



414 Nicollet Mall
Minneapolis, MN 55401

June 29, 2012

—Via Electronic & US Mail—

Darrell Nitschke
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 Mr. Nitschke:

In accordance with Section 49-22-04 of the North Dakota Century Code, Northern States Power Company, doing business as Xcel Energy, 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, as well as the provisions of the Settlement Agreement in Case No. PU-10-657.

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.

Please feel free to contact me at paul.lehman@xcelenergy.com or (612) 330-7529 if you have any questions regarding this report.

Sincerely,

/s/

PAUL J. LEHMAN
MANAGER
REGULATORY COMPLIANCE & FILINGS

Enclosures
c: Service List (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

I, Lindsey Didion, 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 29th day of June 2012

/s/

Lindsey Didion

Northern States Power Company d/b/a Xcel Energy
2012 North Dakota Ten-Year Plan
Service List – Notice of Filing

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505

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

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

Department of Vocational Education
State Capitol Building, 15th Floor
600 East Boulevard Avenue
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
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
JUNE 2012**



**Northern States Power Company
2012 North Dakota Ten-Year Plan**

Table of Contents

I.	Electric Generation Facilities	
	A. Existing Facilities	2
	B. Proposed Facilities – Next Five Years	2
	C. Proposed Facilities – Next Ten Years	7
II.	Electric Transmission Facilities	
	A. Existing Facilities	7
	B. Proposed Facilities – Next Five Years	8
	C. Proposed Facilities – Next Ten Years	12
III.	Natural Gas Pipeline Facilities	
	A. Existing Facilities	13
	B. Proposed Facilities – Next Five Years	14
	C. Proposed Facilities – Next Ten Years	14
IV.	Regional Coordination	14
V.	Environmental Protection	18
VI.	Demand Projections	18
VII.	Appendices	23
	A. Advance Determination of Prudence Filings	i
	B. Effect of Wind Generation on Base Load Plants	ii

**STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION**

IN THE MATTER OF THE 2012 TEN-YEAR
PLAN OF NORTHERN STATES POWER
COMPANY, DOING BUSINESS AS XCEL
ENERGY

TEN-YEAR PLAN

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy with operations in North Dakota, is pleased to submit our annual Ten-Year Plan to the North Dakota Public Service Commission in compliance with Section 49-22-04 of the North Dakota Century Code. NSP-Minnesota (NSPM) has service territory in three upper Midwest states including North Dakota. NSP-Wisconsin (NSPW) has service territory in Wisconsin and Michigan. The Company presently serves approximately 89,000 retail electric customers in North Dakota and around Fargo, Grand Forks, and Minot. 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.

I. ELECTRIC GENERATION FACILITIES

A. Existing Facilities

While we do not currently own electric generation facilities in the state of North Dakota, we do have power purchase agreements (PPA) and exchanges with various utilities for power produced in North Dakota. We purchase 100 MW from Minnkota Power Cooperative, Inc. each summer season from its rights in the Coyote #1 coal fired steam generating unit located in Beulah, North Dakota. We also purchase 12 MW of wind energy from Acciona Wind Energy USA from turbines located near Velva, North Dakota. Additionally, we have 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 our North Dakota loads.

B. Proposed Facilities - Next Five Years

NSPM and NSPW operate their upper Midwest generation resources on a five-state (North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan) integrated system basis (the NSP System). We describe our projected resource needs in our Resource Plan, which is filed roughly every three years with our various state commissions. We filed our 2011-2025 Resource Plan with all five states on August 1, 2010, and filed a subsequent update on December 1, 2011. Our Resource Plan includes planning scenarios based on North Dakota requirements, particularly with respect to how externalities are modeled.

We propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership, PPAs, and energy efficiency programs. This multipronged and flexible approach to resource acquisitions allows us to consider multiple technologies and locations.

In this section, we update the Commission on generation projects currently in progress, and provide a summary of the generation projects we are considering or undertaking in the next five years across our NSP 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.

1. Nuclear Resources

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 thermal power. This will allow us to increase the current generating capacity of 600 MW by approximately 71 MW. The NRC Staff has indicated that 16 of 17 divisions within the NRC have now completed their reviews.

