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Minneapolis, Minnesota 55401-1993

July 1, 2010

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

RE: NORTHERN STATES POWER COMPANY
ANNUAL TEN-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 10 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. A service list is attached.

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

SINCERELY,

/s/

REBECCA EILERS
REGULATORY ADMINISTRATOR

ENCLOSURES
CC: SERVICE LIST (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

I, SaGonna T. Thompson, 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.

TEN-YEAR PLAN FOR MAJOR GENERATION AND TRANSMISSION FACILITIES IN THE STATE OF NORTH DAKOTA

Dated this 1st day of July 2010

/s/

SaGonna T. Thompson

Northern States Power Company d/b/a Xcel Energy
2010 North Dakota Ten-Year Plan
Service List – Notice of Filing

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

Department of Health
State Capitol Building
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Department of Agriculture
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Bismarck, ND 58505

Department of Vocational Education
State Capitol Building, 15th Floor
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Bismarck, ND 58505

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

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

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

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

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

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

Attorney General
State Capitol Building
600 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
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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 2010**



**Northern States Power Company
North Dakota Ten-Year Plan 2010
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**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

IN THE MATTER OF THE 2010 TEN-YEAR
PLAN OF NORTHERN STATES POWER
COMPANY, A MINNESOTA CORPORATION

TEN-YEAR PLAN

INTRODUCTION

Northern States Power Company, a Minnesota corporation operating in North Dakota (“Xcel Energy”, “NSPM” or the “Company”) is pleased to submit our annual Ten-Year Plan to the North Dakota Public Service Commission (the “Commission”) in compliance with Section 49-22-04 of the North Dakota Century Code. Xcel Energy has service territory in three upper Midwest states including North Dakota. The Company presently serves approximately 88,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. Xcel Energy owns just over 250 miles of transmission lines and 14 substations in North Dakota.

This filing contains an expanded Ten-Year Plan submitted in compliance with the Settlement in Case No. PU-07-776 and Commission Rules, including:

- An expanded version of our description of the major generation and transmission initiatives we plan to pursue over the next 5 and 10 years to serve our customers in North Dakota, South Dakota, Minnesota, Wisconsin and Michigan; and
- A schedule of anticipated future applications for Advance Determination of Prudence (“ADP”).

SECTION A: EXISTING ENERGY CONVERSION FACILITIES

While the Company does not currently own energy conversion facilities in the State of North Dakota, the Company does have power purchase agreements and exchanges with various utilities for power produced 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 power exchange arrangement 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. We will be filing our 2011-2025 Resource Plan with the state commissions in North Dakota, South Dakota, and Minnesota by August 2, 2010. Our Resource Plan will include additional planning scenarios based on North Dakota requirements, particularly with respect to how externalities are modeled.

We will most likely propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership, power purchase agreements, and energy efficiency. This multipronged and flexible approach to resource acquisition allows us to consider multiple technologies and locations.

In this section, we update the Commission on generation projects that were included in our 2009 Ten-Year Plan, and provide a summary of the generation projects we are considering or undertaking in the next five years across our five-state integrated system. We believe these projects, considered as a whole with our existing generation assets, result in a robust and diverse portfolio of resources that will provide our customers with cost-effective and reliable service over the long-term.

NUCLEAR RESOURCES

On April 19, 2010 we filed an Application for Advance Determination of Prudence for two Prairie Island Plant projects (Case No. PU 10-127), new Unit 2 steam generators and Units 1 and 2 Extended Power Uprates. As part of that filing we also provided an update on the Monticello Nuclear Plant. Below we provide a summary of our discussions on both plants from that case.

Monticello: In November 2008 we filed an application with the Federal Nuclear Regulatory Commission (“NRC”) to amend the operating license at our Monticello Nuclear Generating Station to allow operation at an increased generating capacity of approximately 71 MW of additional base load capacity and associated energy. We expect to receive a decision from NRC later this year or in early 2011. We began the necessary retrofits for the uprate during the 2009 refueling outage, and will complete them in our 2011 refueling outage.

Prairie Island: On May 16, 2008, we filed applications with the Minnesota Public Utilities Commission (“MPUC”) for two Certificates of Need involving our Prairie Island nuclear generating plant. Approval of MPUC Docket No. E002/CN-08-509 provides for an extended power uprate of 164 MW at Prairie Island. Approval of

MPUC Docket No. E002/CN-08-510 allows for additional dry cask spent fuel storage to support extending operation of the two Prairie Island units through 2033/2034. MPUC approval for these projects was received on December 18, 2009. The order approving the additional dry cask spent fuel storage was stayed until the end of the 2010 legislative session to allow the Minnesota Legislature time to evaluate the decision and provide further direction if deemed necessary. The Minnesota legislature made some changes to Company contributions to the Renewable Development Fund, which is part of the same legislative statute and does not affect North Dakota customers, but took no action regarding the spent fuel storage authorization of the MPUC. Thus, we are currently seeking NRC approval and as stated above have also requested an Advance Determination of Prudence finding to extend the life of Prairie Island, replace the Unit 2 steam generators and increase the production capacity of Prairie Island by approximately 164 megawatts.

