived from renewable (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.

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.



Source: Fuel Cells 2000 website, http:www.fuelscells.org/basics/how.html

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.

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.

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.

Laying the foundation for Hydrogen in Minnesota

Minnesota has a strong presence in the fuel cell industry, with companies such as 3M, Tescom, Entegris, Donaldson and ICM Plastics. Companies such as Praxair, Flint Hills Resources, and Marathon Ashland Petroleum have significant experience with handling hydrogen and developing fueling infrastructure. Also, Minnesota's wind and ethanol industries are or are becoming quite strong with other indigenous renewable fuels developing. Lastly, as discussed in Chapter 2, 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.

Chapter Four
NATURAL GAS – A Bridge Fuel to the Future?

The recent increases in (and volatility of) natural gas prices have pushed the consumption and the availability of natural gas toward the center of the current national energy debate. 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. Instead, natural gas may be viewed as a bridge from traditional fuels to emerging, more efficient fuels and technologies. 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; and
- Increasing Prices and Volatility.

Each is discussed below.

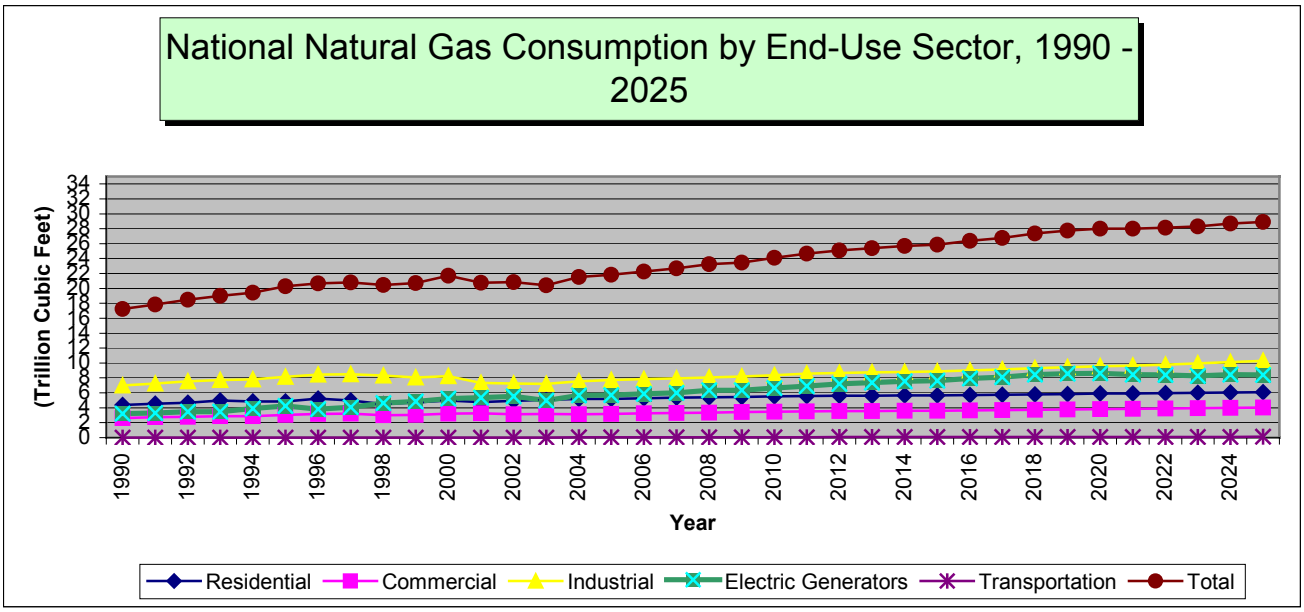
INCREASING DEMAND

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.[20] Consumption of natural gas is likely to continue to increase, barring unforeseen large natural gas price increases that would make it less competitive with alternative fuels.

Statewide, Minnesota's demand for natural gas increased from 248,821 MMcf in 1965 to 313,435 MMcf in 2001. Residential consumption has increased approximately 44.3 percent from 87,309 MMcf in 1965 to 125,984 MMcf in 2001, while commercial consumption has increased approximately 83.5 percent from 52,121 MMcf in 1965 to 95,662 MMcf in 2001.[21] Industrial consumption, which includes electric generation, and deliveries-to-transportation, account for the remaining amount of total Minnesota demand.[22]

[20] In this context, "alternative fuels" are normally considered to be other petroleum-based fuels that can be substituted in equipment, such as propane, fuel oils, and diesel fuels.
[21] Source: REIS
[22] The "deliveries-to-transportation" refer to situations where larger customers purchase natural gas supplies from third-party marketers and transport it to their facilities through the local distribution companies' systems.

On a national level, demand for natural gas has been growing since the 1930s. Residential natural gas consumption has grown from 295,700 MMcf in 1930 to 4,923,151 MMcf in 2002.[23] Commercial consumption of natural gas has grown from 80,707 MMcf in 1930 to 3,121,595 MMcf in 2002.[24] In 2002, total consumption of natural gas was 22,780,710 MMcf and is expected to rise to over 35,411,745 MMcf by 2025.[25]



Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004, Figure 85 data, pg. 89.*

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, as shown in Figure 4 of Appendix 2, which includes data through 2002.) At a national level, natural gas consumption for electricity generation is projected to increase from 5.6 trillion cubic feet (Tcf) in 2002 to 8.4 Tcf in 2025, an average annual growth rate of 1.8 percent.[26] New natural gas-fired peaking and intermediate[27] generation plants will compete with LDCs for natural gas during the traditional summer refill season, thus impacting the volatility of natural gas prices during this period.

[23] Source: U.S. Energy Information Administration Annual Energy Outlook for 2004.
[24] Source: U.S. Energy Information Administration Annual Energy Outlook for 2004.
[25] Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004.*
[26] Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004, Figure 85 pg. 89.*
[27] Unlike "baseload" plants, which operate continuously, "peaking" plants operate only during periods of high demand. "Intermediate" plants can adjust operation and output based on economic dispatch to meet high demand and/or to help run the electric system smoothly during plant outages or planned maintenance.

One way of limiting the demand for natural gas (and electricity) is to utilize energy conservation programs. With the uncertainty and volatility of natural gas prices, conservation programs are an excellent way of slowing increasing demand by reducing a customer's usage, which in turn reduces the customer's energy bill.

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.

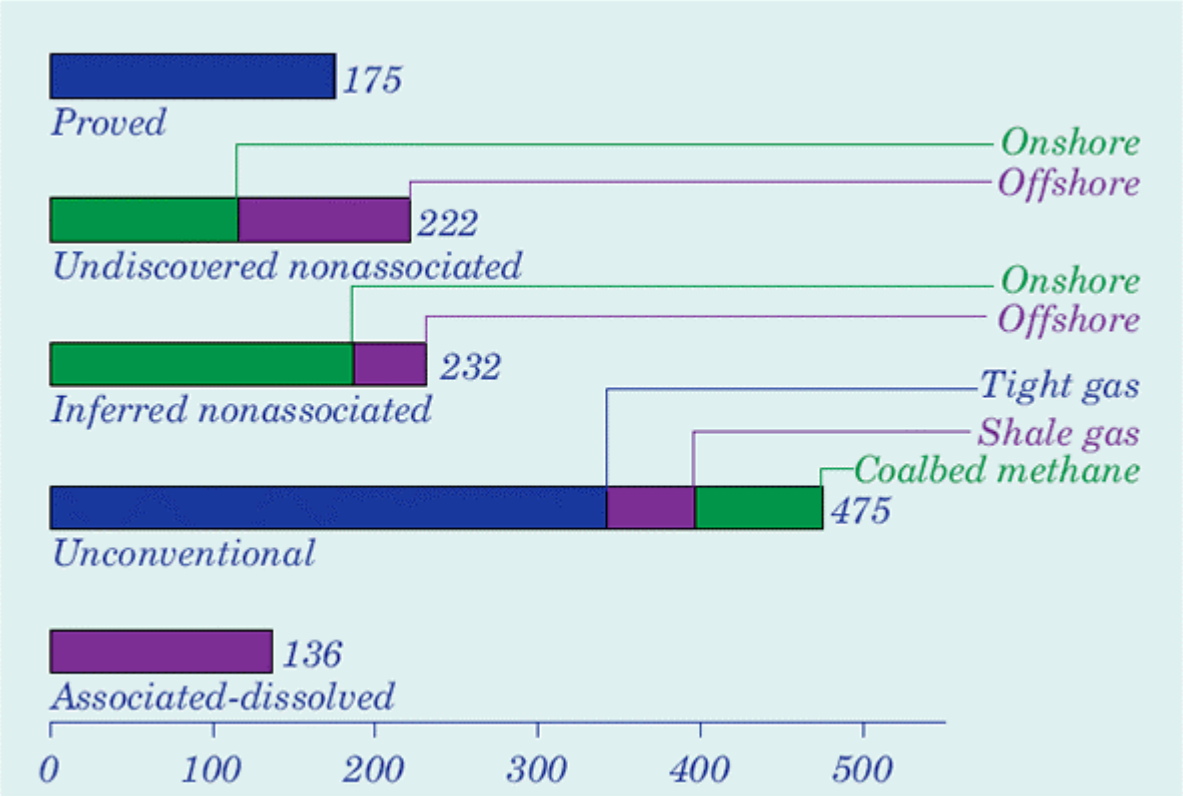
Nationally, the demand for natural gas has been growing and is projected to continue to grow for the near future. Thus, more attention is focusing on potential sources of natural gas supplies to meet such demand. As of January 1, 2002, the EIA states that there is 1,240 Tcf[28] of technically recoverable U.S. (domestic) natural gas resources waiting to be tapped.[29] The natural gas reserve additions reflect an expected increase in exploratory and developmental drilling that will result from an increase in natural gas prices and production revenues.

[28] EIA divides this number into two components, proved and unproved. Proved natural gas reserves (175 Tcf) are located in known and developed reservoirs, for which wells have been drilled and production rates have been demonstrated. Unproved technically recoverable resources include:

- *Undiscovered nonassociated conventional* (222 Tcf) - natural gas resources are unproved resources of natural gas, not in contact with significant quantities of crude oil in a reservoir that are estimated to exist in fields yet to be discovered, based on regional geologic formations and their propensity to hold economically producible natural gas.
- *Inferred nonassociated conventional* (232 Tcf)- natural gas reserves are gas deposits in known reserves that are considered likely to exist on the basis of a fields geology and past production but have not yet been developed through developmental drilling.
- *Unconventional* (475 Tcf)- this category is by far the largest category of unproved reserves. This gas is tight gas found in sandstone, shale and coalbed methane.
- *Associated-dissolved resources* (136 Tcf)- This includes gas in associated-dissolved crude oil reservoirs in the lower 48.

[29] Source: U.S. Energy Information Administration *Annual Energy Outlook for 2004, Figure 10, pg. 33*. However, table 22 on page 91 states that the technically recoverable U.S. natural gas resources as of January 1, 2002 are 1,279.5 Tcf (proved reserves of 183.5 Tcf and unproved reserves of 1,096 Tcf) –thus, this data includes Alaska.

Technically Recoverable Lower 48 Natural Gas Resources as of January 1, 2003
(trillion cubic feet)



Source: U.S. Energy Information Administration Annual Energy Outlook for 2004, Figure 10, pg. 33

Currently, 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, in 2003, the Canadian National Energy Board (NEB) reassessed and revised its earlier estimates of Canadian production. As such, EIA in its *Annual Energy Outlook for 2004* (AEO2004), has decreased its forecasted potential imports from Canada. Net imports of natural gas from Canada are projected to peak at 3.7 trillion cubic feet in 2010, then decline gradually to 2.6 trillion cubic feet in 2025. The depletion of conventional resources in the Western Sedimentary Basin is expected to reduce Canada's future production and export potential, and prospects for significant production increases in eastern offshore Canada have diminished over the past few years. There is also considerable uncertainty about the economic viability and timing of coalbed methane production in western Canada.

