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September 13, 2013

—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 comports 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.

Section 49-22-04 of the Century Code was revised during the 2013 legislative session to require utilities in the state to file their Ten-Year Plans on or before July 1 of every *even-numbered* year (instead of on an annual basis). We had initially interpreted the new statute to mean that our next Ten-Year Plan was to be filed with the commission on or before July 1, 2014. However, in a recent review of our required regulatory filings we realized that the revision to 49-22-04 did not take effect until August 1, 2013. Hence, a Ten-Year Plan needed to be submitted by July 1, 2013. We regret this oversight and seek commission acceptance of this belated filing.

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 (dave.sederquist@xcelenergy.com or (701) 241-8632) if you have any questions regarding this report.

Sincerely,

DAVID H. SEDERQUIST

SR. REGULATORY CONSULTANT  
XCEL ENERGY

Enclosures

c: Service List (WITHOUT ENCLOSURES)

## CERTIFICATE OF SERVICE

I, SaGonna 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 13<sup>th</sup> day of September 2013

/s/

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SaGonna Thompson

Northern States Power Company d/b/a Xcel Energy  
2013 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  
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Department of Agriculture  
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600 East Boulevard Avenue  
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Department of Vocational Education  
State Capitol Building, 15th Floor  
600 East Boulevard Avenue  
Bismarck, ND 58505

Department of Human Services  
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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  
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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  
SEPTEMBER 2013**



# Northern States Power Company 2013 North Dakota Ten-Year Plan

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

IN THE MATTER OF THE 2013 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 North Dakota, South Dakota, and Minnesota. NSP-Wisconsin (NSPW) has service territory in Wisconsin and Michigan. NSPM presently serves approximately 89,000 retail electric customers in North Dakota around Fargo, Grand Forks, and Minot, and 48,000 natural gas customers in the Fargo and Grand Forks areas. The Company owns just over 300 miles of transmission lines and 16 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 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. 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.

### ***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 generally filed every two to 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 environmental 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. The Company is working with the North Dakota PSC and staff to

ensure the resource plan process adequately addresses the concerns and needs of the Commission.

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. NRC approval of our “extended power uprate” (EPU) 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.

As a result of Japan’s Fukushima incident, in October 2011 the NRC’s Advisory Committee on Reactor Safeguards recommended suspension of licensing actions related to containment accident pressure credit.. 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 in October 2013.

The majority of the plant modifications supporting the EPU were made in the Spring of 2011. The last components were 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 April 19, 2011, the Company 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 an EPU. In a letter dated, June 5, 2012 the company requested that the Commission suspend consideration of the EPU portion of the ADP, but move forward with consideration of the new Unit 2 steam generators. On November 28, 2012, the Commission granted the request for an ADP for the Unit 2 steam generators.

## ***2. Fossil Fuel Resources***

**Sherco Upgrades:** 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. As discussed in our September 3, 2013 update letter to the Commission, the unit is expected to return to service before September 30, 2013. We have taken a methodical approach to ensure that we fully understand 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.

On July 1, 2013 the Company filed a Life cycle Management Study for Sherco Units 1 and 2 with the Minnesota Public Utilities Commission (MPUC). The North Dakota filing, which included analysis reflecting zero externalities and no CO<sub>2</sub> costs, was filed on July 23, 2013. The study considers the costs of life extension, installation of environmental control systems, and replacement alternatives.

**Black Dog Peaking Facility:** 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 November 21, 2012, the MPUC issued an Order to establish a Competitive Resource Acquisition Plan docket, determining the appropriate size, type, and timing of the next resource.

The Competitive Resource Acquisition Plan docket generated proposals for 4 projects, intermediate and peaking capacity capabilities of 100-645 MW, with in-service dates beginning in 2017.

As part of the Competitive Resource Acquisition Process (CAP), the Company filed a CON application with the MPUC on April 15, 2013 for the repowering of Black Dog Units 3 and 4 with a 230 MW natural gas fired combustion turbine facility. We filed an ADP for this facility with the Commission on April 26, 2013 in Case No. PU-13-194.

**Red River Valley Peaking Units.** As part of the CAP, the Company also filed a CON application with the MPUC on April 15, 2013 for the addition of a 460 MW natural gas fired combustion turbine facility to be located in the Hankinson North Dakota area that would connect to Otter Tail Power Company's Hankinson substation. We filed an ADP for this facility with the Commission on April 26, 2013 in Case No. PU-13-195.

