2302 Great N. Drive
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Xcel Energy®

July 1, 2016

—Via Electronic Filing & Federal Express—

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

RE: NORTHERN STATES POWER COMPANY
BIENNIAL 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 is in compliance 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.

In compliance with section 69-06-02-02, notice of the filing has been given to each state agency and officer entitled to notice as designated in section 69-06-01-05. A service list is attached.

Please feel free to contact me at dave.sederquist@xcelenergy.com or (701) 241-8632 if you have any questions regarding this report.

Sincerely,

David H Sederquist

DAVID H. SEDERQUIST
SR. REGULATORY CONSULTANT
XCEL ENERGY

Enclosures
c: Service List (WITHOUT ENCLOSURES)

CERTIFICATE OF SERVICE

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

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

Dated this 1st day of July 2016

/s/

Carl Cronin
Regulatory Administrator

Northern States Power Company d/b/a Xcel Energy
2016 North Dakota Ten-Year Plan
Service List – Notice of Filing

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

Aeronautics Commission
PO Box 5020
Bismarck, ND 58502

Attorney General
State Capitol Building, 1st Floor
600 East Boulevard Ave., Dept. 125
Bismarck, ND 58505

Department of Agriculture
State Capitol Building, 6th Floor
600 East Boulevard Ave., Dept. 602
Bismarck, ND 58505-0020

Department of Health
State Capitol Building
2nd Floor Judicial Wing
600 East Boulevard Ave.
Bismarck, ND 58505-0200

Department of Human Services
State Capitol, Judicial Wing
600 East Boulevard Ave., Dept 325
Bismarck, ND 58505-0250

ND Department of Labor & Human Rights
State Capitol, 13th Floor
600 East Boulevard Ave.
Bismarck, ND 58505-0340

Department of Commerce
Division of Economic Development & Finance
Century Center
1600 East Century Ave., Suite 2
PO Box 2057
Bismarck, ND 58502-2057

Energy Development Impact Office
1707 N. 9th St
PO Box 5523
Bismarck, ND 58506-5523

Game & Fish Department
100 North Bismarck Expressway
Bismarck, ND 58501-5095

North Dakota Industrial Commission
Geological Survey
1016 East Calgary Ave.
Bismarck, ND 58503

Governor's Office
State Capitol Building, 1st Floor
600 East Boulevard Ave., Dept 101
Bismarck, ND 58505-0001

Department of Transportation
608 East Boulevard Ave.
Bismarck, ND 58505-0700

State Historical Society of North Dakota
Heritage Center, Capitol Grounds
612 East Boulevard Ave.
Bismarck, ND 58505-0830

Indian Affairs Commission
State Capitol, 1st Floor Judicial Wing – Rm 117
600 East Boulevard Ave.
Bismarck, ND 58505-0300

Job Service of North Dakota
1000 East Divide
PO Box 5507
Bismarck, ND 58506-5507

State Land Department
1707 N. 9th St.
PO Box 5523
Bismarck, ND 58506-5523

Parks and Recreation Department
1600 East Century Ave., Suite 3
Bismarck, ND 58503-0649

Soil Conservation Committee
2718 Gateway Ave., Ste. 104
Bismarck, ND 58503-0585

State Water Commission
900 East Boulevard Ave., Dept. 770
State Office Building
Bismarck, ND 58505-0850

United States Department of Defense
Minot Air Force Base
201 Summit Drive
Minot, ND 58701

United States Fish and Wildlife Service
3425 Miriam Avenue
Bismarck, ND 58501

United States Army Corps of Engineers
1513 South 12th Street
Bismarck, ND 58504

Federal Aviation Administration
Bismarck Airports District Office, BIS-ADO-600
2301 University Drive, Building 23B
Bismarck, ND 58504

North Dakota Transmission Authority
c/o North Dakota Industrial Commission
600 E. Boulevard Ave., Dept 405
State Capitol, 14th Floor
Bismarck, ND 58505-0840

North Dakota Pipeline Authority
c/o North Dakota Industrial Commission
600 E. Boulevard Ave., Dept 405
State Capitol, 14th Floor
Bismarck, ND 58505-0840

Ten-Year Plan for Major Generation and Transmission Facilities

to the

North Dakota
Public Service Commission

Submitted by
Northern States Power Company,
a Minnesota corporation
July 1, 2016

Northern States Power Company
2016 North Dakota Ten-Year Plan

Table of Contents

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE 2016 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, (Xcel Energy or the Company) is pleased to submit our biennial Ten-Year Plan to the North Dakota Public Service Commission (Commission) in compliance with Section 49-22-04 of the North Dakota Century Code.

