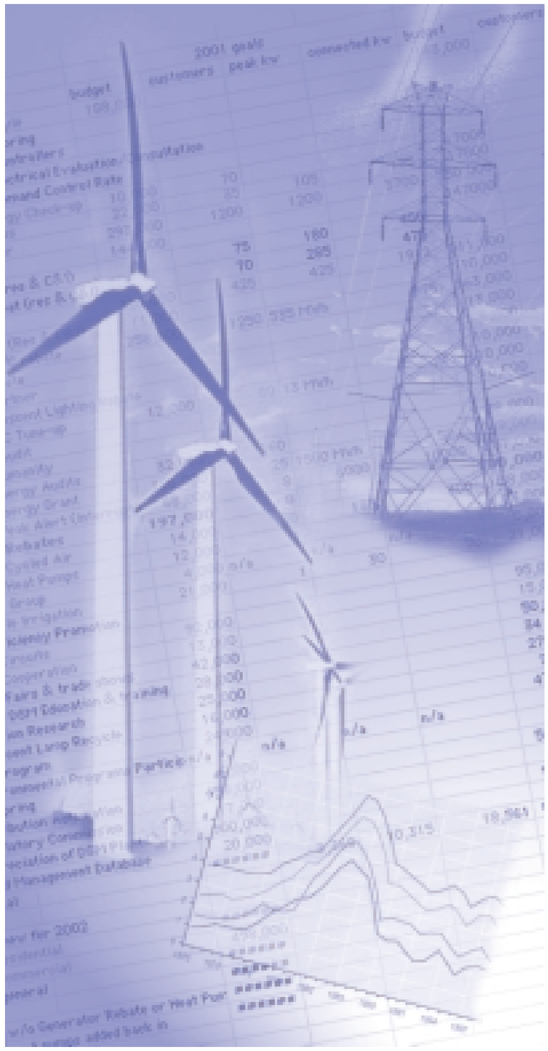
Minnesota Energy Planning Report 2001



Minnesota Department of Commerce

2001 ENERGY PLANNING REPORT

EXECUTIVE SUMMARY

2001 Minn. Laws, Chapter 212 is the first comprehensive energy legislation in Minnesota in several decades. It addresses many energy issues. It also requires us, the Department of Commerce, to prepare this report on energy planning.

This report provides:

- a comprehensive explanation of the energy system;
- trends in energy demand, supply, and prices;
- challenges in ensuring adequate, reliable, environmentally sound, and affordable energy services;
- technology options and other approaches such as energy conservation that can be tapped to meet those challenges; and
- a summary of the new legislation and its potential for assisting in meeting the challenges ahead.

Included in this report (most of Chapter 4) is a separate report, also required by the new legislation, that evaluates the Conservation Improvement Program and its potential to help address the challenges ahead. Also included is an excellent glossary of energy terms (Appendix E), which is strongly recommended reading for those who know a lot, as well as those who know a little, about energy.

We made many of the following recommendations in "Keeping the Lights On" in 2000, although most of the recommendations in that report were adopted as part of the 2001 legislation. Some arise out of the additional information and analysis in this report. In the December, 2002 update to this report, we will refine these recommendations, as well as articulate more specific goals and strategies to meet the goals.

Recommendations

1. Continue accurate and aggressive monitoring of energy supplies and prices by the Department of Commerce (DOC)and others;
2. All potential parties in electric transmission approval proceedings should work diligently to make the new transmission planning oversight process at the Minnesota Public Utilities Commission (PUC) effective.
3. Electric transmission project proposers must:
   (a) increase flexibility in their transmission planning; and
   (b) work early and intensively with affected local landowners and local governments and not wait to get public input until initiation of the state and federal agency approval processes.
4. State agencies should work diligently to ensure that approval processes for power plants and transmission lines are completed in a timely manner with ample opportunity for effective public participation.
5. The overall air pollution emissions level from the power production sector will need to be reduced.
6. Utilities who own electric generating plants should take advantage of their new statutory ability to pass through to ratepayers cost effective voluntary emissions reductions at their plants.
7. In addition to other emission reduction efforts, utilities should include in their integrated resource plans identification of potential emission reduction projects and the PUC should approve projects it finds cost effective.
8. Different criteria need to be developed for determining the need for power plants proposed by nonutilities and for transmission lines primarily to serve bulk transfer arrangements.
9. Net metering for small electric generation facilities owned and operated by industries, businesses, homeowners, and others should be increased from under 40kW to up through 2MW.

10. Advance the date from 2012 to at least 2007 for installation of the additional 400 MW of wind energy Xcel Energy must build or purchase under PUC order.
11. Focus on energy conservation as a means to help meet future electric supply needs and moderate demand growth.
12. Create one or more private energy conservation utilities whose sole purpose would be to implement effective energy savings programs and projects.
13. Expand the sales tax exemption for energy efficient equipment to all Energy Star appliances and efficient natural gas equipment and appliances.

Summary of Findings

Energy planning in Minnesota is mostly adequate, but requires careful monitoring to ensure that it does, in fact, result in adequate, reliable, environmentally sound, and affordable energy for Minnesotans for the long term.

The most pressing challenges in the energy system, which includes electricity, natural gas, petroleum, and petroleum products, lie in electricity. While there are similar challenges in the other sectors relating to supply, transportation, and price, the state has regulatory authority over those issues only in the electricity sector. The Department of Commerce (DOC) does monitor supply, transportation, and prices for all petroleum products. DOC also monitors and the Public Utilities Commission (PUC) ensures that natural gas distribution companies do not pay more than is reasonable and prudent for the natural gas they provide to Minnesotans. Unlike electric capacity, transmission, and prices, however, the state has no authority to oversee the pricing of natural gas as a commodity.

Electric utilities in Minnesota, on the other hand, are vertically integrated monopolies with exclusive service territories. For the most part, they own and operate the generation, transmission, and distribution infrastructure that provides power to homes and businesses. The investor owned electric utilities (referred to as "public utilities" in statutes) are regulated by the PUC as to the services they provide and the rates they may charge to their customers. Cooperative electric associations are managed by their members who are also their customers (except Dakota Electric Association, which has elected to be regulated by the PUC like the public utilities). Municipal utilities are managed by their city councils or other governmental agencies, which are responsible to voters who are also the customers. Cooperative electric associations and municipal utilities are not regulated by the PUC, except on complaint about services or disciminatory prices, but do report certain types of information to the PUC and DOC.

Chapter 1 provides background information about petroleum and petroleum products, natural gas, and electricity. It provides information on supply and price trends over a thirty year period, with some predictions for the future. It also explains the role of government in overseeing or regulating (or not regulating) the various energy sectors. Appendices B and C discuss the history of utility regulation and how rate regulation works in Minnesota respectively.

Challenges

Chapter 2 explores the challenges we face in Minnesota related to the electric system.

Sufficient electric capacity is the first major challenge. At present, Minnesota statutes require the major electric utilities, including the generation and transmission entities that serve cooperative electric associations and municipal utilities, to file with the Public Utilities Commission biennial integrated resource plans. These plans, viewed together, as well as other energy information specific to Minnesota, indicate that Minnesota needs over 2000 megawatts (MW) of additional electric capacity by 2010, but also that existing planning processes are probably sufficient to ensure that we will have enough electricity to power our homes and businesses for the next ten to 15 years. The exact sources of the additional electricity, however, remain uncertain. This uncertainty is both a challenge and an opportunity to take advantage of new, more efficient technologies that recently have become commercially viable, are on the verge of commercial viability, or will be developed to commercial viability over time.

The second and perhaps most critical challenge in electricity is the future viability of the transmission system. We need to closely focus on meeting this challenge in order to ensure continued viability and vitality of energy services for the future.

The third major challenge is reducing pollution from electric generation. Meeting this challenge will require exploring potential emission reduction strategies, pricing them, and choosing those that will provide the largest reductions for the least cost. In addition, we need to take advantage of future emissions reduction technologies or strategies, particularly for mercury and greenhouse gas emissions, as they become available. At the same time we should ensure that any new electric capacity does not increase overall pollution from the power production sector.

The fourth challenge is in affordability of energy services, including electricity, natural gas, propane, fuel oil, and similar energy sources, for Minnesota energy consumers.

All of these challenges are intertwined. This report explores three of the major challenges noted above:

- electric capacity;
- electric transmission; and
- air pollution emissions from existing and future power plants.

A separate report, which will be available in January, 2002, addresses challenges in maintaining affordability of energy services for all Minnesotans.

Electric Capacity

During the next nine years we need to add more than 2000 MW of electric capacity to serve Minnesota consumers. About 1000 MW of that amount is in planning or approval processes now. There has been a major shift in capacity planning. *It appears that capacity will be added in smaller increments as it is needed, rather than by last century's model of huge central power plants with excess capacity into which we grew over time.* This new model will be created as we go.

To get additional capacity into the system, we recommend a conservative approach at this time. First, maximize energy conservation and energy efficiency, as well as load management programs, because they cost the least and impose the fewest infrastructure, logistic, and environmental burdens. Then, develop to the greatest extent Minnesota's own energy resources, such as wind energy with backup to create firm capacity (which is commercially viable now), solar energy, and bioenergy.

Any additional capacity needed once we have maximized conservation, efficiency, and renewable resources should be built using the most environmentally sound, least cost, and most efficient technologies available now and into the future. The energy facilities we build today will be those that provide electricity for many decades. We should not saddle future generations with the kind of difficult challenges we face in the energy system today, particularly the difficulties in transmission siting and routing, pollution abatement, and service affordability.

Energy generation is the subject of more technology research and development today than it has been since at least the 1970s and perhaps as far back as the 1920s and 1930s. We should not limit our future ability to take advantage of new and improved technologies. *We should not rely too heavily on the technologies of the last century, thereby foreclosing our ability to deploy better technologies as they become available.* To the extent that we do build additional facilities using old technology, we should ensure that those facilities use the best, least polluting, least cost, and most efficient processes for generating electricity of which they are capable.

Electric Transmission

The transmission system in Minnesota, the upper midwest, and the nation is aging, operating at or near capacity much of the time, and is being increasingly required to move electricity in ways it was not designed and built to accommodate.

We must both upgrade existing transmission lines and build new ones to accommodate our growing electric demand and federal requirements for open access to the system. Any electric generation technology, if built in large increments, requires new transmission lines. This includes the large wind energy installations in southwestern Minnesota, which have added to the pre-existing need for substantial new transmission capacity in that area of our region.

Article 7 of the new energy legislation amends the Power Plant Siting Act to align need determinations and routing decisions for transmission lines. These changes clarify and streamline state approval processes. In addition, the legislature created a new comprehensive transmission planning process at the PUC. This new process should result in enhancing the public's and state government's abilities to put proposals for new or upgraded lines in the context of the broader regional system and system operational needs, as well as ensuring that specific proposals adequately address local demand growth.

Environmental Emissions

The legislature required us, in consultation with the Minnesota Pollution Control Agency, to address in this report the environmental issues associated with the energy system. Appendix A was prepared primarily by MPCA staff and explores the contribution of electric generation to air pollution problems in the state and their potential effects on health and the environment. In addition, Appendix A provides an initial analysis of the costs of some emission reduction measures. Finally, Department of Commerce staff determined how much these measures would cost typical residential electric ratepayers on an annual basis.

Air pollution emissions from power plants in Minnesota should be reduced, including any additional emissions from new electric generators. Initial analysis shows that significant reductions at existing power plants could be accomplished in a cost effective manner. Utilities should take advantage of new legislation that allows them to implement voluntary, cost effective emission reduction projects and seek permission from the PUC to pass the costs directly on to ratepayers without the necessity of a rate case. In addition, new power plants should achieve the lowest emission rates reasonably feasible, given the range of technologies available.

Most large electric generators in Minnesota use coal as a fuel. Minnesotans get over 75 percent of their electricity from coal fired power plants, not all of them located in the state. Electric generation facilities that are located in the state contribute more than half the sulfur dioxide, nearly a fifth of the nitrogen oxides, about a third of the mercury, and a quarter of the greenhouse gas emitted in the state annually. These pollutants can result in negative effects on human health, crops, forests, and wildlife. Emissions from power plants of sulfur dioxide, nitrogen oxides, and greenhouse gas have steadily increased since the mid 1980s. We have not built any large new coal fired power plants since 1983.

Nearly all of Minnesota's existing coal fired power plants were built prior to air pollution control requirements or were built to meet old New Source Performance Standards (NSPS) under the federal Clean Air Act. As compared even with new coal plants, these plants emit 10 to 20 times the air pollutants as the new plants.

All indications are that federal air pollution standards will become more stringent. For the purposes of energy planning, utilities and other power plant proposers, as well as state approval agencies, need to be alert to the potential that a technology chosen today to generate electricity may become subject to stricter emission standards in the future. Most electric generation facilities are planned to operate for many decades in order to recoup the huge capital investment required. Today's choices about electric plant fuels and design should consider future emission reductions that may be needed to protect human health and the environment, in order to protect ratepayers from needing to pay later for required retrofits. We also should seek to diversify our power production to include more different technologies.

Meeting the Challenges

Electric Technologies and Techniques

Chapter 3 explores the technologies available to generate electricity. The most likely technologies to be used for new electric generation in Minnesota, according to utilities' integrated resource plans, cost considerations, environmental considerations, and logistics are natural gas and wind (with natural gas or other backup).

It also examines the concept of distributed energy resources (DER). DER is not a technology but a set of technologies that lend themselves to smaller electric generators located near where the power is consumed. They reduce stress on the electric generation, transmission, and distribution system and can help avoid huge investment in that system. They also can provide cleaner, higher quality, and more reliable electricity for a consumer or group of consumers. Finally, in an era of heightened security concerns, DER provides greater security than large, central power plants and long distance transmission lines.

Energy Efficiency and Conservation

Another element of DER is energy conservation, which is discussed in detail in Chapter 4. Conservation and efficient use are the best, most readily available, cheapest, and least polluting methods of increasing electric supply by moderating growing demand. The existing Conservation Improvement Program (CIP) along with PUC orders in resource plan proceedings will result in reducing the electric capacity deficit by about 320 to 430 MW. The remainder of the expected 980 to 1,100 MW that will be saved between now and 2010 is already included in the utilities' forecasts of future demand. It is critical to at least maintain the performance of the existing Conservation Improvement Program.

With two changes in the CIP statutes, we could save an additional approximately 130 to 280 MW. The two potential changes are reducing the amount of CIP dollars that may be spent on load management projects that do not actually save energy or even increase overall demand and increasing required spending levels for all electric utilities to the level to which Xcel Energy is subject, 2 percent of gross operating revenues. In total, we could avoid having to add up to 700 MW of new electric supply with a combination of maintaining the existing CIP spending levels and energy savings requirements and making minor changes to increase our focus on energy savings in CIP.

These potential savings from energy conservation will cost, at most, about half of just the construction costs of equivalent new electric generation. As compared with some technologies, conservation per unit costs less than one-quarter of just the construction costs of a generation facility. When the costs to transmit the electricity, pay for the fuel, and operate and maintain generators and transmission systems are included, the costs of conservation are a small fraction of the costs to provide an equivalent amount of new electric supply.

2001 Energy Legislation – Great Leaps Forward

Chapter 5 notes the statutory changes made in the 2001 legislative session, in a cooperative effort between the Administration, the Legislature, and many stakeholders. The changes made in 2001 Minn. Laws, Chapter 212 have great potential for assisting state agencies, utilities, consumers, and others to meet the energy challenges of the future.

This new legislation:

- Requires sustainable building guidelines for new state buildings;
- Requires an energy conservation plan for all public buildings in the state;
- Authorizes joint ventures between utilities to provide utility service;
- Requires the Public Utilities Commission (PUC) to adopt uniform interconnection standards for small distributed energy generation facilities and encourages distributed energy resources;
- Requires the Legislative Energy Task Force to study bioenergy and other renewable energy options in rural areas;
- Attempts to simplify the cold weather disconnection rule;

- Requires utilities to offer budget billing plans and payment agreements to customers in arrears, and prohibits shutoff to households that have medically necessary equipment;
- Requires the Department of Commerce to study affordability of energy services and make recommendations on how to achieve and maintain universal service;
- Expands the renewable energy incentive payment to include a couple small hydropower facilities that need substantial reconstruction and adjusts application of the incentive to develop wind energy to ensure that small producers are the only ones who qualify for it;
- Requires the PUC, municipal utilities and cooperative electric associations to develop service standards;
- Substantially adjusts the regulatory processes for routing transmission lines and siting electric generation plants to clarify the roles of the PUC and the Environmental Quality board (EQB); to speed the processes; and to ensure that both the need for a facility and the environmental effects of a facility are thoroughly addressed in the appropriate forum;
- Establishes for the first time a comprehensive statewide electric transmission planning process;
- Authorizes utilities to directly pass through to ratepayers the costs of transmission upgrades to serve renewable energy generation required by law;
- Requires utilities to develop renewable and high efficiency energy rates (green pricing);
- Makes significant amendments to the Conservation Improvement Program (CIP) to require more focus on projects that result in actual energy savings and higher spending levels for conservation by municipal utilities and cooperative electric associations, and to encourage utilities to use proven cost effective programs statewide; and
- Requires the Department of Commerce to evaluate CIP for effectiveness and make recommendations for any further changes.

In addition to Chapter 212, the Legislature also enacted emissions reduction rider authority for utilities. *2001 Minn. Laws, 1Sp Ch 5, Art. 3, § 12 authorizes the PUC to allow a utility that owns a power plant and voluntarily reduces environmental emissions from the plant to pass through the costs of doing so to its ratepayers without going through a rate case.*

Preparing This Report

For a very short three months, beginning in mid July, 2001 we amassed information, analyzed it, and prepared the first draft. Through late October into November, we held five public meetings to present the draft and gather public comment around the state in Marshall, Fergus Falls, Rochester, St. Paul, and Grand Rapids. In addition we presented the draft report to the Public Utilities Commission, the Environmental Quality Board, the Pollution Control Agency Board, and various public and private groups, again travelling to several Minnesota cities. We consulted with PUC staff, PCA staff, Department of Health staff, and EQB staff. In November, we participated in Minnesota Planning's first Issue Forum on the internet, which focused on energy issues and was an additional avenue for the public to submit comments on the draft report and on energy issues in general.

We received more than 350 pages of written public comment on the draft energy planning report and a large number of comments on the draft Conservation Improvement Program report, the final of which is included here as part of Chapter 4. We reproduced all of the comments, most in reduced format, in Appendices F and G as a separate publication, which is available in hard copy.

Acknowledgements

This final report reflects the work of many staff in three state agencies, as well as the comments of many other state agencies, energy service providers, nongovernmental organizations, businesses, and individuals.

We are very grateful for all the hard work of our own staff at the Department of Commerce. Nearly every person in the Energy Division contributed. They consistently produce high quality work while carrying heavy workloads.

Similarly, we appreciate the excellent contributions of PCA staff and EQB staff who helped write large segments of the report. Thanks also to the busy folks at the PUC and the Health Department for their review and comments on the draft report. Finally, thanks to all who attended presentations, gave oral comments, or submitted written comments. Your contributions were excellent.

A special thanks to:

- Ann Seha, our former Energy Policy Director, now Deputy Commissioner at the Minnesota Pollution Control Agency, who did the lion's share of collecting the information and preparing the first draft;
- Judy Lewandowski, Sandra Maki, Jeanette Dilworth, Rochelle Barnhart, and Karen Stradal who prepared the report for publication;
- Marya White, Manager of Energy Planning and Advocacy, who reorganized the draft report and coordinated incorporation of internal and external comments on the draft report;
- Christopher Davis, Senior Utility Rates Analyst, who shouldered the evaluation of the Conservation Improvement Program and the presentation of the findings from that evaluation; and
- Bob Cupit, Energy Planning Director, who helped write, arranged meetings, critiqued presentations, and did a lot of leg work.

Linda Taylor, Deputy Commissioner for Energy, reviewed and edited the first and final drafts, presented the draft report to the public and to other state agencies, commissions, and boards, and prepared this executive summary.

January 2002

2001 ENERGY PLANNING REPORT

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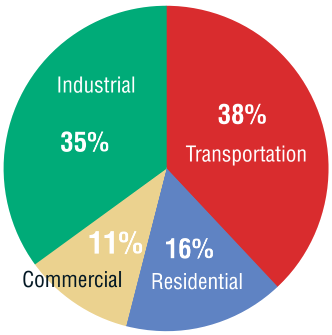
ONE: MINNESOTA ENERGY TODAY

Energy is basic to most activities in our daily lives. We need energy to heat our homes in the winter, cool our homes in the summer, cook our meals, mow our lawns, heat our water, refrigerate and freeze our food, and wash and dry our clothes. When our housework is done, we need energy to provide light to read by, to power our televisions, stereos and computers, and to use our boats and other recreational vehicles. On the farm, energy powers the machines that till, plant and harvest our fields. In commerce, energy powers virtually all aspects of work, from the lighting and computers in our offices to the motors that run industrial and manufacturing processes, such as mining iron and processing ore into taconite, or harvesting wood and processing it into paper products. And when we move about, energy lights our highways and powers our vehicles and airplanes.

In 1999, Minnesotans consumed nearly 1,300 trillion British thermal units (Btus) of energy in the form of electricity, natural gas, and petroleum products.[1] Figure 1-1 shows the relative amounts of energy used by the commercial, residential, industrial and transportation sectors.

Figure 1.1: Energy End Use in Minnesota, 1999

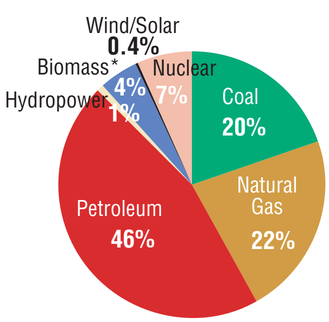
Source: REIS and EIA



In 1999, Minnesotans spent approximately $9.7 billion to purchase the energy we used. Figure 1-2 shows the types of fuel inputs used to produce this energy.[2] An extensive physical infrastructure consisting of piplelines, trucks, barges, trains, and electric transmission lines transports large amounts of energy (oil, coal, natural gas, electricity) into the state and/or around the state for further refining or production and for distribution to consumers.

Figure 1.2: Inputs Used to Produce Energy Consumed in Minnesota, 1998

Sources: REIS and EIA



*includes wood and refuse-derived fuel

This chapter is divided into three sections that focus on petroleum, natural gas, and electricity. Each section discusses trends in the use and cost of each source of energy, describes the infrastructure used to produce and deliver the energy to consumers and explains the regulatory structure for each energy source.

Petroleum

Minnesota has no native source of petroleum. Beginning in the 1990s, the United States began using more oil from foreign than domestic sources. Most petroleum products enter and leave Minnesota by pipeline. Some petroleum products also are transported by barge, rail, ship, or truck. All but a small portion of Canadian crude oil and liquid petroleum gasses (LPG) that are imported into the United States pass through Minnesota to other parts of the Midwest, eastern Canada, and New England.

The refineries that produce most of the petroleum products consumed by Minnesotans are:

- Flint Hills Resources, LP (formerly Koch Refining Company), Twin Cities;
- Marathon Ashland Petroleum Company, Twin Cities;
- Murphy Oil Refinery, Superior, Wisconsin;
- BP-Amoco Refinery, Mandan, North Dakota; and
- Tesaro Refinery, Whiting, Indiana.

Use and Cost of Petroleum in Minnesota

Minnesotans consumed 5,127 million gallons of petroleum products in 1999. Petroleum products include coal, asphalt, and road oil, aviation gasoline, distillate fuel, jet fuel, kerosene, liquid petroleum gases, lubricants, motor gasoline, and residual fuel oil. In 1999, Minnesotans used about 72 percent of all petroleum products for air, land, and water transportation. Transportation fuels include gasoline, diesel fuel and jet fuel. Most agricultural use of petroleum falls under the transportation category. Approximately 21 percent of Minnesotans use either fuel oil or propane for primary heating, which is about 6 percent of total petroleum products consumed in 1999.

Figure 1-3 illustrates that petroleum consumption, after declines in the late 1970s, is about 25 percent higher overall today than it was 30 years ago. For transportation use, the increase was about 75 percent. Figure 1-4 illustrates that gasoline consumption is increasing at a rate significantly

Figure 1.3: Petroleum Products Consumption in Minnesota by Customer Class, 1970–1999 (millions of gallons annually)

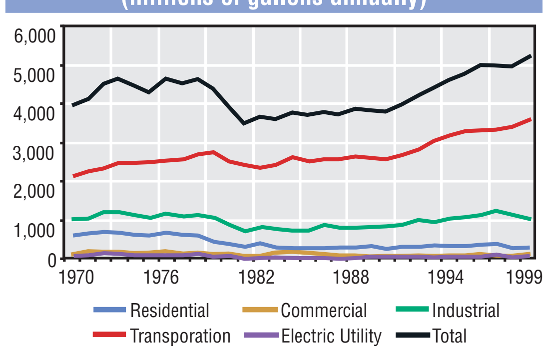


Figure 1.4: Minnesota Population and Gasoline Consumption Trends

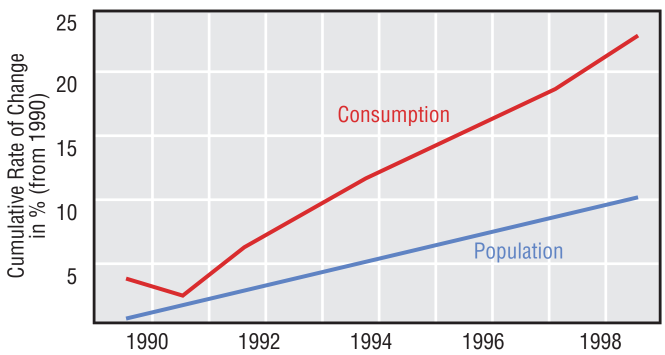


Figure 1.5: Annual Real Expenditures on Petroleum Products in Minnesota by Customer Class, 1970–1999

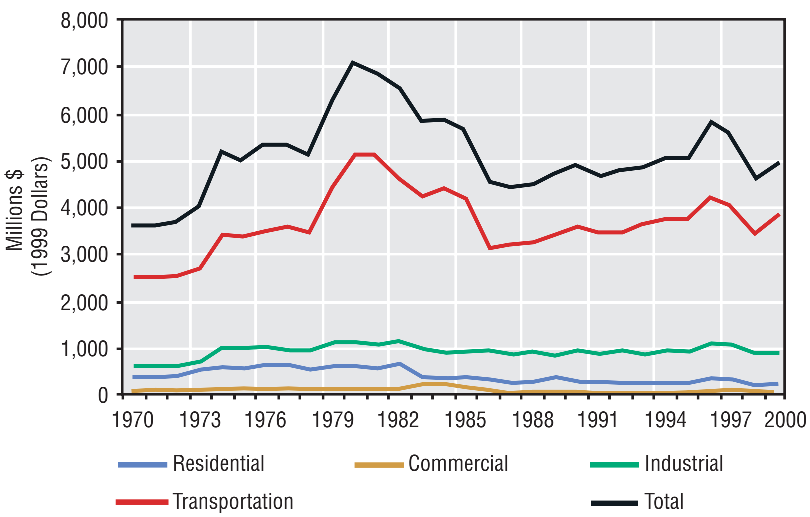
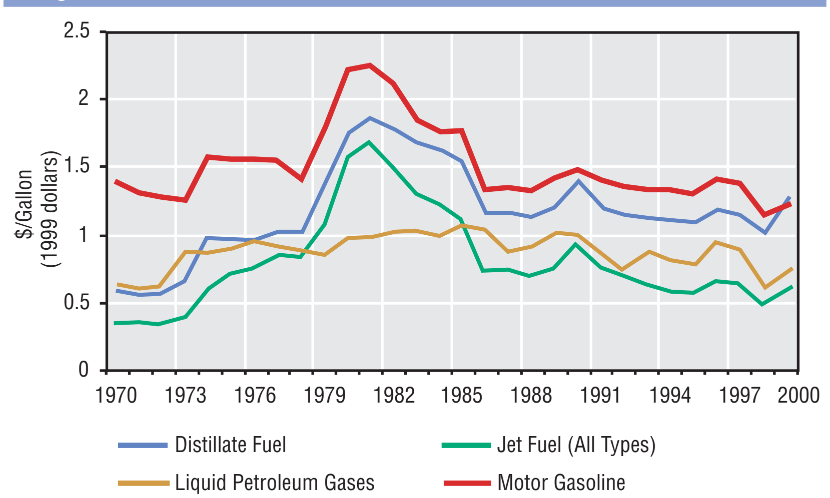


Figure 1.6: Real Prices for Petroleum Products in Minnesota, 1970–1999



greater than population growth in the state. This trend accelerated steadily during the 1990s.

In 1999, Minnesotans spent nearly $5 billion on petroleum products. Figure 1-5 shows that the relative stability of petroleum expenditures from 1985 through about 1995 may have ended. In the last couple of years, petroleum prices and therefore overall expenditures have become increasingly volatile, based on factors that influence supply and demand and the operation of private markets. Overall, Minnesotans spend about 25 percent more in real dollars today than 30 years ago for petroleum products (about 50 percent more overall for transportation fuels).

Figure 1-6 shows retail prices, in real dollars, for petroleum products in Minnesota over the past 30 years. Motor gasoline costs less in real dollars than it did 30 years ago. Liquid petroleum products and jet fuel cost about the same, while the price of distillate fuels has increased by more than 100 percent.

Regulatory Structure

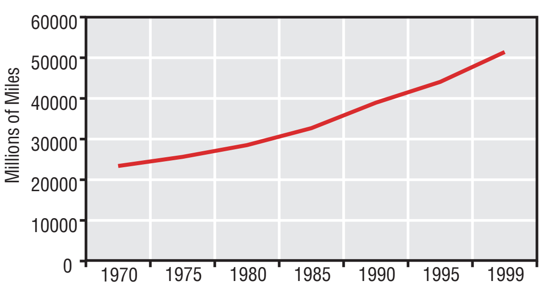
Unlike natural gas and electricity, which are regulated, petroleum products are not considered monopoly (single provider) services and, thus, are not directly regulated. Rather, prices of petroleum products are determined by the cost of crude oil, transportation costs, taxes, and earnings for companies, all of which are impacted by international political and economic market forces.

Supply influences the retail price of finished petroleum products at any given point in time. Higher-than-expected demand for a particular petroleum product or sharply decreased production can create temporary shortages that lead to higher prices. For example, a very cold winter increases the use of propane and fuel oil for home heating. There is a trend toward less storage and more just-in-time production of petroleum products. Stored petroleum products have historically been used to moderate short-term price fluctuations in the market.

Environmental Impacts of the Use of Petroleum

The environmental impact of petroleum products is directly related to the fuel efficiency and control technologies in use on motor vehicles and other equipment, combined with frequency of use of the vehicles and equipment. Most of the increasing use of petroleum products is for transportation. Figure 1-7 shows the large increase in vehicle miles traveled in the state since 1970. In addition to the increasing number of miles traveled, the average fuel efficiency of motor vehicles in Minnesota is decreasing.

Figure 1.7: Vehicle Miles Traveled in Minnesota, 1970–1999



The federal government regulates fuel efficiency of and tailpipe emissions from vehicles. States have some authority in regulating fuel formulations to reduce emissions from vehicles.

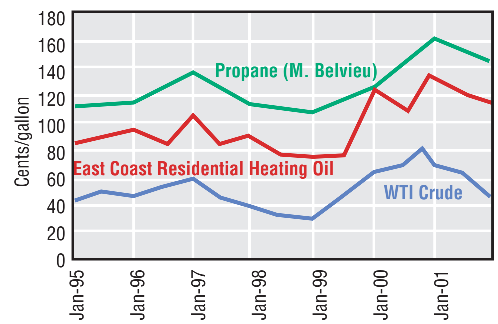
Figure 1-8 shows the relative contributions of on-road, off-road, fuel combustion, and industrial sectors to statewide emissions of nitrogen oxides, volatile organic compounds, and carbon monoxide. Motor vehicles account for the majority of emissions of these air pollutants. Motor vehicle fuels also account for the majority of emissions of several key toxic air pollutants.[3]

This report will not further discuss the use, cost, and environmental effects of petroleum products in the state, except to briefly discuss future prices and supplies of propane and fuel oil below. The petroleum industry, and the price of petroleum, is not regulated by the state. However, the Department of Commerce monitors petroleum supplies and prices and, through the Weights and Measures Division, ensures that the contents of the products are what they purport to be and that measuring devices are accurate. Addressing pollution issues related to motor vehicles is outside the scope of this report.

2000-2001 and 2001-2002 Heating Seasons: Fuel Oil and Propane

This section summarizes the forecast for fuel oil and propane prices for the 2001-2002 heating season from the U.S. Department of Energy's (DOE) Energy Information Administration (EIA).[4] Fuel oil is produced by refineries from crude oil, and propane is produced both by processing natural gas and by refining crude oil. Therefore, the prices of both fuel oil and propane correlate very closely with the price of crude oil. Figure 1-9 illustrates this relationship for both fuels.

Figure 1.9: Relationship of Fuel Oil and Propane Prices to Crude Oil Price, 1995–2001



Storage for both fuels during the summer and fall of 2000 was below normal levels due to the increased price of crude oil. With high demand caused by extremely cold November and December weather, already low inventories were drawn down, and the ability of storage to moderate price volatility was decreased. As a result, prices for both of these fuels increased for consumers during the last heating season.

The current forecast is that crude oil is expected to stay at a price range of between $20 to $30 a barrel through early 2002. This price average, however, does not prevent short-term swings in the price of this commodity. Global inventories of crude oil are lower than normal and likely will serve less to moderate any price volatility that appears. OPEC has reduced production by 3.5 million barrels per day so far this year. This reduction is predicted to leave crude oil inventories at the low end of the normal range, potentially creating a tight crude oil market this winter.

Figure 1.8: Sources of Nitrogen Oxides, Volatile Organic Compounds and Carbon Monoxide, 1999

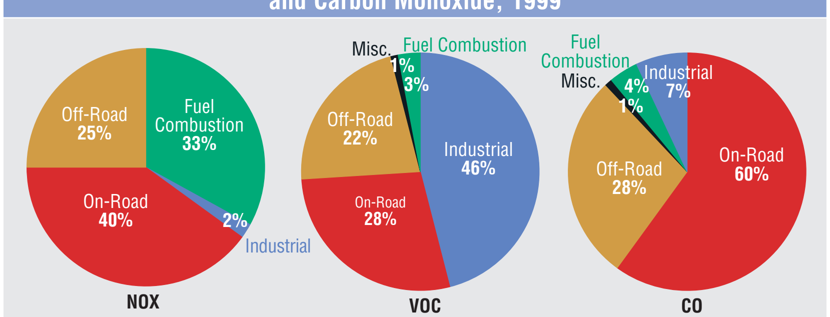


Figure 1.10: U.S. Distillate Fuel Oil Demand

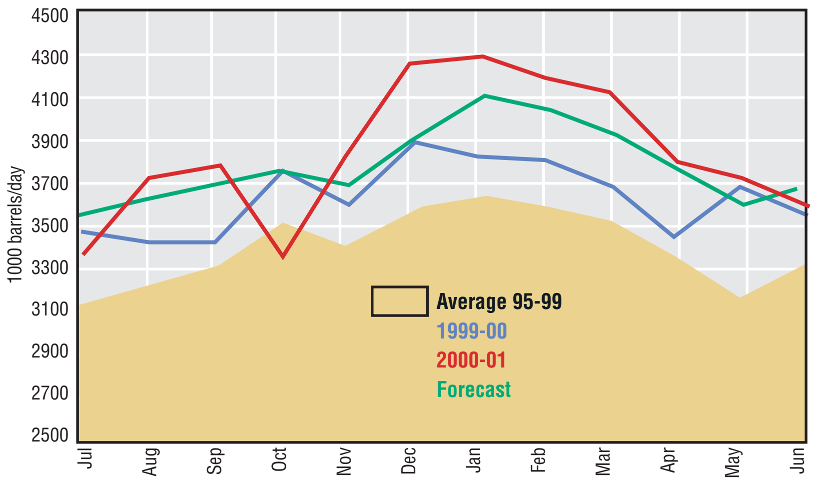


Figure 1.11: U.S. Propane Production

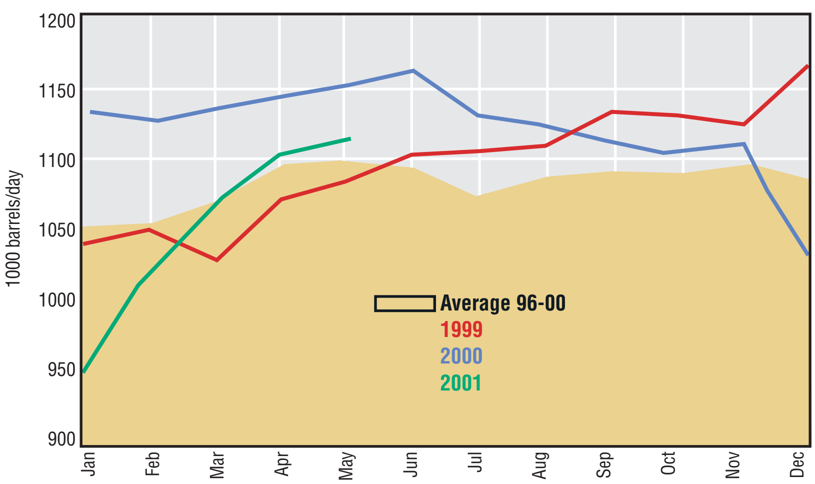
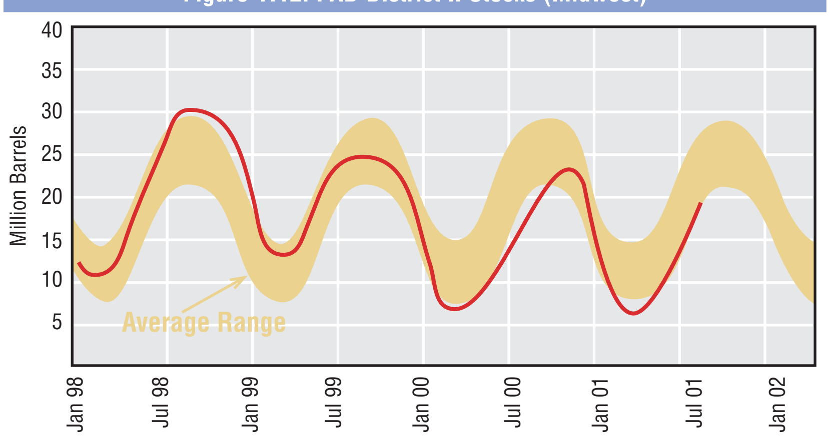


Figure 1.12: PAD District II Stocks (Midwest)



Due to heavy demand for heating oils in the early part of last winter (the winter of 2000-2001), with an unusually cold November and December, demand for fuel oil rose sharply in November and December and was higher than any demand level since 1995. The higher demand drove price increases, which spurred production of fuel oil in January. Most of the increased production was due to a dramatic increase in imports. These imports came primarily from Europe, particularly Russia. Figure 1-10 illustrates relative demand levels between the average of the years 1995 to 1999 and the fuel oil demand levels of last two winters, as well as the demand forecast for 2001-2002.

As we head into the 2001-2002 heating season, national storage levels for fuel oil are slightly above average at 11 million barrels. The five-year average has been 10 million barrels, which is lower than the average of the last 10 years (15.5 million barrels). As a result, EIA predicts that prices will be a little lower than the prices for fuel oil were last winter.

U.S. propane production fell sharply in the winter of 2001. However, as Figure 1-11 shows, U.S. propane production rebounded quickly in the early months of 2001. While 2001 production levels are below 2000 levels, they exceed production levels at similar times of the year in 1999 as well as the average production levels of the years 1996 to 2000.

Propane demand is seasonal, with a winter peak 50 percent higher than summer peak. Production of propane and imports of propane, however, do not vary much throughout the year. As a result, inventories that are built up in advance of the winter help balance the market price of propane. Nationally, inventories of propane in the fall of 2001 are in the average range, but are 41 percent higher than last year.

In the midwest, however, current inventories are lower than average, as illustrated by Figure 1-12. The midwest is one of the highest consuming regions for propane in the country. In the gulf coast region, however, storage is substantially above normal, and, barring a pipeline problem, there is time to get these propane stocks to the midwest before the winter heating season.

The EIA forecasts that residential propane prices will be lower than those last winter, although any unforeseen changes in the price of crude oil and natural gas would affect propane, as well as any problems that emerge with bottlenecks in a pipeline system that is already operating near capacity.

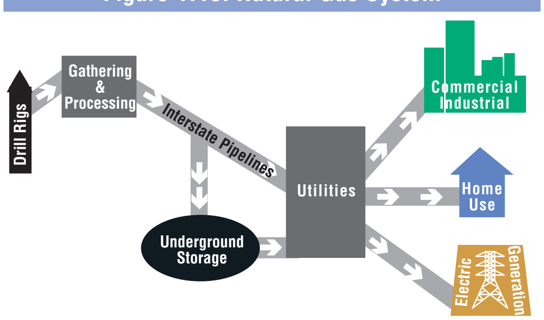
Natural Gas

Sixty-three percent of Minnesota consumers have access to natural gas in their homes. Natural gas utility service is provided by three types of local distribution companies (LDCs): six rate-regulated investor-owned utilities, 18 municipal utilities, and seven private gas companies.[5] The investor-owned utilities serve 95 percent of Minnesota's natural gas customers.

Minnesota has no native source of natural gas. Minnesota utilities obtain natural gas predominantly from natural gas fields in Kansas, Oklahoma, Texas and Alberta, Canada. Natural gas is delivered to the state through interstate pipelines. LDCs distribute the gas to end-use customers. The Northern Natural Gas pipeline transports 80 to 90 percent of the natural gas used in Minnesota. This gas comes from gas fields in the south central United States as well as Alberta, Canada. The Viking and Great Lakes transmission lines bring approximately 7 percent and 3 percent of the natural gas to Minnesota, respectively, from Alberta, Canada.

Natural gas LDCs purchase gas from producers, contract with interstate pipelines to transport the gas to Minnesota, and construct and operate the distribution system that provides natural gas to the end-use customer. Figure 1-13 is a simplified diagram of the natural gas delivery system.

Figure 1.13: Natural Gas System

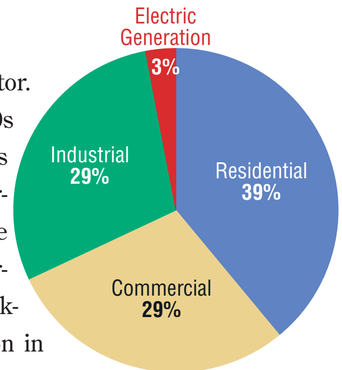


Use and Cost of Natural Gas in Minnesota

Minnesotans consumed a total of 332 billion cubic feet (Bcf) of natural gas in 2000. Figure 1-14 shows the current consumption by residential, commercial, industrial, and electric generation use in the state. Figure 1-15 shows the trends in natural gas consumption by sector and in total in Minnesota over 30 years. This graph shows relatively steady gas usage in the residential and commercial sectors and a moderately increasing usage trend in the industrial sector. After a substantial overall drop during the 1970s and 1980s, usage is back to the early 1970s level. The use of natural gas for electric generation was curtailed during the decade of the 1970s, but it is now being used more often, particularly in other states. Two natural gas peaking electric generation plants began operation in the state in 2001. These plants are not reflected in Figure 1-15.

Figure 1.14: Natural Gas Consumption by Customer Class, 2000

Source: REIS



Because natural gas is so widely used for space heating, usage depends on the relative warmth or coldness of our winters. Figure 1-16 shows weather-normalized natural gas consumption for residential customers in Minnesota.[6] There was a steep decline in use of natural gas between 1970 and 1985, when natural gas prices were high and energy conservation efforts were maximized, and a slower decline between 1985 and 1999.

In 1999, Minnesotans spent approximately $1.37 billion on natural gas. Figure 1-17 shows the trend in real expenditures for natural gas in Minnesota by customer class over the last 30 years in 1999 dollars. Figure 1-18 demonstrates that natural gas prices over the last 30 years, in real dollars, grew by about 25 percent overall.

Figure 1.15: Natural Gas Consumption in Minnesota by Customer Class, 1970–2000

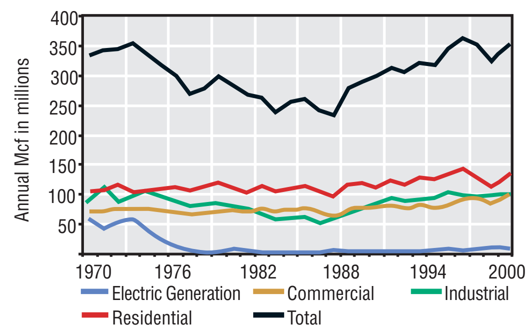


Figure 1.16: Weather Normalized Natural Gas Consumption per Residential Customer, 1970–2000

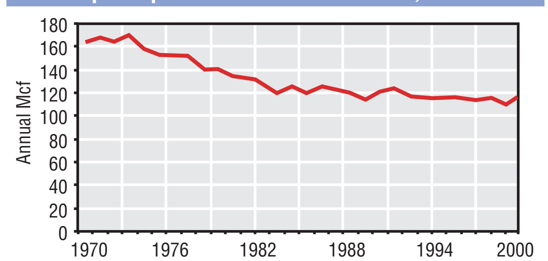


Figure 1.17: Annual Real Expenditures on Natural Gas In Minnesota by Customer Class, 1790–1999

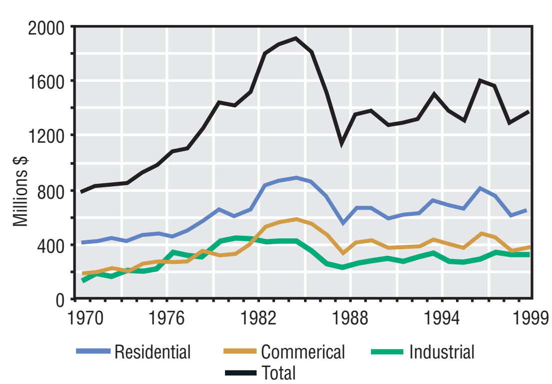


Figure 1.18: Real Prices for Natural Gas in Minnesota by Customer Class, 1970–1999

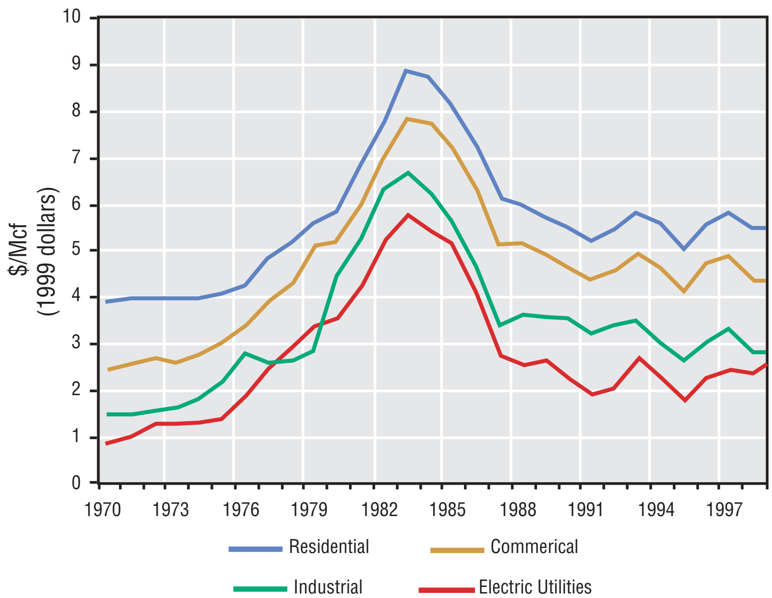


Figure 1.19: Minnesota Natural Gas Prices Relative to Prices in Other States, 1999 ($/ 1000 ft3)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	$5.56	$4.44	$2.98
Minnesota rank	39	42	41
Average U.S. price	$6.69	$5.33	$3.10
Highest price	$18.97	$14.33	$8.21
Lowest Price	$3.64	$2.18	$1.25

Source: EIA

Figure 1-19 shows that Minnesota retail natural gas prices are well below average U.S. prices and are closer to the bottom than the top of the range. Minnesota continued to experience lower than U.S. average natural gas prices even during the record breaking high prices of the 2000-2001 heating season, as discussed below. One reason for this situation is Minnesota's strategic location between the Canadian and the southern U.S. natural gas production areas, which allows Minnesota's gas utilities to competitively purchase gas from both production areas. Interstate pipelines bring natural gas to the state from both areas.

Regulatory Structure

Individual states regulate natural gas retail utilities, which are commonly referred to as local distribution companies (LDCs). LDCs purchase natural gas from unregulated gas producers on an open competitive market and then pay to transport the gas through an open grid-system of federally regulated interstate pipelines to the ultimate retail customer.

In Minnesota, LDCs are rate-regulated by the Minnesota Public Utilities Commission (PUC). The PUC approves the rate an LDC may charge for distributing natural gas received from the interstate pipeline to end-use customers, operation and maintenance costs of the distribution systems, and customer service functions. The bulk of the retail price of natural gas service, however, is the price of the natural gas itself, which is regulated only by the competitive market.[7] LDCs purchase natural gas under a variety of short term and long term contracts. In addition they operate or rent space in storage facilities. Storage helps moderate fluctuations in market prices.[8]

Minnesota Statutes and the PUC allow the amount that LDCs pay to purchase and transport natural gas to be passed directly through to consumers as a purchased gas adjustment on their monthly bills. The PUC may disallow that portion of the commodity costs that it finds inappropriate.

Natural gas utilities were not always regulated as they are today. Prior to the 1970s, gas utilities were vertically integrated monopolies. They owned production fields or rights, pipelines, and local distribution facilities. The commodity price of natural gas was regulated by the federal government through price caps, instead of by the competitive market.

This system was in place until the 1970s, when the United States experienced shortages of natural gas. Price caps on natural gas encouraged suppliers to exploit only the natural gas fields that could produce a profit at the capped price. As a result, natural gas supplies decreased just when the national demand for natural gas increased due to heavy industrial use, use for electric generation, and lack of conservation measures. Natural gas service to some customers and areas had to be curtailed to meet overall existing demand at the time.

Congress passed the Natural Gas Policy Act of 1978 to address these problems. The law promoted conservation and restricted the use of natural gas in new construction, industrial processes, and electric generation. Some applications, like outdoor gas lamps, were banned. At the same time, the law tried to increase the supply of natural gas by removing the price caps, thus deregulating production (the commodity price). This law began the drastic process of deregulating natural gas prices and breaking up vertical monopolies. A series of major orders by the Federal Energy Regulatory Commission, notably FERC Orders Nos. 436, 500 and 636, put into place this restructured gas market. The production of natural gas now is completely deregulated as to price. Pipeline owners must provide nondiscriminatory open access transportation service to LDC and large industrial purchasers. LDC services continue to be regulated (as to price and quality of service) by the state, but LDCs now purchase both natural gas supply and transportation services on the open market.

The results of the Natural Gas Policy Act were dramatic. Initially, gas prices soared at the beginning of the 1980s, largely because gas supplies were still tight. The high prices spurred new production. The higher prices of natural gas, as well as possible shortages, also spurred conservation efforts. These efforts, along with substantial deindustrialization throughout the nation, caused demand to decrease steeply between 1973 and 1988. When new production came on line, prices fell and then stabilized after 1983. This combination of factors created a surplus of available natural gas that has been referred to as the "gas bubble."

Throughout the late 1980s and the 1990s, the gas bubble kept prices fairly low and predictable. With natural gas prices lower in the summer due to less demand, natural gas utilities could purchase natural gas for storage at lower summer prices and then use that stored gas in the winter to protect against price fluctuations during the higher demand winter months. Demand grew throughout this period, but was moderated by conservation and energy efficiency measures. After the long dip in demand, it has just again reached the level it was at in the early 1970s. One of the true success stories in energy conservation is the steady decline in average gas usage by individual households over the past 30 years.

During the 1990s, natural gas became a preferred fuel for industrial customers and for new electric generating plants. Its low price, significantly lower emissions of air pollutants, and relatively low capital and operation and maintenance costs compare very favorably to coal plants. At the same time, the greater demand for use of natural gas to generate electricity in the summer meant that prices did not decrease quite as much as they had in the past. Summer storage of natural gas became more expensive for LDCs. The "gas bubble" that had kept prices low had gradually dissipated by the end of the 1990s, and the long-term relatively low price of natural gas had not encouraged significant new production of natural gas.

