Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

June 30, 2008

Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505

RE: NORTHERN STATES POWER COMPANY
ANNUAL 10-YEAR PLAN

Dear Ms. Jeffcoat-Sacco:

In accordance with Chapter 49-22 of the North Dakota Century Code, Northern States Power Company, a Minnesota corporation hereby submits 8 copies of its Annual Ten-Year Plan for Major Generation and Transmission Facilities in the state of North Dakota. The information contained in the report complies with the rules and regulations of the North Dakota Public Service Commission.

Notice of the filing has been given to each state agency and officer entitled to notice as designated in section 69-06-05 (see attached service list).

If you would like additional copies of the report, or if you have questions regarding information contained in the report, please feel free to contact Dave Sederquist at (701) 241-8632.

SINCERELY,

Rebecca Eilers

REBECCA EILERS
REGULATORY ADMINISTRATOR

ENCLOSURES
CC: SERVICE LIST (WITHOUT ENCLOSURES)

1 PU-08-423 Filed: 7/1/2008 Pages: 55
Ten Year Plan for Major Generation and Transmission Facilities

Northern States Power Company

CERTIFICATE OF SERVICE

I, Carole Wallace, hereby certify that I have this day served notice of the foregoing document on the attached list of persons by delivery by hand or by causing to be placed in the U.S. mail at Minneapolis, Minnesota.

NORTH DAKOTA TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

Dated this 30th day of June 2008

Carole Wallace

Northern States Power Company d/b/a Xcel Energy
2008 North Dakota Ten-Year Plan
Service List – Notice of Filing

Illona A. Jeffcoat-Sacco
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505

Department of Agriculture
State Capitol Building
600 East Boulevard Avenue
Bismarck, ND 58505

Department of Human Services
State Capitol Judicial Wing
600 East Boulevard Avenue
Bismarck, ND 58505

North Dakota Department of Commerce
Economic Development & Finance
1600 East Century Avenue, Suite 2
Bismarck, ND 58503

Governor's Office
State Capitol Building
600 East Boulevard Avenue
Bismarck, ND 58505

Attorney General
State Capitol Building
600 East Boulevard Avenue
Bismarck, ND 58505

Department of Health
State Capitol Building
2nd Floor Judicial Wing
600 East Boulevard Avenue
Bismarck, ND 58505

Department of Vocational Education
State Capitol Building, 15th Floor
600 East Boulevard Avenue
Bismarck, ND 58505

Energy Development Impact Office
PO Box 5523
Bismarck, ND 58506-5523

Game & Fish Department
100 North Bismarck Expressway
Bismarck, ND 58501

State Historical Society
Heritage Center
612 East Boulevard Avenue
Bismarck, ND 58505

Indian Affairs Commission
State Capitol Judicial Wing
600 East Boulevard Avenue
Bismarck, ND 58505

State Planning Division
State Capitol Building
600 East Boulevard Avenue
Bismarck, ND 58201

ND State Land Department
PO Box 5523
Bismarck, ND 58506-5523

State Water Commission
900 East Boulevard Avenue
Bismarck, ND 58502

North Dakota Parks and Recreation Department
1600 East Century Avenue, Suite 3
Bismarck, ND 58503

Job Service of North Dakota
PO Box 5507
Bismarck, ND 58502

Soil Conservation Committee
State Capitol Building
600 East Boulevard Avenue
Bismarck, ND 58505

Aeronautics Commission
PO Box 5020
Bismarck, ND 58502

North Dakota Department of Transportation
608 East Boulevard Avenue
Bismarck, ND 58505-0700

TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES

TO THE

NORTH DAKOTA
PUBLIC SERVICE COMMISSION

SUBMITTED BY
NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION
JULY 2008

Xcel Energy®

Northern States Power Company
North Dakota Ten-Year Plan 2008
Table of Contents

Existing Energy Conversion Facilities	Section A
Proposed Energy Conversion Facilities - Next Five Years	Section B
Proposed Energy Conversion Facilities - Next Ten Years	Section C
Existing Electric Transmission Facilities	Section D
Existing Pipeline Facilities	Section E
Proposed Electric Transmission Facilities - Next Five Years	Section F
Proposed Pipeline Facilities - Next Five Years	Section G
Proposed Electric Transmission and Pipeline Facilities - Next Ten Years	Section H
Regional Coordination	Section I
Environmental Information	Section J
Projected Demand for Service	Section K
Resource Plan Documents	Appendix A
Transmission Lines	Appendix B

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company" or "NSPM"), submits this North Dakota 10 Year Plan 2008 to the North Dakota Public Service Commission ("Commission" or "NDPSC") pursuant to Chapter 49-22 of the North Dakota Century Code.

SECTION A: EXISTING ENERGY CONVERSION FACILITIES

While the Company does not currently own energy conversion facilities in the State of North Dakota, the Company has power purchase agreements with power plants located in North Dakota. Minnkota Power Cooperative, Inc. provides the Company 100 MW each summer season from its rights in the Coyote #1 coal fired steam generating unit located in Beulah, North Dakota. Acciona Wind Energy USA provides the Company with 12 MW of wind energy from turbines located near Velva, North Dakota. Additionally, the Company has a transmission service agreement known as the "Stanton Displacement Agreement" in which 188 MW are supplied from Great River Energy's Stanton Unit, located in the vicinity of Stanton, North Dakota, for the Company's North Dakota loads.

SECTION B: PROPOSED ENERGY CONVERSION FACILITIES - NEXT FIVE YEARS

NSPM and Northern States Power Company, a Wisconsin corporation ("NSPW"), operate their upper midwest generation resources on a five-state integrated system basis (North Dakota, South Dakota, Minnesota, Wisconsin and Michigan). We identify our resource needs in our Resource Plan, the most recent of which was filed with the Minnesota Public Utilities Commission ("MPUC") on December 14, 2007, (Docket No. E002/RP-07-1572) and provided to the Commission shortly thereafter. The Commission took "administrative notice" of the plan on February 22, 2008. We are currently in the comment period on this MPUC docket. Appendix A provides the Executive Summary of the Company's 2007 Resource Plan proposal and our comments submitted June 16, 2008.

As stated in our 2007 Resource Plan, we propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership and power purchase agreements. This multipronged and flexible approach to resource acquisition allows us to consider multiple technologies and locations. We are currently pursuing efforts to construct or purchase at least 200 MW of wind power resources in North Dakota. However, at this time, we do not have definitive plans to construct additional electric generating facilities in the State of North Dakota within the next five years.

We are currently in the final stages of conducting our due diligence on 160 MW of peaking generation. The 2011 peaking resource need was identified and approved in our 2004 Resource Plan (MPUC Docket No. E002/RP-04-1752), and reconfirmed in our December 2007 Resource Plan filing. On December 17, 2007, Xcel Energy also issued a Request for Proposals ("RFP") to acquire up to 500 MW of wind energy through "build/transfer" arrangements. We are currently evaluating bids and conducting due diligence on a number of bids received. Because of confidentiality requirements in the bidding process, the Company cannot disclose the location of the bids; however no location requirements were set in the RFP.

On December 24, 2007, the MPUC issued a Certificate of Need in MPUC Docket No. E002/CN-07-873 for a Company-owned 100 MW wind farm (Grand Meadow) to be constructed near Austin, Minnesota. The Grand Meadow project is presently scheduled to be online no later than December 31, 2008, to take advantage of the federal Production Tax Credit ("PTC"). The Company also plans to acquire 500 MW of Community Based Renewable Energy Resources by 2010.

In addition, the Company is working to expand the capacity and extend the lives of several of our most strategic generating facilities, rather than replace those facilities with new – and more costly – generating facilities.

- As discussed in the 2007 Resource Plan, we are proceeding with upgrades at our Sherburne County ("Sherco") Generating Facility. The Sherco upgrades will result in up to 80 MW of additional base load capacity as well as significant updates to pollution control systems.

- On February 14, 2008, we also filed an application for a Certificate of Need for an extended power uprate at our Monticello nuclear generation plant (MPUC Docket No. E002/CN-08-185). This power uprate will result in 71 MW of additional base load capacity and associated energy.

- On May 16, 2008, we filed applications for two Certificates of Need involving our Prairie Island nuclear generating plant: one to implement an extended power uprate, and the second for additional dry cask storage to support life extension until 2033/2034 (MPUC Docket Nos. E002/CN-08-509 and E002/CN-08-510, respectively). The power uprate at Prairie Island will result in an additional 164 MW of additional base load capacity and associated energy.

- We continue with our rehabilitation and repowering of the Allen S. King plant located in Stillwater, Minnesota; the Riverside plant located in Minneapolis, Minnesota; and the High Bridge plant located in St. Paul, Minnesota. These projects are expected to increase Company-owned generating capacity by just over 400 MW. These upgrades are expected to be completed by May 2009.

In addition to the 400 MW from the repowering of King, Riverside and High Bridge, the Sherco, Monticello and Prairie Island power uprates will result in 315 MW of additional capacity at existing units, that will become available in the 2009 – 2015 timeframe.

SECTION C: PROPOSED ENERGY CONVERSION FACILITIES - NEXT TEN YEARS

At this time, the only plans that we have for generation facilities in the State of North Dakota in the next ten years are for wind energy conversion systems. The exact size and location(s) of such facilities is yet to be determined.