The NSP-Minnesota operating company (NSPM) has service territory in North Dakota, South Dakota, and Minnesota. NSP-Wisconsin (NSPW) has service territory in Wisconsin and Michigan. The Company operates the NSPM and NSPW generation and transmission as the NSP System. We presently serve approximately 92,000 retail electric customers in North Dakota around Fargo, Grand Forks, and Minot, and 54,000 natural gas customers in the Fargo and Grand Forks areas. The Company owns just over 430 miles of transmission lines and 20 substations (69kV and above) in North Dakota.

This Ten-Year Plan contains expanded information in compliance with the Settlement in Case No. PU-07-776 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 customers in our NSPM and NSPW service areas; and
- A schedule of anticipated future applications for Advance Determination of Prudence (ADP).

I. ELECTRIC GENERATION FACILITIES

A. Existing Facilities

__Border Winds Generating Facility.__ The Company solicited additional wind projects through a Request for Proposal (RFP) issued on February 15, 2013 (2013 Wind RFP).

As a result of the 2013 Wind RFP, the Company purchased 150 MW wind facility from RES Americas LLC that is connected to a new substation called Peace Garden on Xcel Energy's Harvey – Glenboro 230 kV line in North Dakota. We filed an ADP for the Border Winds contract with the Commission on August 13, 2013 in Case No. PU-13-742. On February 26, 2014, the Commission approved the Border Winds ADP as part of a comprehensive rate case settlement. The project reached commercial operation on December 3, 2015.

Power Purchase Agreements (PPA) and exchanges 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 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

We describe the projected resource needs for the NSP System in our Resource Plan, which is generally filed every two to three years with our various state commissions. We filed our 2016-2030 Resource Plan on January 2, 2015, and filed a substantive supplement on January 29, 2016. Our Resource Plan (North Dakota Case No. PU-15-019; Minnesota Docket No. E002/RP-15-21) includes planning scenarios based on North Dakota requirements – specifically excluding environmental externalities as required by N.D.C.C.§49-02-23.

Comments from intervening parties in our pending Resource Plan are due to the Minnesota Public Utilities Commission through July 8, with Reply Comments due on August 12.

We propose to continue to fulfill our future electric generating resource needs through multiple resource acquisition processes including competitive bidding, Company ownership, PPAs, and demand side management.[1] This multi-pronged and flexible approach to resource acquisitions allows us to consider multiple generation 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

[1] While the Company has included proposed resources in its Resource Plan, at this point there are no specific plans with sufficient information for listing in the Anticipated ADP Petitions table in Appendix A.

diverse portfolio of resources that will provide our customers with cost-effective and reliable service over the long-term. As the Commission is aware, the Company is working toward development of a Resource Treatment Framework (RTF) to provide the necessary framework to manage resources in the states we serve. The Company will file the RTF with the North Dakota Commission by January 1, 2017.

1. *Nuclear Resources*

Monticello. In November 2008, we filed an application with the 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 operation at the increased thermal power, also known as "extended power uprate" (EPU), allowed us to increase the current generating capacity of 600 MW by approximately 71 MW. On June 30, 2015, Monticello ascended to 2004 MWt (671 MWe) for a period of time, during which we tested its systems and collecting data regarding operating conditions at that level for NRC review. On July 14, 2015, the Company received final notice from the NRC that the Company is permitted to continue operations at full uprate conditions. Since July 15, 2015, Monticello has been routinely generating at or above 671 MWe.

2. *Fossil Fuel Resources*

Black Dog. Black Dog Units 3 and 4 were installed in 1955 and 1960, respectively, and due to changes to environmental permit compliance requirements, these units ceased coal-fired generation on April 15, 2015. These units were at the end of their economic and engineering life.

On April 26, 2013, we submitted an Application requesting an ADP to the North Dakota Commission for our proposed addition of Black Dog Unit 6 and Red River Valley (RRV) Units 1 and 2. The Commission conducted a formal hearing on November 26, 2013, and effective December 16, 2013, consolidated the ADPs, along with several wind proceedings, for hearing on a settlement in the Company's then-pending rate case in Case No. PU-12-813. The Commission held a consolidated hearing on January 23, 2014 and on February 26, 2014 the Commission adopted a revised Second Amended Settlement which approved the proposed ADP for Black Dog 6.