2000-2001 Heating Season

A combination of all of the factors noted above set the stage for the natural gas price spike that Minnesota and the U.S. experienced in the 2000-2001 heating season. In the spring and summer months of 2000, prices were higher than they had been in recent years. The strong economy continued to push growth. Increased demand kept pushing prices higher. A hot summer in the southwestern United States sharply increased demand for air conditioning. For the most part, natural gas fired electric generators met this peak demand, which resulted in an additional large increase in gas usage nationwide. This boosted the price even higher during the summer and discouraged LDCs from placing as much gas in storage as they normally had done, creating a fairly large storage deficit in the fall of 2000.

A "normal" weather season was predicted for the 2000-2001 winter. Instead, the northern tier states across the country experienced the coldest November and December in more than a century. The cold weather created high demand early in the heating season. This, in turn, forced LDCs to draw on already scant natural gas storage reserves sooner than normal. As a result, less stored gas was available to counteract price volatility later in the heating season. December 2000 storage withdrawals were the highest in the seven prior years. For the remainder of the winter, the price protection offered by the storage cushion was, for all practical purposes, lost.

In January 2001 the commodity price[9] per thousand cubic feet (Mcf) of gas was over $10, compared with a commodity price of $2.34 in January of 2000. Consumers were faced with natural gas prices they had not experienced in more than 15 years. Unlike the 1970s, however, gas supply was tight but not short. Gas service was not curtailed, except for customers who chose to pay lower rates in exchange for the ability of the LDC to potentially interrupt their service in times of tight supply. Gas prices fell quickly and began

Figure 1.20: Commodity Weighted Average Cost of Gas for Minnesota Utilities, July 1999–July 2001

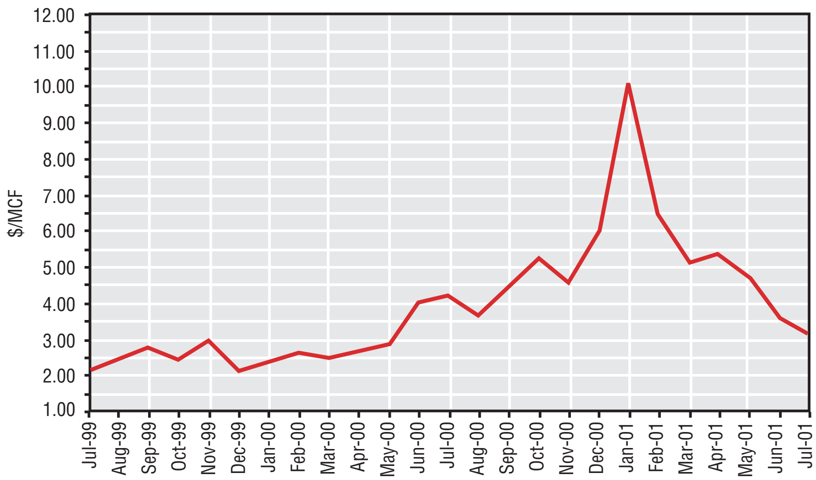


Figure 1.21: NYMEX Henry Hub Expiration Prices

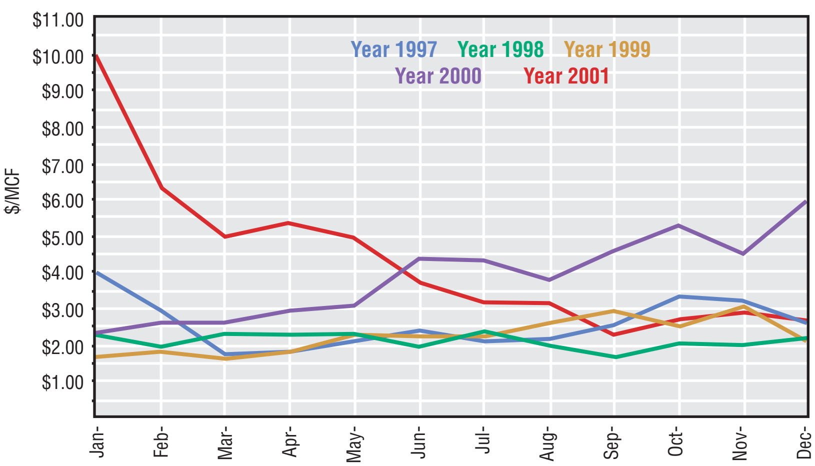
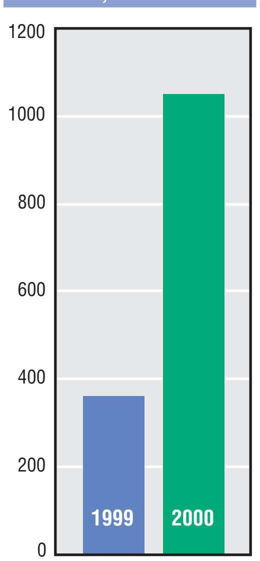


Figure 1.22: Natural Gas Drilling Rig Counts, 1999–2000



to stabilize by late spring of 2001 at a range of $3.50 to $4.00 per Mcf. Since then, commodity prices steadily fell to a low of $1.75 for October of 2001. For December of 2001, the average commodity price for Minnesota customers is $2.63.

The 2000-2001 heating season showed the sort of price volatility that can occur when there is a combination of increased overall demand, as well as increased usage due to a significantly colder than normal winter, combined with low storage and production (supply) levels. Figure 1-20 shows the commodity weighted average cost of natural gas paid by Minnesota's LDCs from July 1999 to July 2001.

One of the continuing problems caused by the high heating prices of the 2000-2001 natural gas heating season is the amount of arrearages owed to LDCs by customers. Even with more than twice the funding, compared with recent years, energy assistance programs were unable to meet the energy needs of low income consumers. A combination of high arrearages from the past and the likelihood of more volatile prices in the future will place extreme stress on energy assistance programs, and on the households they are intended to help. In January 2002, the Department of Commerce will publish an Energy Universal Service Report, required by the legislature, that will discuss options for coordinating the fragmented and inadequate pieces of Minnesota's energy affordability programs.

The Current 2001-2002 Heating Season

Minnesotans heat their homes with natural gas (63%), propane (11%), fuel oil (10%), electricity (11%), and wood (5%). Of these fuels, prices for natural gas, propane, and fuel oil have become increasingly volatile. This section discusses expectations for the 2001-2002 heating season and beyond, to the extent that any predictions can reasonably be made at this time.

As discussed above, the retail natural gas prices that consumers will pay in the 2001-2002 heating season likely will be substantially lower than last heating season.

Energy fuels the economy. In addition to the downward price pressure from the factors noted above, the economy has taken a downturn. An economic downturn further reduces the demand for energy.

The commodity price of natural gas fell from the extreme high of about $10.00 per Mcf (thousand cubic feet) in January, 2001 faster and further than expected. Commodity prices were $3.00 to $4.00 through the spring and summer and had dropped to under $2.00 by October. The closing price for November 2001 was about $3.25. By comparison, commodity prices for November and December of 2000 were over $5.22 and $4.52, respectively. Figure 1-21 tracks the monthly natural gas prices for the past five years.

During the week of November 5, 2001, U. S. DOE's Energy Information Administration (EIA) announced that natural gas producers have increased their gas reserves by 6 percent overall. This increase is historically a large jump in announced reserves. It is enough to provide 152 percent of all the gas consumed in 2000. This increase in supply, mostly in Texas, Oklahoma, Kansas, Colorado and nearby states, is larger and came more quickly than expected. The high prices last winter spurred additional exploration for new supply (see Figure 1-22). These new supplies were not expected to be widely available for a few years. Since the announcement is so recent as of this writing, it is unclear how substantial its effect will be on lowering commodity prices, but it may have a significant lowering effect.

Demand for natural gas also has been lower over the summer and fall (through November) of 2001. The summer across the south and southwestern U. S. was cooler than in 2000. There was, therefore, less demand for electricity for air conditioning in states like Texas and California, which rely substantially on natural gas for electric generation to meet peak demand in the summer. In addition, consumers in California, responding to blackouts and brownouts in the fall and winter of 2000-2001, conserved about 10 percent of the electricity they otherwise would have consumed during the spring and summer of 2001. This drop in demand from states whose demand makes up a large portion of national demand has helped keep supplies available and prices down.

The amount of natural gas in storage is higher than it was in the fall of 2000. In fact, storage levels are 7.5 percent higher than they have been, on average, for the past six years. After having short supplies in storage last year, companies have taken advantage of the lower prices over the summer and fall of 2001 to place more gas in storage. Assuming that the prices paid for the commodity in storage were lower than the prices will be as we move through the winter, this stored gas should place downward pressure on prices. The downward pressure may be less than in past years, because the prices paid may not be much lower than present prices, given that prices continued to fall in the late summer and early fall after much of the storage was filled.

Overall, most of the indications – larger supplies, lower demand, more moderate forecasted weather – should result in lower natural gas prices during the 2001-2002 heating season.

Electricity

This section presents information on the current use and cost of electricity in the state, as well as information on historical use and cost trends. It then describes the system currently in place to serve the electric demands of Minnesota homes and businesses. The section ends with a brief overview of the current electric regulatory structure and a background summary of the history of electric rate regulation.

Electricity Use and Cost in Minnesota

Minnesota homes and businesses consumed a total of 62,532,500 megawatt hours (MWh) of electricity in 2000. Figure 1-23 shows the distribution of this electric consumption between commercial, residential and industrial customers. Many factors influence consumption, including weather, price, population levels and economic growth. Figure 1-24 illustrates that residential and commercial electric consumption have steadily grown over the past 30 years. Industrial consumption has grown at a greater rate during the same time period. Overall, use of electricity has nearly tripled in 30 years. Residential use has nearly doubled. Despite some successful conservation efforts, consumers are using more electric appliances and electronic equipment. In addition, the economic boom of the 1990s drove electric consumption upward. Energy fuels the economy.

Figure 1.23: Minnesota Electric Consumption, 2000

Source: REIS and EIA

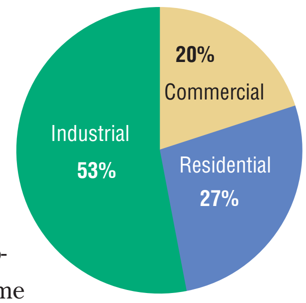


Figure 1.24: Minnesota Electioc Consumption, 1970–2000

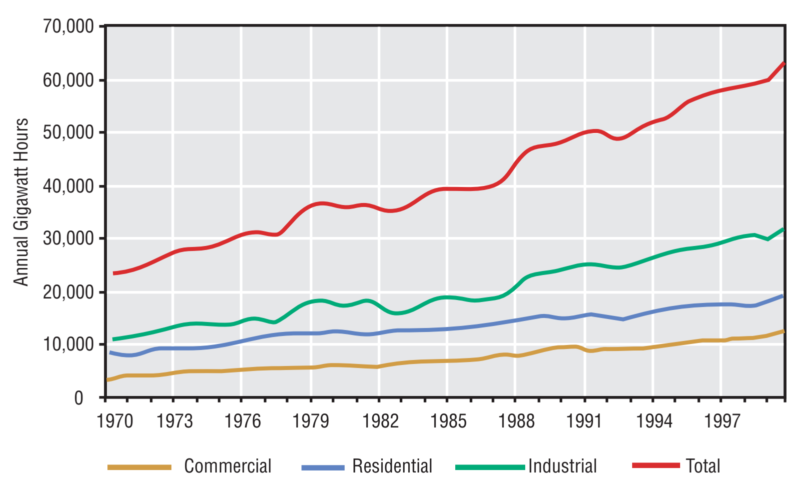


Figure 1.25: Weather Normalized Electric Consumption per Residential Customer, 1970–2000

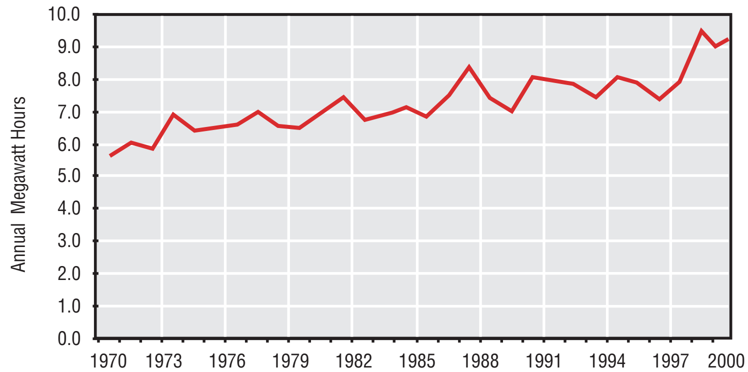


Figure 1.26: Annual Real Expenditures on Electricity in Minnesota by Customer Class, 1970–1999

Source: EIA

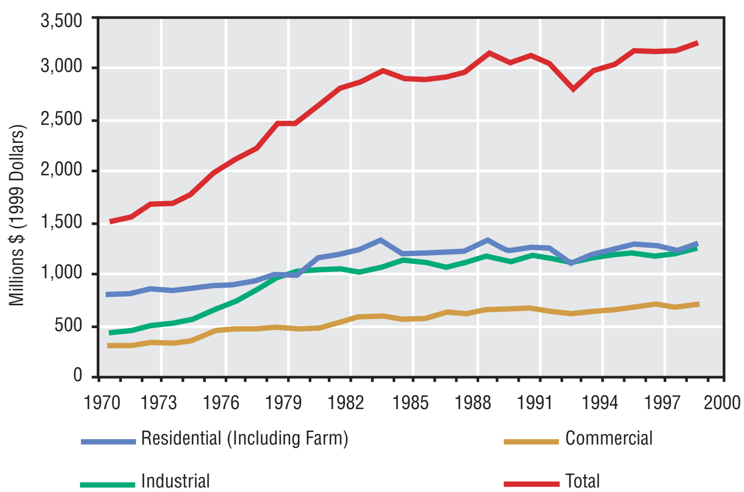
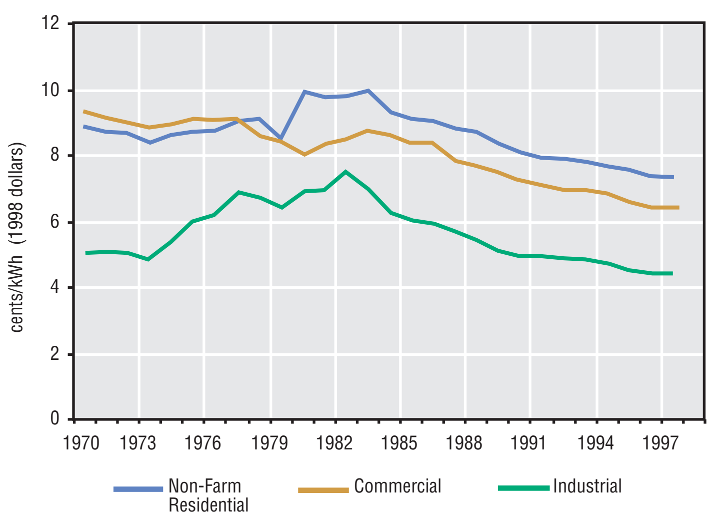


Figure 1.27: Real Prices for Electricity in Minnesota by Customer Class, 1970–1999

Source: EIA



Weather is a major factor in residential usage on a year to year basis. Figure 1-25 shows electric consumption per residential customer, after taking into account differences in weather from year to year. Once weather factors are accounted for, residential usage shows a steady growth trend, with a steeper level of increase in the late 1990s.

In 1999, Minnesotans spent approximately $3.4 billion on electricity. Figure 1-26 shows the historical trend in annual real expenditures on electricity in Minnesota by each major customer class, converted to 1999 dollars. Figure 1-27 shows that the real cost of electricity per kilowatt hour (kWh) has declined steadily since 1980. The latter part of the 1990s, however, shows a flattening of this trend line. Lastly, Figure 1-28 shows that Minnesota enjoys low electric prices relative to other parts of the country. Prices for all Minnesota customer classes are closer to the lowest price nationally than to the highest price.

One of the most significant factors affecting the price of electricity is the availability of generation capacity. As consumption increases and approaches or exceeds the level of available capacity, more capacity must be found by using the electricity we already generate more efficiently, building new generation facilities, or a combination of the two. Necessary new capital investment in the costly infrastructure to generate, transmit, and deliver electricity will cause the price of electricity to increase.

System Description

A complex infrastructure, built up over a century, provides the electricity used by Minnesotans. Minnesota's electric generation and delivery system, like any other, consists of three distinct parts: generation, transmission and distribution. It is an integrated regional system.

One of the most important concepts to understand when discussing electricity needs is the distinction between the term "megawatt" (MW) and the term "megawatt hours" (MWh). A megawatt measures the total electric consumption or generation at a particular instant in time, which is known as the "demand" or "capacity" component of electricity. If Minnesota consumer demand totals 8,000 megawatts at any particular instant, that demand cannot be met unless there exists an equal number of megawatts of generating capacity on utility systems available for use by Minnesota consumers.[10] Generating plants are often rated in terms of their size and ability to contribute to the electricity needs of the system by the greatest number of megawatts that can be generated at any particular point in time by the plant. Conversely, megawatt hours measure electricity consumed or needed over time, which is often referred to as the "energy" component of electricity.[11] For example, the single peak hour of consumer demand in a year may be 8,000 megawatts, but in the course of the whole year, consumers may use 62,000,000 megawatt-hours of electric energy. From a consumer's perspective these measurements are usually expressed in kilowatts and kilowatt hours. A kilowatt is 1/1000 of a megawatt. One megawatt is 1,000 kilowatts. Conversely, a gigawatt is 1,000 megawatts. Increasingly we measure energy overall in gigawatt hours.

Any resource that can turn a turbine can be used to make electricity. Water and wind can turn a turbine directly so they are direct fuels for making electricity. Solar power, which is not used to turn a turbine, makes electricity photovotaically. Otherwise, we use mostly carbon based fuels, such as coal, natural gas, and biomass, that are burned to heat water to make steam and the steam is then used to turn a turbine. We also use nuclear power that heats fuel rods by the continuing fission (splitting) of atoms, which in turn heats the water to make the steam that turns the turbine. Combustion and nuclear technologies are indirect fuels for making electricity, given the intermediate step of creating steam.

Electric current generated by turning the turbine is stepped-up in voltage and then sent into the transmission system. The transmission system is designed to transport electricity at high voltage to electric substations. The substations receive the high voltage power and, using transformers, step the voltage down so that it can be safely received by retail customers.[12] There are often multiple substations between a generator and a consumer. The portion of the electric system by which power is delivered at stepped-down voltages to retail customers is called the distribution system. Figure 1-29 provides a diagram of the basic components of an electric power system.

The approximate cost to build the majority of Minnesota's current electric generation, transmission and distribution system, based on information filed with the Federal Energy Regulatory Commission (FERC) and from Annual Reports for 2000 by utilities serving Minnesota, is more than $13,000,000,000.[13] This figure reflects the historical book value of utility plant in dollars. It has not been adjusted to reflect inflation. Most plants and lines were built twenty to fifty years ago. Therefore, the present value of the utility plants currently serving Minnesota is significantly higher than this estimate.

Figure 1.28: Minnesota Electric Prices Relative to Prices in Other States, 1999 (¢/kWh)

	Residential Customers	Commercial Customers	Industrial Customers
Minnesota price	7.4¢	6.3¢	4.6¢
Minnesota rank	27	30	17
Average U.S. price	8.14¢	7.18¢	4.4¢
Highest price	14.1¢	12.7¢	9.6¢
Lowest Price	5.1¢	4.2¢	2.7¢

Source: EIA

Because electricity cannot yet be stored economically, and must be available on an instantaneous basis as needed, electric generation, transmission, and distribution must work together in a closely coordinated system to meet the demand of consumers at peak times, normally measured in megawatts, as well as be capable of delivering throughout the year the megawatt-hours used by consumers.

Security concerns have been raised lately regarding electric facilities, notably large power plants and key large transmission lines. Since the attack on September 11, 2001, federal and state authorities (including the Department of Commerce and the Public Utilities Commission) have been actively working with utilities to ensure that critical facilities are secured. We expect that the additional security measures will remain in place indefinitely.

Figure 1.29: Components of an Electric Power System

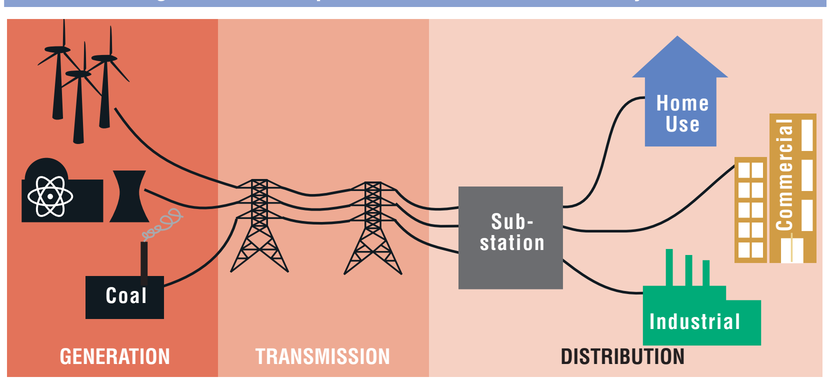
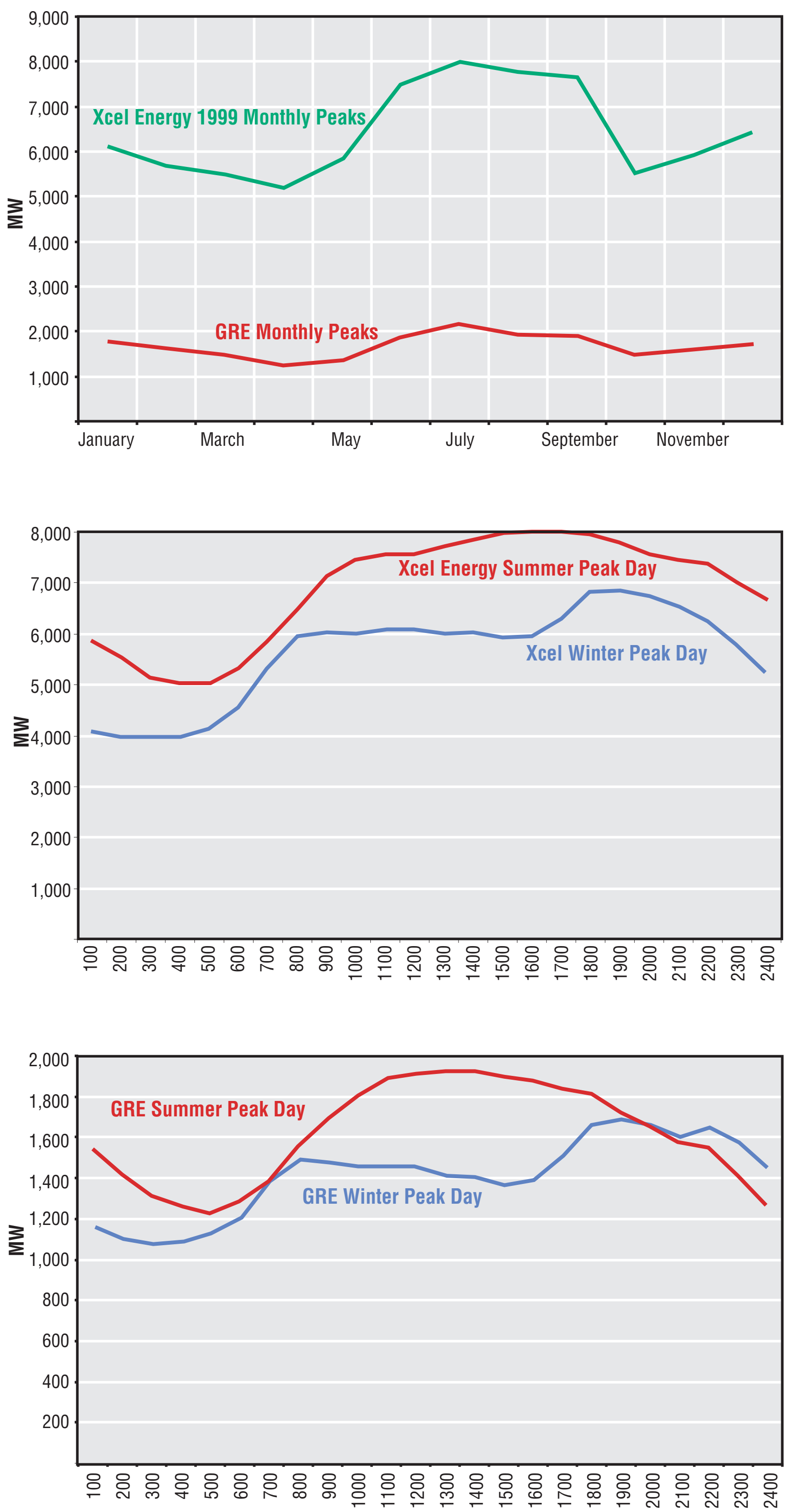


Figure 1.30: Daily and Monthly Load Curves for GRE and Xcel Energy, 1999



Generation

To provide electric service at the lowest possible cost, electric utilities build a mix of baseload, intermediate, and peaking power plants in their systems. A baseload plant is designed to be in operation the majority of hours in the year, except for scheduled maintenance periods. An intermediate plant is operated less frequently at periods of higher demand or when baseload plants are not operating due to maintenance or repair needs. Finally, a utility will build a series of peaking plants that are brought on line only when maximum demand is placed on the system.

The mix in power plants reflects usage patterns by the utilities' customers. This usage pattern is graphically represented in what is called the "load curve." Figure 1-30 displays a daily load curve and an annual load curve for two of Minnesota's utility systems, Great River Energy (GRE) and Xcel Energy. The reason that utilities build different combinations of plants to meet this load is clear from this graph. There must be enough baseload plants to meet the basic, ongoing need for electricity. At the same time, enough intermediate and peaking plants must be available on the system to be called into service at the hours or days of highest use. For Xcel Energy and Great River Energy, and many other electric utilities in the state, the highest periods of peak demand occur during the summer air conditioning season on hot days, particularly during the early evening hours when people arrive home, turn up their air conditioning and start cooking. In areas of the state where natural gas service is not available and there is a greater reliance on electricity to heat homes, the electric peak can occur in the winter months as it generally does in the case of Minnesota Power and Otter Tail Power, although summer peaks are starting to be experienced even in northern Minnesota.

A proper mix of plants is crucial for providing low-cost power. Baseload plants are the most capital-intensive to build, but often have lower operating costs per unit of production. Because these plants are operated as much of the time as possible, the lower operating costs are beneficial to ratepayers. The converse is true for peaking plants which generally have lower capital costs than baseload plants, but, often due to the cost of the fuel that they burn, are more expensive to operate. Peaking plants, for example, are often fueled by natural gas or oil.

Because these plants are operated for only a few hours or days during the year, it is more important for these plants to have lower capital costs, since the high operating costs are only incurred occasionally. As might be expected, intermediate plants are characterized by medium costs to construct and operate. This is the best compromise for plants that will be operated frequently, but not constantly, to meet the electric needs of Minnesotans.

Figure 1-31 shows electric generating plants in Minnesota that are 100 MW or more in total capacity. As the symbols indicate, Minnesota's electric generating plants reflect several different technologies or fuels: coal, nuclear, natural gas, oil and wind. There are many other smaller generating plants using a variety of different fuels and technologies.[14]

The current Minnesota system is the result of decades of separate additions to the power system. Figure 1-32 illustrates the year when some of the largest generating units in the state began operation. Significant peaking units, including two added in 2001, are included on the chart as well. Only smaller intermediate and peaking plants have been built since 1983.

Figure 1-33 lists some plants in neighboring states and Canada that contribute some of the electricity they produce to serve Minnesotans. The locations of these generating plants outside the borders of the state illustrate, in part, the regional and interstate nature of the electric system of which Minnesota is part. Though not listed in Figure 1-33, 46 municipal utilities in Minnesota purchase electricity from large hydro electric generation facilities on the Missouri River.

Even with adding up all the capacity of the in-state and out-of-state electric generators owned by Minnesota utilities, the utilities in aggregate still must purchase an average of 10 percent to meet Minnesota's total electric requirements.[15]

Figure 1-34 illustrates the relative percentage of fuels used to generate electricity that is consumed in Minnesota. Coal and nuclear power plants predominate, accounting for 92 percent of all electric generation serving Minnesota.

Figure 1.31: Electric Generating Plants with a Capacity over 100MW (1998)

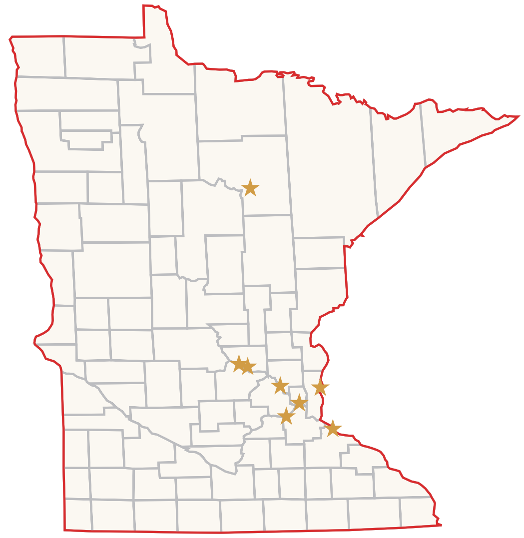


Figure 1.32: Chronology of Construction of Minnesota Power Plants over 100MW (1950-2000)

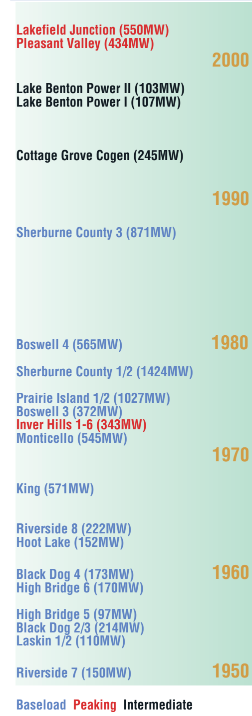
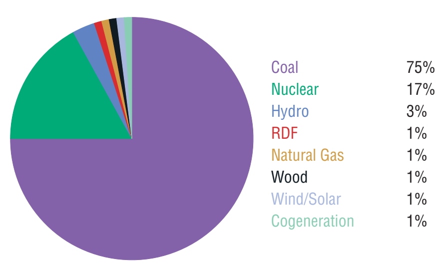


Figure 1.33: Power Plants Outside Minnesota that Serve Minnesota Customers in Part (1998) (over 100MW Capacity)

State	Plant	Utility	Capacity (MW)	Fuel	Operation
North Dakota	Coal Creek	GRE	1076	Coal	1979/80
	Coyote	OTP	149	Coal	1981
	Stanton	GRE	185	Coal	1966
	Young	MP/Minnkota	698	Coal	1970/77
South Dakota	Angus Anson	Xcel	232	Gas	1994
	Big Stone	OTP	444	Coal	1975
Iowa	Kapp	IPC	217	Coal	1967
	Lansing	IPC	260	Coal	1977
	Neal	IPC	134	Coal	1979
Wisconsin	Alma	DPC	189	Coal	1947/60
	French Island	Xcel	142	Oil	1974
	Genoa	DPC	320	Coal	1969
	Madgett	DPC	358	Coal	1979
	Wheaton	Xcel	342	Oil/Gas	1973
Wyoming	Laramie River	MoRiver	272	Coal	1980
Manitoba, CAN	Manitoba Hydro	Xcel	850	Hydro	1970s

Figure 1.34: Fuels Used to Generate Electricityto Serve Minnesota (2000)

Source: REIS



Transmission and Distribution

Utility companies also build and operate a system of transmission and distribution lines that are needed to deliver electric power to retail customers. Minnesota's and the nation's electric systems rely primarily on large, central station baseload generating plants as the primary source of electric energy. This electricity is carried long distances by transmission lines. The North American transmission system has been described as the largest machine ever made by humans. It is a large, intricate network of overhead power lines with many intersections and branches. The larger, high voltage transmission lines deliver "bulk" power to large load centers. Successively lower voltage lines get smaller in size, but with increasing total miles in each voltage class, to connect to every community and electricity customer in Minnesota.

Figure 1.35: High Voltage Transmission Lines

Figure 1-35 shows high voltage transmission lines in the United States. Minnesota's transmission lines connect into an intricate regional system of transmission lines. Utilities own and operate more than 6,500 miles of transmission line (above 115 kV in size) in Minnesota. These lines represent an investment of more than three-quarters of a billion dollars. New lines cost in the range of $250,000 per mile for 115 kV projects to over $1 million per mile for the higher voltages. Other equipment at substations, such as voltage transformers, can cost $20 million or more for a single transmission project. These costs are typically recovered by increases in electricity rates paid ultimately by those who use electricity.

Over time, aging processes including expansion and contraction cause power lines to wear out. Transmission lines face other stresses as well; wind, ice and tornadoes are common causes of outages. Even solar flares can induce large currents in grids and disrupt electric service. Transmission lines generally last 30 to 40 years with routine maintenance. With more aggressive maintenance, utilities can double that. Many lines built in Minnesota in the 1950s, however, are in need of reconditioning or replacement.

As a line is replaced because it is no longer serviceable, or as increased demand for electricity requires additional capacity, the voltage of the line is often upgraded within the existing right-of-way. Where the electric demand is creating new load centers, new lines on new rights-of-way are required. It is often possible to share rights-of-way with other linear infrastructure such as roads and highways.

All electric generating plants are connected to a transmission and distribution grid. The transmission grid requires a high level of interdependence among electric generators, transmission owners, and electric distributors. The system must be balanced between generation and customer demand every second. Electrons generated by any particular generating plant move about the grid freely according to the rules of physics (basically, the path of least resistance). It is impossible to identify an electron at a generation source and follow it to a specific consumer. Electrons also move without regard to state or international borders.

The challenge of keeping the lights on at every moment in time requires a level of interdependent and coordinated operation in the electric industry that is not required of any other industry.[16] Balancing the grid between input and output demands management on a minute by minute basis.

The transmission system is vital to the provision of electric service to customers. The consequences of failures in the system can be significant. Economic consequences of reliability problems are not easily quantified but are significant. On a national scale, the U.S. Department of Energy (DOE) estimates that outages and other significant power fluctuation cost $30 billion per year in lost production.

There are three main categories of responsibility relating to the transmission system:

- Operations,
- Planning, and
- Reliability.

The transmission owning utilities in Minnesota have responsibilities in all three areas. These utilities are responsible for maintaining the existing transmission grid and for building needed additional transmission as well. Other entities that have responsibility for transmission include the North American Electric Reliability Council (NERC) and the Mid-Continent Area Power Pool (MAPP).

NERC is the electric reliability organization for all of North America. It has operated since 1968 as a voluntary organization whose principal mission is to promote the reliability and adequacy of electric supply. Its members are its subregional reliability organizations. All continental states and Canadian provinces are part of one of the subregional organizations. NERC establishes standards to ensure adequate reliability of the electric grid system. It is in the process of transforming itself into a broader industry group with a more mandatory compliance approach and intends to become the North American Electric Reliability Organization, or NAERO.

MAPP, the NERC subregional organization that includes Minnesota, is a voluntary association of electric utilities and other electric industry participants. It was formed in 1972 for the purpose of pooling generation and transmission resources. MAPP continues to transform its original mission to keep pace with industry changes. It now has 107 members including investor-owned utilities, cooperatives, municipals, public power districts, power marketers, regulatory agencies, and independent power producers. MAPP's offices and control center are in St. Paul.

MAPP presently has three main functions:

- it is a reliability council, responsible for the safety and reliability of the bulk electric system, under NERC, including system-wide planning functions;
- it is a regional transmission group, responsible for facilitating open access of the transmission system; and
- it is a power and energy market, where MAPP members and non-members may buy and sell electricity.

By the end of 2001, MAPP's operational and planning functions for most of its members will be transferred into a much larger regional transmission organization, called the Midwest Independent System Operator (MISO), which is discussed in Chapter 2.

Responsibility for daily operation of the transmission grid lies with each individual utility. Each transmission owning utility operates what is known as a control area. The utility balances electric supply with electric demand for that area, controls voltage and frequencies, and controls the loading on the transmission elements within the control area. The individual control areas are linked operationally in our multi state region through the MAPP facilities in St. Paul.

See Chapters 2, 3 and 4 of this report for discussions of challenges to the electric system, including potential capacity issues, both with generation and transmission, as well as environmental issues and the evolving regulatory structure, and the technologies and techniques that could be deployed to address the capacity and environmental issues in the future.

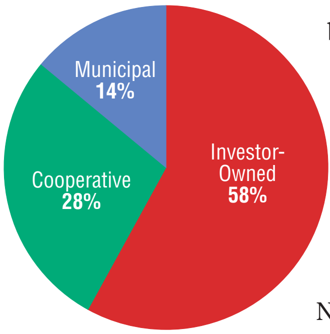
Electric Regulatory History and Structure

Electric utilities in the United States have been in existence since early in the twentieth century. Persistent problems concerning monopoly control of service and service discrimination prompted Congress to begin imposing regulatory controls in the 1930s by enacting laws and creating the Federal Power Commission (now the Federal Energy Regulatory Commission) to oversee and regulate utility practices. Appendix B discusses this regulatory history in detail.

Minnesota electric consumers are served by five rate-regulated investor-owned utilities (IOUs), 46 cooperative electric associations (coops) and 126 municipal utilities (munis). The IOUs are vertically integrated monopolies that, for the most part, have owner and operator rights in generation, transmission and distribution systems, although this ownership structure is beginning to change. Coops and munis are, for the most part, distribution entities that sometimes generate their own power, sometimes purchase power from each other or IOUs, and sometimes join together in generation and transmission entities that own the generation and transmission facilities.[17] Figure 1-36 shows the percentage of Minnesota customers served by each type of utility company.

Figure 1.36: Percentage of Customers Served by Utility Type, 2000

Source: REIS



The regulatory structure differs for each of these types of utilities. Coops are regulated by their members under state statutes that govern their organization and operation. Munis are operated by the municipal governments that own them, which are responsible to the local electorate.[18]

The IOUs, Xcel Energy, Minnesota Power, Otter Tail Power, Alliant Energy and Northwestern Wisconsin, are regulated by the Minnesota Public Utilities Commission (PUC) as to the rates they charge and the services they provide. Appendix C provides an explanation of the theory and practice of setting rates in Minnesota. This rate setting and regulation theory and practice applies to regulated natural gas utilities as well, with minor variations.

Over the past 20 years, Minnesota and other states have developed several specific kinds of regulatory proceedings designed to address the issues of short supply and increasing costs that emerged in the 1970s as well as plan for the future.

The state's interest in electric facility planning has been to ensure that:

- costs to captive retail ratepayers are reasonable;
- the energy supply for customers in the state is adequate and reliable; and
- adverse environmental effects from large energy facilities are within accepted standards.

The PUC oversees planning by utilities for adequacy and reliability of supply and delivery of electricity through the integrated resource planning process (IRP).

Each electric utility must submit its IRP to the PUC every two years using 5, 10 and 15 year planning horizons to determine the additional resources the utility needs to meet forecasted demand. The statutory emphasis in resource planning is on demand-side management, such as conservation, energy efficiency and load management, and on renewable energy resources for adding new capacity to the system. A utility first must show why these resources will not meet its needs before it may propose building traditional electric infrastructure. Utilities also must consider costs in meeting consumers' needs. The PUC approves, modifies, or disapproves each utility's IRP after analysis by the Department of Commerce, the Office of Attorney General, and various interested parties. The PUC and Department scrutinize a utility's investment and operation decisions for compliance with its IRP, as well as reasonableness and prudence, in the utility's next general rate case or certificate of need proceeding.[19]

The legislature also has created the Conservation Improvement Program (CIP). CIP requires electric and natural gas utilities, including munis and coops, to spend a specified percentage of gross operating revenues on efforts to conserve energy in their service areas. The IOUs must submit to the Commissioner of Commerce their CIP plans for review and approval. CIP provides four major benefits:

(1) Individual consumers receive lower energy bills;
(2) Lower demand decreases the need to build costly, unpopular, and environmentally intrusive power plants and transmission lines;
(3) Less need for capital investment in the system keeps all consumers' rates lower than they would otherwise be; and
(4) Access to conservation programs and knowledge allows consumers to take some control of their own energy use and determine their own energy destiny.

In addition, the legislature requires a full analysis of whether conservation and/or renewable energy sources can meet an identified need to avoid adding more nonrenewable energy sources whenever a certificate of need is required for a proposed power plant or transmission line project. Finally, the legislature requires that environmental costs of electric generation begin to be factored into utility resource planning decisions. Chapter 4 of this report is a study of the operation of CIP and its costs, benefits, and effectiveness.

ENDNOTES

1. *The Btu is the measurement of the heat content of energy and is approximately equivalent to the heat produced by one wooden kitchen match.*

2. *This figure does not include fuel used to generate the electricity purchased for Minnesota consumption from marketers or utilities without Minnesota service territory.*

3. *Motor vehicles contribute 58 percent of formaldehyde emissions, 67 percent of benzene emissions, 66 percent of 1, 3-Butadeine emissions, and 67 percent of POM emissions. MPCA Staff Paper on Air Toxics, November 1999 at 111, available on the MPCA website at www.pca.state.mn.us/air/airtoxics.html*

4. *The full forecast can be viewed at www.eia.doe.gov/neic/speeches/main.html#Aug2001.*

5. *A list of the various companies that provide gas utility service in the state can be found in the* Energy Policy and Conservation Report 2000, *Minnesota Department of Commerce, at page 21, available at www.commerce.state.mn.us/pages/Energy/MainEnergyPolicy.htm.*

6. *Adjusting for differences in weather is called "weather normalization," and accounts for increased energy use in hotter summers or colder winters as well as decreased use during years of milder weather.*

7. *Although natural gas commodity prices are subject to the open market, an LDC's purchasing practices are subject to approval by the Minnesota Public Utilities Commission. Commerce reviews an LDC's purchases on a monthly, quarterly and annual basis, and reports its findings and recommendations to the Minnesota Public Utilities Commission.*

8. *Most of the storage by Minnesota's natural gas utilities is in underground geologic formations in Michigan and the southern United States. In Minnesota, local storage of natural gas is found only in a salt dome near Watertown and a facility that liquefies and stores natural gas in a southern suburb of the Twin Cities.*

9. *"Commodity price" as used here means the price that utilities pay for the natural gas for their utility customers. Utilities pass these costs, with no markup on the gas price, to customers.*

10. *Transmission and distribution systems must be sized appropriately to allow this electricity to be delivered to customers.*

11. *In this report, watts and watt-hours will generally be referred to with the prefix "mega," which designates a million watts or watt-hours. Other units that will be referred to in this report will be kilowatts and kilowatt-hours, which designates a thousand, and gigawatts and gigawatt-hours, which designates a billion.*

12. *Some large industrial customers are capable of receiving the power at high voltages, so this step is eliminated for them.*

13. *From FERC Form 1, submitted by Otter Tail Power Company, Interstate Power Company (now Alliant), Northern States Power Company (now Xcel Energy), Minnesota Power (now Allete). From 2000 Annual Reports, submitted by SMMPA, Great River Energy, Missouri River Energy, Dakota Electric Association and Minnkota Power Cooperative.*

14. *This list can be found in Table 9 of the Utility Data Book, available on the Department of Commerce's website at www.commerce.state.mn.us/pages/Energy/Data/MainData.htm.*

15. *Public comments noted confusion about what the "10 percent net import" number in the draft report meant. We have attempted to clarify this statement and apologize for any confusion it caused.*

16. "An interdependent grid of generating plants and transmission lines, instead of a set of individual transmission systems, makes the system both cheaper (fewer transmission lines needed) and more reliable (availability of multiple pathways for the power).

Interconnection and central dispatch increase reliability by giving the operators of the grid more ability to adjust or restore the system after a failure. Because one operator has immediate control over most of the system, she can react to the situation with many possible responses, making it more likely that the outage can be minimized. A typical control center has control over dozens of power stations and hundreds of high-voltage lines, and it monitors virtually every plant and line in its area ….

If this does not sound significant, consider this example. One utility, Union Electric, recently studied the amount of additional power plant capacity it would need to maintain reliable service if it was not interconnected to its neighboring utility. The answer was an additional 1,300 megawatts, 16 percent more generating plant than it requires when interconnected."

—Fox-Penner, Electric Utility Restructuring: A Guide to the Competitive Era, at 34 (1997).

17. A complete listing of these organizations can be found in the Department's Energy Policy and Conservation Report 2000, at pages 20 to 21. See www.commerce.state.mn.us/pages/Energy/MainEnergyPolicy.htm.

18. MN Statutes 216B.026 provides procedures by which both municipal utilities and cooperative electric association customers may elect to become subject to rate regulation by the Public Utilities Commission. Only one electric cooperative association, Dakota Electric Association, has done so.

19. A certificate of need issued by the Minnesota Public Utilities Commission is statutorily required for large energy facilities under MN Statutes 216B.243. The proceeding determines whether a facility is needed before construction or whether there are more preferred ways of meeting potential demand.

TWO: CHALLENGES IN ELECTRICITY

Statewide, unless new capacity is found or built, utilities will experience an electric capacity deficit during the next decade, based on projections available today. Planning procedures are in place, however, that should produce enough electric capacity, through additional generation, transmission and conservation measures, to meet growing demand. The new capacity may look quite different than traditional capacity and it also may be developed in smaller increments as it is needed.

Transmission presents one of the greatest challenges to the electric system. The need for upgrading and extending transmission is immediate. Accomplishing those improvements appears more distant.

Chapter 1 provided an overview of the history and trends in the use and cost of energy in the state and explained the current structure of each major energy industry. This chapter discusses present and future challenges in the electric energy system, focusing on three major areas:

(1) potential electric supply deficiencies;
(2) electric transmission capacity and regulation;
(3) air pollutant emissions from existing and future electric generation plants.

Statewide, unless new capacity is found or built, utilities will experience an electric capacity deficit during the next decade, based on projections available today. Planning procedures are in place, however, that should produce enough electric capacity, through additional generation, transmission and conservation measures, to meet growing demand. The new capacity may look quite different than traditional capacity and it also may be developed in smaller increments as it is needed.

Forecasting electric demand is inherently subject to uncertainty because it tries to predict the future. Nevertheless, efforts to forecast future demand are critical to successful energy planning, because significant programs and infrastructure to ensure adequate electric supply require years of lead time to be put into place.

Of the three categories of major electricity challenges listed above, probably the most acute is sufficient transmission to ensure the continuing reliability of the electric energy system. Of all public benefit infrastructure, transmission lines are the most controversial and, therefore, the most difficult to site. In addition, how we meet the electric capacity challenges in the future has major implications for transmission. Conversely, how and where we build transmission has major implications for the type and size of new generation facilities and how they are dispatched to serve retail consumers and wholesale purchasers.

Emission of air pollutants from existing power plants also needs attention. Due to grandfathered exemptions under the Clean Air Act of 1970, 55 percent of Minnesota's coal-fired electric generating plants (over 3000 MW), are exempt from the most stringent air emission limits. These plants are not being retired as envisioned thirty years ago, and presently emit at rates 10 to 20 times the rate of new, modern plants. Especially at a time when significant new generating capacity may be added to the system, cost-effective emission reductions should be made at the older plants. This chapter and the environmental study in Appendix A recommend that total emissions from utilities in the future be significantly lower than today, including emissions from whatever new generation capacity is needed.

While this report focuses on these three major electric challenges, others are worth noting here for future discussion. Like electric transmission, all infrastructure for the transportation and delivery of all forms of energy is aging and is operating at or near capacity a majority of the time. Pipelines to transport petroleum, petroleum products, and natural gas were, for the most part, also built decades ago. Again, the needed capital investment in transportation of these fuels will be reflected in the prices consumers will pay in the future.

Finally, a challenge as great as, or perhaps greater than, the electric transmission challenge, is affordability of all energy services. We at the Department of Commerce, the PUC, and the Residential Utilities Division of the Attorney General's Office, work continually with utilities to ensure lowest cost energy services to Minnesotans. Even so, this lowest cost will increasingly strain the budgets of Minnesota's seniors, working families, and low income households, which make up over 400,000 households in the state. 2001 legislation requires a separate report on universal service issues. That report will be available in mid to late January 2002.

Potential Electric Supply Deficiencies

This section presents and discusses several perspectives on forecasts of Minnesota's need for additional electric capacity by 2010. It presents forecasts done on a regional level by the Mid-Continent Area Power Pool (MAPP), statewide trend line analysis, and the individual system forecasts done by the various utilities as part of their integrated resource planning (IRP) cycle.

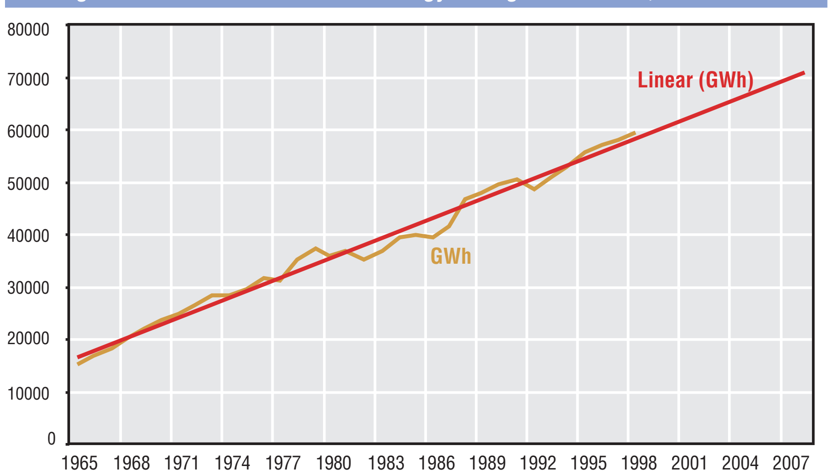
Adding electric infrastructure cannot be done in the short term. Almost all generating and transmission facilities take years to:

- Obtain all of the required various state and federal regulatory clearances and permits.
- Place orders for the major components of the facility.
- Site the facility.
- Build the facility and its appurtenant structures.

Major baseload generating facilities can and have taken up to a decade to move from the drawing board to providing electricity to customers. Because of the need for significant construction lead time, it is critically important—and a challenge—to maintain an active forecast of future generation and transmission needs. Forecasting future electrical demand and supply is the best method for electric service providers to determine what new facilities or programs are needed and when to begin the planning and construction process for specific projects.

A forecast uses data from the past in an attempt to predict the future. The crudest type of forecast is a simple trend line. A trend line simply takes past energy usage and plots a line to fit the data. Figure 2-1 shows the application of a trend line for historic electric energy usage in Minnesota to predict future energy use. The trend line predicts that electric energy usage will increase by 1,267 gigawatt hours (GWh) each year. Figure 2-1 extends the trend line 12 years into the future from the data for the period 1965-1998. By the end of the 10-year forecast in 2010, electric energy usage is predicted to grow to about 72,100 GWh. If electric energy usage occurred perfectly evenly throughout the year, a minimum of 145 MW of new capacity each year would be needed in Minnesota to supply the 1,267 GWh.[20] Because electric energy usage is not constant every day throughout the year, more capacity is needed to meet peaks in demand than would be needed to meet overall growth in energy use.

Figure 2.1: Minnesota Electric Energy Useage Trend Line, 1965–2009



A simple trend line is a poor forecasting tool because it does not allow the forecaster to identify the factors that influence energy use or determine how to influence future energy use. Furthermore, it does not allow the forecaster to change those factors to produce a reliable forecast band. For example, the trend line may implicitly assume that the significant increases in labor force participation which occurred from the 1960s through the 1990s (and are therefore part of the trend-line) will continue even though such increases may not be possible in the future. A more complex forecast could analyze this and other questions. A trend line cannot explain what happened; it can only show on average what happened, and then assume that the exact same thing will continue to happen.

Typical variables that are used to produce more reliable forecasts include economic factors such as employment, investment, and output; weather factors such as heating degree days and cooling degree days; and other factors such as air conditioning saturation, number of customers, and population. Factors affecting short-term consumption are frequently different than the factors affecting long-term trends. Because different factors are more important in the short run versus in the long run, forecasters often use different equations for short-term and long-term forecasts and then blend the two together to create an overall forecast. For example, if a recession is imminent, a short-term forecast may focus on short-run economic variables while a long-term forecast may ignore a looming recession and focus on structural changes, both in the economy and in customer energy-usage patterns, that will have longer-term influence than a one or two year recessionary cycle.