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 liquefied natural gas (LNG). LNG is natural gas in a liquid state maintained at a temperature of –260 degrees 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 increased number of countries including Algeria, Malaysia, Australia, and Trinidad and

Tobago. At this time, there is only limited capability to import LNG into the United States. When planned expansions at the four existing terminals are completed and the new LNG terminals that are projected to start coming into operation in 2007, it is estimated that net LNG imports will increase from 0.2 trillion cubic feet in 2002 to 2.2 trillion cubic feet and 4.8 trillion cubic feet in 2010 and 2025, respectively. While there is no overall infrastructure to deliver LNG to Minnesota, there is a potential for more natural gas supplies becoming available as LNG displaces natural gas supplies consumed in other parts of the country.

In sum, it appears there are adequate supplies available to meet projected demand, at least for some time beyond the 2025 forecast. So the real question then becomes the price at which such supplies are available.

AVAILABILITY OF TRANSPORTATION CAPACITY

There are four major pipelines[30] 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.[31] 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, the largest pipeline, Northern, is already fully utilized in the winter season.[32] The Great Lakes Gas Transmission pipeline has capacity available for any increased natural gas consumption that would occur in the 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. The MIPC and HUC pipelines are reported to be fully subscribed.

As with any fuel, once demand increases beyond the current available pipeline capacity, a significant new investment in infrastructure is required to expand capacity. Such infrastructure investments are expensive[33] and in most cases, require long-term commitments/contracts to be executed prior to construction.

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

[30] The four pipeline systems serving Minnesota include Viking Gas Transmission, Great Lakes Gas Transmission, and Northern Border Pipeline as well as Northern Natural Gas.
[31] Source: Interstate gas pipeline company information reported annually under Minnesota Rule 7610.1200. Some Companies reported their data in decatherms, which were converted to Mcf using a one-to-one ratio.
[32] The heating season is considered to be the five winter months of November, December, January, February and March.
[33] For example, the approximately 80 miles of intrastate pipeline installed by HUC had an initial estimated construction cost of approximately $26 million.

to all customers reflects the increased costs.[34] In contrast, natural gas pipelines located wholly within the state (or Intrastate pipelines) are rate regulated by the MPUC with larger pipelines requiring a Certificate of Need prior to initial construction. The overall delivery infrastructure is aging and needs to be redeveloped and/or improved to meet energy demands into the future.

INCREASING PRICES AND PRICE VOLATILITY

The average wellhead prices for natural gas (including both spot purchases and contracts) according to the EIA shown in the table below:

Natural Gas Prices[35]
(2002 Dollars per Thousand Cubic Feet)

	2002	2010	2015	2020	2025	Annual Growth
Average Wellhead Price	2.95	3.40	4.19	4.28	4.40	1.8%

As shown above, the average wellhead prices are projected to increase from $2.95 per thousand cubic feet in 2002 to $3.40 per thousand cubic feet in 2010. Natural gas wellhead prices are projected to be $4.28 in 2020, when an Alaska pipeline is expected to be completed. Wellhead prices are projected to increase gradually after 2010, reaching $4.40 per thousand cubic feet in 2025. Some of the cost drivers for the increase in natural gas prices are due to newer technologies being used to drill deeper wells and tap harder-to-extract natural gas. Additionally, the fundamental principle of supply and demand will drive prices up. As demand for natural gas increases due to increased usage, the price will increase.

One additional consequence of higher demand and tighter supplies is rapid changes (increases or decreases) in price or increased price volatility. Because natural gas is used for home heating, its consumption (and therefore, its price) is extremely weather dependent. As such, there can be periods of high price volatility during cold days or weeks followed by periods of stable prices.[36]

One method that Local Distribution Companies (LDCs) use to combat price volatility is the use of financial tools. 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[37] with suppliers and other third-parties. The purpose of these tools,

[34] Northern implemented a 30 percent rate increase beginning November 1, 2003 and has recently petition FERC for an increase of an additional 8 percent for a total potential increase of 38 percent from October 31, 2003 to November 1, 2004. The FERC allows implementation of proposed rates subject to refund per FERC's final decision.
[35] Source. U.S. Energy Information Administration *Annual Energy Outlook for 2004, Table A14.*
[36] Volatility adds to the cost of supplying natural gas. In Minnesota, natural gas utilities are allowed to pass all prudently incurred costs on to the consumer on a dollar-for-dollar basis.
[37] Examples of physical hedges include: (1) seasonal use of storage where supplies are purchased and injected into storage and withdrawn for use during periods of high demand or high prices; (2) fixed-price supply contracts where

whether futures contracts of 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 have started using the tools in managing their gas supply portfolio.

In conclusion, the 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. The pipeline infrastructure is aging. To maintain or increase the pipeline capacity, there is a need for continual investments for improvements and expansions. As long as demand increases and supplies remain tight, the price for nature gas will be higher than in the past and will continue to be volatile. Nowadays, natural gas should be viewed as a bridge fuel while exploring and developing alternative fuel sources and technologies.

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supplies are purchased over a period of time at a pre-set or fixed price for use at a later time; and (3) long-term, firm transportation contracts with pipelines where LDC's negotiate transportation charges to ensure capacity in future periods.

Chapter Five
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 Department 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
- Affordability and

CONSERVATION

Strictly defined, conserving or "saving" energy applies only to actions that cut energy use – for example, turning down a thermostat or turning off lights when they are not in use. On the other hand, "energy efficiency" focuses on the most efficient use of energy, which may or may not lower overall energy use. For example, a company might install energy efficient equipment with the goal of increasing production. The company's energy use could stay the same or even rise, but the output per unit of energy used would increase.

Other terms often included under the rubric of energy conservation refer mainly to the efficient management of energy supplies and deliveries. "Load management" describes actions that seek to shift demand for electricity away from hours of the day or seasons of the year when demand normally is highest. Late afternoon on a hot summer day is usually a peak period, and supply and delivery systems can be strained to the point of power failures or brownouts. In addition, the cost of obtaining energy is highest during these periods. By reducing strain on the system, load management helps maintain reliability and prevent costly power failure or the need to obtain expensive additional power at peak periods. An example of load management is when a company makes changes in its production schedule to use the same amount of energy, but at a different (i.e., non-peak) time of the day. This shift decreases the amount of stress on the electric system, and thereby makes it easier and less expensive to deliver energy to all customers.

"Demand Side Management," commonly referred to as DSM, covers an array of activities -- load management, conservation, and efficiency – all designed to affect the timing and amount of energy use.

In addition to traditional DSM activities, the Department has been actively engaged in market transformation projects. Market transformation is a strategy that promotes the manufacture and purchase of energy-efficient products and services. The goal of this strategy is to induce lasting structural and behavioral changes in the marketplace, resulting in increased adoption of energy-efficient technologies. According to the American Council for an Energy Efficient Economy (ACEEE), market transformation measures include low initial costs, rapid paybacks and other benefits besides energy savings.

An emerging area of energy conservation programs involves Builder Operator Certification (BOC) and commissioning and recommissioning activities. BOC provides training to builder operators to operate buildings in the most efficient manner. Commissioning involves "tuning-up" during and post-construction to ensure that all of the various systems are interfacing with each other properly. Recommissioning is a "tune-up" for buildings, which after years of use from their human occupants might not have systems that interface in the most efficient manner. These programs are proving to provide significant benefits, not only in energy efficiency and the associated reduction in energy operating costs, but also improvements in overall building occupant productivity and health.

Achieving the maximum amount of cost-effective conservation is a major policy goal of the Department, as part of an energy policy that responds to the negative impacts of increased energy use on the environment and economy. In addition to the environmental benefits of conservation, conservation can help reduce energy costs and increase the competitiveness of business. Additionally, the August 14, 2003 blackout highlights the reliability importance of conservation in reducing the strain on the electric infrastructure.

**SIDEBAR: Demand Response
Demand response programs are a tool being used by many states to encourage energy efficiency by having fewer electrons moving through the system during peak times. A number of states have established demand response programs which look at generation from a conservation perspective. That is, instead of generating megawatts, demand response asks consumers to generate "negawatts." On-call firm demand reduction is being bid into RFPs for peak load generation - generators are paid capacity credits each month in addition to high per kilowatt-hour rates.

For example, utilities or energy service providers in NY can get paid for curtailing electric load during peak use. There are programs for emergency (short-notice) demand response, day-ahead demand response and a reserve capacity program that contracts resources to meet system supply requirements over a certain contract period.
END SIDEBAR**

Both the federal and Minnesota state governments have acted to advance conservation, employing mandates, financial assistance, and other strategies to reach their goal. The Department of Commerce has responsibility for a number of these programs. Three such programs are discussed below.

Conservation Improvement Program

The Conservation Improvement Program (CIP), enacted by the legislature in 1982, is the primary state conservation program. It requires Minnesota's electric and natural gas utilities to spend a percentage of their annual gross operating income on programs to encourage conservation among all their customers – residential, commercial, and industrial, with specific attention given to providing conservation opportunities for low-income residential users. This requirement amounts to something on the order of over $75 million dollars a year being spent on conservation

in Minnesota. As a result, CIP has had a substantial impact on energy use, and its effectiveness was recognized in 2000 by the ACEEE. The Council ranked Minnesota's utility energy efficiency program among the top six in the nation, based on data collected by the Energy Information Agency.

Under CIP, investor-owned utilities (IOUs) submit their conservation projects to the Department for approval. In the four years (2000 through 2003) since the last Energy Policy and Conservation Report to the legislature, electric IOUs have spent an average of $32.9 million a year. Gas IOUs have spent an average of $7.8 million a year. Four-year energy savings from these programs totaled 988 million kilowatt-hours of electricity and 4.2 billion cubic feet of natural gas. The magnitude of capacity savings due to CIP is better understood by noting that Xcel Energy's programs alone have saved a total of over 2,000 megawatts – the equivalent of Xcel Energy's massive Sherco coal-fired generation facilities. CIP has also lowered the peak demand for electricity and natural gas for investor-owned utilities:

- an average of 140,000 kilowatts per year over the past four years, and
- an average of 13.9 million cubic feet of natural gas per year.

Minnesota's rural electric cooperatives and municipal utilities are also required to invest a percentage of their revenue on conservation programs and submit an annual report on the projects to the Department. The conservation programs of these utilities under CIP are reported to the Department for review and advice, but are not subject to Departmental approval.

The seven generation and transmission electric cooperatives, and their 45 distribution cooperatives, reported spending an annual average of $23.7 million on conservation between 1999 and 2002. In the same period, Minnesota's municipal electric utilities spent an annual average of $9 million on conservation. Education, rebates for efficient lighting and other efficiency improvements, and load management measures are among the most common types of projects, for both types of utilities.

Of Minnesota's seven municipal natural gas utilities, four met the income threshold of $5 million that requires them to spend 0.5 percent of that revenue on conservation. Expenditures over the 1999 to 2002 period averaged $1.4 million annually. Education, rebates, and programs for low-income customers and renters are among the most common.

The Department requires the CIP projects of investor-owned utilities to be cost-effective – that is, the cost of the project must not exceed the cost of the energy saved. Types of projects that have proved effective include:

- For residential electric consumers: discounts and rebates on efficient lighting and central air conditioning, as well as free evaluations of home energy use.
- For residential gas consumers: rebates on insulation, and efficient furnaces and water heaters.

- For commercial electric consumers: rebates on purchase of more efficient lighting and refrigeration equipment.

- For industrial electric customers: rebates on purchase of more efficient motors and industrial processes.

- For commercial and industrial gas customers: rebates for increasing insulation and purchasing more efficient space heating and cooling equipment, as well as free evaluations of energy use and ways to conserve.

As noted above, the CIP program is over 20 years old and has matured as a program. In order to ensure the program's continued success and to document the program's past accomplishments, the Department sought, and received, approval from the Legislative Audit Commission for a program evaluation by the Office of the Legislative Auditor of the CIP program, to ensure the amount of money that ratepayers are putting toward conservation projects continues to be well-spent. That audit is expected to be completed by the end of 2004.

Energy Information Center

The Energy Information Center at the Department promotes energy conservation and efficiency through almost 100,000 public contacts annually by telephone, web site, email, in classes and at presentations. The Info Center offers dozens of energy conservation publications and distributes more than 136,900 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. The Info Center distributes a quarterly electronic newsletter highlighting the Department's activities to more than 1,000 subscribers.

A recent survey concluded that people who contacted the Info Center found the information provided was easy to understand and useful – more than 50 percent surveyed implemented a change using the information they received, and many more planned to take action within the coming year. The Info Center was a sponsor of the Living Green Expo Sustainability Fair, which was attended by 5,000 people in 2002 and more than 11,000 in 2003.