Red River Valley. In our ADP Application, the Company noted that it had filed a similar application for RRV Units 1 and 2 in the Minnesota Public Utilities Commission's Competitive Acquisition Process (CAP) proceeding, Docket No. E002/CN-12-1240, and acknowledged that the outcome of the CAP proceeding could result in the Company pursuing an alternative approach to meet the forecasted 2017-2019 capacity needs. Our proposed Red River Valley Units were not approved in the CAP proceeding. We therefore do not intend to further pursue Red River Valley Units 1 and 2 at this time. We remain, however, committed to developing North Dakota based generation consistent with prudent resource planning principles and consistent with our commitments in the Second Revised Settlement the Commission adopted in its February 26, 2014 Order and the March 9, 2016 Order Approving the First Revised Negotiated Agreement filed on February 22, 2016.

Mankato Energy Center Unit 2. On February 5, 2015, the Minnesota Commission approved a proposal made by the Calpine Corporation for the expansion of the Mankato Energy Center. On February 13, 2015, the Company filed an ADP Application with the North Dakota Commission for 345 MW of capacity and associated energy to be added to the NSP System through a 20-year PPA with Mankato Energy Center, LLC, an affiliate of Calpine Corporation (Calpine PPA) in Case No. PU-15-96. On March 23, 2016, the Commission issued its Findings of Fact, Conclusions of Law and Order in the Case dismissing our application without prejudice. This provides the Company additional opportunities to seek cost recovery for this project in the future.

3. *Hydro Resources*

Manitoba Hydro. The 2015-2025 contract extensions with Manitoba Hydro were implemented through three coordinated agreements on May 1, 2015. 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 Commission granted the request for an ADP for all three PPAs and associated transactions.

4. *Wind Resources*

Courtenay. As part of the 2013 Wind RFP, the Company selected the Courtenay Wind project, conducted negotiations, and signed a PPA for the purchase of 200 MW from Geronimo Wind LLC. The facility will connect to Otter Tail Power's Jamestown, North Dakota substation. We filed an ADP for this contract with the Commission on July 26, 2013 in Case Nos. PU-13-706. On February 26, 2014, the Commission approved the Courtenay ADP as part of a comprehensive rate case settlement. On May 5, 2015 the Company filed an ADP to change the project from a PPA to an acquisition and development in Case No. PU-15-181. On August 26, 2015 the Commission approved this ownership project. The project is currently under construction; several portions of the project are ahead of schedule. The Company expects this project to reach commercial operation in December 2016.

Odell. As a result of the 2013 Wind RFP, the Company signed a PPA for the purchase of 200 MW from Geronimo Wind LLC. The wind facility will connect to a new substation on Xcel Energy's Lakefield Junction – Wilmarth 345 kV line in Minnesota. We filed an ADP for this project with the Commission on July 26, 2013 in Case No. PU-13-707 (Odell). The Commission dismissed the Odell ADP without prejudice. However, the Commission granted an ADP for this project in its March 9, 2016 Order approving the Negotiated Agreement (Case No. PU-12-813). The Odell project is expected to reach commercial operation in December 2016.

Pleasant Valley. As a result of the 2013 Wind RFP, in addition to the Courtenay and Odell PPAs, the Company purchased a 200 MW wind facility from RES Americas LLC that will connect to Great River Energy's Pleasant Valley substation in Minnesota. We filed an ADP for the 200 MW Pleasant Valley wind facility in Case No. PU-13-743. The Commission dismissed the Pleasant Valley ADP without prejudice. However, as part of the Negotiated Agreement in Case No. PU-12-813, the Commission granted an ADP for this project on March 9, 2016. The Pleasant Valley project reached commercial operation November 19, 2015.

5. Solar Energy Facilities

187 MW Solar Portfolio. The Company solicited solar projects through an RFP issued on April 22, 2014. As a result, the Company signed PPAs for the purchase of 187 MW from three proposed solar projects. We filed an ADP for these PPAs with the Commission on November 7, 2014 in Case No. PU-14-810, which the Commission denied on June 17, 2015. The Company expects two of these projects to reach commercial operation by December 2016.