Forecasting is most often performed on a utility system level. Each utility forecasts the demand in its service territory. Regional forecasts can either be performed separately, based on utility-specific forecasts, or calculated by simply accumulating the various utility-specific forecasts.

Electrically, the United States is divided into 10 different regions by the North American Electric Reliability Council (NERC). Each region is a voluntary association of electric utilities. Minnesota is in the Mid-continent Area Power Pool (MAPP) region. MAPP contains all or most of Saskatchewan, Manitoba, North Dakota, South Dakota, Nebraska and Minnesota. It also contains portions of Montana, Iowa and Wisconsin. MAPP was formed in the mid-1960s and presently performs three functions:

- reliability council, responsible for the safety and reliability of the bulk electric system, under NERC;
- regional transmission group, responsible for facilitating open access of the transmission system; and
- power and energy market, where members and non-members may buy and sell electricity.

Utility transmission planning responsibilities for Minnesota and surrounding states have been coordinated and managed through an extensive planning process at MAPP since 1996. MAPP has the authority to order one of its member utilities to build facilities if deemed necessary for reliable grid operations. A key component of the MAPP transmission planning system is a "bottom up" process of sub regional planning groups that includes the member utilities serving five different sub sections of the MAPP region.

Individual utilities that own transmission facilities have had the primary responsibility to plan for the future expansion and maintenance of the transmission grid. Each utility considers a range of forecasts of future load growth expectations and its own selection of choices for electric supply when conducting its transmission planning. The main driving force behind this planning has been the adequacy of electricity supply for local load serving obligations. Increasingly, due in part to federal regulations, transmission planning must take into account considerations for bulk power transactions and open access to the system for nontraditional transmission transactions.

MAPP performs some utility planning to ensure the safety and reliability of the bulk electric system. Each year, all utilities in the MAPP region file a *Load and Capability Report* with MAPP, which then assembles the various filings into a single document. MAPP's most recent *Load and Capability Report* was dated May 15, 2001.

To ensure a degree of commonality, the Department of Commerce often uses the MAPP *Load and Capability Report* to show the current forecast of use of electric energy and capacity in the region. The only major generation and transmission owning utility that serves Minnesota and is not in MAPP is Alliant Energy (formerly Interstate Power Company) which serves only a small number of customers in the state.

Regional Forecast

While there are several sources of forecasts for the region, the Department of Commerce typically relies mostly on forecasts from MAPP. One source of MAPP forecasts is the annual *Reliability Assessment* published by the NERC. The *Reliability Assessment 1999-2008* provides forecasts from each of the 10 NERC regions and an overall grid assessment. In the May 2000 *Reliability Assessment 1999-2008,* MAPP stated that "when load forecast uncertainty is taken into account, the Region may have a capacity deficit by summer 2000 and nearly 5,400 MW deficit by summer 2008." This 1999 forecast informed NERC of significant potential reliability concerns on the utility planning horizon in the MAPP region, and served to focus policymakers and utilities on the need to begin concerted efforts to assure that Minnesota's generation and transmission needs will be met in this decade.

The most recent MAPP-specific forecast was issued in the spring of 2001.[21] MAPP's 2001 forecast shows electric generating capacity as being short 3,500 MW of meeting peak electric demand plus the 15 percent reliability reserve margin by 2010.[22] The lower figures, as compared to the estimates in 2000, reflect two new gas peaking plants that just came on line in 2001, plus other small generating unit additions. They do not reflect other proposed projects, some of which have been approved for construction.

Figure 2-2 illustrates MAPP's forecast of energy use from the *Load and Capability Report* data between 2001 and 2010. MAPP forecasts that energy usage in the region will rise from about 149,000 GWh in 2001 to 176,000 GWh in 2010.[23] This level is equal to an annual growth rate of about 1.9 percent (or 3,019 GWh per year).

Figure 2.2: MAPP U.S. Region Energy Forecast, 2001–2010

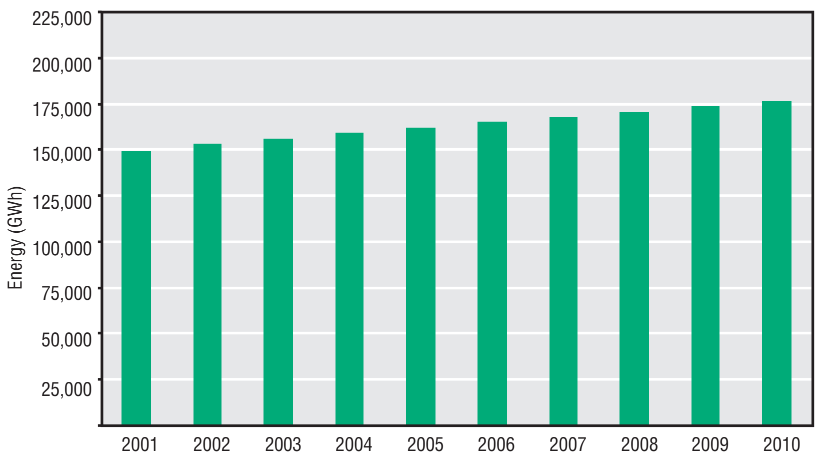


Figure 2.3: MAPP U.S. Regional Electric Capacity Situation, 2001–2010

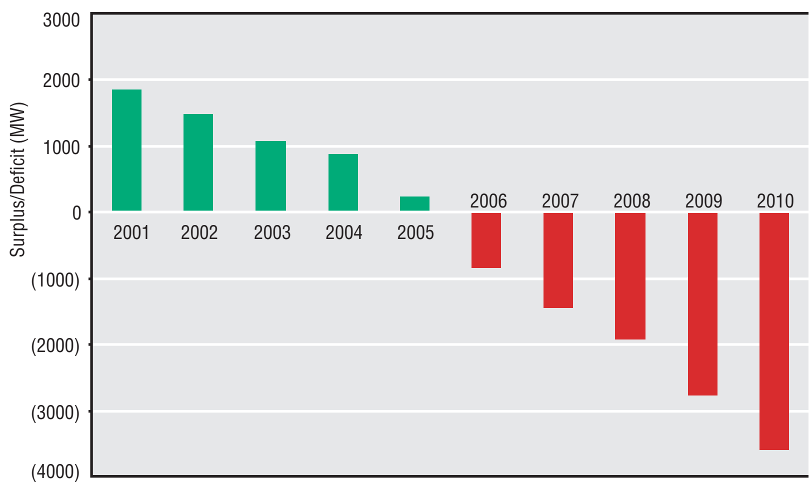


Figure 2-3 provides the results of MAPP's analysis. Figure 2-3 shows that the MAPP region forecasts a net surplus of capacity through 2005. A small net capacity deficit[24] is forecasted for 2006, with the net capacity deficit growing substantially to nearly 3,600 MW by 2010. This result means that entities in the MAPP region must either build new power plants, reduce electric demand growth[25] or find new imports from other regions by 2006. The alternative is to risk not having enough capacity to keep the system reliable and meet customers' energy needs.

On October 16, 2001, NERC released its *Reliability Assessment 2001-2010,* this report states (on page 43),

> *when demand forecast uncertainty is taken into account, the Region [MAPP-U.S.] may be capacity deficient by 2004 summer and nearly 5,442 MW deficient by 2010 summer. MAPP-U.S. utilities have committed to provide an additional 5,018 MW of capacity during this period.*

All of these regional forecasts conclude that, although MAPP is forecasted to have an electric supply deficit by the end of this decade, somewhere between 3,500 and 5,000 MW, the presently sagging economy (which lowers overall demand) and future capacity proposals should go far to balance the electric supply with demand into the future. The key is to remain diligent in encouraging additional sources of generation as well as active conservation of present supplies.

Methods of quantifying the comparison of generation, transmission, and demand side resource alternatives should be further developed. A particularly difficult challenge is the analysis of comparing market price change risks and reliability risks between alternatives. Reliability risks fall into two general categories - system security risks and adequacy of supply risks. The pending deficit in generating capacity in MAPP projections is an example of an adequacy of supply risk. The "regional blackout scenario" that might occur at any time from an extreme storm related disturbance is an example of a system security risk. Effective planning must identify the magnitude and probability of reliability challenges to both adequacy of supply and system security. Priorities for future infrastructure additions must be developed considering a risk management approach that is consistent with the public interest.

Minnesota Forecast

This section attempts to provide insight into what Minnesota's statewide demand will be in 2010. This process must be treated as an approximation, for four reasons. First, statewide data are not available through the MAPP or utility forecasts. Second, the MAPP forecasts are based on data provided by the utilities which often use inconsistent methods of data collection and calculations. Third, many utilities, such as Otter Tail Power Company and Xcel Energy, have operations in several states and must ensure that they are able to meet requirements in each state. Finally, to assure system backup, reliability, and economic and operational efficiencies, the electrical system was designed so that no state could be easily isolated from other states. Therefore, we can produce only a crude forecast for energy use in Minnesota by fitting a simple trend line to data on statewide energy use.[26] The resulting trend line produces an estimate of about 60,719 GWh in 2001 and

72,122 GWh in 2010.[27] This amount equals an annual growth rate of about 1.9 percent per year for energy usage, the same growth rate MAPP assumed in its regional forecast. The trend line is illustrated in Figure 2-1.

In addition to the statewide forecast given above, the forecasts of the larger utilities doing business in Minnesota can be combined to try to get an additional picture of expected statewide demand growth.[28] Figure 2-4 shows the results of combining data from MAPP data. Figure 2-4 shows the larger utilities forecasting energy use of 86,607 GWh in 2001, growing to 102,533 GWh in 2010. These numbers are larger than the statewide numbers quoted above. This fact indicates that the large utilities have significantly more energy use outside of Minnesota than is used by the smaller Minnesota utilities excluded from the data. The large utility[29] energy forecast results in an annual growth rate of about 1.9 percent per year, roughly confirming the 1.9 percent growth rate forecasted by the trend line discussed above and the MAPP regional forecast.

The purpose of combining the large Minnesota utilities' energy forecasts is that they create an estimate of the capacity surplus or deficit faced by the utilities serving the State. Figure 2-5 shows that the large utilities have a Minnesota capacity surplus in 2001 (1,041 MW). That surplus first becomes a deficit in 2006 (653 MW). The deficit grows for the rest of the period, reaching 2,050 MW in 2010. The rise in surplus capacity for 2004 shown in Figure 2-5 reflects the beginning of a 300 MW purchase from Manitoba Hydro by Xcel Energy and the end of a 200 MW firm sales from Xcel Energy to Wisconsin Public Service, for a net increase in capacity of about 500 MW.

Minnesota also must be certain that maintenance of the transmission system meets industry standards, so that risk of outage from physical damage is kept to a minimum. Managing risk from failures of computerized operating systems and from potential sabotage requires a new focus, and becomes increasingly critical as transmission interconnections expand on a national scale. New technologies that better manage the flow of electrons on the existing system should be applied whenever feasible, both to enhance the operation of the existing system and to reduce the need for new lines.

Figure 2.4. Major Minnesota Utility Electric Energy Situation, 2001–2010

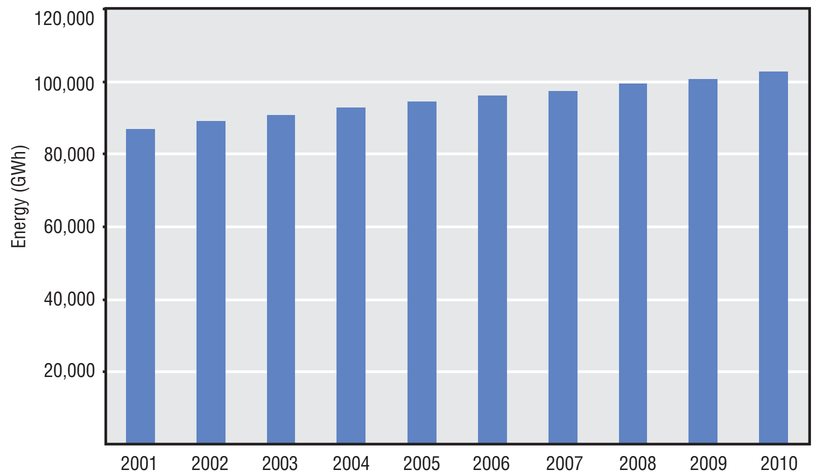


Figure 2.5. Major Minnesota Utility Electric Capacity Deficit, 2001–2010

Figure 2.7: Xcel Electric Capacity Forecast, 2001–2010

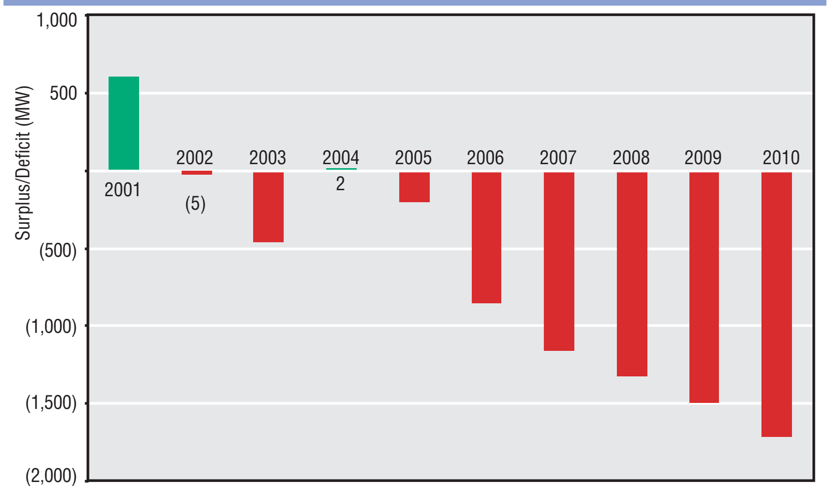


Figure 2.8: Large Utilities with Electric Capacity Deficits Over 100 MW, 2001–2010

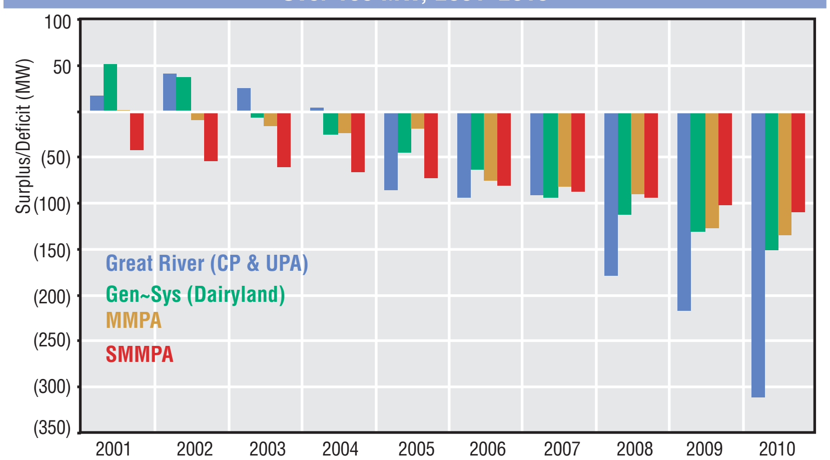
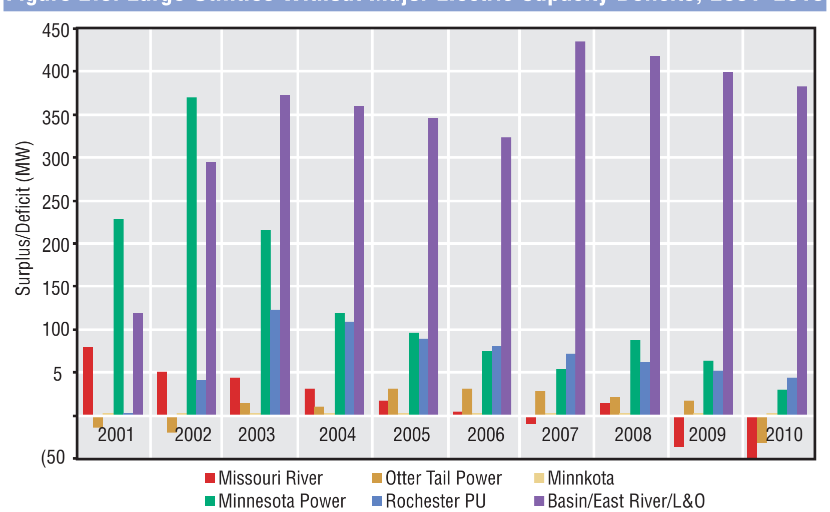


Figure 2.9: Large Utilities Without Major Electric Capacity Deficits, 2001–2010



Utility Specific Forecasts

There are eleven different utilities or organizations that file data with MAPP that meet the definition of 'large' as discussed above. The forecasted annual growth rate in energy use for each is provided in Figure 2-6. Annual growth rates vary from 4.0 percent per year for Missouri River to 0.8 percent per year for Minnesota Power.

Figure 2.6: Large Utility Growth Rates

Utility	Energy Growth Rate (2001-2010)
Missouri River	4.0%
Rochester	3.6%
Great River (CP & UPA)	2.7%
Minnkota	2.5%
SMMPA	2.3%
MMPA	2.2%
Xcel Energy	2.0%
Gen~Sys (Dairyland)	1.8%
Basin/East River/L&O	1.3%
Otter Tail Power	1.0%
Minnesota Power	0.8%

The number of power plants required to produce the energy needs discussed above can be determined by a utility-by-utility capacity analysis. Of the 11 utilities, five show significant deficits (over 100 MW) and the other six have either small deficits or surplus throughout the planning period. By far the largest utility doing business in Minnesota, and the utility with the most significant capacity deficits, is Xcel Energy. In order to produce figures of readable scale, the capacity situation of Xcel is provided in Figure 2-7 and the capacity situations of the other four utilities with significant deficits are provided in Figure 2-8.

Note: Xcel Energy's Prairie Island nuclear-fired generating plant (1,000 MW) will use up its approved spent fuel storage capacity in 2007. Without the legal authority and physical facilities to continue to store spent fuel, Prairie Island must discontinue operation in 2007. In addition, the two reactors at Prairie Island are due for relicensing by the Nuclear Regulatory Commission (NRC) in 2013 and 2014. In order to achieve relicensing by these dates, the relicensing process must begin in 2006 and 2007.

Xcel's forecasts continue to include the capacity presently generated at Prairie Island. The plant will continue to operate or will be replaced with equivalent new or purchased capacity. As required by the Minnesota Public Utilities Commission, Xcel has filed to begin a competitive bidding process, PUC Docket No. E002/M-01-1480, to acquire contingent replacement power as an "insurance policy" in case the Prairie Island plant must be shut down. In addition, under existing PUC orders, the Prairie Island plant will be fully depreciated and its decommissioning fund fully funded by 2007.

Figure 2-9 shows the capacity situations of the six utilities that do not forecast significant deficits. Of the six utilities falling into this category, four show surpluses (three of 50 MW or less), and only Otter Tail Power and Missouri River show small deficits (50 MW or less).

Figure 2.10: Short-Term IRP Forecasts, 2001-2006

Utility	Year IRP filed	2001	2002	2003	2004	2005	2006
Alliant	1999	5	(10)	(28)	(51)	(99)	(123)
Dairyland	2000	(20)	(41)	(87)	(106)	(129)	(152)
Great River Energy	2001	(227)	(224)	(251)	(293)	(394)	(370)
Minnesota Power	1999	249	59	49	38	26	-
Minnkota	1998	65	59	49	45	41	36
Missouri River	2001	-	-	-	-	(12)	(31)
Otter Tail Power	1999	(81)	(92)	(96)	(100)	(74)	(79)
SMMPA	2000	(39)	(52)	(61)	(68)	(76)	(85)
Xcel Energy	2000	(212)	(376)	(422)	(373)	(526)	(1181)

Figure 2.11: Long-Term IRP Forecasts, 2007-2015

Utility	2007	2008	2009	2010	2011	2012	2013	2014	2015
Alliant	(145)	(168)	(391)	(414)	(437)	(460)	(484)		
Dairyland									
Great River Energy	(261)	(360)	(463)	(520)	(536)	(640)	(745)	(853)	(962)
Minnesota Power	-	15	-	-	-	-	-		
Minnkota	32	27	22	17	13	8			
Missouri River	(46)	(60)	(76)	(90)	(110)	(124)	(139)	(155)	(169)
Otter Tail Power	(86)	(94)	(97)	(97)	(97)	(100)	(106)	(109)	
SMMPA	(93)	(101)	(110)	(118)	(126)	(134)	(143)	(151)	(158)
Xcel Energy	(1,468)	(1,633)	(1,853)	(2,026)	(2,198)	(2,360)	(2,515)	(2,675)	

As discussed above, in addition to data provided to MAPP each April 1, most of the larger utilities file integrated resource plans (IRPs) with the Minnesota Public Utilities Commission. An IRP provides a comprehensive overview of a particular utility's forecasts, existing supply-side resources, existing demand-side resources, and action plans to meet potential deficits for a 15-year period.

Currently nine utilities, which ultimately serve the vast majority of Minnesota energy consumers, file IRPs with the Minnesota Public Utilities Commission (PUC).[30] A PUC Order approving or modifying a utility's IRP is binding with respect to rate-regulated investor-owned utilities and advisory only for cooperative and municipal generation and transmission utilities. The utilities file their IRPs at various times, typically every other year. However, some of the cooperative and municipal utilities may have several years between IRP filings. Figure 2-10 shows the estimated surplus or deficit for each of the utilities who have filed an IRP covering the 2001 through 2006 planning period.[31]

Figure 2-11 shows the estimated surplus or deficit, before implementation of any identified action plan, for each of the utilities filing an IRP in the long run (2007 through 2015). Since the filings are made at different times and in different manners, not all of the utilities report a surplus or deficit number through 2014.

Figures 2-10 and 2-11 show that virtually all of the utilities have a deficit at some point during the next 15 years. Therefore, all of the utilities have action plans which involve acquiring more resources. These plans may include more demand-side management (load management, increased efficiency in use, energy conservation), construction of power plants, short-term purchases from the market, long-term purchases from the market, and combinations of the above. Figure 2-12 summarizes the IRP capacity additions planned by the utilities, by year and size, through new power plant construction and by long-term power purchase agreements (PPAs) with other power generators.[32] In most cases, it is not clear what type of generation technology will be proposed or built.

Figure 2.12: IRP Supply Side Action Plan Summary (50MW or More)

Utility	Size (MW)	Type	Date
Otter Tail Power	50	PPA	2000
Dairyland	80	Peaking	2001
Xcel Energy	80	Wind	2002
Great River Energy	250	Peaking	2003
SMMPA	93	Peaking	2003
Xcel Energy	100-600	PPA	2003
Alliant Energy	154	Peaking	2005
Xcel Energy	up to 400	PPA	2006
Xcel Energy	up to 500	PPA	2007
Alliant Energy	538	Peaking	2008
Xcel Energy	up to 600	PPA	2008
Alliant Energy	430	Base	2009
Great River Energy	250	Base	2009
Alliant Energy	215	Base	2010
Alliant Energy	154	Peaking	2010
Otter Tail Power	78	Peaking	2010
Alliant Energy	430	Base	2011
Alliant Energy	215	Base	2012
Alliant Energy	76	Peaking	2012
Alliant Energy	215	Base	2014

NOTE: Alliant Energy is not a member of MAPP, and the vast majority of its customers are not in Minnesota.

This in-depth forecasting analysis shows the importance and the appropriateness of continuing with an IRP or similar process to evaluate future resource needs of each utility system. The different utility systems are experiencing very different growth rates, 0.8 percent to 4.0 percent per year, for different reasons. Similarly, five of the 11 large utility systems forecast major capacity deficits for 2010, two have small deficits, three have small surpluses, and one has a substantial surplus. Any response to the statewide capacity deficit must consider the different circumstances of each individual utility.

In the process of creating this report, we have been able, for the first time, to analyze individual utility IRPs in relation to each other. It is clear that IRPs are important not only individually as documents dealing with individual utility systems, but collectively as tools to determine statewide forecasts and action plans.

The regional, statewide and utility-specific forecast perspectives presented in this section show an estimated Minnesota capacity shortage of at least 2,000 MW by 2010. In addition to electric capacity needs, Minnesota faces transmission issues that are even more complicated and difficult to address than capacity needs. The next section explores these issues.

Electric Transmission Capacity and Regulation

Electric transmission facilities must be in place with enough capacity to move electricity from where it is generated to where it is consumed. Since a wireless technology for transmitting electricity has not yet been developed, there is no alternative to some form of the transmission wires with which we are all familiar.

Many existing transmission lines were installed up to fifty years ago. Some of Minnesota's transmission facilities are reaching the end of their useful lives. Transmission lines built fifty years ago were designed to meet existing and foreseeable future (typically 15 years) demand. Customer numbers and demand levels both have increased dramatically since the 1950s. The transmission lines in place to meet today's demand are the same lines built to meet demand of decades ago. Demand will continue to increase.

In addition, Federal Energy Regulatory Commission (FERC) Order 888 places a strain on existing lines. This order requires transmission owners to provide other utilities and marketers equal access to their lines. The result has been a dramatic increase in wholesale transactions through transmission grids not designed to accommodate a lot of bulk transfer from state to state and region to region. The need for new and/or upgraded transmission facilities is imminent.

This situation presents quite a challenge. Transmission lines are notoriously hard to site. The process usually involves resolution of both landowner and environmental issues. Usually a transmission line and its right-of-way touch or cross the property of many landowners who, collectively or individually, often actively and strongly oppose a transmission line proposal. Transmission lines also may cross wetlands or bisect forests contributing to ecosystem fragmentation. Both upgrading and building new electric transmission is one of Minnesota's biggest energy challenges—balancing environmental protection, landowners' rights, and the need to meet the ever-growing demand for electricity.

In addition, new transmission is needed to develop large-scale wind energy, which is increasingly cost competitive. Minnesota has a tremendous wind energy resource. The best wind resources, however, are in geographic areas distant from load centers where traditional electric generation plants, and therefore transmission lines, have not generally been built. New transmission capacity is critical to the full development of the upper Midwest's substantial wind resources.

Another related challenge surrounds the emergence of merchant power plant construction. "Merchant" plants are built and operated by non-utilities and are not subject to normal utility regulation. The backers of a merchant plant provide the financing for the project, price their product (electricity) as they please (usually to compete in the open market) and take the financial risk of profit or loss. Merchant plants, because they are not deemed "utilities" by Minnesota law[33] do not have the power of eminent domain to assist them in siting their facilities. Merchant plants face unique siting challenges because they must obtain the agreement of local landowners.

Research and advances in energy conservation and other distributed energy resources such as smaller generators located at or near where the electricity is used offer hope that soon there will be a way to ease the burden on the electric transmission system and reduce the need for new lines. A conclusion presented in the 2000 Energy Policy and Conservation Report continues to define strategic direction for infrastructure needs. It reads: "The demand for energy continues to increase but the power generating facilities and transmission infrastructure used to deliver power are already being used to their maximum potential. In order to preserve stable, reliable and attractively-priced energy resources, the energy companies, government and other affected parties must work together to adjust energy planning, management and governance to maximize energy conservation and enable emerging energy fuel sources and generation technologies to be developed and needed infrastructure enhancements to be built.[34]

The Evolving Regulatory System for Transmission

To develop a more competitive electric market, federal regulators are advocating open access to transmission lines by all entities that want to sell or buy electricity.[35] Federal policy changes are the main driving force behind the dramatic changes that have been occurring in the transmission system. The Federal Energy Regulatory Commission (FERC) oversees wholesale electric rates and service standards, as well as the transmission of electricity in interstate commerce. FERC ensures that wholesale and interstate transmission rates charged by utilities are just and reasonable and not unduly discriminatory or preferential. It also reviews utility interchange and coordination agreements. Power suppliers who refuse to comply with FERC regulations are subject to penalties.

FERC issued a landmark policy order in 1996 (FERC Order No. 888) that created an open access policy requirement for all transmission owning entities under its jurisdiction. FERC Order No. 888 requires transmission owners to provide equal access to all market participants on a "first come, first served" basis. The order also sets policies regarding operations of the grid and requires functional separation between the power marketing arm and transmission operating arm of vertically integrated utilities. It shifts the function of the transmission grid from primarily serving the transmission owners' interests (connecting generation with consumers) to creating a common carrier system for electricity that is open to market use, more like natural gas and other pipelines.

Responsibility for transmission infrastructure development and management of the transmission system is shifting from individual utilities in loosely organized regional organizations to more structured regional transmission organizations. Federal policies continue to drive developments in this direction. In 1999, FERC Order No. 2000, strongly encouraged all transmission-owning entities to join a Regional Transmission Organization (RTO).[36] These RTOs would be managed to facilitate independent system operations and stimulate development of large wholesale energy market areas. FERC stated that the ultimate goals of Order 2000 are to: (1) alleviate stress on the bulk power system caused by structural changes in the electric industry; (2) improve transmission grid efficiencies through pricing and congestion management; (3) improve grid reliability; (4) improve energy market performance; (5) increase coordination among state regulatory agencies; (6) reduce transaction costs; (7) facilitate growth and success of state retail access programs; (8) assure non-discriminatory access of transmission systems by separating control of grid operations from the influence of electric market participants; and (9) facilitate "light-handed" regulation.

Order 2000 describes four key characteristics and eight required functions of RTOs. These characteristics and functions are designed to ensure that any RTO will be independent and able to provide reliable, non-discriminatory and efficiently priced transmission service to support competitive regional bulk power markets.

The four minimum characteristics for an RTO are:[37]

(1) independence from market participants;
(2) appropriate scope and regional configuration;
(3) possession of operational authority for all transmission facilities under the RTO's control; and
(4) exclusive authority to maintain short-term reliability.

The required functions that an RTO must perform are:

(1) administer its own tariff administration and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;
(2) create market mechanisms to manage transmission congestion;
(3) develop and implement procedures to address parallel path flow issues;
(4) serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;
(5) operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;[38]

(6) monitor markets to identify necessary transmission additions and upgrades;
(7) plan and coordinate necessary transmission additions and upgrades; and
(8) ensure the integration of reliability practices within an interconnection and market interface practices among regions.

As long as these minimum characteristics and functions continue to be satisfied, FERC also adopted the principle of open architecture which allows for flexible and evolving RTOs that improve structure, geographic scope, market support and operations to meet changing market, organization and policy needs. FERC further clarified its vision for transmission system management in July 2001 by stating that it wants four large RTOs to manage the entire U.S. transmission system. However, FERC has recently suggested it may be reconsidering requiring only four large RTOS.

In the Midwest, most of the transmission owning members of MAPP are in the process of joining with utilities from several other regions in forming the Midwest Independent System Operator (MISO), based in Indianapolis, Indiana. MISO will become the operational control entity for a large multi-state region of the transmission grid.[39] FERC approved MISO as an RTO on December 19, 2001.

FERC expects that RTOs will have operational control of the transmission system including short-term reliability responsibility. MISO also will take over the facilities planning (100kV and above) for its member utilities. As the members of MAPP transition to membership in MISO, the MAPP planning process is expected to be incorporated into the MISO approach, currently still under development. Minnesota utilities and regulators are advocating that MISO retain much of the current MAPP planning process. Some of MAPP's assets and functions (specifically, NERC related liability functions and Power and Energy Market Committee functions) will be maintained in St. Paul under the new MISO structure.

MISO has established two regulatory seats on its Board. One seat is slated to be filled by a representative of one of the State Public Utility Commissions in MISO's territory. The other seat will be filled by a Consumer Advocate representative from one of the states in MISO's territory. Beginning December 2001, the Minnesota Department of Commerce has the privilege of holding the Consumer Advocate seat and the Iowa Utilities Board holds the Commission seat. Our participation on the MISO Board comes at a critical juncture in MISO's development. We expect to participate actively in helping to design MISO's future.

Another new development is the formation of TRANSLink Transmission Co. LLC, announced in September 2001. This "independent transmission company" is being formed by Xcel Energy, Alliant Energy, MidAmerican Energy (mostly an Iowa utility), Nebraska Public Power, Omaha Public Power, and Corn Belt Power (an Iowa cooperative) to take on some of the functions that FERC envisions being performed by a Regional Transmission Operator.[40] These functions would otherwise be performed by the new MISO. The nonprofit MISO has a special provision in its transmission owners' agreement that allows for-profit groups like the newly proposed transmission company to join as special members. American Transmission Co. LLC, a for-profit company that owns and operates the transmission systems of Wisconsin's major utilities, is a member of MISO in the special member category.

TRANSLink is intended to satisfy FERC requirements that electric utilities separate their transmission operations from their power supply (generation plants or power purchases) and wholesale and retail load serving functions. The company will need FERC's and Minnesota Public Utilities Commission's approval for structure, relationship with the member utilities, new tariffs (services and prices), and eventual recovery of costs in rates. The Department of Commerce is actively participating in the proceedings before both bodies to ensure that the public interest of Minnesotans is represented in the creation and operation of this new company.[41] Allocation of costs of constructing and operating the regional transmission system between ratepayers, power sources, bulk power customers, and others will require detailed analysis by the Department and others in these proceedings.

Though there are significant changes occurring in how the electric industry is organized, managed and regulated, there is broad consensus that the transmission system will continue to be federally regulated as the common carrier in the wholesale electric energy market. There is debate, however, about what role state governments will have or whether FERC will be the only regulator for both interstate and intrastate transmission. There is a proposal to grant authority to FERC to approve transmission lines that are needed regionally. This change would entail a large and mostly unprecedented shift of eminent domain authority from states to the federal government. Individual states always have had responsibility for approving the siting and construction of transmission lines. An alternative proposal would require groups of states to form organizations to which the states must grant necessary authority to manage regional planning issues.

The trend toward regionalization of transmission planning functions, coupled with the increasing ability of independent power producers to determine generation type and location, has had a disruptive effect on the traditional planning processes. Managing impacts to ratepayers from the costs of transmission facilities has traditionally been based on need and whether the facilities are "used and useful" to the ratepayers themselves. The evolution of the use of the transmission system for market purposes and for regional transactions has complicated the traditional analysis. As new generation plants are proposed in Minnesota for local needs and for interstate transfers, it is certain that new investment in the transmission system will be required; and adequate, but not intrusive, regulatory processes must be further developed.

The state's interest in transmission issues evolves over time. For example, the development of some of Minnesota's best wind energy resources on Buffalo Ridge in the southwestern part of the state has increased the need for additional transmission from there to the Twin Cities. In December 2001 Xcel Energy filed a Certificate of Need application with the PUC for a 345 kW transmission line and related transmission additions that will significantly increase the transfer of wind energy from the Ridge to the Twin Cities area and address other pre-existing transmission inadequacies in the Sioux Falls, South Dakota area. During the first half of 2002, the PUC will be considering various size, timing, reliability and cost considerations as it reviews the application. Various alternatives involving lower voltage, incremental transmission options are likely to emerge.

After maximizing energy conservation and other distributed energy resources, it is likely that new electric generation capacity must be added in Minnesota over the next decade and beyond. Even if that new generation is mostly from renewable sources like wind, large new transmission lines are necessary. Meeting the dual challenge of upgrading the aged existing system and building new at the same time will take determination and a more open and robust public discussion than has occurred to date.

Transmission line proposers increasingly must involve landowners, local government units, and other interested persons as early in the planning process as feasible. In addition, they must increase the flexibility of their planning processes to more adequately address the concerns of these individuals and groups. The continued reliability of the transmission system rests heavily on utilities and other transmission line proposers and how well and how flexibly they plan for upgrades and new lines.

State approval processes for determining the need for and siting of transmission lines need to be as efficient as possible while allowing meaningful and complete public participation. If transmission proposers wait until these approval processes, however, to involve the public, it is unlikely transmission will be built without long delays and excessive conflict.

Air Pollution Emissions

An important energy planning issue and challenge is what to do about air pollutant emissions from existing power plants. The emissions of concern are "of concern" for many reasons. Many air pollutants from electric power production directly impose health risks on humans. Many also negatively affect the natural environment and directly disrupt ecosystems, impose health risks on plants and animals and, therefore, indirectly affect human health. Energy policy is influenced by pollution control requirements to the degree that these requirements influence fuel choice at proposed power plants, choice of combustion technology, costs of the types of pollution control technology required at new and existing generation facilities, and facility capital and operating costs. Further, under proposed federal caps on

Figure 2.13: Electric Utility Contribution to Current Minnesota Air Emissions

	1999 Emission to the Air (thousand tons)	% of Estimated Statewide Emissions
Greenhouse Gases	35,982	26%
Nitrogen Oxides	87	18%
Sulfur Dioxide	95	58%
Carbon Monoxide	8	<1%
Fine Particulate Matter (2.5 microns)	?	large
Lead	0.03	62%
Mercury	0.0008	40%
Other Metals (Chromium, Arsenic, Nickel)	NA	10-60%

Source: PCA

Figure 2.14: Nonnuclear Baseload or Intermediate Load Electricity Generating Units at Plants Larger than 100 Megawatts*

	Capacity (summer) (MW)	Principal Fuel	Load Type	Start-up Datel	NSPS Status Vintage (Year)
Xcel Energy					
Sherburne County					
unit 1	712.0	coal	Baseload	1976	n/a
unit 2	721.0	coal	Baseload	1977	1976
unit 3	871.0	coal	Baseload	1987	1986
Allen King	571.0	coal	Baseload	1958	n/a
Riverside					
unit 7	150.0	coal	Baseload	1987	1986
unit 8	221.5	coal	Baseload	1964	n/a
High Bridge					
unit 5	97.0	coal	Intermediate	1956	n/a
unit 6	170.0	coal	Intermediate	1959	n/a
Black Dog					
unit 3	113.2	coal	Intermediate	1955	n/a
unit 4	171.8	coal	Intermediate	1960	n/a
XCEL total	3,959.6				
LS Power	252.1	gas	Intermediate	1998	1997
Rochester Publ. Util.					
Silver Lake					
unit 4	60.3	coal	Intermediate	1969	n/a
Minnesota Power					
Clay Boswell					
unit 1	69.0	coal	Intermediate	1958	n/a
unit 2	69.0	coal	Baseload	1960	n/a
unit 3	346.3	coal	Baseload	1973	n/a
unit 4	535.0	coal	Baseload	1980	1979
Syl Laskin					
unit 1	55.0	coal	Baseload	1953	n/a
unit 2	55.0	coal	Baseload	1953	n/a
subtotal	110.0				
Minnesota Power total	1,129.3				
OtterTail Power					
Hoot Lake					
unit 2	64.9	coal	Intermediate	1959	n/a
unit 3	84.0	coal	Intermediate	1964	n/a
Otter Tail Power total	156.9				
Minnesota Total	**5,355.7**				

**Does not include nuclear power reactions Monticello and Prairie Island 1 & 2.*

air emissions, fossil fuel-fired power plants in Minnesota will be required to implement large percentage reductions in emissions of such pollutants as nitrogen oxides, sulfur dioxide and mercury. In addition, some future control requirements that now appear inevitable may require switching to cleaner fuels or cleaner technologies.

2001 Minn. Laws, Ch. 212, Art. 7, Sec. 35 requires this report and the updated report due in 2002, to "identify important trends and issues in energy … environmental effects." Further, the legislation requires the reports to "address, among other issues: … (6) the environmental effects of energy consumption, including an analysis of the costs associated with reducing those effects; …." In preparing the report, The Department of Commerce is to "consult with other state agencies, including … the pollution control agency …."

The following discussion summarizes, and relates to energy planning, the study of environmental effects and control options contained in Appendix A. The appendix was, for the most part, prepared by Staff of the Pollution Control Agency (MPCA).

Addressing Environmental Impacts of Existing Facilities

Air pollutant emissions are the single largest source of environmental impact from electricity generation. Impacts on water and land are discussed as appropriate under each type of generation technology discussed in Chapter 3. This part will briefly discuss:

- current and forecasted emissions of pollutants from existing Minnesota power plants;
- effects of pollutants on human health and the environment;
- developing national regulations governing power plant emissions;
- methods and costs of reducing these emissions; and
- the potential impact on electric rates paid by consumers of various emission reduction methods.

Emissions

One of the most difficult issues in discussing future energy supply is what to do about existing power plants at a time when we need to build more capacity. Existing plants in Minnesota are a significant source, and for some pollutants, the major source of harmful air emissions. Overall emissions of air pollutants from power production need to be held steady and then decreased over time. The trend has been in the opposite direction.

Electric generation in Minnesota is primarily coal-fired. Figure 2-13 shows the total tons of emissions, by pollutant, from electric generation and electric generation's share of total emissions for each pollutant. The emissions of concern are nitrogen oxides (NOx), sulfur dioxide (SO_2), fine particulate matter ($PM_{2.5}$), mercury, and greenhouse gases (mostly carbon dioxide, CO_2).

Only five of Minnesota's coal fired power plants are regulated by New Source Performance Standards (NSPS) under the federal Clean Air Act. Of those five, four are regulated under old NSPS in force when they were approved for construction or substantial reconstruction (one each in 1976 and 1979, and two in 1986). The only generator regulated under current NSPS is the natural gas plant, LS Power Cottage Grove, built in 1998. Figure 2-14 lists the largest plants. Fifteen of the largest generators are not subject to any NSPS because they were constructed before the standards were adopted.

Figure 2-15 shows emissions of four pollutants per unit of production at the largest power plants. By comparison, the present performance standard at new or modified coal fired power plants for NOx is about 0.001 lb. per kWh. The lowest emitting large Minnesota coal plants emit four times that much and the highest emitting plants emit 11 times that much. The present performance standard at new or modified coal plants for SO_2 is about 0.001 to 0.002 lbs. per kWh. The lowest emitting large coal plant emits 1.5 to 3 times that amount and the highest emitting plant emits 10.5 to 21 times that amount.

No commercially available control technologies exist yet for mercury or CO_2. CO_2 emissions can be offset through tree planting and other forms of carbon sequestration. Depending on the type of fuel used and the control technology applied, NOx and SO_2 emissions can be reduced by 30 to 85 percent using readily available equipment and methods.

Since 1986, emissions of SO2, NOx and greenhouse gases from electric generation in Minnesota have either dramatically or steadily increased. Coal use is responsible for all or nearly all of these emissions. The spike in mercury emissions from solid waste incinerators that occurred in the late 1980s appears to be under control due to requirements for stringent mercury input and emission controls at incinerators. See Figures A-5 to A-8 and accompanying text in Appendix A. A steep decrease in SO2 emissions from 1985 to 1986 was due to increased use of lower sulfur western coal. Those emissions overall, however, are now climbing back up to 1985 levels.

Figure 2.15: Emission Rates Per Unit of Electricity Generated at Minnesota Electric Generating Plants

	Emission Rate (lb./kWh generated)				Primary Emission Controls[a,b]	
	NOx	SO_2	CO_2	Hg	SO_2	NOx
Xcel Energy						
Sherburne County	0.003	0.003	2.39	0.00000006	scrubbers	LNC, LNB
Allen King	0.011	0.017	2.10	0.00000002		
Riverside	0.011	0.012	2.11	0.00000003		
High Bridge	0.007	0.005	2.46	0.00000005		
Black Dog	0.010	0.004	2.60	0.00000003		
Minnesota Power						
Clay Boswell	0.004	0.006	2.34	0.00000005	scrubbers	LNC
Syl Laskin	0.006	0.004	2.27	0.00000007		
Otter Tail Power						
Hoot Lake	0.004	0.008	2.77	0.00000005		LNB
Rochester Publ. Util.						
Silver Lake	0.007	0.021	1.78	0.00000004	1	
LSP Cottage Grove	0.0002	0.000	0.94	NA		SCR

[a] LNC1 = low NO_X coal and air nozzles with close coupled overfire air; LNC2 = low NO_X coal and air nozzles with separated overfire air.

[b] low NOx controls 1 at Sherburne County unit 1 and low NO_X controls 2 at Sherburne County unit 2. Wet scrubbers at Sherburne County units 1 and 2 and Clay Boswell unit 4, dry lime scrubbers at Sherburne County unit 3.

The Future of Emissions from Electric Generation

The SherCo 3 unit, added in 1983, is the only relatively new coal-fired generator in Minnesota. The increases in emissions from electric generation are due mostly to increased utilization rates at existing plants, many of which are more than 40 years old. Figure A-9 and accompanying text in Appendix A show the increases in utilization rates.

There likely will be some further increase in use of existing plants. Increasing the overall capacity factors at these facilities by 5 percent or slightly more may be achievable. In aggregate, Minnesota utilities forecast, in their approved IRPs, an increase in coal throughput of about 2.5 million tons between 1999 and 2010.

In addition, new electric generation facilities are likely to be added to meet the growing demand for electricity in Minnesota. In the short term, a number of facilities are proposed and in the process of receiving regulatory approvals or are under construction. Figure 2-16 lists these facilities and their additional contributions to emissions.

Health and Environmental Effects of Emissions

Air pollution from power plants—especially coal-fired power plants—negatively affect human health as well as crops, forests, and wildlife. Coal provides about 75 percent of our electricity needs in Minnesota. Minnesota currently meets federal and state air quality standards. As scientific knowledge of the impacts of various pollutants improves it has become apparent that many of our standards were not as protective as previously thought.

Figure A-17 summarizes the key air pollutants emitted from electric generation and their effects on health and the environment. See Appendix A for more information on the effects of these pollutants. Many of these pollutants of concern directly impose health risks on humans. Many also directly disrupt ecosystems and impose health risks on plants and animals, thereby indirectly affecting human health. Fossil fuel-fired power plants are significant sources of these pollutants. Mercury deposition in our waters, acid rain and global climate change are intermediate-term regional concerns described in Appendix A.

Figure 2.16: Estimated Extra Annual SO_2, NO_X and CO_2 Emissions Associated with Permitted or Planned Expansions to Service or Capacity Added Since 2000

Plant Name	Generation Capacity (Summer) (MW)	Capacity Factor (%)	Net Generation (MWH/yr)	Efficiency in Converting Fuel to Electricity	Emissions SO_2 (tons)	NO_X (tons)	CO_2 (tons)
Pleasant Valley units #1-3	434	5	190,092	0.34	1	18	110,934
Lakefield Junction units #1-6	480	5	210,240	0.34	1	20	122,692
New Ulm unit #7	22	5	9,636	0.34	0	1	7,717
Cascade Creek units #3-4	50	5	21,900	0.34	0	2	12,780
Potlatch Cloquet unit #8	24	65	136,656	0.32	0	66	84,734
Navitas gas turbine	250	5	109,500	0.34	1	10	63,902
Otter Tail Power Solway unit #1	44	5	19,272	0.34	0	2	11,247
Prairie-Gen unit #1	49	5	21,462	0.34	0	2	12,525
St. James Diesel Plant units #1-7	12	5	5,256	0.25	9	117	5,725
Worthington Diesel Plant units #1-6	14	5	6,132	0.25	10	136	6,679
Black Dog units #2,5	143[a]	45[c]	1,144,757	0.5	-28[d]	-41[d]	435,075[d]
District Energy unit #7	25	65	142,350	0.2	39	182	61,668
Heartland Energy and Recycling	4	65	22,776	0.2	7	14	36,824
Fibrominn Biomass Power Plant	50	65	284,700	0.22	155	353	-
Northome Biomass Plant	15	65	85,410	0.26	14	56	-
Perham Resource Recovery	2.5	65	14,235	0.2	2	36	11,746
Grand Rapids power plant	195[b]	65	1,110,330	0.42	767	316	625,590
Total	**1,813.5**		**3,534,704**		**978**	**1,288**	**1,609,838**

[a] net increase in generation capacity after conversion of existing unit 2 to combined cycle gas turbine, retirement of existing unit 1, and addition of unit 5. [b] net increase in generation capacity after subtraction of internal Blandin demand. [c] 45% capacity factor at 290.4 MW of capacity at repowered unit #2 and new unit #5. [d] estimated emissions at repowered unit #2 and new unit #5 less 1999 emissions from old units #1 and 2.

NOTE: In addition, approximately 3,020 tons of existing SO_2 emissions, 2,849 tons of existing NO_X emmissions and 1,215,921 tons of CO_2 would be shifted from the industrial sector to the electricity generation sector with the conversion of the 187.7MW LTV-Taconite Harbor plant to a generating facility serving the grid.

Two types of air pollution could be near-term problems in Minnesota: Particulate Matter and Ozone

Particulate matter, especially very small or fine particles (PM2.5), pose health concerns because they are inhaled and lodge in the lungs. EPA based its 1997 PM2.5 standard on the relationship between fine particles and severe human health effects. Dozens of studies published since the PM2.5 standard was promulgated strengthen the validity of the relationship between fine particles and severe human health effects—from respiratory illness to premature death. Monitored concentrations of PM2.5 in the Twin Cities are not far below the standard. In addition, particles are a major contributor to visibility impairment and regional haze—even in the most pristine areas of Minnesota.

Ozone pollution occurs when NOx and volatile organic compounds in the atmosphere react in hot, sunny weather. Ozone can affect plants and is irritating to the eye, nose, throat and respiratory systems. For the first time since the mid-1970s the MPCA issued air advisories for the Twin Cities in the summer of 2001 due to ozone. Two more summers like that of 2001 and EPA could require Minnesota to submit a plan to reduce ozone—including additional controls on large stationary sources like power plants.

Potential Future Environmental Regulatory Developments

Due to the seriousness of the environmental problems associated with air emissions from the combustion principally of coal and oil, it is now inevitable that air pollution control requirements both nationally and at Minnesota plants will be tightened over the next decade.[42] Allowable emissions, particularly of already regulated pollutants, particularly nitrogen oxides and sulfur dioxide, are likely to be halved. New requirements will be developed for emissions of mercury, and also for greenhouse gases. It is possible, and even likely, that, as the health effects science related to human exposures to ozone and fine and ultrafine particulate matter is better developed, new, more stringent emissions standards will be developed.

Over the lifetimes of the power plants (50 to 75 years) that might be built over the next few years, we will see a progressive downward trend in allowable emissions of all pollutants, at final levels that are a fraction of current allowable levels.

Each downward ratcheting of standards will require the installation of new, ever more effective, expensive control equipment. In the case of some pollutants, like carbon dioxide, fuel switching to cleaner fuels like natural gas and enhanced efficiency of fuel use may be necessary to realize required reductions. This means that the present-day choice of fuels and design for new electricity generating facilities becomes an important consideration in state energy policy. It is imperative that state energy planners pay attention to likely future regulatory demands. To fail to do this is to take the risk that newly constructed plants may not be operable within a decade even with control equipment, or may require a sequence of otherwise unnecessary expensive retrofits.

In the case of existing facilities, emissions must decline under any of the proposed national pollution caps.

Costs of Reducing Emissions

During the 1990s Minnesota power plant owners reduced SO_2 and NOx at a few plants to meet the requirements of the Clean Air Act Amendments of 1990. They did so without significant equipment additions or application of control technologies but by switching to lower sulfur coal for SO_2 and making modifications to a few plants for NOx. Because they have not made major modifications to the existing plants for the most part, there is substantial potential for reducing emissions at these plants.

The pollutants for which the most available and tested control technologies exist are SO_2 and NOx. MPCA staff have identified various options for reducing these pollutants at five modeled power plants. The models were based on Minnesota's existing power plants. These options would apply to plants similar to the five models identified. The staff then determined the most cost effective control technology for each facility, based on the facility's boiler technology. See Appendix A and Figures A-19 to A-24 for a detailed explanation of how MPCA staff determined the technologies and costs.

The Potential Impact on Ratepayers

Department of Commerce Staff then estimated the potential impact on residential rates[43] of installing the identified emissions reduction technologies. As shown in Figures 2-17 and 2-18, the potential average residential rate impact for SO_2 controls could range from \$3.59 to \$27.42 per year. For NOx controls, the annual effects could range from \$1.02 to \$7.87 per customer, for each plant. For any given household, if more than one of its utility's plants installed the control technology, the rate impact would be the total of the amount for each of that utility's facilities that is upgraded. These rate impacts would decrease if the life of a facility were extended beyond its present expected plant operation period and the costs were depreciated over a longer time. It is likely that such a major improvement as pollution control equipment would either directly or indirectly (by offering an opportunity for other improvements) extend the life of an aging plant.

In 2001, the legislature authorized direct pass-through to retail customers of the costs of the emissions reduction technologies. Utilities may now invest in emissions reduction technologies and recover the costs of doing so without a major rate case before the PUC. The portion of the costs attributable to electricity sold on the wholesale market cannot be recovered from the utility's retail customers. The PUC will determine what costs may be passed directly through to retail customers.