FOSSIL FUEL RESOURCES

Sherco Upgrades: We are currently proceeding with an approximate 20 MW upgrade at Unit 3 of our Sherburne County (“Sherco”) coal-fired generating facility. A mercury control system for Unit 3 became operational at the end of 2009. We submitted a plan for mercury control at Units 1 and 2 to the MPUC in December 2009. The Minnesota Pollution Control Agency completed their review of the plan on June 16, 2010. MPUC will now review and evaluate the plan.

Black Dog Repowering: As we have previously discussed, we have been studying repowering the remaining coal facilities at the Black Dog facility. We are looking into replacing the existing 270 MW of coal generation with approximately 650 MW of gas combined cycle generation. Black Dog units 3 and 4 were installed in 1955 and 1960 respectively and are currently near the end of their economic and engineering life. At

this time, we are planning to retire the coal-burning units at the end of 2014 and complete a repowering with natural gas combustion turbines by 2016. We are planning on upgrading the units to combined cycle mode by 2018. We will update the Commission more fully in our 2010 Resource Plan filing, and will file for an Advance Determination of Prudence finding if we decide to move ahead with this project.

THE 2010 MANITOBA HYDRO PURCHASED POWER AGREEMENT

Manitoba Hydro: We have negotiated an extension of our existing power purchase arrangement with Manitoba Hydro that will be implemented through five interlocking agreements as summarized below.

- 375/325 MW System Power Agreement: The term of this agreement is May 1, 2015 through April 15, 2025. Xcel Energy will purchase 375 MW of MISO-qualified capacity during the six summer season months (May – October) and 325 MW of MISO-qualified capacity during the six winter season months (November – April). There are three products available under this agreement: 1) “Fixed Price Energy;” 2) “Additional Energy;” and 3) “Firm LD Energy.” With Fixed Price Energy, Xcel Energy must take and pay for energy Monday through Friday from 7 am through 10 pm (“5 by 16 Fixed Price Energy”) during the summer months and Monday through Friday from 9 am through 8 pm (“5 by 12 Fixed Price Energy”) during the winter months. “Additional Energy” and “Firm LD Energy” are products designed to maximize the use of the transmission system and can be sold at Manitoba Hydro’s option.

- 125 MW System Power Agreement: The term of this agreement will be May 1, 2021 through April 30, 2025, assuming Manitoba Hydro has proceeded with a contract to construct its next major hydroelectric project. Under this agreement, Xcel Energy will purchase an additional 125 MW of (year-round) system capacity. This agreement will provide the same energy products as described for the 375/325 MW System Power Agreement. The terms and conditions are consistent and substantially the same as the 375 MW/325 MW System Power Agreement and the net effect will increase Xcel Energy's system purchase to 500 MW (Summer) and 450 MW (Winter).

If by May 1, 2018, MH has not committed to proceed with a new major hydroelectric project, this contract will terminate, unless MH waives this new project condition, but the 375/325 MW Agreement will remain in place.

- 350 MW Diversity Agreement: This Agreement allows the parties to extend their 350 MW capacity exchange through April 30, 2025. To accomplish this arrangement, the parties will terminate the existing diversity exchange agreements as of May 1, 2015 and replace them with a single agreement. Similar to the existing diversity exchange agreements, the parties will exchange 350 MW of qualifying capacity on a seasonal basis at no cost to the other party. During the summer, Manitoba Hydro must offer energy to Xcel Energy seven days per week during the four MISO peak hours to ensure MISO approval of the capacity. Beyond this obligation, Xcel Energy is not required to purchase energy.

Taken together, the Manitoba Hydro transaction provides us with significant capacity and energy at times that maximize the value to the Company. It utilizes an existing

transmission path, which can support as much as 892 MW per hour of transfer. Because of the energy profile of these contracts, there will be many hours of the year when substantially less power is flowing over the transmission path. The contracts collectively provide Manitoba Hydro the option to sell additional “option energy” to Xcel Energy at a price that is advantageous to ratepayers. And the transaction provides our customers access to the environmental attributes of Manitoba Hydro’s system, which consists predominantly of hydro generation resources. The Agreements are contingent upon approval by the Canadian government and the MPUC. We will also initiate an ADP docket before the Commission later in 2010.

RENEWABLE RESOURCES

In our 2008 Ten-Year Plan, we discussed our commitment to construct or purchase at least 200 MW of wind power resources in North Dakota. As the Commission is aware, the Merricourt Wind Project will satisfy 150 MW of this commitment.

