414 Nicollet Mall
Minneapolis, MN 55401

October 2, 2009

Darrell Nitschke, Executive Director
North Dakota Public Service Commission
State Capitol Building, Dept. 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: In the Matter of the Application for an Advance Determination of Prudence for the CapX2020 Group 1 Transmission Projects Northern States Power Company, Case No. PU-_____

Dear Mr. Nitschke:

Northern States Power Company, a Minnesota corporation ("Xcel Energy"), hereby submits an original and seven copies of an Application for an Advance Determination of Prudence and supporting documents for the CapX2020 Group 1 Transmission Projects. Xcel Energy is applying for an Advance Determination of Prudence for the CapX2020 Group 1 Transmission Projects simultaneously with Otter Tail Power Company ("Otter Tail") as both companies are members of the CapX2020 Initiative. Otter Tail is simultaneously filing similar materials.

For Xcel Energy, the enclosed submittal is intended to replace the joint filing made by Xcel Energy and Otter Tail on September 18, 2009 in this matter (the "September 18 Filing") so as to conform with the North Dakota Public Service Commission's (the "Commission") filing requirements and evidentiary procedures. Most of the enclosed materials are designated as "Joint" filings to reflect that both Xcel Energy and Otter Tail rely on the same material in support of their individual filing. All "Joint" documents are identical to the items submitted by Otter Tail and are intended to be applicable to both Otter Tail and Xcel Energy. Separate copies will be provided by Otter Tail for its filing. Xcel Energy respectfully requests that the original September 18 Filing be deemed as Otter Tail's original filing in this matter and supersede the information provided in September 18 Filing, except as indicated.

Xcel Energy makes this filing pursuant to North Dakota Century Code § 49-05-16 and the Commission's rules of procedure in North Dakota Administrative Code § 69-02-02-04. Enclosed in this filing are:

1) Joint Application for an Advance Determination of Prudence:

   a) Xcel Energy Appendix A – intentionally left blank for Xcel Energy;

   b) Joint Appendix B – Project Construction Schedule;

   c) Joint Appendix C – MISO Cost Allocation Methodology;

2) Joint Exhibit A – Direct Testimony, Schedules and Verification of Ms. Laura McCarten (an original signed and notarized verification of Ms. McCarten's verification was included with the September 18 Filing and is in the possession of the Commission);

3) Joint Exhibit B – Direct Testimony, Schedules and Verification of Mr. Timothy J. Rogelstad (an original signed and notarized verification of Mr. Rogelstad's verification was included with the September 18 Filing and is in the possession of the Commission);

4) Joint Exhibit C – Direct Testimony, Schedules and Verification of Mr. Paul J. Lehman (an original signed and notarized verification of Mr. Lehman's verification was included with the September 18 Filing and is in the possession of the Commission); and

5) Verification of Mr. James R. Alders verifying the filing on behalf of Xcel Energy.

Also included in the September 18 Filing were (a) Xcel Energy's filing fee in the amount of $125,000 and (b) the motion of Mr. Lawrence Bender requesting the admission *pro hac vice* of several attorneys to appear before the Commission in this matter. Xcel Energy respectfully requests that these items as well as the original

signed and notarized verifications of the three witnesses (Exhibits A, B and C) be deemed to be filed with the Commission in the instant matter.

Xcel Energy looks forward to working with the Commission in the review of this filing and respectfully requests that the Commission make a determination that the Group 1 Transmission Projects meet the Advance Determination of Prudence requirements of N.D.C.C. § 49-05-16.

Xcel Energy appreciates the opportunity to provide these additional materials to address the administrative concerns of Commission Staff. Please feel free to contact Dave Sederquist at 701-241-8632 with any questions or if the Commission requires any additional items to deem our application complete.

Sincerely,

James R. Alders

JRA/zs
Enclosures

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION	**CASE NO. PU-_____**
OTTER TAIL POWER COMPANY	**CASE NO. PU-_____**
IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 TRANSMISSION PROJECTS	**JOINT APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE**

INTRODUCTION AND SUMMARY

Northern States Power Company, a Minnesota corporation, ("Xcel Energy") and Otter Tail Power Company ("Otter Tail") (collectively "Applicants"), each respectfully submit this Application to the North Dakota Public Service Commission (the "Commission") for an Advance Determination of Prudence ("ADP") pursuant to North Dakota Century Code § 49-05-16 for the construction of the following four high-voltage transmission line projects, of which three will be constructed in a double-circuit compatible configuration, necessary to maintain the reliability of the transmission system serving the region:

- A 345 kV line and associated equipment between Fargo, North Dakota and the Northwestern quadrant of the Twin Cities, Minnesota (the "Fargo Project");

- A 345 kV line, associated system connections and equipment between eastern South Dakota and the Southeast quadrant of the Twin Cities in Minnesota (the "Brookings Project");

- A 345 kV line and associated system connections and equipment between the Southeast quadrant of the Twin Cities in Minnesota to La Crosse, Wisconsin (the "La Crosse Project"); and

- A 230 kV line and associated equipment between Bemidji and Grand Rapids, Minnesota (the "Bemidji Project").

(collectively referred to as the "Group 1 Projects"). Applicants, together with nine other regional utilities,[1] through a comprehensive planning effort that has become known as the CapX2020 Transmission Expansion Initiative ("CapX2020"), have identified the Group 1 Projects as necessary for a number of interrelated reasons to maintain the reliability of the transmission system serving the region. Development and construction of the Group 1 Projects is a reasonable and prudent way to implement new transmission investment for the region for the following reasons:

- The collaborative and joint effort among utilities, resulting in the Group 1 Projects, allows for efficient planning and development of transmission, permitting, routing, scheduling, material purchasing, overall project development, and improves costs and project benefits;

- The Group 1 Projects are needed for overall system reliability;

- The Group 1 Projects are needed to address community service reliability issues in Fargo, Grand Forks, the greater Red River Valley, and several other communities in the region;

- The Group 1 Projects are needed to support generation expansion in North Dakota and the region;

- The construction of the 345 kV Group 1 Projects using a double-circuit compatible configuration is a prudent and available alternative.;

- The Group 1 Projects are needed to establish a common foundation for future development across the system to allow for regional generation to access the wider MISO market; and

- The Group 1 Projects cost effectively balance immediate and future needs.

[1] The current roster of 11 CapX2020 sponsoring utilities who are playing a role in CapX2020 include: Central Minnesota Municipal Power Agency, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency and WPPI Energy, Northern State Power Company, a Wisconsin corporation, and Xcel Energy (collectively the "CapX2020 Utilities").

In the aggregate, the Group 1 Projects will require investment of approximately $1.8 billion.[2] Applicants will provide the estimated cost impact to their North Dakota ratepayers of their proposed investment in the Group 1 Projects and a description of how those costs are allocated to North Dakota customers. Applicants will, in general, recover their capital costs for their ownership of the Group 1 Projects through the Midwest Independent Transmission System Operator, Inc. ("MISO") from users of the MISO Transmission System.[3] Based on the current MISO cost allocation for the Group 1 Projects (as discussed more fully later), the cumulative effect on Xcel Energy's and Otter Tail's North Dakota ratepayers is likely to represent less than 5% of the total retail rate impact of the investment in the Group 1 Projects by the CapX2020 Utilities.

Through discussion of the reasons identified above, Applicants will demonstrate that the Group 1 Projects are reasonable and prudent and provide a cost-effective way to serve the multiple needs of North Dakota, as well as the region and that North Dakota will receive substantial direct benefits from construction of the Group 1 Projects. In support of their Application, Applicants have filed Direct Testimony and Exhibits of the following witnesses:

- Laura McCarten – Testimony relating to the relationship of the CapX2020 Utilities and the overall CapX2020 Initiative.

- Timothy Rogelstad – Testimony relating to the transmission planning process, the coordinated CapX2020 Initiative transmission planning efforts, and the benefits of the Group 1 Projects.

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[2] Final ownership decisions have not yet been made and participants will have the opportunity to decide whether or not to invest in any of the projects at the time all material permits have been acquired. At this time, the CapX2020 Utilities anticipate ownership to generally be in proportion to the anticipated impacts on each utility's customers. As of the date of this Application, Applicant Xcel Energy is expected to have an ownership interest in all four of the CapX2020 Group 1 Projects while Applicant Otter Tail is expected to have an ownership interest in all the CapX2020 Group 1 Projects except the La Crosse Project. Ownership issues are addressed in the accompanying Direct Testimony of Ms. Laura McCarten.

[3] As Transmission Owning Members of MISO, Applicants will recover their proportionate investment in the Group 1 Projects pursuant to the cost allocation policies and ratemaking requirements of the MISO Tariff. It is the cost of charges that Applicants will pay to MISO pursuant to MISO's cost allocation policy that will impact their retail customers. Cost impact issues are further discussed in the accompanying Direct Testimony of Mr. Paul Lehman.

- Paul Lehman – Testimony relating to the cost recovery and allocation methodologies for the Group 1 Projects.

The remainder of the Application is organized into the following sections:

- Standard of Review for an ADP
- Request for Separate Dockets and Scheduling Conference
- Description of Applicants and the Group 1 Projects
- Reasons Supporting an ADP for the Group 1 Projects
- Applicants' Estimated Ratepayer Impact
- Communications and Service
- Conclusion

STANDARD OF REVIEW

North Dakota law provides that the Commission may issue an Order approving an advance determination of prudence if "the [C]omission determines that the resource addition is reasonable and prudent." Specifically, North Dakota law provides:

> **49-05-16. Advance Determination of Prudence.** A public utility proposing to construct, lease, or make improvements to an energy conversion facility, renewable energy facility, transmission facility, or proposed energy purchase contract from another entity or person for the purpose of ensuring reliable electric service to its customers may file an application with the commission for advance determination of prudence regarding the proposal....

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking. N.D.C.C. § 49-06-02. The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances. *See* Charles F. Philips, Jr., THE REGULATION OF PUBLIC UTILITIES – THEORY AND PRACTICE at 292 (Public Utility Reports 1988); *see also* David. J. Muchow, William A. Mogel, ENERGY LAW AND TRANSACTIONS at § 4.02[3][b] (2009).

Under N.D.C.C. § 49-05-16, the Commission may issue an order approving the prudence of a transmission facility if three conditions are met:

a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the transmission facility addition;

b. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and

c. The commission determines that the transmission facility is reasonable and prudent.