Policy Recommendations

It is likely that new, nonrenewable electric generation plants constructed in Minnesota to meet growing demand for electricity will increase overall emissions of air pollution. Setting a goal of not increasing emissions from electric generation over present levels is worth exploring. This would entail among other things, definitive action to "clean up" older plants, especially when new plants are constructed in order to help maintain or decrease overall current emissions levels. Fortunately, there are readily available emissions reduction technologies for existing plants that would not overburden ratepayers with high costs. Additionally, switching from coal to natu-

Figure 2.17: Estimated Rate Impact of Installing SO_2 Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 \$[2] (b)	Annual Baseload \$ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 \$ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	1.2381	10.30	1.1924	9.92
2	Hoot Lake 2	10.23	2.3816	24.35	2.2743	23.25
3	High Bridge 6/Riverside	7.78	0.4802	3.74	0.4612	3.59
4	A.S. King	7.78	1.3804	10.74	1.3316	10.36
5	Clay Boswell 3	8.32	3.4615	28.79	3.2970	27.42

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report
[2] Sheet 1
[3] column (a) times column (b)
[4] column (a) times column (d)

Figure 2.18: Estimated Rate Impact of Installing NOx Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 \$[2] (b)	Annual Baseload \$ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 \$ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	0.3140	2.61	0.3044	2.53
2	Hoot Lake 2	10.23	0.8151	8.33	0.7699	7.87
3	High Bridge 6/Riverside	7.78	0.1313	1.02	0.1313	1.02
4	A.S. King	7.78	0.3543	2.75	0.3363	2.62
5	Clay Boswell 3	8.32	0.4545	3.78	0.4160	3.46

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report
[2] Sheet 1
[3] column (a) times column (b)
[4] column (a) times column (d)

ral gas, which is being done at part of Xcel Energy's Black Dog plant, is an option that utilities ought to explore.[44] There may be older, smaller plants that emit a disproportionate amount of air pollutants that ought to be closed. All of these options ought to be explored in each utility's Integrated Resource Plan as it is regularly updated.

Additional policy considerations include whether to require utilities to prepare studies on cost effective pollution controls at some of their major existing uncontrolled generating plants. Another issue that may need to be addressed, depending on the response of utilities to the opportunity provided by the emission rider, would be to require certain projects to be implemented that the Public Utilities Commission determines to be cost-effective for ratepayers and to have significant positive impact on environmental emissions. The present emissions rider language makes implementation of a project entirely voluntary with the utility.

ENDNOTES

20. Electric energy refers to how much electricity is used during a given period of time, typically an hour, a month, or a year and is measured in kilowatt hours, megawatt hours, or gigawatt hours. Electric demand or electric capacity refers to how much electricity customers are pulling from the electric system in a given instant and is measured in kilowatts (KW), megawatts (MW) or gigawatts (GW). These concepts are discussed in Chapter 1.

21. MAPP issues forecasts for MAPP-USA and MAPP-Canada. This section presents the MAPP-USA forecast. However, it is important to keep in mind that MAPP operates as a region, without regard to federal or state political boundaries.

22. The 15 percent reserve margin ensures that, even if a major power plant must be taken off the system during hours of peak usage, alternative power sources can be brought on line to keep the lights on.

23. One GWh represents the amount of electricity 128 typical residential customers of Xcel Energy might use in a year.

24. A "capacity deficit" usually means a shortage of electricity to meet peak demand by customers on a very hot, humid day as well as fulfill MAPP's 15 percent reserve capacity.

25. The forecasts include the reduction in demand that would have been achieved by the existing utility conservation programs. The forecasts do not include further reductions expected to be attained by implementing the 2001 legislative changes to the conservation programs. This issue is further discussed in Chapter 4.

26. See the Department's 1998 Minnesota Utility Data Book, *which contains data for 1965 to 1998.*

27. In 2000, Minnesotans consumed 62,532 GWh of electricity, higher than the trend line prediction for 2001. See Figure 1-3.

28. Here "large" is defined as being utilities that file data separately with MAPP and either file an integrated resource plan with the Public Utilities Commission or have a capacity surplus or deficit of at least 100 MW in one year.

29. The organizations are Xcel Energy, Otter Tail Power Company, Minnesota Power Company, Great River Energy, Gen~Sys Energy (Dairyland Power Cooperative), Basin Electric Power Cooperative (representing East River Electric and L&O), Minnkota Power Cooperative, Southern Minnesota Municipal Power Agency, Missouri River Energy Services, Rochester Public Utilities, and Minnesota Municipal Power Agency.

30. The 9 utilities are: Alliant Energy Corporation, Minnesota Power Company, Otter Tail Power Company, Xcel Energy Inc., Dairyland Power Cooperative, Great River Energy, Minnkota Power Cooperative, Inc., Missouri River Energy Services, and Southern Minnesota Municipal Power Agency.

31. The numbers presented for Minnesota Power are the Company's figures from its 1999 IRP. The Department of Commerce disagrees with those figures and believes the surplus is substantially larger, because Minnesota Power did not factor into its forecast certain peak management opportunities available to it. The exact size of this is known to the Department, but is claimed a trade secret by Minnesota Power and is thus not included in this report. The figures filed in MP's most recent IRP, filed November 1, 2001, indicate that MP may experience deficits in the 15-year planning period. However, those figures are still under review.

The numbers presented for Great River Energy (GRE) are GRE's figures. The Department has questioned the accuracy of GRE's filing, and expressed concern over how load-building activities have played a role in GRE's capacity situation. Since IRPs are only advisory for GRE, the Department's comments are simply a matter of public record. No binding Minnesota Public Utilities Commission Order is pending, but the Minnesota Public Utilities Commission will issue an advisory Order.

32. Xcel Energy uses a bidding process to choose generation capacity from either independent power producers, other utilities, Xcel or Xcel's subsidiaries. Xcel has bid in this process, but has not won a bid.

33. Minnesota Statute § 216B.02, subd. 4 defines utilities as providing retail electric service to the public.

34. Energy Policy and Conservation Report for 2000, Minnesota Department of Commerce, p. 38, available at www.commerce.state.mn.us.

35. The North American power grid is actually three loosely interconnected grids which are minimally interconnected to each other, if at all: one in Texas and two more (east and west), splitting the rest of the country roughly along the Continental Divide. Minnesota and other north central states encompassed by MAPP are in the eastern grid. Figure 1-36 shows the transmission grid in the United States.

36. Recent FERC Orders have threatened to disapprove mergers unless utilities join RTOs.

37. FERC Docket No. RM99-2-000, Order No. 2000, December 20, 1999, pp. 151-152.

38. TTC stands for total transmission capability and ATC stands for available transmission capability. OASIS is the Federal Energy Regulatory Commission's Open Access Same-Time Information System, which informs potential customers of the price and availability of service and other related information.

39. Please see Appendix F, Part 1 for copies of background information on MISO presented to MISO's Board at its December 13, 2001 meeting in Indianapolis.

40. However, MISO will continue to perform the functions of security coordination and market monitoring.

41. For example, Commerce filed a rehearing request challenging FERC's authority over the transmission component of Minnesota's electric bundled retail rate. Commerce also challenged a MISO cost adder being forced on to Minnesota's electric bundled retail rate. This rehearing request is still pending before the FERC.

42. Regulatory developments of significance for electricity generation facilities that we foresee for the next decade include: new or tightened national emission caps for sulfur dioxide and nitrogen dioxide; emission standards for mercury or, in lieu of that, a national mercury emission cap; and some as yet undefined control regime for greenhouse gases.

Sulfur Dioxide and Nitrogen Oxides: *Due to the lack of improvement of acidity levels in northeastern U.S. water bodies and persistent high surface ozone levels throughout the eastern U.S. The Bush Administration is proposing a national cap on NOx emissions and a new, lower cap on* SO_2 *emissions. National emission reductions of between 50 and 80 percent are being discussed for each of these pollutants. These would take effect in 2012.*

Mercury: *Under a proposed federal rulemaking, due out in 2003, mercury controls will be developed for coal-burning power plants. These will become effective beginning in 2007, and will require at least 50 percent mercury control, and possibly as much as 85 percent mercury control.*

As an alternative to this, a national cap on mercury emissions that would reduce emissions from power plants by 50 to 90 percent using a cap-and-trade program also is being considered.

Greenhouse Gases: *This past fall, all of our major international trading partners, including the nations of western Europe and Japan, agreed to the provisions of the Kyoto Protocol on greenhouse gas emissions control. The Kyoto Protocol requires mandatory emission reductions of 5 percent from 1990 emission levels of all developed economies. These countries can exert pressure across a range of issue areas, including trade liberalization, military cooperation, and other security issues. If the United States decides at some point to join the Protocol, U.S. greenhouse gas emissions would need to be reduced by 7 percent below 1990 levels.*

Fine Particulate and Regional Haze: *Due to the proximity of Minnesota power plants to Class I areas like the BWCA and Isle Royale, additional pollution control requirements for* SO_2 *and NOx are required by 1999 Federal regional haze rules beginning in 2011. When required, these controls will cover facilities built between 1962 and 1977, including many existing Minnesota power plants. No new emissions of* SO_2 *and NOx that will degrade visibility in these areas are allowed from any source.*

43. Because of the variance among IOUs' rates and among different sizes of commercial and industrial customers' rates, a general rate impact analysis would have been very difficult to calculate and not representative of these customers' energy situations.

44. As part of negotiated settlements with interested parties, Xcel Energy agreed to study repowering (with natural gas) options at three of its plants, King, High Bridge, and Riverside. Through a separate agreement during the 2001 legislative session, Xcel Energy agreed to study other emission control options at these plants. The cost figures above will in all likelihood apply to those plants. The legislature could require all utilities to prepare similar analyses for their plants. Another possibility is for the Legislature to require utilities to install emissions control equipment that is cost effective and would significantly reduce emissions, after the utilities' studies are complete.

THREE: STRATEGIES TO MEET ELECTRIC DEMAND

The range of efficiency a particular generation technology can achieve in converting the energy in its fuel to electricity is important because nationally in 2000 about two-thirds of all energy used to generate electricity was lost, usually as heat, in the process of its conversion from fuel to electricity. Another 9 percent of electricity generated is lost in the process of transmission and distribution to customers. Further losses are suffered, and energy wasted, if the end-user uses the electricity to power low efficiency machines, appliances and light bulbs. Efficiency factors vary between categories of generation technology and even within each category.

This chapter lists electric generation technologies and discusses their efficiencies, potential for and barriers to further development, costs to construct and operate new facilities, and environmental effects of each technology. No generation technology exists that either does not bring with it adverse economic or environmental effects or does not have other significant barriers to its greater deployment. For example, Appendix A, prepared by Pollution Control Agency staff, provides detailed material on the environmental and potential health effects of coal technologies, and to a much lesser degree, natural gas and other combustible fuel technologies.

Figure 3.2: Relative Emissions from Electric Utilities Nationally, 1999

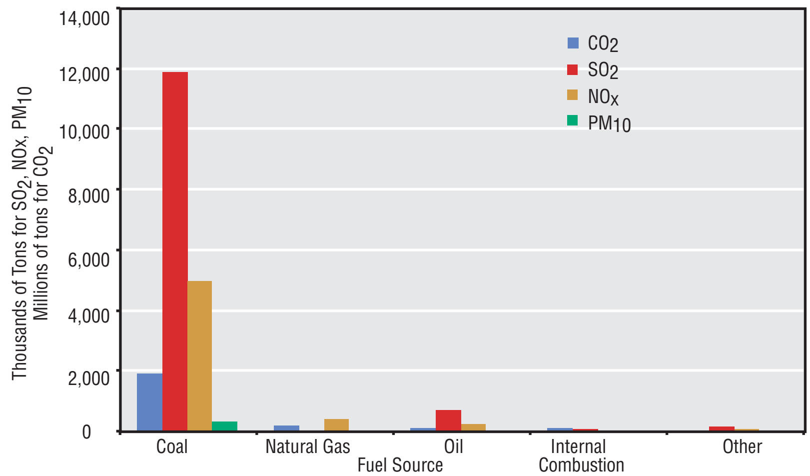
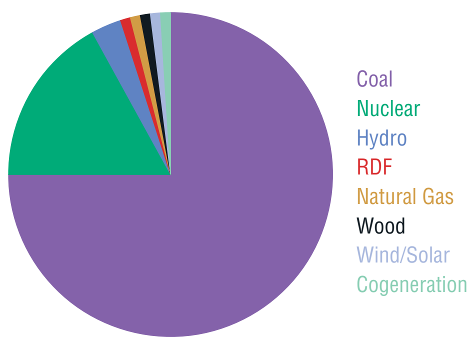


Figure 3.1: Fuel Used to Generate Electricity to Serve Minnesota, 2000



When thinking about future strategies to meet electric demand, it is helpful to first review the current system. Figure 3-1 shows the fuel inputs used to generate Minnesota's electricity in 2000.[45] Minnesotans consumed 62,532,000 megawatt hours of electricity in 2000, and spent $3.4 billion to purchase it for an average of 5.43¢ kWh. The largest environmental impact of electric generation is through its air emissions. In 1999 emissions included, for instance, 35,982,000 tons of greenhouse gases, 87,000 tons of nitrogen oxides, 95,000 tons of sulfur dioxide, and 0.8 ton of toxic mercury. Figure 3-2 shows that, when compared to coal, other electric generation sources contribute significantly smaller amounts of these air pollutants.[46]

The range of efficiency a particular generation technology can achieve in converting the energy in its fuel to electricity is important because nationally in 2000 about two-thirds of all energy used to generate electricity was lost, usually as heat, in the process of its conversion from fuel to electricity. Another 9 percent of electricity generated is lost in the process of transmission and distribution to customers.[47] Further losses are suffered, and energy wasted, if the end-user uses the electricity to power low efficiency machines, appliances and light bulbs. Efficiency factors vary between categories of generation technology and even within each category.

Conservation addresses efficiency of use by consumers and is addressed in Chapter 4. It is the best option for our energy future. Investment in conservation measures is the cheapest investment we can make in the energy system. It should be maximized before we decide to make the higher investments necessary for generation technologies, which nearly all also come with longer term fuel and operation and maintenance costs that are not subject to price-moderating regulation.

Figure 3-3 shows projects by time, size and type, that are under construction, approved, or for which

Figure 3.3: New Electric Generation Projects in Process

Project	Location	Type	Year	Size	Fuel
Under Construction (139 MW)					
Black Dog _	Dakota County	Intermediate	2002	114 MW	Gas
District Heating	St. Paul	Baseload		25 MW	Waste Wood
Approved Purchased Power Agreement (PPA) (100 MW)					
EPS/Beck		Baseload		50 MW	Whole Trees
FibroMinn	Benson	Baseload		50 MW	Turkey Litter
Won All-Source Bid, PPA Pending (250 MW)					
Navitas/NEA		Intermediate Peaking		50 MW 250 Gas	Wind
Application Expected (225 MW)					
Rapids Power LLC	Grand Rapids	Baseload	2005	225 MW	Coal, Wood
Other (268 MW)					
Bid Selection in Process by Xcel Energy		Intermediate		80 MW	Wind
LTV Power Plant	Taconite Harbor	Baseload		188 MW	Coal

approval processes are underway, in Minnesota. These projects total 1,032 MW of capacity.[48]

One of the important things to keep in mind is that in evaluating new technology, the relevant cost figures are the cost to build a new facility. Comparison of costs should occur among potential new facilities and their costs, not with reference to the costs of existing facilities that were built 20 to 50 years ago. This section attempts to provide the proper context to be able to make that comparison. A more difficult cost comparison, except in the broadest terms, is the relative costs of fuel and operation and maintenance for new facilities.

In 2001, the Legislature provided a significant impetus to further development of renewable generation technologies by establishing a renewable technology objective, and requiring utilities to exert good faith efforts to achieve the objective. This objective is designed to increase the percentage of energy generated by renewable resources to 1 percent in 2005 and then gradually to 10 percent by the year 2015. In addition, the Legislature required a specific portion of renewable energy generation to focus on biomass energy production technologies. We will closely monitor the utilities' progress in meeting this objective and may, in the future, recommend adjustments to it.

We will continue to advocate for an increase in the threshold for net metering for distributed generation resources to 2 megawatts. As the discussion of net metering found later in this Chapter shows, the very low avoided cost figures used to date, combined with the very low threshold for net metering of less than 40 kilowatts, is a substantial barrier to maximum cost-effective deployment of a variety of distributed generation technologies and combined heat and power technologies at Minnesota's industrial facilities. The PUC should generically set prices for net metered power between 41 kW and 2 MW. The present statute should be amended to cover 40 kW and below, as well as address interconnection requirements that are years out of date.

Finally, the decisions made today will be the technologies, with both their costs and their environmental impacts, for the next 40 to 50 years, or possibly longer. As a result, major investments must be made with an eye to long-term implications of today's decisions. In particular, policymakers should keep in mind the promising technology represented by the development of fuel cells and pilot projects in the storage of electricity. Their potential to revolutionize the production of energy in the next 10 to 15 years, and reduce substantially its environmental effects, cannot be overstated.

Improved Technology

Technology improvements in electric generation transmission, distribution, and consumption are likely. Improved control components will be developed and installed to handle the increased complexity of operation of electric systems. Solid state controls and power conditioning equipment are likely to grow in importance. Transmission system owners need improved telecommunications with all parts of their networks. Improved conductors, transmission line towers and underground transmission technologies could help alleviate bottlenecks and reduce the cost of new lines.

The Electric Power Research Institute (EPRI), the research and development arm of the electric industry, reports that use of real time information generated by new monitoring technology has allowed one western U.S. utility to improve capacity on a major circuit and defer construction of a new transmission line for up to five years with savings of up to $20 million. New superconducting cable technology has the potential to carry three to ten times the current of existing underground cable systems. The first installation is underway in Detroit. It has promise for many applications, especially in constrained rights-of-way.

EPRI recommends that the existing radial, electromechanically controlled grid needs to be transformed into an electronically controlled, smart electricity network in order to handle the escalating demands of competitive markets in terms of scale, complexity and power quality.

In Minnesota, we need to include improved technology options in our deliberations about improved or new transmission, as well as new generation. Utilities and other transmission proposers must treat technology options as a distinct component of the transmission planning process.

TECHNOLOGIES TO GENERATE ELECTRICITY

This section will discuss in turn each of several technologies that are available to generate electricity. The first group of technologies includes hydropower, solid waste combustion, landfill gas, and diesel/biodiesel generation. All these technologies, while well-established, are limited in the amounts of electric capacity they are able to generate for Minnesota.

Nuclear power, coal, natural gas and wind make up the next several well-established electric generation technologies discussed. This group of technologies currently provide the majority of electric generation in the state.

A discussion on distributed energy resources (DER) follows, focusing on the use of combined heat and power as a mechanism to increase efficiency. DER is local, small-scale generation that crosses over many technologies. The technologies may vary in environmental emissions—microturbines, fuel cells, and wind turbines can all be considered DER.

Finally, there is a discussion of the various technologies that are expected to be more prevalent in the coming years or decades. These future technologies include biogas, biomass, solar and fuel cells.

LIMITED CAPACITY TECHNOLOGY

Hydropower Located in Minnesota

Hydroelectric power plants convert the potential energy in water pooled at a higher elevation into electricity by passing the water through a turbine and discharging it at a lower elevation. The water moving downhill turns the turbine to generate electric energy.

Hydropower projects are generally operated in a run-of-river, peaking, or storage mode. Run-of-river projects use the natural flow of the river and produce relatively little change in the stream channel and stream flow. A peaking project impounds and releases water when the energy is needed. A storage project extensively impounds and stores water during high-flow periods to augment the water available during low-flow periods, allowing the flow releases in power production to be more constant. Many projects can function in more than one of these modes.

Currently, there are approximately 22 hydroelectric generating stations in the state of Minnesota, producing slightly under 150 megawatts of capacity. Figure 3-4 lists the four largest projects; the rest of the projects are under four megawatts of capacity (the majority of those are under two megawatts).

Figure 3.4: Largest Hydropower Projects Located in Minnesota, 1998

		MW
Thompson	MP	72.6
Blanchard	MP	18
Fon Du Lac	MP	12
Hennepin Island	Xcel	12

Out-of-state hydropower projects in Wisconsin and South Dakota that generate some electricity used in Minnesota include approximately 19 projects that have a total capacity of 255.6 megawatts.[49] Additionally, Minnesota imports 850 megawatts of hydropower from Manitoba Hydropower.

While the theoretical potential of hydropower development in the upper Midwest states amounts to approximately 2,500 megawatts over 471 sites, practical development of this capacity requires that the supporting infrastructure, such as transmission lines, site access and dam development, is either present or readily able to be developed. There is not a single site in Minnesota, Wisconsin, North Dakota or Iowa with more than 52 megawatts of potential capacity. South Dakota has three sites with more than 129 megawatts of potential capacity, but two of these sites are beyond the jurisdiction of the South Dakota Public Utilities Commission and a third site has no dam or power generating capacity built.[50]

The Canadian part of the MAPP region includes southern Manitoba and southern Saskatchewan. Manitoba, through its Crown Corporation Manitoba Hydro, currently generates roughly 5,000 MW of hydropower and has the potential for developing an additional 5,000 MW of hydro power generation capacity.

The portions of Manitoba Hydro's generation which is delivered directly into Minnesota is transmitted principally via a 500 kV transmission line from Manitoba into Minnesota. Manitoba Hydro is currently in the process of obtaining permits for a new 230 kV transmission line between Manitoba and North Dakota. This transmission line would provide greater transfer capability between Manitoba and the U.S.

Many issues have been raised as to environmental and socio-economic issues stemming from Manitoba

Hydro's development of its hydropower facilities. Please see Part 2 of Appendix F (public comments) for the comments of parties involved in discussion of these issues.[51]

The operation of a hydroelectric generating station is a well-developed technology and, therefore, the reliability of a plant is very high, except in periods where the presence of ice or sustained drought reduces the availability of water to turn the turbines. The overall efficiency of a hydroelectric plant in converting the energy of the water into electricity is about 80 percent as compared with 33 to 42 percent for coal and 55+ percent for natural gas.[52]

While hydroelectric stations have few air emissions, they can have significant environmental effects related to the altered flow of bodies of water, water quality degradation, effects on fish and aquatic population, blockage of upstream fish migration, and flooding of land. In addition, the decay of organic matter in the shallow lakes created as a result of hydroelectric projects results in the production of small amounts of greenhouse gases.[53]

The capital costs for constructing a hydropower facility is estimated to be in the range of $1,700 to $2,300 per kilowatt (1996 dollars). These costs would necessarily be for multiple small facilities based on availability of the resource. Operating costs of hydroelectric plants are generally fairly low, because the flowing river water generally has no direct cost associated with its use.[54]

Given that the significant hydroelectric resources of the state have already been captured and used for the generation of electricity for several decades, it does not appear that there is a potential for significant development of in-state hydropower to meet part of Minnesota's additional electricity needs.

Energy from Solid Waste Management

Electric energy can be generated as a byproduct of solid waste management in two different ways.

First, landfill gas (LFG) can be collected and burned to produce some electricity. Second, mixed municipal solid waste can be processed into refuse-derived fuel and burned in generators to produce some electricity, or can be mass burned without processing to produce some electricity. Both methods of generating electricity have been used by the state as part of the state's comprehensive approach to solid waste management.[55]

Mixed Municipal Solid Waste

In the Waste Management Act, Minnesota Statutes Chapter 115A, the state began a series of initiatives in the 1980s to reduce the amount of solid waste deposited in landfills in Minnesota. In addition to a dramatic increase in recycling efforts, many counties chose to either build or send solid waste to facilities that could burn the waste and reduce its volume and generate some electricity to help offset the cost of the project. The building of incinerators or conversion of power plants to burn solid waste was implemented aggressively in the 1980s, and was controversial due to concerns about air emissions from burning the wide variety of materials present in solid waste. The state has now developed, and has had in place for some time, a comprehensive environmental regulatory program with waste combustor rules that apply to this type of facility.

Minnesota currently burns about one quarter of its municipal solid waste in municipal waste combustors. Five of the state's ten municipal waste combustors generate electricity and the others produce steam for sale to co-located manufacturing facilities. Figure 3.5 shows the five waste combustors that burn either refuse-derived fuel or unprocessed solid waste and generate electricity for sale to the local utility.[56] This table shows that, at present, waste combustors in the state generate a combined total of 128 megawatts of electric capacity.

Figure 3.5: Waste Combusters that Generate Electricity, 1999

Company/Location	MW	Utility Sold To	Type
Xcel Red Wing	21.3	Xcel	RDF
Xcel Wilmarth	22	Xcel	RDF
Great River-Elk River	42.1	Xcel	RDF
Hennepin County	38	Xcel	Mass Burn
Olmsted County	4.7	Rochester Public Utility	Mass Burn

No new municipal solid waste combustor has been built in the state since a court decision struck down counties' ability to require that waste be sent to these facilities. As a result, if it is cheaper to transport the solid waste to a landfill, waste haulers have chosen to do so. This change has largely resulted in Minnesota's solid waste being trucked out of state for disposal in landfills. It is unclear, given that the waste cannot be required to be burned in these facilities, whether there is further room for economic development of any more facilities.

More importantly, the main function of these facilities was to implement county solid waste management plans and reduce the amount of solid waste directly landfilled. While these facilities generate some electricity that helps defray the cost of the solid waste management function, they would not, standing alone, have been likely to be economically viable electric generation plants.

The primary air pollutants related to municipal solid waste combustion are polychlorinated dioxins and furans ("dioxins") and mercury. Dioxin is produced when waste containing chlorine compounds is burned. The amounts of dioxin formed during waste combustion is variable and dependent on the composition of the waste, the temperatures at which it is burned, and the type and operation of air pollution control devices. Mercury releases depend on the amount of mercury in the waste and subsequent air pollution control devices. Air pollution control has significantly reduced mercury emissions in the past decade.

Landfill Gas

Significant quantities of methane gas and other volatile organic compounds are emitted from municipal solid waste deposited in landfills. This gas can be used for generating electricity on the site of the landfill. An electric generating plant using Landfill Gas (LFG) is similar to one using natural gas, except it needs more careful monitoring of equipment because of the potentially corrosive nature of LFG. An LFG system consists of a gas collection system which gathers the LFG being produced within the landfill, a diesel generator or gas turbine which converts it into electricity, and interconnection equipment to deliver the electricity to the power grid. Figure 3-6 shows five projects in the state where LFG is used to generate electricity.

Figure 3.6: Landfill Gas Systems that Generate Electricity, 1999

Location	MW	Sales to
Pine Bend	12	Xcel
Burnsville	4.2	Xcel
Flying Cloud	4.8	Xcel
Elk River	.5	Conexsus
Anoka	5	NOCO Cooperative

Many of the LFG gas projects that can generate significant amounts of electricity have already been constructed. A 1996 study by the United States Environmental Protection Agency concluded that landfill gas based electric generation potential in Minnesota is about 14.3 megawatts. Another study, developed in conjunction with the certificate of need for the Lakefield Junction natural gas plant, estimated that LFG-based electric generation in Minnesota could add approximately two megawatts per year in additional generating capacity if all landfill gas opportunities could be developed.[57]

These systems convert energy at an efficiency rating of approximately 17 to 26 percent. This figure includes an allowance that approximately 70 to 80 percent of the gas generated in a landfill is capable of collection, as well as the typical efficiency of generators being between 25 and 33 percent. LFG systems are reliable, and are expected to be available for combustion more than 90 percent of the time.[58]Burning methane, instead of releasing it directly into the air, reduces greenhouse gas emissions. It increases emissions of nitrogen oxides and lesser amounts of other air pollutants. The overall emissions from this type of project provides a net benefit to the atmosphere due to the combustion of greenhouse gases (methane).

The capital costs for constructing a landfill gas facility is something less than $1,000 per kilowatt. Annual operating expenses are likely less than for a typical fuel-fired power plant because the landfill gas is not typically a purchased input. If a landfill gas system is capable of producing electricity in some amount, the income to the combustion system operator would offset part of the overall cost of abating direct landfill gas emissions.[59]

Investments have been made in Minnesota for the equipment that could burn LFG to generate electricity where it is economical. MP-Allete investigated the prospects for further LFG combustion to generate electricity a couple of years ago and found that the cost-effective sites had already been developed. Like the combustion of solid waste, the combustion of LFG to generate electricity serves more to improve the economics of the solid waste management system, rather than contribute a significant amount of capacity to the electric grid. In that sense, the fact that these projects can generate electricity can be helpful to the state in reaching its solid waste management and air emission goals. It is unlikely, however, that sufficient capacity exists from either approach to significantly contribute to needed new electric capacity in the state.

Diesel/Biodiesel

Diesel generators are one of the most polluting types of generation per kilowatt-hour generated, emitting many air pollutants at high levels. In recent years, a lot of distributed generation capacity[60] has been installed in the state of Minnesota. Informal surveys suggest that, in aggregate, 300 MW of installed distributed generation capacity currently may be in place in the metropolitan Twin Cities area. Modular diesel capacity is the most popular form of distributed generation. Most diesel generators are small, 1 MW or less in generating capacity.

Aggregate annual emissions from modular diesel generation are probably small in relation to statewide emission totals. However, due to their short stacks, and their placement where people work and live, operation of modular diesel generators can significantly degrade local air quality conditions and can lead to violation of ambient air quality standards. Modeling of diesel generators by PCA staff frequently shows violation of emergency-episode levels for NOx which are associated with acute human health effects. Diesel generators are a priority for the PCA with regards to local air quality concerns.[61]

Pollutants emitted from diesel combustion include NOx, CO, CO_2 and SO_2. Further, particulate matter from diesel engines is an important concern. The EPA, International Agency for Research on Cancer (IARC), National Toxicology Program (NTP), the World Health Organization, and other health agencies identify diesel particulate matter or diesel exhaust as a probable human carcinogen. Scientists are working to improve the estimate of the potency of diesel exhaust in causing human lung cancer. See Appendix A for a detailed discussion of these pollutants and their effects on humans and the environment.

A potential partial mitigation of the emissions from diesel generators is biodiesel fuel which emits much lower levels of pollutants. Biodiesel fuel is commonly made from a chemical reaction between soybean oil, methanol, and lye, although other non-petroleum oils and greases can be used. Biodiesel can be used in its pure form or can be blended to any percentage. A common blend is a ratio of 20 percent biodiesel mixed with 80 percent petroleum diesel, also known as B20.

Biodiesel's use as a transportation fuel in diesel engines is becoming well known. Biodiesel can also be readily used in standby, emergency, and remote diesel electric-generators. The State Energy Office in the Department of Commerce funded a successful demonstration of the use of biodiesel in over 15 diesel generators which provided the electricity for the Taste of Minnesota in St. Paul in 2000.

Many new diesel generator installations fall under the threshold for environmental or energy regulations which makes them an attractive choice for peak power needs. While the actual run-times for these diesel generators are generally low on an annual basis, their combined use on hot days can produce significant amounts of pollution. While numerous studies have been conducted on emissions from transportation engines burning biodiesel, relatively few tests have been done on emissions of diesel generators burning biodiesel. In general, however, results likely are similar to those of the transportation engines burning biodiesel.[62] Biodiesel can reduce sulfur, carbon monoxide, volatile organic compound, and particulate matter emissions in proportion to the amount of diesel fuel it replaces. Biodiesel slightly increases nitrogen oxide emissions, which is the pollutant that most frequently exceeds emergency-episode levels when modeled. The environmental suitability at a given location of a diesel-powered or a biodiesel-powered generator has to be evaluated on a case-by-case basis.

The cost of biodiesel has dropped significantly since 2000 largely due to a federal program to encourage biodiesel production.

A typical 2 MW stand-by diesel generator may only operate 200 hours each year and consume roughly 25,000 gallons of fuel. If the cost of diesel fuel is higher than \$1.00/gal, which has been the case since 2000, the incremental cost gap shrinks accordingly. The barriers to the widespread adoption of biodiesel are primarily cost and lack of a developed distribution system. Also, utilities and consumers lack motivation to use biodiesel since no direct requirements or incentives exist to promote it or to discourage petroleum diesel.

DOMINANT GENERATING TECHNOLOGIES

Nuclear

Approximately 20 percent of the electricity consumed in Minnesota is generated from nuclear power. Nuclear power accounts for 36 percent of Xcel Energy's regional generating capacity that provides 16% of the electricity consumed in Minnesota. This energy is generated from the nuclear plant located in Monticello (545 megawatts) and the two nuclear reactors located at Prairie Island (1,027 megawatts).

In a nuclear power plant, uranium atoms are split, causing a chain reaction called nuclear fission. The reaction is kept under control with control rods. The reaction generates heat that heats water. The hot water generates steam that turns turbines to produce electricity.

The Monticello plant began operations in 1970 and is licensed to operate until 2010. Currently, the Monticello plant has sufficient arrangements to handle the spent nuclear waste produced in plant operations through the end of its license period. The Prairie Island nuclear plant began commercial operation in 1973 and 1974, with Unit 1's license expiring in 2013 and Unit 2's license expiring in 2014. The Prairie Island plant does not, however, have authorization to dispose of enough spent nuclear waste to be able to run through its licensed life. Under current Minnesota Statutes, which limit the storage of spent nuclear waste in dry casks at the plant site, the Prairie Island plant needs to shut down in 2007. The future of any further storage or disposal of spent nuclear fuel on the Prairie Island site is subject to a high level of public scrutiny and controversy. This report does not undertake to describe the details or options available in that debate.

If there is no increase in the number of dry casks that the legislature allows to be stored at Prairie Island, and if there is no storage alternative brought on line by 2007, the Prairie Island plant will shut down at that time. To prepare for that eventuality, the Minnesota Public Utilities Commission required Xcel Energy to conduct a bidding process to replace the power produced by the Prairie Island plant. This bid is for a contingency of 1,070 megawatts of electric power. The bidding process should be completed in the fall of 2002. A successful bid will provide information about what the costs are for Minnesota ratepayers to replace the power provided by Prairie Island after 2007. In addition, the plant will be fully depreciated in 2007 and, by that date, the fund to decommission the plant will be fully funded.

Partly due to the substantial public controversy and difficult trade-offs involved in construction of a nuclear plant, as well as the fact that MN Statute § 216B.243, subd. 3 prohibits issuance of a certificate of need for any new nuclear plant, a new nuclear plant in Minnesota is unlikely during the time horizon of this planning report. Nuclear plants, due to highly sophisticated technology and the need for redundant systems to ensure safety, are very capital-intensive to build. Once the plant is built, however, nuclear power plants generally offer relatively low marginal operating costs to produce energy. The issue of nuclear waste disposal, however, remains. A new nuclear power plant would cost approximately $2,188 per kilowatt.[63] This figure must be treated as an estimate, because no new nuclear power plant has been built in the United States since 1978.

Electricity produced by nuclear power plants results in the production of high-level and low-level radioactive waste for long-term disposal. The viability of any new nuclear plant would also depend on having a successful strategy for permanent disposal of spent nuclear fuel, which is a hazardous waste that must be sequestered from the environment for 250,000 years from the time it is generated. There is also a slight potential for the accidental release of radioactivity from the plant itself. Human exposure to radioactivity can have short-term effects in very high doses, and long-term chronic effects, such as increased cancer incidence, for low-level exposure. In addition, water needed for cooling reactors is often discharged back into natural water bodies creating thermal pollution of the water body. Nuclear power production, on the other hand, emits no air pollutants.[64]

Coal

Coal-fired power plants have been the predominant source of electricity in this country for the last century. Coal provides 75 percent of Minnesota's electricity and is the U.S. largest domestic fuel source. A coal-fired power plant burns coal in a boiler, which generates heat that turns water into steam that turns turbines to generate electricity. This is the basic operation of a pulverized coal boiler. Nearly all Minnesota coal plants utilize this technology. Because a new traditional coal-fired power plant is about 33 percent efficient in turning the energy in the coal into electricity and because burning coal creates significant air pollutant emissions, intensive research has been done on improving the efficiency of and reducing the emissions from coal combustion.[65]

Two combustion technologies that exist to improve coal combustion performance are fluidized bed combustion and coal gasification. In fluidized bed combustion, the operating principle is to feed crushed fuel into the boiler and burn it with the use of a bed that consists of sand or fuel ash. Combustion air is introduced to the boiler: the primary air flows upwards and fluidizes the bed while the secondary air is injected above the bed. This method burns coal in a bed that transfers heat to water, generating steam. This steam is pressurized and used to turn a turbine shaft, which subsequently drives an electric generator. Limestone is added to the bed to reduce the amount of acid gases released during combustion.[66] Fluidized bed combustion technology is about 42 percent efficient and has been commercially available for many years.

In coal gasification, a gasifier converts coal into large gaseous components by applying heat under pressure in the presence of steam. This process produces carbon monoxide and hydrogen, referred to as "syngas." The clean syngas remaining after pollutant separation is used to fuel a combustion turbine.[67] This technology may become commercially viable. It is currently being demonstrated in DOE pilot projects. Coal gasification is about 38 percent efficient.

Coal is the most abundant fossil fuel resource in the United States, with major deposits in the eastern states such as West Virginia and Kentucky, and in the western states of Wyoming, Montana, Colorado and Utah. Coal prices historically have been stable, peaking in the energy crisis period in the mid-1970s at $48.34/ton and gradually falling to a price of $16.00/ton in 1999.[68] Because western coal is less expensive to mine and has up to 85 percent lower sulfur emissions when burned than eastern coal, coal production is increasing in the west and staying level or declining slightly in the east.[69] Transportation costs are projected to decline slightly, but are heavily influenced by fuel prices.[70]

While cost and supply of the fuel are not barriers to operating new coal-fired power plants, the cost of building a new coal plant is a barrier. Figure 3-7 shows just the cost to construct a new coal facility. Those costs range from $920 to $1,400 per kilowatt of nameplate capacity (between $1 billion and $1.5 billion for a 1,000 megawatt plant). Fuel and operational costs add to those figures for the life of the facility.

In addition to the impacts from air pollutants discussed in Chapter 2 and Appendix A, coal combustion results in large amounts of ash containing toxic metals that requires specialized disposal.[71] Large volumes of water drawn from rivers and other natural sources is used for steam turbines and/or for cooling and then returned at a higher temperature creating thermal pollution of the water body. In addition, the mining, transportation, and storage of coal also have adverse environmental effects. Heat is

Figure 3.7: Annual Emissions of SO_2, NOx and CO_2 from New 500 MW Baseload Generating Units

Plant Type	Fuel Used	Thermal Efficiency	Net Generation (MWH/year)	Cost[a] ($/kW)	Annual Emissions (Tons/year)[b] SO_2	NO_X	CO_2
Natural Gas Combined Cycle	Gas	0.55	2,847,000	$375-600[1]	79	79	1,027,085
Pulverized Coal/Steam Turbine	Coal	0.33	2,847,000	$1,092-$1,219[2]	2,502	1,177	3,136,433
Circulating Fluidized Bed/Steam Turbine	Coal	0.42	2,847,000	$920-$1,306[2]	1,966	809	2,464,340
Integrated Gasification Combined Cycle	Coal	0.38	2,847,000	$1,200-$1,400[3]	1,534	703	2,723,744
Existing Pulverized Coal/Steam Turbine[4]	Coal	0.30	2,847,000		16,204	12,153	3,450,076

[a] calculated using a 65% plant capacity factor
[b] assumes that all new facilities meet New Source Performance Standards and Best Available Control Technology standards
NOTE: Data for the Integrated Gasification Combined Cycle technology are based on the operation of two facilities. Those facilities participated in the U.S. Department of Energy's Clean Coal Technology program.
[1] Actual costs of recent Minnesota Projects
[2] Annual Energy Outlook 2001, Table 43, EIA and Docket No. IP4/CN-01-1306 (Rapids Power) (1999 dollars)
[3] Figures used by the World Bank, www.worldbank.org/fpd/em/power/sources/svc_coal.stm.
[4] Emission rates representing performance of a non-NPSP Minnesota pulverized coal generating unit: 1.0 lb/mmBtu SO2, 0.75 lb/mmBtu NOx

given off in the process of turning coal into electricity that, in most cases, is wasted rather than captured and used.

Natural Gas

A new natural gas fired plant costs from $365 to $600 per kilowatt of nameplate capacity and can be sized smaller without losing economies of scale. The result is that a natural gas plant is better able to be sited to take advantage of the heat produced, which increases the efficiency of the fuel, and to avoid costly upgrades to transmission systems. Of course, natural gas plants also have higher ongoing fuel and operational costs as well and are limited in where they may be sited due to pipeline capacities and locations. Fuel costs for natural gas has received a lot of attention since the huge price spike during the 2000-2001 heating season and, while prices are now low and predicted to remain so for the next two to three years, the increased volatility in the price of natural gas is of concern.

Natural gas has been the predominant fuel for new electric generating plants in the United States for the last few years, due to a combination of the relatively low price of natural gas as a fuel in the summer and the favorable air emission characteristics of a natural gas plant. For example, this year, two natural gas peaking plants (combustion turbines) were brought on line in Minnesota, located where natural gas pipelines and high voltage transmission lines are in close proximity. This allowed for efficient delivery of gas to the plants and for access of the plants to the electric transmission system. The Lakefield Junction project, which has a capacity of 486 MW, cost approximately $375 per kilowatt. Similarly, the Pleasant Valley plant, with a capacity of 434 MW, was built at a cost of approximately $436 per kilowatt. These facilities have added over 900 MW of peaking capacity to the grid in Minnesota, with little controversy associated with their construction.

Another kind of natural gas plant project is the decision by Xcel Energy to repower Units 1 and 2 of its Black Dog electric generating plant in Burnsville with gas-fired combined-cycle generating technology. This project will convert coal-fired to gas-fired technology, at the same time the capacity of both units will increase a total of 114 megawatts.[72] This addition to Xcel's summer generation capability is expected to be available by the summer of 2002. The cost of the repowering was estimated to be approximately $600 per kilowatt. Xcel Energy, under the terms of one of its merger settlements, has studied the feasibility of converting some of the units at St. Paul's High Bridge plant and at the Riverside generating station in Minneapolis to natural gas as well.[73]

Natural gas-fired generation plants are generally peaking (combustion turbines) or intermediate plants (combined-cycle units), not constant-burning baseload generation. Minnesota's ability to add gas-fired generation to meet the state's capacity needs relates to the capacity of natural gas pipelines to deliver enough natural gas to fuel additional power plants. For the southern portion of the state where electricity demand peaks in the summer, the need to transport natural gas to peaking plants does not compete with the priority use of the pipelines to transport natural gas for home heating in the winter. With the addition of gas-fired generating plants the system does, however, require different adjustments, depending on location. New pipeline capacity costs between $1 to $2 million per mile to construct.

Of course, adding a large user on an existing pipeline may cause other operational issues for the pipeline. When a natural gas electric generation plant is proposed, the Department of Commerce, the PUC, and other parties carefully analyze limitations and mitigation options to ensure continuing reliable natural gas service for all (new and existing) customers on that pipeline segment.

The price of natural gas, like prices of other petroleum products, fluctuates constantly in reaction to various current and expected market forces both here and around the world. Supply and demand for natural gas affects markets and prices. See Chapter 1 for a more detailed discussion of natural gas prices. Coal prices, relative to recent natural gas prices, are more stable and predictable.

Using natural gas to make electricity results in substantially fewer negative environmental effects than coal. This is one of the reasons that most new electric generation in the nation uses natural gas. The relative "cleanness" of natural gas as a fuel contributes to the lower costs of building natural gas generating plants.

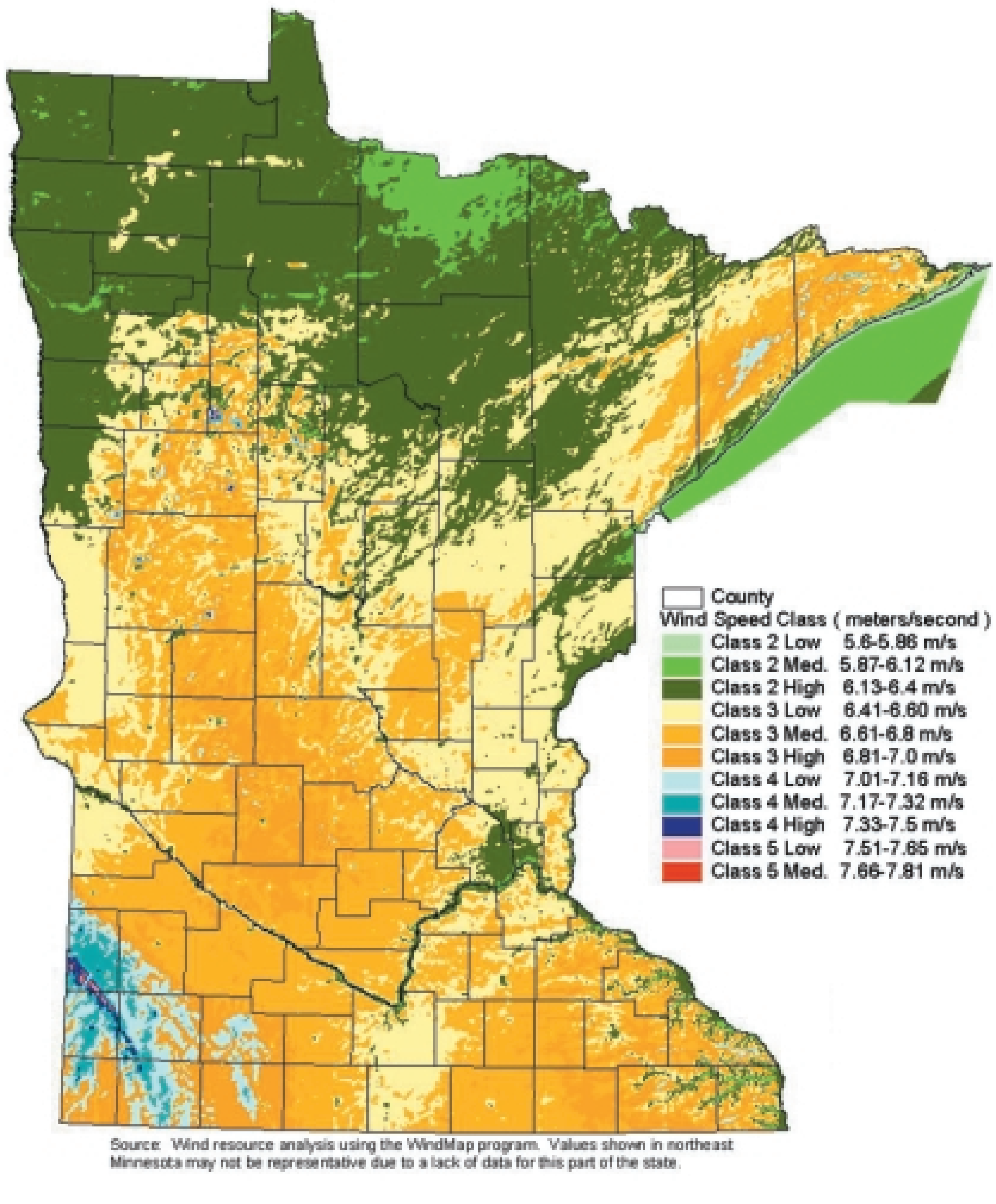
Additionally, gas is a much more efficient fuel than coal. A new conventional pulverized coal steam turbine is about 33 percent efficient in taking the energy in coal and turning it into electric energy. The most efficient coal technology is about 42% efficient. A natural gas simple cycle generator is about 35 percent[74] efficient. A combined cycle natural gas generator reaches efficiencies of 55 percent or more.

Natural gas has very little sulfur compared to coal. A conventional new coal plant emits about 30 times more SO_2 than a combined cycle gas plant for the same amount of electricity generated. "Clean coal" technologies, as noted in Figure 3-4, do not reduce this gap very much.

Mercury emissions from natural gas combustion are negligible, unlike coal.

Natural gas combustion does emit nitrogen oxide. A conventional new coal plant emits about 14.5 times more NOx than a combined cycle gas plant for the same amount of electricity generated. Again, the "clean coal" technologies only marginally reduce this disparity.

Figure 3.8: Minnesota's Wind Resource by Wind Speed Class



Source: Wind resource analysis using the WindMap program. Values shown in northeast Minnesota may not be representative due to a lack of data for this part of the state.

All carbon based fuels emit carbons, notably carbon dioxide, when burned, including natural gas. For the same amount of electricity generated, a conventional new coal plant emits three times more CO_2 than a gas plant. While the carbon content of similar amounts of coal and gas may be about the same, it takes a lot less gas to make the same amount of electricity because of its higher efficiency in turning the energy in the fuel into electric energy.

While there are barriers to deployment of significant amounts of natural gas fired power plants in Minnesota, the environmental superiority of the fuel and its ability to be turned off and on rapidly, as well as its lower costs make gas an attractive fuel for electricity, at least for the short term, in strategic locations to take advantage of summer availability. Natural gas also works well as back up for wind energy when the wind does not blow on hot summer days.

Wind

Construction of commercial scale wind energy plants costs about $800 to $1,000 per kilowatt of nameplate capacity. Wind also is the only presently commercially viable Minnesota energy resource that can provide electricity on a large scale without relying on resources that must come from outside the state. In addition, the fuel will cost the same 50 or 100 years from now as it costs today—$zero. Wind energy production emits no pollutants. Moreover, wind energy, backed up with firm capacity from gas, coal, storage, or, eventually, fuel cells and similar technologies can provide reliable, reasonably priced electricity.

Minnesota installed more wind capacity from 1995-2000 than any other state—over 380 megawatts. Minnesota ranked second in the nation in installed wind capacity at the beginning of 2001, but will be passed by several other states by the end of the year. Wind energy is the fastest growing electric generation technology because the technology has developed to the point that it is cost-competitive with other technologies, the fuel is free, and environmental impacts are virtually none.

Turbines installed in 2001 were 1.5 MW each, with an annual efficiency of up to 40 percent in turning wind into electricity.[75] Wind turbines require a sufficient wind resource. Minnesota is ranked third in the nation for wind potential.[76] North Dakota and South Dakota are ranked first and second for wind resource. They are a potential source for wind-generated electricity for Minnesota as well. Minnesota's wind potential is in the hundreds of thousands of megawatts of capacity. Only a small portion of that is physically and economically practical, but the number is in the thousands of megawatts.

The Department of Commerce has conducted a wind resource assessment program for many years. The program monitors wind resources in Minnesota to accurately measure and map wind speeds. Department data helps individuals, companies, utilities and independent power producers perform an initial assessment of the potential feasibility of a chosen wind site without the usual cost and delay of erecting a tower to measure the wind speeds for a long period of time. Figure 3-8 is the resulting map of Minnesota's wind resource by wind speed class. Good wind resources are Class 3 and above; Minnesota has several Class 3, 4 and 5 wind areas.