SECTION D: EXISTING ELECTRIC TRANSMISSION FACILITIES

Xcel Energy's existing electric transmission line facilities are listed in Appendix B. Xcel Energy has no plans to retire any electric transmission facilities in North Dakota within the next ten years.[1]

SECTION E: EXISTING PIPELINE FACILITIES

Xcel Energy operates an 11.9-mile intrastate natural gas pipeline facility in the State of North Dakota, from an interconnection with Williston Basin Interstate Pipeline Company near Mapleton, North Dakota to the Company's gas distribution system in Fargo. The Commission granted a Certificate of Public Convenience and Necessity and Corridor Certificate for this facility in Case No. PU-400-89-426. Xcel Energy has no plans to retire any intrastate natural gas pipeline facilities in North Dakota within the next ten years.

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1 On October 1, 2007, Xcel Energy and Great River Energy ("GRE") completed a tax free exchange of certain Xcel Energy-owned transmission and substation facilities in North Dakota and Minnesota for GRE-owned substation facilities in North Dakota and Minnesota, in order to better rationalize transmission facility ownership and operations. We submitted our filing seeking Commission approval of the proposed asset exhange on September 1, 2006 (Case No. PU-06-393). The filing was approved by the Commission on December 6, 2006.

SECTION F: PROPOSED ELECTRIC TRANSMISSION FACILITIES - NEXT FIVE YEARS

A group of investor-owned, cooperative and municipal utilities in eastern North Dakota, Minnesota, eastern South Dakota, and western Wisconsin, completed a high-level visionary study looking at the bulk transmission needs in their combined market areas over the next 15 years. This analysis, known as CapX 2020, identified the possible need for one or two 345 kV lines from western North Dakota to the Twin Cities. One of the lines proposed will pass through the Fargo area to serve growing energy needs in the Red River Valley.

From this vision study the CapX 2020 utilities developed more specific proposals for the first group of new high voltage lines needed, referred to as Group 1 projects. The Group 1 projects include three 345 kV projects, and one 230 kV project. The first of these facilities is proposed to be placed in service in 2011 and the other facilities will be placed into service over the following years ultimately completing in 2015. The approximate lengths and general location of the proposed lines are as follows:

- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota.
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota.
- A 230 mile, 345 kilovolt line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota, and Granite Falls, Minnesota.
- A 150 mile, 345 kilovolt line between the southeast Twin Cities, Rochester, Minnesota, and LaCrosse, Wisconsin.

Xcel Energy and Great River Energy filed a Certificate of Need application for the three 345 kV projects with the MPUC on August 16, 2007, in MPUC Docket No. ET2, E002/CN-06-1115. The Certificate of Need application is now being considered in public hearings and contested case hearings. A portion of the proposed Fargo - Twin Cities 345 kV project would be constructed in North Dakota. The CapX 2020 participants intend to submit a combined application for a Certificate of Public Convenience and Necessity to the Commission in July 2008. Corridor Certificate and Certificate of Site Compability applications will follow in December 2008. The 345 kV facilities are proposed to be in service by 2015, although that may be accelerated.

A Certificate of Need application for the 68 mile 230 kV project was filed with the MPUC on March 17, 2008, in MPUC Docket No. E017, E015, ET6/CN-07-1222. Even though it will be constructed entirely in Minnesota, this project has the potential to substantially improve load serving capability in the northeastern part of

North Dakota. The 230 kV project is proposed to be in service by 2011-2012.

The CapX 2020 Group 1 projects will benefit North Dakota by improving transmission infrastructure and reliability, alleviating existing delivery constraints, and expanding the transmission capability to allow expanded generation investment, including wind generation, in North Dakota.

More information about the CapX 2020 initiative is available at www.capx2020.com.

SECTION G: PROPOSED PIPELINE FACILITIES - NEXT FIVE YEARS

At this time we do not have plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next five years.

SECTION H: PROPOSED ELECTRIC TRANSMISSION AND PIPELINE FACILITIES - NEXT TEN YEARS

The previously discussed CapX 2020 vision plan identified the possible need for one or two 345 kV lines from western North Dakota to the Twin Cities in Minnesota. As a result of the Renewable Energy Standard ("RES") adopted by the 2007 Minnesota Legislature, the Minnesota Transmission Owners ("MTO"), a group of investor-owned, cooperative and municipal utilities who own 115 kV and above transmission in Minnesota, including the Company, commissioned a number of studies focused on meeting the RES and other generation and load serving needs through 2025. The studies to determine the transmission required for the next ten years are expected to be completed by the end of this year. The initial MTO studies and future updates will be available at the MTO website at: www.minnelectrictrans.com.

A high-level study to update the original CapX 2020 Vision Study to 2025 is expected to be completed early in 2009. This new Vision Study will incorporate rapidly changing trends, such as increasing the use of wind generation to fulfill RES requirements for Minnesota and the surrounding states, as well as proposals to increase power delieveries from Canada. It is possible additional bulk transmission will be proposed to be constructed in North Dakota as a result of these studies.

At this time, we do not foresee the need for any new intrastate natural gas pipeline transmission facilities in North Dakota in the next ten years.

SECTION I: REGIONAL COORDINATION

All major transmission planning performed by Xcel Energy is now coordinated through the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") on a regional basis, consistent with the Federal Energy Regulatory Commission ("FERC") orders dated: (a) May 2000, authorizing the transfer of functional control of the Company's high voltage transmission system to the Midwest ISO; (b) December 2001 finding the Midwest ISO to be the first FERC-approved regional transmission organization ("RTO"); and February 15, 2007 (Order No. 890), requiring RTOs and their member utilities to use coordinated regional transmission planning.[2] The Midwest ISO issues an annual Midwest ISO Tranmission Expansion Plan ("MTEP") after coordinated planning and stakeholder review. Prior to 2007, these plans were issued biennially. MTEP 2007 was approved by the Midwest ISO Board of Directors in December 13, 2007 and is available at the Midwest ISO web site at www.midwestiso.org.

The Midwest ISO is continuing the use of the existing subregional planning groups of the Mid-Continent Area Power Pool ("MAPP"), which coordinate the planning of the utilities within the MAPP region. This coordination applies to all NSPM facilities in North Dakota, South Dakota, and Minnesota and NSPW facilities in Wisconsin and Michigan.[3] As a result of complying with the FERC Order No. 890 rules, Midwest ISO has also implemented its own Sub-Regional Planning Meetings. The Company participates in the Western Region meetings. Midwest ISO coordinates these meetings with the Northern MAPP Sub-regional Planning Group ("SPG") meetings. Both of these groups provide forums for stakeholder input and coordination of plans and NSPM actively participates in each one. This joint planning is intended to maximize use of existing facilities and minimize the amount of new facilities. Additional regional planning coordination is provided by the Dakotas-Montana Power Suppliers Group.

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[2] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reh'g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). The Midwest ISO's Order No. 890 regional transmission planning process was conditionally accepted for filing in *Midwest Independent Transmission System Operator, Inc.*, 123 FERC ¶ 61,164 (May 15, 2008).

[3] NSPM and NSPW are members of MAPP, which continues to provide certain planning functions; and the Midwest Reliability Organization ("MRO"), which provides certain Regional Reliability Coordination ("RRC") functions required by the North American Electric Reliability Council ("NERC") and previously provided by MAPP. NSPM and NSPW are also participants in the Midwest Contingency Reserve Sharing Group Agreement ("Midwest CRSGA") administered by Midwest ISO. NSPM and NSPW withdrew from the MAPP Generation Reserve Sharing Pool ("MAPP GRSP") effective June 1, 2008. NSPM and NSPW now participate directly in the Midwest CRSGA rather than indirectly through the MAPP GRSP.

Another example of coordination by the utilities is the formalization of the MTO organization. The MTO consists of all transmission owning utilities in Minnesota. However, several MTO members (the Company, Great River Energy, Otter Tail Power, etc.) also own significant transmission in North Dakota. The MTO was formed to submit coordinated biennial transmission planning reports to the MPUC as required by Minn. Stat. 216B.2425. The MTO group is presently developing coordinated short-term regional plans and longer term (25 years) vision plans for the bulk transmission needs throughout the upper Midwest and the transmission required to meet the various states' Renewable Energy Standards. The MTO utilities also coordinate their planning with the CapX 2020 planning processes, the MAPP SPG processes and the Midwest ISO MTEP process.

SECTION J: ENVIRONMENTAL INFORMATION

Specific environmental information will be provided to the Commission in future regulatory filings when specific facilities are identified for construction.

SECTION K: PROJECTED DEMAND FOR SERVICE

NSPM and NSPW operate an integrated electric generation and transmission system (the "NSP System") serving customers in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan. The North Dakota portion of the NSP System 25-year historical native energy requirements and non-coincident peak demand are shown in Table Xcel Energy-ND-1. Xcel Energy produces long-range "median" NSP System forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, Xcel Energy also develops a bandwidth to supplement its "median" forecasts. These scenarios are intended to describe uncertainty in a business-as-usual context: a relatively narrow range of U.S. economic growth with no basic change in the relationship between the regional and national economies. Table Xcel Energy-1 shows the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. Table Xcel Energy-ND-2 shows the North Dakota portion of the NSP System forecast.

The forecast for the NSP System is based on forecasts of jurisdictional sales by major customer class: residential with and without space heating, small commercial and industrial ("SC&I"), and large commercial and industrial ("LC&I"). Each customer class is modeled independently for the five states included in the NSP system. The native energy requirements are determined by applying a loss factor on total sales.