The Commission's standard for issuing an advance determination of prudence is, therefore, similar to the determination that would be made in a rate case, while the timing of the decision is different. Rather than wait to consider the prudence of a particular investment in a rate case after construction, the advance determination of prudence process considers prudence at the time of the decision to invest in the resource, instead of well after the investment has been made. Thus, the standard to be applied in this proceeding does not impose a higher or different standard for approval than would be found in a rate case; rather, it is the same or similar standard applied at a different point in time in the resource acquisition process.

In this Application, Applicants provide a projection of costs to the date of the anticipated commercial operation of the Group 1 Projects as well as the reasons they believe their investment in the Group 1 Projects with the other participating utilities is both reasonable and prudent.

REQUEST FOR SEPARATE DOCKETS AND SCHEDULING CONFERENCE

Due to the fact that the Group 1 Projects will affect Xcel Energy's and Otter Tail's ratepayers differently, Applicants respectfully request that the Commission assign this matter two case numbers, one for each Applicant, respectively. N.D. Admin. Code §§ 69-02-01-04; 69-02-01-10. Applicants respectfully request, however, that the Commission address both cases simultaneously as the basis for an ADP because Applicants' development of the Group 1 Projects is similar for both Xcel Energy and Otter Tail. N.D. Admin. Code §§ 69-02-04-04; 69-02-01-10.

In addition, Applicants request that the Commission hold a scheduling conference addressing both dockets as soon as practicable to discuss a procedural schedule for this matter. Applicants further request that the Commission render a final determination regarding the prudence of Applicants' proposed participation in the development of the Group 1 Projects in accordance with N.D.C.C. § 49-05-16(2).

DESCRIPTION OF APPLICANTS AND GROUP 1 PROJECTS

A. Xcel Energy

Xcel Energy is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code. The full name and address of Xcel Energy is:

Northern States Power Company,
a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

Xcel Energy also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, North Dakota 58102

Xcel Energy's Certificate of Incorporation and amendments thereto were filed with the Commission on September 30, 2009 and are incorporated herein by reference.

Xcel Energy and its affiliate Northern States Power Company, a Wisconsin corporation ("NSP-W") operate an integrated utility system in a service territory in five upper Midwest states including North Dakota. Xcel Energy presently serves approximately 86,000 retail electric customers in and around Fargo, Grand Forks and Minot, North Dakota. Xcel Energy owns approximately 250 miles of transmission lines and 12 substations in North Dakota and is in the processes of developing the Merricourt Wind Project in North Dakota. Xcel Energy is a participating utility in all four of the Group 1 Projects.

B. Otter Tail

Otter Tail is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code. The full name and address of Otter Tail is:

Otter Tail Power Company
215 South Cascade Street
Fergus Falls, Minnesota 56537

Otter Tail's Certificate of Incorporation and amendments thereto are attached as Appendix A.

Otter Tail serves retail electric customers in North Dakota, Minnesota and South Dakota. Otter Tail presently serves approximately 56,900 customers in North Dakota. In North Dakota, Otter Tail is a part-owner and serves as operating agent of the Coyote Station near Beulah, owns 56 MW of fuel oil combustion turbines near Jamestown, owns 40.5 MW (and purchases the energy output of an additional 19.5 MW) of wind generation near Langdon, owns 48 MW of wind generation near Ashtabula, owns 49.5 MW of wind generation near Luverne, purchases the energy output of 19 MW of wind generation near Edgeley and owns 2,725 miles of transmission lines.

C. Group 1 Project Descriptions

Applicants and the other CapX2020 Utilities determined that new transmission facilities are needed in the region to address several categories of issues facing the region, as described further below and in the testimony of Mr. Timothy Rogelstad. The Group 1 Projects are described in this Section and depicted in the Regional Projects Maps.

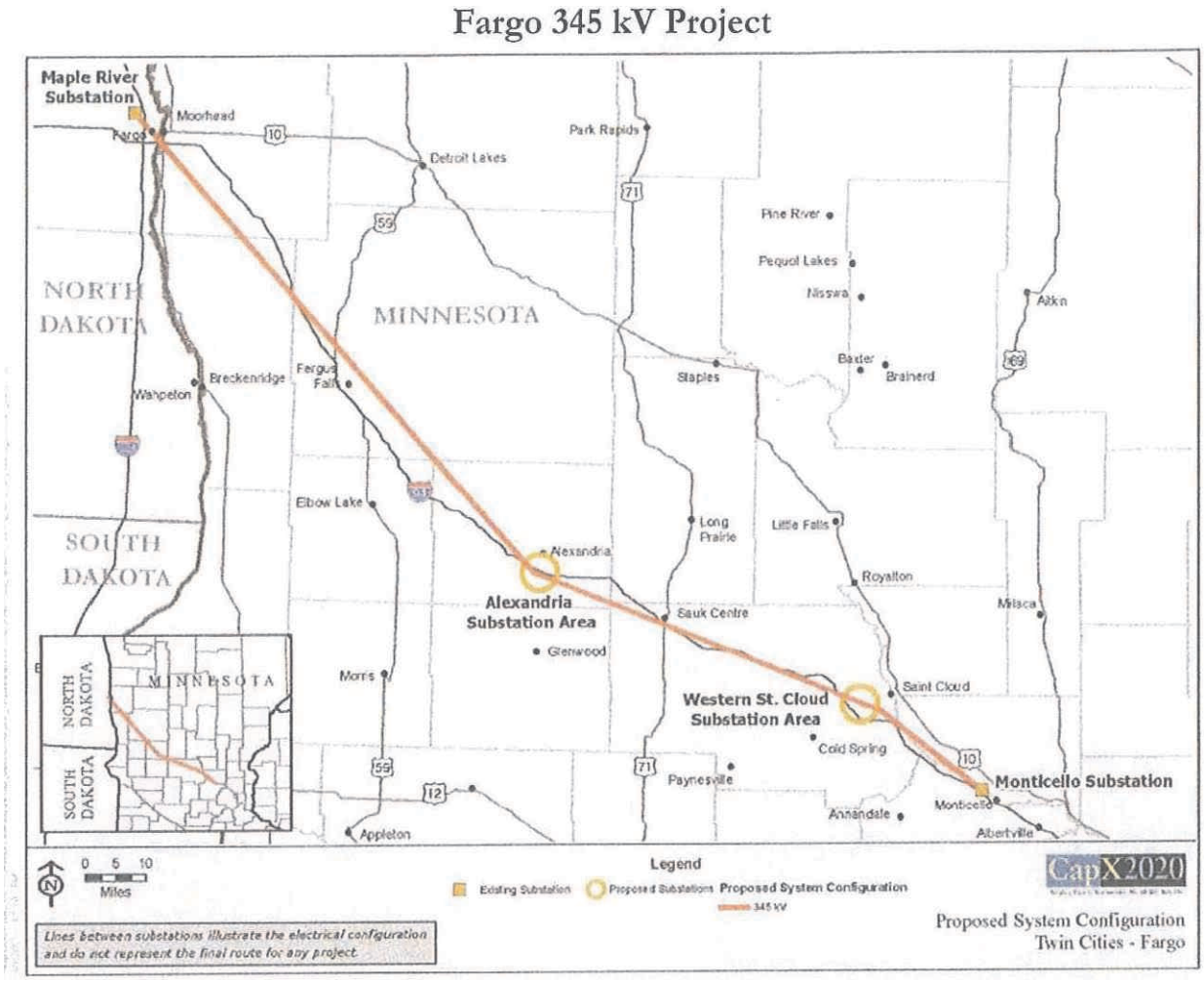
1. The Fargo Project

The Fargo Project will consist of an approximately 250-mile long, 345 kV transmission line from a connection near Fargo, North Dakota to Alexandria, Minnesota, to St. Cloud, Minnesota, and ending at the Monticello Substation near the Twin Cities, Minnesota.

Each of these line segments will be constructed in a double-circuit compatible configuration by using structures capable of supporting a second circuit in the future. The first segment will consist of a 345 kV circuit between the Fargo, North Dakota area, either at the existing Maple River Substation or at a new Fargo area substation approved by the Commission during the route permitting phase and an expanded substation in the Alexandria, Minnesota area (Alexandria Substation). This segment will be approximately 120-150 miles long depending on how it is ultimately routed. The second segment will consist of a 345 kV circuit from the Alexandria Substation to a new substation (Quarry Substation) on the western side of St. Cloud, Minnesota. This segment would be approximately 60-80 miles long. The third segment will include a 345 kV circuit between Quarry Substation and Monticello Substation on the Monticello Power Plant site in Monticello, Minnesota. This segment will be approximately 30-40 miles long.

Figure 1 is a map showing the proposed Fargo Project area and configuration:

Figure 1



2. The Brookings Project

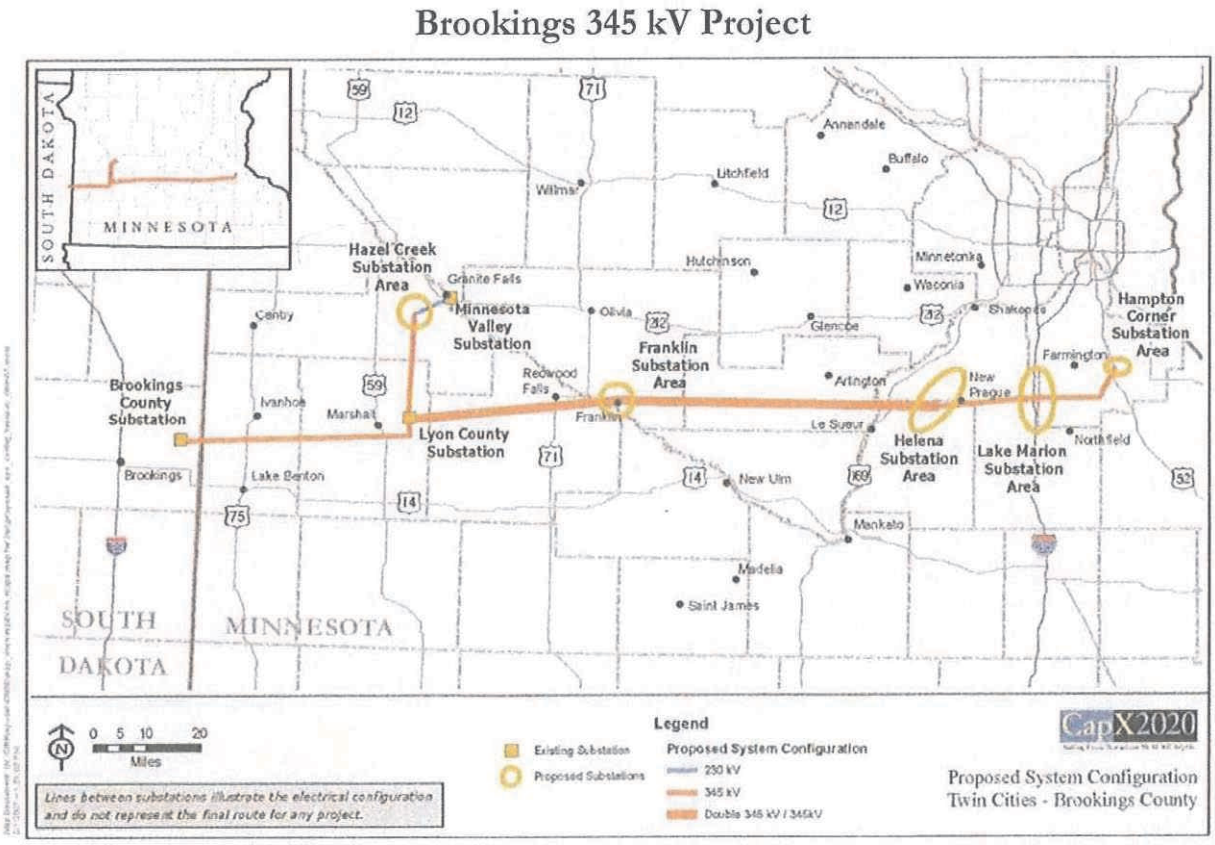
The Brookings Project is an approximately 200-mile long, 345 kV transmission line that will consist of a series of 345 kV segments between the Brookings County Substation in Brookings County, South Dakota and a new substation in the southeast corner of the Twin Cities area in Minnesota with intermediate connections to load centers. The Brookings Project will also include an approximately 25-mile, 345 kV circuit from the Lyon County Substation near Marshall, Minnesota to a new substation southwest of Granite Falls, Minnesota (Hazel Creek Substation), and an approximately 8 to 10 mile, 230 kV transmission line from the Hazel Creek Substation to the existing Minnesota Valley Substation on the east side of Granite Falls, Minnesota.

The western-most segment will be a 345 kV circuit between the Brookings County Substation and the Lyon County Substation. This segment will be approximately 50 to 55 miles long and will be constructed in a double-circuit compatible configuration by using structures capable of supporting a second circuit in the future. The next segment will be from the Lyon County Substation to the new Hazel Creek Substation and then on to Minnesota Valley Substation near Granite Falls, Minnesota. This segment will be approximately 35 miles long, will in part replace an existing 115 kV line, and will be constructed in a double-circuit compatible configuration by using structures capable of supporting a second 345 kV circuit in the future. The next segment will consist of a double circuit 345 kV transmission line between the Lyon County Substation and a new substation in the Franklin, Minnesota area. This segment will be approximately 45 miles long. The next segment of the Project will consist of a double circuit 345 kV transmission line between the Franklin, Minnesota area substation and a new substation (Helena Substation) generally in the vicinity of New Prague, Minnesota. The Franklin – Helena segment of the Project will be approximately 45 miles long.

There are two additional 345 kV single circuit segments of the Brookings Project in the far southern part of the Twin Cities metropolitan area in Minnesota. From the Helena Substation, the 345 kV single circuit will continue east to the Lake Marion Substation in Scott County, Minnesota. From the Lake Marion Substation, the 345 kV circuit will continue to the new Hampton Substation. These two segments combined will be 45 to 55 miles long and will be constructed using the double-circuit compatible configuration.

Figure 2 is a map showing the Brooking Project area and configuration:

Figure 2



3. The La Crosse Project

The La Crosse Project is an approximately 150-mile long transmission line that will consist of a series of 345 kV transmission line circuits from the Southeast Twin Cities area to Rochester, and on to La Crosse, Wisconsin. The La Crosse Project also includes two new 161 kV transmission lines in the Rochester, Minnesota area.

The northwestern terminus of the La Crosse Project will be the new Hampton Substation which will connect the new 345 kV transmission line to the existing Prairie Island – Blue Lake 345 kV transmission line in the vicinity of Hampton, Minnesota. From the new Hampton Substation, the new 345 kV transmission line will be routed to a new substation (North Rochester Substation). This segment of the La Crosse Project will be approximately 40 to 50 miles long and will be constructed using the double-circuit compatible configuration.

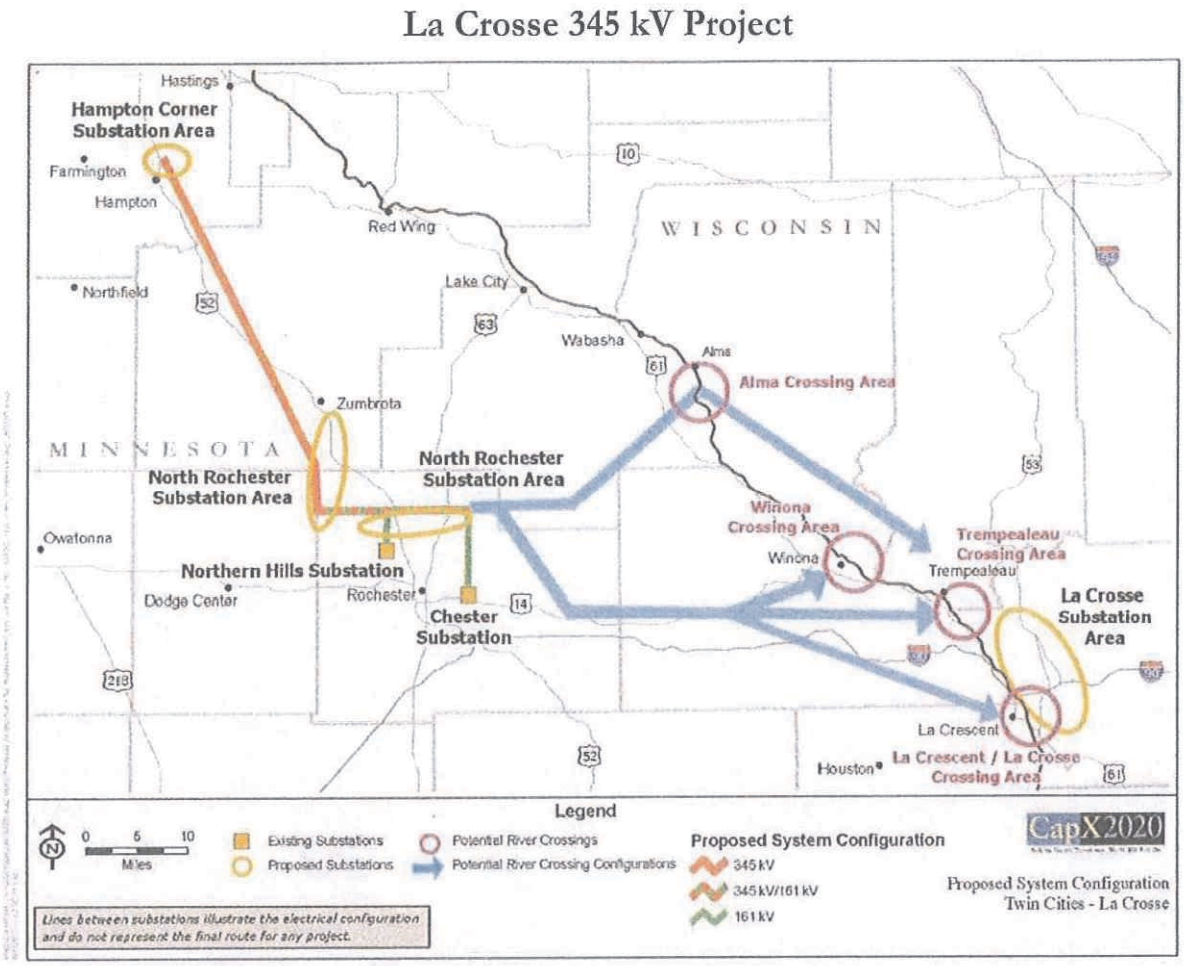
As part of the La Crosse Project, two 161 kV transmission lines will connect the new North Rochester Substation to two existing distribution substations in the Rochester

area, the Chester and Northern Hills Substations. The North Rochester – Northern Hills 161 kV transmission line will be approximately 10 – 15 miles long. The North Rochester – Chester 161 kV transmission line will be approximately 20 to 30 miles long.

The remaining segment of the 345 kV transmission line will connect the North Rochester Substation to a substation in the La Crosse, Wisconsin area. The estimated length of the segment will be 45 – 90 miles depending on where the line is routed to cross the Mississippi River and may be constructed using the double-circuit compatible configuration.

Figure 3 is a map showing the proposed LaCrosse Project area and configurations:

Figure 3

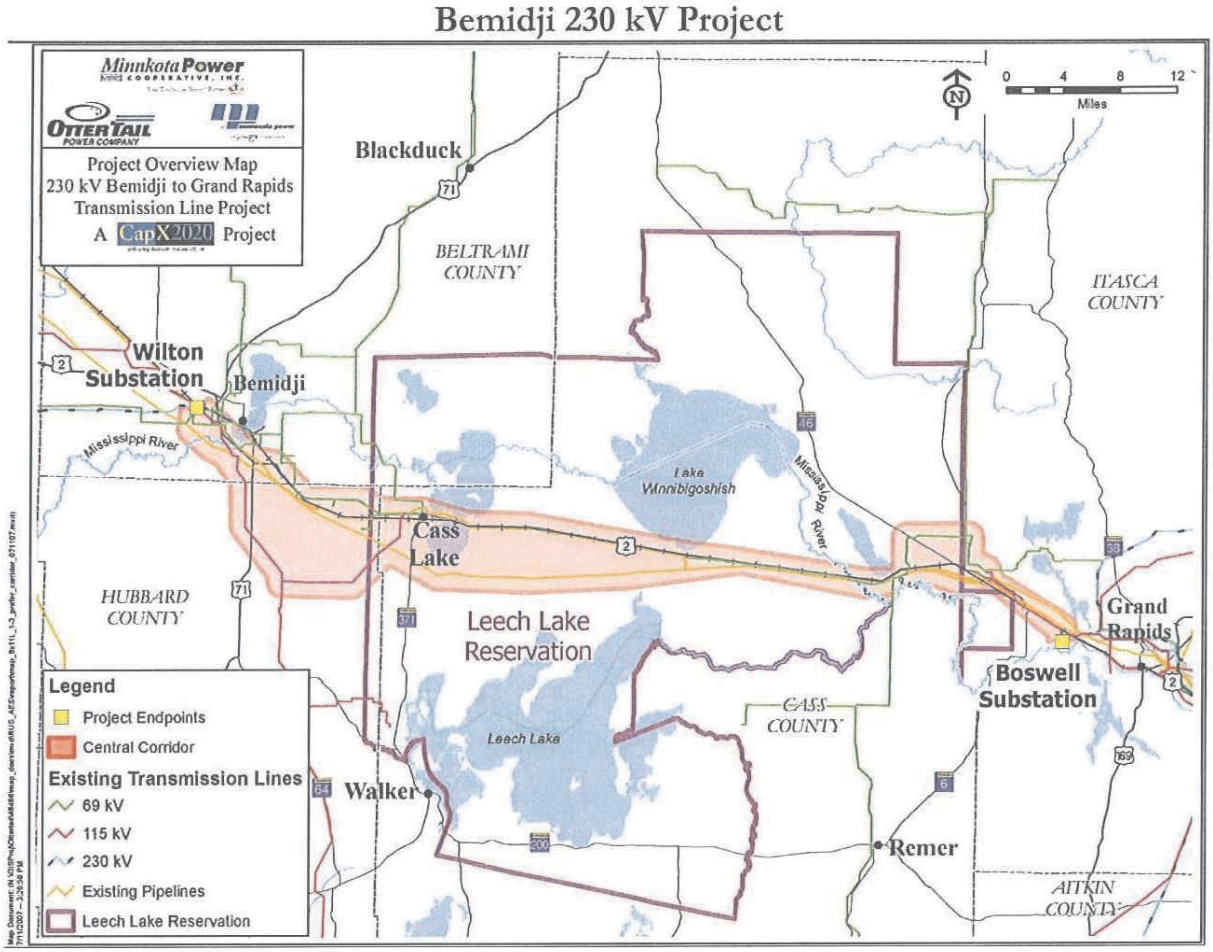


4. The Bemidji Project

The Bemidji Project is an approximately 68-mile long, 230 kV transmission line from the Wilton Substation near Bemidji, Minnesota to a substation near Cass Lake (Clear Lake Substation) and then to the Boswell Substation in Cohasset, Minnesota.

Figure 4 shows the proposed Bemidji Project area and configuration:

Figure 4



D. Double-Circuit Compatible Configuration

Applicants and the other CapX2020 Utilities initially considered constructing single-circuit 345 kV lines for three 345 kV projects of the Group 1 Projects – Fargo, LaCrosse and Brookings (except for the Lyon County – Helena segment of the Brookings Project which was initially designed to be double circuited) (referred to as the "Three 345 kV Projects"). As a result of the long-term planning horizon and Applicants' desire to ensure the transmission system continues to meet customer

requirements in the future, Applicants decided to construct the Three 345 kV Projects using double-circuit capable structures.

A "double-circuit compatible" configuration means that the segments of the Three 345 kV Projects would be built on structures and on right-of-way sufficient to accommodate a second 345 kV circuit at some point in the future. Only one circuit would be strung upon construction. The second circuit will be strung when circumstances warrant and all necessary regulatory approvals are received. This configuration ensures that these projects will be available for future expansion (via deployment of the second circuit) when that additional capacity is deemed to be needed by the Commission.

The CapX2020 Utilities are currently exploring the cost, technical, and potential regulatory issues surrounding whether it would be more appropriate to install the davit arms and conductor for the second circuit of the Three 345 kV Projects at the time of initial construction. The lines would be operated as a single circuit until future circumstances and regulatory approvals deem the second circuit necessary. CapX2020 planners are analyzing the installation of all davit arms as part of initial construction which may be a lower cost approach because it would mitigate the need for larger structures and would avoid expensive and complex construction on the poles after the first circuit has been energized. As part of the analysis, CapX2020 planners are also considering the potential impacts of installing the second set of conductors as part of initial construction. The potential benefits may include: (i) less impact to landowners because of a single construction period, (ii) lower line losses and operating costs because of the additional conductor and (iii) avoiding complex and perhaps costly construction methods to add a second circuit to structures holding a "live" circuit. The CapX2020 Utilities will continue to analyze the impacts, costs and regulatory issues associated with concurrent installation and will provide additional information in the future.

E. Estimated Costs of Group 1 Projects

The estimated installed cost of each Project is as follows:

- The Fargo Project: $500-750 million
- The Brookings Project: $650-800 million
- The La Crosse Project: $400-500 million
- The Bemidji Project: $100-140 million

Applicants offer these costs as currently developed estimates, with full acknowledgement that there is a degree of variability in the estimates presented. Right

now, many of the Projects are in early stages of the routing and other regulatory processes and therefore, the precise routes of the lines are yet to be determined. As explained in the Projects descriptions above, the total length of each line is still approximate and can range significantly depending on the final route that is approved. In addition, project managers are working together to develop Request for Proposals and construction and procurement contracts in order to begin vendor selection for materials and supplies required for the Group 1 Projects. At this stage, none of those agreements are finalized nor executed and therefore, there are no definitive costs pertaining to procurement activities. The project managers have developed reasonable estimates of the range of costs for each project and the final cost of the Projects is expected to fall within a range depending upon final routes, configurations, final vendor agreements, and other factors.

As with any projects of this magnitude, cost estimates will continue to be refined as more detailed information becomes available. Applicants will update the Commission with the latest cost information in subsequent updates and in routing filings.

F. Project Schedule

The in-service dates for the Group 1 Projects are currently contemplated as follows:

- The Fargo Project: Monticello – St. Cloud segment 2011, St. Cloud – Fargo segment 2015;
- The Brookings Project: Brookings Co. – Helena segment 2012, Helena – Hampton Corner segment 2013;
- The La Crosse Project: North Rochester – Northern Hills 161 kV line 2012, 345 kV circuits 2015; and
- The Bemidji Project: 2012.

Preliminary development schedules for each of the Group 1 Projects are presented as Appendix B. In total, the Group 1 Projects represent about 700 miles of transmission line construction. Scheduling the construction of multiple, large-scale Projects in the same time frame is a complex undertaking. Project planners are working with engineering consultants, construction vendors and equipment providers to refine project estimates. It is likely some adjustments to in-service dates and schedules will be required to overcome resource limitations and develop the Projects as cost effectively as possible. Potential regulatory hurdles, such as the timing of route permits, environmental permits, CPCNs, and issues related to the MISO Tariff may

also impact the schedule. Applicants will keep the Commission informed as changes occur to the schedules.

G. Regulatory Status of the Group 1 Projects

1. North Dakota

Xcel Energy and Great River Energy plan to make applications with the Commission soon for a Certificate of Public Convenience and Necessity ("CPCN") and for Corridor Compatibility and Route Permits for the North Dakota portion of the Fargo Project. These applications will seek approval to construct the North Dakota portion of the Fargo Project and will provide a record to determine the route for that segment.

2. Minnesota

a. Certificates of Need

Applicants have obtained Certificates of Need for the Group 1 Projects from the Minnesota Public Utilities Commission ("MPUC"). On May 22, 2009, applicants for the Minnesota Certificates of Need (Xcel Energy and Great River Energy) for the Three 345 kV Projects (Fargo, La Crosse and Brookings) obtained the requested Certificates of Need from the MPUC. In that Order, the MPUC granted certificates of need for each of the Three 345 kV Projects, finding that the projects are necessary to provide benefits throughout the upper Midwest region.[4] At that time, the MPUC decided to place certain conditions on the Brookings Project, requiring the capacity enabled by that project to be dedicated to renewable energy sources without regard to the established and approved Resource Plans of Xcel Energy and Great River Energy. Xcel Energy and Great River Energy subsequently sought reconsideration of that Order and requested that the MPUC remove the conditions. At its July 14, 2009 Agenda Meeting, the MPUC agreed to reconsider its decision and decided to modify the conditions. The conditions provide a number of reporting requirements and seek to coordinate resource planning and transmission planning in Minnesota. In addition, the conditions require that Xcel Energy and Great River Energy coordinate acquiring renewable generation projects with the proposed in-service dates of the Brookings

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[4] See In the Matter for the Application of Northern States Power Company and Great River Energy for Certificates of Need for Three 345 kV Transmission Line Projects and Associated System Connections, MPUC Docket No. ET02, E002/CN-06-1115, Order Granting Certificates of Need With Conditions (May, 22, 2009). More information about the Minnesota process can be found at http://www.puc.state.mn.us/docs/capx2020c.pdf.

Project, unless such acquisition is not contemplated in their resource requirements and is excused by a future order of the MPUC.

In its July 14, 2009 Order, the MPUC granted a Certificate of Need for the Bemidji Project, recognizing the need for this line to serve communities in the Grand Forks and Northern Red River Valley areas.[5]

b. Routing Proceedings

On June 4, 2008, Applicant Otter Tail, Minnesota Power and Minnkota Power Cooperative filed an Application for a Route Permit for the Bemidji Project with the MPUC. That process is ongoing.

On December 29, 2008, Great River Energy and Xcel Energy filed an Application for a Route Permit for the Brookings Project with the MPUC. That process is ongoing.

On April 8, 2009, Xcel Energy and Great River Energy filed an Application for a Route Permit for the Monticello, Minnesota to St. Cloud, Minnesota segment of the Fargo Project with the MPUC. That process is ongoing.

Xcel Energy and Great River Energy anticipate filing route permit applications for the remainder of the Fargo Project and for the Minnesota portion of the La Crosse Project later in 2009.

Applicants and other CapX2020 Utilities are also working with the U.S. Department of Agriculture's Rural Utilities Service to comply with federal environmental review standards by completing the Environmental Impact Statement process for the Bemidji Project.

3. South Dakota

Great River Energy anticipates filing an application for a Facilities Permit with the South Dakota Public Utilities Commission for the South Dakota portion of the Brookings Project in the near future.

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[5] *In the Matter of the Application of Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative, Inc. for a 230 kV Transmission Line from Bemidji to Grand Rapids, Minnesota*, MPUC Docket No. E017, E015 & ET-6/CN-07-1222, Order Granting Certificate of Need (July 14, 2009).

4. Wisconsin

Xcel Energy anticipates that an Application for a CPCN, which addresses both need and routing for the Wisconsin portion of the La Crosse Project, will be filed with the Wisconsin Public Service Commission in late 2009.