The available wind resource is affected by a combination of elevation (higher is better), land use (less obstructed by trees and buildings for long distances is better), and geographic location. The southwestern corner of the state contains the best wind resource, mainly due to a geologic formation called the Buffalo Ridge which has elevated ground in a plains area of the state. There are other much smaller areas in the state that also contain Class 4 and 5 wind resource, but much of the western and southern portions of the state is covered by what are considered "good" wind resources. Local site conditions dictate specific wind resources.[77]

Figure 3-9 (next page) shows wind power development in Minnesota over the last 10 years, along with a list of planned installations. The biggest boost to the deployment of wind power was the Minnesota Legislature's mandate in 1994 that Xcel Energy deploy 425 MW of wind power by the end of 2002, of which 299 MW are currently operating. Xcel Energy has contracted for another 130 MW of wind power to complete this part of the mandate. The 1994 legislation also required the PUC to order Xcel Energy to acquire an additional 400 MW of wind power if the PUC found it to be cost-effective. The PUC has done so, and Xcel Energy must deploy 400 MW more wind power by 2012. The 2012 date should be moved up, assuming that transmission infrastructure will

Figure 3.9: Wind Power Development in Minnesota

Nearest City	Developer	Date	MW	Affiliated Electric Utility
Marshall	Navitas Energy[A]	1992	0.6	Marshall Muni. Util.
Buffalo Ridge	Kenetech Windpower	1994	24.82	Xcel Energy[C]
Chandler (I)	enXco, PRC[B]	1998	1.98	Great River Energy[G]
Lake Benton (I)	Enron Wind Corp.	1998	107.25	Xcel Energy
Woodstock	Edison Capital	1999	10.2	Xcel Energy
Moorhead (I)	Moorhead Pub. Ser.	1999	0.75	Moorhead Pub. Ser.[G]
Hendricks	Navitas Energy	1999	11.25	Xcel Energy
Lake Benton (II)	FPL Energy	1999	103.5	Xcel Energy
Hendricks	Navitas	1999	11.88	Xcel Energy
Elk River	Navitas Energy	2001	0.66	Xcel Energy
Ruthton	Navitas Energy	2001	14.52	Xcel Energy
Hendricks	Navitas Energy	2001	11.88	Xcel Energy
Averill	Navitas Energy	2001	1.98	Xcel Energy
Chandler (II)	enXco, PRC	2001	3.96	Great River Energy[G]
Total Installed			307.28	
Estimated homes/yr	107,671*			
Planned Installations				
Wilmont	Navitas Energy	2001	0.9	SMMPAG
Moorhead (II)	Moorhead Pub. Ser.	2001	0.75	Moorhead Pub. Ser.
Murray/Pipestone County	Navitas	2001	79.5	Xcel Energy
Murray County	EnXco	2001	79.5	Xcel Energy
Hendricks	Navitas Energy	2001	0.9	Otter Tail Power[G]
Hendricks	Navitas Energy	2001	1.8	Xcel Energy
Murray/Pipestone County	Navitas Energy	2001	51	Xcel Energy

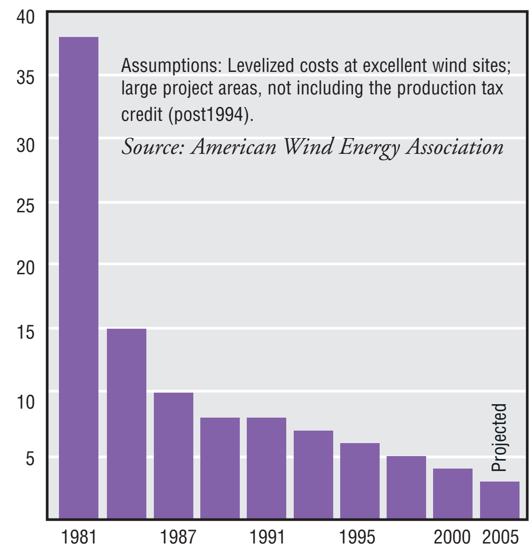
A- Navitas Energy, formerly Northern Alternative Energy
B- PRC: Project Resources Incorporated
C- Xcel Energy, formerly Northern States Power Company, is mandated to construct 425 MW of wind power by the end of 2001 and an additional 400 MW by 2012. All Xcel Energy Projects are applied to the mandate.
G- Green power program.

be in place.

Figure 3-9 includes some sites where wind power is used as a small, distributed energy source located close to local load, such as the Moorhead, Elk River and Averill locations. The market for locally-owned wind installations has not yet developed into a mature industry. Moorhead Public Service Utility, Lac Qui Parle School and two farmers in southwestern Minnesota are the exceptions. Municipalities, educational institutions, cooperatives, non-profits, local companies and individuals are critical in the development of locally sited, locally owned wind turbines. Several interested groups in Lake City and Northfield are working with the Department to monitor local wind resources in anticipation of installing wind turbines, but the major impediment to further installations is a lack of financing. The installed costs, expected turbine output, and benefits stream can be determined with reasonable accuracy, but the perceived risk for a sizeable loan limits many projects without significant equity collateral. One of the advantages of the smaller facilities is that they may be interconnected at the distribution level, reducing need for and the cost of large transmission upgrades.

The cost of wind energy is strongly affected by average wind speed and the size of a wind farm. Small differences in average winds from site to site mean large differences in electricity production and, therefore, in cost. Larger wind farms often provide beneficial economies of scale. The cost of wind energy, however, is dropping fast, and large-scale wind is now competitive with the cost of conventional electric generation. Wind power today costs only about one-fifth as much as in the mid-1980s, and its cost is expected to decline by another 35-40 percent by 2006.[78] Figure 3-10 shows the dramatic drop in the cost of wind power since 1981. The U.S. Energy Information Administration studied the cost of wind and concluded that the 2000 reference installed cost is $983/kW, and that cost could drop under $800/kW by 2010. [79]

Figure 3.10: Cost of Wind Power (¢/kWh), 1981-2005



These study estimates are confirmed by the costs of actual projects. Figure 3-11 shows a series of 5 MW and greater wind projects deployed between 1996 and this year, with the most recent deployment dropping below $900/kW. Xcel Energy's deployments of wind power have been achieved at competitive cost levels of between 3 and 4 cents/kWh, with Xcel's standard small wind tariff set at $0.033/kWh. The

Figure 3.11: Wind Project Costs, 1996-2001

Location	Year	Size	Cost
Vermont	1996	6MW	$1650/kW
Iowa	1999	193MW	$1250/kW
Woodstock, MN	1999	10MW	$1250/kW
Hendricks, MN	1999	12MW	$1425/kW
Hendricks, MN	1999	11MW	$1350/kW
Texas	1999	34MW	$1176/kW
Texas	2001	125MW	$880/kW

standard small wind tariff offers any non-utility wind site a fixed and standard price throughout Xcel Energy's service territory for the electricity produced and sold back to Xcel. A standard contract and interconnection agreement was also developed as part of an effort to reduce the transaction costs of price negotiation and interconnection requirements.

Wind generation has few adverse environmental effects. The primary concern has been the accidental deaths of migratory birds that fly into the turbine blades or towers. The Department of Commerce and the Environmental Quality Board (EQB) worked with the Department of Natural Resources to analyze migratory paths of birds and avoid those locations in wind energy facility siting. Additionally, the increased height and size of turbines has allowed manufacturers to reduce blade speed. The same amount of electricity is still produced, but the birds are less likely to hit the turbines than in the past. The EQB has closed its study on wind energy's effect on birds, due to lack of an effect in Minnesota. It is studying the effects on a species of bat.

While wind does not blow at all times in all locations, in the best wind power locations the wind blows well over 300 days per year. Electricity demand fluctuations, like wind fluctuations, are not abnormal and vary by thousands of MW in a single day and hundreds in a single hour, as shown in Figure 1-10. Xcel Energy, for example, normally uses generating units to "load follow" the fluctuations in the system.

Utilities in the MAPP region carry a 15 percent planning reserve above annual peak demand levels to assure adequate system performance and to guard against sudden loss of power, for whatever reason, at generating stations in the system. For example, the nuclear reactor, Prairie Island 1, went out of service unexpectedly for several weeks in August and September of 2001, including the week of peak electric use. Similarly, the King and Monticello plants were not operating at full capacity during the 2001 peak due to limits on the heat of the water they could release to the St. Croix and Mississippi Rivers. The reserve margin exists to cover this sort of contingency without the lights going out. The same reserve margin can cover wind generators.

The potential of wind energy in Minnesota is limited by the wind resources that are economical to develop and the percentage of the total grid-system that can accommodate a variable generating technology, like wind energy, without causing system instability. The exact point at which the integration of intermittent generation such as wind begins to degrade system integrity is unclear, but the technical literature suggests that it is at penetration levels in excess of at least 5 percent.[80] Wind power is currently used to generate about 1 percent of Minnesota's electricity on an annual basis.[81]

Other countries have learned to manage wind power as a much larger part of utility systems. In portions of Denmark, wind power accounts for 25 percent of the electricity on the electric grid at certain times of the year.[82] As a comparison, Denmark has 2,836 MW of wind capacity out of 12,000 MW total capacity (2000), in an area that is 16,629 square miles inhabited by 5.4 million people. Minnesota has 300 MW wind capacity out of 11,000 MW total capacity (2001) in an area that is 84,068 square miles inhabited by 4.9 million people.

A major issue in increasing use of wind power is transmission. The Buffalo Ridge wind resource area of Southwestern Minnesota is a part of the state that is relatively sparsely populated. Consequently there has historically been little need for load serving transmission infrastructure to be built in this area. The existing transmission system consists mostly of 115 kV level facilities and has been upgraded and utilized to the fullest extent possible to absorb the current increment of wind generation resources. If additional wind resources are to be developed in the area, then additional transmission infrastructure will be required to move the energy out of the area to distant load centers.

The development of another 400 MW in Buffalo Ridge would nearly double the total wind capacity in the area and would likewise require an increase of existing transmission outlet infrastructure to deliver the energy to distant load centers. Transmission planners have been evaluating options for accommodating this projected increase in demand for transmission system use and have concluded that an enhanced transmission system is needed. Even without additional wind development, this project is needed to provide additional electric reliability to the city of Sioux Falls and to strengthen the grid generally. Xcel Energy filed with the PUC a transmission proposal in December 2001, to address these needs.

DISTRIBUTED ENERGY RESOURCES

Distributed Energy Resources (DER) is not one technology but a group of technologies and approaches that lend themselves to specialized applications. Energy conservation is an example of DER and is discussed in Chapter 4.

DER also is local, small-scale power generation, and although it is receiving heightened attention, is not a new concept. Starting with Thomas Edison's first plant in the Wall Street district of New York City, early electrical generation was predominately small scale. Such a system was popular with factories, which could put to use the waste heat generated by power plants and save money. As utility systems developed, however, economies of scale could be realized with larger power production facilities. As the price of centrally produced power fell, it was more economical for businesses and factories to purchase power from a centralized source. The only industries that still continued to produce their own power were those industries that had byproducts that could be used to fuel a boiler, i.e. the forest products and petroleum industries.

Modern distributed energy resources often offer better efficiencies than central station power generation and transmission, because the electricity is generated close to the end user. This avoids the line losses that occur in the typical transmission and distribution system. Another efficiency that distributed generation can offer over central station generated electricity is the ability to capture the heat from the electric generation process and use it to heat or cool a conditioned area, or offset the costs of a particular manufacturing process.

Distributed generation can employ wind turbines, small hydroelectric plants, microturbines, photovoltaics, fuel cells or diesel generators—essentially any small generation source located at or near where the electricity is used. The environmental impacts depend on the generation source and are shown in Figure 3-12. Some of the technologies listed in Figure 3-12 are not yet commercially viable, e.g. fuel cells.

Figure 3.12: Relative Emissions from Various Distributed Generation Sources

Techology	Pollutant, lb/MMBtu			
	NOx	CO_2	CO	SO_2[b]
Microturbine[a]	0.21-0.4	119	0.11	0.0006
Internal combustion engine (natural gas)[c]	1.94	110	0.353	0.00059
Internal combustion engine (diesel)[c]	4.41	164	0.95	0.29
Internal combustion engine (landfill gas)[d]	0.6	0[g]	0.6	0.01
Internal combustion engine (digester biogas)[e]	0.23	0[g]	0.58	0.001
Fuel Cell[a f]	0.003	1	--	0.0204
Wind	0	0	0	0
Solar photovoltaic	0	0	0	0

[a] Data from U.S. Installation, Operation, and Performance Standards for Microturbine Generator Sets, Borbely-Bartis et al, August 2000, Prepared for the US DOE under Contract DE-AC06-76RL01830)
[b] Sulfur dioxide emissions will vary depending on fuel sulfur content.
[c] EPA AP-42 emission factors uncontrolled.
[d] Values from MPCA database.
[e] Data from P. Lusk, Methane Recovery from Animal Manures: The Current Opportunities Casebook. National Renewable Energy Laboratory, September 1998.
[f] Values here are representative of fuel cell with a reformer using methane or more complex carbohydrate.
[g] CO_2 emissions from renewable fuels are counted as zero because emissions are rapidly offset by growth of biomass in subsequent years.

Distributed Energy Resources Using Combined Heat and Power

Generating electricity through the combustion of fossil fuels inevitably produces heat. Combined heat and power (CHP) is the process of utilizing the heat generated as a result of electricity production. Centralized power plants operate at electrical conversion efficiencies of roughly 30 to 35 percent. This means that roughly 70 percent of the energy content of coal, for example, is released into the atmosphere as waste heat. One of the distinct advantages of distributed generation is its location nearer the end-user. The heat is readily available for utilization. When the heat associated with the electric generation is fully utilized the efficiency of the entire system can approach 80 percent. Such a process has inherent cost savings because the natural gas or electricity that would otherwise have been used to heat or cool an area is no longer needed.[83]

Boilers and steam turbines are the most common method of CHP, and both have been around for a long time. These systems burn the widest range of fuels, and have been popular with those industries that can use the byproducts of their production processes, notably the forest products and petroleum industries.

Microturbines are like jet engines. Microturbines are able to generate electricity efficiently with low emissions and high value heat. The heat can be used to heat or cool a conditioned area, dehumidify a conditioned area, or offset some of the energy costs within a particular manufacturing process. Microturbines are currently commercially available, and cost about $1000/kW.

St. Paul has one of the world's premier CHP projects. The St. Paul District Heating and Cooling Plant has provided both heating and cooling services for the buildings that operate in the downtown area of St. Paul. Construction is now underway to incorporate an electrical generation system that will burn both waste wood from the metro area and coal. Once completed, this facility will provide power, cooling, and heat for the 141 buildings that are connected to the system in downtown St. Paul. The efficiency of the new CHP plant in downtown St. Paul is expected to approach 75 percent. With the planned biomass CHP project, estimated air emission reductions include 280,000 tons of CO_2 and 600 tons of SO_2. Other district heating systems that have cogeneration facilities include the public utilities in Willmar, Hibbing, Virginia and New Ulm, the University of Minnesota in Minneapolis, and the Franklin Heating Station in Rochester. The St. Paul project, at 25 MW capacity, is larger than what usually would be considered distributed generation. Other smaller distributed generation technologies are excellent CHP producers or candidates as well.

A recent state study inventoried Minnesota's cogeneration (CHP) potential and did case studies on three high potential cogeneration sites: Rahr Malting in Shakopee (9.3 to 10.4 MW), Chippewa Valley Ethanol in Benson (3.4 to 7.4 MW) and Duluth Steam Cooperative (0.9 MW).[84] The study surveyed 142 facilities that had potential for large (over 1 MW) cogeneration projects and received 32 responses. Analysis of the survey responses indicated that four sites had high CHP potential and ten sites had some CHP potential.[85] The specific case studies found potential for economic deployment of CHP at the three facilities analyzed. The main variables affecting economics are the price of the fuel (natural gas, biomass or coal) that would be used in each CHP project and the ability to sell excess power into the grid at the market price of electricity.[86]

Power Quality and Reliability

Electric outages can have significant financial impacts. The losses are not limited solely to the lost business that a power outage brings with it, but also equipment downtimes, startup, and lost production. To address this concern, some businesses make large capital investments in distributed generation technologies such as fuel cells and microturbines.

How can heat be used to cool a building?

Cooling with heat provides a year round application for the heat produced by certain distributed generation resources.

Absorption cooling is different from traditional mechanical cooling in that liquids are the medium used for refrigeration, rather than vapors. Less work is required to operate an absorption refrigeration system than a mechanical refrigeration system. However, an absorption refrigeration system requires that the working fluid, which is generally a mixture of ammonia and water, be separated. This separation is accomplished through the use of heat. When a low-cost source of heat is available the economics of an absorption refrigeration system are greatly improved. Thus, combined heat and power systems can provide electrical generation and space conditioning on a year round basis. There are two types of absorption refrigeration systems currently available, double effect and single effect. Single effect absorption systems typically have a coefficient of performance (COP) of 0.65. Double effect systems are somewhat more efficient than their single effect counterparts, and have COPs in the range of 1.2, meaning that for every unit of work that goes into the system, there are 1.2 units of cooling.

Desiccant (Dehumidification) wheels remove the moisture from the air, making it more comfortable at higher temperatures, as well as easier to cool. A desiccant wheel can provide major benefits in Minnesota because of the humid conditions we experience in the summer. A desiccant wheel consists of a wheel of packed material capable of removing moisture from the exterior environment. As the wheel removes moisture, heat is required to remove the moisture from the desiccant wheel. There are many applications where the removal of moisture is advantageous to the space conditioning of a facility. Basically, dry air is much easier to cool than humid air. Indoor ice rinks are an example of a niche market for desiccant wheels. Within the context of a CHP system, the heat generated by the system can, in turn, be used to recharge the desiccant wheel.

Desiccant wheels also have a niche market in supermarkets and grocery stores, where high humidities contribute more to the cooling load. Supermarkets can take advantage of the waste heat from a microturbine or other distributed energy resource to recharge a desiccant wheel application. This helps the supermarket reduce the high humidities, as well as generate electricity to offset their utility consumption.

In both applications low cost, high quality heat is necessary for the process to be economic.

In addition to increased reliability, these technologies also offer higher quality power than that provided by the grid. Quality of electric power refers to how pure the electron stream is. The higher the quality the more constant and pure the flow of electrons. The high tech industry requires very high quality electricity.

Some businesses that have "mission critical" operations also require an extremely high level of power reliability. "Six nines" of reliability is quickly becoming the requirement for many businesses that operate in today's e-commerce market. Six nines of reliability means that power must be available 99.9999 percent of the time, which is equivalent to a power outage of 32 seconds per year. Utility power averages 99.9 percent reliability, which is the equivalent of over eight hours per year of power outages. These stringent requirements for power reliability have become a necessity for businesses that lose extraordinary amounts of money during a power outage.

A recent report by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy, entitled *Strategic Plan For Distributed Energy*

Resources, estimates the cost of power outages for different business segments shown in Figure 3-13.

Figure 3.13: Cost of Power Outages

Industry	Average Cost of Downtime Per Hour
Cellular Communications	$41,000
Telephone Ticket Sales	$72,000
Airline Reservations	$90,000
Credit Card Operations	$2,580,000
Brokerage Operations	$6,480,000

Interconnection of Distributed Energy Resources to the Grid

Work is being conducted at state and national levels to develop a standard for interconnecting distributed generation facilities to the utility grid. For many years utilities have cited line worker safety as the main reason for opposing particular distributed generation projects. The Institute of Electrical and Electronic Engineers (IEEE) P1547 working group is developing a voluntary standard for the interconnection of distributed generation equipment, including CHP, to electric power systems. There are more than 300 participants in the working group and the standard is expected to be published sometime in 2002.

The legislature has required that the PUC adopt standards for interconnection of distributed energy facilities of 10 MW or less capacity that use natural gas or an equally clean or cleaner fuel. These new standards should remove some barriers to deployment of these technologies. Standards have already been studied and adopted in other states. The PUC has opened a docket to establish these interconnection standards, E999/CI-01-1023.

Presently, for facilities that are 40 kW or larger (and do not qualify for net metering), interconnecting with their local utility requires an intricate, confusing, and lengthy process that balances the costs, timeframe, and intricacies of developing an equitable, legal agreement between the two entities, while maintaining safety and quality standards.[87] The ability of distributed generation technologies to "plug and play," along with uniform, interconnection standards will encourage deployment.

Net Metering

The statutory threshold for net metering should be increased to 2 MW from the current 40 kW. In its purest form, net metering simply lets a distributed generator's electric meter spin forward and backward, depending on whether the on-site generation meets all on-site needs or whether further electricity is drawn from or sent to the grid. At the end of the month (or other time period), the balance is trued up and a check is paid by the utility or the consumer, depending on whether more electricity was consumed or generated.

Minnesota was one of the first of about 30 states to enact net metering in the early 1980s. Net metering is available to renewable, waste, and cogeneration energy facilities of less than 40 kW, which is a relatively small size. For example, it is smaller than the common size of today's wind turbines, often 250 kW, 750 kW, or larger. Net metering policy has not been revisited in a long time and should be. Net metered facilities, especially those over 40 kW, can reduce the amount of electricity that a utility must purchase or generate for its system and can reduce the need to build large central power plants and transmission lines. The price a utility would pay for power from a 41kW to 2MW facility should be the present wholesale price for electricity.

Technological advances have been achieved that can simplify the net metering process, reduce costs to both the utility and the net metering facility, and maintain safety. One example is the existing requirement for installing two electric meters. For a solar-electric system (2 kW), the metering charge from the utility can be greater than the value of the electricity produced during winter months and a significant percentage in the summer months. For a small wind system (20 kW), this metering charge is only a fraction of the monthly energy charge. Making the second meter optional for the consumer/generator would, in cases where the single meter is sufficient, reduce costs. Letting consumers decide whether to install the second meter might be an important option to consider, when it is necessary to know the exact amount of electricity generated.

FUTURE TECHNOLOGIES

Anaerobic Digesters—Biogas

Anaerobic digestion is not a particularly new process or technology for producing electricity. Recently, its value in reducing, mitigating, and/or disposing of certain waste-streams has become apparent. Methane gas is produced when organic matter is broken down by bacteria in the absence of air. This decomposition can occur in landfills, manure facilities, waste-water treatment plants, and other industrial waste streams. This biogas can be captured for use in generating electricity and usable heat. By heating the organic waste and maintaining optimal chemical conditions in the digester, it is possible to maximize biogas production. Several facilities exist in the state for biogas production using anaerobic digestion, but one location of particular interest is at farms and facilities that house animals.

Animal manure has been traditionally collected and stored for later application to farm fields. The storage facilities are generally large earthen basins, tanks or concrete pits that can pose air and water risks to the surrounding community. An anaerobic digester acts as a manure processing facility that treats the waste before it is sent to the holding basin. Processing the manure removes many of the compounds that cause the acrid odor, reduces pathogens, produces methane gas, and creates what is ultimately a better product—stabilized organic matter. Anaerobic digestion is not a solution in every instance, but it can be part of the answer to many livestock waste issues.

Manure digesters have energy, environmental, social, and agricultural benefits, although capturing all of these potential benefits in monetary form is difficult. The most direct monetary gain comes from selling back electricity to the local utility and using the waste heat instead of purchasing and burning propane or other energy sources for heating buildings and water. It is difficult to place a value on the reduced risk of a raw manure spill, the decreased odor in neighboring areas, the better quality fertilizer resource, or the input of capital development and income in rural communities with complete accuracy. These monetary values will vary by installation. The electricity produced, however, is secondary to the benefits of better manure management.

The digester itself consists of a large pit (generally concrete) that contains the manure and a flexible/inflatable or rigid cover to contain the methane gas. An engine-generator burns the methane to produce electricity, although a microturbine or fuel cell could ultimately work as well. Piping, wiring, pumps, generator housing, and other associated components are needed as well. The digesters have an operating life of 15 to 20 years or more, with a major clean-out of sand and debris from the digester required approximately every five years.

Methane digesters have a high capital cost, mostly consisting of the concrete and excavation of the digester itself and the engine generator. Currently there is one methane digester operating in Minnesota. The operating digester in Princeton, Minnesota cost approximately $355,000 to build and was funded with a combination of grants, loans, and private funds.[88] It was built to contain the manure from 1,000 dairy cows and currently has a 125 kW generator, which is undersized for the amount of methane gas that is being produced. There are plans to add an additional generator at this site in the future.

Estimating the costs of future facilities is difficult and contingent on a variety of factors. Payback is critically a function of feedlot size. For dairy operations, a feedlot size of 500 to 800 head of milking cows is generally thought to be the size threshold for economic viability. For such large feedlots, payback periods of less than five years can be expected. Due to the large capital costs involved, anaerobic digestion generally is not economic at small feedlots. Other important factors besides feedlot size include the buyback rate for the electricity and the utilization of the waste heat in place of propane gas for heating buildings and water. The 2001 Legislature authorized an incentive payment of $0.015/kWh to new qualifying digester systems, which mirrors the payment for certain small hydropower and wind facilities and could push borderline projects into the realm of profitability.

The largest single barrier to further installation of manure digesters is the small size of most Minnesota feedlots. Access to financing is also a challenge. As with wind turbines, the perceived risk limits the access to financing, especially with existing outstanding loans for many farmers. Additionally, many of the secondary benefits such as odor abatement and less hazardous organic waste are not given monetary value in the traditional sense. Advocates for anaerobic digesters may consider seeking a requirement that facilities sited in certain areas such as near water sources or homes must use digesters. Another option might be to seek a requirement that anaerobic digester technology be installed at a particular site in response to environmental problems or violations at the facility. These options are not really related to energy issues and would be best deliberated by agricultural and environmental agencies.

Forest and Agricultural Products—Biomass

Biomass energy installations generally combust forest and/or agricultural products in a similar manner to coal power plants. Biomass can be classified into two categories—closed-loop and open-loop. Closed-loop systems use a product that is grown or developed specifically for producing energy, such as alfalfa, switch grass or cultivated poplar, aspen or willow. Open-loop biomass systems use a product that is a by-product or waste of another activity. Examples of fuel sources include waste wood from logging or paper processing, urban wood collected after storm damage, sawdust that is made into pellets, or poultry litter.

Biomass facilities convert fuel to electricity with an efficiency of 15 to 30 percent, depending on fuel quality. Dry, low-ash biomass fuels yield higher efficiencies than wet, high ash feedstocks. National studies indicate that these facilities cost about $1,476 per kW (1996 dollars).[89]

Biomass fuels can also be "co-fired" with other traditional fossil fuels at boilers that are capable of handling this fuel. The fuel mix (wood and coal) can be adjusted according to the cost and supplies of the available fuels. To co-fire wood successfully with coal, the power plant's fuel feed system and boiler must be capable of handling wood. Future combustion capacity will need to consider the fuel handling needs: pulverized coal-fired boilers cannot routinely accept wood; cyclone boilers can (and have) burned wood chips and sawdust; nearly all spreader-stokers are already burning wood fuels. Minnesota Power's proposed Rapids Power Project is a circulating fluidized bed that will be able to burn both fuels.

The capital cost of a new biomass facility may be competitive with a coal facility of similar size, depending on the amount of fuel preparation needed. For example, open-loop facilities that burn already prepared waste wood like urban waste wood may not need to install equipment that shreds and sizes wood to feed easily into a boiler. These facilities instead need to devote resources to address planning, coordination and transportation to ensure that they secure fuel at reasonable prices. If the initial projects are not successful, then the facilities will need to install some sort of processing equipment to be able to accept a wider variety of wood types.[90]

Closed-loop systems are viewed as having a greater potential to provide reliability in the long-term over open-loop systems; however, their fuel costs are higher than open-loop systems because they must include the cost of raising and harvesting the fuel.

It will take some work to develop dedicated crops. Hybrid trees could potentially be grown on marginal quality or Conservation Reserve Program (CRP) land, providing additional income to agricultural areas, if farmers/landowners make these lands available. It takes up to 10 years for trees to mature enough to harvest. During this period, farmers must bear the production costs without income from this crop. In addition, landowners are concerned that, should the market not appear during this period, they would face significant landclearing costs to return to more traditional agricultural crops. These are barriers that need to be addressed.

Open-loop systems compete with other systems already in place in Minnesota. For example, the wood products industry has been efficient at converting its waste wood into usable energy for its own production, but little appears to be widely available for large power plants. Therefore, an important aspect of developing future wood-waste-fired projects is to investigate the amount of wood available. Poultry-litter facilities are competing with litter's existing use as fertilizer.

Each of the bioenergy fuels described here (biogas from animal wastes, wood and briefly, poultry litter) all have attractive environmental benefits to their expanded use. Most obviously, they represent no net gain in carbon dioxide emissions to the atmosphere when combusted to produce electricity. Because they are low in fuel sulfur, they represent lower SO_2 emissions, especially if used to displace fuels currently in use, like wood for coal. They generally have fewer toxic constituents, and so do not contribute substantially to the release of persistent bioaccumulative toxics.

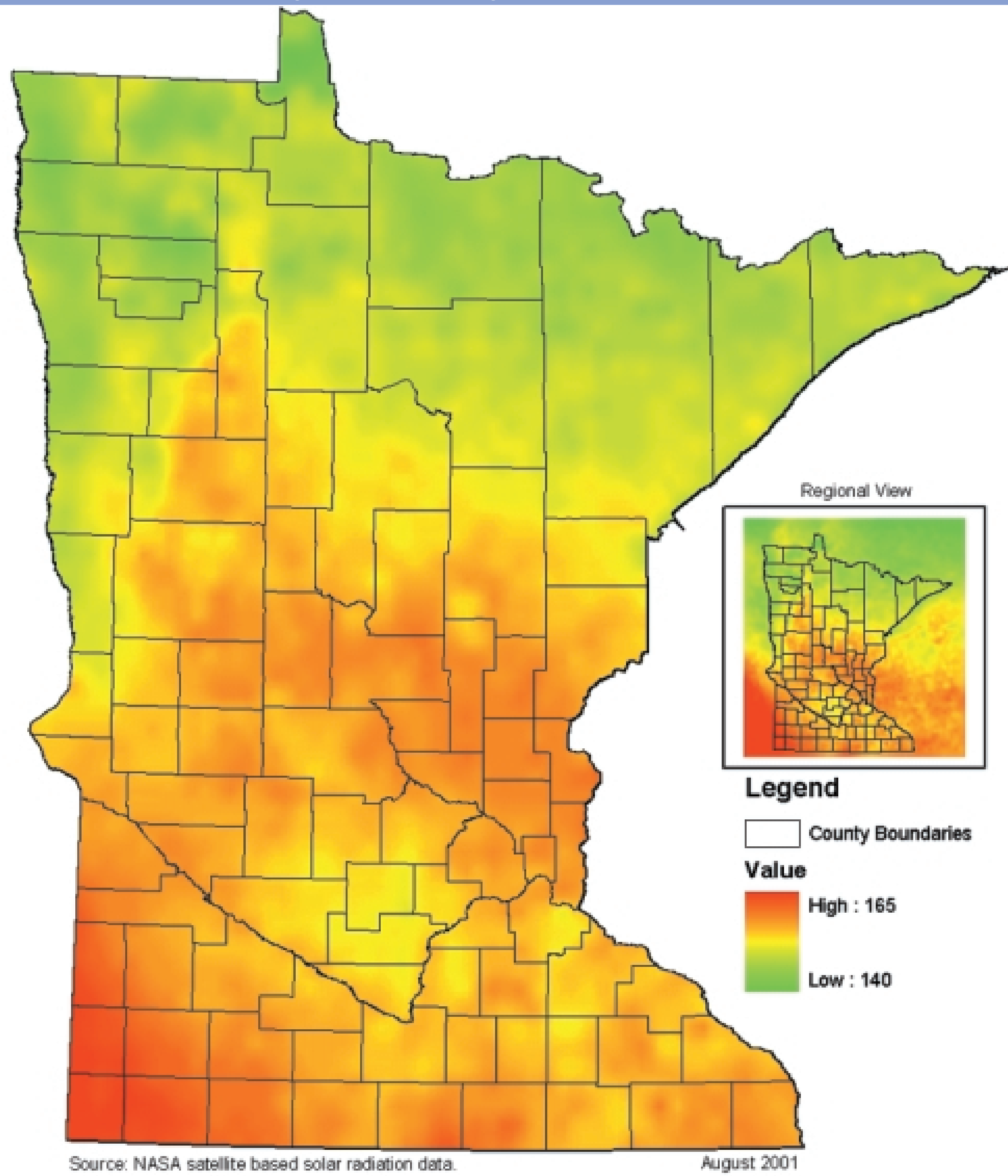
Figure 3-14 compares the emissions of wood, poultry litter and animal waste to that from pulverized coal (as

Figure 3-14: Comparison of Bioenergy Fuels to Coal for CO_2, SO_2 and NOx

Facility	CO_2 lb/mmBtu	SO_2 lb/mmBtu	NO_X lb/mmBtu	CO_2 lb/mmBtu	SO_2 lb/kwh	NO_X lb/kwh
Pulverized Coal (Taconite Harbor)	213	1.2	0.08	2.2	0.0024	0.0008
Wood (District Energy)	51	0.032	0.15	0.87	0.005	0.0026
Poultry Litter (Fibrominn)	0	0.07	0.16	0	0.0011	0.0025
Animal Waste Digester gas/IC Engine	0	0.001	0.23	0	0.004	1

represented by emissions from the Taconite Harbor coal power plant at Schroeder, Minnesota). Of most interest are the emissions of nitrogen oxides (NOx) from biomass fuel-fired facilities. Due to the high amounts of nitrogen in biofuels, NOx emissions are higher than traditional fossil fuels, even when best available control technologies like selective noncatalytic reduction is used. The concern related to NOx emissions is not inconsequential; the Twin Cities exceeded ozone standards for the first time in nearly 20 years this past summer. Ozone exceedances are related to NOx and volatile organic compounds (VOC) emissions. Replacing traditional fossil fuels with biofuels will not alleviate ozone concerns; in fact, use of these fuels in projects will require close attention to prevent aggravating ozone issues.

Figure 3.15: Annual Average Solar Insolation, 1998-2000



Solar

Solar-powered electricity can be made using a variety of technologies, but for practical purposes is limited to what are called photovoltaics, which are flat solar panels made of silicon cells that transform sunlight into electricity. The panels themselves perform reliably, with warranties of 20 years or more. The secondary equipment that distributes and transforms the electricity into a grid-compatible form tends to be the technological weak link. Solar electricity has remained outside of the mainstream largely because of costs and efficiencies. Traditional paybacks on solar installations remain high and the large market is in off-grid and niche applications such as solar-powered outdoor decorative lighting.

Some Minnesota cabins are powered by solar electricity, as well as a scattering of small buildings at state parks and other facilities. The majority of the large orange flashing construction signs are solar powered, as well as many emergency call boxes on the state's highways. There are less than 100 kW of grid-connected photovoltaics installed in Minnesota, with the largest installations being at the old Science Museum (St. Paul), Battle Creek Elementary School (St. Paul), the Burnsville Transit Station, and in Winnebago, Minnesota. Xcel Energy manages 17 photovoltaic installations around the Twin Cities of about 2 kW each as part of its Solar Advantage Program which began in 1996.

The Department has recently completed a resource map outlining the solar resources in the state, shown in Figure 3-15 (see previous page). The southwestern portion has the highest areas of solar resource, with the northeastern portions being the lowest. These extremes differ by only about 10-15 percent and, unlike wind power, represent a direct proportional relationship between insolation and power generation. Insolation, as opposed to radiation, is that portion of the sun's rays that reach the earth at sufficient strength to create usable energy.

Surprisingly, Minneapolis has a greater summer solar resource than Jacksonville (FL), as shown in Figure 3-16. Minneapolis, however, has a very low winter solar resource, which makes Minneapolis and Jacksonville nearly equal in terms of estimated annual electricity production.

Initial data from Xcel Energy's Solar Advantage Program indicate lower electricity production amounts than those estimated in Figure 3.16, ranging from 1,174 to 1,334 kilowatt hours per kilowatt of installed capacity per year. Tree shading, snow cover, and low tilt-angle were all factors in the decreased "real-world" generation data.

Figure 3.16: Regional and National Photovoltaic Estimated Electric Production

Regional	kWh/kW/yr	National	kWh/kW/yr
International Falls	1,497	Seattle, WA	1,225
LaCrosse, WI	1,547	New York, NY	1,528
Rochester	1,575	Jacksonville, FL	1,623
Fargo, ND	1,613	Phoenix, AZ	2,037
Minneapolis, MN	1,621		
Mason City, IA	1,638		
Sioux Falls, SD	1,652		

Source: NREL

Xcel Energy estimated an installed cost of \$8,500/kW in 1996, which was much less than comparable installations at the time[91]. This amount equates to a cost of about \$0.30/kWh over 20 years. Current installed costs are estimated at \$6,000-7,000/kW. Despite these costs, there is a high demand for solar electric systems, especially in California, where electricity problems and state incentive programs are widely available.

Solar electricity, like wind energy, is an intermittent technology. However, solar electricity has a positive correlation with electricity demand, meaning that solar panels statistically produce electricity when it is needed most—hot, summer days. Department of Commerce staff analyzed three of the Xcel Energy Solar Advantage installations. During periods of highest electricity demand the installations exhibited from 26-68 percent capacity. Tracking mechanisms, which let the panels actively follow the sun across the sky during the day, can increase this capacity performance even further.

The wide-spread commercialization of photovoltaics is largely dependent on manufacturing cost reductions, research and development gains, and/or incentives for installation. Photovoltaics' installed capacity in Minnesota will likely remain limited in the near-term.

One area of potential development, other than those already mentioned, is in urban locations with electric demands that are taxing the transmission and distribution system. An example might be in south

Minneapolis where electric demand is increasing from the Metropolitan Airport Commission's Sound Abatement program, which retrofits homes with new central air conditioners. Transmission and/or distribution system upgrades may be necessary in the future unless demand is decreased or unless additional generation can be locally sited. Photovoltaics, with their silent operation, low-profile, no pollution and summer use potential for air conditioning might be an alternative to these grid upgrades.

Photovoltaic cells used to produce electricity from the sun's energy produce no emissions to the air or water in operation. Access to solar energy may require the removal of some trees in certain operations.

Recently the Minnesota Department of Commerce's State Energy Office received a $1.15 million grant from Xcel Energy's Renewable Development Fund to develop a PV rebate program. This program is intended to increase the number of grid connected, PV installations in Minnesota by lowering the upfront costs by about 25 percent. The grant is subject to PUC approval prior to implementation of the program.

Fuel Cells

The modern version of fuel cell technology was originally developed as part of the Apollo moon program. A fuel cell is an electrochemical device that operates much like a battery. As long as hydrogen and oxygen fuel flow into it, direct current electricity and hot water will flow out of it. Since it operates on a chemical combination of hydrogen and oxygen to produce water and heat it has no combustion process and no air emissions. Because of the modular characteristics of the technology, installations can be sized from small kW scale applications to multi-MW installations.

Developing a sufficient hydrogen source to operate many fuels cells is one of the complex sets of requirements for broad utilization of this technology. Hydrogen can be produced from water by electrolysis (the source of the electricity for electrolysis could be renewable or conventional sources), but the most common source of hydrogen today is through refining of crude oil, or from methanol, ethanol, natural gas (methane), and even gasoline or diesel fuel. Using these traditional fuels that contain hydrogen as an energy source for fuel cells requires a pre-treatment of the fuel, in a "fuel reformer" that extracts the hydrogen for use in the fuel cell. Wind turbines can efficiently produce hydrogen from water.

Most fuel cell technologies are at the beginning of their commercial deployment. There are many types of fuel cell technology under development, Phosphoric Acid, Proton Exchange Membrane (PEM), Molten Carbonate, Solid Oxide, Alkaline, Direct Methanol, and Regenerative fuel cells. Each version of the technology type is at its own stage of development and commercialization. Phosphoric Acid cells were the first to be commercially deployed. A 250 kW version has been marketed for years. There are now over 200 of these fuel cells installed in the U.S.

Demonstration systems based on each of the other approaches are in operation. A major commercialization effort has been initiated by companies at the 5 kW size range for residential applications for electricity and hot water use. A much larger 5 MW demonstration system is now powering a post office complex in Alaska.

There are a variety of size options for this technology. Fuel cells can be created in sizes so small that they are being considered as power sources for portable phones. PEM fuel cells are attracting attention in the transportation market due to their light weight. Significant R&D activity is underway in the automotive industry to optimize these size and weight attributes.

The integration issues for fuel supply and heat and water outputs, along with low manufacturing volumes, have tended to make fuel cells expensive compared to more established gas turbine or gas engine products. Over time, with product evolution and increased sales volumes, fuel cells may be a more competitive power generation source.

These solid-state devices can operate at relatively high fuel-to-electricity conversion efficiencies (47-65 percent). This efficiency advantage coupled with the potential for use of the thermal hot water output makes this a likely competitive technology to the more conventional turbine or engine based technologies. Figure 3-17 shows the current and forecasted cost of fuel cell generation, and also shows how costs are expected to decrease as mass production increases. Maintenance costs for future fuel cell technologies are largely unknown. Many current fuel cells designs call for a major maintenance over-

Figure 3.17:

Cost of Fuel Cell Electric Generation | Estimated Costs for 50kW PEM Fuel Cell if Mass Produced

Time Frame	Cost ($/kW)	Units of Production	Steam Methane Reformer, PEM Fuel Cell and Inverter/Controller	Compressor, Hydrogen
2000-2004	$3,625	1	$404,800 ($8,096/kW)	$172,864 ($3,457/kW)
2005-2009	$3,000	100	$144,054 ($2,881/kW)	$79,947 ($1,599/kW)
2010-2014	$2,425	10,000	$52,186 ($1,044/kW)	$44,281 ($886/kW)

haul after five years that replaces the main fuel cell component (the stack).

Fuel cell technology is undergoing rapid change. Many entities are developing commercial products and much research is underway to improve the current state of technology. Many companies are expecting to enter the commercial marketplace with a product in the next three years.

Hydrogen

Hydrogen is the third most abundant element on the earth's surface, where it is found primarily in water and organic compounds. Hydrogen is produced generally from the electrolysis of water or the reformation of such fuels as natural gas, coal, gasoline, ethanol or methanol to extract the hydrogen component. When hydrogen is burned or when it is converted to electricity directly using a fuel cell it joins with oxygen to form water. A hydrogen-based economy would need a future hydrogen infrastructure that would make hydrogen widely available to the consumer market much like the current petroleum infrastructure. This infrastructure would allow the use of hydrogen for a variety of uses in fuel cells such as producing heat and electricity in homes and businesses or as a transportation fuel.

There are a variety of sources of hydrogen and technologies used in its production. The four main technologies used to produce hydrogen are thermochemical, electrochemical, photoelectrochemical and photobiological. Thermochemical technologies are being used to produce hydrogen by reforming fuels such as natural gas, coal, methanol, gasoline, ethanol or other biomass fuels. Electrochemical technologies use the process of electrolysis to produce hydrogen by passing an electrical current through water. Photoelectrochemical technologies produce hydrogen by illuminating a water-immersed semiconductor with sun light. Photobiological technologies produce hydrogen using the natural photosynthetic activity of bacteria and green algae. Currently the most economic source of hydrogen, widely available today, is from the reformation of natural gas to remove and clean the trapped hydrogen.

The future use of hydrogen as a fuel will largely depend on development of a safe and cost-effective infrastructure for fuel storage and transportation. Hydrogen is currently stored in tanks as a compressed gas or a cryogenic liquid. Hydrogen can be transported in tanks or the compressed gas can be sent through pipelines. New technologies that store hydrogen in a solid state are being developed that are safer and more efficient than storage as a gas or liquid.

Hydrogen has the potential to be used in a variety of applications to provide fuels or energy in the form of heat and electricity. Hydrogen can be used to power internal combustion engines or turbines which in turn can be used to power vehicles or turn electrical generators. It can be used in stationary fuel cells in homes and businesses to provide a source of heat and electricity. Much of the current focus is on the use of hydrogen as a clean fuel to power fuel cells for a variety of transportation applications.

Electricity Storage Technologies

The lack of cost-effective storage technologies is one of the key obstacles to efforts to improve the economics of electric generation by allowing cheaper stored power to meet peak demand instead of extremely expensive peak power. If economical electric storage technologies could be developed and fielded they could also increase the flexibility and reliability of intermittent renewable resources such as solar and wind. Electric storage could also provide power during peak power plant outages.

One of the more promising technologies now being installed is a type of regenerative fuel cell developed by UK-based Innogy Technology Ventures. This system uses a chemical electrolite to convert electrical energy to chemical energy in a reversible process. A demonstration project will install one of these systems for the Tennessee Valley Authority. This utility scale demonstration project is expected to cost approximately $25 million, have a peak capacity of 12 MW and a storage capability of 120 MWh.

ENDNOTES

45. Nationally, the fuel mix is 52 percent coal, 20 percent nuclear, 16 percent natural gas, 7 percent hydropower, 3 percent oil and 2 percent renewables. National Energy Policy, 1-6, May 2001.

46. Vehicles, on- and off-road, are significant contributors of air pollutants, as discussed in Chapter 1. Vehicles also contribute significantly to greenhouse gas emissions.

47. 2000 Annual Energy Review, EIA, at 217.

48. In 2001, two gas peaking facilities, Lakefield Junction and Pleasant Valley, added 920 MW of peaking capacity to the system, reducing the Minnesota portion of the capacity deficit from about 3,000 MW to the 2,000 MW discussed in Chapter 2.

49. Department of Commerce, Utility Data Book, Table 9 (1998).

50. Docket No. CN-99-1815, Black Dog Repowering Project Environmental Report, at 24 (2000).

51. Our thanks to the Premier of Manitoba and his staff, Manitoba Hydro and the Pimicikamak, Tataskweyak and Nisichawayasihk Cree Nations for their insightful and eloquent comments.

52. Id., Note 51, at 25.

53. Greenhouse gas emissions from hydropower are many times smaller per kWh generated than from coal-fired generation.

54. Id., Note 51, at 26.

55. The state has burned mixed municipal solid waste for the past 15 years, and landfill gas for the past seven years.

56. Incinerators operated by the City of Fergus Falls, Polk County, Pope-Douglas Counties, the City of Perham and the City of Red Wing process solid waste, but do not generate electricity.

57. Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis at 37 (2000).

58. Id. at 38.

59. Id. at 39.

60. See discussion on Distributed Energy Resources on page 68 of this report.

61. The PCA checks emissions from non-emergency diesel generators proposed at facilities under going permitting to ensure that they do not violate standards. Existing generators are evaluated on a case-by-case basis.

62. Conversation on October 1, 2001 with Shaine Tyson, Renewable Diesel Project Manager, National Renewable Energy Laboratory, Golden, Colorado.

63. Xcel Energy's comments, included in Appendix G, state that Pebble Bed Modular reactor costs approximately $1,100 kW.

64. Upstream and downstream fuel cycle activities do have emissions impacts. A detailed discussion may be found in the Comments by the North American Water Office dated November 21, 2001.

65. Existing Minnesota traditional coal-fired power plants are, on average, 38 percent efficient. The slightly higher efficiency reflects the absence of pollution control equipment that is required for a new plant.

66. Sources: Docket No. IP4/CN-01-1306 (Rapids Power).

67. Source: National Energy Technology Laboratory, DOE, www.fetc.doe.gov/products/power1/gasificationframeset.htm

68. Annual Energy Review 2000, EIA, at 212. The price of coal when it peaked in the 1970s reflected the high price of its competing fuels such as natural gas and oil.

69. Annual Energy Outlook 2001, EIA, at 92 and 94.

70. Id. at 92 and 94.

71. Comments submitted by the POWER Campaign provide a further discussion of emissions from coal combustion waste.

72. The air emission characteristics of coal and natural gas are shown in Figure 3-4.

73. In an agreement stemming from the 2001 Minnesota Legislative session, Xcel Energy agreed to study a variety of emission-reduction options for all metropolitan plants as a prerequisite to filing a proposal for an Emission Reduction Rider under the terms of the new statute.

74. Xcel's Black Dog plant retrofit filing projected a 49.2 percent efficiency rate.

75. Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis at 28 (2000).

76. 1993 Pacific Northwest Laboratory study at http://www.nrel.gov/wind/potential.html.

77. The wind resource is the fuel that produces the electricity to payback the cost of the turbine. Placing a turbine in a less resource rich wind site will not cost more, but the payback period for an investment will be longer.

78. American Wind Energy Association fact sheet, "Comparative Cost Of Wind And Other Energy Sources"

79. http://www.eia.doe.gov/oiaf/aeo/assumption/tbl77.html

80. http://www.nationalwind.org/pubs/wps.wes09.htm (National Wind Coordinating Committee)

81. There may be specific time periods when the percentage is higher or lower depending on wind conditions and demand.

82. http://www.windpower.dk/faqs.htm#anchor58865 (Danish Wind Industry Association)

83. The U.S. Combined Heat and Power Association was formed in early 1998. It has developed the goal of doubling the CHP installations (from 1998 levels) in the U.S. from 46 GW to 92 GW by 2010. Much of the additional capacity will come in the industrial sector, where there is an estimated potential of 88 GW of CHP. Some of the target industrial markets that have been identified are pulp and paper, chemicals, food processing, metals, and machinery.

84. Inventory of Cogeneration Potential in Minnesota, Minnesota Planning (2001).

85. Projects classified as good, some potential, and poor are listed in the study. Id. at 16.

86. Id. at 18-34. Not allowing for economics, potential CHP deployment in Minnesota is over 1600 MW at large facilities (over 1 MW) and over 800 MW at small facilities (under 1 MW). Id. at vi.

87. A proposed wind turbine installation that is 40 kW or larger often necessitates hiring a lawyer and an engineer to understand and negotiate a complicated interconnection agreement with the utility, making deployment especially difficult for small cities, institutions, small businesses and farmers.

88. Nelson & Lamb, Final Report: Haubenschild Farms Anaerobic Digester, The Minnesota Project, December 2000.

89. Docket No. CN-99-1815, Black Dog Repowering Project Environmental Analysis, at 35 and 37 (2000).

90. In addition, waste wood users are faced with the task of keeping treated wood out of the facility. Pentachloraphenol (PCP)-treated wood contribute to the production of dioxins in the flue gases, which may require further air pollution control equipment. Chrominated copper arsinate (CCA)-ash is highly toxic (much more than the wood itself). Both of these wastes could require the use of more sophisticated air pollution control equipment to avoid unacceptable releases to the air, and could result in ash that requires special handling and disposal.

91. Solar Electric Power Association, Northern States Power Company Solar Advantage Program. http://www.ttcorp.com/uprg/scoop/reports/nspc.htm

FOUR: ENERGY CONSERVATION – THE BEST ENERGY OPTION

The first 20 years of the Minnesota Conservation Improvement Program (CIP) have saved enough energy to avoid building four or five new power plants that would have been funded by rate increases. The current CIP program is saving about 128 MW of demand per year in the service territories of Minnesota's rate-regulated investor-owned utilities, avoiding the need to construct and pay for a 640 MW power plant every five years. These programs are cost effective in that the energy conservation programs cost ratepayers less than the cost of constructing new generating capacity. For example, the 640 MW were saved at an average cost to ratepayers of $343/kW while a coal plant that produced 640 MW would have cost ratepayers $1000-$1400/kW to build plus the costs of fuel and operation and maintenance.

After that long exposition on electric supply options for meeting Minnesota's increasing demand for electricity, we come to energy conservation. Even those supply side technologies that do not pollute and potentially can supply a lot of electricity at reasonable cost have downsides like creating a need for large upgrades of transmission systems or simply being in early stages of development and not yet readily available. In addition, all of them require a moderate to large amount of capital investment, which necessarily increases rates to consumers.

Reducing the demand, or at least reducing the rate of growth in demand, has no downside. Energy conservation and greater efficiency in the use of energy, including load management that shifts energy usage to lower demand parts of the day, is easy, costs little, and gives consumers their only opportunity for self-determination in relation to energy.

Two of the primary benefits of energy conservation are intuitive. The first is that consumers have smaller bills for utility service when they use less energy. The second is that by reducing inefficient energy use, Minnesotans experience fewer emissions of pollutants that cause health problems and damage the environment. A kilowatt hour not consumed is one that need not be generated. A kilowatt hour not generated emits no pollutants.

The third benefit, a huge one that is often overlooked, is that good conservation programs reduce rates for all ratepayers on a utility system. When a utility adds a power plant, the costs of the plant are put into the utility's rates as an increased charge per unit of consumption for all ratepayers on the system. If sufficient conservation occurs on the system as a whole, so that a new electric generation unit is avoided or delayed, all ratepayers have rates lower than they would otherwise have had.

The first 20 years of the Minnesota Conservation Improvement Program (CIP) have saved enough energy to avoid building four or five new power plants that would have been funded by rate increases. The current CIP program is saving about 128 MW of demand per year in the service territories of Minnesota's rate-regulated investor-owned utilities, avoiding the need to construct and pay for a 640 MW power plant every five years. These programs are cost effective in that the energy conservation programs cost ratepayers less than the cost of constructing new generating capacity. For example, the 640 MW were saved at an average cost to ratepayers of \$343/kW while a coal plant that produced 640 MW would have cost ratepayers \$1000-\$1400/kW to build plus the costs of fuel and operation and maintenance.

Last year, the legislature increased the state's commitment to energy conservation because of its concern over rising energy prices and the need to plan for additional electric capacity. The 2001 energy legislation made changes to the CIP program that should result in more energy conservation than in the past. The changes increased the spending required for conservation programs by municipal utilities and cooperative electric associations to the same level required of investor-owned utilities, increased the focus of all CIP spending on programs that actually reduce energy use, and established consistent statewide reporting and program evaluation to allow assessment of statewide progress and evaluation of the effectiveness of conservation programs.

The legislature also required the Department of Commerce to prepare the following report on the role of energy conservation in the future and to assess and make recommendations on how to improve the utilities' energy conservation programs.

Please note that energy conservation, as used in this chapter, means primarily physical improvements that result in less energy consumption and that can be relied on, once they are installed, to continue to use less energy into the future. Another type of energy conservation is consumer behavior such as setting a thermostat lower or turning off lights in unoccupied rooms, which result in lower bills and system savings, but cannot be relied on in an energy planning sense to provide capacity in the system for the long term. The line between physically reliable system improvements and less reliable, but very important, conservation behaviors is sometimes blurry. For example, energy efficient equipment often must be operated properly to ensure in reality the energy savings of which it is capable.