The NSP System peak is apportioned to jurisdictions based on the native energy requirements by state and the load factor by state. Consequently, the summer and winter "peak loads" provided in Table Xcel Energy-ND-2 represent the North Dakota jurisdiction customer demand at time of the NSP System seasonal peak demand. This "coincident" demand is appropriate for generating capacity requirement forecasting.

It is important to note, however, that a "non-coincident" peak demand must be used in evaluating transmission capacity requirements. This is because the transmission system must be able to supply the full local customer demand at all times. Due to load diversity caused by weather variations within the multi-state NSP System, peak customer demands in Xcel Energy's North Dakota service areas can be as much as 25 percent higher than the demands registered during the hour in which the total system peak demand occurs. It is these local "non-coincident" peak demands that determine the need for transmission improvements required for load serving functions.

Table Xcel Energy-ND-1
Northern States Power Company
State of North Dakota
Historical Energy and Peak Load Requirements (1980 - 2007)

Year	Energy (GWh)	Annual Growth	Non-Coincident Peak Load (MW)	Annual Growth
1980	1,237	---	267	---
1981	1,265	2.3%	295	10.5%
1982	1,369	8.2%	275	-6.8%
1983	1,441	5.3%	308	12.0%
1984	1,484	3.0%	303	-1.6%
1985	1,544	4.0%	322	6.3%
1986	1,553	0.6%	311	-3.4%
1987	1,553	0.0%	312	0.3%
1988	1,658	6.8%	323	3.5%
1989	1,844	11.2%	374	15.8%
1990	1,904	3.3%	399	6.7%
1991	1,925	1.1%	373	-6.5%
1992	1,883	-2.2%	376	0.8%
1993	1,771	-5.9%	333	-11.4%
1994	1,796	1.4%	360	8.1%
1995	1,916	6.7%	362	0.6%
1996	1,984	3.5%	382	5.5%
1997	1,911	-3.7%	351	-8.1%
1998	1,958	2.5%	352	0.3%
1999	1,950	-0.4%	363	3.1%
2000	2,053	5.3%	370	1.9%
2001	2,048	-0.2%	384	3.9%
2002	2,119	3.5%	403	4.8%
2003	2,171	2.4%	395	-2.0%
2004	2,158	-0.6%	403	2.2%
2005	2,289	6.1%	426	5.7%
2006	2,353	2.8%	439	3.0%
2007	2,378	1.1%	463	5.5%

Table Xcel Energy-ND-2
Northern States Power Company
State of North Dakota
Forecast of Energy and Peak Load Requirements (2008 - 2026)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2008	2,343	351	382
2009	2,389	360	387
2010	2,418	368	391
2011	2,446	373	392
2012	2,476	379	394
2013	2,501	385	395
2014	2,527	390	396
2015	2,553	396	398
2016	2,580	401	399
2017	2,605	407	400
2018	2,631	413	402
2019	2,657	420	404
2020	2,685	427	406
2021	2,711	434	408
2022	2,740	441	410
2023	2,768	448	412
2024	2,798	455	415
2025	2,824	462	417
2026	2,853	470	419

Average Annual Growth Rate, 2008-2026:			
% growth:	**1.0%**	**1.5%**	**0.5%**

Notes:

1) Peak Load is ***coincident*** to the Xcel Energy system peak.
2) Winter Peak = MAPP Winter Peak season, 2008 is 2008-2009 winter peak.
3) Peak Load forecast growth from 2018 - 2026 is based on average summer and winter ND peak growth rates from 2008 through 2017.

Table Xcel Energy-1
Northern States Power Company
State of North Dakota
Forecast of NSP System Energy and Peak Load Requirements (2008 - 2026)

Year	Energy (GWh)	Summer Net Peak Load (MW)	Winter Net Peak Load (MW)
2008	47,762	8,857	7,034
2009	48,307	9,024	7,099
2010	48,633	9,154	7,118
2011	48,984	9,243	7,125
2012	49,532	9,365	7,155
2013	50,005	9,483	7,175
2014	50,464	9,600	7,195
2015	50,929	9,718	7,217
2016	51,410	9,836	7,235
2017	51,835	9,941	7,243
2018	52,262	10,045	7,249
2019	52,687	10,150	7,254
2020	53,140	10,282	7,249
2021	53,542	10,406	7,239
2022	53,969	10,536	7,231
2023	54,397	10,665	7,222
2024	54,840	10,796	7,213
2025	55,254	10,926	7,201
2026	55,696	11,061	7,190

Average Annual Growth Rate, 2008-2026:			
% growth:	**0.9%**	**1.2%**	**0.1%**

Notes:
1) Peak Load is ***coincident*** to the NSP System peak.
2) Winter Peak = MAPP Winter Peak season, 2008 is 2008-2009 winter peak.
3) Peak Load is the Net Peak (interruptible)

APPENDIX A

Xcel Energy's 2007 Resource Plan Executive Summary – December 14, 2007, including errata updates – April 9, 2008

Xcel Energy's comments to the MPUC regarding withdrawal from the Mid-Continent Area Power Pool Generation Reserve-Sharing Pool, the new reserve margin standards for the Midwest/MISO Planning Reserve Sharing Group, and the implications for the 2007 Resource Plan – June 16, 2008.

1. Executive Summary

Introduction

Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company"), submits to the Minnesota Public Utilities Commission ("MPUC" or "Commission") our 2007 Resource Plan covering the period 2008 – 2022 for consideration and approval. This Plan identifies how we propose to meet our customers' needs for capacity and energy while complying with significant new initiatives enacted by the 2007 Minnesota Legislature regarding renewable energy, demand-side management ("DSM"), and greenhouse gases.

The Minnesota Legislature has clearly specified an expansion path for new resources in the state, and we fully support this "Environmental Leadership" approach. We believe that a strong commitment to reducing the environmental impact of energy use and production is essential, offers an important hedge to future costs of increased environmental regulation, and can be accomplished while maintaining reasonable customer rates and reliable service. We thus support the goals and requirements adopted by the 2007 Minnesota Legislature, and believe they establish an appropriate path for us to pursue. This Resource Plan provides our proposal for achieving compliance while maintaining reasonable customer rates.

Like previous filings, then, this Plan presents our analysis of customer needs and resource options under a variety of assumptions. More so than other filings, however, this Plan is driven by our efforts to implement new legislative requirements, providing for 2600 MW of new wind resources, increased DSM goals of approximately 30 percent energy savings and 50 percent demand savings, and a 22 percent, 6-million ton reduction in carbon emissions by 2020. Compliance with these requirements results in significant changes in our resource needs from previous Plans – most notably, the elimination of the incremental, 375-MW base load need identified in our 2004 Resource Plan due to the significant additions of wind energy on our system needed to comply with the Renewable Energy Standard ("RES"). As a result, the composition of needed resources for our system has changed, and our preferred path now imposes far fewer environmental costs than previous plans have suggested.

To ensure we comply with these new legislative requirements in an efficient and cost-effective manner, it is critical that we implement an effective resource acquisition process, building on the acquisition process adopted in our 2004 Resource Plan. To this end, we present a long-term view of our system needs, our proposals for meeting those needs while complying with legislative requirements, and a process for addressing the contingencies that will inevitably arise.

Thus, our 2007 Resource Plan includes:

- *A new forecast that projects a need for additional capacity and energy.* This forecast anticipates annual energy growth of approximately 1% at the median forecast and approximately 1% annual demand growth at the 90% forecast level over the planning horizon. While lower than previous forecasts due to expanded DSM efforts, this load growth will require the addition of approximately 3200 nameplate rated MW of non-wind resources on our system by 2022.

- *The addition of up to 2600 MW of new wind resources by 2020 to meet our renewable requirements.* Minn. Stat. § 216B.1691 provides that we generate or procure renewable resources to meet milestones for renewable energy amounting to a total of 30 percent of retail sales by 2020, at least 25 percent of which must be wind energy. Consistent with Subdivision 7 of that statute, we have also proposed our approach for acquiring these significant wind resources in an efficient and effective manner that will maintain reasonable rates for customers.

- *A plan to meet the Energy Conservation Policy Goal beginning in 2010, as provided by Minn. Stat. §216B.2401.* This statute provides that we are to attempt to achieve annual energy savings equal to 1.5 percent of annual retail energy sales of electricity directly (through energy conservation improvement programs and rate design) and indirectly (through energy codes, appliance standards, and other means). This Plan presents our assessment of the economic potential for additional savings on our system and our initial proposal for addressing the expanded statutory requirements for DSM. The specific programs to achieve these goals need to be developed and approved as part of the Company's 2010 Conservation Improvement Program ("CIP") filing.

- *Retention of existing resources and capacity expansions where appropriate.* Given our customers' significant need for new resources, retaining and expanding the value of existing assets is important to ensuring reasonable costs for our customers. Our existing fleet is located at strategic points on our system that must be maintained for reliability and take the best advantage of existing transmission resources. Our Plan calls for retention and expansion of our nuclear fleet, key coal-fired units, and aging peaking facilities, where appropriate. Our proposals accomplish these expansions in a manner that still achieves the carbon-reduction goals adopted by the 2007 Legislature.