Applicants are also working with the U.S. Department of Agriculture's Rural Utilities Service to comply with federal environmental review standards by completing the Environmental Impact Statement process for the La Crosse Project.

Applicants will provide updates regarding the current status of all regulatory filings to the Commission and additional updates as further regulatory filings are made for each of the Group 1 Projects.

REASONS SUPPORTING AN ADP FOR THE GROUP 1 PROJECTS

A. The Collaborative and Joint Effort Among Utilities, Resulting in the Group 1 Projects, Allows for Efficient Planning and Development of Transmission, Permitting, Routing, Scheduling, Material Purchasing, Overall Project Development, and Improves Costs and Project Benefits

1. A Coordinated Approach

The CapX2020 Initiative was developed to create a regional approach to transmission planning that would help coordinate the development of transmission infrastructure to meet the increasing demand for electricity in the upper Midwest region.[6] Regional utilities developed a long-range plan, the "Vision Plan", from which the utilities began to formulate strategies for implementing the transmission system additions that would be necessary to address regional needs over the next decade and beyond.

CapX2020 has established a coordinated regional approach to addressing both regional and community reliability needs, and longer-term growth. A coordinated regional approach is essential in part because some utility companies serving customers in the region serve customers in a multi-state system. For example, Applicant Xcel Energy serves customers in North Dakota, South Dakota, and Minnesota, with an affiliate serving Wisconsin and Michigan. Applicant Otter Tail serves customers in North Dakota, South Dakota, and Minnesota. Companies with multi-state service territories plan on a system wide-basis, not on a state-by-state basis.

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[6] More information on the CapX2020 initiative can be found at www.capx2020.com. Please see the Direct Testimony of Laura McCarten for information regarding the business relationship and investment strategies of the CapX2020 Utilities.

The analysis undertaken in the Vision Plan took a similar system-wide approach to considering what transmission would be beneficial for the entire region. The analysis consists of simulations of the performance of the electrical transmission system as the demand for power grows over time. Based on the most recent forecasts from utility planners at the time of the analysis, demand for power was projected to grow significantly in the service territories of regional utilities by 2020. Because forecasts are uncertain predictions of the future, engineers tested their results with lower projection of growth as well. The performance of the transmission system also depends on the location of generation that is needed to serve the growing demand for electricity. In the Vision Plan analysis, wide ranges of locational generation dispersion were tested to determine their affect on transmission requirements.

Transmission engineers modeled the performance of the existing transmission system under a variety of growth and locational generation dispersion circumstances and found numerous situations in which the system would not meet reliability standards established by the North American Electric Reliability Corporation ("NERC"). The analysis found increasing weakness in the ability of the transmission system to reliably meet demand as the need for power grows system wide.

The analysis then tested a series of transmission alternatives to address the system deficiencies that were identified. Some of the alternatives were identified by the Vision Plan study effort and some of the alternatives were identified in previous studies to address sub-regional concerns on the system.

The Vision Plan supports several important conclusions. First, it is clear that without major transmission investments the system will experience repeated limitations in power capacity that threaten reliability. Since the transmission and generation system of the region operates as one integrated system, equipment failures in any one part of the system can affect service across broad geographic areas. In many respects, reliable service to our North Dakota customers depends on equipment and transmission lines far from the state. Second, to the extent North Dakota needs to import energy, access to generation to serve North Dakota customers can be restricted by the performance of the system elsewhere and those restrictions will grow without improvements to the system. Third, North Dakota is a net-exporting state and is dependent upon a robust transmission system to access regional markets for excess generation. The ability to export North Dakota generation is already constrained and new transmission is needed to enhance that access.

Based on this analysis, the CapX2020 Utilities determined that the Group 1 Projects are necessary under any reasonable set of future circumstances (this is addressed more fully below). They address the most immediate system reliability issues while

providing a platform to build upon for additional transmission projects that will be needed in the future.

The Fargo and Bemidji Projects strengthen the immediate ties from the Red River Valley and the rest of North Dakota to the rest of the network serving the region, thereby enhancing reliability. The Brookings and La Crosse Projects strengthen the network in ways that reduce the chances of problems elsewhere affecting North Dakota and increase system capacity to access generation markets further east and south.

The testimony of Mr. Timothy Rogelstad describes the CapX2020 Vision Plan analysis in more detail.

2. Joint Development and Construction of Projects

To ensure cost-effective implementation of the Group 1 Projects, Applicants, through their participation in the CapX2020 Initiative, have provided for a prudent means of developing the Projects. The CapX2020 Initiative was formed to meet the growing transmission needs of all utilities in the region. By coordinating regional planning, the region's utilities are able to develop solutions to regional transmission needs instead of piecemeal solutions that could lead to duplicative transmission facilities being built. Further, by acting as a group, the CapX2020 Utilities obtain improved efficiency in permitting, routing, scheduling, material purchasing, and overall project development. Overall, Applicants' participation in the initiative allows us to lessen our costs and achieve greater benefits from the Group 1 Projects due to the strength and size of the organization.

By working together, the CapX2020 Utilities have been able to develop a comprehensive set of alternatives for improvement of the transmission system, as opposed to crafting piecemeal solutions that would result from individual utility solutions. This coordinated approach provides real value to North Dakota. By combining their resources and working together, the CapX2020 Utilities will reduce the overall amount of transmission that would otherwise need to be constructed to serve North Dakota. Thus, overall, North Dakota's customers will be responsible for lower costs than would otherwise have happened. In addition, one of the important features of the Vision Plan was the recognition that significant new generation from North Dakota is likely. A coordinated transmission plan that accommodates that predicted new generation will provide North Dakota with significant new transmission capacity at a time when new generation in the area is likely.

Second, working together within the regulatory environment to jointly file applications for permits in all of the affected jurisdictions allows regulators to more

fully understand the scope, benefits, and impacts of the projects and not be subjected to numerous separate filings by individual utilities on separate projects that may often times work at cross purposes. Applicants believe that their joint efforts have improved the overall efficiency in obtaining the necessary regulatory permits. The current Application provides the Commission with an opportunity to consider simultaneously the requests of two utilities for their respective costs incurred in the same projects. This approach provides the Commission with valuable insights into the joint planning process while also ensuring that the Commission can review both utilities' expenditures arising out of the same projects.

Third, the joint approach of Applicants and the other CapX2020 Utilities is a prudent way to proceed with developing the projects in order to spread the costs among a broad array of utilities. An investment of approximately $1.8 billion for all of the Group 1 Projects would be difficult for any one utility to undertake. By collaborating with a number of other regional utilities, Applicants are able to successfully spread their risks and balance their costs. This multiparty approach is a prudent way to proceed through the development, construction, and ownership phases. Once again, this joint approach provides significant benefits to North Dakota. North Dakota is the beneficiary of major new transmission infrastructure that provides substantial opportunity for significant future generation and load growth, while being responsible for less than 5% of the costs.

Finally, Applicants and the CapX2020 Utilities recognize that there will be benefits arising from a coordinated effort in securing materials and services required to build the Group 1 Projects. As such, a joint sourcing approach is being utilized in order to minimize or eliminate inter-project competition for labor and material resources, maximize leverage in the market by standardizing specifications and sourcing for the total volume of major materials and resource needs across all four project, establish a common request for proposal ("RFP") process to present "one CapX2020 face" to the market, eliminate inefficiencies, and enhance inter-project flexibility where possible for services.

For example, utilizing a joint sourcing process across the projects creates a spend volume asset. This volume consolidation and early RFP activity allows manufactures and suppliers the ability to plan fabrication in advance of the delivery needs. This approach works to avoid the premium costs associated with orders outside of the lead time and typically garners more attractive pricing when the suppliers, manufactures and contractors are able to advance plan their production schedules or field resources.

Applicants believe that absent their participation, the ability to develop an overall transmission system solution as comprehensive and robust as the Group 1 Projects would not have been possible.

B. The Group 1 Projects are Needed for Overall System Reliability

It has been decades since significant improvements have been made to the regional network and the system has reached its limits. Multiple areas of concern on the system, which will only get worse over time, require additional transmission in order to enhance the overall system reliability, including reliability for North Dakota customers who are reliant on the interconnected regional system. The Group 1 Projects address many near term- and mid-term system issues.

The Group 1 Projects represent a prudent and coordinated set of transmission improvements designed to address both near and long-term needs of Applicants' customers as well as the needs of the other regional utilities. Planning engineers analyzed many alternatives to constructing the Group 1 Projects to confirm whether these were the correct projects to construct. Alternatives considered included upgrades to currently built facilities, double-circuiting existing facilities, adding localized generation and using higher and lower voltage transmission lines. Applicants determined that these alternatives did not adequately meet all of the identified needs. The Group 1 Projects, on the other hand, provide sufficient transmission to satisfy all of the identified needs, plus provide a solid platform for future system expansion to address future growth. By providing a foundation for future system build-out, the Group 1 Projects are a prudent way to cost-effectively meet additional system-wide needs past the year 2020 planning horizon.[7]

C. The Group 1 Projects are Needed to Address Community Service Reliability Issues in Fargo, Grand Forks, the Greater Red River Valley, as Well as Several Other Specific Communities in the Region

In addition to system wide growth concerns, the transmission system must be able to reliably deliver power to individual communities. Transmission planners monitor the performance of the system and identify limits that could affect power deliveries to individual communities or load centers on the system. Power must be able to flow even if one of the most critical elements of the system fails.

There are a number of situations developing on the system in which service is threatened if a critical piece of equipment fails during high demand periods. The four Group 1 Projects have been configured to address these emerging community service reliability issues.

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[7] For additional information regarding CapX2020 planning activities beyond the year 2020 planning horizon, please see the Direct Testimony of Mr. Timothy J. Rogelstad.

1. Red River Valley

The major population centers in the Red River Valley in North Dakota are an example of growing concern about community service reliability. Electrically, a broad area from Grand Forks to Fargo, and from Jamestown to Brainerd and Alexandria depends on a system of high voltage transmission lines to provide electrical power. As the demand for power grows in the area over the next several years, the failure of a key 345 kV transmission line – the Center – Jamestown – Maple River line – could jeopardize service to the entire area.

The area has experienced the outage of the Center – Jamestown – Maple River 345 kV line on more than one occasion in recent years. In 2005, the line was down for 34 hours on November 29th and 30th, during a three-day snow and ice storm. The storm caused 57 different line outages in the area and caused service interruptions to nearly 50,000 customers in North Dakota, South Dakota, and Minnesota, including intentional interruptions to prevent failures on overloaded facilities.