Merricourt Wind Project: The Merricourt Wind Project is a 150 MW wind energy generation facility consisting of 100 GE 1.5 MW wind turbines located within a project site encompassing approximately 9,600 acres in McIntosh and Dickey Counties in North Dakota. We have entered into a build/transfer agreement with the wind development company enXco to develop the facility. Primary construction on the Merricourt Wind Farm will occur in Spring of 2011, and we anticipate that commercial operation will be achieved by December 2011.

Nobles Wind Project: The Nobles Wind Project is a 201 MW wind energy generation facility consisting of 134 GE 1.5 MW wind turbines located in Nobles County on the Buffalo Ridge in Minnesota. We have entered into a similar

build/transfer agreement with enXco for the Nobles Wind Project as we did for the Merricourt project. We expect the Nobles Wind Project to begin commercial operation by December 2010.

Grand Meadow: The Grand Meadow project was developed by enXco and constructed by Mortenson Construction in 2008. In December 2008 the wind farm became fully operational and project ownership was transferred to Xcel Energy.

Community Based Energy Development (“CBED”): The Company currently has 96 MW of CBED projects under contract that are eligible for meeting the North Dakota Renewable Energy Objective (“REO”). The Company also has 243 MW of CBED projects under contract that are in the process of being constructed. Of these projects, about 82 MW are expected to be in service by the end of 2010. The remaining projects are expected to be in service sometime in 2011. We plan to file an ADP regarding the largest of these projects later this year.

Bay Front: On September 23, 2009, we filed a request for an ADP (Case No. PU-09-659) for our proposal to invest \$58.1 million to install biomass gasification technology at our Bay Front Power Plant in Ashland, Wisconsin.

Since the September filing, NSPW has contracted with consultants to complete the phase two combustion study for the existing boiler, evaluated a variety of gasification technologies and potential suppliers, and commissioned the preliminary designs for two primary gasification technologies. As a result of the combustion study and the evaluation of the gasification technologies, the Company has learned that additional boiler modifications are required, beyond those included in the ADP application.

The results of the gasification technology evaluation indicate that enhancements will be needed to the gasification equipment and procedures to increase the energy concentration in the synthetic gas in order to sustain stable combustion without significant natural gas co-firing. In addition, as a result of the production of a synthetic gas, the building housing the gasifier will need to be constructed to the standards of a hazardous area; a much higher standard than originally determined. These additional modifications have increased the estimated project cost to almost \$79 million.

The Company is looking at ways to reduce the cost, but because of the size of the estimated increase, NSPW is examining the project and potential next steps. Based on the results of these discussions, we will either amend our ADP request or withdraw it.

SECTION C. PROPOSED ENERGY CONVERSION FACILITIES - NEXT TEN YEARS

At this time, our plans for additional generation facilities in the State of North Dakota in the next ten years involve wind energy conversion systems. We are planning to issue an RFP this summer for 250 MW of wind. If there are projects that meet our bid requirements that are located in North Dakota, these projects will be part of our plans to develop additional wind energy conversion systems in North Dakota. We plan to submit an ADP for the projects selected as part of this RFP most likely in 2011.

SECTION D. EXISTING ELECTRIC TRANSMISSION FACILITIES

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

Table 1. Xcel Energy North Dakota Transmission Lines

**Northern States Power Company
North Dakota Transmission Lines**

| State | Description | Functional Unit | Voltage | Line Miles |
|----------------------------|---------------------------------|-----------------|---------|---------------|
| <u>230 kV Lines</u> | | | | |
| ND | Maple River (Minnkota) | 0910 | 230 kV | 3.60 |
| ND | Maple River (Minnkota) | 0911 | 230 kV | 8.07 |
| ND | Drayton (Minnkota) | 0912 | 230 kV | 28.34 |
| ND | Sheyenne-Fargo | 0915 | 230 kV | 4.17 |
| ND | Prairie (Minnkota) | 0916 | 230 kV | 6.60 |
| ND | Manitoba Hydro Inter (Glenboro) | 0920 | 230 kV | 56.20 |
| Total 230 kV | | | | 106.98 |
| <u>115 kV Lines</u> | | | | |
| ND | Maple River-Sheyenne | 0839 | 115 kV | 11.61 |
| ND | Souris-Neal | 0850 | 115 kV | 24.99 |
| ND | Mallard-Souris | 0860 | 115 kV | 5.22 |
| ND | Cass County-Sheyenne | 0866 | 115 kV | 3.54 |
| ND | Prairie-Nordic1 | 5510 | 115 kV | 2.00 |
| ND | Prairie-Nordic2 | 5511 | 115 kV | 1.98 |
| Total 115 kV | | | | 49.34 |
| <u>69 kV Lines</u> | | | | |
| ND | Minnkota-Prairie | 0733 | 69 kV | 48.66 |
| ND | Prairie-Grand Forks | 0746 | 69 kV | 5.97 |
| ND | South-Hatton | 0768 | 69 kV | 28.96 |
| ND | Prairie-Minnkota | 0772 | 69 kV | 13.26 |
| ND | Elk Valley-Larimore | 0776 | 69 kV | 1.75 |
| ND | Grand Forks (WAPA) | 0786 | 69 kV | 1.91 |
| Total 69 kV | | | | 100.51 |

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.