In October 2011, the NRC's Advisory Committee on Reactor Safeguards recommended suspension of licensing actions related to containment accident pressure credit related to Japan's Fukushima incident. This recommendation has delayed the pending licensing actions for Monticello. Based on consultation with the NRC, approval of Monticello's license amendment is now expected to occur prior to the Spring 2013 scheduled refueling outage.

The majority of the plant modifications supporting the EPU were made in the Spring of 2011. The last components will be installed during a scheduled refueling outage in the spring of 2013. This will allow the plant to generate at the higher MW level once we receive final approval from the NRC.

Prairie Island: On December 18, 2008, the Minnesota Public Utilities Commission (MPUC) issued two Certificates of Needs (CON) for our Prairie Island nuclear generating plant. Approval of Docket No. E002/CN-08-509 provided for an EPU of

164 MW at Prairie Island. Approval of Docket No. E002/CN-08-510 allows for enough additional dry cask spent fuel storage to support extending operation of the two Prairie Island units through 2033 and 2034, respectively.

On April 19, 2011, we filed an Advance Determination of Prudence (ADP) application (Case No. PU-10-127), with the Commission for two new steam generators at Unit 2 and the EPU project. On June 27, 2011, the NRC approved our request to extend the operating licenses for Units 1 and 2. On March 30, 2012, we filed a Notice of Changed Circumstances with the MPUC regarding changes in timing and scope of the EPU project. The Company also notified the Commission of this matter in Nuclear ADP Status Update Letters regarding the EPU on January 31, 2012 and June 5, 2012. In our June 5th letter, we requested the Commission suspend consideration of the EPU portion of the ADP, but move forward with consideration of the ADP for the new Unit 2 steam generators. At this time, we anticipate review and reaffirmation decisions by the MPUC in late 2012 or early 2013. The EPU at Prairie Island is now expected to provide an additional 135 MW of additional base load capacity and associated energy, which we currently believe could be implemented between 2016 – 2018 timeframe; however, the timing is subject to change based upon NRC review.

2. Fossil Fuel Resources

Sherco Upgrades: As discussed in our May 15, 2012 letter to the Commission following a scheduled fall 2011 outage at Sherco Unit 3, which included completion of a 22 MW uprate project, Unit 3 experienced significant vibration damage during final post-overhaul testing. Work is currently being done to collect evidence and assess the damage. As discussed in our letter, the last phase of our efforts will encompass all repair and restoration efforts. Based on our current assessment of conditions, our restoration plan targets Sherco 3 coming back online in the first quarter of 2013. However, the restoration is complex and given the remaining work to be done, there

remains some degree of uncertainty regarding the completion date. We have taken a methodical approach described in this report to ensure that we fully learn the nature and root cause of the event and are able to return Sherco 3 safely to reliable service as soon as possible. We are also working on the optimization of the mercury control system for Unit 3. We plan to complete this testing in 2013 once the unit returns to service.

The Resource Plan update filed on December 1, 2011 identified the commencement of a life extension study for Sherco Units 1 and 2. The life extension study will also contemplate the installation of a mercury control system. Based on pending Environmental Protection Agency rules, we anticipate that the system we install may also be required to control other hazardous air pollutants. We plan to submit these results with the next Resource Plan filing.

Black Dog Repowering: 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. Changes to environmental permit compliance requirements will likely result in these units ceasing coal-fired generation in 2014. On March 15, 2011, we filed a CON application with the MPUC for the repowering of Black Dog Units 3 and 4 to a larger natural gas fired combined cycle facility. On December 7, 2011, we filed a Motion to Withdraw Application and Request regarding the afore mentioned CON. The motion was based upon the revised economic outlook and lower expectation of customers' future demand for capacity.