The Bemidji Project will strengthen electrical ties with the rest of the transmission system east of the Red River Valley and alleviate concerns in the northern part of the Red River Valley centered on Grand Forks. With the Fargo Project, reliable service to Fargo, North Dakota and the southern portion of the Red River Valley electrical area will be maintained.

2. Other Communities

Other communities in and around the Red River Valley area will also be served by portions of the CapX2020 Group 1 Projects. The Alexandria area is another example of growing reliability concerns. The loss of a 115 kV circuit in the Alexandria area could result in significant reduction in reliability. Similarly, existing problems in the St. Cloud area call for a new 345 kV connection in the near future. A single transmission line outage could also jeopardize service to the St. Cloud area during high demand periods.

The Fargo Project was a prudent choice as it addressed multiple customer service issues (St. Cloud, Alexandria, Fargo) while simultaneously providing a robust connection that will accommodate growth in and around North Dakota. Likewise, the Bemidji Project is also needed to alleviate reliability concerns in Bemidji and surrounding area.

The other CapX2020 Group 1 Projects also address important local community reliability issues. With regard to the La Crosse Project, today the transmission system serving Rochester, Minnesota cannot meet the demand for power should any one of

three sources to the city fail during high demand periods. That is why Rochester Public Utilities must run its Silver Lake generating station to ensure reliable service to the city even when more economical power is available. Similarly, system reliability concerns are developing on the system serving the La Crosse, Wisconsin and Winona, Minnesota areas.

Finally, the Brookings Project provides community service benefits to a number of communities in Western Minnesota as well as the Southern Suburbs of the Twin Cities. Long term, this facility provides benefits to Marshall, New Ulm, New Prague, and other regional communities as well as providing additional transmission to support the growing suburban communities such as Lakeville, Minnesota. The Brookings Project alleviates strain on the system in the Southern Twin Cities metro area and provides an important link to the larger transmission system.

D. The Group 1 Projects are Needed to Support Generation Expansion in Both North Dakota and the Region

There is a growing need for transmission capacity to support significant new generation throughout the region. The Group 1 Projects will increase system capacity to support generation expansion in North Dakota. They will increase the North Dakota Export ("NDEX"), thus increasing the ability to reliably export generation produced in North Dakota to energy markets to the east and south. Transmission studies have shown that the Group 1 Projects will increase NDEX by several hundred megawatts. The Fargo Project is expected to increase transfer across the NDEX limit by approximately 350 MW (depending upon the size and location of generation), which will support additional outlet for generators in northwest Minnesota and southeastern North Dakota. The Bemidji Project increases NDEX by about 100 MW. And the combination of building both the Fargo and Bemidji Projects results in approximately 550 MW of NDEX increase. The Brookings Project will result in further increases to NDEX. Recent analysis has shown that the combined effect of the Group 1 Projects should result in an overall incremental increase to NDEX of 700-800 MW. Actual results will be dependent upon the size and location of future generation.

To serve this growing demand of customers in the upper Midwest, large amounts of new electric generation of all kinds will need to be installed. Taking into account emerging policies regarding new generation sources as well as growing demand, several thousand megawatts of new generation will be needed in the coming decade and beyond. These anticipated generation additions further justify the expansion of the bulk transmission network serving the region.

Additional transmission facilities are needed to move the electricity generated to load centers where that power will be used. Further, regional utilities are now required or encouraged to supply additional electricity from renewable sources. For example, North Dakota and surrounding states all have renewable energy goals and requirements. North Dakota lawmakers passed the Renewable and Recycled Energy Objective that established the goal of achieving ten percent of retail electric sales from renewable and recycled energy sources by 2015. N.D.C.C. § 49-02-28. Legislative initiatives of this type throughout the region contribute to a need for additional renewable generation. Furthermore, interest nationally in renewable energy has intensified.

Large scale generation projects are often not constructed near the load that will consume the electricity generated. For example, North Dakota currently has substantial generation based on traditional fossil fuels and has rich wind resources that can be developed. However, North Dakota's loads are not large enough to absorb all of the electricity that is and can be generated within the state. Further, the ability to export generation out of North Dakota is constrained by limits on the existing system. Additional generation outlet will allow existing and new generation to reach areas where it can be consumed.

The Group 1 Projects will increase the amount of generation that can be supported in and exported out of North Dakota by increasing the capacity of the transmission system to move energy between North Dakota and the rest of the system further east by several hundreds of megawatts. The Brookings Project will allow the continued development of generation in western Minnesota and eastern South Dakota and alleviate some strain on the transmission system in North Dakota by creating an additional path for North Dakota based generation to move eastward. The La Crosse Project will provide additional capacity to transmit generation and is an important step toward building transmission capacity that will allow generation better access to energy markets for generation produced in the region. The Group 1 Projects are a necessary prerequisite for subsequent transmission projects that will increase the capacity of the system to receive even larger blocks of power from the Dakotas.

Notably, the addition of the Brookings Project (in addition to the Fargo and Bemidji Projects) will further increase the NDEX limit, providing an enhanced ability for North Dakota to maximize its participation in developing regional markets.

The additional generation outlet capabilities created by the Group 1 Projects will provide significant benefits to North Dakota and the region. By increasing power export capability and providing a path to the wider energy markets administered by MISO, the Group 1 Projects will enhance existing generation value and create the potential for additional generation development. The ability to support this additional

generation can also help spur economic development in North Dakota and the region for support services and manufacturing related to the development of generation. In particular, the state has over the last few years experienced job growth and economic development in the areas of construction services and manufacturing related to renewable energy.

E. The Construction of the 345 kV Group 1 Projects Using a Double-Circuit Compatible Configuration is a Prudent and Available Alternative

Applicants are proposing to build the Three 345 kV Projects to include the capability for adding a second circuit in the future for the remainder of the facilities in order to maximize the use of corridors and rights of way, provide for a cost-effective way to increase future capacity and create key regional transmission corridors. The discussion below demonstrates that this "double-circuit compatible" configuration is a reasonable and prudent course of action in light of the alternative configurations considered by the planners.

1. Alternatives Considered for the Three 345 kV Projects

As described above, the CapX2020 planning process demonstrated that new transmission is a prudent option to meet all identified need categories.[8] The planning process identified a number of transmission upgrades that are necessary in the near and mid term planning horizons to keep pace with customer needs. None of the alternatives considered were found to satisfy all of the identified needs in a cost-effective manner. Finally, with regard to the Three 345 kV Projects, planners determined that having the future ability to expand the capacity by adding a second circuit as circumstances warrant is a reasonable and prudent use of resources.

Both higher and lower voltage configurations were considered. An important factor in the alternative voltage analyses was the interest in making use of the existing transmission system in the region and thereby reducing the need to upgrade other facilities to accommodate the Group 1 Projects. The Three 345 kV Projects are designed to expand and strengthen the existing 345 kV system located in North Dakota and surrounding states, while the Bemidji Project is designed to coordinate with the existing 230 kV system located in the Bemidji-Grand Rapids area. All of the Group 1 Projects work together and with the overall system to provide a robust and reliable transmission system for regional utility customers through 2020 and beyond.

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[8] Please see the Direct Testimony of Mr. Timothy J. Rogelstad for a more complete discussion of the CapX2020 planning process.

Higher voltage lines, such as 500 kV or 765 kV transmission lines, could be used to provide high capacity transmission of power. While these voltages may have been appropriate for some needs, these voltages would not be as advantageous as matching the existing 345 kV and 230 kV systems in North Dakota and our region. While these voltages could meet the identified generator outlet need, the capacity of these higher voltage lines would be limited by the amount of energy flows that could be handled by the lower voltage system, thereby lessening the system reliability and community service reliability benefits. In order to properly utilize these extra high voltage lines, new high voltage transmission lines (either 230 kV or 345 kV – depending on the surrounding system configuration) would have to be built to support a 500 kV or 765 kV transmission project to avoid overloading the surrounding lower voltage (115 kV and 69 kV) system. The use of a double-circuit compatible configuration for the Three 345 kV Projects will provide similar transmission capacity to a 500 kV transmission line when the double circuit is complete but the additional cost of obtaining that additional capacity is deferred to when the surrounding transmission system is capable of supporting it.

Lower voltage lines were also evaluated. The lower voltage lines were determined not to be a reasonable alternative in a majority of situations because they cannot provide efficient transfer capability over the long distances required to satisfy all identified needs. Lower voltage lines result in higher line losses which reduce the efficiency and desirability of this alternative, especially for generator outlet capability. In addition to losses, Applicants determined that it would be necessary to implement multiple lower voltage lines in a given area to provide the same transmission capacity from a single 345 kV line. This could result in a proliferation of route corridors and would create significant additional environmental impacts with no added electrical performance.

A number of other alternative configurations were considered in determining that the Group 1 Projects are a reasonable and prudent set of upgrades that are appropriate for the system. Applicants considered double-circuiting the Group 1 Projects and in some instances concluded that double-circuiting and co-locating transmission lines can be appropriate. However, there are limitations on the ability to double circuit lines based on relevant reliability requirements. For example, one factor that must be considered whether double circuiting is a feasible option is compliance with NERC Standard TPL-003-0, System Performance Following Loss of Two or More Bulk Electric System Elements. This standard requires transmission planners to demonstrate that the system can be operated reliably under specified contingency conditions. The 345 kV Group 1 Projects, as proposed in the double-circuit compatible configuration, satisfy all relevant NERC criteria.

Applicants also analyzed whether upgrading existing facilities would satisfy the identified needs and found that refurbished and upgraded facilities were not adequate to address all of the necessary issues.

Finally, under some circumstances, the availability of local peaking generation can delay the need for new transmission. However, in this circumstance, local generation could not satisfy all of the categories of need identified and use of local generation is not an appropriate replacement for the Three 345 kV Group 1 Projects.

For the Three 345 kV Projects, the double-circuit compatible configuration will maximize the use of corridors and rights of way and will offer a cost-effective way to increase future capacity. This configuration will also create key regional transmission corridors. The double-circuit compatible configuration will allow for future capacity additions to the bulk power network on existing structures within these rights-of-way instead of on new structures in new corridors. This helps to mitigate proliferation of corridors and is a prudent expenditure in anticipation of future needs.