- *Plans to efficiently acquire and install the ~~2600~~ <u>2300</u> MW of intermediate and peaking resources needed to support the additional wind resources and meet our customers' growing needs.* Combined, the load reductions that will be achieved from expanded DSM efforts and energy production provided by new wind resources change the type and timing of new resources needed on our system. Given the intermittent nature of wind energy and increasing peak-day requirements, supporting the reliability of our system will require significant additions of peaking capacity, as well as additional intermediate capacity. When combined with our planned wind additions, these resources offer the most reasonable cost path for new additions. We propose a plan for developing and acquiring such peaking and intermediate resources in a timely and efficient manner, making the most effective use of available transmission resources and retaining the use of the two-track resource acquisition process adopted in our 2004 Resource Plan.

- *A resource mix that will achieve Minnesota's goal for carbon reductions by 2020.* Our modeling suggests that implementation of our Plan will ensure our compliance with the state's carbon-reduction milestones, providing a 22-percent (6-million ton) reduction in CO_2 emissions from 2005 levels by 2020. Achieving the longer-term goals will be challenging, as we have fewer opportunities for reductions in fossil-fuel use on our system after that point. Nonetheless, we are committed to working to achieve the state's goals of carbon management and reduction in fossil-fuel use, and will continue to work with stakeholders to that end going forward.

Combined, we think our Plan sets forth an appropriate path for meeting our customers' needs in an efficient and effective manner while accomplishing the Environmental Leadership approach adopted by the State and supported by the Company. We welcome discussion of our Plan with all stakeholders.

Five-Year Action Plan

To successfully ensure our compliance with new statutory requirements, acquire sufficient resources to meet our customers' needs, and maintain reliable service at reasonable rates, we propose the following five-year Action Plan:

- *Significantly increase DSM goals to meet legislative requirements.* To date, we have been successful in meeting the goals established in previous Resource Plans; however, we believe that it will be more challenging to meet the new legislative goals. This Plan presents our assessment of economic potential on our system, consistent with the statute. Based on our evaluation, we propose to achieve 1.1 percent annual savings, and will continue to explore means of expanding this goal in the future through both expanded customer programs and system infrastructure investments.

- *Install sufficient renewables to meet the state Renewable Energy Standard.* We are committed to meeting the RES, and estimate it will require the addition of approximately 2600 MW of new wind resources on our system by 2020. In our Renewable Energy Plan, we have provided our plan for complying with the RES, outlining our proposal for utility-owned resources, Community-Based Energy Development ("C-BED"), and purchases from third parties to fulfill these requirements. We expect to issue our solicitation for new proposals shortly, and will continue to negotiate with C-BED providers to ensure our compliance with near-term RES milestones.

- *To permit continued operation of our nuclear plants, obtain NRC license extensions and Certificates of Need for a 20-year life extension and power uprates at Prairie Island ("PI") nuclear generating units 1 and 2 and Monticello.* Our analysis shows that relicensing and continued operation of our nuclear fleet will save customers approximately $1.1 billion over the 20-year license extension period. We plan to file an application for a Certificate of Need for a 71 MW power uprate at our Monticello plant in early 2008, as well as Certificates of Need for both life extension and power uprates at PI 1 and 2 by Spring 2008.

- *Pursue capacity expansion at our three Sherco coal-fired units.* Our analysis confirms that additional capacity at our Sherco plant remains cost-effective and should be pursued. This Resource Plan seeks approval of the 17 MW project at Sherco 3, and we intend to file separately for approval of an Emissions Reduction Project for environmental improvements and 69 MW capacity expansion at Sherco 1 and 2. To offset the slight increase in carbon emissions due to these capacity expansions, we offer reductions from our Black Dog coal-fired plant or other system resources, which will be detailed in our upcoming filing. In this way, we can keep this portion of our expansion path carbon-neutral, furthering our overall effort to comply with the state's carbon management goals while meeting increasing customer needs.

- *Investigate and pursue repowering as appropriate to retain and maximize the value of our existing fleet.* Our Metropolitan Emissions Reduction Project ("MERP") offered a great opportunity for reducing emissions while extending the useful life of important system resources. We will continue to pursue potential repowering and life-extension projects and propose them for implementation, if appropriate. Our Black Dog plant offers one such possibility, which we intend to further study as a potential future proposal. In addition, we intend to explore contract negotiations for continued refuse-derived fuel for our Red Wing and Wilmarth plants to determine the future of those facilities.

- *Initiate a new proceeding for approval of a 375 MW intermediate and 350 MW peaking contract with Manitoba Hydro beginning in 2015.* While our Resource Plan no longer indicates a need for additional base load resources beyond investments in our existing fleet, it does indicate substantial need for peaking and intermediate resources. Our analysis confirms that our proposed term sheet with Manitoba Hydro, currently offered for approval in a separate proceeding (Docket No. E-002/CN-06-1581), is a cost-effective resource and fills an important need for intermediate and peaking resources during the planning period. Because the underlying nature of the identified need has substantially changed from the 2004 Resource Plan, we propose to close the on-going proceeding and initiate a new proceeding pursuant to the two-track resource acquisition process approved by the Commission in conjunction with our prior Plan. We believe this new process would be more efficient were we to complete contract negotiations and initiate the new proceeding with the filing of a proposed purchased power agreement. We expect to make such a filing by Fall 2008. We present in greater detail our proposal for addressing the ongoing proceeding under separate cover, as required by the Commission's Order in Docket Nos.E-002/RP-04-1752, E-002/M-07-2, and E-002/CN-06-1581.

- *Initiate proceedings for up to 320 MW of new peaking resources for 2012 and 600 MW of intermediate resources by 2015.* While the timing and amount of additional resources depends on the timing of wind acquisitions, we project the need for substantial additional resources relatively early in the planning period. Because we believe that these resources would be integrated on our system most efficiently and effectively in a coordinated, planned basis -- such as through the development of an energy campus strategically located on our system -- we expect to propose to develop and construct many of these facilities using the two-track resource acquisition process. Our Action Plan proposes to initiate these near-term processes in late 2008 and 2009, respectively, to ensure the resources are developed in time to meet projected system requirements.

- *Continue and support efforts to ensure that sufficient transmission resources are available to get needed generation to load.* While federal regulatory requirements separate generation from transmission, both are needed to serve customer needs. Our experience with bidding demonstrates the significant influence transmission access and availability has on our resource selection. Given the significant need projected for the planning period, it is important that adequate transmission is developed in a timely fashion. We plan to continue our advocacy before state and federal regulatory bodies to encourage transmission planning and investment, to work with the Midwest Independent Transmission System Operator ("MISO") to facilitate interconnection of resources, and to work with regional utilities to ensure appropriate planning and investments are made. CapX2020's Application for a Certificate of Need for additional transmission resources, currently pending before the Commission, should help ensure a robust transmission network to reliably meet projected needs.

While these actions seek to implement our preferred course, we recognize the uncertainty over whether all components will be approved and successfully accomplished. Therefore, we have also developed plans to help hedge this risk, making available options that will allow us to best meet our customers' needs. These plans include:

- *Acquisition of resources through the approved resource acquisition process in the event of a projected supply shortfall, and delay, elimination, or reduction of resource acquisitions in the event of projected supply surplus.* In the event any approved resource is not developed and available to meet projected needs on a timely basis -- for example, should a selected resource fail to obtain needed permitting -- we propose to pursue resource acquisitions according to a hierarchy described in this Plan to address the shortfall. We would make the appropriate regulatory filings under our approved resource acquisition process to secure these resources to implement these contingency plans, as needed. Likewise, in the event we anticipate lower needs, such as if our DSM efforts achieve greater success than anticipated by this Plan, we would delay, reduce or cancel planned acquisitions as appropriate. In this way, we retain the flexibility to adapt to changing system requirements in an appropriate manner.

- *Conduct periodic assessments to consider the combined impacts of the many events that will be occurring on our system.* As always, we will continue to carefully monitor developments affecting our system. To the extent that we need to respond to a development in a way not addressed by this Resource Plan, we will file with the Commission under Minn. Rule 7543.0500, subd.5, for a notice of changed circumstance. Careful monitoring and prompt action will be required to ensure we successfully manage resources during this period of continuing market development and change.

We believe this comprehensive Action Plan will result in a robust, diverse, and reasonable-cost system for providing electricity service to our customers. Our Plan relies on a variety of resources to meet our customers' needs, is designed to fulfill all statutory requirements, and strikes a reasonable balance among competing objectives. We respectfully request that the Commission approve our Plan, and welcome the opportunity to engage in a constructive dialogue with all stakeholders to ensure a sound energy future for our customers.

Chapter Summaries

To assist in understanding the key components of our proposed Resource Plan, we provide the following summaries of each chapter of this filing.