SECTION F. PROPOSED ELECTRIC TRANSMISSION FACILITIES - NEXT FIVE YEARS

In this section, we provide a brief description of significant transmission developments planned by the Company in North Dakota and elsewhere in the NSP service territory.

CapX2020: A group of investor-owned, cooperative and municipal utilities in Minnesota, eastern North Dakota, eastern South Dakota, and western Wisconsin ("CapX2020 Utilities"), 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 the CapX2020 Vision Study, identified, among other projects, the need for a 345 kV line from western North Dakota to the Twin Cities, passing through the Fargo area to serve growing energy needs in the Red River Valley.

From this Vision Study the CapX2020 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 345 kV and 230 kV lines are as follows:

- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota (“Fargo Project”);
- 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 (“Brookings Project”);
- A 150 mile, 345 kilovolt line between the southeast Twin Cities, Rochester, Minnesota, and La Crosse, Wisconsin (“La Crosse Project”); and
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota (“Bemidji Project”).

Xcel Energy and Great River Energy, on behalf of the other participating CapX2020 Utilities, filed a Certificate of Need application for the three 345 kV projects (Brookings, Fargo and La Crosse Projects) with the MPUC on August 16, 2007. The MPUC approved Certificates of Need for all three 345 kV projects.

With regard to the Fargo Project, in April 2009, a Route Permit for the Monticello to St. Cloud segment of the Monticello-Fargo project was filed in Minnesota. The matter will be heard by the MPUC in July 2010. In October 2009, a Route Permit for the St. Cloud to Fargo segment of the Monticello-Fargo project was filed in Minnesota. We anticipate filing for a Certificate of Corridor Compatibility in ND for the Fargo project in late summer 2010, as well as a Certificate of Public Convenience and Necessity in July 2010.

With regard to the Brookings Project, a portion of that project is proposed to be constructed in South Dakota. Xcel Energy and Great River Energy, on behalf of the CapX2020 Utilities, proposed to own the Brookings Project and filed a Route Permit application with the MPUC (Docket No. ET-2/TL-08-1474). The Administrative Law Judge issued his Route Permit recommendation on April 22, 2010. The ALJ Order stated that all conditions were met and the MPUC should issue the Route Permit. Exceptions were filed on May 7, 2010 by various intervening groups. The Company anticipates the MPUC will schedule a hearing in early summer to deliberate and discuss the record and consider the ALJ recommendation. A filing for a Corridor Permit in SD for the Brookings Project is expected later in 2010.

With regard to the Bemidji Project, in March 2008, Otter Tail Power Company and Minnkota Power Cooperative filed an application for a Certificate of Need with the MPUC. An application for a Route Permit for this project was filed in June 2008. In July 2009, the MPUC issued a Certificate of Need. An MPUC decision on the route is expected by Summer/Fall 2010.

With regard to the La Crosse Project, a Route Permit Application was filed with the MPUC in January 2010. An application for a Certificate of Public Convenience and Necessity will be filed with the Wisconsin Public Service Commission later in 2010.

The CapX2020 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 CapX2020 Initiative is available at www.capx2020.com.

Buffalo Ridge Incremental Generation Outlet (“BRIGO”) Transmission

Project: In September 2007, we received a Certificate of Need from the MPUC to add three 115 kV transmission lines in southwestern Minnesota. These lines together are known as the BRIGO transmission project:

- Lake Yankton Substation to a new substation near Marshall, Minnesota (Southwest Marshall) - 15 Miles.
- Fenton substation to Nobles County substation - 23 Miles.
- Yankee substation to Brookings County (South Dakota) substation #2 - 6.5 Miles.

The purpose of these transmission facilities is to improve reliability to the growing City of Marshall, Minnesota load and to increase the level of wind generation outlet from the Buffalo Ridge of Minnesota and South Dakota by 350 MW. These projects were completed at the end of 2009 and are now in-service.

Chisago-Apple River Transmission Project: In February 2008, we received a Certificate of Need from the MPUC to construct a 115/161 kV line from the Chisago County substation to just east of St. Croix Falls, Wisconsin where it will interconnect with a new Dairyland Power Cooperative 161 kV line from Apple River. This joint project is to provide reliable power to north central Wisconsin and the far north Twin Cities suburbs. This project is scheduled to be completed in 2011.