Buildings, Benchmarks and Beyond (B3)

As mentioned earlier, in 2001, the Minnesota Legislature established a goal of achieving 30 percent savings in existing public buildings throughout the state. The Legislature, in setting this energy savings goal directed the Departments of Administration and Commerce to do two things:

1) To undertake conservation benchmarking for all public buildings. There are over 10,000 such buildings, so the work is expected to focus on creating and prioritizing a list of poorly performing buildings.

2) 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.

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.[38] 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.

**SIDEBAR: Federal Funds for Renewable and Energy Efficiency
The State Energy Program (SEP) is the only federally-funded, state-based program administered by the US Department of Energy. The SEP provides resources directly to the States for allocation by them based on each State's specific needs and market environment.

The total national program was funded by Congress at $45 million in FY2003. Minnesota received approximately $917,000. In addition to program grants, this federal appropriation funds the Energy Information Center and staff positions in the Department.

SEP funds are used to develop and manage a variety of programs to increase energy efficiency, reduce energy use and costs, develop alternative energy and renewable energy sources and reduce reliance on non-U.S. sources of energy.

To measure the return on investment of the SEP, the DOE asked Oak Ridge National Labs to complete an evaluation. The evaluation found that each $1 invested in SEP results in cost savings of $7.23.
END SIDEBAR**

**SIDEBAR: Bringing Dollars to MN via Competitive Grants
The Department has successfully brought $1,800,000 to the State of Minnesota via competitive grants in the last two years. These grants help improve energy efficiency in key Minnesota industries in addition to promoting energy independence and clean fuels in the transportation sector. This funding is in addition to money received via the Federal State Energy Program.

In 2003 the Department was awarded over $1,000,000 for the following:

- Boise Paper Plant, Paper Dryer Energy Efficiency Improvements, $634,850 (State Technology Advancement Collaborative)

- Schwan's Home Service: Convert 90 Gasoline Trucks to Diesel, $188,000 (State Energy Program Special Projects)

- Rebuild Minnesota, $77,912 (State Energy Program Special Projects)

[38] See http://www.cbsr.umn.edu/03/index.html for a copy of the guidelines.

- Energy Code Education and Upgrade, $60,258 (State Energy Program Special Projects)

- Indoor Air Quality Monitoring in Federal Buildings, $46,000 (State Energy Program Special Projects)

In 2002 the Department was awarded $800,000 for the following:

- E85 Infrastructure Expansion, $250,000 (State Energy Program Special Projects)

- Propane Truck Fuel Development, $200,000 (State Energy Program Special Projects)

- Develop Energy Innovations for Mining and Forest Products, $185,000 (State Energy Program Special Projects)

- National Energy Foundation, Energy Education in Midwest Schools, $100,000 (State Energy Program Special Projects

- Energy Code Technical Support and Implementation, $65,000 (State Energy Program Special Projects)

END SIDEBAR**

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 Department 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 Department seeks to achieve this goal, including:

- the Renewable Energy Objective;

- the Conservation Improvement Program;

- support for legislation allowing continued operation of Xcel Energy's Prairie Island nuclear generation facility, which is a base load generation resource that emits no air pollution;

- support for Xcel Energy'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 Energy and the Izaak Walton League of America, discussed below.

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, the three facilities' owner, Xcel Energy, filed with the Commission the Metropolitan Emissions Reduction Project or MERP. This voluntary filing fulfilled a commitment made to the Izaak Walton League, as part of Xcel's merger proceeding before the Commission in 2000.

This project 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 would 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.

This project will provide a number of benefits to the metro area and to the state.

1. Besides improving the esthetics of the riverbank in Minneapolis and St. Paul, air quality should be measurably improved in the Twin Cities, reducing emissions at the plants significantly. According to the MPCA, sulfur oxide emissions would be reduced by 95 percent, nitrogen oxide by 95 percent and particulate matters by 70 percent. Repowering the two plants with natural gas will reduce mercury emissions from those facilities 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.

2. 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 maintains its reliable electric system.

3. The additional 300 MW of power generated by the new natural gas-fired facilities will be needed in the coming years to meet the needs of the growing Twin Cities area.

4. The use of flexible and efficient natural gas-fired combined cycle turbines at the High Bridge and Riverside facilities will enable the further development of large-scale wind powered electric generation facilities by providing complementary backup generation resources for use at times when wind turbines are not generating electricity (a process known as "load following").

For these benefits, Xcel ratepayers are being asked to pay a 6-8 percent increase in their electric rates. Such an increase is substantial and, in most cases, would garner opposition, especially from those groups especially sensitive to energy prices. However, MERP has met with wide and almost unanimous support. With Governor Pawlenty's leadership, a strong and broad coalition of support was established, including representatives of the legislature, the business community, energy and environmental regulators, public health officials, citizens and environmentalists. By order dated March 8, 2004, the Commission approved the MERP project, clearing the way for the greatest single reduction in emissions in Minnesota history.

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 having to focus 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 Department'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, Department 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 Department of Commerce. These programs serve between a quarter and a third of the Minnesota households that are eligible for assistance.

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

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 Department contracts with 39 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 credit with their energy vendor enabling the household to pay a portion of their heating costs. Renters and homeowners 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 2003, the program served 122,609 Minnesota households with an average bill payment assistance grant of $408 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
- 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 providers also provide advocacy and referral services throughout the program year.

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 of Commerce staff administers the year-round fund through the same 39 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 with federal LIHEAP dollars.

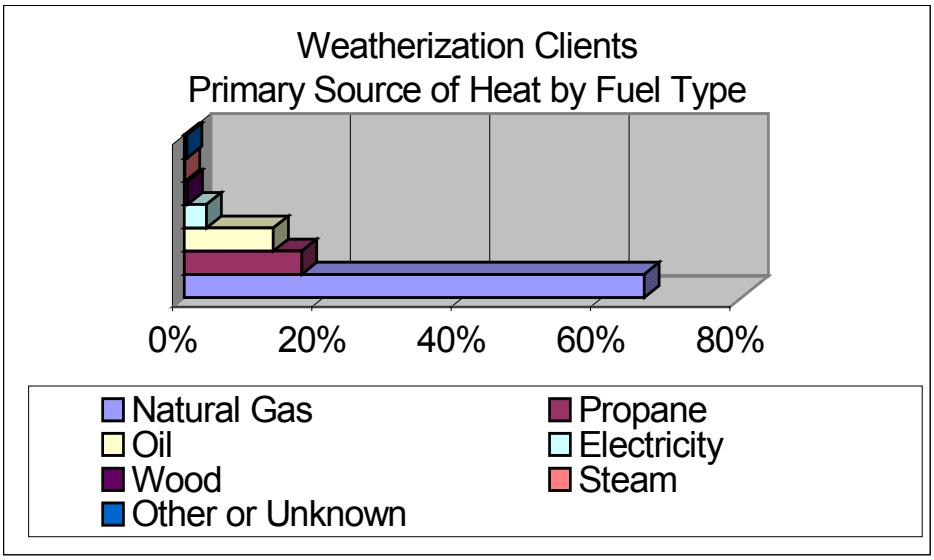
Minnesota Weatherization Assistance Program

The State Energy Office 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. In effect, this program reduces homeowners' reliance upon other programs, such as LIHEAP, to pay heating bills and frees up dollars in that program to assist other clients.

During FY2002, Minnesota received $9.68 million in WAP funds from the Department of Energy, which served 3,074 households. 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 the contractor can assess the client's home to identify the most necessary or helpful improvements. Correcting health and safety hazards and potentially life-threatening conditions is the first consideration in WAP activities.



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.

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
- testing, repairing, or replacing home mechanical systems to ensure efficiency and safety.

Electronic Household Energy Technology Project

The Electronic Household Energy Technology (eHEAT) project is a new undertaking by the Department that will help LIHEAP and WAP service providers streamline program efficiency and increase focus on customer service. Currently the state's 40 service providers are using various software, mailing and database programs, leading to information gaps. The result of the project will be a centralized web based data and payment management software program that will streamline administrative costs and enhance program analysis. The program is expected to be operating by the end of 2004.

Minnesota Low-Income Statutes

Minn. Stat. § 216B.16, subd. 14, requires Xcel Energy to offer a 50 percent discount on the first 300 kWh 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.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, also known 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 pays at least 10

percent of its income toward utility bills. 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.

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 1

THE ENERGY SECTIONS OF THE TELECOMMUNICATIONS AND ENERGY DIVISION OF THE MINNESOTA DEPARTMENT OF COMMERCE

There are three sections within the Telecommunications and Energy Division which handle energy issues for the Department of Commerce. These units are the State Energy Office, the Energy Planning and Advocacy Unit and the Office of Energy Assistance Programs. Each of these sections is summarized below.

State Energy Office

As one of three sections in the Energy Division of the Minnesota Department of Commerce, the State Energy Office is the main state conduit for U.S. Department of Energy (DOE) funding, receiving both State Energy Program and Weatherization dollars. State energy programs are implemented through loans and grants, maximizing the benefits of energy efficiency and renewable energy through promoting energy conservation in buildings and demonstrating renewable energy technologies, with the objective of bringing them closer to market realities. Weatherization grant activities are funneled through community action agencies throughout the state, assisting low-income households weatherize their homes to use energy more efficiently and lower their energy bills for the long term. The State Energy Office also includes the Energy Information Center, which provides conservation information directly to Minnesota consumers. The Energy Information Center has operated continuously since 1974, responding to phone calls and sending brochures that provide practical advice on various energy issues. The SEO continues to promote energy conservation in all buildings through code involvement and public education.

Energy Planning and Advocacy

The Energy Planning and Advocacy unit (EPA unit) intervenes on the public's behalf in all natural-gas and electric utility matters before the Public Utilities Commission (PUC). The EPA unit's role is to ensure that energy rates are reasonable and service is reliable. The EPA unit works in energy rate cases, miscellaneous rate proposals, integrated resource planning, nuclear decommissioning and nuclear waste disposal, mergers and acquisitions, depreciation rates, capital structures, electric service territory matters, and consumer complaints. The EPA unit also works on energy conservation, both with the Commission and within the Department. The EPA unit collects data on Minnesota's energy production, use and rates, maintains historical databases, and conducts analyses of energy use in Minnesota, from production to distribution. The EPA unit also develops and advocates energy policy issues before the legislature, federal agencies, in cooperation with other state agencies, and in regional and national forums such as matters before FERC. EPA is a leader and active participant in electric transmission activities through its seat on the MISO Advisory Committee and OMS.

Office of Energy Assistance Programs

The Office of Energy Assistance Programs administers Minnesota's Low Income Home Energy Assistance Program (LIHEAP). LIHEAP helps eligible low-income households meet their immediate winter heating needs and is funded by the U.S. Department of Health and Human Services. The Department contracts with 39 local nonprofit organizations, local government organizations, and tribal organizations to provide services to the public.