2001 Minnesota Energy Legislation

Energy legislation enacted in 2001 improved Minnesota's ability to meet its future energy needs through changes in statutes governing the Conservation Improvement Program (CIP). In addition, the legislature required a study of CIP both to ensure that it is being implemented effectively and to ascertain whether additional emphasis should be placed on energy conservation. Specifically, 2001 Minn. Laws, Ch. 212, Art. 8, Section 15 of the Act states:

> Sec. 15. [CONSERVATION INVESTMENT PROGRAM STUDY.] (a) The commissioner of commerce shall study the conservation investment program created under Minnesota Statutes, section 216B.241, and make recommendations to the legislature on changes in the program that will assist the program to obtain the maximum energy savings possible from spending and investments under the program. The study must include, at a minimum: (1) a review of administrative burdens imposed by the program with the goal to reduce them to the maximum extent consistent with ensuring that the program will meet its goal of maximum energy savings with program funds; (2) identification of spending and investments with high potential for saving energy and suggestions for targeting the program at those expenditures and investments; and (3) appropriate levels of spending and investment under the program. (b) The commissioner shall solicit written public comment on the study and submit a report and a copy of the written comments to the committees of the legislature having principal jurisdiction on energy matters by November 15, 2001.

In compliance with this statutory provision, this report provides:

(1) an overview of CIP and its major achievements to date;
(2) an estimate of how much natural gas and electric energy conservation can be expected to be provided through utility programs in the next ten years;
(3) how much those programs could reduce the state's future need for electric capacity;
(4) recommendations for how to maximize energy savings by reducing administrative burdens and increasing commitment to promising projects; and
(5) recommendations for appropriate spending and investment levels under the program.

Overview of the Conservation Improvement Program

The CIP statute[92] was first enacted by the legislature in 1982. Since 1991, the statute has required Minnesota's electric and natural gas utilities to spend a percentage of their annual Minnesota revenues on projects designed to encourage conservation among all their Minnesota customers—residential, commercial, and industrial, with specific attention given to providing conservation opportunities for residential renters and low income persons.

Under CIP, investor-owned utilities (IOUs) submit their conservation projects to the Department of Commerce (Department or DOC) for approval. From 1997 to 2000, electric IOUs spent $171.1 million in CIP, for an average of $42.7 million a year. Gas IOUs spent $57.4 million, for an average of $11.5 million a year. Five-year electric demand savings have totaled 641 MW (an average of 128 MW a year), with an average cost of $343 per kW of capacity saved. Five-year energy savings from these projects have totaled 1,680,843 MWh (an average of 336,169 MWh a year) and 4,665,206 Mcf of natural gas (an average of 933,623 Mcf a year).[93]

CIP programs have helped Minnesota avoid significant amounts of utility investment in energy and demand (additional generation capacity). Conservation investments by Minnesota's electric IOUs under their 1996-2000 CIPs will result in saving 21.8 billion kWh over the lifetime of the investments (enough electricity to power more than 700,000 Minnesota homes for five years)[94] at an average cost to the utility of 1.4 cents per kWh.[95] Natural gas savings resulting from gas IOU CIP expenditures over the same period totals 85 million Mcf, enough natural gas to supply energy to 772,925 average Minnesota homes for a year at a cost to the utility of only $0.68 per Mcf.[96]

Recent increases in energy price volatility and amended statutory requirements are likely to result in higher savings in the future. During the 2000-2001 heating season, natural gas prices skyrocketed. Although natural gas prices have subsequently dropped to lower levels, we expect that the future cost of energy will be higher, and certainly more volatile, than it has been in the past decade. Consequently, the relative cost effectiveness of energy conservation investments as compared to supply side additions is higher than in the past few years. In addition, consumers are becoming more aware of their energy costs and are interested in ways to save energy. The potential for energy conservation to make larger inroads is greater than it has been in the recent past.[97] In fact, a study released December 11, 2001, entitled "Attitudes and Behaviors of Residential Customers About Energy Efficiency" by Primen, (an energy market intelligence company) indicates that energy efficiency is the number one issue affecting appliance purchasing decisions.[98]

In addition to the IOUs, Minnesota's rural electric cooperative associations and municipal electric utilities also are required to invest a portion of their revenues in load management and energy conservation activities. For the most part, the municipal and cooperative utilities have concentrated their investments in load-management activities and consumer education, with some of the larger utilities making forays into energy savings projects. Although the municipal and cooperative utilities have sent annual reports to the Department, the reports have not used comparable estimates of actual energy and demand savings. The new legislation requires municipal and cooperative utilities to provide information that will enable the Department and other parties to determine more accurately their programs' contributions to reducing the need for future electric and natural gas resources. Consequently, by 2003, the state will have a much clearer view of the cost effectiveness of the municipal and cooperative utilities' CIP investments.

Load management projects play an important role in reducing the state's need for electric capacity. Indeed, load management projects tend to very cost effectively reduce the need for new generating capacity. In future years, we will attempt to estimate the potential additional contribution of load management to reducing the state's need for additional capacity. We did not focus on load management achievements in this report because all electric utilities, municipal, cooperative and investor owned, already have a large financial incentive to reduce their demand through load management without spending conservation investment dollars and are doing an excellent job. There are, however, many actual energy conservation projects, ones that save capacity and energy, that also cost effectively avoid the need for future generating plants.

Municipal and cooperative utilities have not been in the forefront of energy conservation, with a few notable exceptions. By working with these utilities to identify known, proven measures, we hope to minimize the state's future cost of supplying electric needs by helping the municipal and cooperative utilities tap their underdeveloped energy conservation potential.

Historic Overall CIP Results

Figure 4-1 shows that the electric IOUs have saved significant amounts of energy and demand (need for new generating capacity) over the past nine years. The average cost per kW of new electric capacity saved over the nine years is $343.[99] As shown in Figure 4-3, this amount is a substantially lower cost to ratepayers than the cost of new electric capacity.

To put the savings into perspective, by 2010 these investments will result in annual energy savings equivalent to the amount of electricity that would be produced by a 380 MW baseload plant generating electricity 24 hours a day each year—or the amount used by more than 400,000 average Minnesota homes. The demand savings provided over the last nine years is equal to five 250 MW peaking plants. As can be seen, there was a significant increase in the cost of saving electric energy and demand between 1992 and 1994,

Figure 4.1: Investor-Owned Electric Utilities' Historical CIP Savings

	Energy Savings (MWh)	Demand Savings (kW)	Average Cost per kW Saved
1992	200,393	110,223	$258
1993	344,107	180,120	$240
1994	464,610	166,500	$314
1995	495,552	150,033	$458
1996	377,209	145,315	$396
1997	487,149	150,015	$280
1998	299,418	122,649	$383
1999	214,161	94,047	$437
2000	302,906	129,364	$317
TOTAL	**3,185,505**	**1,248,266**	

Figure 4.2: Xcel Electric Historical CIP Savings

	Energy Savings (MWh)	Demand Savings (kW)	Average Cost per kW Saved
1992	162,010	105,461	$243
1993	265,480	168,575	$229
1994	339,152	153,024	$281
1995	431,162	134,172	$387
1996	377,209	123,174	$331
1997	487149	129,872	$262
1998	299,418	114,042	$292
1999	214,161	83,132	$363
2000	302,906	116,845	$298
TOTAL	**2,878,647**	**1,128,297**	

Figure 4.3: The Costs of Electric Capacity Conservation versus New Power Plants[102]

Technology	Low Cost - High Cost
Investor-owned utility demand-savings costs	$250 to $1,000 per kW
Natural gas combustion turbine (peaking)	$360 to $425 per kW
Natural gas combined cycle (intermediate to baseload)	$375 to $600 per kW
Coal baseload	$920 to $1,400 per kW
Wind	$800 to $1,200 per KW

but the cost has remained relatively constant since 1995.[100] An analysis of these costs just for Xcel Energy (in Figure 4-2) shows a similar pattern: the costs increased between 1992 and 1995, but have remained relatively constant or declined since 1995.[100] Xcel Energy's average cost for saving demand over the nine-year period is $299.[101]

The range of electric IOU demand savings costs is compared to the range of estimates for new installed capacity in Figure 4-3.

Based on these costs of new capacity, Minnesota's CIP costs compare very favorably with the price of supply side capacity investments, even without considering the additional benefits of avoided fuel and operation and maintenance costs and avoided transmission and distribution costs of all of the energy saved.

This cost comparison, however, is not dispositive because the lifetime of a conservation measure may be different than the lifetime of new peaking or base-load capacity. The best way to determine whether an energy conservation measure is cost effective is to perform an analysis that takes into account the lifetime of the energy conservation measures. In some cases, energy conservation may cost more than new capacity investments, but will still be cost effective because the *combined* energy and demand savings cost less than a *combined* equivalent supply of energy and demand.

Figure 4-4 shows that the natural gas IOUs also have saved significant amounts of energy since 1997 at an average cost less than even the low range of monthly wholesale natural gas prices. [103]

The cost of saving natural gas has declined in the past two years mostly because utilities have been focusing on commercial and industrial customer energy savings.[104]

Figure 4.4: Investor-Owned Natural Gas Utilities' Historical CIP Savings

	Energy Savings (Mcf)	Average Cost per Mcf Saved	Lowest Monthly Natural Gas Price	Highest Monthly Natural Gas Price
1997	1,001,836	$0.84	$1.78	$.4.00
1998	945,983	$0.80	$1.67	$2.36
1999	1,310,255	$0.51	$1.67	$3.09
2000	1,349,630	$0.51	$2.34	$6.04

Potential Additional Future Energy and demand Savings Through CIP

Figure 4-5 estimates the amount of electric energy and demand and natural gas energy savings the state can achieve by 2010 just through utility-sponsored (municipal, cooperative, and investor-owned utilities) energy conservation programs.[105] Figure 4-5 assumes that municipal and cooperative utilities ramp up their commitment to energy conservation projects as required by the 2001 energy legislation.

Figure 4.5: Potential Cumulative Energy and Demand Savings by 2010

	Energy Savings	Demand Savings
Electric	3,000-3,200 GWh	980-1,100 MW
Natural Gas	105,000,000 MCF	

The cumulative natural gas savings are equivalent to providing natural gas to 102,000 average Minnesota homes for ten years. The cumulative electric savings are equivalent to providing electricity to 38,000 to 41,000 average homes for ten years.[106] Figure 4-5 estimates overall potential energy conservation in the state for utility programs assuming present legislation.

When each utility submits its forecast of future energy needs to the Midcontinent Area Power Pool (MAPP), the forecast already accounts for the fact that the utilities' energy conservation projects will reduce their customers' energy and demand needs in the future. Consequently, when determining how much of the demand savings (capacity savings) estimate can be used to meet new electric capacity needs, we first must eliminate the amount of demand savings that are accounted for by the utility estimates. Energy conservation resulting from existing energy conservation statutes and PUC Orders[107] can be used to provide 326 to 434 MW of the projected electric capacity deficit (see Chapter 2). Stated another way, only 650 to 670 MW of the 980 to 1,100 MW of energy capacity available from conservation is included in utility demand forecasts.

The contribution of energy conservation to the state's energy and capacity needs through 2010, could be increased beyond the 326 to 434 MW identified above by:

- Treating municipal and cooperative utilities' load-management expenditures the same as electric IOUs' load-management expenditures—only load-management projects that result in energy savings would count towards statutory spending requirements. Effectively, this increases the percentage of municipal and cooperative utilities' CIP spending that must be used on energy conservation (and not load management) projects to higher than 50 percent.

- Increasing the percentage of gross operating revenues that all electric municipal, cooperative and IOU utilities must spend on CIP to 2 percent (the amount required of Xcel Energy).

The first step could save an additional 84 to 189 MW of capacity. The second step could save an additional 48-83 MW of capacity. These strategies should be considered in future legislative energy discussions.

Figure 4-6 shows how energy conservation could be used to reduce the Spring 2001 MAPP forecasted capacity needs for the MAPP US region and for major Minnesota electric utilities.

Consequently, energy conservation could reduce the MAPP forecasted capacity shortages by 330 to 706 MW, depending on future legislation or on utilities' voluntary efforts or increased spending. We will track the state's progress toward meeting the potential shown in Figure 4-5 and include in the 2002 update to this report an analysis of that progress.

Please see Appendix D for an explanation of how we calculated the numbers above.

Maximizing Energy Savings

CIP funds are finite and a valuable resource. Every effort should be made to maximize energy savings from conservation investments while meeting all of the public policy provisions of the statute. Energy savings can be maximized by minimizing administrative costs, focusing utility efforts on proven cost effective technologies and processes, and encouraging utilities to invest in promising new technologies and marketing techniques. Each of these options is discussed below.

Minimizing Administrative Costs

Administrative costs for implementing CIP can have an impact on the amount of energy savings per dollar spent.

Both the Department of Commerce (DOC) and utilities incur CIP administrative costs. These costs include:

Figure 4.6: How Energy Conservation May Reduce Electric CapacityShortages

	MAPP US Region	Major Minnesota Utilities
2010 Shortfall	3,579 MW	2,050 MW
After Conservation [108]	3,145-3,253 MW	1,616-1,724 MW
Muni/Co-op 100% [109]	2,956-3,169 MW	1,427-1,640 MW
Statewide 2% spending [110]	3,062-3,205 MW	1,533-1,676 MW
All scenarios [111]	2,873-3,121 MW	1,344-1,592 MW

- The cost to utilities to research, plan, and submit new and existing project proposals.
- The cost of DOC's and other parties' review of the submitted proposals.
- The cost of compliance filings.

Investor Owned Utilities

IOUs reduce the administrative cost of CIP when they provide complete and accurate information up-front and respond in a timely manner to information requests.

We have taken several actions during the past five years to reduce the resources consumed by the CIP approval process and to expedite decisions for investor owned utilities. These steps include:

- setting timelines for completion of staff review,
- streamlining our cost effectiveness analysis,
- granting utilities the flexibility to modify projects or surpass goals when the changes result in a cost effective project,
- reviewing utility proposals at a customer class level instead of an individual project level, and
- reducing the degree of analysis of existing, successful projects.

In response, the number of time-consuming miscellaneous filings for investor owned utilities has been reduced and the overall decisions are being handled in a more timely manner.

Currently, IOU conservation improvement programs are approved once every two years. Despite attempts to streamline the process, the submission and approval of a plan continues to consume a significant amount of DOC's, utilities' and other parties' resources. Allowing utilities to file for and implement programs for three rather than two years is potentially one way to further reduce CIP's administrative burden. The drawbacks may include greater difficulty in estimating budgets and goals three, rather than two years into the future, intervening changes in technologies and standards and a reduction in accountability[112]

An option for reducing administrative costs would be to create a "conservation utility" as discussed later in this chapter.[113]

Municipal and Cooperative Utilities

The administrative costs of cooperative and municipal utilities are likely to increase as they develop and implement new programs, evaluate these programs, and communicate their results. As the Minnesota Municipal Utility Association noted in its comments on the draft CIP study, most municipal utilities will be operating under testing and evaluation allowances of $5,000 or less. Potential energy savings should not be eaten up by administrative costs that may be incurred by so many small entities complying with the state law. There are five primary ways to alleviate this potential problem. First, the municipal and cooperative utilities can use standardized and pre-packaged programs with proven track records.[114] Second, we will provide information on a variety of cost effective programs, and the utilities may choose the ones that best fit their customer needs.[115] Third, the utilities can band together to provide the greatest pool of resources. Fourth, we are developing templates for conservation reports so that utilities will understand the kind of information that we will need to evaluate completed and proposed programs. Fifth, all utilities could be required to share or report the results of their CIP funded research or pilot projects. Increasing the time between conservation program filings from two to three years for municipal and cooperative utilities, as suggested by some parties, is inappropriate because these utilities are just beginning to implement large scale energy conservation programs that will need closer attention in the beginning years.

All Utilities

In its comments on the draft of this CIP study, one party recommended that DOC sponsor a forum where utilities and other industry professionals exchange ideas about successful programs and what projects can be tailored to meet community or customer needs.[116] We agree that this would be an additional way to minimize the administrative costs of all utilities. We will work with various interested parties to set up a useful forum.

Identifying Cost-Effective Projects

Energy conservation projects are considered cost effective to society when their costs are less than the cost to build and operate new energy supplies. The appropriate way to measure cost effectiveness is to consider all of the benefits of a project. For example, assume an electric energy conservation project that saves 10 kW of summer peaking capacity also saves 16,500 kWh. It would not be appropriate to compare the cost of the energy conservation measure with the avoided costs of 10 kW of peaking capacity. It is also necessary to add the benefits of saving the 16,500 kWh.

Figure 4-7 shows that the average cost for an individual commercial and industrial project to save natural gas was between $0.12 cents and $1.72 per Mcf.[117] (The calculations in Figures 7-12 are for projects that were implemented between 1997 and 2000.) For example, of the natural gas utilities that offered incentives at any time between 1997 and 2000 for energy efficient commercial and industrial boilers, the average cost to save an Mcf was approximately $0.16 per Mcf: the lowest cost was $0.12 per Mcf and the highest cost was $0.25 per Mcf. Calculating these ranges provides information about the most cost effective projects and can be used by utilities to help estimate the cost of using similar measures for their customers. The calculations in Figure 4-8 can be interpreted in a similar manner.

Figures 4-9 and 4-10 show the costs of commercial and industrial projects saving electric energy and demand.

Figures 4-11 and 4-12 show residential projects and their costs of saving electric energy and demand.

All of these projects have been determined to be cost effective for at least one IOU utility in Minnesota. For the most part, these projects remain cost effective over all reasonable ranges of future electric and natural gas costs.[118]

Projects that maximize energy savings

Minnesota's experience indicates that commercial and industrial projects are the most cost effective energy conservation projects, both for electricity and natural gas. Residential projects tend to be not as cost effective for two reasons. First, Minnesota's building code and federal appliance standards have reduced the energy savings potential for efficient versus standard homes and appliances because the standards have raised the baseline for energy efficiency. Second, convincing an individual customer to change his or her purchasing behavior has a cost. Considerably more residential customers must change purchasing practices to save a unit of energy than the number of commercial and industrial customer purchases it takes to save the same amount of energy. DOC will continue to require IOUs to devote an appropriate amount of their budgets to commercial and industrial projects.

Other impacts on a program's savings

In general, the type of projects the Commissioner of Commerce approves for CIP spending can be ranked according to how much energy they save in the following order (most energy saved to least energy saved per $ spent):

1. Commercial and industrial projects
2. Non-low income residential projects
3. Low income projects
4. Educational/audit/research projects

Although commercial and industrial projects are the most cost effective, it is not appropriate to invest only in these projects for two main reasons. First, energy conservation programs are one of the only means of giving customers control of their energy usage. Denying access to these projects to any customer class would be unfair, particularly when all customer classes typically pay for the overall CIP. Second, cost effective potential exists in all of the areas and should be exploited where possible.[119] Some parties have asked the Commissioner to limit utilities' investments in projects that do not have direct energy savings—educational and research projects in particular. These investments, however, often will improve future energy savings efforts. For example, research into market saturation of technologies may assist utilities in determining how to best target their CIP investments for maximum results. We will continue to support a limited amount of funding for indirect impact projects such as research and education projects, recognizing that some of these expenditures may result in the prized energy conservation efforts of tomorrow.

Figure 4.7: Commercial and Industrial Projects Ranked According to Average Cost of Saving Natural Gas

End-use	Average $/ Mcf	Low $/ Mcf	High $/ Mcf
Boilers	$0.1597	$0.1145	$0.2492
Custom	$0.4979	$0.3320	$1.7189
Water Heating	$0.8704	$0.7643	$1.0570

Figure 4.8: Residential Projects Ranked According to Average Cost of Saving Natural Gas

End-use	Average $/ Mcf	Low $/ Mcf	High $/ Mcf
Space Heating	$1.03	$0.55	$1.33
Water Heating	$1.21	$0.95	$2.34
Weatherization	$3.52	$1.73	$7.05

Figure 4.9: Commercial and Industrial Projects Ranked According to Lowest Average Cost for Saving Energy

End-use	Average $/	Low $/ kWh	High $/ kWhkWh
Custom Grant	0.0022	0.0008	0.005
Compressed Air	0.0024	0.0021	0.0028
Lighting	0.0029	0.0021	0.0179
Refrigeration	0.0038	0.0021	0.0215
Air Conditioning	0.0057	0.0039	0.0120
Motors	0.0074	0.0064	0.0116

Figure 4.10: Commercial and Industrial Projects Ranked According To Lowest Average Cost for Saving Demand (capacity)

End-use	Average $/ kW	Low $/ kW	High$/ kW
Custom Grant	295	135	483
Compressed Air	322	247	478
Lighting	366	297	573
Refrigeration	369	275	1,949
Air Conditioning	386	275	545
Motors	535	291	1,434

Figure4.11: Residential Projects Ranked According to Lowest Cost for Saving Demand (capacity)

End-use	Average $/ kW	Low $/ kW	High$/ kW
Saver's Switch	205	160	236
Central AC	764	719	828

Figure 4.12: Residential Projects Ranked According to Lowest Cost for Saving Energy (capacity)

End-use	Average $/	Low $/ kW	High$/ kW kW
Lighting	$0.0414	$0.0225	$0.0489
Central AC	$0.0973	$0.0916	$0.1055

Promising Approaches and Technologies for Saving Minnesota's Energy

The amount of energy saved by an investment depends on numerous factors, including the ability to educate and motivate customers to change their investment habits, the types of technology and processes involved, and how a project is implemented. Below are five recommendations for how Minnesota can maximize its energy savings in the future.

ENERGY STAR®

The ENERGY STAR label designates appliances, motors, lighting, electronics, and other energy using devices that exceed the energy code or standard by a specific amount. Manufacturers and retailers can affix the ENERGY STAR label to all of their qualifying products to help consumers make easy choices about the efficiency of their purchases.[120]

ENERGY STAR has expanded to cover new homes, most commercial buildings, residential heating and cooling equipment, major appliances, office equipment, lighting, consumer electronics, and other products. Last year alone ENERGY STAR saved Americans $5 billion on their energy bills without sacrificing product features, quality, or personal comfort.[121] A large benefit from the ENERGY STAR label is that it is an easy way for customers to identify energy efficient products with assurance that the products are indeed more efficient than standard ones. Customers are not required to have a detailed understanding of what makes one product more efficient than another.

Examples of ENERGY STAR products include commercial and residential clothes washers, natural gas furnaces, residential lighting, refrigerators, air conditioners, and consumer electronics.

Figure 4.13: ENERGY STAR Market Penetration and Energy-Savings Estimates

Technology	Market Penetration	Average Savings per Unit (per year)
Room air conditioners	13%	27-54 kWh [122]
Clothes washers	15.5%	550 kWh
Dishwashers	16%	145 kWh
Refrigerators	15%	56 kWh
Audio electronics	30%	45 kWh
Lighting	NA	80 kWh
Variable Speed Drive on Furnaces	NA	570 kWh

Figure 4-13 shows the U.S. Department of Energy's (DOE) estimate of the Minnesota market penetration of a few electric residential ENERGY STAR products.

In general, the ENERGY STAR products with the most energy savings potential for residential customers include variable-speed drives on furnaces,[123] clothes washers, lighting, and dishwashers. Even though they do not save large amounts of energy, efficient room and central air conditioners are important to Minnesota because they reduce energy at the summer peak. Increasing their efficiency can have a large impact on reducing Minnesota's need for future peaking capacity. These ENERGY STAR products are some of the ones that utilities are promoting nationally through a combination of incentives to customers, manufacturers, middle market actors, and through education. In addition, ENERGY STAR audio and video electronics typically do not cost more than standard electronics. Consequently, consumer education and incentives to retailers who stock ENERGY STAR products are typically the means for promoting these technologies. DOE estimates that Minnesota could save 4 MW and 31 million kWh (enough electricity to power 3,600 Minnesota homes) each year if ALL units sold in the state were ENERGY STAR.

Several IOUs have already initiated projects promoting ENERGY STAR residential products and municipal and cooperative utilities have expressed considerable interest. Some product promotions may not be individually cost effective. If each utility issues a specific amount of rebates and one counts only the energy savings of those products, the costs may be greater than the benefits (avoided energy costs.) However, by promoting a select amount of ENERGY STAR products during 2002 and 2003, the state, utilities, and energy service companies can increase the penetration of those products and further educate customers about the ENERGY STAR label, encouraging them to purchase other ENERGY STAR products.

The Department of Commerce will work with utilities, energy service companies, consumers, and others to increase the proportion of ENERGY STAR washing machines being sold by ENERGY STAR partner manufacturers and/or retailers. The aggressive goal we propose is an increase of 2 percent over the current annual rate of growth, as measured by sales between 2000 and 2001.[124] Setting this goal is expected to: help motivate all of the actors involved in achieving the goal; be used as an educational tool for public awareness; and be useful in helping to determine what strategies can be used in the future to increase energy efficiency in the state. To further promote penetration of ENERGY STAR products, we are encouraging utilities and retailers to participate in ENERGY STAR'S promotion of efficient cooling equipment such as air conditioners, dehumidifiers, and ceiling fans in the spring of 2002.

One commenter raised the concern that the ENERGY STAR program focuses on electric rather than natural gas technologies and that some of its standards are lower than what the utilities have been promoting.[125] We are actively encouraging the ENERGY STAR program to include more gas technologies, especially since some of them, such as water heaters, tend to be more efficient than electric water heating. In addition, we are encouraging the ENERGY STAR program to increase the qualifying efficiency level on natural gas furnaces; to consider requiring qualifying units to have variable speed drive; and to increase the efficiency level of electric central air conditioners.

Other Regional Approaches to Saving Energy

The section on ENERGY STAR above has already described a national approach to promoting energy conservation in addition to or in conjunction with CIP. We are also encouraging Minnesota utilities to work with the Midwest Energy Efficiency Alliance (MEEA), a regional network of organizations collaborating to promote energy efficiency. MEEA's mission is to foster increased market penetration of existing energy efficiency technologies and promote new technologies, products, and best practices. DOC is a member of MEEA. DOC's State Energy Office Manager serves on the MEEA Board as Vice-Chair.

MEEA is working with DOC and several Minnesota utilities to promote energy conservation. MEEA is also working with regional representatives of retail chains like Sears, Home Depot, and True Value Hardware to encourage them to stock and promote ENERGY STAR products. By encouraging the promotion of energy conservation campaigns on a statewide, region-wide, or even nation-wide basis, groups like MEEA and campaigns to promote ENERGY STAR are helping to ensure that consumer demand is permanently transformed to focus on buying energy efficient products most of the time.

Some municipal and cooperative utilities have also made suggestions about how the state can assist the utilities in obtaining better deals from manufacturers on efficient equipment. We will continue to explore these ideas with all utilities. By grouping together, the state's utilities can have a larger impact on what types of equipment is stocked and sold in the state.

Promoting Building Recommissioning and Design Assistance

Two new energy conservation strategies promise to provide significant energy savings for Minnesota's commercial and industrial energy consumers. The first, building recommissioning, involves investigating existing buildings to ascertain whether the building's lighting, heating, ventilation and air conditioning (HVAC) systems, motors and other systems are operating properly.[126] Skilled auditors often find that controls have been disengaged, ductwork has been pierced, or other systems are not functioning. The second strategy, design assistance, involves improving architectural plans for new buildings so that the buildings exceed the efficiency presently required by the energy code. Xcel Energy's *Energy Assets* project is an example of design assistance. Xcel Energy's prime contractor, the Weidt Group of Minnetonka, received an international award in 2001 for the project from the European Council for an Energy Efficient Economy (ECEEE).[127] We encourage other utilities to adopt these approaches when appropriate as part of their CIPs.

In the 2001 legislative session, Minn. Stat. §16B.325 was amended to require the Departments of Administration and Commerce to develop sustainable building design guidelines for all new state buildings by January 15, 2003. One of the primary objectives of these guidelines is to ensure that all new state buildings have an energy performance at least 30 percent better than buildings built under the existing energy code, as well as to encourage continued energy conservation improvements and indoor air quality standards that provide healthy working environments. These guidelines will be mandatory for all new buildings receiving funding from the state bond proceeds fund after January 1, 2004. In addition, the Department of Administration, in consultation with DOC, must develop a comprehensive energy conservation plan for all public buildings in the state

Conservation Utility

Currently, CIP creates an inherent conflict in that it requires utilities to promote conservation of energy when their core business is to sell consumption of energy. To eliminate this conflict, three states—New York, Vermont, and Wisconsin have implemented a conservation utility approach. A conservation utility differs from the current CIP structure in that the administration of energy conservation programs is handled by an entity whose sole purpose is to save energy. This structure frees the regular utilities to perform their basic role—selling their customers energy. For example, in Vermont, a state agency put out to bid the administration of the state's entire conservation program. The winning bidder is currently contracting with other organizations to deliver the programs. A conservation utility can be designed so that it delivers programs statewide, when appropriate, or target specific projects, marketing approaches, etc. to specific regions of the state. A conservation utility should be a private entity, either a for-profit or non-profit business. The conservation utility could also be several conservation utilities that implement programs in different regions of the state.

Our conservation utility recommendation received both support and opposition in comments. The opposition to the conservation utility generally came from utilities and large power customers. The support generally came from energy efficiency and low income advocates. Among the two groups, there was some agreement that the concept would be best tested when delivering projects to low income customers. The greatest opposition came to using the conservation utility concept to delivering services to large commercial and industrial users because these customers rely on a personal relationship with the utility account representative when making strategic energy efficiency decisions. One commenter suggested that we could move towards a conservation utility now by taking two steps. First, we could develop standard projects that are implemented statewide, including standard savings and rebate levels. Second, we could encourage more alternative energy providers to implement programs.[128] Another party states that the conservation utility concept was not developed enough for parties to evaluate and suggested several questions and concerns that need to be answered before making a decision about a conservation utility.[129] We agree that these questions and concerns must be further answered before deciding how and whether the conservation utility will work in Minnesota. Further, we will continue to evaluate the results of similar efforts in Vermont, New York, and Wisconsin. The 2002 update to this report will include a more refined recommendation for establishing a conservation utility.

Centralized coordination and/or funding of low income projects

Several utilities have requested that DOC consider centralizing statewide energy conservation programs that serve low income households. We are considering this recommendation given that some utilities have had great difficulty in meeting their low income goals and that energy affordability is an important societal issue.

Currently, low income CIP dollars are administered separately from low income weatherization dollars provide by DOE. Central coordination of these funds could help ensure that the dollars are used to leverage each other and obtain the maximum benefits for low income customers. We are working with the utilities and other parties to explore this idea. No statutory changes are necessary to move to central administration of these funds.

In addition to these proposed changes, we agree with the Energy Cents Coalition and other commenters that one way to improve the cost effectiveness of low income projects is to concentrate efforts on low income customers who use relatively large amounts of energy.

Expansion of sales tax exemption

In the 2001 special legislative session, Minn. Stat. §297A.67 was amended to include a sales tax exemption for certain energy efficient products. Products that qualify for this sales tax exemption are:

- residential lighting fixtures and compact fluorescent light bulbs with Energy Star labels,
- electric heat pump hot water heaters with an Energy Factor of at least 1.9,
- natural gas water heaters with an Energy Factor of at least 0.62,
- natural gas furnaces with an AFUE (efficiency rating) greater than 92 percent, and
- photovoltaic devices.

This sales tax exemption is effective for qualifying products purchased between August 1, 2001 and July 31, 2005. This list should be amended to include large appliances with Energy Star labels. Reliant Energy Minnegasco has raised the issue that this extension could disadvantage efficient natural gas products because Energy Star has not extended their label to some gas technologies. We are encouraging Energy Star to include more gas technologies, and we encourage natural gas utilities to do so as well.

Use CIP to implement real time pricing for customers.

Customers are able to make better energy use decisions if they have better information about their energy costs. Technology exists to give consumers hour-by-hour energy cost information. Minnesota Power recommended that some CIP dollars be used to help implement real time pricing projects. They noted that real time pricing projects are more likely to be cost effective for large customers than small ones. This issue is currently being debated before DOC's Commissioner in Docket No. E017/CIP-01-1187. In addition, real time pricing issues are being discussed before the PUC in Docket No. E002/CI-01-1024. We note that, although even residential customers may benefit from real time information about their energy use,[130] we remain concerned that the technology costs are too high at this time to make residential applications cost effective.

DOE's Web Based Audit

DOE currently maintains a highly informative website that helps consumers conduct their own energy audit. The information is specific to utility rates in the consumer's area. It gives consumers extensive, but easy to understand, information about ways they can reduce energy use in their homes without sacrificing comfort. Because DOE allows utilities to link to this website at no cost, Minnesota utilities should make this information widely available to Minnesota consumers at little to no cost. The website address is www.homeenergysaver.lbl.gov.

Recommended Level of Spending

As shown above and as projected in electric utility resource plans, IOUs' current levels of energy conservation efforts result in cost effective investments. Given the continued cost effectiveness of this resource acquisition method, increasing energy conservation spending would result in additional cost effective energy and demand (new capacity) savings. Before increasing spending levels, however, we should focus our attention on ensuring the success of two new CIP developments. First, municipal and cooperative utilities should have sufficient time to design and offer their projects and learn from their experiences before deciding whether an increase in their spending levels is appropriate. Second, two of the utilities operating in the state that need new electric resources the most—Xcel Energy Electric and Alliant Energy Electric—are already mandated by the PUC to exceed the energy savings level that would occur at the minimum statutory spending levels. These utilities must already spend more than the minimum amounts and we should analyze the success of this additional spending before requiring an overall increase statewide.

Recommendations

Based on extensive review of CIP's history, results, and potential for the future, we recommend that:

- The time between IOU CIP filings be increased administratively to three years,
- All electric and natural gas utilities implement the most cost effective projects, with due consideration for the statute's emphasis on CIP spending for renters and low income households.
- All utilities and state and local agencies encourage using Energy Star and other existing marketing themes to reach Minnesota customers.
- All utilities increase the penetration of building recommissioning and building design assistance programs and projects.
- The legislature begin discussions of establishing a private conservation utility (or utilities).
- DOC coordinate, in consultation with utilities and others, CIP low income, DOE low income weatherization, and any energy assistance funds.
- the legislature extend sales tax exemptions to all Energy Star appliances and select efficient natural gas appliances.
- Utilities use DOE's audit website and provide their customers with links to the website.
- DOC continue analysis of CIP minimum statutory spending levels and the potential for additional cost effective conservation by increasing those minimums.

Except for the conservation utility and sales tax exemptions, these recommendations do not require legislative changes. Any further encouragement or incentives for energy conservation from the legislature, however, will help increase the role of energy efficiency and conservation in keeping electric and natural gas retail prices low, meeting new capacity needs, and reducing the health and environmental burdens associated with energy production, transportation, and consumption.

ENDNOTES

92. Minn. Stat. § 216B.241.

93. Capacity or demand is the rate *at which electricity or natural gas is transferred. For electricity, capacity or demand is usually measured in Megawatts (MW), which is equivalent to a million watts. For natural gas, capacity or demand is usually measured in Mcfs (thousand cubic feet). By saving capacity, society reduces the maximum size (and associated costs) that (an) electric generating unit(s) or natural gas pipeline(s) need to be. Energy is the* measure *of the amount of electricity or natural gas transferred. Electricity transferred is measured in kilowatt-hours (kWh) or megawatt-hours (MWh). Saving kWh or Mcf reduces the need to generate electricity or drill and transport natural gas. If kWhs or Mcfs are saved on an ongoing basis, during peak times of use, these energy savings also produce capacity savings.*

94. Assumes an average annual Minnesota electricity consumption of 7,800 kWh and average lifetime of the energy conservation measures of 13 years.

95. The cost to society of the savings is approximately 1.0 cent more per kWh for a total cost of approximately 2.4 cents per kWh. The additional participant's cost is calculated from Xcel Energy's latest electric biennial CIP filing.

96. The participant's cost is approximately $0.90 per Mcf more, for a total cost to society of $1.58 per Mcf. The estimate of an additional $0.90 per Mcf for participant costs is calculated from Reliant Energy Minnegasco's 2001-2002 CIP.

97. A downturn in the U.S. economy followed the large energy price increases. The worsening of economic conditions will reduce the ability of some consumers to invest in efficient products. It is difficult to predict what net impact this will have, but it does make rebate programs more important in encouraging conservation.

98. In previous surveys, price had been the number one factor.

99. This figure only reflects the cost of saving demand to the utility. Society's cost of reducing demand is higher when the participant (customer) incurs an additional cost. The utilities' cost-effectiveness analysis from the societal perspective takes into account the participant's incremental cost to see whether the project is cost-effective.

100. One exception is 1999, when Xcel Energy's costs were higher than previous years, bringing up the state's average for that year.

101. Includes both energy conservation and load-management project costs.

102. New nuclear power costs have not been included since current state law prohibits their construction. Also, for new generation, the figures reflect only construction costs, not future fuel and operation and maintenance costs.

103. These are commodity costs only. Source: New York Mercantile Exchange, Henry Hub (Midwest).

104. We are concerned that utilities count energy savings for some industrial customers differently from others. We will be working with the utilities to ensure a common method.

105. The amount of load-management demand reductions from utility programs is not included but also are significant.

106. Not all energy conservation measures have a ten-year lifetime. Thus the cumulative savings occurring per year in 2010 is slightly less than depicted. However, when taking into account that these measures last at least an average of 13 years, the number of households that could be provided energy per year is more than tenfold of that depicted. In other words, the electric savings would be enough to power more than 400,000 homes for ten years and the natural gas savings would be enough to power more than 1 million homes for ten years.

107. In Docket No. E002/RP-00-787, the Commission ordered Xcel Energy to achieve energy savings totaling 264 MW more of cumulative demand savings by 2010 as compared to the levels proposed by the company.

108. Energy conservation not embedded in utilities' forecasts.

109. Assumes that municipal and cooperative electric utilities have to devote all of their CIP spending to energy conservation projects, not allowed to spend 50 percent on load-management projects.

110. Assumes that all Minnesota electric utilities are required to spend 2 percent of their gross operating revenues on CIP investments.

111. Assumes both that municipal and cooperative electric utilities have to devote all of their CIP spending to energy conservation projects, not allowed to spend 50 percent on load-management projects, and that all Minnesota electric utilities are required to spend 2 percent of their gross operating revenues on CIP investments.

112. Comments of Minnesota Energy Consumers.

113. Consortium for Energy Efficiency and the Environment/Izaak Walton League.

114. Despite this approach, some cost-effectiveness analysis will have to occur after the fact to ensure that the designed program is delivering desirable results.

115. In response to concerns of Missouri River Energy Services, the Department notes that it has no intention to require an unregulated utility to implement a specific program.

116. Missouri River Energy Services.

117. These costs include utility costs only. They are the appropriate costs for comparing the costs of a utility producing a resource for its customers. Since participants also incur a cost, the cost to society as a whole is higher.

118. However, some of the residential projects are marginal, with cost effectiveness varying with the cost of natural gas and electricity. For example, weatherization is not always cost effective when only natural gas prices are considered.

119. Minnesota Energy Consumers noted in their comments that it would be imprudent to deny CIP dollars to large power users in order to fund less cost-effective residential projects.

120. The designation was introduced by the U.S. Environmental Protection Agency (EPA) in 1992 as a voluntary labeling program designed to identify and promote energy-efficient products. EPA partnered with the U.S. Department of Energy in 1996 to promote the Energy Star label, with each agency taking responsibility for particular product categories.

121. The air pollution reductions from these savings are equivalent to taking ten million cars off the road. http://www.epa.gov/nrgystar/newsroomfactsheet/.htm.

122. The amount of energy savings depends on what part of the state that the air conditioner is used. An air conditioner is used more often in the Twin Cities than in Duluth. Consequently, an efficient air conditioner saves more energy in the Twin Cities than in Duluth.

123. The variable speed drive can save energy in the winter and summer since the furnace fan is used to distribute cool air from an air conditioner.

124. Like Wisconsin, the Department will evaluate progress towards the goal by evaluating the penetration of Energy Star clothes washers. Currently, Energy Star clothes washers are estimated to have 15.5 percent of the Minnesota market. The resulting goal is approximately 20 percent.

125. Reliant Energy Minnegasco.

126. Although Reliant Energy Minnegasco notes that these projects often have payback periods of less than one year, and therefore, may not need CIP funding, these types of projects are not occurring to the extent they could, therefore, CIP funding is appropriate.

127. The project was awarded "The Program Most Likely to Meet the Intent of the Kyoto Protocols in the Shortest Time."

128. Comments from the Center for Energy and the Environment and the Izaak Walton League.

129. Customers for CIP reform.

130. Comments from Chris Robbins (see Appendix G).

FIVE: LEGISLATIVE CHANGES IN 2001: HOW THEY RELATE TO ENERGY CHALLENGES

In the 2001 legislative session, the Ventura Administration and others proposed significant new energy legislation. After much discussion, the Legislature passed and Governor Ventura signed the new legislation – 2001 Minn. Laws, Chapter 212. The new legislation grants a number of new tools and sets new directions in energy that will be very helpful as we face the challenges ahead. This chapter summarizes the new legislation and how it relates to those challenges.

As noted in Chapter Two there are three categories of challenges ahead in the energy system discussed in this report. The fourth major challenge, affordability of energy services, is addressed in a separate report on universal energy service. The three major challenges addressed in this report are:

1. Adequate supply of electricity;
2. Adequate transmission capacity and adequate transmission regulatory oversight; and
3. Emissions of pollutants from existing and future power plants.

Energy Conservation and Energy Efficiency

The one option that addresses all of the challenges of the system is energy conservation. Conserving electricity and/or using it more efficiently lessens the need to build expensive new power plants. It likewise lessens the need to upgrade existing transmission lines or build new ones. Conservation lessens the need to build new power plants that may increase emissions of air pollutants. Finally, by reducing the need for new facilities, conservation keeps rates for service more affordable for more Minnesotans.

Chapter 212 includes a number of provisions related to energy conservation:

Public Buildings

Article 1 requires adoption of sustainable building guidelines to ensure that future state buildings exceed the existing commercial energy code by at least 30 percent and to ensure lowest lifetime costs and healthy indoor environments. In addition, it requires the Department of Administration to gather energy usage data for all existing public buildings in the state and develop a comprehensive energy conservation plan for those buildings. When these provisions are effectively implemented, public buildings will serve as models for other commercial buildings.

Conservation Improvement Program

Article 8, sections 4-7, and 11-14, make significant changes to the existing Conservation Improvement Program (CIP) described in Chapter 4. These changes include:

(1) redefining energy conservation to mean an actual reduction in energy use;

(2) requiring increased spending, over time, on conservation activities by municipal utilities and cooperative electric associations;

(3) reducing, over time, how much load management that does not reduce energy use may be counted as conservation spending by munis and coops;

(4) requiring munis and coops to submit to Commerce a biennial overview and evaluation of their CIPs;

(5) encouraging Commerce to establish a list of successful conservation programs for replication throughout the state;

(6) authorizing the Commissioner of Commerce to order independent audits of invester owned utilities' CIPs;

(7) requiring munis and coops, in consultation with Commerce, to evaluate their CIPs and submit a report to the legislature in June, 2002; and

(8) allowing utilities to spend up to five percent of their CIP budgets on distributed energy resources.

Electricity Supply and System Reliability

Distributed Energy Resources (Other than Conservation)

Article 3 requires:

(1) the Public Utilities Commission (PUC) to adopt generic standards for interconnection of distributed energy resources (defined as electric generators of 10 megawatts or less that use natural gas or another similarly clean or cleaner fuel), which should begin to break down some barriers to installation and operation of smaller generation facilities;

(2) munis and coops to adopt similar interconnection standards; and

(3) makes explicit the commission's authority to order investor owned utilities to undertake adequate preventive maintenance to ensure that power plants and transmission lines are available to maintain the reliability of the system.

Article 8, Section 2, requires utilities to establish pricing programs for "high-efficiency, low emissions distributed generation" facilities of up to 10 megawatts capacity. This allows utilities to offer their customers electricity generated by these facilities at a higher (or lower) price than electricity from existing facilities. If enough customers sign up to pay the offered prices more distributed facilities will be installed. This program also envisions establishing a tradeable credits system for utilities.

Renewable Energy Sources

Article 5 amends the renewable energy production incentive payments statute to extend the deadline for small hydro projects to qualify and to clarify ownership criteria for the types of wind facilities that are eligible to receive the 1.5 cents per kWh incentive. We continue to have problems applying this statute and further changes may be necessary.

Article 8, Section 3, establishes a “renewable energy objective” that encourages utilities to have in their generation portfolios electricity generated from renewable resources. The objectives set in the legislation are 1 percent by 2005, adding another percentage point each year until 2015, when the objective is 10 percent.

Reliability and Performance Standards

Article 6 requires the PUC and munis and coops to adopt safety, reliability, and service quality standards relating to quantity and length of service interruptions, customer service response time and adequacy, disconnections and the like.

Emissions of Pollutants

Chapter 212 does not directly address emissions from the power production sector except to require that this report address potential approaches to this problem and to continue to include environmental issues as issues of concern in determining the future of the energy system in general.

Transmission Planning

Article 7, Section 30, requires the PUC to maintain a list of certified high voltage transmission line projects. Each year, utilities are to identify deficiencies in the transmission system, alternative means of addressing those deficiencies, and issues associated with them. The PUC may certify any transmission line project noted by a utility and place it on the certified list. Certification of a transmission line in this process satisfies the existing requirement for a certificate of need. This is a new process that will allow a broader approach to approving transmission line projects in relation to each other and to system-wide needs instead of the former practice of analyzing each proposal individually.

Power Plant and Transmission Line Siting and Routing

One of the most significant parts of Chapter 212 is Article 7, which amends the Power Plant Siting Act (PPSA) and the Certificate of Need statute to streamline regulatory approvals for power plant and transmission line proposals. Following is a description of the PPSA and an explanation of the changes made in 2001.

The legislature enacted the Power Plant Siting Act (PPSA) in 1973. At that time new generation plants and transmission lines were needed in the state. Also, the negative effects of energy infrastructure construction on the Minnesota environment had become apparent. The purposes of the PPSA remain the same today as they were in 1973:

> The legislature hereby declares it to be the policy of the state to locate large electric power facilities in an orderly manner compatible with environmental preservation and the efficient use of resources. In accordance with this policy, the [environmental quality] board shall choose locations that minimize adverse human and environmental impact while ensuring continuing electric power system reliability and integrity and ensuring that electric energy needs are met and fulfilled in an orderly and timely fashion.[131]

In 1973, the demand for electric energy was increasing at a rate of 7 to 8 percent per year, and had been doing so for decades. By 1973, there were approximately 5,500 megawatts of electric generation capacity located in Minnesota. If demand had continued to increase at historic rates, generation capacity would have needed to be doubled in the next ten years. In the mid 1970s, nuclear power plants were starting to fall into public disfavor. Most proposals for new power plants were for coal fired power plants. Finally, locating new generation plants outside of the state requires long distance, high voltage transmission lines, which are difficult to route.

While several transmission lines and a handful of power plants were sited under the PPSA in the 1970s, electric demand growth slowed considerably as a result of a recession, deindustrialization, and a wave of energy conservation efforts. By 1981 to 1983, the annual average growth of electric use in Minnesota was very low. As the economy recovered after 1983, the demand for electricity in Minnesota began to increase again but at much lower levels than in the early 1970s. These factors resulted in a 15 year period, between 1982 and 1997, where very little generation was sited in Minnesota compared to the 1960s and 1970s. No new transmission line over 200 kilovolts has been routed in Minnesota since 1981.[132] Figure 5-1 shows the chronology of power plants sited under the PPSA. Figure 5-2 shows the same information regarding high voltage transmission lines.

As explained above, growth in electric demand and the need for more power in the region have created a potential need for building more generation. Growth in demand also has begun to strain the capabilities of transmission lines throughout the upper Midwest region. Routing transmission lines and siting power plants under the PPSA likely will occur more frequently in this decade.

In 2001, the legislature made the most significant changes to the PPSA since its enactment 28 years ago (2001 Minn. Laws, Ch. 212, Art. 7). The changes were designed to clarify and streamline the siting of power plants and routing of transmission lines, while preserving effective public participation in the issues relevant to these decisions.

First, the amended statutes align the thresholds for the certificate of need process before the Minnesota Public Utilities Commission (PUC) with the thresholds for routing or siting by the Environmental Quality Board (EQB). Although there have been few transmission line proposals in recent years, two controversial proposals concerned the Arrowhead transmission line in Duluth and the proposed Chisago transmission line. In both cases, the decision required more review time than provided by law, and involved controversy over the need for the project. Neither required a certificate of need from the PUC.

Despite the long time between the Chisago and Arrowhead transmission routing proceedings and the proceedings in the 1970s, they bogged down in the same way.[133] When the PUC had not made a determination of need, the decision on where to route a transmission line became extremely controversial in front of the EQB. The controversy focused on whether the transmission line was needed at all instead of where to locate it. In the history of the PPSA, the proceedings that did not bog down were those where the PUC determined a need or where need was completely apparent.

Figure 5.1: Power Plants Sited Under the PPSA, 1973-2001

Sherburne County 3	800MW	Coal	1975
Clay Boswell 4	500MW	Coal	1976
Cottage Grove Cogeneration	245MW	Gas	1994
Lakefield Junction	550MW	Gas	1999
Pleasant Valley	434MW	Gas	2000

Figure 5.2: Transmission Lines Routed Under the PPSA, 1973-2001

Warroad to Little Fork	230KV	105 miles	MP	1974
N. Dakota to Coon Rapids	400KV	172 miles	CU	1976
	345KV	28 miles		
Kettle River to Chisago	500KV	80 miles	MP	1976
Chisago to Grant	345KV	35 miles		
Forbes to Manitoba	500KV	200 miles	Xcel	1977
Kettle River to Forbes	500KV	60 miles	MP	1977
Boswell to Blackberry	230KV	19 miles	MP	1979
Benton to Milaca	230KV	25 miles	UPA	1980
Sherco to Benton	345KV	17 miles	Xcel	1981
Pleasant Valley to Nearest Line	345KV	<1 mile	GRE	2000

As a result of the statutory changes, more transmission line proposals will be presented to the PUC for a determination of need because smaller lines now require a Certificate of Need (CON). In the CON proceeding, the participatory rights of the public were not changed. This places the need determination in the best forum. It should allow the routing process to focus exclusively on locating the transmission line in the most appropriate way possible considering environmental and land use issues.

Of the various potential natural and human environmental effects of transmission lines that are reviewed in project certification proceedings, public concern is often focused on the possibility of health effects from exposure to electromagnetic frequency, or EMF. Several state agencies, including the Minnesota Department of Health, continue to monitor and assess the scientific research on this issue, as they have in the past, and will continue to inform the public debate. There are numerous transmission line design, construction and operational factors that have to be reviewed in a public process.

The second major change in the PPSA is the elimination of the exemption process in favor of a shorter, alternative review process for smaller power plants and transmission lines. Prior to 2001, certain power plants and transmission lines would be presented to the EQB for a determination as to whether the project should be sited under the PPSA or was exempt from state siting. An exemption approval resulted in sending the project to local authorities for a proceeding to decide the route site. It was, in essence, a whole proceeding to determine the next proceeding.

The 2001 changes establish an alternative review process for smaller proposals whereby the applicant or an affected local unit of government can decide to present the proposal to the EQB for decision. If that is the case, the EQB will decide the matter within six months. Whether the EQB or a local government makes the decision, there is only one proceeding that results in a final decision.

Other changes create tighter standards that should result in proceedings being completed on time, rather than being extended multiple times. An example is the elimination of the so-called "process to decide a process" problems in the PPSA. The statute categorizes projects by size, establishes the level of environmental review and public procedure that will apply, and sets forth a clear timeline for decision. This provision should prevent timelines being extended because of state or local government jurisdictional disputes, or contentions that further levels of environmental review should be required. Finally, siting and routing decisions should be more timely because, in almost every case, a definitive determination of need will have been made by the PUC.

These improvements to the PPSA maintain the same public participation procedures that have applied throughout its history. The only difference in public participation is that members of the public who wish to participate in the need determination must do so before the PUC because that issue will not be decided by the EQB. The certificate of need process before the PUC has always been an open public process.