Southwest Twin Cities 115 kV Conversion: This project involves two areas of rebuilding, a 25 mile western section and an 18 mile eastern section of existing 69 kV to 115 kV between Glencoe and Waconia substations and Scott County and Westgate substations in the southwest suburbs of the Twin Cities. This project is required due

to load growth in these outer ring suburbs of the Twin Cities. A Certificate of Need for the western section is expected to be filed in mid 2010. This project is expected to be completed in 2012.

Merricourt Interconnection: The Merricourt Wind project will interconnect with the Montana-Dakota Utilities (“MDU”) transmission facilities. This will require the construction of additional transmission infrastructure. This project is presently proceeding through the MISO interconnection study process. The final transmission infrastructure needed, ownership structure and cost estimates will be determined through that process. Initial results indicate this will require approximately 20 miles of new 230 kV transmission lines as well as additional investments to other facilities in the area. MDU has filed an intent to file an application for a Certificate of Corridor Compatibility and a Route Permit with the Commission. The Commission has acknowledged that intent.

Greater Rochester Area Transmission Project: This project, also known as the Pleasant Valley area projects, is a proposal to construct two 161 kV lines in the greater Rochester, Minnesota area:

- Pleasant Valley to Byron substation (18 miles)
- Byron to West Side Energy Center (10 miles), this will complete the existing double circuit line between the Byron to Cascade Creek 115 kV line. SMMPA is responsible for building this line.

There are a number of wind projects proposed in this area and at various stages within the MISO Interconnection study process. The MISO studies for Xcel Energy’s Grand Meadow project and the Wapsipinicon Wind farm determined that interconnecting these projects would cause transmission system constraints and would

require the construction of the Pleasant Valley-Byron 161 kV line. Until this new upgrade is constructed, the wind projects are sometimes limited in the amount of power they can deliver to the system.

Xcel Energy submitted the Certificate of Need and Route Permit filings with the MPUC in December of 2009 for the Pleasant Valley to Byron 161 kV line. The decisions on both of these by the MPUC are expected later in 2010.

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

In addition to the CapX2020 Initiative, Xcel Energy participates in transmission planning with a larger group of utilities called the Minnesota Transmission Owners (“MTO”). The MTO consists of all of the investor-owned, cooperative and municipal utilities that own transmission facilities 100 kV and above in Minnesota. Several MTO members (e.g., the Company, Great River Energy, Otter Tail Power, etc.) also own significant transmission facilities in North Dakota. These utilities are required by Minnesota law to file a biennial transmission plan with the MPUC by November 1 of every odd-numbered year, and formed the MTO to develop and submit a unified plan. The MTO has commissioned a number of studies focused on meeting renewable energy objectives and requirements and other generation and load serving needs through 2025. The MTO group also performs an annual 10 year assessment of the member utility system for compliance with the North American Electric Reliability Corporation (“NERC”) Transmission Planning (“TPL”) standards.

The MTO utilities also coordinate their planning with the CapX planning process and the MISO Midwest Transmission Expansion Plan (“MTEP”) process. These are comprehensive studies encompassing the impacts and needs over more than just Minnesota. These MTO studies are available at the MTO website at www.minnelectrictrans.com.

As a result of two recent studies, the MTO has identified an additional project, as discussed below, that it believes is necessary to meet regional reliability and generation outlet needs within the next 10 years:

Upgrade Existing Minnesota Valley to Blue Lake 230 kV line: This project, otherwise known as the “Corridor Upgrade,” would replace the existing 230 kV line between the Blue Lake Substation in Shakopee, Minnesota and the Minnesota Valley Substation near Granite Falls, Minnesota with a double-circuited 345 kV line, continued to the new Hazel Creek substation south of Granite Falls, Minnesota. This upgrade would provide significant new transmission capacity from the Dakotas, southwestern Minnesota and western Minnesota to the Twin Cities, at an estimated cost of \$350 million. The Corridor Upgrade would provide an increase in generation delivery from the Dakotas and the Buffalo Ridge on the order of 2000 MW. The project will also serve to enhance system reliability by backing up the Brookings Project. The MTO believes this project should be the next transmission project pursued after the CapX2020 Group 1 Projects.

SECTION I: REGIONAL COORDINATION

All major transmission planning performed by Xcel Energy is now coordinated through MISO on a regional basis. MISO issues an annual MTEP after coordinated planning and stakeholder review.

As a result of complying with the FERC Order No. 890 rules,¹ MISO has also implemented Sub-Regional Planning Meetings as part of their annual MISO Transmission Expansion Plan (MTEP) development process. The Company participates in the Western Region meetings. These Sub-Regional Planning meetings 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

Another example of coordination by the utilities is the formalization of the MTO organization. In addition to the Minnesota biennial transmission planning work of the MTO, the MTO utilities also coordinate their transmission planning activities with the CapX2020 planning processes, and MISO's MTEP process.