Since most of the benefits of a second circuit can not be realized until other future transmission projects occur, the CapX2020 Utilities determined that the most prudent option is to install larger structures now that are capable of carrying the second circuit at some time in the future as circumstances warrant. Applicants and the other CapX2020 Utilities are reviewing the timing and other implications of the double-circuit compatible approach.

2. Project Specific Alternatives

Below, Applicants address a number of the project-specific alternatives considered that demonstrate the prudence of the double-circuit compatible configuration for each of the three 345 kV projects.

a. The Fargo Project

With regard to the Fargo Project, a number of alternative transmission and generation configurations were considered and analyzed to determine that the 345 kV double-circuit capable configuration is the most prudent available project to satisfy the identified needs. Significantly, providing a new 345 kV source linking the greater Red River Valley area to the 345 kV system serving Twin Cities load centers provides a strong electrical connection between two significant load pockets in the region and, therefore, helps create a stronger and more robust regional electric system. Using lower voltage lines, such as 115 kV or 161 kV lines, would not serve that purpose.

Nevertheless, lower voltage alternatives along with upgrading the existing system were considered but found to be electrically inferior at significant cost. Adding additional

capacitor banks to the existing 115 kV system was found to be insufficient to overcome the long term system issues in the Red River Valley. Even adding a second 230 kV line in the region would have resulted in significant expense without equivalent system performance as offered by the Fargo Project.

When considering all of the communities served by the Fargo Project, it was concluded that a lower voltage option would result in many more miles of transmission construction at significant expense, while providing inadequate overall system performance. In addition to the proliferation of corridors, relying upon lower voltage lines to serve the types of needs supporting the Fargo Project would result in higher losses, and a more inefficient system.[9] The study work that was done specifically for the Fargo Project determined that adding the Fargo Project along with the Bemidji Project results in the best available losses profile.

A number of other options were also considered but found not to be preferable to the double-circuit compatible configuration. 345 kV single-circuit, 345 kV double-circuit, 345/500 kV double circuit, 500 kV single circuit and 500 kV double-circuit were all considered. Generally the higher voltage lines were found to increase costs significantly while not providing any near-term benefits. A single-circuit 500 kV line would have increased costs by $170 million or more with no immediate ability to take advantage of the increased voltage. Similarly deploying a second 345 kV circuit at this time was found to increase costs with no corresponding near-term electrical benefit. It was found that building the poles slightly larger to accommodate deployment of a second circuit in the future provided the best balance of up-front cost versus long-term benefits. Using the larger "double-circuit compatible" structures would result in an incremental increase in costs compared to 345 kV single-circuit of about 20% or around $80-100 million. This increased investment now provides a prudent first step toward deploying the second circuit in the future when circumstances warrant.

For example, assuming the addition of 1,200 MW of generation from the North or the West of Fargo would require significant additional transmission. Thus if significant generation from Central North Dakota is deployed, new transmission will be needed to accommodate that generation. Applicants determined that under such a scenario, adding a second circuit to the Fargo Project would provide the transfer

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[9] When electric energy is transmitted, some of it is dissipated or "lost" as heat during transmission. This means that additional electric energy must be produced and transmitted to make of for the amount that was lost. Losses are correlated to the impedance of the transmission line, which simply means that the larger the conductor/higher the voltage, the lower the losses. Losses consist of deman (MW) and energy (MWh) losses which can be derived to estimate the amount of additional generation that must be deployed to satisfy customer requirements.

capability necessary for such a major generation addition. If major new generation is developed in Central North Dakota, additional transmission will be required to carry that power from the source to regional load centers. Having the ability to further expand the system with the second circuit will facilitate ensuring that the transmission system is adequate for whatever new generation is proposed.

b. The Brookings Project

A primary need for the Brookings Project is to facilitate additional generation from the west to major load centers to the south and east. As such, planners focused on voltages that would facilitate bulk transfer of power from these regions. A 345 kV line was found to fit well with the existing system to provide for bulk transfers of generation from west to east.

Similar to the Fargo Project, a variety of options were considered, including 345 kV single-circuit, 345 kV double-circuit, 345/500 kV double-circuit, 500 kV single-circuit and 500 kV double-circuit. Once again, it was determined that deploying higher voltage or double circuit options immediately would result in significant additional cost without near-term benefits. For example a 500 kV single-circuit line would increase costs by $175 million or more with no immediate ability to take advantage of the increased voltage. Rather, the double-circuit compatible configuration provides the future ability to achieve comparable long-term capacity goals as would be found with a 500 kV line but results in only an approximately 8% or $50 million increase at this time. In the future when the second circuit is needed, the additional installation costs will better match the timing of that need.

c. The La Crosse Project

The La Crosse Project was developed following a number of study efforts to determine the most prudent configuration. Planners recognized that providing a 345 kV source from the Twin Cities load center to the southeast would provide a strong 345 kV source to the south and east. It will also provide an additional high voltage path for electric transfers both into and out of the region. When coupled with other expected regional transmission projects, the La Crosse Project will be an important element to facilitate power transfers from generation sources in the west to major load centers to the south and east.

Nevertheless, planners investigated whether a series of 161 kV transmission lines would satisfy the identified needs at reasonable costs. For example, additional transformers and a new 161 kV line near Rochester, Minnesota could have addressed the specific Rochester community service needs but would have cost a similar amount to provide Rochester with the 345 kV source and this addition would have no impact

on addressing community service needs in La Crosse. To address La Crosse needs, planners modeled additional generation in the area and found that it did not overcome the overload conditions identified in the relevant timeframe. A 161 kV rebuild option was also considered. But these options were inadequate and would have resulted in $173 million investment while not addressing all of the issues that needed to be addressed.

Once again, planners concluded that the double-circuit compatible option was the best configuration for the La Crosse Project. Near-term needs are adequately served by the first 345 kV circuit. The double-circuit capable structures would result in an approximately 20% increase, or about $60 million. For this investment, the CapX2020 Utilities are provided with the flexibility to add the second circuit in the future as circumstances warrant. This flexibility is particularly key in this instance as the La Crosse Project crosses the Mississippi River. By having the ability to add the second circuit to the existing facility, the utilities will be able to take advantage of a single river crossing and avoid the difficult permitting issues that would arise if a new river crossing was proposed.

3. The Bemidji Project

Finally, the Bemidji Project is primarily intended to address community service reliability issues in the Red River Valley as well as the Bemidji lakes area. It is configured at 230 kV (instead of 345 kV as is the case with the other Group 1 Projects) to better match the existing transmission system in the project area.

The Bemidji Project is not configured to be double-circuit compatible. Planners considered four specific options, the Bemidji – Grand Rapids 230 kV Project, a Winger – Wilton 230 kV Project, a Badoura – Wilton 230 kV Project, and rebuilding a series of 115 kV lines. Each of these projects were within 20% of each other on an installed cost basis. The analysis of these four options showed that the Bemidji Project provides by far the most incremental load serving capability and is the lowest cost option. It should also be noted that the Bemidji Project provides a transmission solution through the 2020 timeframe, while deploying the Badoura Project would necessitate additional transmission or generation upgrades prior to 2020.

F. The Group 1 Projects are Needed to Establish a Common Foundation for Future Development Across the System to Allow for Regional Generation to Access Regional Markets

The CapX2020 Utilities investigated a broad range of possible scenarios and found the Group 1 Projects are a necessary common foundation for future development across the system and will provide greater opportunities for regional generation to

access regional markets. Additional export capacity and market access will also provide a platform for the development of additional North Dakota based generation, including renewable generation from areas with favorable wind resource profiles.[10]

In addition, the Group 1 Projects provide flexibility that will be beneficial to North Dakota. The specific benefits of transmission and the precise amount of capacity it will support is dependent upon the size and location of new generation. At this time, the size and location of new generation is not yet known. As a result, the Vision Plan examined three separate generation expansion scenarios, including one that assumed significant new generation from North Dakota. The study found that the Group 1 Projects constitute common facilities that are needed under any reasonable set of future generation expansion scenarios. In other words, these four projects are necessary to support regional needs regardless of the generation scenario considered. Thus constructing these lines will result in a significant increase in NDEX and will lay the foundation for future generation development in North Dakota.

Even before the construction of new generation, North Dakota is a net exporter of electricity. This means that during many hours of the year it is necessary for North Dakota to have a robust transmission system to export its excess energy. The CapX2020 Group 1 Projects will facilitate that access and will create additional capacity to support the export of excess energy. The need for additional transmission capacity for exports to the broader market from North Dakota is likely to increase as a number of major wind-energy projects are currently being actively developed in North Dakota. In addition, it is reasonable to expect that additional wind-energy will be developed in the coming years if the transmission is constructed that will be necessary to export that energy to the market.

G. The Group 1 Projects Cost Effectively Balance Immediate and Future Needs

Of the fifteen facilities identified as needed under all scenarios studied by CapX2020 planning engineers, the Group 1 Projects were selected as the first to be built because they were also deemed necessary to meet more immediate community reliability needs. By choosing to build those facilities that meet more immediate needs first, the CapX2020 Utilities are deferring the costs of additional facilities until they are needed. Further, by building the facilities in a double-circuit compatible configuration, the Group 1 Projects will maximize the use of existing corridors by building for expected

[10] For a further description of the direct benefits of the Group 1 Projects to North Dakota, please see the accompanying Direct Testimony of Mr. Timothy J. Rogelstad.

future needs, while deferring the costs of the extra circuit until additional system benefits can be realized by its construction.

By making the 345 kV lines double-circuit compatible, Applicants are providing a prudent platform for future grid expansion. It will also provide a cost effective way to maximize use of existing infrastructure and corridor sharing. Choosing the double-circuit compatible configuration provides important and prudent advantages. This configuration will cost less to upgrade in the future as increasing consumer needs call for future grid expansion. This configuration will help the CapX2020 Utilities maximize the use of existing rights-of-way and existing infrastructure. And, this configuration will result in less impact to landowners when a second circuit is added in the future, and thus should also reduce likelihood of potentially contentious and difficult siting matters in the future. Each of the four Group 1 Projects has unique challenges for siting the lines. Additionally, each of the Three 345 kV Projects crosses a navigable river (requiring potentially challenging additional regulatory review). By planning on the front end for a second circuit, Applicants can avoid having to site yet another right of way across important navigable waters in the future and incurring additional costs. Addressing as many issues as possible with these lines will help the utilities avoid having to come back and revisit these same issues with a new line.