In Response to the Competitive Resource Acquisition Plan docket a number of other proposals were submitted as alternatives to our Black Dog and Red River Valley Peaking facility proposals. These alternate proposals included a PPA proposal from Calpine to increase the output of the existing Mankato Energy Center by 345 MW; a PPA proposal from Invenergy to increase the output of the existing Cannon Falls Generating Plant by 179 MW; a PPA proposal from Invenergy to construct a new 358 MW natural gas fired combustion turbine facility; a PPA proposal from Geronimo Energy to construct 100 MW of new distributed solar facilities; and a proposal from Great River Energy to provide 100-200 MW of accredited capacity from 2016 to 2018.

The proposals have been deemed substantially complete and accepted. This Case is being heard by the Office of Administrative Hearings in Minnesota. The ALJ is expected to provide a report to the MPUC by January 1, 2014.

### ***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 Company filed an ADP for this transaction with the Commission on February 8, 2012 in Case No. PU-12-70. On August 1, 2012, the North Dakota Public Service Commission granted the request for an ADP for all three power purchase agreements and associated transactions.

### ***4. Renewable Resources***

**Courtenay and Odell:** The Company solicited additional wind projects through a Request for Proposal (RFP) issued on February 15, 2013. As a result of that solicitation, the Company received a number of very competitive bids, conducted negotiations, and signed PPAs for the purchase of 400 MW from Geronimo Wind LLC. The energy will come from a 200 MW facility that will connect to Ottetail Power's Jamestown North Dakota substation (the Courtenay Project) and from a 200 MW facility that will connect to a new substation on Xcel Energy's Lakefield Junction – Wilmarth 345 kV line Minnesota (the Odell Project). We filed an ADP for this contract with the Commission on July 26, 2013 in Case Nos. PU-13-706 (Courtenay) and 13-707 (Odell).

**Border Winds and Pleasant Valley Wind Facilities:** In addition to the PPAs, as a result of the RFP we have completed negotiations and signed agreements for the purchase of 350 MW from RES Americas LLC from a 200 MW facility that will connect to Great River Energy’s Pleasant Valley substation (the Pleasant Valley Project) and from a 150 MW facility that will connect to a new substation on Xcel Energy’s Harvey – Glenboro 230 kV line in North Dakota (the Border Winds Project). We filed an ADP and Certificate of Public Convenience and Necessity for the Border Winds contract with the Commission on August 13, 2013 in Case Nos. PU-13-742 and 743, respectively. We filed an ADP for the Pleasant Valley contract with the Commission on July 26, 2013 in Case No. PU-13-708.

***C. Proposed Facilities - Next Ten Years***

At this time, plans for additional electric generation facilities in the State of North Dakota over the next ten years include the 460 MW Red River Valley Peaking Facility and 350 MW of wind energy facilities. This is a competitive process.

**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	Line Description	Line Number	Voltage	Line Mileage
ND	Letellier-Drayton	912	230	28.7
ND	Prairie-Grand Forks (WAPA)	916	230	6.8
ND	Maple River-Wahpeton (MPC)	910	230	3.6
ND	Maple River-Sheyenne	911	230	8
ND	Sheyenne-Fargo(WAPA)	915	230	4.3
ND	Sheyenne-Audubon (OTP)	911	230	1.4

ND	Audubon (OTP)-Hubbard (MP)	909	230	38.3
ND	Harvey-Glenboro (OTP)	920	230	56.4
	<b>Total 230 kV</b>			<b>147.5</b>
ND	Maple River-Red River	839	115	5.6
ND	Maple River-Cass County	839	115	2.7
ND	Cass County Tap-Moderow (MPC)	839	115	1.9
ND	Moderow (MPC)-Sheyenne	839	115	1.5
ND	Cass County-Sheyenne	866	115	3.5
ND	Mallard-Souris	860	115	5.3
ND	Souris-Velva	850	115	19.6
ND	Velva-McHenry	850	115	5.2
ND	McHenry-Neal	850	115	0.2
ND	Prairie-Nordic1	5510	115	2
ND	Prairie-Nordic2	5511	115	1.98
	<b>Total 115 kV</b>			<b>49.48</b>
ND	Ada-Ada (MPC)	757	69	3.1
ND	Gateway-Grand Forks Steam	746	69	0.9
ND	Gateway-Prairie	746	69	5.5
ND	Grand Forks (WAPA)-Central	786	69	4.6
ND	Central-Sugar Hills	786	69	0.8
ND	Sugar Hills-Park	786	69	0.8
ND	Park-Park Tap	786	69	2.3
ND	Prairie-Emerado	772	69	13.3
ND	Prarie-Thompson	733	69	8.5
ND	Thompson-Reynolds	773	69	7
ND	Reynolds-South	773	69	10
ND	South-Hillsboro Tap	773	69	8.6
ND	Hillsboro Tap-Hillsboro	773	69	1.9
ND	Hillsboro-Trail County	773	69	1
ND	Trail County-Elm River	773	69	9.3
ND	South-Mayville (MPC)	768	69	12
ND	Mayville (MPC)-Mayville	768	69	1.2
ND	Mayville-Hatton	768	69	14.8
ND	Elk Valley-Larimore	776	69	1.7
	<b>Total 69 kV</b>			<b>107.3</b>

### ***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 was completed and placed in-service in September 2012. Construction started on the Brookings project in May 2012 and on the La Crosse project in February 2013. The three 345 kV projects have an in-service date of 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.