Aurora. On April 15, 2013, Geronimo Energy LLC submitted a proposal for the 100 MW Aurora solar generation project through a 20-year PPA. The project was selected and approved by the Minnesota Public Utilities Commission as a resource in the CAP proceeding. We filed an ADP for this project with the Commission on February 13, 2015 in Case No. PU-15-95. On September 16, 2015 the Commission denied the ADP. The Company has proceeded with this project, and expects to reach commercial operation by December 2016.

C. Proposed Facilities – Next 10 Years

At this time, specific plans for additional electric generation facilities in the State of North Dakota over the next 10 years include the 200 MW Courtenay wind energy facility, described above. As also outlined above, the Company has proposed changes to its generation resources and mix as part of its pending 2016-2030 Resource Plan.

Additionally, on March 9, 2016, the Commission approved the First Revised Negotiated Agreement between the Company and Commission Advocacy Staff that included a renewed commitment by the Company to build generation in North Dakota. Specifically, the Company committed:

> *By the end of 2025, [the Company] will build or have located in eastern North Dakota a natural gas-fired electric generation facility with a capacity of at least 200 MW. The combustion turbine will be treated as an [Xcel Energy] System resource and its costs will be allocated to all states and customers served by the [Xcel Energy] System. If the combustion turbine is not in-service by December 31, 2025, [the Company] will refund to its North Dakota customers 50 percent of the revenues collected from North Dakota customers that exceed the revenues that would have been collected from January 1, 2016 through December 31, 2025 if North Dakota customers had paid an adjusted system average cost for fuel, and energy and associated capacity, for the six biomass PPAs identified in the Negotiated Agreement.* [2]

The Commission's March 9, 2016 Order also outlined the need for a long-term RTF which the Company is required to file with the Commission by January 1, 2017 and implement on January 1, 2018.[3] We continue to work on the development of the RTF in compliance with this requirement. In addition, a copy of the Aurora Compliance Filing on Jurisdictional Cost Issues that was filed with the Minnesota Public Utilities Commission on June 13, 2016 (MPUC Docket Nos. E002/M-15-330; E002/M-16-223) was provided to the North Dakota Public Service Commission.[4] The Aurora Compliance filing contains information that relates directly to the Company's efforts to develop a RTF that can accommodate differing state energy policies and priorities.

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[2] *N. States Power Co. 2013 Elec. Rate Increase Application et al.*, Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195, ORDER APPROVING SETTLEMENT at 4 (N.D. P.S.C. Mar. 9, 2016).

[3] Id.

[4] See Case Nos. PU-12-813, PU-13-706, PU-13-707, PU-13-708, PU-13-742, PU-13-743, PU-13-194, PU-13-195.

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 10 years.

Table 1. NSP North Dakota Transmission Lines

Line Description	Line Number	kV	Line Mileage
Bison-Alexandria SS (MRES)	0955	345	135.7
Total 345 kV			**135.7**
Letellier-Drayton	912	230	28.7
Prairie-Grand Forks (WAPA)	916	230	6.8
Maple River-Wahpeton (MPC)	910	230	3.6
Maple River-Sheyenne	911	230	8
Sheyenne-Fargo(WAPA)	915	230	4.3
Sheyenne-Audubon (OTP)	911	230	1.4
Audubon (OTP)-Hubbard (MP)	909	230	38.3
Harvey-Glenboro (OTP)	920	230	56.4
Total 230 kV			**147.5**
Maple River-Red River	839	115	5.6
Maple River-Cass County	839	115	2.7
Cass County Tap-Moderow (MPC)	839	115	1.9
Moderow (MPC)-Sheyenne	839	115	1.5
Cass County-Sheyenne	866	115	3.5
Mallard-Souris	860	115	5.3
Souris-Velva	850	115	19.6
Velva-McHenry	850	115	5.2
McHenry-Neal	850	115	0.2
Prairie-Nordic1	5510	115	2
Prairie-Nordic2	5511	115	1.98
Total 115 kV			**49.48**

Ada-Ada (MPC)	757	69	3.1
Gateway-Grand Forks Steam	746	69	0.9
Gateway-Prairie	746	69	5.5
Grand Forks (WAPA)-Central	786	69	4.6
Central-Sugar Hills	786	69	0.8
Sugar Hills-Park	786	69	0.8
Park-Park Tap	786	69	2.3
Prairie-Emerado	772	69	13.3
Prarie-Thompson	733	69	8.5
Thompson-Reynolds	773	69	7
Reynolds-South	773	69	10
South-Hillsboro Tap	773	69	8.6
Hillsboro Tap-Hillsboro	773	69	1.9
Hillsboro-Trail County	773	69	1
Trail County-Elm River	773	69	9.3
South-Mayville (MPC)	768	69	12
Mayville (MPC)-Mayville	768	69	1.2
Mayville-Hatton	768	69	14.8
Elk Valley-Larimore	776	69	1.7
Total 69 kV			**107.3**

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, which includes updates on previously proposed facilities.