3. Hydro Resources

Manitoba Hydro: We have negotiated an extension of our existing PPAs with Manitoba Hydro that will be implemented through three coordinated agreements. These contracts with Manitoba Hydro provide the NSP System with significant capacity and energy which is available at times that maximize the value to the Company. The agreements utilize an existing transmission path, which can support as

much as 892 MW per hour of transfer. However, 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 agreements were approved by the MPUC on May 26, 2011 (Docket No. E-002/M-10-633). We filed an ADP for this transaction with the Commission on February 8, 2012 in Case No. PU-12-70. The Advocacy Staff recommended approval of these new PPAs through a memorandum dated June 12, 2012. An informal hearing is scheduled for July 11, 2012.

4. Renewable Resources

Prairie Rose Wind Facility: We solicited additional wind projects through a Request for Proposal (RFP) issued in September 2010. As a result of that solicitation, we have completed negotiations and signed a PPA for the purchase of 200 MW from Geronimo Wind LLC from a facility that will connect to the Angus C. Anson substation in southeast South Dakota. We filed an ADP for this contract with the Commission on January 31, 2012 in Case No. PU-12-59. Written testimony was subsequently filed in June 2012 and the Commission is currently reviewing our application.

Community Based Energy Development: We currently have approximately 210 MW of community-based wind on the system that qualifies for inclusion toward the North Dakota Renewable Energy Objective with another approximately 116 MW under contract and scheduled for construction in the next couple of years. With the exception of the 79 MW Goodhue Wind Project, no project is large enough to trigger the rate case Settlement Agreement provision requiring the filing of an ADP application. On March 7, 2012, the Company submitted a letter to the Commission advising them of uncertainty regarding the development of the Goodhue Wind Project. Consistent with our letter, if the Goodhue Project is able to successfully navigate the developmental challenges it currently faces, we will file an ADP application for that project, as well.

C. Proposed Facilities - Next Ten Years

At this time, our plans for additional electric generation facilities in the State of North Dakota over the next ten years involve primarily wind energy conversion systems. However, we anticipate the expiration of the PTC at the end of 2012 will produce upward price pressure for wind generation. As a result, we believe it is appropriate to reassess our wind generation procurement efforts until after 2012 to allow the potential post-PTC market to develop. As a part of our post-PTC assessment, we will continue to look for opportunities to meet our objective to acquire 200 MW of cost-effective wind power from facilities located in North Dakota. Additional wind resources will be acquired only if the price is determined to be reasonable and competitive with alternate energy resources.

The Company's Resource Plan Update, filed December 1, 2011, identified the need for future gas generation between the years of 2017-2022. An RFP process will be conducted to fulfill these needs. Proposals meeting the requirements of the RFP, including those located in North Dakota, will be evaluated.

II. ELECTRIC TRANSMISSION FACILITIES

A. Existing Facilities

Our existing electric transmission line facilities in North Dakota are listed in Table 1 below. We have no plans to retire any electric transmission facilities in North Dakota within the next ten years.

Table 1. NSP North Dakota Transmission Lines

State	Description	Functional Unit	Voltage	Line Miles
	<u>230 kV Lines</u>			
ND	Audobon-Hubbard	0909	230 kV	38.3
ND	Maple River (Minnkota)	0910	230 kV	3.60
ND	Maple River (Minnkota)	0911	230 kV	8.07

ND	Drayton (Minnkota)-Letellier	0912	230 kV	28.34
ND	Sheyenne-Fargo	0915	230 kV	4.17
ND	Prairie (Minnkota)-Grand Forks	0916	230 kV	6.60
ND	Manitoba Hydro Inter (Glenboro)	0920	230 kV	56.20

Total 230 kV **145.28**

115 kV Lines

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	4.96
ND	Prairie-Nordic1	5510	115 kV	2.00
ND	Prairie-Nordic2	5511	115 kV	1.98

Total 115 kV **50.76**

69 kV Lines

ND	Minnkota-Prairie	0733	69 kV	46.3
ND	Prairie-Grand Forks	0746	69 kV	6.4
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)-Prairie	0786	69 kV	7.72

Total 69 kV **100.51**

B. Proposed Facilities – Next Five Years

In this section, we provide a brief description of significant transmission developments planned by the Company on its NSP System in North Dakota and other states.