A Route Permit was granted by the MPUC for the Monticello to St. Cloud segment of the Fargo project 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 North Dakota Public Service Commission approved a Certificate of Corridor Compatibility and a Route Permit in September 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 granted a Route Permit for the Minnesota portion of this Project in May 2011. A Facility Permit application for the South Dakota segment of the project was filed with the South Dakota Public Utilities Commission in November 2010 and granted by the commission in June 2011. The 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 by Orders issued on October 6, 2011 and November 10, 2011 (Case Nos. PU-09-676 and PU-09-678).

Otter Tail Power Company, Minnkota Power Cooperative, and Minnesota Power, 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 230 kV Bemidji project was completed and energized in September 2012.

A Route Permit for the La Crosse project was filed with the MPUC in January 2010 and granted by the MPUC in May 2012. A Certificate of Public Convenience and Necessity application was filed with the Public Service Commission of Wisconsin (PSCW) in January 2011 and approved by the PSCW in May 2012.

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](http://www.capx2020.com).

**Southwest Twin Cities 115 kV Conversion Projects: 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 the proposed solutions is the 115 kV line from Glencoe to West Waconia, this project would be completed by Fall of 2013.

The second of these projects requiring a CON is in or near the Minnesota cities of Chanhassen, Shorewood, Excelsior, Deephaven, Greenwood, Minnetonka, and Eden Prairie<sup>[1]</sup>. During the regulatory proceedings NSP was requested to study additional system alternatives, this resulted in a new preferred plan to operate the existing Scott County – Bluff Creek – Westgate 115 kV line as double circuit. The new transmission alternative would not require converting the existing 69 kV line through Excelsior and Deephaven to 115 kV. The MPUC decision on the project is expected in Fall of 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 kV<sup>[2]</sup>. 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 Fall of 2013.

**Scott County 345 kV:** The yearly NERC transmission planning compliance assessments in the past have indicated that Eden Prairie 345-115 kV transformers would be overloaded in the near future. “NSP BDS Unit 3&4 Retirement Transmission Study” also indicated that the retirement of Black Dog Units 3 and 4 in 2015 would result in overloading the Eden Prairie transformers beyond their

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<sup>[1]</sup> 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.

<sup>[2]</sup> 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.

emergency rating. The “Southwest Twin Cities Phase 2 Study Update” performed to address the Southwest Twin Cities load serving deficiencies also indicated that a new 345 kV source would be needed at Scott County around 2023. Therefore, to address the load serving deficiencies and 345-115 kV transformer capacity issues, the Scott County 345 kV Expansion project was found to be the most cost effective plan.

Facilities include new 345 kV double circuit line from the Helena – Blue Lake 345 kV line to Scott County substation and install two new 345-115 kV transformers at Scott County substation. NSP intends to file the permit application for the 345 kV line by the end of 2013. Construction of the project would begin end of 2014 or early 2015.

**Hollydale Project:** The Company reviewed its distribution system for the western Twin Cities Metro area in 2010 during *The Plymouth Area Load Serving Study*. It was found that there was a deficiency on the distribution system in its ability to deliver power and the best distribution system plan would be to add a new injection source at the Hollydale Substation. Subsequently a transmission planning study *Hollydale/Meadow Lake Load Serving Study* was performed. It was found that the best way to supply the request was reconstruction of an existing 69 kV line to 115 kV and integration into the 115 kV western Twin Cities Metro network.

Facilities will include a rebuild of the Plymouth – Medina 69 kV line to 115 kV, construction of a new Pomerleau Lake 115 kV substation and modifications at Medina to allow a connection to this line. The project constructs about 9 miles of 115 kV transmission line. An additional *Addendum* and *Supplement* have been provided to the state of MN to confirm the need and provide additional details on this project selection.

State permitting began on this project in 2011. Certificate of Need proceedings are in progress and are expected to conclude in early 2014. State route proceedings are

expected to be completed in 2014. The scheduled in-service date of the project is 2015.