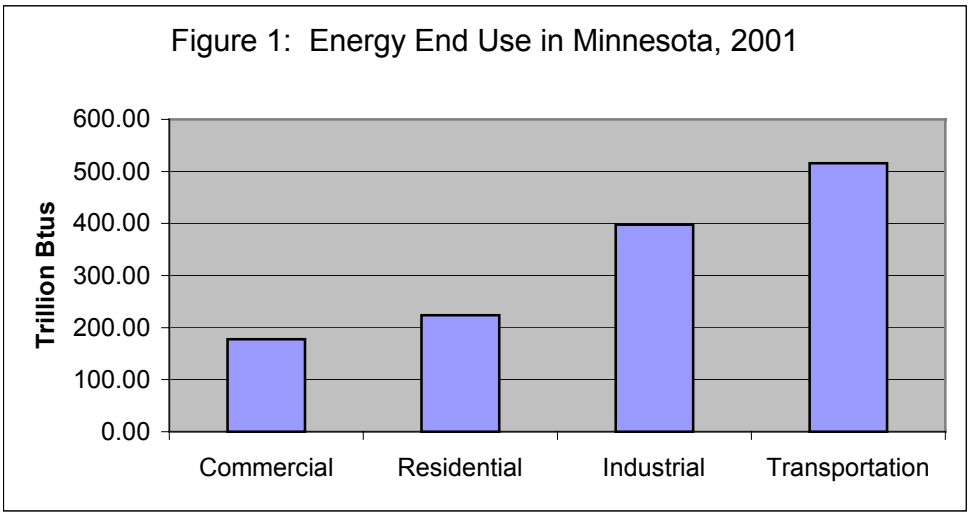
Appendix 2

MINNESOTA ENERGY INFORMATION

Sidebar: The data in this chapter and Appendix ___ 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 1,314.74 trillion BTUs of energy (electricity, natural gas, petroleum products, coal and biomass) in 2001.[39] Figure 1 shows the relative amounts of energy Minnesotans use for commercial, residential, industrial and transportation purposes.[40]



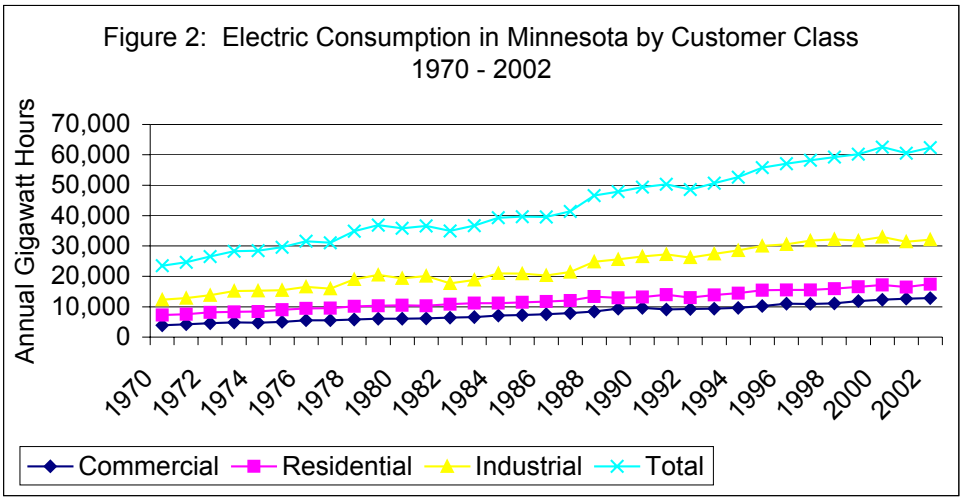
Source: REIS database and EIA.[41]

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

[39] Btu (British thermal unit is the common measurement of the heat content in energy, and is approximately equivalent to the heat produced by one wooden kitchen match.
[40] A list of electric and natural gas utilities and other statistics may be found in the Department's Utility Data Book at http://www.commerce.state.mn.us.
[41] Website addresses for these and other information sources are included in Appendix 5.

Electricity

Minnesotans consumed a total 62,364 gigawatt[42] hours of electricity in 2002. Figure 2 shows total electric consumption since 1970 and breaks down that electric consumption into the residential, commercial and industrial customer classes.



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).

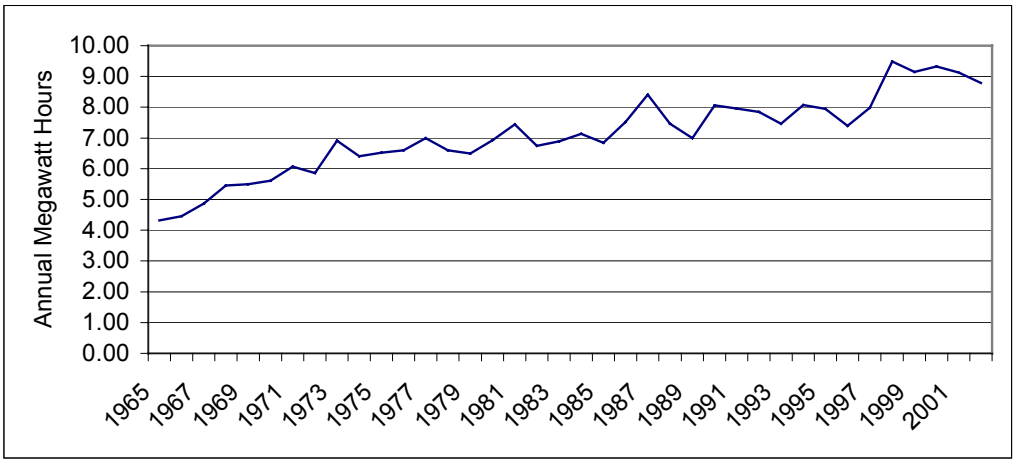
This graph illustrates Minnesota's increasing demand for electricity, both overall and in the various sectors. Total demand for electricity has increased an average of 3.1 percent annually over the 1970 – 2002 period. Demand by commercial customers has grown the most in that span, increasing 3.7 percent annually. The annual growth rates for residential and industrial customers for the same period were 2.7 percent and 3 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.

[42] Gigawatt (GW) means one billion watts.

Figure 3: Weather Normalized Electric Consumption Per Residential Customer
1965 - 2002

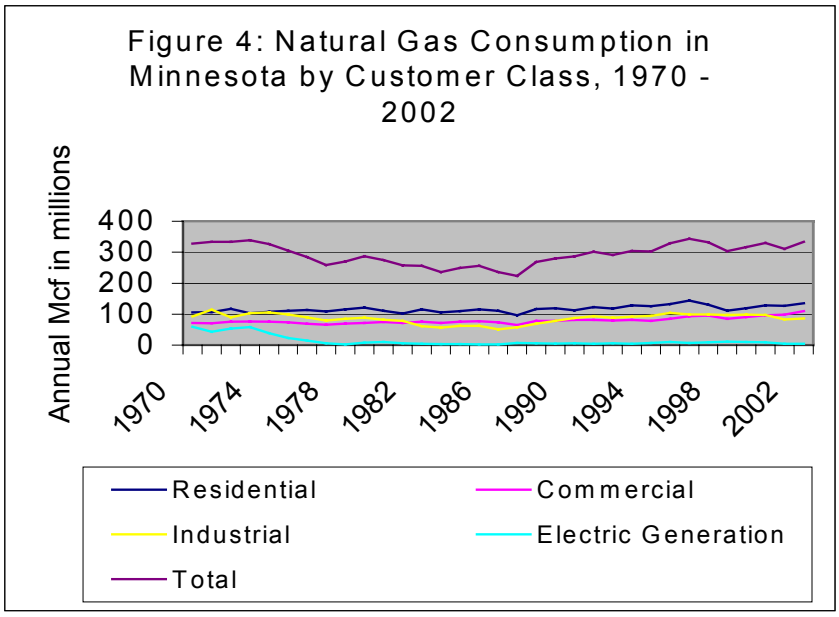


Sources: REIS database, DNR – State Climatologist at http://www.climate.umn.edu

Natural Gas

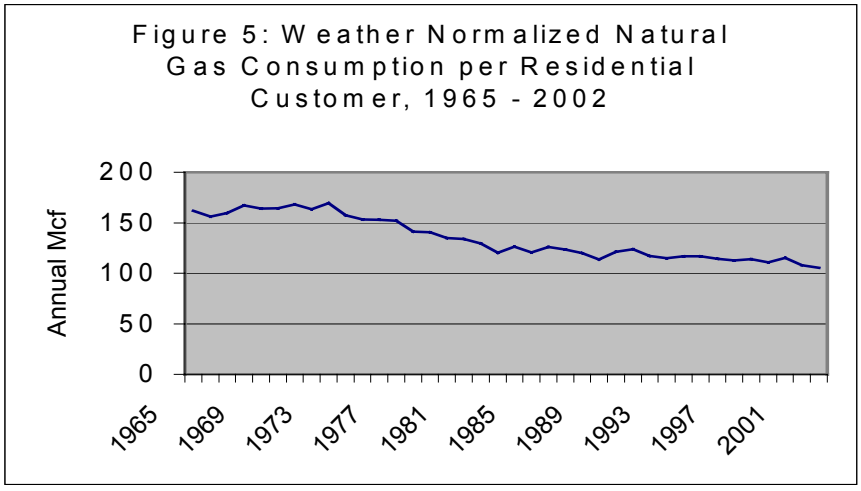
Minnesotans consumed a total of 269.8 Bcf (billion cubic feet) of natural gas in 2002.[43] Figure 4 shows Minnesota's natural gas consumption by residential, commercial, industrial, electric generation and transportation customers (which includes pipeline operation and, since 1990, natural gas fueled vehicles).

[43] Natural gas may be measured in Mcf (thousand cubic feet) or therms. (One Mcf is roughly equivalent to 1 million Btus or 1 dekatherm.)



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.

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, (which is based on data ending in 2002), the increase will be more noticeable starting in 2003 as recently approved natural-gas facilities go on line 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.

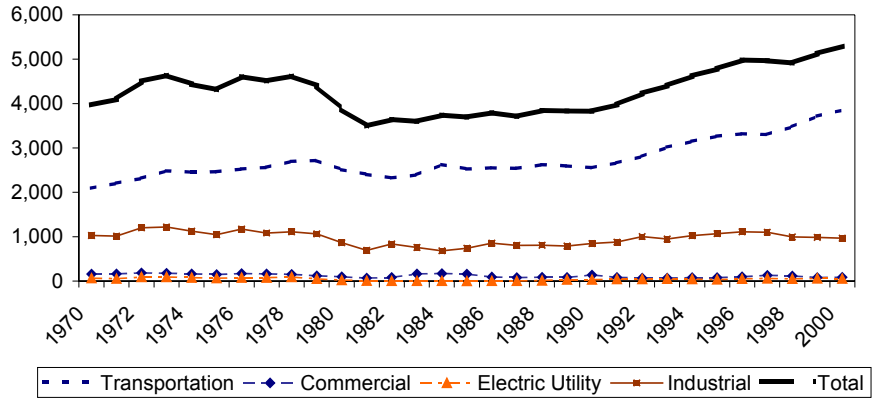


Sources: REIS database, DNR – State Climatologist

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 of natural gas has declined by 56.5 Mcf per year (or approximately 35 percent) over the last thirty-seven years. A major reason 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 6: Petroleum Products Consumption in Minnesota by Customer Class, 1970 - 2000 (millions of gallons annually)



Source: EIA State Energy Data 2000 Consumption tables at http://www.eia.doc.gov/emeu/states_use_multistate.html

Petroleum

Minnesotans consumed a total of 691.5 trillion Btus (5,670 million gallons) of petroleum products in 2002.[44] Figure 6 shows the total petroleum consumption in Minnesota for the residential, commercial, industrial, transportation, and electric generation customer classes.

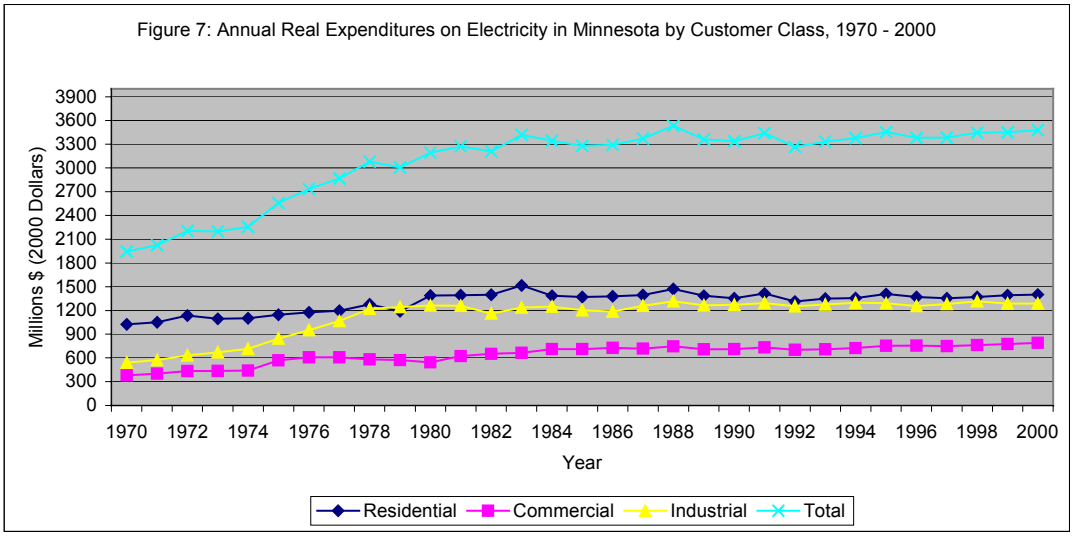
In 2002, Minnesotans used about 85 percent of all petroleum products for transportation (air, land, and water). This amount includes asphalt and road oil as well as fuels like diesel, jet fuel, and motor gasoline. Most agricultural use of petroleum is also included in the transportation category. About 9 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 6 percent of the total petroleum products used in 2002.