1. *CapX2020*

CapX2020 lines have recently gone in service. The following is an update on those 345 kV and 230 kV lines:

- A 230 mile, 345 kV line between Brookings, South Dakota, and the southeast Twin Cities, plus a related 30 mile, 345 kV line between Marshall, Minnesota, and Granite Falls, Minnesota (Brookings Project). This project is currently in service.
- A 250 mile, 345 kV line between Fargo, North Dakota, and Alexandria, St. Cloud and Monticello, Minnesota (Fargo Project). All segments from Monticello to St. Cloud to Alexandria to Fargo are currently in service.
- A 150 mile, 345 kV line between the southeast Twin Cities, Rochester, Minnesota, and La Crosse, Wisconsin (La Crosse Project) is currently in service.

- A 68 mile, 230 kV line between Bemidji and Grand Rapids, Minnesota (Bemidji Project). This project has been completed and is now in service.

2. *Prairie Substation 3rd 345/115 kV 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 NSPM'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 NSPM's Prairie substation.

The facilities required for this project include a short 230 kV line from Minnkota Power Co-op's Prairie substation to NSPM's Prairie substation and a new 230-115 kV transformer at NSPM's Prairie substation. The new Prairie transformer #7 was placed in service at the end of 2015.

3. *Fargo Load Serving*

NSPM'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. NSPM performed the "Fargo Load Serving Study" to identify transmission plan to address these load serving deficiencies in this area, and determined that a five mile 115 kV line from Maple River substation to Red River substation would be the least cost option.

The facilities include building five 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. We anticipate filing the permit application for this project in the second half of 2016 with construction of the project beginning after Commission approval.

4. *Minot Load Serving Plan*

A joint study with Basin Electric Power Cooperative, Western Area Power Administration, and Central Power Electric Cooperative has been completed for the Minot Area. NSP is proposing to construct a new 20 mile 230 kV from GRE's existing McHenry substation to a new propose NSP 230/115 kV substation called Magic City. The new 230 kV will help offload the existing 115 kV lines in the area and provide additional transformation capacity and voltage support to the Minot area.

5. *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 is been placed in service.

The last of these projects is the upgrade of the transmission lines in and near the City of Chaska, Minnesota from their current 69 kV capacity to 115 kV. 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.

The second of these projects requiring a Certificate of Need is in or near the cities of Chanhassen, Shorewood, Excelsior, Deephaven, Greenwood, Minnetonka, and Eden Prairie,[1] Minnesota. During the regulatory proceedings NSPM 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.

6. Scott County 345 kV

The yearly North American Electric Reliability Corporation (NERC) transmission planning compliance assessments in the past have indicated that Eden Prairie Substation 345-115 kV transformers would be overloaded in the near future. The "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 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.

[1] 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.

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. NSPM filed a minor alteration Route Permit in February 2014, and the Route Permit was granted in April 2014. This project has been placed into service in 2015.

7. *Bailey Road 345 kV*

The Bailey Road project is a new proposed 345/115 kV substation located in eastern metro area to provide relief for the observed transformer overloads at NSP's existing Red Rock substation and provide additional distribution capability in the growing Woodbury area. This project is expected to be in-service in 2018.

C. Proposed Facilities – Next 10 Years

Xcel Energy participated in a large regional Multi Value Project (MVP) study with Midcontinent Independent System Operator (MISO) to determine what large regional transmission build-outs would be necessary to increase the overall reliability and efficiency of the transmission system. The costs of these projects are being shared to beneficiaries across the entire MISO North/Central 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 Case No. PU-16-145.

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 Minnesota Commission 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 10-year assessment of the member utility system for compliance with the NERC

Transmission Planning standards. The MTO utilities also coordinate their planning with the CapX planning process and the MISO 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.minnelectrans.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, North Dakota, to our natural gas distribution system in Fargo, North Dakota. The Commission granted a Certificate of Public Convenience and Necessity 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 10 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 10 Years

At this time we do not have formal plans to construct any new intrastate natural gas pipeline transmission facilities in North Dakota within the next 10 years. However, we are continually reviewing the potential for serving additional gas retail demand in eastern North Dakota. We will inform the Commission if these projects become viable.