Landscape

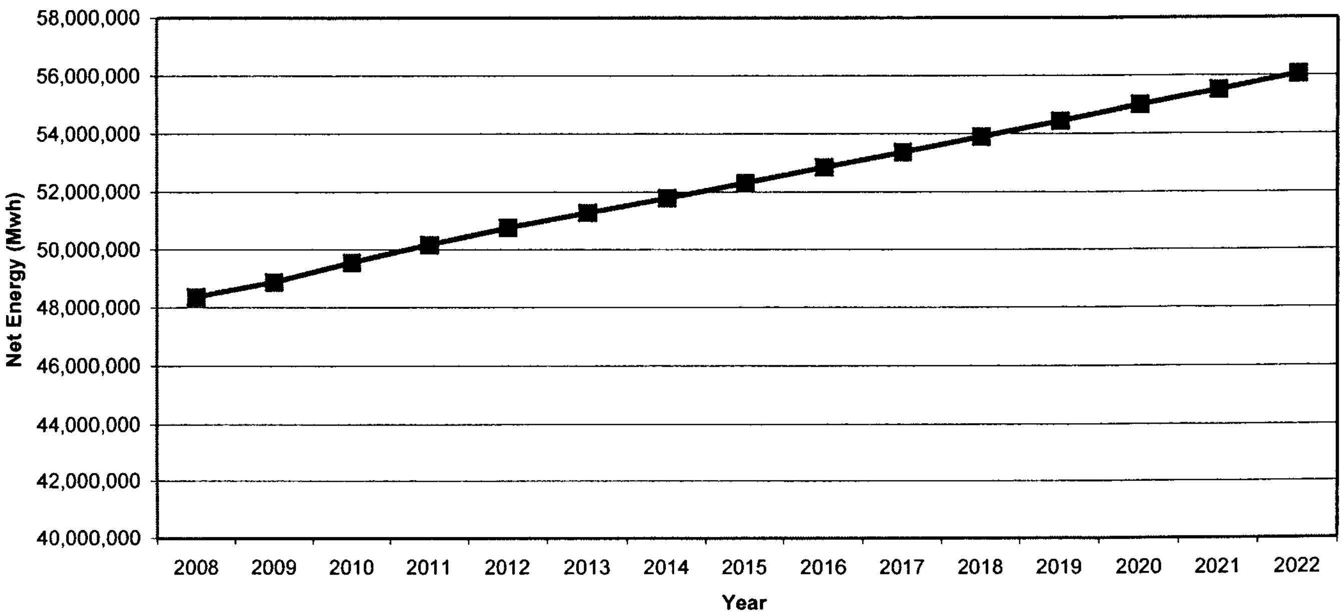
This chapter provides an overview of the context for this Resource Plan, including a summary of the major legislative initiatives enacted in 2007 and Xcel Energy's overall business plan. This context is important to our Plan, as new initiatives such as the RES and Next Generation Energy Act (addressing C-BED, DSM, and climate change) help drive our Plan.

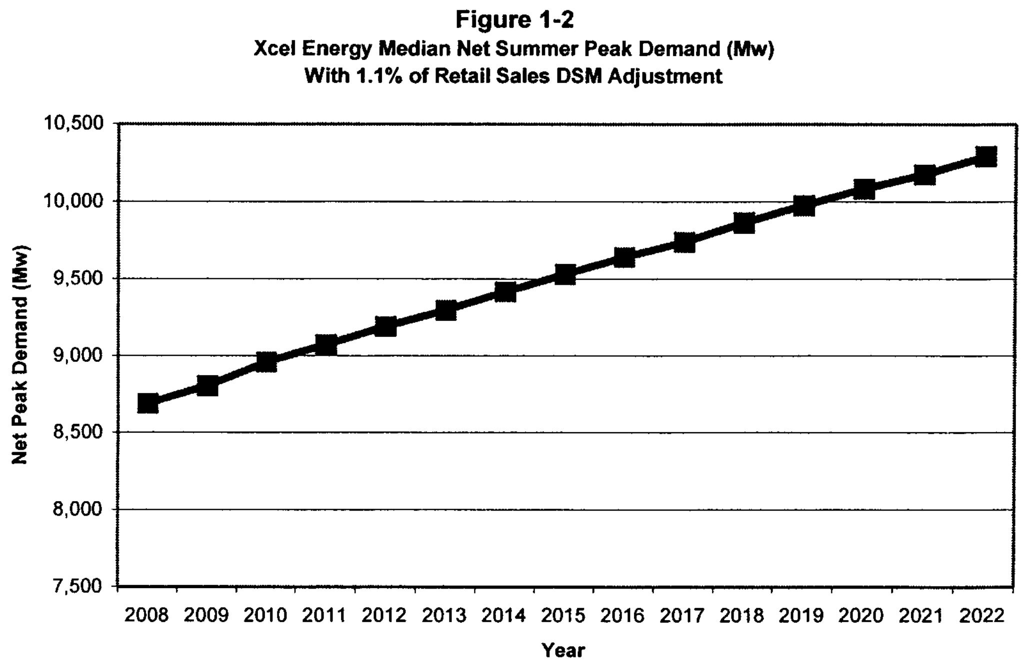
Forecast

A resource plan begins with a projection of customer demand for capacity and energy over the planning horizon. This chapter outlines our forecasting methods and results. In it, we discuss the reflection of various methodology changes discussed with the Department since our last Resource Plan and further explain our methods and approach. Our forecast projects annual energy growth of approximately one percent based on the median forecast for the planning period and annual demand growth rate of approximately one percent at a 90 percent forecast level. As explained in this chapter, we believe using this 90 percent confidence interval for forecasted demand is important to ensuring we have met our planning obligations to MISO and the Mid-Continent Area Power Power ("MAPP").

Our forecast for energy and capacity over the planning period is as follows:

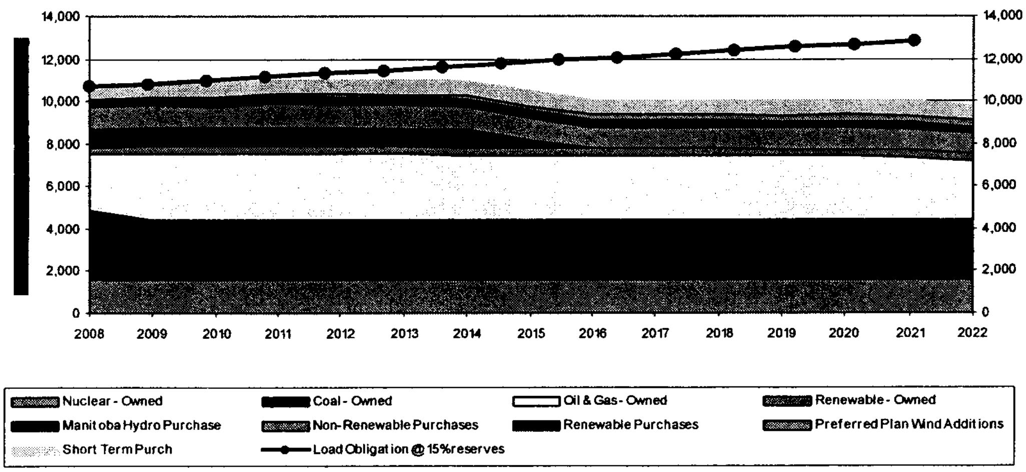
Figure 1-1
Median Net Energy (Mwh)
With 1.1% of Retail Sales DSM Adjustment





In addition, we compare the forecasted need to our current capabilities, identifying the overall resource need to be met over the planning horizon:

Figure 1-3
Requirements and Resources 2008-2022



Based on this comparison, we anticipate the need for additional generating resources starting in 2012, and reaching approximately ~~3200~~3300 nameplate rated MW by 2022.

Modeling and Preferred Plan

Sound analysis is critical to developing an appropriate Plan. In this chapter, we present our analytical methods and approach, identifying the various risks posed during the planning horizon and our comparative analyses to reflect them.

We began our modeling using a number of assumptions regarding the forecast, existing resources, renewable energy, and environmental externalities. We then modeled a number of scenarios varying these assumptions to test sensitivities. This modeling information provides a foundation of how different acquisition and customer growth scenarios will affect our resource needs. Because of the significant amounts of wind resources we will be adding over the planning period, the model results as well as our experience point to the need to acquire significant intermediate and peaking resources. Wind energy will significantly increase, providing large amounts of future energy, while new peaking resources will be required to provide complementary capacity and wind-following capability. As a result, these peaking and intermediate resources should only moderately add to our use of natural gas to supply electric energy, but will add to the amount of gas-fired capacity available to meet peak requirements. Based on our analysis, experience and judgment, we propose the following Preferred Plan:

Table 1-4
2007 Preferred Plan

Preferred Plan	PVRR	$60,054,763	($000)		
	Planned Additions	**Combined Cycle**	**Combustion Turbine**	**Pulverized Coal With CO2 Sequestraition**	**Wind Additions**
2008		High Bridge CC 624MW			
2009	Rahr 12MW	Riverside CC 508MW			100MW CBED 209MW Grand Meadows 100MW
2010					200 MW
2011	Monticello 68MW		160MW		200MW CBED 200MW
2012	Sherco 2 30MW Sherco 3 10MW		320 MW		200 MW
2013	Sherco 1 44MW PI 1 83MW	Black Dog 300MW			200 MW
2014					200 MW
2015	Manitoba Hydro 375MW Manitoba Hydro DIV 350 PI 2 87MW	600 MW			200 MW
2016					200 MW
2017					200 MW
2018		600 MW			200 MW
2019					200 MW
2020					200 MW
2021	Manitoba Hydro 125MW				
2022		600 MW			100 MW

To assess the robustness of our Plan, we performed several scenarios that tested the impact in terms of costs and environmental impacts of various other potential
resources into the Plan. We show the resulting PVRRs of those scenarios in the following table:

Table 1-5

Preferred Plan PVRRs and Alternative PVRR Differences ($millions)