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, with a terminal point in 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 approximate lengths and general location of the proposed 345 kV and 230 kV lines are as follows:

- 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”) at a total estimated cost between \$650 and \$800 million;
- A 250 mile, 345 kilovolt line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota (“Fargo Project”) with a total estimated cost between \$500 and \$750 million;
- A 150 mile, 345 kilovolt line between the southeast Twin Cities, Rochester, Minnesota, and La Crosse, Wisconsin (“La Crosse Project”) with a total estimated cost between \$400 and \$500 million; and
- A 68 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota (“Bemidji Project”) with a total estimated cost between \$100 and \$140 million.

The first segment of the Fargo Project was placed in service in 2011 and the remainder of the project is currently under construction. The Bemidji Project is also currently under construction and completion is expected by the end of 2012. The Brookings and La Crosse Projects are not yet under construction, and will be placed into service over the next few years with total project(s) completion in 2015.

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

With regard to the Fargo Project, a Route Permit was granted by the MPUC for the Monticello to St. Cloud segment in July of 2010, and construction was complete by the end of 2011. In June 2010, a Route Permit for the St. Cloud to Fargo segment was approved. In North Dakota, the Certificate of Public Convenience and Necessity (CPCN) was issued in January of 2011. The Certificate of Corridor Compatibility and the Route Permit are expected to be issued in summer 2012.

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 other owners of the Brookings Project, filed a Route Permit application with the MPUC on December 29, 2008 (Docket No. ET-2/TL-08-1474). The MPUC issued the final Route Permit for the Minnesota portion of this Project in May 2011 and the South Dakota Commission granted the Facility Permit for the South Dakota portion of the Brookings Project in June 2011. This project was approved as a Multi-Value Project (MVP) through the Midwest Independent System Operator (MISO) process in December 2011.

In North Dakota, an ADP was approved for the CAPX Group I projects (Case Nos. PU-09-676 and PU-09-678) through Orders issued on October 6, 2011 and November 10, 2011.

Otter Tail Power Company, Minnkota Power Cooperative, and Minnesota Power, on behalf of themselves, Great River Energy, and Xcel Energy, filed a CON application with the MPUC for a 70 mile 230 kV line between the Boswell Substation near Cohasset, MN, to the Wilton Substation near Bemidji, known as the Bemidji line. The project includes expanding the substation near Cass Lake, MN, with a new 230/115 kV transformer. The MPUC issued a CON in July 2009 and a Route Permit in November of 2010. The current schedule for the Bemidji Project shows a projected late 2012 in-service date. Once completed, this project will help support the increasing loads in the Red River Valley region.

With regard to the La Crosse Project, a Route Permit was filed in Minnesota and a CPCN application was filed with the Wisconsin Public Service Commission. The final route was approved in early 2012.

The CapX2020 Group 1 projects listed above 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.

Southwest Twin Cities 115 kV Conversion Projects: In 2006, Xcel Energy and Great River Energy completed a study (*Southwest Metro 115 kV Transmission Development Study*) of the load-serving needs in the regions of Scott, Carver, and Hennepin Counties to the west side of the Twin Cities metro area. The conclusions reached in that study confirmed the results of previous studies that showed that portions of the existing transmission system were not capable of supporting the growing system loads over the next 5 to 10 years. The study also identified three distinct load-serving areas within the larger study area and identified solutions for meeting the load-serving needs of each of these transmission areas. Since that study was completed, we have conducted further evaluations to refine the timing for proposing solutions to the transmission system.

The first of these proposed solutions involves modifications to the existing Glencoe – Waconia transmission facilities in Minnesota. On November 14, 2011, a CON was granted by the MPUC¹. This CON request was filed on November 30, 2010, and calls for the construction of two miles of new 69 kV transmission line², 6 miles of

¹ In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, and the City of Glencoe for a Certificate of Need for 115 kV Transmission Line Upgrades to the Glencoe – Waconia 69 kV System, Docket No. E002/CN-09-1390, November 30, 2010.