[44] Petroleum products, as used in this section, include: asphalt and road oil, aviation fuel, distillate fuel, jet fuel (all types), kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel.

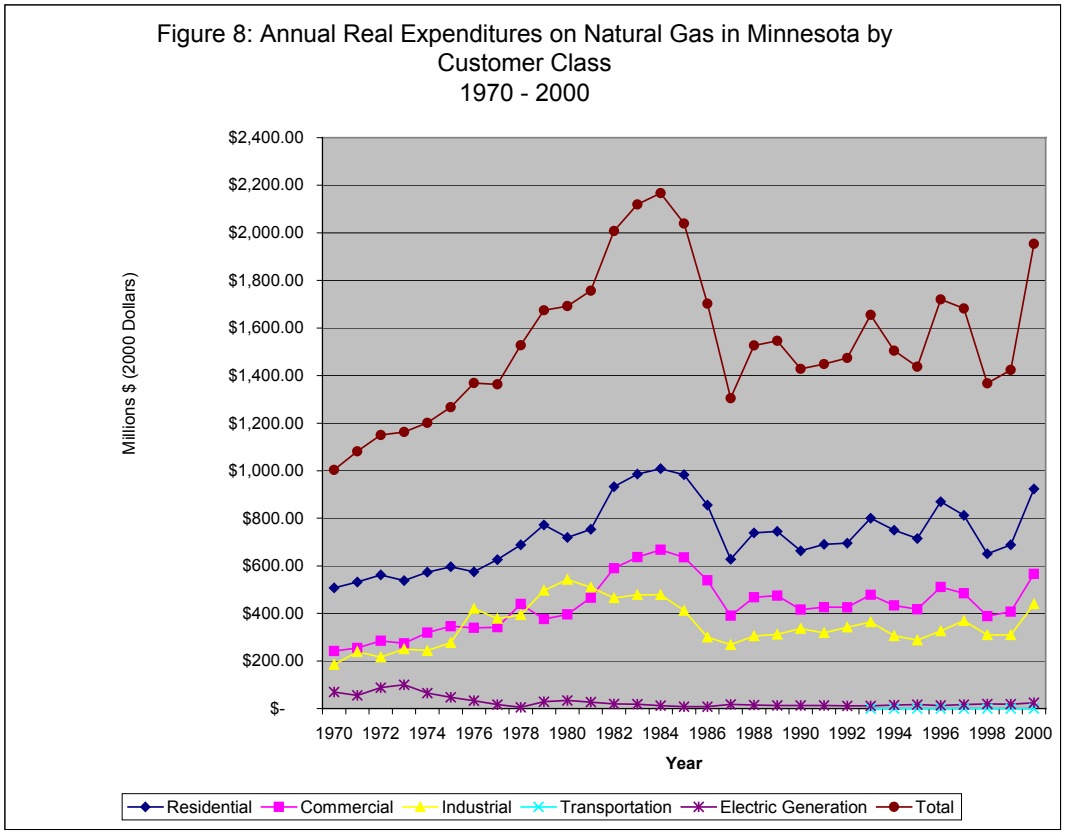
HOW MUCH DOES MINNESOTA'S ENERGY COST?

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 report has been converted to year 2000 dollar values.

In 2000, Minnesotans spent about $3.5 billion on electricity, $2.0 billion on natural gas and $6.7 billion on petroleum products.

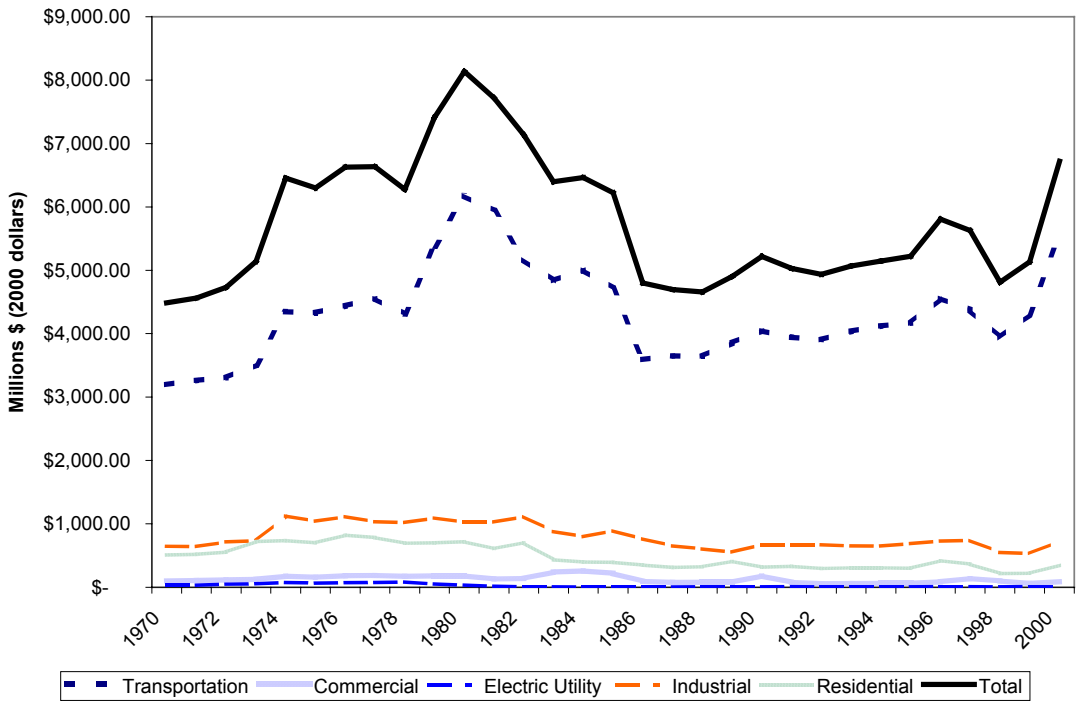


Sources: *State Energy Price and Expenditure Report 2000, Energy Information Administration*
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO



Sources: *State Energy Price and Expenditure Report 2000, Energy Information Administration*
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO

Figure 9: Annual Real Expenditures on Petroleum Products in Minnesota by Customer Class, 1970 - 2000



Source: EIA State Energy Data 2000 Price and Expenditures tables at http://www.eia.doc.gov/emeu/states_price_multistate.html

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 2002 in Minnesota and the corresponding national average prices. This table shows that the electric rates paid by Minnesota commercial customers ranked 12th lowest nationally in 2002 (they were 19th lowest in 2000). For Minnesota industrial customers, electric rates were 18th lowest nationally (30th lowest in 2000), while the rates for Minnesota residential customers ranked 21st lowest in 2002 (same 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 10: 2002 Minnesota Electric Prices Relative to Prices in Other States (¢/kWh)

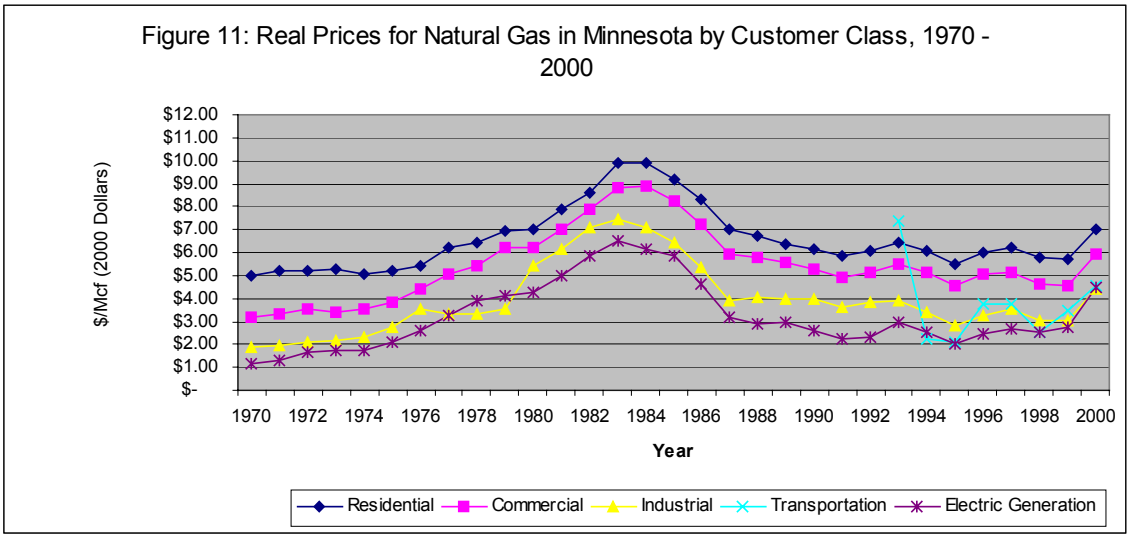
	Residential Customers	Commercial Customers	Industrial Customers
Minnesota Price	7.49¢	5.88¢	4.19¢
Minnesota Rank*	21st	12th	18th
Average U.S. Price	8.46¢	7.86¢	4.88¢
Highest Price	15.63¢	14.11¢	11.24¢
Lowest Price	5.65¢	5.30¢	3.09¢

* 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-Electric Sales and Revenue 2002

Natural Gas

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



Sources: *State Energy Price and Expenditure Report 2000, Energy Information Administration*
U.S. Department of Labor, Bureau of Labor Statistics, Series ID: CUURA211SAO, CUUSA211SAO

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.

Figure 12: 2002 Minnesota Natural Gas Prices Relative to Prices in Other States
(Dollars per Thousand Cubic-Feet)

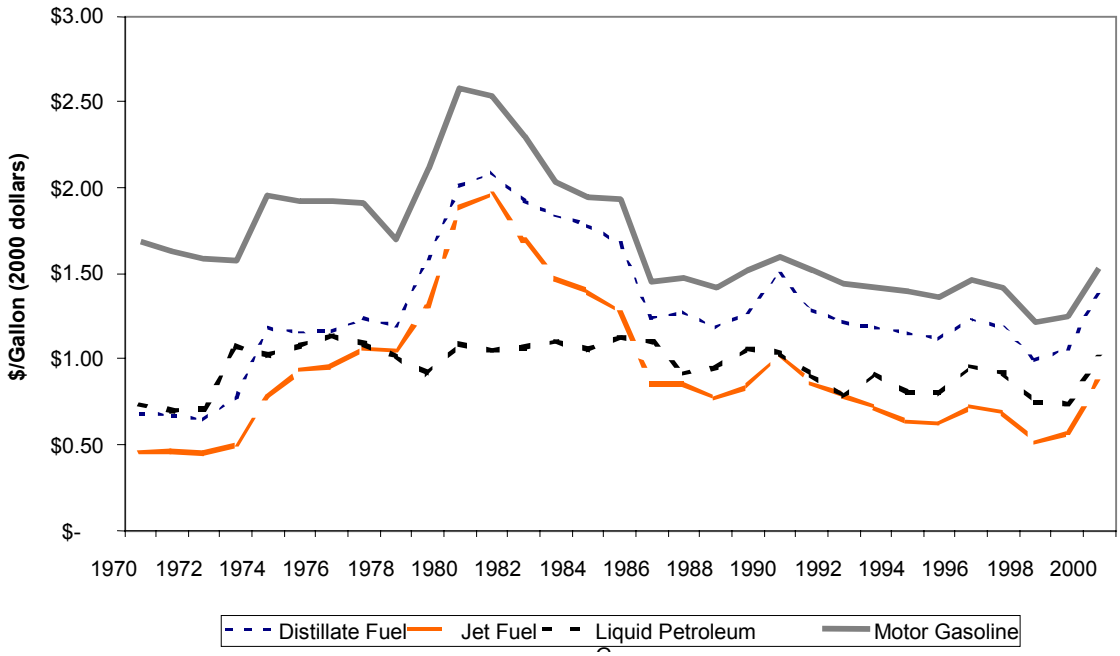
	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	$6.41	$5.21	$3.95
Minnesota rank	10th	7th	8th
Average U.S. price	$7.90	$6.52	$3.85
Highest price	$23.62	$17.74	$10.05
Lowest Price	$4.41	$3.48	$1.62

Source: EIA, Natural Gas Monthly January 2004

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 good prices due to competition between Canadian and U.S. natural gas production areas and relative price difference between gas producers.