	Base Assumptions	Low Load	High Load	Coal + 20%	Gas +20%	Nuclear+20%	Coal-20%	Gas-20%	Nuclear-20%	Externalities High	Externalities Low	CO2 $9	CO2 $40	MISO ON	Capital Cost ecsl 3%	Capital Cost escl 5%
Preferred Plan	60,055	58,829	61,572	60,925	62,657	60,423	59,187	58,272	59,759	60,179	60,235	55,808	67,691	59,981	61,498	64,871
Pref. Plan minus Peakers	460	462	460	460	481	460	460	439	460	460	460	460	474	456	442	396
Pref. Plan minus Sherco Upgrades	196	183	214	183	283	196	210	124	196	196	195	225	157	144	191	182
Pref. Plan minus Monticello Upgrade	333	325	342	338	377	321	328	285	344	334	334	294	410	301	332	328
Pref. Plan minus Prairie Island Upgrades	589	571	610	599	689	574	580	486	603	591	592	504	752	546	575	543
Pref. Plan minus Manitoba Hydro	235	233	235	239	310	235	231	155	235	236	236	185	326	210	231	214
Pref. Plan minus Black Dog	982	1,009	947	1,033	804	982	918	1,126	982	996	1,002	884	1,186	1,015	1,007	1,065
Pref. Plan with DSM 1.3%	(547)	(545)	(546)	(554)	(720)	(547)	(541)	(444)	(547)	(549)	(550)	(457)	(707)	(528)	(580)	(647)

Finally, given the rapidly changing marketplace, we believe contingency planning and flexibility is needed to take appropriate, responsive action should selected resources fail to be developed or are otherwise delayed. To that end, we propose a contingency plan that preserves the ability to meet our obligation to serve customers -- including constructing our own facilities -- subject to appropriate regulatory approvals.

Renewables

This chapter discusses our planned efforts to acquire renewable energy to comply with the RES, which is central to our overall Plan. In it, we provide an overview of our Renewable Energy Plan, submitted on December 10, 2007 in compliance with 2007 Session Laws, Chapter 136, Section 10. That plan sets forth our renewable resource acquisition strategy for meeting near-term RES milestones, and outlines our vision for achieving greater balance in our total renewable energy portfolio, striving for utility owned, C-BED, and purchased wind energy in relatively comparable proportions. The Renewable Energy Plan describes our intent to solicit proposals for up to 500 MW of wind energy, allowing us to acquire resources as a hedge for ensuring compliance with initial RES milestones while gaining better knowledge to support future development. We will also continue to work with C-BED developers to provide an initial 500 MW of C-BED by 2010.

This chapter also provides further analysis of the cost and other implications associated with our planned acquisition of renewable resources. Our Plan contemplates the addition of approximately 3,000 MWs of nameplate wind between 2008 and 2022, and our modeling indicates that these are the lowest cost available resources. To formulate the costs for this scenario, we assumed that the Federal Production Tax Credit ("PTC") for wind would be available until 2015, and note that the future of the PTC and transmission access and availability are key and require on-going monitoring and advocacy to support our efforts to meet the RES.

Existing Fossil and Refuse Derived Fuel Resources

As evidenced by our MERP project, now well into the construction and completion phases, we believe that it is critical to retain and maximize the value of our existing fleet. This chapter provides an overview of our existing fossil and refuse derived fuel plants, discusses their place in our analysis, and provides information regarding our on-going evaluation of retirements and repowering. We expect to continue to operate all of our existing resources, except as noted throughout the planning period and have reflected in our analysis additional investments needed to support continued operation. We note that some of these resources are good candidates for refurbishment or repowering. In particular, we will be doing life extension and environmental projects at our Sherco Plant, and will be evaluating options for the remaining coal-fired units at our Black Dog plant. We will continue to perform maintenance and monitoring activities at all other existing plants to ensure that we can operate them as long as it makes economic sense. We will continue to evaluate these issues and will bring any proposals to the Commission as they become more fully developed.

New Resources

Our Plan anticipates that we will require significant amounts of natural gas peaking and intermediate capacity over the planning horizon. We expect that some additional capacity could be developed at existing sites, but will also seek to establish "energy campuses" in conjunction with other generation facilities and potentially allow for development of biofuels, battery storage and other concepts. The purpose of an energy campus is to locate these needed resources close to the intermittent wind resources they are intended to support and near natural gas and transmission lines to take advantage of the fuel and delivery systems. We believe such a coordinated effort will provide the most cost-effective combination of resources for our customers.

This chapter also discusses the appropriate level, cost and available storage of natural gas-fired capacity on our system. Natural gas plants can offer benefit to a utility's portfolio due to its lower capital costs and operating flexibility, particularly when used to meet peaking or intermediate needs or to support intermittent resources such as wind energy. However, as the Commission is well aware, natural gas prices have risen over the past several years and have become quite volatile. Determining the appropriate role for natural gas-fired resources on our system is important for the development of this Plan.

As discussed in this chapter, our analysis indicates that our overall portfolio will benefit from the addition of natural gas resources to support the new wind developments, as the wind/natural gas combination provides needed capacity and energy at lower overall costs than other available alternatives. In addition, our analysis indicates that while the share of natural gas capacity in our portfolio would increase from 29 to 40 percent over the planning horizon, the amount of natural gas used to generate electricity would increase from approximately 8 to 13 percent. This result occurs because the anticipated wind resources will supply large portions of our overall energy needs, thus the natural gas resources would generate electricity for relatively few hours of the year.

Finally, our Plan does not call for any new, coal-fired generation for the foreseeable future, as our analysis indicates such resources are not cost-effective for our system at this time, particularly since we believe carbon capture and sequestration must be included for any new coal resources. In our view, failure to reflect the costs of carbon capture and sequestration in the evaluation of new coal facilities would leave customers open to substantial risk of higher costs due to potential future carbon regulation.

Nuclear

Retaining the benefits of our nuclear fleet is a key component of our Plan. This chapter presents our analysis of the value of life extension and power uprates at these facilities, assesses various replacement alternatives, and outlines our plan for pursuing relicensing for the Prairie Island units and power uprates at both PI and Monticello through upcoming regulatory filings.

Because the Company does not currently see a need to add new base load resources beyond those provided by investments in our existing fleet, we are not planning any new nuclear plants. While we believe new nuclear generation may offer promise because it does not contribute to greenhouse gases, it is not currently in our plans.

DSM

This chapter presents our analysis of the cost-effectiveness of additional DSM. The 2007 DSM legislation requires a significantly higher DSM rate than we have traditionally achieved, even though our current programs are among the most aggressive in the nation. While consistently we have captured 0.6 to 0.8 percent of our retail sales levels in energy efficiency savings, the Next Generation Energy Act sets a goal of 1.5 percent energy savings and requires a minimum goal of one percent, pending approval from the Commissioner of the Department of Commerce.

To achieve these aggressive goals, we need to modify our approach to delivering conservation programs. At this time, we have not yet fully determined the feasibility of achieving these goals or developed a detailed implementation plan. However, our analysis indicates that energy savings of 1.1 percent are achievable and sustainable over the planning period, and we expect to propose this level to the Commissioner for approval. We thus believe it is appropriate to adopt this level for planning purposes, and will continue to work to expand our goals as our plans develop.

Distributed Generation

We have previously studied the potential for distributed generation on our system, but distributed generation resources have not been a significant part of our resource mix to date. This outlines new studies in hopes that we can obtain more of this valuable resource in the future.

Environment

This chapter outlines how we intend to meet the carbon management and reduction goals. Because of the diversity of our system, we are able to present a resource plan that will manage and reduce our carbon emissions. The chapter also presents a status report on environmental regulations and our compliance with regulations and various Commission Orders regarding environmental issues.

Transmission

Detailed transmission planning now takes place in the Minnesota Transmission Planning Process, which takes place every two years. In conjunction with other transmission-owning utilities in the state, we submitted a Biennial Transmission Plan to the Commission on November 1, 2007. This chapter offers a summary of that plan and outlines how the addition of transmission and our renewable energy goal coincide. We believe transmission infrastructure is on track for our earliest milestones, but critical work and evaluation will be necessary for future renewable energy standard milestones. The CapX 2020 initiative and coordinated transmission study will help provide this critical information to allow us to continue to add renewable energy successfully.

Compliance

In this chapter, we review the various Commission Orders, legislation and administrative rules that provide requirements for this plan. We include a matrix listing of these various requirements to facilitate the compliance review of our Plan.

Conclusion

This Plan offers a great opportunity to implement our shared vision with the state for a sustainable energy future. While implementation of these aggressive goals will be challenging, we are well prepared to craft new approaches to meeting those challenges.

We offer a comprehensive Action Plan to set us on course for implementing this vision. Our Plan will ensure we implement the sizable amount of new resources required to meet our customers' growing needs, meet new environmental challenges and requirements, and adapt to changing circumstances as they arise. Implementation of our Plan will ensure a robust, diverse, and reliable system to provide reasonably priced, environmentally sound electricity to our customers.

We welcome consideration of our Plan, and look forward to dialogue with stakeholders.

Xcel Energy®

414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

June 16, 2008

- VIA ELECTRONIC FILING -

Burl W. Haar
Executive Secretary
Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101-2147

RE: RESOURCE PLAN COMMENTS
DOCKET NO. E002/RP-07-1572

Dear Dr. Haar:

Northern States Power, a Minnesota corporation, respectfully submits the attached Comments to the 2007 Resource Plan. Please direct any questions regarding this filing to me at (612) 330-7975.