The MTO also coordinated and performed two major transmission studies. The Dispersed Renewable Generation Transmission Study investigated the potential to install 600 MW of dispersed renewable generation in and around Minnesota with minimal impacts to the transmission system. The other study was a series of studies under the heading of Renewable Energy Standard transmission studies that

¹ *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 reb’g*, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2008) (Order No. 890-A); *order on reb’g* 123 FERC ¶ 61,299 (Order No. 890B) (June 23, 2008). MISO’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).

investigated the short and long-range transmission requirements in Minnesota and North and South Dakota for the MTO utilities to meet the Minnesota RES.

Xcel Energy is also actively supporting the on-going work of the Upper Midwest Transmission Development Initiative (“UMTDI”). Formed in September 2008 by the Governors of North Dakota, South Dakota, Iowa, Minnesota and Wisconsin, the goal of the UMTDI is, in coordination with MISO, to:

1. identify key wind generation resource zones within these Upper Midwest states, as well as the transmission projects and infrastructure needed to develop those resources in a cost-effective manner; and
2. develop reasonable cost allocation criteria for the transmission projects identified.

An executive committee made up of a representative of the Governor’s office from each state and a regulatory commission from each state was formed to plan and implement a work plan focused on these two areas. Activities to address both areas of the UMTDI work plan have been underway for the past two years, and the UMTDI executive committee plans to submit recommendations to the five governors by the fall of 2010.

Xcel Energy is also involved with the MISO led Regional Generation Outlet Study (“RGOS”) whose goal is to identify mutually beneficial bulk transmission lines that would facilitate the compliance with all state and possible national renewable energy standards for states in the MISO footprint. These include the states from the UMTDI group along with states further east that exist in the MISO footprint. Study work began in 2008 and is still ongoing.

Finally, the Company is participating in the Strategic Midwest Area Renewable Transmission (“SMART”) Study² that was commissioned in August of 2009. The SMART study’s goal is to develop a 20-year transmission plan that ensures reliable electricity transport, provides an efficient transmission system to integrate new generators and foster efficient markets, minimizes environmental impacts, and supports state and national energy policies.

Phase One of the study identified future transmission needs in the upper Midwest to support renewable energy development and to transport that energy to load centers. Study participants evaluated various transmission alternatives designed to support the integration of significant new wind generation within the study area, including North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan and Ohio.

The study’s Phase One results recommend three alternatives for further study based on a rigorous reliability assessment and stakeholder input. (1) a 765 kV transmission solution; (2) a 765 kV and limited direct current transmission solution; and (3) a combined 345 kV and 765 kV transmission solution. These three alternatives will be further studied during the second phase of the SMART Study, scheduled for completion during the third quarter of 2010. The Phase One report can be downloaded at www.smartstudy.biz.

² Xcel Energy and Electric Transmission America – a joint venture of American Electric Power, MidAmerican Energy Holdings Company, American Transmission Company, Excelon Corp., and NorthWestern Energy – are cosponsoring the SMART Study.

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 2. 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 3 shows the long-range system forecast of native energy requirements, summer peak, and winter peak demand for the NSP System. Table 4 shows the North Dakota portion of the NSP System forecast.

The forecast for the NSP System is based on forecasts of jurisdictional retail 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 4 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 2. Historical Energy and Peak Load Requirements
(1985 - 2009) North Dakota portion of NSP System**

| Year | Energy (GWh) | Annual Growth | Non- Coincident Peak Load (MW) | Annual Growth |
|-------------|-------------------------|--------------------------|---|--------------------------|
| 1985 | 1,237 | --- | 267 | --- |
| 1986 | 1,265 | 2.3% | 295 | 10.5% |
| 1987 | 1,369 | 8.2% | 275 | -6.8% |
| 1988 | 1,441 | 5.3% | 308 | 12.0% |
| 1989 | 1,484 | 3.0% | 303 | -1.6% |
| 1990 | 1,544 | 4.0% | 322 | 6.3% |
| 1991 | 1,553 | 0.6% | 311 | -3.4% |
| 1992 | 1,553 | 0.0% | 312 | 0.3% |
| 1993 | 1,658 | 6.8% | 323 | 3.5% |
| 1994 | 1,844 | 11.2% | 374 | 15.8% |
| 1995 | 1,904 | 3.3% | 399 | 6.7% |
| 1996 | 1,925 | 1.1% | 373 | -6.5% |
| 1997 | 1,883 | -2.2% | 376 | 0.8% |
| 1998 | 1,771 | -5.9% | 333 | -11.4% |
| 1999 | 1,796 | 1.4% | 360 | 8.1% |
| 2000 | 1,916 | 6.7% | 362 | 0.6% |
| 2001 | 1,984 | 3.5% | 382 | 5.5% |
| 2002 | 1,911 | -3.7% | 351 | -8.1% |
| 2003 | 1,958 | 2.5% | 352 | 0.3% |
| 2004 | 1,950 | -0.4% | 363 | 3.1% |
| 2005 | 2,053 | 5.3% | 370 | 1.9% |
| 2006 | 2,048 | -0.2% | 384 | 3.9% |
| 2007 | 2,119 | 3.5% | 403 | 4.8% |
| 2008 | 2,171 | 2.4% | 395 | -2.0% |
| 2009 | 2,158 | -0.6% | 403 | 2.2% |