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 Federal Energy Regulatory Commission 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 MTEP 13 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 1,100 MWs of southward transmission service requests (TSR) and one signed PPA by Minnesota Power. The TSRs will be served by one of two options. The first option is a 500 kV transmission line to a new 500 kV/345 kV substation in the Fargo-Moorhead area that taps the Fargo to Alexandria 345 kV CAPX line. The second option 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 TSRs 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 North Dakota portion of the NSP System's 25-year historical native energy requirements and non-coincident peak demand are shown in Table 2 below. 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 below 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 Energy and Peak Load Requirements (1991 – 2015) North Dakota portion of NSP System

Year	Energy (GWh)	Annual Growth	Non-Coincident Peak Load (MW)	Annual Growth
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%	468	4.2%
2013	2,479	2.5%	453	-3.2%
2014	2,491	0.5%	444	-2.0%
2015	2,418	-2.9%	456	2.7%

Table 3. Forecast of NSP System Energy and Peak Load Requirements (2016 - 2034)

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2016	45,064	9,142	6,425
2017	45,129	9,235	6,474
2018	45,062	9,274	6,489
2019	45,423	9,325	6,529
2020	45,616	9,349	6,535
2021	45,610	9,388	6,569
2022	45,767	9,414	6,576
2023	45,821	9,454	6,606
2024	45,967	9,451	6,589
2025	46,045	9,471	6,596
2026	46,128	9,469	6,588
2027	46,408	9,485	6,608
2028	46,844	9,491	6,620
2029	46,758	9,522	6,658
2030	47,238	9,584	6,705
2031	47,710	9,663	6,785
2032	48,267	9,737	6,845
2033	48,695	9,823	6,912
2034	49,048	9,905	6,964
Avg Annual Growth Rate 2016-2034 % growth:	**0.5%**	**0.4%**	**0.4%**

1) Peak Load is ***coincident*** to the NSP System peak.
2) Winter Peak = MISO Winter Peak season, 2016 is 2016 – 2017 winter peak.
3) Peak Load is the Base Peak (uninterrupted).

Table 4. Forecast of Energy and Peak Load Requirements (2016 - 2034) North Dakota portion of NSP System

Year	Energy (GWh)	Summer Peak Load (MW)	Winter Peak Load (MW)
2016	2,461	397	402
2017	2,468	402	410
2018	2,484	408	411
2019	2,502	410	412
2020	2,522	414	415
2021	2,530	416	418
2022	2,541	417	417
2023	2,559	424	422
2024	2,580	426	424
2025	2,587	427	424
2026	2,597	430	426
2027	2,614	433	428
2028	2,636	437	430
2029	2,645	440	433
2030	2,657	443	435
2031	2,673	446	437
2032	2,695	450	439
2033	2,708	453	442
2034	2,721	456	444
Avg Annual Growth Rate 2016-2034 % growth:	**0.6%**	**0.8%**	**0.5%**

1) Peak Load is ***coincident*** to the NSP System peak.
2) Winter Peak = MISO Winter Peak season, 2016 is 2016 – 2017 winter peak.
3) Peak Load forecast growth from 2026 – 2034 is based on average summer and winter ND peak growth rates from 2016 through 2025.

APPENDIX A
Schedule of ADP Filings

Pending ADP Petitions

Project	Date Filed	Case	See Page
LaCrosse-Madison 354 kV Transmission	03/28/2016	PU-16-145	10

Anticipated ADP Petitions

Project	Est. Date
North Dakota sited CT	Completion by 2025-2026

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 April 1, 2015 through the last hour on March 31, 2016. 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, if we 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, the NSP system 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 the NSP system 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 3,147,080 MWhs. Wind production contributed to 597,685 MWh or 19.0% of MWhs backed down. Changes in customer load accounted for 68,051 MWh or 2.2% of the MWhs backed down. MISO Market Dispatch was responsible for 2,481,344 MWh or 78.8% 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 365 days evaluated, there were 238 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 April 3, 2015, base load generation was backed down for four consecutive hours in part due to wind generation. This was considered a cycle. On April 4, 2015, 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

The Company complied with Order Point 3 in its 2010 ten-year plan.