Petroleum

Figure 13 : Real Prices for Petroleum Products in 1970 - 2000



Source: EIA, State Energy Data 2000 Price and Expenditure tables at http://www.eia.doc.gov/emeu/states_use_multistate.html

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.

**SIDEBAR For Petroleum Price Section:

> 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. ***

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 the 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.

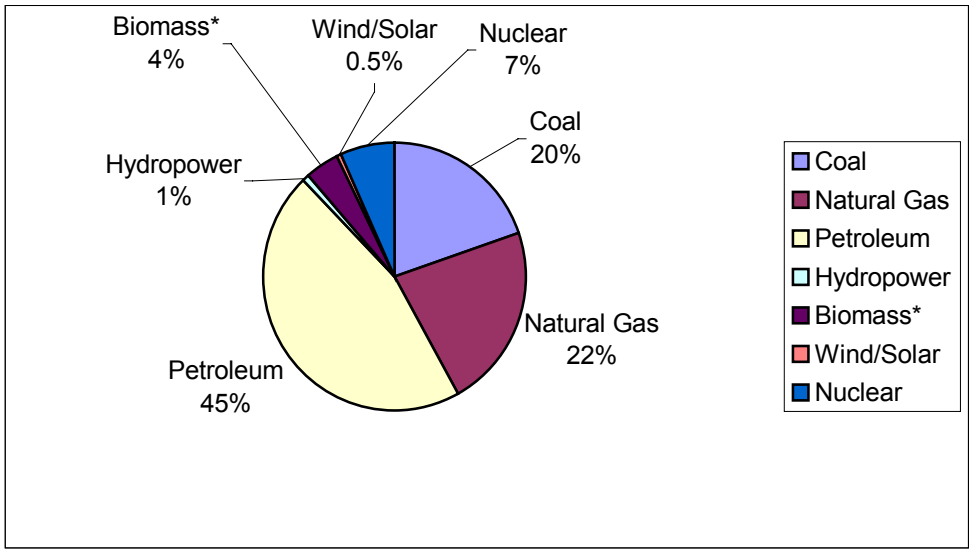
Unexpected demand for a particular product can also create temporary shortages that lead to higher prices. For instance, very cold weather increases the use of propane products for space heating and very wet or very dry weather increases or decreases the agricultural use of petroleum products.

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.

WHERE DO MINNESOTANS GET THEIR ENERGY?

In 2000, Minnesota required a total of 1,506 trillion Btus of fuel to produce all of the energy we 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.

Figure 14: Total Inputs Used to Produce All Energy Consumed in Minnesota, 2000



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

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.[45] 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.

[45] Smaller generating facilities, sometimes referred to as "distributed generation", may be located adjacent to cities or other areas of heavier electricity use in order to better serve fluctuating electricity needs in that area.

***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 an established geographic area. 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.[46] 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.

Figure 15: Percentage of Customers and Load Served by Different Electric Utility Types in 2002

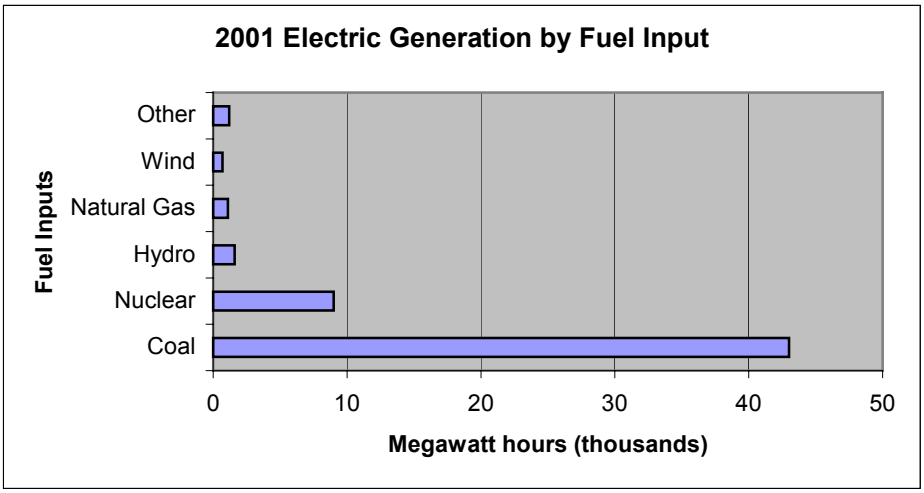
Type of Entity	# Customers	% Total Customers	Total GWh	% Total GWh
IOU, Regulated	1,389,382	58%	41,912.3	67%
Cooperative	663,696	28%	11,662.4	19%
Municipal	329,656	14%	8,789.5	14%

Source: REIS

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.

[46] Only one distribution electric cooperative association – Dakota Electric Association headquartered in Farmington, Minnesota – has made this election.

Figure 16



Source: REIS

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.[47] 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.[48]

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 FERC-approved interstate pipes

[47] Source: Department of Commerce 2002-2003 Annual Fuel Report, February 27, 2002, Table G16, Docket No. E,G999/AA-03-1264.
[48] Source: The "three pipelines" include ANR Pipeline Company, Centra Pipeline and Williston Basin Interstate Pipeline.

may provide greater access to Minnesota of Rocky Mountain gas supplies. Since interstate pipeline capacity is available to all shippers on a non-discriminatory 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 Minnesota Department of Commerce reviews the LDCs' gas costs to ensure that they are reasonable and makes recommendations to the Minnesota Public Utilities 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 twenty 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.

Figure 17: Percentage of Customers and Volume of Gas Served by Natural Gas Utilities (2002)

Type of Entity	# Customers	Percent of Total Customers	Total Mcf	% Total Mcf
IOU, regulated	1,338,943	94	251,415,002	93.2
Municipal	73,787	5	17,694,814	6.6
Private, unregulated	5,492	1	705,682	0.2

Source: REIS database

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 exclusive LDC for that area. The high capital costs of developing the infrastructure to deliver natural gas to low density populations located long distances from major pipelines hinders further development.

Petroleum

The United States imports more than 60 percent of its petroleum resources, either in the form of crude oil or refined products. U.S. crude oil imports have risen from 44 percent of new supply in 1990 to 62 percent in 2002. U.S. finished, or refined, product imports have remained fairly steady in the 1990s at about 6 percent of total demand.

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. The world currently uses approximately 27,010 million barrels of crude oil per year. 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.

Increasing Imports

In 2002 the United States met over 60 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. The fact that Minnesota does not receive a large percentage of its crude oil feedstocks from areas such as 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.

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.

Appendix 3

State Regulatory Programs to Promote Renewable Energy Development

Statute	*Description*
Renewable Development Fund	**Minn. Stat. § 116C.779.** This statute requires Xcel Energy to transfer to a renewable development account (the "Renewable Development Fund" or RDF) $16 million annually for each year spent fuel is stored in dry casks at the utility's Prairie Island nuclear generation facility. Money from the fund is spent with the approval of the Public Utilities Commission, but the RDF is an account internal to Xcel Energy, not an account in the state treasury. Of this $16 million, up to $4.5 million is to be used for production incentives for small wind facilities under Minn. Stat. § 216B.41, and $1.5 million for production incentives for other renewables. There is no definition for "renewables" in this statute. That definition is left to a renewable development fund board, which determines which projects get funded. The board is currently made up of two Xcel Energy representatives, one representative of environmentalists, one representative from local government, and a representative of the Mdewakanton Dakota tribal council at Prairie Island.
Net Metering	**Minn. Stat. § 216B.164.** This statute requires utilities to purchase the output of certain renewable energy facilities of 40 kilowatts or less, net of the amount of electricity used by the owner of the facility. The rate that a utility is required to pay for this net energy is the utility's average retail rate (the amount that the utility charges retail customers for electricity). The statute incorporates the federal PURPA definition for qualifying facilities.
State PURPA statute	**Minn. Stat. § 216B.164.** This statute requires a distribution utility to purchase the output of certain renewable facilities of greater than 40 kilowatts at the utility's full avoided cost of energy and capacity of the utility's least cost renewable resource, or the bid of a competing supplier of a least cost renewable energy facility, whichever is lower. The statute incorporates the federal PURPA definition for qualifying facilities.

"Green Pricing" programs	**Minn. Stat. § 216B.169.** This statute requires each distribution utility to offer customers the option to purchase renewable energy. Distribution utilities are those utilities that provide electric service directly to retail customers. Rural electric cooperatives and municipal distribution utilities are examples of distribution utilities. Investor-owned utilities, such as Xcel Energy or Minnesota Power, are also included. This statute uses the Integrated Resource Planning statute definition of renewables.

Renewable Energy Objectives	**Minn. Stat. § 216B.1691.** This statute requires each generation and transmission cooperative, municipal power agency, and investor-owned utility to make a good faith effort to get 10 percent of their power supply from renewable energy by 2015. The Public Utilities Commission issued an June 2004 Order detailing certain standards and criteria for evaluating a utility's performance under the REOs. The Commission will now turn its attention to developing a weighted scale of how energy produced by various eligible energy technologies shall count toward a utility's objective. In establishing this scale, the commission shall consider the attributes of various technologies and fuels, and shall establish a system that grants multiple credits toward the objectives for those technologies and fuels the commission determines is in the public interest to encourage. Under the REO statute, the energy generated by an eligible energy technology counts toward the REO. The statute defines "eligible energy technology" as an energy technology that: (1) generates electricity from the following renewable energy sources: solar; wind; hydroelectric with a capacity of less than 60 megawatts; hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or biomass, which includes an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel; and (2) was not mandated by Laws 1994, chapter 641 (the 1994 Prairie Island statute), or by commission order issued pursuant to that chapter prior to August 1, 2001. The 2003 legislature made the REO a requirement for Xcel, and specified that the utility must contract for or develop an additional 300 MW of wind.

Distributed Energy Resources	**Minn. Stat. § 216B.2411.** This statute allows utilities to spend 5 percent of their required conservation spending under Minnesota Statutes, section 216B.241, on renewable energy projects, provided the utility is meeting their REO. Project costs may be pooled between utilities. This statute also has its own definition of what an eligible energy renewable energy source is, which is a bit broader than the REO definition, but narrower than the IRP definition.

Integrated Resource Planning	**Minn. Stat. § 216B.2422.** This statute establishes a preference for renewable energy in planning for power supply requirements. The statute prohibits the Public Utilities Commission from approving the construction of a nonrenewable energy facility unless the utility proposing the facility has demonstrated that a renewable energy facility is not in the public interest. It also requires a utility to use environmental cost values established by the Commission in the utility's resource plans. This statute has the broadest definition of what qualifies as renewable, specifying that: "Renewable energy" means electricity generated through use of any of the following resources: (6) wind; (6) solar; (6) geothermal; (6) hydro; (5) trees or other vegetation; or (6) landfill gas.

Wind Power Mandate	**Minn. Stat. § 216B.2423.** This statute requires Xcel Energy to acquire 825 megawatts of wind energy capacity.

Biomass Power Mandate	**Minn. Stat. § 216B.2424.** This statute requires Xcel Energy to acquire 125 megawatts of biomass energy capacity by December 1998.

Renewable Energy Production Incentive	**Minn. Stat. § 216C.41.** This statute provides 1.5 cents per kilowatt-hour produced by up to 200 megawatts of eligible renewable energy facilities. Eligible renewable energy facilities includes certain: · small wind energy facilities (under 2 megawatts) · on-farm anaerobic digester facilities · refurbished hydroelectric dams The production incentive for the first 100 MW of capacity is paid out of the general fund by a statutory appropriation (i.e., not subject to biennial appropriation). The production incentive for the second 100 MW of capacity is paid for out of Xcel Energy's Renewable Development Fund. All of the 200 MW of capacity is fully subscribed. Another $1.5 million of production incentives may be paid out of the Renewable Development Fund under this statute to eligible on-farm biogas recovery facilities for production incentives for other renewables.