Table 3. Forecast of NSP System Energy and Peak Load Requirements (2010 - 2028)

| Year | Energy (GWh) | Summer Net Peak Load (MW) | Winter Net Peak Load (MW) |
|-------------|-------------------------|--|--|
| 2010 | 45,650 | 9,140 | 7,097 |
| 2011 | 46,191 | 9,315 | 7,238 |
| 2012 | 46,824 | 9,483 | 7,380 |
| 2013 | 47,214 | 9,631 | 7,490 |
| 2014 | 47,757 | 9,779 | 7,610 |
| 2015 | 48,077 | 9,897 | 7,692 |
| 2016 | 48,530 | 10,016 | 7,778 |
| 2017 | 48,803 | 10,122 | 7,860 |
| 2018 | 49,231 | 10,228 | 7,942 |
| 2019 | 49,569 | 10,321 | 8,024 |
| 2020 | 50,138 | 10,425 | 8,110 |
| 2021 | 50,473 | 10,504 | 8,188 |
| 2022 | 50,903 | 10,586 | 8,269 |
| 2023 | 51,260 | 10,670 | 8,348 |
| 2024 | 51,853 | 10,757 | 8,432 |
| 2025 | 52,303 | 10,834 | 8,515 |
| 2026 | 52,894 | 10,930 | 8,606 |
| 2027 | 53,395 | 11,018 | 8,697 |
| 2028 | 54,055 | 11,103 | 8,790 |

Average Annual Growth Rate, 2010-2028:

% growth: 0.9% 1.3% 1.2%

Notes:

- 1) Peak Load is *coincident* to the NSP System peak.
- 2) Winter Peak = Winter Peak season, 2010 is 2010 - 2011 winter peak.
- 3) Peak Load is the Net Peak (interruptible)

**Table 4. Forecast of Energy and Peak Load Requirements
(2010 - 2028)
North Dakota Portion of NSP System**

| Year | Energy (GWh) | Summer Peak Load (MW) | Winter Peak Load (MW) |
|-------------|-------------------------|--------------------------------------|--------------------------------------|
| 2010 | 2,478 | 321 | 424 |
| 2011 | 2,512 | 330 | 441 |
| 2012 | 2,546 | 332 | 457 |
| 2013 | 2,575 | 343 | 447 |
| 2014 | 2,611 | 352 | 456 |
| 2015 | 2,631 | 358 | 469 |
| 2016 | 2,659 | 360 | 477 |
| 2017 | 2,699 | 375 | 471 |
| 2018 | 2,744 | 383 | 480 |
| 2019 | 2,780 | 387 | 497 |
| 2020 | 2,823 | 395 | 505 |
| 2021 | 2,864 | 403 | 514 |
| 2022 | 2,910 | 411 | 523 |
| 2023 | 2,944 | 420 | 532 |
| 2024 | 2,978 | 429 | 542 |
| 2025 | 3,014 | 438 | 551 |
| 2026 | 3,055 | 447 | 561 |
| 2027 | 3,082 | 456 | 571 |
| 2028 | 3,118 | 466 | 581 |

Average Annual Growth Rates, 2010-2028:

% Growth: **1.3%** **2.1%** **1.7%**

- Notes:**
- 1) Peak Load is *coincident* to the Xcel Energy system peak.
 - 2) Winter Peak = MAPP Winter Peak season, 2010 is 2010 - 2011 winter peak.
 - 3) Peak Load forecast growth from 2020 - 2028 is based on average summer and winter ND peak growth rates from 2010 – 2019.

APPENDIX A
Schedule of Advance Determination of Prudence Filings.

The following tables identify those projects for which we intend to seek an ADP finding from the Commission, along with a page number in this Plan where a description of the proposed project can be found.