² Note that this section will be built to double circuit standards to accommodate additional 115 kV facilities needed for the third phase of development described below.

new 115 kV transmission line, and to upgrade approximately 20 miles of 69 kV transmission line to 115 kV capacity near the cities of Glencoe, Norwood Young America, and Waconia along with the construction of a new substation and certain substation modifications. The project is located in Carver and McLeod counties of Minnesota.

The second of these projects requiring a CON is in or near the Minnesota cities of Chanhassen, Shorewood, Excelsior, Deephaven, Greenwood, Minnetonka, and Eden Prairie³. This project calls for the upgrade of the Bluff Creek – Westgate 69 kV transmission line to 115 kV capacity. This entails upgrading approximately 14 miles of 69 kV transmission line to 115 kV capacity as well as modifications of 2 substations. We filed a CON with the MPUC in March 2012 and a decision is expected in early 2013.

The last of these projects is the upgrade of the transmission lines in and near the City of Chaska from their current 69 kV capacity to 115 kV⁴. This project proposes to construct 8.5 miles of new 115 kV transmission facilities and change the operating voltage of 2.9 miles of an existing 69 kV line to 115 kV. We filed a CON with the MPUC in May 2012 and a decision is expected in early 2013.

C. Proposed Facilities – Next Ten Years

We were recently involved in a large regional MVP study with MISO to determine what large regional transmission build-outs are necessary to increase the reliability of the overall transmission system. The costs of these projects will be shared across the entire MISO footprint. These projects qualify for MVP cost treatment based on their

³ In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Bluff Creek – Westgate Transmission Line Upgrade from 69 kV to 115 kV capacity, Docket No. E002/CN-11-332.

⁴ In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for a Certificate of Need for the Upgrade of the Southwest Twin Cities (SWTC) Chaska Area 69 kilovolt Transmission Line to 115 kilovolt Capacity, Docket No. E002/CN-11-826.

contributions to increased reliability, economic benefits, or supporting compliance with one or more of the states' renewable requirements.

The CapX2020 Brookings County is one of the 18 MISO board approved transmission lines from this study. In addition there are several lines which Xcel Energy will have an ownership stake in. One of these lines is a Big Stone-Brookings County 345 kV line which is expected to provide outlet capabilities for renewable projects.

In addition to the MISO MVP process, 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., Xcel Energy, 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. The MTO was formed 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 ten-year assessment of the member utility system for compliance with the North American Electric Reliability Corporation Transmission Planning 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 the entire region. These MTO studies are available at the MTO website at www.minnelectrictrans.com.

III. NATURAL GAS PIPELINE FACILITIES

A. Existing Facilities

We operate 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, ND, to our natural gas distribution system in Fargo, ND. The Commission granted a CPCN and Corridor Certificate for this facility in Case No. PU-400-89-426. We have no plans to retire any intrastate natural gas pipeline facilities in North Dakota within the next ten years.

B. Proposed 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.

C. Proposed Facilities - Next Ten 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 ten years.

IV. REGIONAL COORDINATION

All major transmission planning performed by the Company is now coordinated through MISO on a regional basis. MISO issues its annual transmission expansion plan after coordinated planning and stakeholder review.

As a result of complying with the FERC Order No. 890 rules, MISO has also implemented Sub-Regional Planning Meetings as part of their annual MTEP development process. We participate in the Western Region meetings. These Sub-Regional Planning meetings provide forums for stakeholder input and coordination of plans and we actively participate 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, as noted above. In addition to the 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 (DRG) 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 investigated the short and long-range transmission requirements in Minnesota, North Dakota, and South Dakota for the MTO utilities to meet renewable energy objectives and standards.

The results of the MTO DRG Transmission study found that the lower and higher voltage transmission grid is constrained in Minnesota when viewed in aggregate statewide, and more transmission is needed to meet renewable energy objectives and standards.

We are also actively supporting the Upper Midwest Transmission Development Initiative (UMTDI), formed in September 2008 by the Governors of North Dakota, South Dakota, Iowa, Minnesota, and Wisconsin.