**Prairie Substation 3<sup>rd</sup> 345/115 k V Transformer:** The “2010 Voltage Stability Study” and the “Grand Forks Load Serving Study” indicate that the Grand Forks area is susceptible to voltage instability during the loss of both the existing 230-115 kV transformers at NSP’s Prairie substation. The study indicated that the least cost plan to address the voltage instability in the area is to install a third 230-115 kV transformer at NSP’s Prairie substation.

The facilities required for this project include a short 230 kV line from Minnkota Power Co-op’s Prairie substation to NSP’s Prairie substation and a new 230-115 kV transformer at NSP’s Prairie substation. As part of this project, NSP’s Prairie substation would be re-configured to NSP’s current substation standard. The permit application for this project would be filed in 2013 and construction would begin in 2014.

**Fargo Load Serving:** NSP’s yearly planning assessments have indicated that the existing Fargo area 115 kV system and the 230-115 kV transformers are deficient in the ability to serve the load during double contingency conditions. NSP performed the “Fargo Load Serving Study” to identify transmission plan to address these load serving deficiencies in this area, and determined that a 5 mile 115 kV line from Maple River substation to Red River substation would be the least cost option.

The facilities include building 5 miles of new 115 kV line from Maple River substation to Red River substation, and substation work at Maple River and Red River to accommodate the new line. The permit application for this project would be filed in late 2013 and construction of the project would begin in 2014.

**Minot Load Serving Plan:** NSP has a near term proposal to install 30 MVARs of capacitor bank capability at Souris substation. The capacitor banks are expected to be

in service by 2016. These capacitor banks will provide voltage support during contingency and high load levels. A joint study with Basin Electric Power Cooperative, Western Area Power Administration, and Central Power Electric Cooperative is being commissioned to determine long term solutions for the Minot Area.

### ***C. Proposed Facilities – Next Ten Years***

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

The CapX2020 Brookings County transmission line is one of the 17 MISO board approved transmission lines from this study. In addition, Xcel Energy will have an ownership stake in the 70-mile Big Stone South-Brookings County 345 kV transmission line and the 150-mile La Crosse-Madison 345 kV transmission line.

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](http://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 (MTEP) 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.

<https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx>

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 Company participates in all MISO targeted planning studies, which are studies that happen outside the normal MTEP process. MISO has performed two targeted studies in the last two years. The first targeted study was the Manitoba Hydro Wind Synergy Study. This was an economic planning study to determine the benefits to the MISO system of 1) increased regulation of wind by the unique storage characteristics of the Manitoba Hydro reservoir and generation system 2) the economic advantage of additional Manitoba Hydro resources to the MISO Market and 3) evaluate a new economic modeling software (PLEXOS) and a new economic model of Manitoba Hydro based on the economic value of stored water. The Synergy study evaluated a 500 kV transmission line to the Fargo/Moorhead area and a 500 kV transmission line to the Duluth Area. The Synergy study report will be included as a part of the MTEP13 report. The conclusions of the Synergy study were that there was benefit to having access to additional hydro resources, both transmission options had similar benefits, and with extended Manitoba Hydro MISO has lower production costs and load payments. The Synergy study was a high level vision study and no transmission

was approved for inclusion in MTEP Appendix A for MISO Board of Directors approval. The second targeted study was the Northern Area Study (NAS). The NAS investigated several transmission plans to solve economic congestion and reliability issues in the Northern MISO footprint including North Dakota, Minnesota, Wisconsin and Michigan. The study addressed potential large industrial loads, potential generation retirements, and increased imports from Manitoba. The study found that there is not enough economic benefit to recommend a transmission project, MISO could realize the economic benefits of the proposed Manitoba Hydro generation with little additional transmission investment. The NAS report will be included in the MTEP 13 report.

The Company is also participating in the Manitoba Hydro Transmission Service Request study. There are presently 1100 MWs of southward transmission service requests (TSR) and one signed Power Purchase Agreement (PPA) by Minnesota Power. The TSRs will be served by one of two options. The first is a 500 kV transmission line to a new 500 kV/345 kV substation in the Fargo-Moorhead area. The second is a 500 kV transmission line to an existing substation on the Iron Range (Blackberry) and a double circuit 345 kV transmission line to the Arrowhead substation near Duluth. MISO TSR evaluation demonstrates that both options can meet the transmission service requests with limited additional network upgrades. Any line approved through the TSR process will be included in Appendix A of the MTEP report and submitted for approval by the MISO Board of Directors.

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. The initial EIPC study effort is expected to be completed after the last phase of study work is completed which is focused on the interdependency of gas and electric infrastructure across the Eastern Interconnection of the U.S.