Appendix 4

BLACKOUT SYMPOSIUM SUMMARY

The Office of Energy Reliability of the Minnesota Department of Commerce held a conference on November 10, 2003, to discuss the events that lead to the blackout on August 14, 2003, and reaction of Minnesota's utilities to those events. Ken Wolf, the state's Reliability Administrator and head of the Office of Energy Reliability, organized the conference.

The morning session began with an address by Nora Mead Brownell, one of the five members of the Federal Energy Regulatory Commission. Commissioner Brownell thanked the Minnesota Department of Commerce and the Minnesota Public Utilities Commission for their leadership on reliability issues, and especially for their efforts to address these issues cooperatively with stakeholders – to keep the discussion from devolving into a "industry vs. environmentalists" or "utilities vs. regulators" impasse. It is critical, said Commissioner Brownell, that the lights stay on, but it is "even more critical that we dig down deep and ask how we plan together for the future."

Regarding the blackout itself, Ms. Brownell said that the joint U.S./Canadian investigation is continuing, and that we don't yet know what caused the blackout.[49] She said we do know two things about the blackout. One of those is that the blackout was not caused by a single event – "complex systems have complex answers." The other is that utility deregulation or "restructuring" was not a cause of the blackout, but being "caught in the middle of restructuring made us more vulnerable" to the cascading events that resulted in the blackout.

Commissioner Brownell made several key points:

- There has been a serious disinvestment by utilities in transmission infrastructure, partly as a result of the "financial melt-down" of the energy utility industry that followed in the wake of the Enron debacle.

- We have a integrated transmission grid, and that we are each heavily dependent on our neighboring states and utilities – the transmission system is becoming ever more regional.

- State and federal jurisdictional boundaries were developed at a time when the grid looked different. This disparity continues to lead to difficulties, but these can be overcome with cooperation and communication.

- We need mandatory reliability rules, and a regulatory entity with the authority and resources to enforce those rules. These rules are likely to be included in a federal energy bill, if Congress passes such a bill.

[49] The "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," U.S.-Canada Power System Outage Task Force, was issued on April 5, 2004, and can be accessed at http://www.nerc.com.

- We need to encourage deployment of new technologies, such a transmission technologies to allow the grid to be operated more efficiently, and generation technologies to allow electricity to be generated much more cleanly.

- We do need more wires – "big lines" – and that lapses in reliability of the electric system are costing the economy billions of dollars.

It is, said Commissioner Brownell, "our shared obligation" to ensure a reliable, efficient, environmentally friendly energy system for the future.

Ken Wolf gave the conference a primer on the relationships between the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Council (NERC), the Midwest Independent System Operator (MISO) and the Mid-Continent Area Power Pool (MAPP). Following Mr. Wolf's presentation, Paul Barber gave a detailed primer on transmission system design and operation, and a moment-by-moment account of the blackout itself. Mr. Barber is a NERC consultant, and is the steering committee facilitator for the Joint U.S./Canada blackout investigation.[50]

Jim Torgerson is the President and Chief Executive Officer of MISO, and addressed the conference as to the ISO's efforts to enhance reliability in the region following the blackout. The electric system, Mr. Torgerson told the attendees, is not being used in the manner that it was developed. "We're seeing flows that were not contemplated, and management of the system is much more complicated. Mr. Torgerson stressed that MISO is the reliability coordinator for the Midwest region, but is not a control area operator. As such, MISO has no ability to actually balance load and generation, but instead monitors the regional grid, and gives direction to the control area operators. Thus, enhanced modeling and monitoring systems, as well as enhanced communications systems, are vital to improving MISO's ability to ensure reliability in the region. In addition to these, MISO is also increasing the number of security coordinators and operations engineers on its staff, and increasing the overall certification levels of its staff beyond those required by NERC standards.[51] MISO has also been moving toward assuming more operational control over the grid through the development and implementation of a new market tariff, but many concerns arose from MISO members about that tariff. As a result, MISO withdrew that tariff filing from FERC, and is working with its members on refining that initiative.[52]

Conference attendees then heard from Minnesota transmission planners and operators, in a panel presentation entitled "Blackout: Can it Happen Here?" Claire Moeller, the director of Xcel Energy's Control Center Operations talked in detail about the near-miss in 1998, when a series of

[50] To view the presentations given at the Symposium go to www.state.mn.us/mn/externalDocs/Commerce/Blackout_Symposium_111303040523_Blackout.ppt
[51] The current status of MISO's reliability responses to the blackout can be reviewed at www.midwestiso.org/initiatives/reliability/index.shtml.
[52] MISO subsequently refiled the energy market tariff on March 31, 2004. In its Order on May 26, 2004, FERC moved the market start date for the Midwest ISO from December 1, 2004 to March 1, 2005. A summary of the Order can be reviewed at http://www.ferc.gov/press-room/pr-current/05-26-04.asp.

lightning strikes nearly brought down the electric grid for the Midwest and parts of Canada. As a result of quick action on the part of Canadian system operators, Mr. Moeller said, this event "was a footnote, rather than a headline."

Donald Kom, executive director of the Central Minnesota Municipal Power Agency, talked about a number of frustrations with the current electric system in the region. Transmission costs for one of the cities his utility serves have more than doubled in the past few years, but transmission service to that city may in fact be worse. His utility purchases "firm" transmission service from the grid, but that service is curtailed more often than not. The transmission models that MISO uses to plan for transactions across the system show significant impacts region-wide for even very small transactions. Kom pointed out that while the electric system is complex, the solutions to these problems are not all that complicated, telling the audience that "You have to put poles in the ground, and wires in the air."

William Kaul, vice president of transmission for Great River Energy, then addressed the significant policy changes that the industry has faced, since Congress passed the Energy Policy Act of 1992. In that legislation, Congress tackled the energy utility industry, "the last great monopoly." These regulatory upheavals have lead to the disintegration of old institutions, and the emergence of new ones.

William Head, chief operating officer of MAPPCOR (which provides professional, technical and administrative services to MAPP) cautioned that increased transmission infrastructure and better operational practices does not necessarily mean that a blackout will not happen here. He also raised a concern that the industry may be faced with a shortage of transmission engineers over the coming years.

Following that panel, Audrey Zibelman, chief executive office of TRANSLink Development Company, talked about a number of concerns regarding the transmission system, and how an entity like TRANSLink could address some of those concerns. Ms. Zibelman reiterated a point that Commissioner Brownell made earlier in the day, that utilities are not investing in transmission infrastructure. While energy sales have increased by $67 billion a year since 1975, transmission investments have decreased by $103 billion a year over that time. Ms. Zibelman also emphasized another of Commissioner Brownell's points, that the grid is regional in nature, and that policies and institutions to manage that grid have to have a regional focus. TRANSLink, as an independent transmission company approved by FERC, was designed to provide the following services to regional utilities:

- coordinated system planning
- grid investment
- consolidated system operations
- tariff administration and

Ms. Zibelman argued that having TRANSLink taking over these functions from MISO, MISO could then focus on market development and administration, regional planning oversight, and regional reliability oversight. However, she also cautioned that the future of TRANSLink is not clear, but should be made clear in the coming weeks.[53]

Tom Ferguson, vice president for power delivery and transmission for Minnesota Power, was the final speaker of the day. Mr. Ferguson spoke to the conference about Minnesota's transmission planning process. Under the new state transmission planning process, each transmission owning utility in the state is required to identify and address inadequacies in the utility's transmission system, solicit public input from the public and local governments on those inadequacies, and file a plan with the Minnesota Public Utilities Commission by November 1 of each odd numbered year. The most recent plan[54] (filed on November 3, 2003) was submitted jointly by the Minnesota utilities subject to the planning requirement.

[53] On November 23, 2003 TRANSLink disbanded, citing market uncertainty to be a primary factor.
[54] A copy of this plan can be viewed or downloaded at http://www.minnelectrans.com/.

Appendix 5

ENERGY INFORMATION RESOURCES

The following Web sites contain documents or additional information about some of the subjects and programs referenced in this report:

Minnesota Department of Commerce -- http://www.commerce.state.mn.us/:

- Energy Conservation and Renewable Energy Consumer Information – click on Energy Info Center
- Energy Policy Reports – click on Businesses We Regulate > Energy Utilities > Energy Utilities > Energy Policy.
- B3 Information – click on Consumer Info and Services > Buildings and Builders > B3 project guidelines.
- Low Income Energy Assistance and Weatherization Program Information – click on Heating Assistance.
- Energy Data Reports – click on Businesses We Regulate > Energy Utilities > Energy Utilities > Energy Data & Statistics

Joint Minnesota utilities transmission plan filing – http://www.minnelectrans.com/

Ventura Administration follow-up Energy Planning Report – http://www.me3.org/

Minnesota Public Utility Commission – http://www.puc.state.mn.us

Minnesota State Legislature: Statutes, Session Laws, and Rules – http://www.leg.state.mn.us/leg/statutes/asp/

DOE Energy Efficiency and Renewable Energy Web site – http://www.eere.energy.gov/

DOE Energy Information Administration – http://www.eia.doe.gov/

Clean Energy Resource Team Web site – http://www.cleanenergyresourceteams.org/

American Council for and Energy Efficient Economy – http://www.aceee.org/

ENERGY STAR Web site – http://www.energystar.gov/

Appendix 6

STATE REVIEW OF PROPOSED LARGE ENERGY FACILITIES
Prepared by Staff of the Environmental Quality Board

I. Introduction

Any person proposing to construct a new large energy facility such as a power plant or a transmission line or a pipeline may be required to obtain a certificate of need from the Public Utilities Commission confirming the need for the new facility and a permit from the Environmental Quality Board identifying the site for a new power plant or a route for a new transmission line or pipeline.

Public Utilities Commission. A certificate of need for new large energy facilities has been required since 1974. Initially, the authority to issue certificates of need was vested in the Minnesota Department of Energy. In 1982, the Department of Energy was abolished and the authority to issue certificates of need was transferred to the Public Utilities Commission. Minn. Stat. § 216B.243. In the past several years the PUC has issued certificates of need for several gas-fired peaking and intermediate plants, several high voltage transmission lines, including four new lines in southwestern Minnesota designed to transport wind power off Buffalo Ridge, a large wind facility, and several pipelines.

Environmental Quality Board. The Minnesota Environmental Quality Board has had the authority since 1973, when the Power Plant Siting Act was passed, Minn. Stat. §§ 116C.51 to 116C.69, to site large electric power generating plants and to route high voltage transmission lines. The EQB has been permitting large wind energy conversion systems since 1995. Minn. Stat. §§ 116C.691 to 116C.697. The EQB has been routing intrastate natural gas and petroleum pipelines since 1987. Minn. Stat. § 116I.015.

In the past 30 years the EQB has issued permits for ten large power plants, fourteen high voltage transmission lines, ten large wind projects, and nineteen intrastate pipelines. See the EQB's webpage for a list of projects that have been permitted:
http://www.eqb.state.mn.us/EnergyFacilities/index.html

II. Minnesota Public Utilities Commission – Certificate of Need

A. Large Energy Facility. A certificate of need from the Public Utilities Commission is required for a "large energy facility." Minn. Stat. § 216B.243, subd. 2. A "large energy facility" is defined in Minn. Stat. § 216B.2421, subd. 2, to include the following:

(1) Any electric power generating plant of 50 megawatts or more
(2) Any high voltage transmission line with a capacity of 200 kilovolts or more
(3) Any high voltage transmission line with a capacity of 100 kilovolts or more with more than ten miles of its length in Minnesota or that crosses the state line.

(4) Any pipeline used to transport coal crude petroleum or petroleum fuels or oil greater than six inches in diameter and having more than 50 miles of its length in Minnesota.
(5) Any pipeline for transporting natural or synthetic gas at a pressure in excess of 200 pounds per square inch with more than 50 miles of its length in Minnesota.
(6) Any facility capable of storing 100,000 gallons of liquefied natural gas.
(7) Certain underground gas storage facilities.
(8) Nuclear fuel processing or waste storage facilities.
(9) Any facility capable of processing more than 75 tons of combustible fuels per hour.

B. Rules. Minn. Stat. § 216B.243 contains requirements for obtaining a certificate of need, and the PUC has promulgated rules describing the procedures to follow and establishing standards for issuance of certificates of need. Minn. Rules Chapter 7853 and 7849 (power plants and transmission lines) and chapter 7851 (pipelines). Other PUC rules applicable to certificate of need applications can be found in Minn. Rules chapter 7829 and 7855.