An executive committee made up of a representative of the Governor's office from each state, and a regulatory commission from each state submitted an Executive Committee Final Report in September 2010. The report identified six renewable transmission corridors for potential primary transmission development, identified regional renewable energy zones most likely to support substantial wind development, and developed a set of cost allocation principles as a foundation for ongoing cost

allocation discussions. The UMTDI will continue to focus on cost allocation in future planning endeavors.

We are 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 now part of the MISO MVP study. The MVP study process has provided justification for cost allocation amongst MISO stakeholders for a portfolio of MVPs finalized in December of 2011.

We also participated in the Strategic Midwest Area Renewable Transmission (SMART) Study that was commissioned in August of 2009. The SMART study's goal was to develop a 20-year transmission plan that ensures reliable electricity transport, efficiently integrates new generation, fosters efficient markets, minimizes environmental impacts, and supports state and national energy policies.

Phase One of the SMART 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 SMART 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.

The study's Phase Two further investigated the economic benefits of alternatives (1) and (3) and was completed in October of 2010. Alternative (2) was eliminated due to its similarity to alternative (1). The economic analysis was performed with four separate economic cases: Base Case Wind, High Gas Futures, Low Carbon Future, and Low Wind Future.

The SMART study's Phase Two results indicate there are no meaningful economic differences between alternatives (1) and (3) in the 2029 time frame.

The Phase One and Two reports can be downloaded at www.smartstudy.biz.

We are participating in the Northern Area Study that was initiated by MISO in June of 2012. The Northern Area Study's goal is to develop a top down plan for MISO Market Efficiency projects or portfolios in the Northern portion of the MISO footprint which includes North Dakota, Minnesota, Manitoba, Wisconsin and Michigan. We will also participate in MISO's Market Efficiency Planning Study which will be a part of the annual MTEP cycle. The Market Efficiency Planning Study's goal is to develop a top down plan for MISO Market Efficiency projects or portfolios in the MISO footprint.

Finally, we are participating in the Eastern Interconnection Planning Collaborative (EIPC). EIPC is an effort to involve the entire Eastern Interconnection Planning Authorities to determine the effects of various policy options determined to be of interest by state, provincial and federal policy makers. EIPC was commissioned by the Department of Energy (DOE) and includes state and federal policy makers, consumer and environmental interests, transmission planning authorities and other energy market participants. The funding opportunity from the DOE has two parts, Module A and Module B. Module A allows the eastern 40 states to collaborate on assessing existing transmission infrastructure and conduct planning scenarios to benefit the entire eastern United States. Module B allows energy leaders in each of

the 40 eastern states to gather as a single entity to collaborate on transmission planning in the entire Eastern Interconnection. The study work began in early 2010.

V. ENVIRONMENTAL PROTECTION

Specific environmental information and efforts to involve land-use planning agencies will be provided to the Commission in future regulatory filings pertaining to specific facilities identified for construction.

VI. DEMAND PROJECTIONS

The NSP System integrates electric generation and transmission to serve customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. The North Dakota portion of the NSP System's 25-year historical native energy requirements and non-coincident peak demand are shown in Table 2. We produce long-range "median" NSP System forecasts of native energy requirements, summer peak, and winter peak demand. For planning purposes, we also develop a bandwidth to supplement our 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 fundamental 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 state jurisdictional sales by major customer class: residential (with and without space heating), small commercial and industrial, and large commercial and industrial. Each customer class is modeled independently for the five states 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 state jurisdictions based on their native energy requirements and respective load factors. 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” peak 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 among states within the NSP System, peak customer demands in our North Dakota service area can be as much as 25 percent higher than it is 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 ND Energy and Peak Load Requirements
(1987 - 2011)

Year	Energy (GWh)	Annual Growth	Non- Coincident Peak Load (MW)	Annual Growth
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%
2008	2,478	4.2%	427	-7.8%
2009	2,379	-4.0%	427	0.0%
2010	2,422	1.8%	445	4.2%
2011	2,441	0.8%	449	0.9%