## **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 primarily 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**  
**(1988 - 2012)**

<b>Year</b>	<b>Energy (GWh)</b>	<b>Annual Growth</b>	<b>Non- Coincident Peak Load (MW)</b>	<b>Annual Growth</b>
1988	1,658		323	
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%
2012	2,419	-0.9%	438	-2.5%

**Table 3**  
**Forecast of NSP System Energy and Peak Load Requirements**  
**(2013 - 2031)**

<b>Year</b>	<b>Energy (GWh)</b>	<b>Summer Peak Load (MW)</b>	<b>Winter Peak Load (MW)</b>
2013	44,498	9,174	6,549
2014	44,406	9,203	6,557
2015	44,521	9,264	6,602
2016	44,820	9,326	6,643
2017	44,934	9,401	6,696
2018	45,165	9,477	6,749
2019	45,432	9,549	6,810
2020	45,743	9,629	6,878
2021	46,016	9,705	6,941
2022	46,296	9,782	7,006
2023	46,524	9,848	7,053
2024	46,738	9,906	7,095
2025	46,908	9,946	7,124
2026	47,284	10,015	7,182
2027	47,629	10,073	7,230
2028	48,023	10,133	7,283
2029	48,380	10,188	7,334
2030	48,724	10,260	7,395
2031	49,012	10,329	7,457

**Average Annual Growth Rate, 2012-2030:**

**% growth:                      0.5%                      0.7%                      0.7%**

- Notes:**
- 1) Peak Load is *coincident* to the NSP System peak.
  - 2) Winter Peak = MISO Winter Peak season, 2013 is 2013 - 2014 winter peak.
  - 3) Peak Load is the Base Peak (uninterrupted)

**Table 4**  
**Forecast of ND Energy and Peak Load Requirements**  
**(2013 - 2031)**

<b>Year</b>	<b>Energy (GWh)</b>	<b>Summer Peak Load (MW)</b>	<b>Winter Peak Load (MW)</b>
2013	2,507	372	410
2014	2,524	376	413
2015	2,545	382	418
2016	2,570	386	421
2017	2,588	393	425
2018	2,609	398	430
2019	2,631	403	433
2020	2,655	408	438
2021	2,680	415	444
2022	2,706	420	449
2023	2,729	425	453
2024	2,752	431	458
2025	2,779	436	462
2026	2,805	441	466
2027	2,830	447	470
2028	2,858	452	475
2029	2,885	458	479
2030	2,910	463	484
2031	2,933	469	488

**Average Annual Growth Rate, 2012-2030:**

**% Growth:           0.9%           1.3%           1.0%**

- Notes:**
- 1) Peak Load is *coincident* to the Xcel Energy system peak.
  - 2) Winter Peak = MISO Winter Peak season, 2013 is 2013 - 2014 winter peak.
  - 3) Peak Load forecast growth from 2023 - 2031 is based on average summer and winter ND peak growth rates from 2013 through 2022.

**APPENDIX A**  
**Schedule of ADP Filings.**

Pending ADP Petitions

Project	Date Filed	Docket	See Page
Border Winds	8/13/2013	PU-13-742	7
Courtenay PPA	7/26/2013	PU-13-706	6
Odell PPA	7/26/2013	PU-13-707	6
Pleasant Valley	7/26/2013	PU-13-708	7
NSP Nat. Gas CT Proposals	4/26/2013	PU-13-194	16
Prairie Rose Wind PPA	1/31/2012	PU-12-059	14

Anticipated ADP Petitions

Project	Est. Date	Docket	See Page
Big Stone - Brookings 345 kV	TBD	NA	15
CAP Resource Selection(s)*	Q1 2014	NA	4

\* If the final resource selections from the MN Competitive Acquisition Process to fill the anticipated 2017-2019 capacity need are different from the Company's current natural gas combustion turbine proposal (Case No. PU-13-194), a new ADP application will be filed.

## **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 points:

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 8,760 hours from the first hour on June 1, 2012 through the last hour on May 31, 2013. 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, 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 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 1,667,547 MWhs. Wind production contributed to 274,126 MWh or 16.4% of MWhs backed down. Changes in customer load accounted for 4,522 MWh or 0.3% of the MWhs backed down. MISO Market Dispatch was responsible for 1,388,899 MWh or 83.3% 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 142 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 12, 2012, base load generation was backed down for four hours in part due to wind generation. This was considered a cycle. On June 13, 2012, 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

Per the ADP for the Nobles Wind Project dated August 12, 2009, in Case No. PU-08-907, the Company reported on Order Point 3 in the 2010 10-year plan.