Respectfully Submitted,

Sara Cardwell

SARA CARDWELL
MANAGER, REGULATORY ADMINISTRATION

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
David Boyd	Commissioner
J. Dennis O'Brien	Commissioner
Thomas Pugh	Commissioner
Phyllis Reha	Commissioner

IN THE MATTER OF NORTHERN STATES POWER COMPANY'S, A MINNESOTA CORPORATION, APPLICATION FOR RESOURCE PLAN APPROVAL 2008-2022

DOCKET NO. E002/RP-07-1572

COMMENTS

INTRODUCTION

Northern States Power Company ("Xcel Energy" or the "Company"), a Minnesota corporation submits to the Minnesota Public Utilities Commission ("Commission") these comments regarding our Application for Resource Plan Approval 2008 – 2022. These comments address Xcel Energy's withdrawal from the Mid-Continent Area Power Pool ("MAPP") Generation Reserve-Sharing Pool ("GRSP"), the new reserve margin standards for the Midwest/MISO Planning Reserve Sharing Group ("PRSG"), and the implications for our 2007 Resource Plan.

Chapter 4 of our 2007 Resource Plan foreshadowed the Company's transition from MAPP to the Midwest/MISO PRSG and provided an early estimate of what the impact may be. However at the time of the Resource Plan filing, many of the variables used to calculate resource adequacy under the Midwest/MISO PRSG were not precisely defined. The information we are providing in these comments is based on a more up-to-date analysis, utilizing assumptions that have been finalized.

As we discuss below, although the change from the MAPP to the Midwest/MISO PRSG entails many modifications to the assumptions used in calculating our total capacity obligation, this update indicates that only a minor adjustment to our preferred expansion plan is needed. Specifically, new reserve margin requirement will necessitate only a minor adjustment to our short-term capacity purchases. The other elements of our Preferred Plan remain unchanged and the impact on the Present Value of Revenue Requirements ("PVRR") is small.

A. MID-CONTINENT AREA POWER POOL (MAPP) GENERATION RESERVE-SHARING POOL (GRSP)

For the 2007 Resource Plan, Xcel Energy used reserve margin assumptions based on continued membership in the MAPP GRSP. These assumptions included a 15% reserve margin, a 90/10 peak forecast, capacity accreditation based on Uniform Rating of Generation Equipment ("URGE"), and an annual target of 750 MW for short-term capacity purchases.

MAPP's 15% reserve margin was a result of a study conducted by MAPP in 2003 that analyzed outage rates, load diversity, forecast uncertainty, and transmission interconnections and was approved by the Regional Reliability Council in the Spring of 2004.

In MAPP, reserve margins are applied to actual observed peak loads to derive the total capacity obligation. If accredited capacity is below the calculated obligation, the Company is required to purchase *Reserve Capacity Deficiency Service, Schedule* B retrospectively to make up the difference. Schedule B capacity is significantly more expensive than market capacity. In order to avoid Schedule B capacity purchases we have historically planned to have sufficient capacity to cover our 90/10 peak forecast plus a 15% reserve. The 90/10 forecast is approximately 6% higher than the median, or a 50/50 forecast.

For accreditation of thermal resources, the MAPP GRSP specifies the use of URGE. Part of this rating methodology specifies that a unit's capacity should be measured under "average conditions of operation." The use of average summer weather conditions results in higher capacity ratings than would be achievable during extremely hot conditions that normally occur during the summer peak demand periods. Hydro units also receive favorable accreditation under MAPP rules. Hydro units are accredited based on the maximum amount of pooling available, even if this amount is not sustainable over a multi day period.

To comply with the MAPP GRSP standards, we have historically included a target of 750 MW for short-term capacity in our resource plans. The actual levels of short-term purchases vary from year to year to adjust for unexpected changes in load forecasts and total capacity. The 750 MW was selected based on the level of firm transmission paths that Xcel Energy either controlled or had a reasonable expectation we could access. Purchasing short-term capacity provides some flexibility in our portfolio, but does not provide the same level of system reliability as do owned units and long-term PPAs.

Table 1 provides a summary of loads and resources from Xcel Energy's Preferred Plan as provided in Chapter 4 of our Application for Resource Plan Approval 2008 – 2022.

Table 1 – 2007 IRP Preferred Plan – Load & Resources

2007 IRP - 90/10 Peak, 15%RM, URGE Capacity

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
90/10 Peak	10,392	10,584	10,882	11,142	11,382	11,614	11,873	12,102	12,359	12,588	12,848	13,090	13,347	13,581	13,857
DSM	-90	-138	-253	-370	-488	-608	-729	-852	-976	-1,102	-1,229	-1,358	-1,488	-1,619	-1,752
Load Management	-984	-1,012	-1,036	-1,054	-1,055	-1,052	-1,048	-1,045	-1,042	-1,038	-1,035	-1,031	-1,028	-1,025	-1,021
Net Peak	9,318	9,434	9,593	9,719	9,838	9,954	10,095	10,205	10,341	10,448	10,584	10,701	10,832	10,937	11,084
15% Reserve Margin	1,398	1,415	1,439	1,458	1,476	1,493	1,514	1,531	1,551	1,567	1,588	1,605	1,625	1,641	1,663
Total Obligation	10,716	10,849	11,032	11,176	11,314	11,447	11,609	11,736	11,892	12,015	12,172	12,306	12,456	12,578	12,746
2007 URGE															
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Coal	3,307	2,931	2,931	2,756	2,649	2,693	2,693	2,693	2,593	2,593	2,593	2,593	2,593	2,593	2,593
Nuclear	1,612	1,651	1,661	1,699	1,699	1,773	1,775	1,850	1,849	1,849	1,849	1,849	1,849	1,849	1,849
Bio	304	316	316	316	316	275	272	272	272	272	239	239	234	206	206
CC	1,337	1,783	1,783	1,783	1,783	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035	2,035
CT	1,720	1,720	1,720	1,720	1,720	1,705	1,642	1,642	1,642	1,642	1,642	1,581	1,581	1,581	1,366
Oil	442	442	442	442	442	442	442	442	442	442	442	442	442	442	442
Wind	141	191	216	268	293	314	340	368	391	419	448	461	483	482	494
Hydro	306	288	288	288	288	288	288	288	288	285	285	285	285	285	275
MH & GRE	900	900	850	850	850	850	850	760	760	760	760	760	760	885	885
Short Term	644	639	837	923	853	750	850	750	750	750	750	750	750	750	750
CT 2011	-	-	-	143	143	143	143	143	143	143	143	143	143	143	143
2012 CTs	-	-	-	-	286	286	286	286	286	286	286	286	286	286	286
CCs 2015,20018,2022	-	-	-	-	-	-	-	564	564	564	1,128	1,128	1,128	1,128	1,693
Total Capacity	10,712	10,860	11,042	11,186	11,320	11,554	11,617	12,094	12,015	12,040	12,600	12,552	12,570	12,665	13,016
Reserve Margin	15.0%	15.1%	15.1%	15.1%	15.1%	16.1%	15.1%	18.5%	16.2%	15.2%	19.0%	17.3%	16.0%	15.8%	17.4%

B. MIDWEST/MISO PLANNING RESERVE SHARING GROUP (PRSG)

On June 1, 2008, Xcel Energy withdrew from the MAPP GRSP to join the Midwest/MISO PRSG[1]. The Midwest/MISO PRSG requires a 14.2% reserve margin applied to the median, or 50/50 forecast, and utilizes Maximum Dependable Capability ("MDC") for capacity accreditation. The change does not significantly affect the Company's Resource Plan. The only change that we expect to make is a reduction in short-term capacity purchases, with a new target of 200 MW that will be phased in gradually.

The Midwest/MISO PRSG's 14.2% reserve margin was based on a Loss of Load Expectation ("LOLE") study conducted by MISO. Although the current LOLE study only specifically addressed the 2008-2009 planning period, we assume that 14.2% will continue to be the reserve margin target throughout our fifteen-year planning period. The study calculated the minimum amount of capacity needed to meet a loss of load probability target of 0.1 days per year.

The Midwest/MISO PRSG's reserve margin is a *planning* standard based on forecasted peak and does not retrospectively evaluate actual system demand and does not have punitive capacity charges for unexpectedly high system peaks. As a result, we will use our median, or 50/50 peak forecast for calculating total capacity obligation under the Midwest/MISO PRSG.

As noted above, in order to meet the stringent MAPP standards, we planned for and acquired capacity to a very high level of certainty by preparing to meet our capacity needs at a 90% forecast level. The penalties for failing to hold adequate reserves over the actual peak were significant and it was therefore prudent to acquire capacity to meet the higher load probabilities. Under the Midwest/MISO PRGS, our reserves are known and are calculated by taking 14.2% of our 50/50 forecasted peak. As a result of this change, our capacity obligation is considerably decreased (by both the difference between the 90% and 50% forecast and the difference between the 15% and 14.2% reserve margins).