Pending ADP petitions

| Project | Date Filed | Docket Number | Description (page number) |
|---|------------|---------------|------------------------------|
| Bay Front Biomass Gasification Project | 9/23/09 | PU-09-659 | 8 |
| CapX2020 Group 1 Transmission Projects | 10/5/2009 | PU-09-678 | 11 |
| Two Prairie Island Nuclear Generating Station Projects: New Unit 2 Steam Generators and Units 1 and 2 Extended Power Upgrades | 4/19/2010 | PU-10-127 | 3 |

Possible ADP petitions – timing and certainty of project moving forward dependent on outcome of resource planning process and other key decisions.

| Project | Description (page number) |
|------------------------------------|------------------------------|
| 250 MW of Wind Projects | 9 |
| Black Dog Units 3 and 4 Repowering | 4 |
| CBED PPAs | 8 |
| Manitoba Hydro PPA | 5 |

APPENDIX B

Report on the Effect of Wind Generation on Baseload Plants

In the Commission's orders on the Company's applications for Advance Determination of Prudence for the Nobles and Merricourt Wind Projects dated August 12, 2009 in Case Nos. PU-08-907 and PU-08-908, the Commission included the following order points³:

2. NSP will report to the extent possible, as part of its annual 10-year plan, all reductions in the energy produced at its base load generation units that would not have occurred except for the existence of wind generation. The report will include the time of the event, length of the event, base load plant affected and the amount of energy not produced at the base load plant during the event.
3. NSP will report, as part of its next 10-year plan, on the impacts and costs associated with taking coal plant production up and down to accommodate wind resources during off peak hours.

Order Point 2

In response to order point 2, we performed an analysis of the NSP system performance over 7,296 hours from the first hour on July 1, 2009 through the last hour on April 30, 2010. To establish a criteria as to what would constitute reductions in energy production, we looked at the set points for each unit established in our Energy Management System. Units have an economic maximum and an economic minimum set point that comprise the normal dispatch range. For the purposes of this study, we assumed that any time a unit was not operating at its economic maximum, it was "backed down". We then attributed the cause of the reduced baseload production each hour to load, wind, market dispatch, or some combination based on the net energy position for the NSP system over the hour.

As an example, let's assume load is 500 MWs, wind is 100 MWs and Sherco Unit 1 is the only baseload resource online with a maximum capability of 680 MWs. By itself, NSP would only need 400 MWs from Sherco to serve load. If the unit were in fact dispatched to 400 MWs by MISO, we would attribute 180 MWs of backed down generation to our load (680 – 500), and 100 MWs to the wind. If MISO backed the unit down further to 300 MWs, the additional 100 MW reduction would be attributed to market dispatch. There are also times when baseload units remain loaded above

³ The order points were numbers 2 and 3 in the Nobles order and 4 and 5 in the Merricourt order.

the level necessary to serve NSP load net of wind generation due to the market wide demand for energy.

It is important to note that the cause of reductions in baseload energy production cannot be determined with certainty given the regional dispatch of generation in MISO. Wind generation may play a role in MISO market dispatch decisions, but the company does not have enough information to determine definitively the cause of these decisions. Nevertheless, the analysis described above provides a reasonable framework for assessing the impact of wind on the NSP system.

The results show that the total amount of energy that was not produced that could have been produced during the study period if no baseload generation was backed down was 2,339,681 MWhs. Wind production was contributed to 400,824 MWh or 17% of MWhs backed down. Changes in customer load accounted for 140,936 MWh or 6% of the MWhs backed down. MISO Market Dispatch was responsible for 1,797,921 MWh or 77% of the MWhs backed down. There were many hours where baseload generation was backed down for a combination of market dispatch, wind production and customer loads.

Out of the 300 days evaluated, there were 219 cycles in which wind generation contributed to backing down base load generation. We define a cycle as the period of time over which the base load generation was backed down. As an example, on July 1, 2009, base load generation was backed down for six hours in part due to wind generation. This was considered a cycle. On April 16, 2010 during the hour beginning at 4 am, base load generation was backed down for one hour in part due to wind generation. This was also counted as one cycle.

Order Point 3

In response to order point 3, the Company has been studying the effect of cycling on our base load coal generating facilities. Our studies have focused on three coal fired thermal units, one in Minnesota, Colorado, and Texas. These studies are not complete at this time but preliminary results indicate that cycling our baseload plants can result in increased O&M costs, a reduction in the life of key plant components, a decrease in unit reliability and an increase in fuel costs per unit of output. We are working with a Technical Advisory Committee assigned by the Colorado Public Utilities Commission which is reviewing our modeling assumptions related to coal plant cycling versus curtailing wind generation during system minimum conditions as part of the Colorado 2007 Resource Planning effort.

As noted above, while we have observed that these baseload plants were backed down from the levels at which they may otherwise have been operating, we have also observed that wind generation is only one reason for that operational change, with variation in customer load and MISO dispatch decisions also contributing to the cycling of these plants. We know that increased cycling will lead increased costs associated with additional wear on the facilities and suboptimal operating conditions. However, we have not yet been able to quantify these costs or to estimate the direct effect that wind generation has on these cost increases.

As the amount of power generated from renewable energy sources like wind and solar becomes a larger part of our generation fleet, so does the impact of its intermittency. Planning for, reacting optimally to, and quickly responding to these varying generation sources can have a significant impact on our overall fleet which will require careful management to assure optimization.