Finally, utilities may now propose multiple transmission projects at one time (see Transmission Planning above), and have them certified as to need or not certified as to need by the PUC in the same proceeding. This procedure is expected to allow citizens a greater understanding of the inter-relationship of the transmission needs of different utilities and how proposals for new or upgraded lines fit into longer term transmission planning. As required by 2001 legislation, Minnesota transmission owners filed their first statewide transmission planning report with the PUC on November 1, 2001. The report identified 65 transmission line projects that may be needed in Minnesota over the next ten years. The PUC's review process will be developed to address the mandated objectives of (1) identifying future inadequacies in the state's transmission system; (2) identifying alternatives that can solve the inadequacies; (3) assessing general economic, environmental , and social issues associated with the alternatives; and (4) involving the general public, local governments, and regional transmission groups. It is important that all interested parties monitor this proceeding to determine whether the greater statewide context in which individual transmission line proposals are discussed will help everyone gain a better understanding of the interrelationships and need for new transmission. It is also important to determine if this joint process results in greater efficiencies. This type of proceeding has not been attempted elsewhere, and the initial proceeding should be watched carefully to determine whether it is attaining its objectives.

Very shortly the effectiveness of the new process will be tested by both power plant and transmission line proposals. Further changes should not be made to the PPSA until the 2001 changes can be implemented and the proceedings evaluated. The exception is the need for clear criteria for approving a certificate of need for a merchant plant and/or a bulk power transmission line. We initially supported exemption of merchant plants from the certificate of need statute. We became concerned about this position, however, when it became apparent that without a need determination the EQB locational proceeding would become bogged down in questions of need that citizens feel have not been properly dealt with in a public forum. As a result, these facilities should be subjected to some appropriate review as to need. The existing criteria for the certificate of need, however, do not apply as well to merchant plants and bulk power transmission lines as they do to utility owned facilities dedicated to serve local customers. The statutes assume that power plants and transmission lines will be built by vertically integrated utility monopolies subject to regulatory oversight by the PUC as has been the case historically. Since merchant plants are not plants that propose to include their capital costs in the base rates of utility consumers, the current criteria in the certificate of need statute need some revision to properly evaluate proposed merchant plants. Additionally, with the federal changes to the bulk power transmission market, the certificate of need criteria for these transmission facilities should be reviewed for possible change. We continue to request public comment on this issue.

ENDNOTES

131. Minnesota Statutes 116C.53, subd. 1 (2000).

132. This historical summary was derived from Hynes, Routing Transmission Lines and Siting Power Plants, Sept. 1999, available from the Environmental Quality Board.

133. See Electric Power Facility Siting and Routing Projects, 1973-1981, Environmental Quality Board.

APPENDIX A: DEALING WITH ENVIRONMENTAL IMPACTS OF EXISTING ELECTRIC GENERATION

The environmental impact of electricity is a significant factor in energy policy and planning to meet Minnesota's generating capacity deficit. Because different generating technologies range from significant air emissions (coal) to low air emissions (natural gas and biomass) to no air emissions (wind, solar and nuclear), energy policy and generation mix choices that will be made in the next few years may require other up-front policy choices to manage environmental impacts. The state should evaluate the benefits and cost-effectiveness of adding more pollution control to existing generating plants based on the environmental effects described in this section, and require installation of controls as appropriate. If generation technology choices in the future include significant new air emissions, this policy decision is even more necessary.

The first part of this section analyzes the environmental impacts of the current electric generating system in Minnesota, and explores alternatives to reduce or mitigate those impacts. This section focuses on air emissions, which are the single largest source of environmental impact from electricity generation. This section will explain the air emissions that result from electricity generation in Minnesota, describe the health and environmental impacts of those emissions, describe the regulatory programs that have been in place to mitigate environmental impacts, and describe upcoming pollution control programs that will require further emission reductions from electricity generation, or require that current levels of emissions not grow any larger. Finally, this section will discuss options for further emissions control in Minnesota's existing coal plants, most of which were not required to meet the most stringent Clean Air Act requirements because they were constructed before those requirements took effect.

Figure A.1: Electric Utility Contribution to Current Minnesota Air Emissions

	1999 Emission to the Air (thousand tons)	% of Estimated Statewide Emissions
Greenhouse Gases	35,982	26%
Nitrogen Oxides	87	18%
Sulfur Dioxide	95	58%
Carbon Monoxide	8	<1%
Fine Particulate Matter (2.5 microns)	?	large
Lead	0.03	62%
Mercury	0.0008	40%
Other Metals (Chromium, Arsenic, Nickel)	NA	10-60%

Source: PCA

Current and Forecasted Emissions from Electric Generation in Minnesota

Air emissions from electricity generation in Minnesota are shown in Figure A-1 for 1999 in tons of emissions and as a percent of total statewide air emissions from all emitting sectors from Minnesota. Included are air emissions of nitrogen oxides (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), fine particulate matter ($PM_{2.5}$), lead, mercury, other metals, and greenhouse gases. With the exception of CO emissions, electricity generation currently contributes a substantial fraction of total statewide air emissions. One-fifth of NOx emissions and one-quarter of greenhouse gas emissions from Minnesota sources derive from electricity generation, while electricity generation accounts for about 40 percent of all statewide mercury emissions and 58 percent of statewide SO_2 emissions. Sources of $PM_{2.5}$ in the state are less certain, and are currently being studied in preparation for implementing the new federal air quality standards for $PM_{2.5}$. However, it is thought that coal combustion during electricity generation could be a large source.

There are about 350 generating units located in Minnesota supplying power to the grid, some 9395 MW of installed capacity. Using 1999 plant utilization rates as a measure, about 6,900 MW of this would be classified as baseload capacity, with 2,050 MW classi-

Figure A.2: Nonnuclear Baseload or Intermediate Load Electricity Generating Units at Large Plants

	Capacity (summer) (MW)	Principal Fuel	Load Type	Start-up Date	NSPS Status Vintage (Year)
Xcel Energy					
Sherburne County					
unit 1	712.0	coal	Baseload	1976	n/a
unit 2	721.0	coal	Baseload	1977	1976
unit 3	871.0	coal	Baseload	1987	1986
Allen King	571.0	coal	Baseload	1958	n/a
Riverside					
unit 7	150.0	coal	Baseload	1987	1986
unit 8	221.5	coal	Baseload	1964	n/a
High Bridge					
unit 5	97.0	coal	Intermediate	1956	n/a
unit 6	170.0	coal	Intermediate	1959	n/a
Black Dog					
unit 3	113.2	coal	Intermediate	1955	n/a
unit 4	171.8	coal	Intermediate	1960	n/a
XCEL total	3,959.6				
LS Power	252.1	gas	Intermediate	1998	1997
Rochester Publ. Util.					
Silver Lake					
unit 4	60.3	coal	Intermediate	1969	n/a
Minnesota Power					
Clay Boswell					
unit 1	69.0	coal	Intermediate	1958	n/a
unit 2	69.0	coal	Baseload	1960	n/a
unit 3	346.3	coal	Baseload	1973	n/a
unit 4	535.0	coal	Baseload	1980	1979
Syl Laskin					
unit 1	55.0	coal	Baseload	1953	n/a
unit 2	55.0	coal	Baseload	1953	n/a
subtotal	110.0				
Minnesota Power total	1,129.3				
OtterTail Power					
Hoot Lake					
unit 2	64.9	coal	Intermediate	1959	n/a
unit 3	84.0	coal	Intermediate	1964	n/a
Otter Tail Power total	156.9				
Minnesota Total	**5,355.7**				

**Does not include nuclear power reactors Monticello and Prairie Island 1 & 2.*

Figure A.3: Net Generation and Emissions During 1999 from Electric Generation Plants Located in Minnesota

	1999 Net Generation (MWH)	Emissions NOx (tons)	SO2 (tons)	CO2 (tons)	Hg (lb.)
Xcel Energy					
Sherburne County	13,289,695	22,285	20,667	15,864,259	809.57
Allen King	3,295,770	18,479	27,251	3,465,485	58.8
Riverside	2,164,668	12,176	13,441	2,279,736	88.92
High Bridge	1,185,039	3,946	2,942	1,457,755	60.73
Black Dog	1,382,947	7,080	3,005	1,795,939	44.81
Minnesota Power					
Clay Boswell	6,172,773	12,382	17,305	7,230,445	315.93
Syl Laskin	570,635	1,570	1,008	646,863	38.50
Otter Tail Power					
Hoot Lake	629,190	1,365	2,479	870,831	30.88
Rochester Publ. Util.					
Silver Lake	206,166	683	2,184	183,044	8.33
LSP Cottage Grove	650,667	51	2	306,597	NA
TOTALS	**29,547,550**	**80,017**	**90,284**	**34,100,954**	**1456.47**

Source: PCA

fied as peaking, and the remainder as intermediate load capacity. Baseload plants are plants that, over the course of a year, operate more than 50 percent of the time. Intermediate-cycling plants operate between 15 and 49 percent of the time, while peaking plants operate 0 to 14 percent of the time.

Most air emissions in Minnesota derive from large baseload and intermediate cycling facilities. Baseload and intermediate cycling facilities located in Minnesota of more than 100 MW of capacity are listed in Figure A-2, along with summer capacity rating, facility start-up date, fuel type, and the status of each plant under the New Source Performance Standards (NSPS) of the federal Clean Air Act. Under NSPS, generation facilities constructed after 1972 are required to meet certain minimum performance standards with regard to air emissions of SO_2, NOx, CO, lead, and particulate matter. Generation facilities that were constructed before 1972 are exempt from NSPS.

NSPS have been revised a number of times, leading to the application of different standards to different plants depending on the year of their construction. NSPS have become progressively more stringent, so control requirements at plants subject to newer NSPS tend to be much more stringent than older NSPS requirements.[134] Where NSPS applies, Figure A-2 indicates the vintage (year) of NSPS standard to which the facility is subject. While NSPS applies to five generating units, four are subject only to older, less stringent NSPS. Fifteen large baseload and intermediate load generating units are exempt from NSPS entirely, comprising 3,030 MW of the 5,559 MW (55 percent) of installed baseload and intermediate-load capacity in the state.

Emissions at Minnesota's large baseload and intermediate plants for 1999 are shown in Figure A-3 for SO_2, NOx, CO_2 and mercury. In 1999, 80,017 tons of NOx and 90,284 tons of SO_2 were emitted to the atmosphere from large baseload and intermediate load plants larger than 100 MW located in Minnesota. In 1999, mercury emissions from these facilities were an estimated 1,456 lbs., while some 34.1 million tons of CO_2 was emitted from these plants. In 1999, net generation at these plants was some 29.5 million megawatt-hours. As might be expected, the greatest emissions occurred at the two largest generation facilities, Xcel Energy's Sherburne County facility and Minnesota Power's Clay Boswell generating facility.

Emissions of SO_2, NOx, CO_2 and mercury per kWh of net electricity generation is shown in Figure A-4 for 1999 for baseload and intermediate load plants of 100 MW or more located in Minnesota. Emissions of NOx vary from 0.0002 to 0.01 lb. per kWh, or by about 50-fold from the lowest emitting to the highest emitting facility. Emissions of SO_2 vary from 0.0001 lb. per kWh to 0.021 lb. per kWh, or by more than 100-fold from the lowest to the highest emitting facilities. Emissions of CO_2 range from 0.94 lb. per kWh to 2.77 lb. per kWh, and those for mercury from 0.00002 to 0.00007 lb. per MWH. The current performance standards for NOx for new or modified coal-fired facilities is equivalent to about 0.001 lb. per kWh, and that for SO_2 to about 0.001 to 0.002 lb. per kWh.[135]

The lowest emitting baseload or intermediate load facility per kWh-generated is the natural gas-fired LSP-Cottage Grove cogeneration facility. Xcel's King and Riverside plants are the highest emitting plants presently in service for NOx, and the King plant and the Silver Lake facility owned by Rochester Public Utility are the highest emitting plants for SO_2. Regarding CO_2, the Hoot Lake and Black Dog facilities are the top-emitting plants, while for mercury, Sherburne County and Syl Laskin are the top-emitting facilities.

The wide range of emissions per kWh of net electricity generated results from, among other factors, differences in the type of fuels used, the use and vintage of any pollution control equipment, and the efficiency of conversion of thermal energy to electricity at the plant. While there exists no commercially available control technology for CO_2 and mercury, depending on type, pollution control equipment can lower emissions of NOx and SO_2 by 30 to 85 percent. The efficiency of power generation in converting the energy content of fuel to electricity typically varies from about 32 percent for older existing coal-fired facilities to 55 percent for new combined cycle natural gas units. Pollution control equipment installed at baseload and intermediate load generating facilities located in Minnesota is listed in Figure A-4.

On a per kilowatt hour basis, emissions of SO_2 and NOx have declined on a statewide basis. Total emissions, however, continue to rise.

Emissions trends for all Minnesota electricity generating plants are shown in Figures A-5 to A-8 for

Figure A.4: Emission Rates Per Unit of Electricity Generated at Minnesota Electric Generating Plants

	Emission Rate (lb./kWh generated)				Primary Emission Controls[a,b]	
	NOx	SO2	CO2	Hg	SO2	NOx
Xcel Energy						
Sherburne County	0.003	0.003	2.39	0.00000006	scrubbers	LNC, LNB
Allen King	0.011	0.017	2.10	0.00000002		
Riverside	0.011	0.012	2.11	0.00000003		
High Bridge	0.007	0.005	2.46	0.00000005		
Black Dog	0.010	0.004	2.60	0.00000003		
Minnesota Power						
Clay Boswell	0.004	0.006	2.34	0.00000005	scrubbers	LNC
Syl Laskin	0.006	0.004	2.27	0.00000007		
Otter Tail Power						
Hoot Lake	0.004	0.008	2.77	0.00000005		LNB
Rochester Publ. Util.						
Silver Lake	0.007	0.021	1.78	0.00000004	1	
LSP Cottage Grove	0.0002	0.000	0.94	NA		SCR

[a] LNC1 = low NO_X coal and air nozzles with close coupled overfire air; LNC2 = low NO_X coal and air nozzles with separated overfire air.
[b] low NOx controls 1 at Sherburne County unit 1 and low NO_X controls 2 at Sherburne County unit 2. Wet scrubbers at Sherburne County units 1 and 2 and Clay Boswell unit 4, dry lime scrubbers at Sherburne County unit 3.

Figure A.5: Sulfur Dioxide Emissions from Electricity Generation in Minnesota

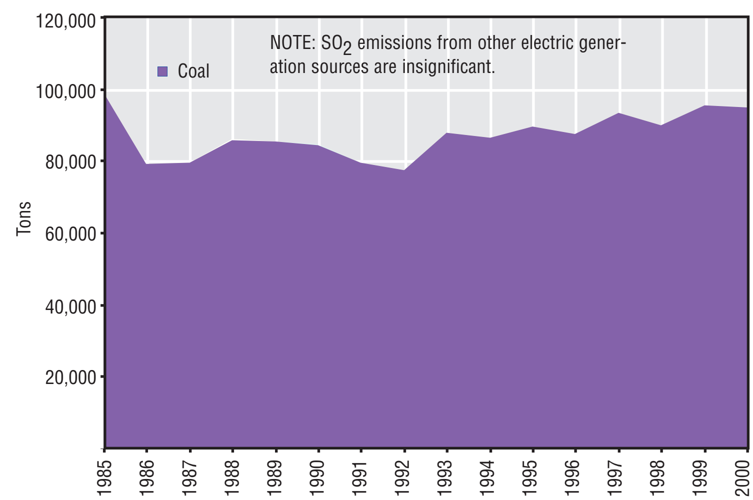


Figure A.6: Nitrogen Oxides Emissions from Electricity Generation in Minnesota

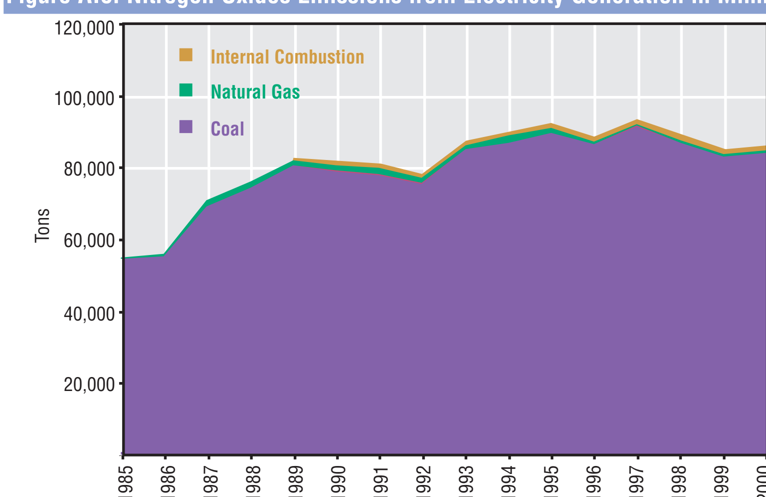


Figure A.7: Greenhouse Gas Emissions from Electric Generation in Minnesota

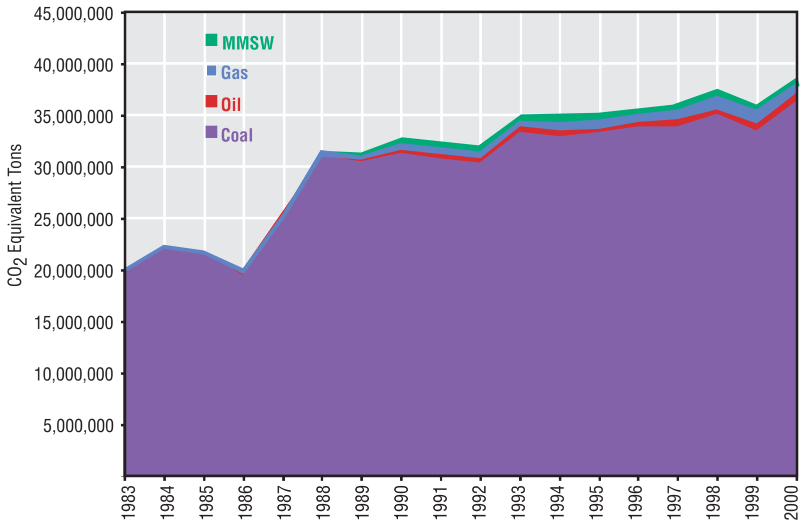


Figure A.8: Mercury Emissions from Electric Generation in Minnesota

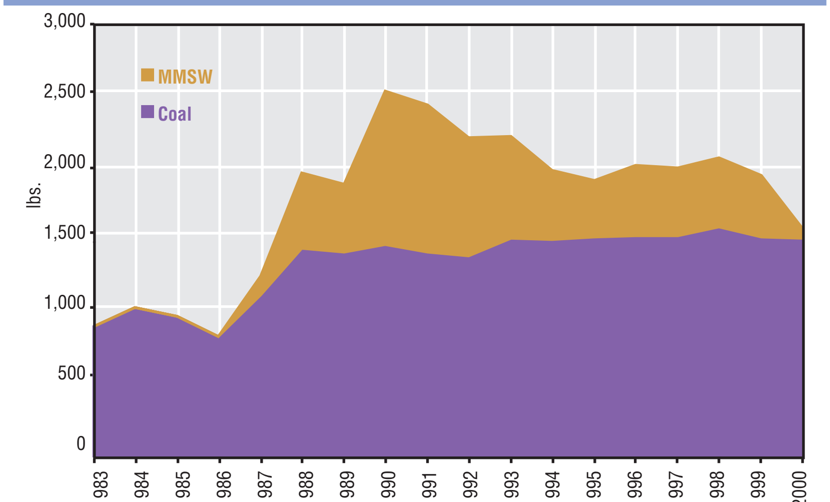
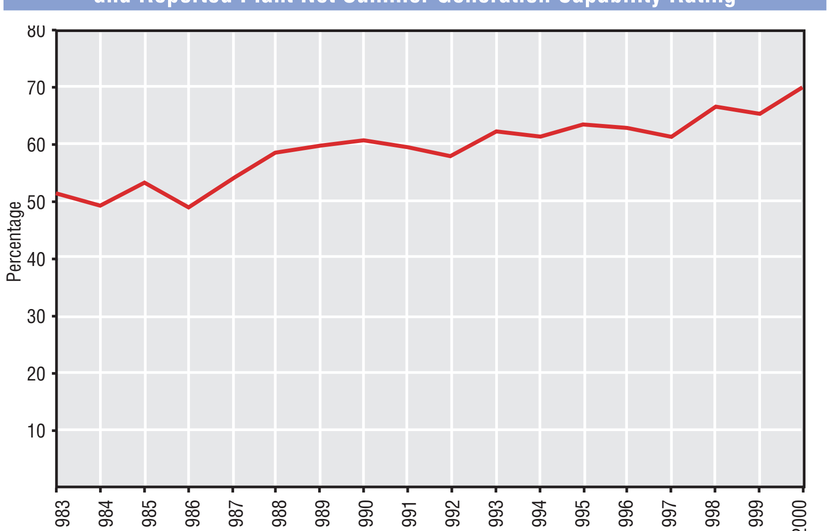


Figure A.9: Net Electric Generation in Minnesota Baseload Plants as a Percentage of Potential Generation at 8760 Hours of Operations and Reported Plant Net Summer Generation Capability Rating



sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury. Figures A-5 and A-6 show SO_2 and NOx emissions, respectively, from electricity generation from 1985 to 2000. These figures show that most emissions of SO_2 and NOx result from coal-fired facilities. Emissions of SO_2 have increased from about 78,000 tons in 1986 to about 95,000 tons in 2000, or at an overall average rate of about 1.3 percent per year.

SO_2 emissions prior to 1986 were higher, falling from the early 1980s to 1986 due to increased use of low sulfur western coal as a fuel. Since 1985, NOx emissions have increased from 58,000 tons per year to about 87,000 tons per year, or about 2.7 percent per year.

The estimated long-term trend in emissions of greenhouse gases is shown in Figure A-7. About 99 percent of all greenhouse gases produced during electricity generation in Minnesota are in the form of carbon dioxide. Emissions of nitrous oxide (N_2O) comprise most of the remainder. In terms of fuels, most emissions of greenhouse gases derive from coal combustion, with the combustion of solid waste, petroleum coke and natural gas contributing only a small part to total emissions. Since 1983, emissions of greenhouse gases from electricity generation in Minnesota have approximately doubled, increasing from about 20 million CO_2-equivalent tons to the current 38.6 million CO_2-equivalent tons. Emissions are increasing at a rate of 3.9 percent per year.

Finally, Figure A-8 shows the estimated 17-year trend in mercury emissions from electricity generation in Minnesota. Most mercury that is emitted during power production in Minnesota currently is derived from coal combustion. Due to enhanced mercury controls at solid waste incinerators, emissions of mercury from electricity generation have declined about 40 percent since 1990, falling from about 2,500 lb. of mercury in 1990 to the current 1,500 lb. in 2000. With most emissions from solid waste incineration now eliminated, at present levels of emission control any increase in coal combustion at Minnesota's electricity generation facilities will result in increased mercury emissions to the atmosphere.

With the exception of unit 3 at Xcel Energy's Sherburne County facility, relatively little new generation capacity has been built in Minnesota since

1983. Most of the increases in air emissions have derived from higher utilization rates of existing plants. Historical utilization rates for baseload and intermediate load plants larger than 100 MW in Minnesota are shown graphically in Figure A-9. This figure shows that utilization rates have steadily increased since 1983, rising statewide from 50 percent to the current estimated 70 percent. Much of this has occurred at coal-fired facilities, resulting in the upward movement of air emissions depicted in the Figures A-5 through A-8.

With regard to increased utilization of existing generating plants, the long-term trend favors at least some increased utilization. A further increase in capacity factors at existing facilities of 5 percent or more might be achievable. In their respective integrated resource plans filed with the PUC, Xcel Energy, Minnesota Power and Otter Tail Power in aggregate forecast an increase in coal throughput through existing facilities of about 2.5 million tons of coal between 1999 to 2010.

In addition to increased utilization of existing facilities, new plants will be added. Figure 3-3 in Chapter 3 of the main report lists the generating plants under construction or planned in Minnesota. This list does not include conversion of the LTV Taconite Harbor power plant for use in supplying the grid with electricity. LTV is currently in a bankruptcy proceeding. The Hoyt Lakes and Taconite Harbor facilities are for sale in the bankruptcy proceeding. The conversion of the Taconite Harbor plant to a grid power plant will shift approximately 3,000 tons of SO_2, 2,850 tons of NOx and 1.2 million tons of CO_2 from the industrial sector to the electricity generating sector.

Based on the emission and operating characteristics of similar types of newly constructed or operating plants, Figure A-10 estimates the contribution of this expansion in statewide generation capacity to annual statewide emissions of SO_2, NOx and greenhouse gases.[136] These additions can be expected to generate about 3.5 million MWh of additional electricity each year. Annually associated with this generation, however, would be an extra 1.6 million tons of carbon dioxide, 980 tons of SO_2 and 1,290 tons of NOx. This translates to an increase in statewide emissions of about 4 percent for CO_2, and 1 and 1.5 percent for SO_2 and NOx, respectively.

Using the projected increase in coal throughput at existing facilities, current emission levels (see Figure A-3) and emissions associated with new con-

Figure A.10: Estimated Extra Annual SO_2, NOx and CO_2 Emissions Associated with Permitted or Planned Expansions to Service or Capacity Added Since 2000

Plant Name	Generation: Capacity (Summer) (MW)	Capacity Factor (%)	Net Generation (MWH/yr)	Efficiency in Converting Fuel to Electricity	Emissions: SO_2 (tons)	NO_X (tons)	CO_2 (Tons)
Pleasant Valley units #1-3	434	5	190,092	0.34	1	18	110,934
Lakefield Junction units #1-6	480	5	210,240	0.34	1	20	122,692
New Ulm unit #7	22	5	9,636	0.34	0	1	7,717
Cascade Creek units #3-4	50	5	21,900	0.34	0	2	12,780
Potlatch Cloquet unit #8	24	65	136,656	0.32	0	66	84,734
Navitas gas turbine	250	5	109,500	0.34	1	10	63,902
Otter Tail Power Solway unit #1	44	5	19,272	0.34	0	2	11,247
Prairie-Gen unit #1	49	5	21,462	0.34	0	2	12,525
St. James Diesel Plant units #1-7	12	5	5,256	0.25	9	117	5,725
Worthington Diesel Plant units #1-6	14	5	6,132	0.25	10	136	6,679
Black Dog units #2,5	143[a]	45[c]	1,144,757	0.5	-28[d]	-41[d]	435,075[d]
District Energy unit #7	25	65	142,350	0.2	39	182	61,668
Heartland Energy and Recycling	4	65	22,776	0.2	7	14	36,824
Fibrominn Biomass Power Plant	50	65	284,700	0.22	155	353	-
Northome Biomass Plant	15	65	85,410	0.26	14	56	-
Perham Resource Recovery	2.5	65	14,235	0.2	2	36	11,746
Grand Rapids power plant	195[b]	65	1,110,330	0.42	767	316	625,590
Total	**1,813.5**		**3,534,704**		**978**	**1,288**	**1,609,838**

[a] net increase in generation capacity after conversion of existing unit 2 to combined cycle gas turbine, retirement of existing unit 1, and addition of unit 5. [b] net increase in generation capacity after subtraction of internal Blandin demand. [c] 45% capacity factor at 290.4 MW of capacity at repowered unit #2 and new unit #5. [d] estimated emissions at repowered unit #2 and new unit #5 less 1999 emissions from old units #1 and 2.

NOTE: In addition, approximately 3,020 tons of existing SO_2 emissions, 2,849 tons of existing NO_X emmissions and 1,215,921 tons of CO_2 would be shifted from the industrial sector to the electricity generation sector with the conversion of the 187.7MW LTV-Taconite Harbor plant to a generating facility serving the grid.

Figure A.11: Historic and Forecasted Emissions of CO_2, SO_2 and NOx from Electricity Generation in Minnesota

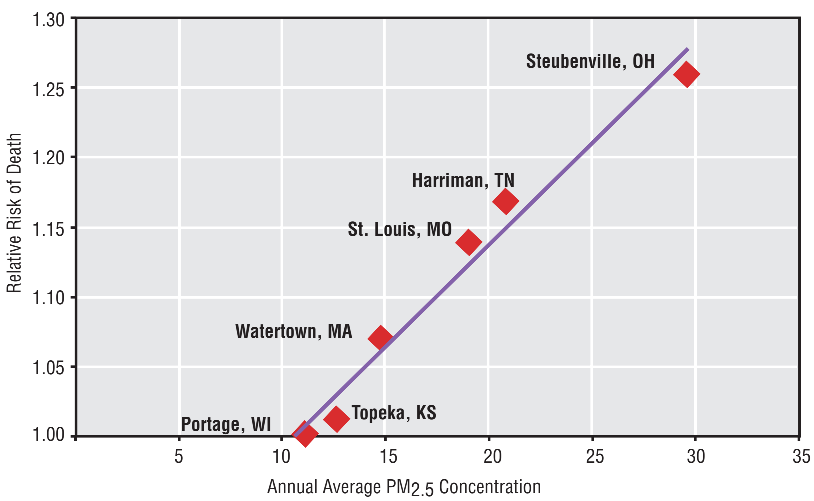
	Year 2000	2005	2010
CO_2			
Baseline 2000 Emissions	38,638,000	38,638,000	38,638,000
Emissions from Increased Use, Existing Plants[a]	-	454,000	3,208,000
Emissions from New Generation Capacity	-	1,610,000	1,610,000
total	38,638,000	40,702,000	43,456,000
SO_2			
Baseline 2000 Emissions	94,915	94,915	94,915
Emissions from Increased Use, Existing Plants[a]	-	1,065	7,494
Emissions from New Generation Capacity	-	978	978
total	94,915	96,958	103,387
NO_X			
Baseline 2000 Emissions	88,291	88,291	88,291
Emissions from Increased Use, Existing Plants[a]	-	1,125	7,435
Emissions from New Generation Capacity	-	1,288	1,288
total	88,291	90,704	97,014

Sources:Figures 3.3 and 3.13 above

[a] Calculated from projected increased coal use from 1999 levels at large baseload and intermediate load plants, as given in the integrated resource plan filings of Xcel Energy, Minnesota Power and Ottertail Power

NOTE: emissions from the Taconite Harbor plant are not included, since these would not represent new emissions but simply a shifting of emissions from the industrial sector to the electricity generation sector.

Figure A.12: Relative Risk of Death vs. Fine Particle ($PM_{2.5}$) Concentration



struction (see Figure A-10), aggregate statewide emission levels from electricity generation facilities located in Minnesota are forecasted in Figure A-11 through 2010. This forecast does not include any new generation needed to meet the capacity deficit forecast in Chapter Two, beyond the current projects listed in Figure A-10. Figure A-11 shows that CO_2 emissions will increase 4.8 million tons by 2010, leading to a roughly 12 percent increase in emissions from current levels by 2010. In the case of NOx, emissions will increase 8,723 tons by 2010, or 10 percent. SO_2 emissions will increase 8,472 tons by 2010, or 9 percent.

Finally, it might be noted that the projections given in Figure A-11 assume that no new pollution control requirements are instituted in the state and that emissions will continue at current rates per MMBtu of energy input. The imposition of more stringent controls on existing plants could dramatically change this rate, thereby reducing levels of future emissions.

Health and Environmental Impacts of Electric Generation

Sulfur dioxide and nitrogen oxides emitted from power plants interact with other compounds in the air to form fine particles and to cause acid rain. Nitrogen oxides react with volatile organic compounds to form ozone in hot, sunny weather. Mercury is a toxic pollutant that contaminates some fish, making them unsafe for human or wildlife consumption. Carbon dioxide is a greenhouse gas that contributes to global climate change. This section briefly describes the health and environmental impacts of these pollutants.[137]

Particulate matter

Airborne particulate matter, especially very small particles from combustion sources such as power plants, diesel and gasoline powered engines and vehicles, and wood burning, are creating health concerns at current outdoor concentrations. Particles are emitted directly, or can be formed when ammonia and combustion gases such as nitrogen oxides and sulfur dioxide chemically transform into particles. Very small particles are inhaled deeply into the lungs where the body cannot easily remove them.

A substantial body of published scientific literature, such as the Harvard Six Cities Study findings displayed in Figure A-12, have shown an association between increased particles in the air and premature death from heart and respiratory disease.[138] Numerous studies also show the number of asthma attacks per day goes up as particles in the air increase.[139]

In 1997, EPA added two new standards for fine particles ($PM_{2.5}$), set at 15 micrograms per cubic meter and 65 micrograms per cubic meter, respectively, for the annual and 24-hour standards. Beginning in 2002, based on three years of monitoring data, EPA will designate areas as nonattainment that do not meet the standards. Monitored yearly, average concentrations of fine particles in the Twin Cities typically range from 11 to 14 micrograms per cubic meter. Scientists studying health effects have found health effects at levels below the standards. In cities with lower particle concentrations, including some likely to meet current federal ambient air standards, both hospital admissions and deaths from heart and lung disease rise when particles in the air increase.[140] EPA reviews air quality standards about every five years. EPA is currently revising the Criteria Document for Particulate Matter to reflect the recent evidence regarding ambient particulate matter air concentrations and health effects. EPA may use this information to propose a more restrictive particulate matter standard.

While the evidence for health effects from air pollution has strengthened over time, especially fine particles derived from fossil fuel combustion, scientists are actively researching *how* particles contribute to these health effects: What are the biological mechanisms? Which physical and chemical properties of the particles are most relevant to their toxicity? Answering these questions will help determine which sources are most culpable.

Methods are unavailable to specifically apportion health effects based on differences in emission sources. Given this uncertainty, human health risk estimates are simply based on particle mass. Using the assumption that fine particles from all sources have an equal ability to cause adverse effects, several researchers have developed ballpark estimates of the benefits from reducing power plant emissions.

One article referenced an estimate that reducing emissions from older coal-fired power plants in the U.S. could provide substantial benefits to public health, including the avoidance of 18,700 premature deaths, 3 million lost work days, and 16 million restricted activity days each year—primarily due to reductions in particulate emissions.[141] Other studies, such as that by the Environmental Law Institute shown in Figure A-13, have tried to quantify the public health-based financial benefits of reducing particle emissions from power plants.

Figure A.13: Billions of Dollars Saved in Public Health Costs as Result of Reduced Use of Coal in ElectricGeneration in Comparison to Business-as-usual Scenario for 2010

	Morbidity	Mortality	Total
SO2	1.2	23.2	24.5
NOx	0.4	1.6	2.0
Total	1.6	24.8	26.4

*Data from Environmental Law Institute Report, May 2001. Health benefits calculated only as result of particulate reductions due to lowered SO_2 and NO_X emissions under the scenario of 50 percent reduction in coal with replacement primarily by natural gas. The report notes that because of the uncertainties in the estimation of health benefits, the assumptions made for these calculations were conservative and therefore these estimates may provide lower benefit estimates compared to other studies. In addition, the health benefits modeled did not include co-benefits of lowered urban ozone levels, reduced acid deposition and eutrophication, and increased visibility. Nor does the estimate include the benefits of lowered mercury or carbon dioxide emissions. Values are calculated for the U.S.

In addition to health impacts, small particles reflect light more efficiently than large particles and reduce visibility. Particles are not the only cause for visibility impairment but they are a major contributor. Figure A-14 shows how the Twin Cities skyline can look depending on the degree of visibility. The concentration of particles in the air was 15 micrograms per cubic meter on the left and 35 on the right.[142]

Figure A.14: Particulate Pollution Contributes to Visibility Impairment

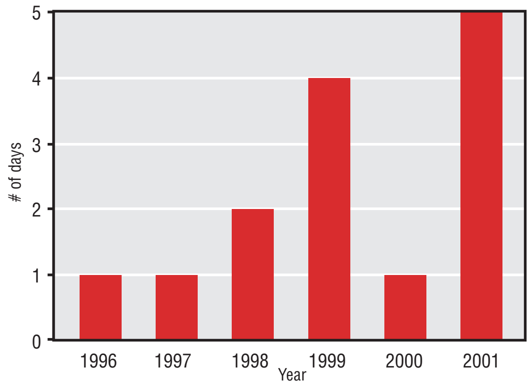
Downtown St. Paul from Mounds Park

Ozone

Ozone can be good or bad depending on where it is found. In the earth's upper atmosphere, ozone occurs naturally and forms a protective layer that blocks out harmful ultraviolet radiation. In the earth's lower atmosphere, ozone is formed when pollutants (nitrogen oxides and volatile organic compounds) emitted from power plants, transportation, industrial plants and other sources react chemically in sunlight.

Ozone pollution is a concern in the summer when weather conditions needed to form it—hot, sunny days—typically occur. Minnesota currently meets federal and state ozone standards. However, this past summer, for the first time since the mid-1970's, air advisories were issued on six days for the Twin Cities due to ozone. Ozone effects can include respiratory irritation, coughing, throat irritation, chest

Figure A.15: Number of Days with Ozone Levels Greater than the 8-Hour Standard (ppb)



tightness, lung injury, asthma aggravation, and increased susceptibility to respiratory infections. Those most susceptible to the effects of ozone include children and adults who are active outdoors and people with respiratory disease.

Figure A-15 shows the number of days that the daily 8-hour average ozone concentration exceeded the standard for the past five years. Two more summers like 2001 could cause parts of Minnesota to be designated as nonattainment. (The method for determining attainment states requires several years of data). Nonattainment results in a federally mandated plan typically including controls on large stationary sources and mobile sources.

Mercury

Of Minnesota's 85,000 square miles, 5,100 square miles are covered by lakes, rivers and streams, but a particularly toxic form of mercury, methyl mercury, contaminates the fish in much of Minnesota's waters. Surprisingly, the fish in some of Minnesota's most remote, pristine lakes are among our most contaminated. Tourism is a major industry in these areas, due in part to the good sport fishing. In most waters in Minnesota, over 95 percent of the mercury falls from the atmosphere in rain or as dry fallout. It gets into the lakes when it is washed out of the atmosphere in rain or falls as fine particles, is converted to methyl mercury in sediments and wetlands, and then accumulates up the aquatic food chain to reach high concentrations in fish.

Methyl mercury is a nerve poison, so eating too much contaminated fish can harm health. If a person does not eat a large amount of game fish, they are probably not at risk. However, children and developing fetuses are susceptible to subtle, long-term nerve damage, even with small amounts of methyl mercury. Therefore, the Minnesota Department of Health—in its annual fish consumption advisory—provides guidance on how many fish are safe to eat. In addition, mercury contamination could also be affecting the health of fish-eating wildlife, like loons. The long-term solution to this problem is not to limit how much fish people eat (which offers no protection to Minnesota's wildlife), but to reduce the input of mercury to lakes.

Up to 90 percent of the airborne mercury landing on northern Minnesota lakes blows in from outside the state. Ten percent of the mercury comes from in-state sources. Coal-fired power plants within Minnesota contribute incrementally to the contamination of any particular lake or river within Minnesota. Other sources can have larger local impacts depending on the amount of mercury released, the species of mercury, and stack height.

Mercury in the environment undergoes many transformations before it is finally taken up into fish. Because the total pool of mercury is too large, the amount of mercury being emitted and the amount of mercury already in the environment needs to be reduced, regardless of emission source or chemical form.

Metals

Power plants also emit metals such as cadmium, arsenic, vanadium, chromium, nickel and lead. Lead has historically been a concern in Minnesota's urban areas.

Atmospheric lead is emitted from a variety of stationary sources. Nationwide, primary and secondary metals processing, waste incineration other than municipal waste, and aircraft are the most significant air emissions contributors of lead today. Coal burning in utility boilers contributes about 2 percent to the total releases of lead to the air today. According to EPA's National Air Pollutant Emission Trends Report (1999), total lead emissions from all sources dropped from 220,860 short tons in 1970 to 4,199 short tons in 1999. Nationally, coal burning in utility boilers released 327 tons of lead in 1970, and 72 tons in 1999.[143]

In Minnesota, lead in the air has dropped significantly. Between 1984 and 1994, average lead concentrations decreased 87 percent, from 0.53 µg/m3 to 0.06 µ/m3 (compare to the national ambient air quality standard of 1.5 µ/m3). Minnesota's emissions profile is similar to the national profile, suggesting that today, the most significant contributors to atmospheric lead emissions are metals processing (lead and other metals smelters) and aircraft use of leaded fuel.[144]

Global Climate Change

Global warming results from the accumulation in the atmosphere of very long-lived gases that act to absorb infrared radiation, trapping it in the lower atmosphere and leading to globally rising surface and atmospheric temperatures. As a result of global warming, virtually every component of what we know as weather will change. Temperature will change. Rainfall will change, both in terms of its intensity, its distribution across seasons, and in its aggregate annual amount. Surface evaporation will change, as will seasonal soil moisture, run-off and stream flow. Some seasons will lengthen in duration, some dramatically shorten. The length of periods of peak heat and humidity will change, as will cloudiness, wind speed, patterns of storminess, and virtually every other component of weather.

These changes, should they occur, could dramatically effect the ecology of Minnesota. Ecological systems are tightly coupled to prevailing climate. As climate changes, ecological communities change. In Minnesota, ecological systems vary widely from a cold climate boreal forest in the extreme north to a warm temperate oak parkland in the south, woodland in the east and prairie in the west. As climate changes, particularly as it warms, Minnesotans will see a progressive forced northward march of conditions favorable to warm temperature forests now dominant to our south, and the progressive shrinkage of cool and cold climate vegetation types. Few ecological systems now found in Minnesota are likely to survive this without significant disruption.

Figure A.16: Carbon Emissions, CO_2 Concentrations and Temperature Change, 1000-2000

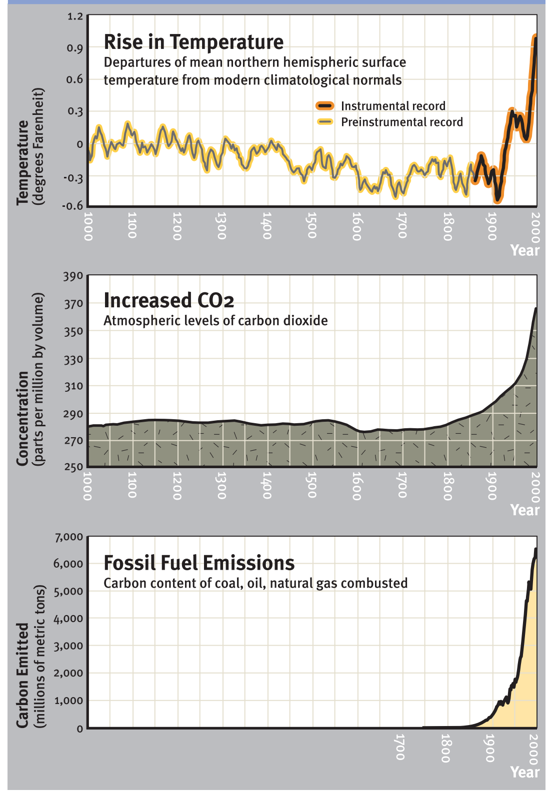


Chart by Matt Kania

Gases that contribute to global warming are called greenhouse gases. The principal greenhouse gas is carbon dioxide or CO_2. Most human-produced CO_2 is emitted during the combustion of coal, oil and natural gas. Since the beginning of industrialization about 150 years ago, atmospheric concentrations of CO_2 have risen about 30 percent, as shown in Figure A-16. Continued dependence on these fuels as the principal global source for energy will result in at least a doubling of preindustrial atmospheric concentrations of CO_2, and perhaps as much as a tripling. It has been widely accepted in the scientific community for three decades that a doubling of the preindustrial level of CO_2 will cause mean global surface temperature to rise between 1.5 and 4.5 degrees Celsius—a view reaffirmed by the U.S. National Academy of Sciences earlier in 2001 in its latest scientific review of the question.[145]

Since the beginning of industrialization, the mean surface temperature of the earth has risen about 0.7 degrees Celsius. For many hundreds of years prior

Figure A.17: Principal Heath and Environmental Impacts of Air Pollutants Emitted From Coal-Fired Power Plants

Pollutant	Effects	Geographical Scope of Effect*
Sulfur Dioxide	Respiratory disease, acidification, crop losses, visibility impairment	Local, regional
Nitrogen Oxides	Respiratory disease, acidification, crop losses, visibility impairment, eutrophication	Local, regional
Particulate Matter	Respiratory and cardiac disease, premature death, visibility impairment	Local, regional
Mercury	Central nervous system disease	Local, regional, global
Metals	Various - depends on the metal	Local, regional
Secondarily formed pollutants		Local, regional
•SO_4 from SO_2	Acidification	
•NO_3 from NO_X	Acidification, eutrophication	
•$PM_{2.5}$ from SO_2 and NO_X	Respiratory disease, prematuredeath, visibility impairment	
•Ozone from NO_X	Respiratory disease, visibility impairment	
Carbon Dioxide	Climate change	Global

*Local: Within 100 miles; Regional: Within 1,000 miles

to industrialization, global surface temperature was very stable at levels much cooler than now. Beginning in 1900, global temperatures abruptly turned up in a warming without any parallel in the record of the prior 1,000 years. (see Figure A-16)

Most climatologists expect the warming trend to continue and even accelerate as emissions of greenhouse gases continue to accumulate in the atmosphere. It has been common for several decades to find in the scientific literature estimates of future warming of 2 to 3 degrees Celsius over the next 50 to 100 years. Recently, the UN Intergovernmental Panel on Climate Change concluded that, accounting for uncertainties, mean global surface temperature will rise 1.4 to 5.8 degrees Celsius over the next 100 years.[146]

In general, the degree of forecasted warming is roughly comparable to the amount of warming that the earth experienced at the end of the last ice age, when rising global temperatures changed a perennial winter-like climate throughout much of the northern half of the northern hemisphere into the present warm climate. This provides a measure of the intensity and geographic scale of the changes in ecological and other natural systems that are contemplated. As a rule of thumb, each 1 degree Celsius rise in temperature in the Northern Hemisphere is associated with a northward displacement of climatic and ecological regions of about 100 miles.

Once present in the atmosphere in elevated concentrations, CO_2 persists in the atmosphere at elevated concentrations for hundreds of years. This renders a CO_2-induced warming, once initiated, essentially irreversible by natural means over a time scale of several lifetimes.

In 2000, the U.S. Department of Commerce prepared a national assessment of impacts from global warming. Specific effects that are thought likely to result in Minnesota include:

- retreat of the spruce-fir ‘boreal’ forest of the Boundary Waters Canoe Area and replacement by northern hardwood forest;
- progressive replacement of much of the aspen-birch forest for northern Minnesota by temperate deciduous forest and deciduous savanna, and associated decline in habitat for some wildlife currently inhabiting the state;
- loss of 50 to 100 percent of stream habitat for cold water fishes like brook trout and decline of habitat for cold water fishes in shallow Minnesota lakes;
- heightened influx of invasive species into Minnesota waterways and lakes;
- expansion of insect populations in Minnesota, requiring more intensive public health measures associated with the control of insect-borne diseases;
- reduced Great Lakes lake levels, requiring new investments in harbor facilities in Duluth-Superior, and affecting the competitiveness of the Great Lakes shipping business and industries that depend on it; and
- reduced opportunities for winter recreation.

Agricultural production is thought likely to increase. However, due to higher summer surface temperatures, the number of days conducive to the formation of high levels of ozone may increase, leading to declining air quality. Large new public expenditures may become necessary to account for climatic uncertainty in the design of sewage and wastewater treatment facilities, the in-land barge system and the flood control infrastructure.

It is now generally recognized that some limit on atmospheric CO_2 levels will be necessary in the future to minimize the risks of global climate change to society. Current global policy is summarized in the provisions of the 1992 United Nations Framework Convention on Climate Change, of which the U.S. is a signatory. Under the terms of the Convention, the parties are required to implement policies to stabilize their emissions of greenhouse gases to the atmosphere at 1990 levels. The stated goal of the Convention is the avoidance of 'dangerous' human interference in global climate. The level at which to cap CO_2 concentrations has yet to be determined.

Acid Rain

Acid rain—or acid deposition- causes acidification of lakes and streams and contributes to damage of trees and many sensitive forest soils. The primary causes of acid deposition are sulfur dioxide and nitrogen oxides. Thus, coal-fired power plants are significant contributors to acid rain. Acid deposition is a complex problem whose sources are often distant from its impacts and is highly variable across time and geography. Prevailing winds blow the compounds that cause both wet and dry acid deposition across state and national borders, and sometimes over hundreds of miles.

Acid rain causes a cascade of effects that harm or kill individual fish, reduce fish population numbers, completely eliminate fish species from a water body, and decrease biodiversity. Some types of plants and animals are able to tolerate acidic waters. Others, however, are acid-sensitive and will be lost as waters become more acidic. The impact of nitrogen on surface waters is also critical. Nitrogen plays a significant role in episodic acidification and new research recognizes the importance of nitrogen in long-term chronic acidification as well. Nitrogen is also an important factor in causing eutrophication (oxygen depletion) of water bodies.

In Minnesota, our lakes and soils are fairly well-buffered and the effects of acid rain are not considered a problem here. However, in the northeastern United States soils and lakes are much more sensitive to the effects of acid rain. Despite declining national emissions of sulfur dioxide, recent scientific study is showing that the capacity of lakes and soils to recover from acid deposition is less than previously thought.[147] Many lakes in the northeast U.S. are acidic and have few or no fish. *Science* reports the researchers are calling for an additional 80 percent cut in emissions beyond the current mandate and that may only bring partial recovery to fish and trees by 2050.[148]

Conclusion

Power plants—especially coal-fired power plants—contribute significantly to the environmental and health impacts from air pollution. Figure A-17 summarizes the key air pollutants emitted from electric generation and their effects on health and the environment.

Current and Developing National Regulations Governing Utility Emissions

This section's review of current and developing national programs will show that, due to these health and environmental effects, utilities must continue to reduce emissions under programs already being implemented and further cuts are expected to be required under new programs. As a result, total emissions from utilities in the future will have to be significantly lower than today, including emissions from whatever new generation capacity is needed.

In the past thirty years, numerous federal regulations and programs have affected air emissions from the electric power industry as shown in Figure A-18. Arguably the most successful and cost-effective program has been the Acid Rain Program—an emissions "cap and trade" approach that has resulted in sulfur dioxide emissions dropping 4.5 million tons and nitrogen oxides emissions dropping 1.5 million tons from 1990 levels nationally. However, based upon the failure of lakes and streams to recover despite the drop in emissions, some scientists are calling for further reductions beyond the 1990 Clean Air Act Amendments.

New Source Review is an older, more traditional regulatory program that is undergoing change. One intent of New Source Review is to require existing plants to improve their emissions control when they undergo a major modification. The New Source

Figure A.18: Major National Air Quality Programs Affecting U.S. Electric Utilities

1970
National Air Standards/ State Implementation Plans

New Source Review/Visibility Programs
PM_{10} National Air Standard

1980

1990
UN Framework on Climate Change International Treaty (USA signatory)

Acid Rain SO_2 Phase 1
Acid Rain NOx Phase 1
NOx NSPS Revision

2000
Acid Rain NOx Phase 2 and SO_2 Phase 2

Assess Attainment of Revised $PM_{2.5}$ and Ozone Air Standards
Interstate NOx Air Pollution Petitions/NOx State Plans
US/Canada NOx Treaty
Periodic Review of Ozone & $PM_{2.5}$ Air Standard
Mercury Standards Implemented/Implement Regional Haze Rules
Kyoto Protocol or alternative US Response

2010

Review process identifies the most appropriate (i.e., lowest) level of emissions for a process on a case-by-case basis and applies the current best available control technology to the source.[149]

In the near future, electric power plants will be the focus of a number of major initiatives to reduce air emissions, described in the next few paragraphs.

Mercury National Emission Standard for Hazardous Air Pollutants

EPA is developing a rule to limit mercury emissions from utilities. As required by the 1990 Clean Air Act Amendments, EPA studied emissions of hazardous air pollutants (or air toxics) from fossil-fuel-fired power plants and found in December 2000 that air toxics control (e.g. mercury control) is appropriate for coal-fired and oil-fired utility boilers. EPA is scheduled to propose a Maximum Achievable Control Technology standard by 2003 for these sources that is expected to focus on mercury control.

Regional Haze Rules

EPA recently finalized a regional haze rule designed to return visibility to natural conditions in national parks and wilderness areas. The rule will require power generators to reduce SO_2 and NOx emissions either through implementation of best available retrofit technology or a trading program yet to be developed.

Implementation of New $PM_{2.5}$ and Ozone Standards

Since the $PM_{2.5}$ national ambient air quality standard for fine particles was set in 1997, dozens of new published studies, taken together, collectively strengthen the association between $PM_{2.5}$ and severe human health effects. In 1997, EPA also established a new standard for ozone. If a state has areas that do not meet an air quality standard, then the Clean Air Act requires the state to adopt emissions control requirements in the form of State Implementation Plans to bring nonattainment areas into compliance.