C. Application. The PUC rules establish what information must be included in an application for a certificate of need. For example, Minn. Rules parts7849.0200 and 7851.0220. The application must be accompanied by the payment of a fee to cover the costs of processing the application. The PUC will determine whether the application is complete. An applicant may request in advance of filing the application that it not be required to submit certain information that is not pertinent to the proposed project. A person proposing to construct a new large energy facility must apply for a certificate of need before applying for a permit from the Environmental Quality Board. Minn. Stat. § 216B.243, subd. 4.

D. Environmental Review. Under rules promulgated by the Environmental Quality Board in February 2003, preparation of an Environmental Report is required as part of the certificate of need process. Minn. Rules parts 4410.7010 – 4410.7070. The EQB is the responsible governmental unit with the obligation to prepare the document. The public is afforded an opportunity to participate in the development of the scope of the Environmental Report. Minn. Rules part 4410.7030. The EQB has four months from the time a complete application is submitted to complete the Environmental Report.

E. Public Hearing. The Public Utilities Commission is required to hold a public hearing on an application for a certificate of need. Minn. Stat. § 216B.243, subd. 4. The objective of the public hearing is to obtain public opinion on the necessity of granting the certificate of need. Usually, an administrative law judge from the Office of Administrative Hearings presides at the hearing and writes a report and makes a recommendation on whether to issue the certificate of need.

F. Final Decision. Minn. Stat. § 216B.243, subd. 3 and Minn. Rules part 7849.0120 establish the standards to be applied in determining whether a certificate of need should be issued. Generally, the standard is that the applicant has established that there is a need for additional electricity and that the demand cannot be met through energy conservation and load management measures or other more prudent and feasible alternative to the proposed project. Once the PUC has determined

that there is a need for the proposed facility, questions of need, including size, type, and timing, and alternative system configurations and voltage for a proposed high voltage transmission line are final and will not be reviewed by the Environmental Quality Board. Minn. Stat. § 116C.53, subd. 2.

The PUC has six months from the time the application is submitted (or supplemented if the PUC determines the original application is incomplete) to make a final decision on the application. Minn. Stat. § 216B.243, subd. 5.

G. Alternatives to Certificate of Need. Although a decision on the need for a proposed large energy facility is required, there are other ways besides the issuance of a certificate of need in a special proceeding by which the PUC can determine that there is a need for the new facility. One way is through the certification of the need for a new high voltage transmission line in the transmission planning process that was established in 2001. Minn. Stat. § 216B.2425. Utilities are required to submit a transmission plan to the PUC in November of each odd numbered year. A utility may seek certification of the need for new lines through this process. Another way is through the resource planning process. Minn. Stat. § 216B.2422, subd. 6. Also, a certificate of need is not required for an electric power generating plant that is selected through a bidding process approved by the Commission. Minn. Stat. § 216B.2422, subd. 5.

III. Minnesota Environmental Quality Board –Site or Route Permit

A. Large Energy Facility. The Power Plant Siting Act, which establishes the authority of the Environmental Quality Board, does not use the term "large energy facility" but instead refers to "large electric power generating plants" and "high voltage transmission lines." A "large electric power generating plant" is defined as electric power generating equipment designed for or capable of operating at a capacity of 50 megawatts or more. Minn. Stat. § 116C.52, subd. 5.

A "high voltage transmission line" is defined as a conductor of electric energy designed for and capable of operation at a nominal voltage of 100 kilovolts or more. Minn. Stat. § 116C.52, subd. 4.

A "large wind energy conversion system" is a combination of wind turbines with a wind capacity of five megawatts or more. Minn. Stat. § 116C.691, subd. 2.

A pipeline falling within the jurisdiction of the EQB is an intrastate pipeline that is designed to be operated at a pressure of more than 275 pounds per square inch if it carries natural gas and more than six inches in nominal diameter designed to transport hazardous liquids such as petroleum. Minn. Stat. § 116I.015, subd. 5.

Thus, any person proposing to construct a power plant of 50 megawatts or more, regardless of fuel type, even wind power, is required to obtain a certificate of need from the Public Utilities Commission and a permit from the Environmental Quality Board. Any person proposing to construct a transmission line of 200 kilovolts or more is required to obtain a certificate of need and a permit from the Environmental Quality Board. A person proposing to construct a transmission line of between 100 and 200 kV is required to obtain a permit from the EQB but is not required to

obtain a certificate of need from the PUC unless the line is more than ten miles in length or crosses the state border. Similarly, with pipelines, a certificate of need may be required only if the pipeline has more than 50 miles in Minnesota, but a permit from the EQB may be required regardless of length.

B. Rules. The Environmental Quality Board has promulgated rules that apply to applications for site permits and route permits. For power plants and high voltage transmission lines, the rules are found in Minn. Rules chapter 4400. The wind rules are in chapter 4401. And the pipeline rules are in chapter 4415.

For power plants and transmission lines, the Power Plant Siting Act actually establishes two different processes for considering an application for a permit. One process is referred to as the Full Process, and the other is called the Alternative Review Process. There are separate rules for each process. The Full Process is described in Minn. Rules parts 4400.1025 – 4400.1900 and the Alternative Review Process is described in parts 4400.2000 – 4400.2950. The size of the project determines which process applies. The smaller, less environmentally invasive projects, like power plants under 80 megawatts or burning natural gas and transmission lines under 200 kilovolts, are subject to the Alternative Review Process. The statute establishes what projects qualify for the alternative review. Minn. Stat. § 116C.575.

Some of the smallest projects are eligible for review by local units of government with jurisdiction over the project rather than review by the Environmental Quality Board. Minn. Stat. § 116C.576. The EQB has established the procedure that must be followed by local units of government in considering a permit for such projects. Minn. Rules part 4400.5000.

C. Application. Minn. Rules part 4400.1150 establishes the requirements for what information must be included in an application for a permit for a power plant or transmission line, regardless of the size or type of the project. An applicant for a permit for a project undergoing full review must identify both a preferred site or route and an alternative site or route. An applicant for a permit for a project eligible for alternative review is not required to propose an alternative site or route but must identify any sites or routes that were rejected and explain why. In addition, the application must be accompanied by the payment of a fee. Minn. Rules part 4400.1050. The EQB Chair will determine within ten days of submission of the application whether the application is complete. The applicant is required to notify the public that an application has been submitted and that the project has been proposed for construction.

The requirements for submitting an application for a wind project or a pipeline project are found in Minn. Rules chapters 4401 and 4415, respectively.

D. Environmental Review. Depending on the size and type of the project and whether the Full Process or the Alternative Review Process applies, the EQB prepares either an Environmental Impact Statement or an Environmental Assessment on the project. Minn. Rules parts 4400.1700 and 4400.2750. The primary difference is that an EIS requires both a draft and a final, whereas an Environmental Assessment does not undergo revision. The public can participate in the development of the scope of the environmental document at a public meeting and through submission of written comments. Id.

No separate environmental review document is prepared for proposed wind projects. Instead, the EQB Chair prepares a draft permit and provides the public with an opportunity to comment on the document at a public meeting. Minn. Rules parts 4401.0500 and 440.0550. With pipeline projects also, no discreet environmental review document is required, although the EQB holds a public meeting in each country where the pipeline will be constructed. Minn. Rules part 4415.0700.

E. Public Hearing. The EQB is required to hold a public hearing as part of the process for a permit for a power plant or transmission line. Minn. Stat. §§ 116C.57, subd. 2d, and 116C.575, subd. 6. For the larger projects, the public hearing is a contested case hearing presided over by an administrative law judge. For the smaller projects, the EQB has discretion regarding how formal a hearing to schedule. Minn. Rules part 4400.2850. In either event, the public has full opportunity to participate. With wind projects and pipeline projects, no public hearing is mandatory but the EQB could decide to hold a public hearing.

F. Final Decision. The final decision on a permit application is made by the full Environmental Quality Board. The Board takes into account a number of considerations in deciding what site to approve for a new power plant or what route to designate for a new transmission line, including the potential human and environmental impacts of the proposed project. Minn. Stat. § 116C.57, subd. 4. The Board may also impose appropriate conditions in the permit.

For wind projects, the Board determines whether the project is compatible with environmental preservation, sustainable development, and the efficient use of resources. Minn. Rules part 4401.0600, subp. 3.

The EQB has one year from the time the permit application was accepted to reach a final decision on a project undergoing review under the Full Process. Minn. Stat. § 116C.57, subd. 7. The EQB has six months to make a decision on the smaller projects under the Alternative Review Process. Minn. Stat. § 116C.575, subd. 7. For wind projects, the statutory deadline is180 days, Minn. Stat. § 116C.694, and for pipelines, the time is nine months. Minn. Stat. § 116I.015, subd. 3(5).

III. Joint Proceedings.

A. Joint Environmental Review. The EQB rules recognize that environmental review of a proposed project can be combined to address in one document the issues necessary for the PUC to make a decision on the need and size and type of the project and the issues necessary for the EQB to designate a specific site or route for the project. Minn. Rules part 4410.7060. The matter cannot be combined, of course, unless the project proposer has identified a proposed site or route for the project at the time the certificate of need is applied for and has submitted a permit application to the EQB with the site specific data necessary for the EQB to begin its review.

B. Joint Hearing. In some instances both the Public Utilities Commission and the Environmental Quality Board could decide to hold a joint hearing. The statute allows for the two agencies to hold a joint hearing if doing so is feasible, more efficient, and may further the public interest. Minn. Stat. § 216B.243, subd. 4. The EQB rules recognize that a joint hearing may be held. Minn. Rules

parts 4400.1800, subp. 3 and 4410.7060, subp. 4. Both agencies have determined that a joint hearing on the Mankato Energy Center project, a 640 megawatt natural gas fired power plant in the Mankato, Minnesota, area is appropriate, and that hearing is scheduled for July 12, 2004.

Appendix 7

PUBLIC UTILITIES COMMISSION RATE PLAN
Pursuant to Minn. Stat. 216C.18, subd. 1a

The Public Utilities Commission's section will be included once it is received by the Department.

Appendix 8

MINNESOTA STATUTES 2003, 216C.18

216C.18 State energy policy and conservation report.

Subdivision 1. **Report on trends and issues.** By July 1 of 1988 and every four years thereafter, the commissioner shall issue a comprehensive report designed to identify major emerging trends and issues in energy supply, consumption, conservation, and costs. The report shall include the following:

(1) projections of the level and composition of statewide energy consumption under current government policies and an evaluation of the ability of existing and anticipated facilities to supply the necessary energy for that consumption;

(2) projections of how the level and the composition of energy consumption would be affected by new programs or new policies;

(3) projections of energy costs to consumers, businesses, and government;

(4) identification and discussion of key social, economic, and environmental issues in energy;

(5) explanations of the department's current energy programs and studies; and

(6) recommendations.

Subd. 1a. **Rate plan.** The energy policy and conservation report shall include a section prepared by the Public Utilities Commission. The commission's section shall be prepared in consultation with the commissioner and shall include, but not be limited to, all of the following:

(1) a description and analysis of the commission's rate design policy as it pertains to the goals stated in sections 216B.164, 216B.241, and 216C.05, including a description of all energy conservation improvements ordered by the commission; and

(2) recommendations to the governor and the legislature for administrative and legislative actions to accomplish the purposes of sections 216B.164, 216B.241, and 216C.05.

Subd. 2. **Draft report; public meeting.** Prior to the preparation of a final report, the commissioner shall issue a draft report to the Environmental Quality Board and any person, upon request, and shall hold a public meeting. Notice of the public meeting shall be provided to each regional development commission.

Subd. 3. **Final report, distribution.** The commissioner shall distribute the final report to any person upon request.

HIST: 1974 c 307 s 11; 1975 c 271 s 6; Ex1979 c 2 s 19; 1981 c 356 s 138,248; 1982 c 561 s 3; 1982 c 563 s 8; 1983 c 179 s 2; 1983 c 231 s 3; 1983 c 289 s 115 subd 1; 1984 c 654 art 2 s 100; 1987 c 186 s 15; 1987 c 312 art 1 s 10 subd 1