Table 3
Forecast of NSP System Energy and Peak Load Requirements
(2012 - 2030)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2012	45,307	8,967	6,836
2013	44,809	9,014	6,830
2014	44,889	9,089	6,873
2015	45,095	9,174	6,919
2016	45,466	9,263	6,963
2017	45,675	9,355	7,011
2018	45,909	9,452	7,057
2019	46,085	9,537	7,098
2020	46,315	9,624	7,141
2021	46,494	9,692	7,175
2022	46,789	9,775	7,222
2023	47,096	9,850	7,250
2024	47,431	9,922	7,271
2025	47,689	9,966	7,270
2026	48,022	10,018	7,281
2027	48,413	10,077	7,295
2028	48,880	10,137	7,308
2029	49,308	10,188	7,323
2030	49,754	10,254	7,348

Average Annual Growth Rate, 2012-2030:

% growth: 0.5% 0.7% 0.4%

- Notes:**
- 1) Peak Load is *coincident* to the NSP System peak.
 - 2). Winter Peak = MISO Winter Peak season, 2012 is 2012 - 2013 winter peak.
 - 3) Peak Load is the Base Peak (Uninterrupted)

Table 4
Forecast of ND Energy and Peak Load Requirements
(2012 - 2030)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2012	2,485	324	434
2013	2,524	334	442
2014	2,550	341	448
2015	2,574	347	452
2016	2,601	353	456
2017	2,617	358	458
2018	2,641	363	463
2019	2,666	370	467
2020	2,696	378	474
2021	2,718	383	476
2022	2,743	389	480
2023	2,767	395	485
2024	2,794	402	489
2025	2,818	408	494
2026	2,845	415	498
2027	2,870	422	503
2028	2,902	429	508
2029	2,926	436	512
2030	2,953	443	517

Average Annual Growth Rates, 2011-2029:

% Growth: 1.0% 1.7% 1.0%

- Notes:**
- 1). Peak Load is *coincident* to the Xcel Energy system peak.
 - 2). Winter Peak = MISO Winter Peak season, 2012 is 2012 - 2013 winter peak.
 - 3). Peak Load forecast growth from 2022 - 2030 is based on average summer and winter ND peak growth rates from 2012 - 2021.

APPENDIX A
Schedule of ADP Filings.

Pending ADP petitions

Project	Date Filed	Docket	See Page
Prairie Island Steam Generators and EPU	4/19/2010	PU-10-127	3
Prairie Rose Wind PPA	1/31/2012	PU-12-059	6
Manitoba Hydro PPA	2/8/2012	PU-12-070	5

Potential ADP petitions

Project	Est. Date	Docket	See Page
Goodhue Wind PPA	Late 2012		6
Big Stone - Brookings 345 kV	2013		13
Prairie Island EPU	2013		4
Black Dog Repowering	2015		5

APPENDIX B

Report on the Effect of Wind Generation on Baseload Plants

In the Commission's Order 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 points:

2. NSP will report to the extent possible, as part of its annual ten-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 ten-year plan, on the impacts and costs associated with taking coal plant production up and down to accommodate wind resources during off peak hours.

Ordering Clause 2

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 we do not have enough information to definitively determine the cause of the decisions. Nevertheless, the analysis described below provides a reasonable framework for assessing the impact of wind on the NSP system.

We performed an analysis of the NSP system performance over 8,784 hours from the first hour on June 1, 2011 through the last hour on May 31, 2012. To establish a criteria as to what would constitute a reduction 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 in 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, assume NSP’s load is 500 MWs. Wind generation can provide 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 net wind. 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 the level necessary to serve NSP load net of wind generation due to the market wide demand for energy.

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 3,588,213 MWhs. Wind production contributed to 504,318 MWh or 14 percent of MWhs backed down. Changes in customer load accounted for 51,294 MWh or 1 percent of the MWhs backed down. MISO Market Dispatch was responsible for 3,032,601 MWh or 85 percent 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 366 days evaluated, there were 204 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 June 5, 2011, base load generation was backed down for five hours in part due to wind generation. This was considered a cycle. On June 24, 2011, base load generation was

backed down for one hour in part due to wind generation. This was also counted as one cycle.

Ordering Clause 3

The Company reported on Order Point 3 in the 2010 ten-year plan.