In order to ensure that we can reliably meet all of our loads, we are further proposing changes in how we determine our plant capacity for purposes of meeting our capacity

[1] The Midwest/MISO PRSG was formed by a group of midwestern utilities as an alternative to MAPP and is administered by MISO. MISO is developing its own PRSG that will include a larger geographic area but is expected adopt the same reserve margin and accreditation standards as the Midwest/MISO PRSG.

obligation. The Midwest/MISO PRSG does not prescribe a method of establishing capacity levels for generating units. While it is a valid and common test to measure the capacity of power plants, the URGE rating does not represent the level at which a plant can produce energy for any sustained amount of time. In addition, MAPP provided generous rules for outages, including allowing us to maintain the accreditation for units even when outages were in excess of a year. As a result, many of the resources that we counted to meet our capacity obligation under MAPP cannot be relied on to produce energy on a sustained basis over an extended peak period.

Moving now to a 14.2% reserve margin over a 50/50 forecast, we need to ensure that the resources we rely on to meet peak load will also be available to produce energy in the event that our actual peaks exceed our 50% forecast (a 50% probability). The concept has shifted from an "emergency reserve margin" where we are planning to meet our peak load and hold 15% reserves in case of emergency, to a "working reserve margin," where we are planning to use our reserves to meet our electricity needs in the event that our actual peaks are higher than our 50% forecast. As a result, we need to be able to rely on all or most of our reserves to produce energy at a reasonable cost when needed.

To ensure this step, we are proposing adjustments to the way that we count and acquire capacity. First, instead of using URGE ratings, we are proposing to use Maximum Dependable Capacity ("MDC") to rate our units. MDC is defined as:

> *A unit's maximum capability that can be achieved dependably during emergency conditions for 4 continuous hours on 3 consecutive days. The MDC rating will be calculated for summer assuming 90th percentile temperatures.*

This definition is more restrictive than URGE and results in lower accredited capacity for most units. However the new MDC estimates, calculated in the spring of 2008, did result in higher accredited capacity for our nuclear and combined cycle units. The higher accredited capacity values are the result of updated information on plant performance. Hydro units will be accredited based on maximum expected generation during on peak hours over a four to five day period assuming average water conditions. This is a more realistic estimate of how the hydro units can operate during a prolonged summer heat wave.

The net result of the changes to reserve margin, peak forecast, and capacity accreditation is that Xcel Energy will be required to purchase less short-term capacity in the future. The new target for short-term capacity purchases will be 200 MW and will be phased in gradually. This will result in lower total system costs without affecting system reliability as the major elements of our Preferred Plan remain unchanged.

The change to short term purchases is uniform across all of the scenarios presented in our 2007 Resource Plan and reduces all PVRRs by approximately $293 million. Because the PVRRs for all the alternatives and scenarios presented in Chapter 4 of the Resource Plan will be reduced by the same amount, the PVRR differences presented in Tables 4-2 and 4-4 remain unchanged.

Table 2, as found on the following page, provides a summary of loads and resources under the new Midwest/MISO PRSG. Table 3 summarizes the differences between Tables 1 and 2.

Table 2 – Midwest/MISO PRSG – Load & Resources

2007 IRP - Midwest PRSG - 50/50 Peak, 14.2%RM, MDC Capacity

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
50/50 Peak	9,827	10,019	10,313	10,560	10,798	11,022	11,260	11,491	11,724	11,946	12,194	12,430	12,663	12,884	13,132
DSM	-90	-138	-253	-370	-488	-608	-729	-852	-976	-1,102	-1,229	-1,358	-1,488	-1,619	-1,752
Load Management	-984	-1,012	-1,036	-1,054	-1,055	-1,052	-1,048	-1,045	-1,042	-1,038	-1,035	-1,031	-1,028	-1,025	-1,021
Net Peak	8,753	8,869	9,024	9,137	9,255	9,362	9,482	9,594	9,706	9,806	9,930	10,041	10,148	10,240	10,358
14.2% Reserve Margin	1,243	1,259	1,281	1,297	1,314	1,329	1,346	1,362	1,378	1,392	1,410	1,426	1,441	1,454	1,471
Total Obligation	9,996	10,128	10,305	10,434	10,569	10,692	10,829	10,956	11,084	11,198	11,340	11,467	11,589	11,694	11,829
2008 MDC Estimate															
	2008	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Coal	3,155	2,801	2,801	2,562	2,561	2,604	2,604	2,604	2,504	2,504	2,504	2,504	2,504	2,504	2,504
Nuclear	1,642	1,682	1,692	1,730	1,730	1,806	1,809	1,885	1,884	1,884	1,884	1,884	1,884	1,884	1,884
Bio	269	281	281	281	281	246	243	243	243	243	210	210	205	180	180
CC	1,396	1,873	1,873	1,873	1,873	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128	2,128
CT	1,573	1,573	1,573	1,573	1,573	1,560	1,504	1,504	1,504	1,504	1,504	1,455	1,455	1,455	1,255
Oil	397	397	397	397	397	397	397	397	397	397	397	397	397	397	397
Wind	141	191	216	268	293	314	340	368	391	419	448	461	483	482	494
Hydro	167	149	149	149	149	149	149	149	149	147	147	147	147	146	136
MH & GRE	900	900	850	850	850	850	850	760	760	760	760	760	760	885	885
Short Term	356	282	475	608	434	209	377	200	200	221	200	200	200	200	200
CT 2011	-	-	-	143	143	143	143	143	143	143	143	143	143	143	143
CTs 2012	-	-	-	-	286	286	286	286	286	286	286	286	286	286	286
CCs 2015,20018,2022	-	-	-	-	-	-	-	564	564	564	1,128	1,128	1,128	1,128	1,693
Total Capacity	9,996	10,128	10,305	10,434	10,569	10,692	10,829	11,231	11,152	11,198	11,737	11,700	11,718	11,817	12,184
Reserve Margin	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	17.1%	14.9%	14.2%	18.2%	16.5%	15.5%	15.4%	17.6%

Table 3 – Difference Between Tables 1&2

Loads and Resources

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Peak	-565	-565	-569	-582	-583	-592	-612	-611	-635	-642	-654	-660	-684	-697	-726
DSM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Management	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Peak	-565	-565	-569	-582	-583	-592	-612	-611	-635	-642	-654	-660	-684	-697	-726
15% Reserve Margin	-155	-156	-158	-160	-162	-164	-168	-168	-173	-175	-178	-179	-184	-186	-192
Total Obligation	-720	-721	-727	-742	-745	-756	-780	-780	-808	-817	-832	-839	-868	-883	-917
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Coal	-152	-130	-130	-194	-88	-89	-89	-89	-89	-89	-89	-89	-89	-89	-89
Nuclear	30	31	31	31	31	33	33	35	35	35	35	35	35	35	35
Bio	-34	-34	-34	-34	-34	-29	-29	-29	-29	-29	-29	-29	-29	-26	-26
CC	59	90	90	90	90	92	92	92	92	92	92	92	92	92	92
CT	-147	-147	-147	-147	-147	-145	-138	-138	-138	-138	-138	-126	-126	-126	-110
Oil	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45	-45
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139	-139
MH & GRE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Short Term	-288	-357	-362	-314	-419	-541	-473	-550	-550	-529	-550	-550	-550	-550	-550
Total Capacity	-716	-732	-737	-752	-751	-862	-788	-863	-863	-842	-863	-851	-851	-849	-832

CONCLUSION

In summary, Xcel Energy's move from MAPP GRSP to the Midwest/MISO PRSG provides the opportunity to eliminate some short-term capacity purchases while maintaining system reliability at lower costs. Although the change involves multiple modifications to our load and resource forecast, it does not materially change our Preferred Plan.

Dated: June 16, 2008

Northern States Power Company,
a Minnesota corporation

Sara Cardwell

SARA CARDWELL
MANAGER
REGULATORY ADMINISTRATION

Certificate of Service

I, Carole Wallace, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/RP-07-1572

Dated this 16th day of June 2008

Carole Wallace

In the Matter of Xcel Energy's 2008-2022
Integrated Resource Plan

E002/RP-07-1572

5-23-2008

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APPENDIX B

Xcel Energy Transmission Lines

Northern States Power Company
North Dakota Transmission Lines

State	Description	Functional Unit	Voltage	Line Miles
	230 kV Lines			
ND	Maple River (Minnkota)	0910	230 kV	3.60
ND	Maple River (Minnkota)	0911	230 kV	8.00
ND	Drayton (Minnkota)	0912	230 kV	28.70
ND	Sheyenne-Fargo	0915	230 kV	4.30
ND	Prairie (Minnkota)	0916	230 kV	6.60
ND	Manitoba Hydro Inter (Glenboro)	0920	230 kV	56.32
	Total 230 kV			**107.52**
	115 kV Lines			
ND	Maple River-Sheyenne	0839	115 kV	11.70
ND	Souris-Neal	0850	115 kV	26.00
ND	Mallard-Souris	0860	115 kV	5.30
ND	Cass County-Sheyenne	0866	115 kV	5.00
ND	Prairie-Nordic1	5510	115 kV	2.00
ND	Prairie-Nordic2	5511	115 kV	2.10
	Total 115 kV			**52.10**
	69 kV Lines			
ND	Minnkota-Prairie	0733	69 kV	46.37
ND	Prairie-Grand Forks	0746	69 kV	6.30
ND	South-Hatton	0768	69 kV	28.60
ND	Prairie-Minnkota	0772	69 kV	13.30
ND	Elk Valley-Larimore	0776	69 kV	1.70
ND	Grand Forks (WAPA)	0786	69 kV	10.16
	Total 69 kV			**106.43**

NSP Transmission Lines – 115 kV and above
2008