The MPCA will be able to determine its compliance status with the $PM_{2.5}$ standard in 2002 (3 years of data is needed to determine compliance). The MPCA expects Minnesota will be below the standards, but by a narrow margin. Recent exceedances of the ozone standard in Minnesota and states to the east suggest the possibility of future control requirements in Minnesota to address the ozone problem. Power plants are significant contributors to $PM_{2.5}$ and ozone precursor emissions.

NOx Reduction Requirements

In 1998, EPA finalized the NOx State Implementation Plan (SIP) call which requires the District of Columbia and 19 states (whose emissions contribute significantly to downwind ozone nonattainment problems) to revise their SIPs to control summertime NOx emissions. In response, all of these states are choosing control strategies that focus on reducing power plant emissions. In a separate action, in January 2000, EPA finalized a rule which was issued in response to petitions from some northeastern states under section 126 of the Clean Air Act. The rule requires large electric generating units and large boilers and turbines in 12 states and D.C. to control summertime NOx emissions under the Federal NOx Budget trading program beginning May 1, 2003. Minnesota is currently not one of these states.

Potential Multi-Pollutant Regulation Proposal by the Administration

EPA and the White House are working to finalize the details of a legislative proposal that will set limits on the utility emissions of three major air pollutants—nitrogen oxides, sulfur dioxide and mercury—through the use of a “cap and trade” program. The strategy consists of establishing an emissions cap for existing sources. In return for the cap, New Source Review would be relaxed and plants undergoing a modification would not necessarily need to install the best available control technology.

Multi-Pollutant Regulation Proposals by Congress

Legislation has been introduced in both the House and Senate that would require power plants to further reduce emissions. Representative Waxman’s bill (H.R. 1256) and Senator Jefford’s bill (S. 556) are very similar. Both bills would require:

- Plants 30 years old or more to comply with requirements for new sources within five years after enactment.
- Aggregate emissions reductions—not facility specific reductions.
- 75 percent reduction in NOx emissions from 1997 levels by 2007.

- 75 percent reduction in SO_2 emissions from Phase II acid rain levels by 2007.
- 90 percent reduction in mercury emissions from 1999 levels by 2007.
- Carbon dioxide emissions to 1990 levels by 2007.
- Regulations within 2 years. (S. 556 would require each plant to achieve reductions if EPA fails to meet timeline.)

Both bills may allow market-oriented mechanisms, except for mercury, to achieve these reductions. They also would allocate required emissions reductions equitably, taking into account reductions before enactment of the legislation. Jefford's bill also includes policies to reduce the rate of growth in natural gas consumption.

Reducing Emissions from Existing Power Plants

By applying proven pollution control technologies at Minnesota's existing coal-fired power plants, utility companies can reduce the emission rates of several pollutants. In particular, proven technologies can be installed that would significantly reduce the emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx) at Minnesota's power plants.

Within the last ten years, Minnesota's electric utilities reduced SO_2 and NOx emission rates at some of their power plants, primarily to comply with the Acid Rain provision of the 1990 Clean Air Act Amendments. The Acid Rain program allows system-wide averaging; companies can reduce emissions significantly at one plant while other plants continue to emit at higher levels. To comply with the SO_2 provisions of the Acid Rain program, many of Minnesota's power plants switched from the higher sulfur coals they were using to lower-sulfur coals. Few, if any, plants were significantly modified to meet the new standard. To meet the NOx requirements of the Acid Rain program, companies that needed to reduce their system-wide emissions may have modified one or two facilities, while the others are operated as before. With a significant reduction at a small number of units, the company's average could meet the standard.

By using these methods to comply, the utilities have preserved opportunities for further improvement. For example, none of Minnesota's large power plants meet both of the emission standards for SO_2 and NOx for new plants set in the federal New Source Performance Standard (NSPS) for electric utility generating units.[150] (The NSPS basically requires a 90 percent reduction in the amount of SO_2 that the plant could emit without added controls. The NSPS sets a limit of 1.6 pounds of NOx per megawatt-hour of electricity generated.) Figure A-19 shows the characteristics of Minnesota's baseload

Figure A.19: Characteristics of Selected Baseload and Intermediate Load Coal-Fired Utility Boilers in Minnesota

Name	Approximate Capacity	Boiler type	Estimated SO_2 Emission rate	Estimated NOx Emission rate
MP – Clay Boswell 1	70 MW	Wall-fired	0.85 lb/mmBtu	0.4 lb/mmBtu
MP – Clay Boswell 2	70 MW	Wall-fired	0.85 lb/mmBtu	0.8 lb/mmBtu
MP – Clay Boswell 3	350 MW	Tangential	0.85 lb/mmBtu	0.3 lb/mmBtu
MP – Clay Boswell 4	535 MW	Tangential	0.15 lb/mmBtu	0.3 lb/mmBtu
MP – Syl Laskin 1	55 MW	Tangential	0.3 lb/mmBtu	0.5 lb/mmBtu
MP – Syl Laskin 2	55 MW	Tangential	0.3 lb/mmBtu	0.5 lb/mmBtu
OPC – Hoot Lake 2	65 MW	Tangential	0.6 lb/mmBtu	0.6 lb/mmBtu
OPC – Hoot Lake 3	85 MW	Wall-fired	0.6 lb/mmBtu	0.3 lb/mmBtu
RPU – Silver Lake	60 MW	Wall-fired	1.7 lb/mmBtu	0.4 lb/mmBtu
Xcel – A. S. King	570 MW	Cyclone	1.6 lb/mmBtu	1.1 lb/mmBtu
Xcel – Black Dog 3	115 MW	Wall-fired	0.35 lb/mmBtu	0.3 lb/mmBtu
Xcel – Black Dog 4	170 MW	Wall-fired	0.35 lb/mmBtu	0.8 lb/mmBtu
Xcel – High Bridge 5	100 MW	Wall-fired	0.4 lb/mmBtu	0.4 lb/mmBtu
Xcel – High Bridge 6	170 MW	Wall-fired	0.4 lb/mmBtu	0.6 lb/mmBtu
Xcel – Riverside 6	80 MW	Wall-fired	0.4 lb/mmBtu	0.9 lb/mmBtu
Xcel – Riverside 7	150 MW	Wall-fired	0.35 lb/mmBtu	0.9 lb/mmBtu
Xcel – Riverside 8	220 MW	Cyclone	1.4 lb/mmBtu	1.1 lb/mmBtu
Xcel – Sherco 1	710 MW	Tangential	0.2 lb/mmBtu	0.3 lb/mmBtu
Xcel – Sherco 2	720 MW	Tangential	0.2 lb/mmBtu	0.3 lb/mmBtu
Xcel – Sherco 3	870 MW	Wall-fired	0.35 lb/mmBtu	0.3 lb/mmBtu

NOTES: Data as reported by US Department of Energy for 1999.
Clay Boswell unit 4 and Sherco units 1, 2, and 3 are controlled for SO2.
NOX controls are installed at Clay Boswell unit 4, A..S. King, and Sherco units 1, 2, and 3.

Figure A.20: Characteristics of Modeled Boilers

Model Number	Capacity	Boiler Type	Uncontrolled SO_2 Emission Rate	Uncontrolled NOx Emission Rate	Facility with Similar Characteristics
1	100 MW	Wall-fired	0.9 lb/mmBtu	0.6 lb/mmBtu	MP: Clay Boswell 2
2	100 MW	Tangential	0.4 lb/mmBtu	0.45 lb.mmBtu	OTP: Hoot Lake 2
3	150 MW	Wall-fired	0.35 lb/mmBtu	0.7 lb/mmBtu	Xcel: High Bridge 6/ Riverside
4	400 MW	Cyclone	1.5 lb/mmBtu	0.9 lb/mmBtu	Xcel: A.S. King
5	400 MW	Tangential	0.85 lb/mmBtu	0.35 lb/mmBtu	MP: Clay Boswell 3

and intermediate coal-fired utility boilers, and their estimated emission rate.

The MPCA analyzed several control technologies that can be applied to the types of electricity generating units found in Minnesota. The SO_2 control efficiency and the cost of three types of scrubbers[151] were evaluated using five models. Characteristics of these models and Minnesota facilities with similar characteristics are shown in Figure A-20.[152] Because the boiler design does not usually affect whether a scrubber can be installed, the three SO_2 control methods were applied to each of the five models.

The MPCA also assessed a larger number of NOx control technologies for the same five models. While some of the control technologies can be added on to almost any boiler (e.g., selective catalytic reduction, or SCR; and selective non-catalytic reduction, or SNCR; and natural gas reburn), some control methods must be matched with specific boilers.[153]

Three boiler configurations were investigated. Wall-fired units are the most common boiler types found in Minnesota. The NOx emissions from wall-fired units may be reduced by the installation of low-NOx burners (LNB) with or without overfire air (OFA). Minnesota also has a few tangentially-fired boilers and cyclone boilers. Coal-and-air nozzles may be installed to reduce NOx in tangentially fired boilers with either close-coupled overfire air or separated overfire air, or both.[154] To reduce emissions at cyclone boilers, coal reburning technology may be added.

Figure A.21: Estimated Costs for Installing SO_2 Controls on Plants (low-cost technology to meet NSPS)

Model Number	Baseload Annual Capital Cost (millions, 1997$)	Intermediate Load Operating Cost (millions, 1997$)	Annual Operating Costs (millions, 1997$)
1	38.4	2.8	2.3
2	38.4	2.8	2.3
3	56.4	4.1	3.4
4	134.1	10.0	8.2
5	134.1	10.0	8.2

*Values to be added

The MPCA looked at three SO_2 control technologies on five boiler models in Figure A-21. Minnesota has a number of coal-fired utility boilers that are used to generate electricity in Minnesota. These units vary by their size, the type of boiler, and by their SO_2 emission rate. To assess the range of costs for controlling SO_2 emissions, the MPCA looked at three SO_2 control technologies on the five boiler models introduced earlier. The three flue-gas desulfurization options each achieved at least a 90 percent reduction in emissions (LFSO, which achieves an SO_2 reduction of 95 percent; LSD, 90 percent; and MEL, 95 percent). Calculations were performed at two capacity factors (a baseload case of 65 percent and a intermediate load case of 40 percent).

Using an EPA analysis of SO_2 scrubbers[155]as the basis of the computation, the MPCA estimated that the cost of installing SO_2 controls on these boilers would range from about $40 million to nearly $190 million, with the cost increasing with the size of the boiler.[156, 157] Estimates of annual operating costs (fixed plus variable) ranged from roughly $2 million to about $10 million. (Note that capital costs are the same for both baseload and intermediate load facilities.) Operating costs increase with the size of the boiler and with increased use. Similarly, the estimated annualized costs range from roughly $5.5 million to over $25 million, rising as the size of the boiler rises and also with increased use.[158]

The cost-effectiveness of control is figured by dividing the annualized cost by the number of tons of SO_2 removed from the flue gas (and therefore not emitted to the atmosphere). For the five modeled boilers, the estimated cost of the lowest-cost control at baseload conditions ranged from $1159 to $4861 per ton of SO_2 removed. For intermediate loads, the estimated cost-effectiveness decreased; the cost per ton ranged from $1729 to $7316.

The cost-effectiveness of a control option usually increases with the amount of SO_2 removed. (In other words, the cost to remove a ton of a pollutant decreases.) This amount of SO_2 removed is related to the level of the uncontrolled emissions and the removal efficiency of the control technology. For a given capacity factor and control technology, the order of cost-effectiveness for the boilers (from highest to lowest) is likely to reflect the order of maximum annual emissions (from highest to lowest). Because emissions are tied to boiler use, controls installed at units with higher capacity factors (such as baseload plants) are likely to be more cost-effective than those added at boilers with lower capacity factors (intermediate load plants and peaking plants).

These trends are generally supported in the analysis. Figure A-22 shows that controlling Model 4 would be the most cost-effective choice. Controlling the other models, particularly Models 2 and 3, would be less cost-effective.[159]

To evaluate the effectiveness and cost of control technologies that reduce emissions of NOx, the MPCA again used the five boiler models presented in the discussion of SO_2 control technologies. The number of control configurations analyzed varied with the different boiler models, as the applicable control technologies varied by boiler type. In addition, some control technologies could be used together. An EPA model was used to determine the effectiveness of the control technologies and to calculate their costs.[160, 161]

The most effective single control technology was SCR (selective catalytic reduction). The analysis assumed that SCR reduced high concentrations of NOx by 80 percent and low concentrations of NOx by 70 percent.[162] Four of the five models were able to meet the NSPS standard for NOx (1.6 pounds of NOx per megawatt-hour) with only SCR. Alone, however, SCR was not usually the most cost-effective control technology. Frequently, a combination of technologies achieved the desired reductions for the lowest cost.

As shown in Figure A-23, the cost of installing effective controls (i.e., those that would allow the controlled unit to meet the standard of 1.6 lb NOx/MW-hr) ranged from about $9 million to roughly $27 million. Costs for a specific type of control rose as the size of the controlled unit increased. In addition,

Figure A.22: Estimated Cost to Meet NSPS Standard for SO_2 Emissions

Model Number	Lowest Cost Option to Meet NSPS for SO_2 (selected technology)	Cost-effectiveness for a Baseload Plant	Cost-effectiveness for an Intermediate Load Plant
1	Magnesium-enhanced lime	$2,088/tpy	$3,146/tpy
2	Magnesium-enhanced lime	$4,697/tpy	$7,079/tpy
3	Magnesium-enhanced lime	$4,861/tpy	$7,316/tpy
4	Magnesium-enhanced lime	$1,159/tpy	$1,729/tpy
5	Magnesium-enhanced lime	$2,044/tpy	$3,051/tpy

Figure A.23: Estimated cost for installing NOx controls on plants(low-cost technology to meet NSPS)

Model number	Capital cost (millions, 1995$)	Baseload annual operating cost (millions, 1995$)	Intermediate Load annual operating cost (millions, 1995$)
1	8.8	.8	0.7
2	11.6	1.1	0.9
3	14.5	1.1	1.1
4	26.8	4.2	3.6
5	15.5	1.5	1.1

Figure A.24: Estimated Costs to Meet NSPS Standard for NOx Emissions[a]

Model Number	Lowest cost option to meet NSPS for NOx (selected technology)	Cost-effectiveness for a baseload plant	Cost-effectiveness for an imtermediate load plant
1	SCR	$973/tpy	$1499/tpy
2	Gas Reburn with SCR	$1353/tpy	2290/tpy
3	LNB with SCR	$694/tpy	$1086/tpy
4	LNC3 with Gas Reburn	$653/tpy	$957/tpy
5	LNC2 with Gas Reburn	$1034/tpy	$1422/tpy

[a] cost in 1995 dollars

though, the type of unit played a role, with wall-fired units being the least expensive to control to this level, and cyclone units the most expensive units to control. Figure A-24 shows the most cost-effective control technology that achieved the desired emission level, and the associated cost per ton of NOx controlled. Again, the highest-polluting units (in this case, models 3 and 4) were the most cost-effective to control.

The analyses above indicate that, to meet the requirements that New Source Performance Standards place on new electricity generating units, utility companies must spend an estimated $1000 to $7000 per ton of SO_2 removed and an estimated $650 to $2300 per ton of NOx removed. This compares with values in the literature for similar changes of an estimated $322 per ton of SO_2 removed[163] and an estimated $975 to $2140 per ton of NOx removed.[164]

The MPCA did not investigate the efficiency or cost of technologies to control mercury and carbon dioxide. Few control efficiencies or cost estimates have been firmly established for retrofits to reduce mer-

Figure A.25: Estimated Rate Impact of Installing SO_2 Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	1.2381	10.30	1.1924	9.92
2	Hoot Lake 2	10.23	2.3816	24.35	2.2743	23.25
3	High Bridge 6/Riverside	7.78	0.4802	3.74	0.4612	3.59
4	A.S. King	7.78	1.3804	10.74	1.3316	10.36
5	Clay Boswell 3	8.32	3.4615	28.79	3.2970	27.42

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report [2] Sheet 1 [3] column (a) times column (b) [4] column (a) times column (d)

Figure A.26: Estimated Rate Impact of Installing NOx Controls on Plants (Low-Cost Technology to Meet NSPS)

Model Number	Facility with Similar Characteristics to:	Annual 2000 Residential MWH Usage[1] (a)	Baseload Cost Per MWH 2000 $[2] (b)	Annual Baseload $ Cost per Residential Customer[3] (c)	Intermediate Load Cost Per MWH 2000 $ (d)	Annual Intermediate Load Residential Customer[4] (e)
1	Clay Boswell 2	8.32	0.3140	2.61	0.3044	2.53
2	Hoot Lake 2	10.23	0.8151	8.33	0.7699	7.87
3	High Bridge 6/Riverside	7.78	0.1313	1.02	0.1313	1.02
4	A.S. King	7.78	0.3543	2.75	0.3363	2.62
5	Clay Boswell 3	8.32	0.4545	3.78	0.4160	3.46

Assumes that these additions do not lengthen the life of the facility. Longer life would reduce the annual costs.
[1] MN Jurisdictional Annual Report [2] Sheet 1 [3] column (a) times column (b) [4] column (a) times column (d)

cury emissions. However, the U.S. Environmental Protection Agency (EPA) and U.S. Department of Energy (DOE) continue to examine the injection of activated carbon and other control technologies that reduce mercury emissions. Increasing the efficiency of existing plants or switching fuels from coal to natural gas also reduce mercury emissions.

At present, no economically feasible technologies exist for the capture and disposal of CO_2 from power plant flue gases.[165] Three opportunities exist for CO_2 emissions control by the electric utilities. To reduce CO_2 emissions during electricity generation, electricity generators could switch from coal to natural gas. On a per kilowatt-hour basis, the combustion of natural gas to produce electricity results in the production of about one-third of the CO_2 produced when using coal as a fuel source. Second, electricity generators could offset emissions through carbon sequestration in standing biomass and soils. During plant growth, carbon dioxide is removed from the atmosphere and stored in plant biomass or soils. The average acre of timberland in Minnesota stores about 30 tons of carbon.

The Department of Commerce estimated the residential rate impact of installing central technology on the existing Minnesota plants that most resemble the modeled units. Rate impacts range from \$3.59/year to \$27.42/year for SO_2 controls, as shown in Figure A-25. For NOx controls, rate impacts range from \$1.02/year to \$7.87/year, as shown in Figure A-26. If controls are installed at more than one plant in one utility system and/or for both pollutants, total rate impacts can be estimated by summing the individual rate impacts.

These estimates assumed that the addition of pollution controls would not increase the useful life of the facility. While all of the representative facilities are older plants, even among the five facilities, the remaining life for depreciation purposes is more than twice as long as the oldest facility.[166] Rate impacts would decrease if the control equipment were depreciated over a longer period of expected plant operation.

Policy Recommendations

This section provided detailed information on the current level of emissions from electricity generation in the state, the different environmental impacts associated with those emissions, and a survey of relevant national environmental program initiatives. While electric generation is not the only source contributing to the environmental problems described in this section, it is a major source of these types of problematic emissions. Electric generation must not increase and should, over time, decrease its contribution to harmful air emissions. As we add new power plants, we must take care not to compound existing problems. If new plants are constructed that result in significant new sources of emissions, emissions from existing plants should be subject to stricter controls or some of the existing plants should close to ensure no net increase in overall emissions from the electric generation sector.

In 2001, the legislature responded to growing public concern over air emissions from existing electric generating plants by enacting an emissions reduction rider that allows utilities to propose cost-effective pollution controls on existing plants, and receive rate recovery. Minnesota's largest utility, Xcel Energy, has agreed to analyze possible emission control options at three of its plants by the summer of 2002. The study by Pollution Control Agency staff of possible control options presented in this section of the report will give policymakers a sense of the kinds of costs that would be incurred in installing pollution control equipment at selected existing facilities.

Policy considerations for the legislature include whether to require other utilities to prepare studies on cost effective pollution controls at some of their major existing uncontrolled generating plants. Another issue that may need to be addressed, depending on the response of utilities to the opportunity provided by the emission rider, would be to require certain projects to be implemented that the Public Utilities Commission determines to be cost-effective for ratepayers and to have significant positive impact on environmental emissions. The present emissions rider language makes implementation of a project entirely voluntary with the utility. Lastly, since it is likely that new electric generation plants constructed in Minnesota to meet growing demand for electricity will increase overall emissions of air pollutants, emissions at existing plants should be reduced by at least as much as new emissions.

ENDNOTES

134. This is because NSPS are based on the best available technology at the time they are adopted, and control technologies of the 1990s are superior to those of the 1970s.

135. NSPS do not regulate mercury and CO_2 emissions.

136. Figure A-10 includes the two new gas peaking plants, Pleasant Valley and Lakefield Junction, because they were added in 2001 and their emissions thus occur after 1999. Figure A-10 also includes a handful of small capacity additions that were not listed in Figure 3-3 in Chapter 3 of the main report because their construction is below the thresholds for PUC approval.

137. Other sources of these pollutants also contribute to these pollution problems, but as shown in Figure A-1, electric generation is a significant or predominant source category for these pollutants.

138. Dockery, D.W., C.A. Pope III, X. Xu, J.O. Spergler, J.H. Ware, M.E. Fay, B.G. Ferris, Jr., and F.E. Speizer, 1993. An Association Between Air Pollution and Mortality in Six U.S. Cities, New England Journal of Medicine, *pp. 281-287.*

139. EPA. Air Quality Criteria for Particulate Matter, Office of Research and Development, EPA/600/p. 95/001, April 1996.

140. Daniels, J.J., Dominici, F., Sanet, J.M., Zeger, S.L., 2000. Estimating Particulate Matter-Mortality Dose-Response Curves and Threshold Levels: An Analysis of Daily Time-Series for the 20 Largest US Cities, American Journal of Epidemiology, *Vol. 152, No. 5, pp. 397-406.*

Schwartz, J. 1999. Air Pollution and Hospital Admissions for Heart Disease in Eight U.S. Counties. Epidemiology, Vol. 10, No. 1, pp. 17-22.

Schwartz, J. and A. Zanobetti, 2000. Using Meta-Smoothing to Estimate Dose-Response Trends Across Multiple Studies, with Application to Air Pollution and Daily Death. Epidemiology, *Vol. 11, No. 6, pp. 666-672.*

141. Science, vol 293 17 August 2001, at 1257.

142. The left photo was taken on Sept. 14, 2000 at about 8:00 a.m. from Mounds Park in St. Paul. The right photo was taken on June 28, 2001 at 12:30 p.m.

143. U.S. EPA, 2001. National Air Emissions Trends. Website http://www.epa.gov/ttn/chief/trends/trends99/tier3_yrsemis.pdf accessed December 10, 2001.

144. MPCA. Minnesota Air: Air Quality and Emissions Trends. September 1997, p. 153.

145. The US National Academy of Sciences reviewed the underlying science of global climate change in 1979, 1981, 1983, 1987 and 1991, concluding in each instance that, with a doubling of atmospheric CO_2, mean global surface temperature would rise 1.5 to 4.5 degrees Celsius.

146. While there is virtually no debate about the reality of the observed surface warming, scientists debate the degree to which mean global surface temperature will rise. However, even climate skeptics have concluded that at least some continuation of the observed 20th century warming is likely. To the degree that they have furnished estimates of future warming, these scientists have tended to support forecasts near the lower end of this range, 1 to 2 degrees Celsius, with one low value near 0.5 degrees Celsius.

147. BioScience, March 2001/ Vol 51 No. 3 pp. 180 –198.

148. Science Vol. 292, April 13, 2001 pp. 195-196.

149. New source review, because it is case-by-case, does not suffer from the control requirement failing to be equal to stringent new technology. New source review was enacted to address this deficiency in the design of the NSPS program.

150. The New Source Performance Standards for utilities (40 CFR 60 Subparts D, Da, and Db) address emissions of SO_2, NOx, and particulate matter. Emissions of other pollutants, including mercury and carbon dioxide, are not restricted by these regulations. A federal emission limit for mercury will probably be a part of a new National Emission Standard for Hazardous Air Pollutants (NESHAP) for utilities. The U.S. Environmental Protection Agency does not regulate carbon dioxide.

151. The three SO_2 control technologies are limestone forced oxidation (LFSO), limestone spray drying (LSD), and magnesium-enhanced lime (MEL). Each of these flue-gas desulfurization technologies use scrubbing to reduce SO_2 emissions.

152. The "representative" facilities exhibit characteristics that most closely resemble the modeled units. However, the characteristics of the modeled units and the identified facilities are not identical.

153. While most SO_2 emissions are formed from the direct combustion of sulfur contained in the coal, NOX emissions are formed in two ways. First, nitrogen in the coal can be oxidized (combusted). This creates a relatively small amount of NOx. The second way in which NOx is formed involves the heating of the air provided for combustion. When heated, the nitrogen in the air may react with nearby oxygen to form NOx. This reaction is more likely at higher temperatures. It generates most of the NOx created at a utility boiler.

By redesigning the combustion chamber, the amount of NOx generated by the second method can be limited. However, this requires boiler-specific modifications. This is the reason that some of the control methods must be matched with specific boilers.

154. Coal-and-air nozzles with close-coupled overfire air is referred to as LNC1. When coal-and-air nozzles are used with separated air, it is called LNC2. LNC3 refers to the case in which both types of air supply are used with the nozzles.

155. Srivastava, Ravi K., and Jozewicz, Wojciech. Controlling SO_2 Emissions: An Analysis of Technologies. EPA/600/SR-00/093, November 2000.

Also: Srivastava, Ravi K. Controlling SO_2 Emissions: A Review of Technologies. EPA/600/R-00/093, November 2000.

156. Costs for SO_2 controls are provided in 1997 dollars.

157. The actual costs of installing SO_2 controls at a particular plant must be determined on a case-by-case basis. This analysis relies on average costs from previous installations.

158. Annualized costs are calculated by distributing the cost of the initial installation over the lifetime of the equipment, plus interest, and adding that cost to the annual operating costs. In this case, an interest rate of 6 percent and a twenty year life were used.

159. Model number 2 had a cost-effectiveness of $4697/ton, while model number 3 had a cost-effectiveness of $4861/ton. Model number 4's cost-effectiveness was $1159/ton.

160. EPA. Analyzing Electric Power Generation Under the CAAA. Office of Air and Radiation, July 1996.

161. The actual costs of installing NOx controls at a particular plant must be determined on a case-by-case basis. This analysis relies on costs from previous installations.

162. High NOx concentrations are those exceeding 0.5 lb/mmBtu.

163. Energy Information Administration. "The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update." (Costs in 1995 dollars.)

164. Butraw, Dallas; Palmer, Karen; Bharvirkar, Ranjit; and Paul, Anthony. "Cost-effective Reduction of NOx Emissions from Electricity Generation." Discussion Paper 00-55, Resources for the Future, December 2000. (Costs in 1997 dollars.)

165. It is expected that systems for CO_2 capture could be commercially available within several decades at reasonable costs.

166. The remaining lives are: 6 years for Boswell 2, 11.3 years for Hoot Lake, 7.9 years for High Bridge 6, 5 years for King, and 12 years for Boswell 3.

APPENDIX B: HISTORY OF ELECTRIC UTILITY REGULATION

There have been major problems in establishing our nation's electric system, its industry structures, and the regulatory structures that govern it. These problems resulted in federal legislation early last century. For example, as electric companies grew, several firms created massive holding companies that acquired numerous local power companies. Seven holding companies controlled 60 percent of the electric power generated in the United States by the late 1920s. The complexity of the holding company structures began to defeat the efforts of local regulators to track company expenses and revenues and properly regulate rates. In addition, the U. S. Supreme Court held that interstate wholesale transactions between companies within a holding company and between holding companies were outside the jurisdiction of local regulators. The result was a system of virtually unregulated monopolies.

Congress responded in 1935 by passing the Public Utilities Holding Company Act (PUHCA) and the Federal Power Act (FPA). PUHCA created restrictions on the corporate structure of electric companies that curbed many of the holding company abuses, including extortionist rates and poor service. Additionally, the FPA established a system where retail electric rates would be regulated by state governments and wholesale electric transactions between utilities would be regulated by a new federal independent regulatory commission originally called the Federal Power Commission, now known as the Federal Energy Regulatory Commission (FERC).

In addition, by the 1930s it was apparent that private electric utility companies were not going to electrify rural areas because of high costs and relative low returns on transmission and distribution lines required to serve a sparse population. Rural citizens did not have access to electric service. Congress passed the Rural Electrification Act to encourage development of rural cooperative electric associations to provide electricity to rural areas.

A period of nearly 50 years passed without significant change in the legal structure governing the electric utility industry.

> For decades following the onset of regulation, electric utilities experienced large, steady sales growth and declining prices. ... Between 1925 and 1970, the industry quadrupled the number of customers, but increased plant capacity 13 fold and sales by a factor of 25. ... Between 1906 and 1970, the average price of power to residences declined from 10 cents per kilowatt-hour to about 2.6 cents—even before adjustment for inflation. Of course, declining costs and prices as output increases are just what the theory of natural monopoly predicts...[167]

During this period, utilities found that building ever-larger power plants decreased the cost of electricity per kilowatt-hour sold to customers, due to the efficiencies of large-scale generation of electric power.

During the 1970s, however, the equation changed completely. Inflation and oil price shocks raised interest rates to high levels. At the same time the price of fuels used in power plants skyrocketed. Dawning awareness of the cumulative environmental effects of emissions from large electric power plants lead to the onset of environmental requirements to put costly pollution control equipment into new electric power plants. By the 1970s, utilities also started to find that further increases in the size of electric power plants no longer achieved the expected economies of scale. Finally, increases in energy costs prompted consumers to seriously reduce consumption.

> Utilities, which had seen steady rapid growth of demand throughout the first half of the century, built for a continuation of that level of demand growth. Plants grew larger and larger. It is certain that the oil crisis of the early 1970s forced fuel prices up, causing reductions in demand. Reduced demand left utilities with excess capacity. Customers had to pay for that excess. For the first time in history, electricity prices began to rise. Many public utility commissions would not allow utilities to recover the cost of building excess capacity from their consumers.[168]

With the development of more efficient small combustion units and alternative technologies, it was no longer necessarily the case that the large central utility coal or nuclear plant was the most cost-effective way to produce electricity.

Concern over the rising cost of electricity and the changing economies of scale of electric production lead Congress to pass the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA encouraged alternative generation resources from renewable energy technologies and co-generation. These small-scale methods of electric generation were called "qualifying facilities," and utilities were required to buy the electricity that these facilities generated at a rate equal to the cost that would be avoided by not constructing additional utility electric plants. PURPA's implementation encouraged electric production by non-utility generators. Despite PURPA and the changing economics of electric production, another round of large coal and nuclear plants were built around the country, ending in the mid-1980s.

In 1992, Congress passed the Energy Policy Act (EPAct) to further develop a more competitive wholesale electric industry. EPAct also allowed the FERC to require utilities to allow wholesale producers of electricity to transmit their electricity along utility transmission lines for wholesale sale. PURPA and EPAct spurred the growth of non-utility generation facilities, called Independent Power Producers (IPPs), that contract with utilities to provide part of the generation resources needed to serve retail customers, as well as an increasingly market-based wholesale electricity market. In 2000, nonutility power producers produced 21 percent of the electricity in the United States, although that figure is much smaller in Minnesota.[169]

ENDNOTES

167. Fox-Penner Electric Utility Restructuring in A Guide to the Competitive Era at 12 and 14 (1997).

168. Congressman Bingaman, White Paper on Electricity Legislation, at 4 (July 20, 2001).

169. Annual Energy Review 2000, EIA at 220.

APPENDIX C: UTILITY REGULATION IN MINNESOTA

In Minnesota, state regulation has been in effect since 1974, when it became apparent that regulation through the existing system of local utility franchises had become too complicated and inefficient.

Rate and service regulation for electric utilities has been in existence in nearly every state since early 1900s. After the many problems of a system of non-interconnected small electric power companies emerged in the early 1900s, economists declared electric utilities "natural monopolies." The theory of natural monopoly is that a single, regulated provider can provide service to an area at the lowest total cost to customers. This lower cost is largely due to the elimination of redundant infrastructure, such as multiple transmission and distribution systems. In addition an interconnected system allows for construction of very large electric power plants that provide a lower average cost per unit of production (thus giving ratepayers the benefit of "economies of scale"). This served well during a time of explosion in demand for electricity, due to the electrification of the entire country, that continued through the mid-1970s.

Electric utility regulation works by a "regulatory compact" whereby utilities receive exclusive service territories in exchange for an obligation by the utility to provide adequate and non-discriminatory service to all persons and businesses in the service territory. The rates charged to customers are set by the Minnesota Public Utilities Commission (PUC). Rates are set at a level that allows the utility, under prudent cost management, to recover its costs of providing retail electric service and to earn a reasonable return on the investment made by the utility's shareholders in utility plant.

When the PUC evaluates a request for a change in rates, it does so through a "general rate case." A general rate case is usually initiated by a state regulated utility when it seeks to increase rates for its services to customers. The rate case provides a means to thoroughly examine the expenses, revenues and expected rate of return to shareholders of public utilities and set rates accordingly. Parties to a rate case include at least the utility and the Department of Commerce, which provides the public interest analysis and advocacy before the PUC. Other parties usually include the Residential Utility Division of the Attorney General's Office, which advocates solely for the interests of residential and small business customers, customer advocates, shareholder advocates, energy advocates, and environmental advocates. Any person can intervene as a party in any proceeding before the PUC.

A general rate case consists of two parts. First, the PUC determines the "revenue requirement" for the utility, which answers the question: "how much should we pay in total to the utility?" The revenue requirement is determined by selecting a representative year of operation of the company, evaluating the expenses of the company (including a return on shareholder investment)[170] and the expected revenues, and subtracting expenses from revenues to determine whether there is a surplus or deficit for the utility company. If a surplus is found, then a refund will be provided to customers and lower rates will be established for future years. If a deficit is found, then rates are increased. Once the revenue requirement is established, the PUC evaluates the cost of serving the various customer classes of the utility, such as residential, commercial, farm, industrial and municipal lighting, and determines the rate that can be charged each class.[172]

The general rate case is a mechanism by which a utility's rates are periodically evaluated to be sure that they are reasonable and allow the utility's shareholders the opportunity to receive a reasonable return on their investment. In a rate case, a utility always has some expenses that have increased since the prior rate case and some expenses that have decreased. The rate case is a means of balancing where all of these expenses are properly evaluated and combined to determine whether the utility is under- or over-earning in total. The utility then moves forward from the general rate case with the incentive to manage its expenses in the best possible way to earn a greater return for shareholders. If a utility seeks to include investments and other expenses in the next set of rates, the PUC company managers must evaluate business risk in much the same way as managers of industries that are not rate regulated. The general rate case preserves a risk element for utility managers as well as incentives to prudently control expenditures.

It is true that a number of years may occur between a utility's rate case filings. That does not mean, however, that the utility's rates and dollar recoveries from ratepayers are not scrutinized. Every year the Department of Commerce analyzes each regulated electric and natural gas utility's rate of return. These returns, on an actual basis and a weather normalized[173] basis, are compared to the PUC approved rate of return to ensure that utilities are not over earning. Any evidence of over earning is investigated further and, if warranted, Commerce presents its findings to the PUC for further action.

ENDNOTES

170. The return on investment allowed is determined by multiplying a percentage of profit (rate of return) by the total undepreciated value of utility plant serving the customers (the "rate base").

172. This part of a rate case is called "rate design."

173. See Glossary in Appendix E.

APPENDIX D: METHODOLOGY FOR ENERGY CONSERVATION ESTIMATES

Figures 5 and 6 in Chapter 4 provide estimates for how much energy and demand could be saved through the utilities' investments in energy conservation. Several parties requested that we explain the method used to calculate these energy and demand savings. In addition, some parties, Xcel Energy and Customers for CIP Reform in particular, pointed out that when making these estimates, several factors needed to be taken into account. In particular, we need to be mindful that:

- capacity savings from energy conservation tend to cost more than capacity savings from load management,
- it will be more difficult for smaller municipal and cooperative utilities to achieve cost levels similar to Xcel due to smaller customer size,
- municipal and cooperative utilities tend to have more residential customers which are more costly to serve with conservation programs.

As explained below, we attempted to account for these factors in our estimation method.

Estimation Method

Calculating Xcel Energy's annual energy and demand savings

We assumed that Xcel Energy would meet the energy and demand savings set by the PUC in Docket No. E002/RP-00-787. These assumptions did not change for Figure 5 or Figure 6 in Chapter 4, because Xcel Energy must already spend more than 2% of gross operating revenues to meet existing PUC requirements.

Calculating Alliant Energy's annual energy and demand savings

We assumed annual energy savings of 18,475 MWh and demand savings of 3 MW for 2001 through 2010. These assumptions did not change for Figure 5 or Figure 6, again because Alliant must spend at or above the 2% level to meet requirements already set.

Calculating Otter Tail Power Company's (OTP or Otter Tail) annual energy and demand savings

We assumed annual energy savings of 13,000 MWh and demand savings of 2 MW for 2001 through 2010. We increased these annual savings to 17,300 MWh and 2.6 MW for the scenario in which all electric utilities potentially are required to increase spending to 2 percent of gross operating revenues.

Calculating Minnesota Power's annual energy and demand savings

We assumed annual energy savings of 18,000 MWh and demand savings of 4 MW. We increased these annual savings to 23,940 MWh and 5.2 MW for the scenario in which all electric utilities potentially are required to increase spending to 2 percent of gross operating revenues.

Calculating cooperative and municipal utilities' energy and demand savings

Step 1: We used cooperative and municipal utilities' 1997 gross operating revenues from Table 3 of the Minnesota Utility Data Book, inflated 1997 figures by 1 percent per year to 2001, and used 2001 figures for 2001-2010.

Step 2: We obtained yearly budgets by multiplying the result of Step 1 by 1.5 percent, the existing statutory spending requirement.

Step 3: We assumed that municipal and cooperative utilities will spend the following percentage of the annual budgets determined in Step 2 on energy conservation:

2001	10%
2002	10%
2003	20%
2004	30%
2005	50%
2006	50%
2007	50%
2008	50%
2009	50%
2010	50%

Step 4: We developed the range of capacity and energy savings by dividing the results of Step 3 by the average energy and demand savings costs of Xcel Energy and Otter Tail Power.

As can be seen, Otter Tail's average cost of demand savings is more than twice that of Xcel Energy. Xcel Energy's energy savings costs have averaged approximately 17 percent more than Otter Tail's. By using the two different utility costs, we attempted to provide a high and a low scenario.

Step 5: To evaluate the impact of increasing the statutory spending requirement to 2 percent we multiplied the ranges developed in Step 4 by 1.33 (2 percent/1.5 percent)

Step 6: To evaluate the impact of requiring that municipal and cooperative utilities are held to the same standards as investor owned utilities in regards to what load management qualifies for statutory spending requirements, we assumed that the savings would increase by 50 percent of the range of capacity and energy savings calculated in Step 4 .

We are open to suggestions for how to improve our study. Comments may be sent to:

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APPENDIX E: GLOSSARY

AFV—Alternative Fuel Vehicle

Biofuels—Alcohols, ethers, esters, and other chemicals made from raw biological material such as herbaceous and woody plants, agricultural and forestry residues, and a large portion of municipal solid and industrial waste.

Biomass—Organic waste from agricultural, livestock, and lumber industry products, dead trees, foliage, etc., and is considered a renewable energy source. Biomass can be used as fuel and is most often burned to create steam that powers steam turbine generators. It is also used to make transportation fuels like ethanol and biodiesel, and chemicals like pyrolysis oil that can be burned like oil to produce energy.

Bottleneck Facility—A point on the electric system, such as a transmission line, through which all electricity must pass to get to its intended buyers. If there is limited capacity at this point, some priorities must be developed to decide whose power gets through. It also must be decided if the owner of the bottleneck may, or must, build additional facilities to relieve the constraint.

Btu—British thermal unit; the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit under stated conditions of pressure and temperature (equal to 252 calories, 778 foot-pounds, 1,005 joules and 0.293 watt-hours). It is the U.S. customary unit of measuring the quality of heat, such as the heat content of fuel.

Bulk Power Supply—Often this term is used interchangeably with wholesale power supply. In broader terms, it refers to the aggregate of electric generating plants, transmission lines, and related-equipment. The term may refer to those facilities within one electric utility, or within a group of utilities in which the transmission lines are interconnected.

CIP—Conservation Improvement Program

CO—Carbon Monoxide

CO_2—Carbon Dioxide

Cogeneration—(also Combined Heat and Power) Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.

Combined Cycle—An electric generating technology in which electricity and process steam is produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

cf—cubic foot; the U.S. customary unit of measurement of gas volume. It is the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor. One cubic foot of natural gas equals 1,000 British thermal units under standard conditions of atmosphere (one) and temperature (60 degrees Fahrenheit).

Commodity Price—The portion of a natural gas sales or transportation rate based upon the volume actually shipped or used.

Control Area—An electric system bounded by transmission lines that are equipped with metering and telemetry equipment to track and report power flows with adjacent control areas. A control center for each control area controls the operation of generation within its portion of the transmission grid, schedules interchanges with other control areas, and helps to stabilize the frequency of alternating current in the interconnection. Control centers are currently operated by individual utilities, power pools, ISOs or RTOs.

Cooperative electric association or utility—utility owned and operated by its members.

DC—Direct current.

Demand—The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts (kW), megawatts (MW), or gigawatts (GW), at a given instant or averaged over any designated interval of time. Demand should not be confused with Load or Energy.

Demand Charge—A fee based on the peak amount of electricity used during the billing cycle.

Department or DOC—the Minnesota Department of Commerce.

Deregulation—The elimination or restructuring of regulation from a previously regulated industry or sector of an industry.

Distributed Energy Resources—(Also called distributed power, distributed energy, distributed generation.) Both electric demand reduction (energy conservation, load management, etc.) and supply generated at or near where the power is used. A distributed generation system involves amounts of generation located on a utility's distribution system for the purpose of meeting local (substation level) peak loads and/or displacing the need to build additional (or upgrade) local distribution lines.

Distribution—The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

DSM (Demand Side Management)—Programs to influence the amount or timing of customers' energy use.

DOE—U.S. Department of Energy.

Economies of Scale—Economies of scale exist where the industry exhibits decreasing average long run costs with increases in size.

EIA—The United States Department of Energy's Energy Information Administration.

Electric Energy—The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

Electric System Losses—Total electric energy losses in the electric system. Losses are primarily due to electric resistance within transmission system lines and transformers.

Utility—A corporation, person, agency, authority, or other legal entity that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy or natural gas primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated.

EMF—Electromagnetic fields.

Eminent Domain—The process by which rights to land needed for public interest facilities is acquired regardless of objection by the landowner. Eminent domain is generally applied by or through the power of the relevant siting authority that found the facilities to be in the public interest.

Energy Conservation—Using less energy, either by greater energy efficiency or by decreasing the types of applications requiring electricity or natural gas to operate.

Energy Efficiency—Using less energy (electricity and/or natural gas) to perform the same function at the same level of quality. Programs designed to use energy more efficiently — doing the same with less. For the purpose of this paper, energy efficiency is distinguished from DSM programs in that the latter are utility sponsored and financed, while the former is a broader term not limited to any particular sponsor or funding source.

EPA—U.S. Environmental Protection Agency.

Federal Energy Regulatory Commission (FERC)—The Federal Energy Regulatory Commission regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.

GWh—gigawatt-hour; the unit of energy equal to that expended in one hour at a rate of one billion watts. One GWh equals 1,000 megawatt-hours.

Greenhouse gases—Greenhouse gases are water vapor, carbon dioxide, tropospheric ozone, nitrous oxide, methane, and chlorofluorocarbons (CFCs).

Grid—A system of interconnected power lines and generators that is managed so that power from generators is dispatched as needed to meet the requirements of the customers connected to the grid at various points. Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

Investor owned utility (IOU)—Common term for a privately owned (shareholder owned) gas or electric utility regulated by the Minnesota Public Utilities Commission (referred to in statutes as a "public utility").

Independent System Operator (ISO)—A neutral and independent organization with no financial interest in generating facilities that administers the operation and use of the transmission system. ISOs exercise final authority over the dispatch of electricity from generators to customers to preserve reliability and facilitate efficiency, ensure non-discriminatory access, administer transmission tariffs, ensure the availability of ancillary services, and provide information about the status of the transmission system and available transmission capacity. An ISO may make some transmission investment decisions.

Interconnected System—A system consisting of two or more individual electric systems that have connecting tie lines and whose operations are synchronized.

Interconnection—When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT (Texas), Quebec, and Alaska. When not capitalized, the facilities that connect two systems or control areas. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a control area or system.

IRP—Integrated Resource Planning.

KV—A kilovolt equals 1,000 volts.

Kilowatt (kW)—This is a measure of demand for power. The rate at which electricity is used during a defined period (usually metered over 15-minute intervals). Utility customers generally are billed on a monthly basis; therefore, the kW demand for a given month would be the 15- minute period in which the most power is consumed. Customers may be charged a fee (demand charge) based on the peak amount of electricity used during the billing cycle. (Residential customers are generally not levied a demand charge.)

Kilowatt-hour (kWh)—This is a measure of consumption. It is the amount of electricity that is used over some period of time, typically a one-month period for billing purposes. Customers are charged a rate per kWh of electricity used.

Load—An end use device or customer that receives power from an energy delivery system. Load should not be confused with Demand, which is the measure of power that a load receives or requires. See Demand.

Load Center or Load Pocket—A geographical area where large amounts of power are drawn by end-users.

Local Distribution Company (LDC)—Common term for a privately-owned natural gas utility that provides retail natural gas services to end use customers and is usually regulated by the PUC.

Long Range Planning—The process of forecasting long term loads, determining a reasonable set of potential resources to meet these loads (including reduction of loads through energy efficiency), analyzing the costs (sometimes including externality costs) of several possible mixes of such resources, and identifying the resources to be secured to meet such future needs.

Mcf—one thousand cubic feet; a unit of measure of gas volumes.

Minnesota Public Utilities Commission (Commission or PUC)—the state agency with regulatory jurisdiction over certain Minnesota utilities.

MISO—Midwest Independent System Operator.

MAPP—Mid-Continent Area Power Pool.

MVA—A megavolt-ampere equals 1,000 kVA.

MW—A megawatt equals 1,000 kilowatts or 1 million watts.

MWh—megawatt-hour; the unit of energy equal to that expended in one hour at a rate of one million watts. One MWh equals 3,414,000 Btus.

Monopoly—The only seller with control over market sales.

Natural Monopoly—A situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries that exhibit decreasing average long run costs due to size (economies of scale). According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

NERC—The North American Electric Reliability Council is the coordinating arm of the nine member regional reliability councils. (See also Reliability Councils).

NOx—Nitrogen Oxides

PURPA—Public Utility Regulatory Policies Act of 1978.

PV—Photovoltaic

Obligation to Serve—The obligation of a utility to provide nondiscriminatory electric service to any customer who seeks that service, and is willing to pay the rates set for that service. By law, utilities have the obligation to serve in return for exclusive service territories.

Parallel Path Flow—As defined by NERC, this refers to the actual flow of electric power on an electric system's transmission facilities resulting from scheduled electric power transfers between two other electric systems. (Electric power flows on all interconnected parallel paths in amounts inversely proportional to each path's resistance.) Contract transmission paths, the electricity contracted for between sellers and buyers, do not define the way electricity actually flows.

Peak Load or Peak Demand—The electric load that corresponds to a maximum level of electric demand within a specified time period, usually a year.

Performance Based Regulation (PBR)—Any rate setting mechanism that attempts to link rewards (generally profits) to desired results or targets. PBR sets rates, or components of rates, for a period of time based on external indices rather than a utility's cost of service. Other definitions include light handed regulation that is less costly and less subject to debate and litigation. A form of rate regulation that provides utilities with incentives to reduce their costs.

Power Authorities—Quasi governmental agencies that perform all or some of the functions of a public utility.

Power Pool—Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

Public Good—A good (or a service) that will not be produced and delivered solely by the free market. Economists call these "public goods" because the public consumes them, but they do not solely benefit a single buyer or group of buyers. There is no way to produce a public good without producing a value to society at large. It is unlikely that an individual would pay out of his or her own pocket to ensure that a public good is produced because the value is not exclusively individual.

Public Interest Goals—Public interest goals of utility regulation include: 1) inter-and intra-class and intergenerational equity); 2) the equal treatment of equals (horizontal equity); 3) balancing long- and short-term goals that have the potential to affect intergenerational balance; 4) protecting against the abuse of monopoly power; and 5) general protection of the health and welfare of the citizens of the state, nation, and world. Environmental and other types of social costs are subsumed under the equity and health and welfare responsibilities.

Public Utility—By Minnesota Statute, an investor owned utility regulated by the PUC. "Public utility" excludes municipal utilities, cooperatives, and power marketing authorities.

Real time Pricing—The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.

Regional Reliability Councils (RRC)—Regional reliability councils were organized after the 1965 northeast blackout to coordinate reliability practices and avoid or minimize future outages. They are voluntary organizations of transmission owning utilities and in some cases power cooperatives, power marketers, and nonutility generators. Membership rules vary from region to region. They are coordinated through the North American Electric Reliability Council (NERC). There are ten major regional councils plus the Alaska Systems Coordinating Council.

REIS—Regional Energy Information System; the Minnesota Department of Commerce's computerized state energy data collection and information system required under Minnesota Statutes. It includes energy data the DOC collects directly from energy suppliers as well as data collected by other state departments such as the Minnesota Department of Revenue, Petroleum Taxation Division. It also includes energy data specific to Minnesota collected by the U.S. Department of Energy, the U.S. Department of Commerce, Bureau of Census and the U.S. Department of Transportation.

RDF—Refuse derived fuel, composed of processed garbage, that is used in some electric generation plants.

Reliability—Electric system reliability has two components—adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electric demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities. Reliability also refers to the security and availability of natural gas and petroleum supply, transportation and delivery.

Renewable Resources—Renewable energy resources are naturally replenishable, but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Research and Development (R&D)—Research is the discovery of fundamental new knowledge. Development is the application of new knowledge to develop a potential new service or product. Basic power sector R&D is most commonly funded and conducted through the Department of Energy (DOE), its associated government laboratories, university laboratories, the Electric Power Research Institute (EPRI), and private sector companies.

Reserve Margin—Capacity over and above anticipated peak loads, maintained for the purpose of providing operational flexibility and for preserving system reliability. Reserve margins cover for planned and unplanned outages of generation and/or transmission facilities.

Restructuring—The reconfiguration of the vertically integrated energy monopolies. Restructuring usually refers to separation of the various utility functions into individually operated and owned entities.

RTO—A regional transmission organization designed to operate the grid and its wholesale power market over a broad region and with independence from commercial interests. An RTO would also have a role in planning and investing in the grid, though how it would conduct these activities remains unresolved. An RTO would also coordinate with other RTOs.

Substation—A facility for switching electric elements, transforming voltage, regulating power, or metering.

Tariff—A document, approved by the responsible regulatory agency, listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

Thermal Rating—The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements.

Time-of-Use (TOU) Rates—The pricing of delivered electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices that may fluctuate many times a day and are weather sensitive, rather than varying with a fixed schedule.

Transmitting Utility (Transco)—This is a regulated entity that owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide nondiscriminatory connections, comparable service and cost recovery.

Unbundling—Disaggregating utility service into its basic components and offering each component separately for sale with separate rates for each component. For example in electric service, generation, transmission and distribution could be unbundled and offered as discrete services with separate payment for each.

Universal Service—Energy service sufficient for basic needs (an evolving bundle of basic services) available to and affordable by virtually all members of the population.

Utility—A regulated entity that exhibits the characteristics of a natural monopoly. For the purposes of the electric industry, "utility" generally refers to a regulated, vertically integrated monopoly electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system that serves retail customers.

Vertically Integrated Monopoly—A single entity (provider) which performs all of the basic functions of production, transportation and delivery. For example, in the electric industry a vertically integrated electric utility performs all three basic functions of generation (production), long distance transmission (transportation) and local distribution (delivery) of electrical energy to consumers.

Watt—The unit of measure for electric power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under pressure of one volt.

Weather normalized information—Information adjusted to remove fluctuation due to changes in weather.

Wholesale Competition—Power producers competing to sell their power to a variety of distribution companies.

Wholesale Power Market—The purchase and sale of electricity from generators to resellers (who sell to retail customers and/or other resellers) along with the ancillary services needed to maintain reliability and power quality at the transmission level.