Finally, as noted, Applicants' analysis shows that the second circuit could be deployed in the near- to mid-term depending upon a variety of factors, including additional generation development. As discussed earlier, applicants analyzed the effect on the system if 1,200 MW of new generation is added to the system from the North or West of Fargo. The analysis showed that with 1,200 MW of new generation, the second circuit of the Fargo Project (or some other major new facility) would be necessary. Of course, upgrading the existing line would be cheaper than acquiring new right-of-way and constructing a whole new project. In addition, Applicants concluded that it would be cost effective to install the larger double-circuit compatible structures now to facilitate more cost effective future upgrades. This same analysis holds true for each of the Three 345 kV Projects.

VI. ESTIMATED COST IMPACT TO APPLICANTS' NORTH DAKOTA RATEPAYERS OF THE GROUP 1 PROJECTS

Applicants anticipate that, collectively, their North Dakota customers will be responsible for less than 5% of the total retail cost impact of the approximately $1.8 billion Group 1 Project investment. In other words, of the total cost impact to the retail ratepayers of all the CapX2020 Utilities due to MISO charges, Xcel Energy's and Otter Tail's North Dakota ratepayers will be responsible for less than 5% of the MISO charges attributed to the Group 1 Projects. These costs will be recovered through the MISO cost allocation mechanisms (discussed in detail below). Based on

the currently-applicable MISO mechanisms, the cumulative effect on Xcel Energy and Otter Tail's North Dakota ratepayers will be in the approximate range of $16-18 million in yearly MISO charges, representing only $75-100 million in investment of the total $1.8 billion of investment by the CapX2020 Utilities in the Group 2 Projects.

As described more fully in the following analysis, Xcel Energy estimates that additional annualized revenue requirements to recover from its North Dakota customers will be in the range of $9-10 million for yearly MISO charges, representing approximately $40-60 million for the North Dakota allocation of its investment. Otter Tail estimates that additional annualized revenue requirements to recover from our North Dakota customers in the range of $7-7.5 million for yearly MISO charges, representing approximately $35-40 million for the North Dakota allocation of its investment.

A. Applicants' Anticipated Investment Shares in the Group 1 Projects

The CapX2020 Utilities' coordinated approach to planning speaks to the regional benefits of these projects. But each CapX2020 Utility ultimately has different load serving needs and different amounts of capital available to invest. Ultimate ownership of each of the Group 1 Projects was left until the end in order to accomplish the following: one, allow for joint planning and permitting of the Project because regardless of ownership, all of the Group 1 Projects are needed; and two, allow for the regulatory approvals to be obtained and evaluated by the utilities so that each utility had the opportunity to assess the regulatory requirements and its capacity for investment and its ownership.

For the purpose of developing the Group 1 Projects and sharing in the development costs, the CapX2020 Utilities have agreed to certain project investment percentages. The table below illustrates the investment targets currently contemplated by the CapX2020 participating utilities. Each utility, including Applicants, has the right (but not the obligation) to take ownership up to the identified project development percentage. Each utility may invest up to the percentage, choose to invest in a lower percentage, or choose to not invest at all in a Project. If the utility ultimately declines to take ownership to its designated level, the excess is offered to the other participants. The decision whether or not to invest in the construction of a Project will be made after all major permits have been issued for that Project.

Figure 7: Project Development Percentages

Project Name:	Fargo	La Crosse	Brookings	Bemidji
Applicable Project Development Percentage				
Central Minnesota Municipal Power Agency	--	--	2.2%	--
Dairyland Power Cooperative	--	11.0%	--	--
Great River Energy	25%	--	16.5%	13.0%
Minnesota Power	14.7%	--	--	9.3%
Minnkota Power	--	--	--	31.5%
Missouri River Energy Services	11.0%	--	5.1%	--
Otter Tail Power Company	13.2%	---	4.1%	20.0%
Rochester Public Utilities	--	9.0%	--	--
Southern Minnesota Municipal Power Agency	--	13.0%	--	--
WPPI Energy	--	3.0%	--	--
Xcel Energy	36.1%	64.0%	72.1%	26.2%
Totals:	100%	100%	100%	100%

As Figure 7 shows, Applicant Otter Tail is not expecting to own any portion of the La Crosse Project. Otter Tail chose not to invest in the La Crosse Project because it wants to own facilities closer to its existing transmission facilities. Because each utility has a finite amount of resources available for investments in the Group 1 Projects, Applicant Otter Tail has determined that it would invest its available resources on the Projects closest to its customers.

B. Cost Responsibility Assigned By MISO to Applicants

Investment in any particular transmission line by a utility does not determine the cost allocated to it pursuant to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("MISO Tariff"). To the contrary, a portion of the La Crosse Project for example, qualifies for certain MISO cost allocation methodologies and will be socialized across all MISO members including Applicant Otter Tail.

Therefore, while ownership and cost allocation are related issues, there are important distinctions. Regardless of who owns a Project, costs will be allocated to utilities based on MISO's cost allocation methodology.

As members of MISO, Applicants will recover their respective investments in each of the Group 1 Projects pursuant to the MISO Tariff. The cost of ownership, reflected in the final ownership agreements negotiated amongst the utilities, will be entered into each of the Applicant's revenue requirements formula for the segments of each Project eligible for cost sharing pursuant to Attachment FF of the MISO Tariff (sometimes referred to as RECB designations).[11] Depending upon how MISO categorizes a line, different cost allocation factors will be applied. For those segments of the Group 1 Projects without a RECB designation, MISO will compute each owner's revenue requirements and transmission charges pursuant to Attachment O of the MISO Tariff. MISO will calculate revenue requirements and then provide payments to each Applicant to recover their investments. These payments are derived from charges MISO assesses on users of its Transmission System, including Applicants. It is these MISO charges that will ultimately impact our ratepayers. Appendix C contains more discussion of MISO cost allocation methodologies for the Group 1 Projects.

Given the size and scope of the Group 1 Projects (the largest regional transmission project in the upper Midwest in decades) there are novel issues that still need to be resolved in order to finalize Project cost recovery and allocation and ultimately, the cost responsibility assigned to Applicants. The CapX2020 Utilities continue to work on issue resolution with MISO – which is responsible for the operation of the majority of the region's transmission infrastructure. Applicants are transmission-owning members of MISO, and through MISO, Applicants will recover their capital costs and be assessed use charges.

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[11] Please see Appendix C for a discussion of RECB designations. These designations can create important distinctions with important cost allocation implications. Appendix C describes some of these distinctions and the impact they could have on the costs in this circumstance.

For example, the cost recovery and allocation issues regarding the Brookings Project are in flux. As discussed in Appendix C, MISO, Applicants and other stakeholders have begun discussing alternative ways to allocate the costs of the Brookings Project.

Furthermore, Otter Tail and other transmission owning members of MISO are currently in discussions with MISO regarding the need for MISO to adjust its cost allocation methodology, particularly in the circumstance of transmission that is designated primarily available for the interconnection of new generation. Because of the location of the Otter Tail system, there is a large amount of generation in the MISO Queue that is seeking to interconnect to the MISO Transmission System within Otter Tail's pricing zone. But much of that generation will likely be used for the benefit of other regional and national utilities. Based on MISO's current Tariff methodology, a substantial proportion of the cost to build the transmission facilities necessary to interconnect that generation to the transmission grid will be disproportionately borne by Otter Tail ratepayers and Otter Tail will not obtain the corresponding benefit of the generation. Stated another way, under the current MISO Tariff requirements, the utility that purchases or owns the generation may not be responsible for the cost of the transmission needed to interconnect that generation. Otter Tail is working with MISO to seek better ways to allocate the costs of these generator interconnection projects so that Otter Tail's ratepayers do not disproportionally subsidize projects that benefit the customers of other utilities.

Due to the disparate impacts of MISO's cost allocation methodology on Otter Tail's ratepayers as described in the preceding paragraph, Otter Tail has submitted notice to MISO which reserves to Otter Tail its right to withdraw from MISO should the issue not be satisfactorily remedied. Otter Tail has indicated that it is not necessarily Otter Tail's desire to leave MISO. So that Otter Tail may preserve all options with MISO, advance notice required pursuant to the MISO Owners Agreements was deemed advisable. In an effort to address these concerns, MISO submitted to the Federal Energy Regulatory Commission ("FERC") a proposal to modify the cost allocation methodology contained in its Tariff for the costs associated with generators interconnection to its Transmission System on July 9, 2009. The outcome of this process may result in changes to the way the costs for the Brookings Project will be allocated to Applicants and other MISO members. Applicants will keep the Commission informed on this process and of the impact any revised Tariff procedure may have on this proceeding.

Therefore, both MISO's cost allocation methodology for transmission projects designated to be primarily for generator interconnection, and Otter Tail's participation in MISO may change prior to construction of the Group 1 Projects. Applicants will keep the Commission informed as project cost recovery and cost allocation issues

become clearer. In this Application, Applicants will provide a discussion of cost recovery using MISO's cost allocation methodology and Applicants' budgeted capital costs applicable as of the date of filing this Application.

As mentioned above, Applicants will earn a rate of return on their capital costs for the Group 1 Projects pursuant to the MISO Tariff. MISO will collect Applicants' revenue requirements for the Group 1 Projects from charges allocated to various users of the MISO Transmission System. It is the charges that Applicants will pay to MISO based on MISO's cost allocation methodology that will be passed on to Applicants' ratepayers. Appendix C contains an explanation of MISO's cost allocation methodology for each of the Group 1 Projects as well as the expected MISO charges Applicants will incur for the Group 1 Projects.

Applicants recognize that the uncertainties surrounding the MISO cost allocation process make it difficult for the Commission to make definitive decisions about this project because it is impossible to know the precise level of cost responsibility that will be assigned to North Dakota. Applicants believe, however, that the Commission can nevertheless order that the costs incurred on the Brookings Project are prudent in spite of the potential that cost allocation is in flux.

The Brookings Project provides significant value to North Dakota in any case. The NDEX limit will be increased if the Brookings Project is deployed in addition to the Fargo and Bemidji Projects. The presence of this line, therefore, provides real value in making it easier for existing and new North Dakota generation to reach the regional market. In addition, the Brookings Project is an indispensible project for developing major new wind-energy generation in Western Minnesota, Eastern South Dakota, and Southeastern North Dakota. MISO has already determined that the Brookings Project is a necessary system element to address the current demand for new wind generation. In short, the Brookings Project is a reasonable and prudent system addition at this time whether or not the MISO cost allocation mechanism changes.

C. Estimated Cost Impact on Applicants' North Dakota Ratepayers

The impact to Xcel Energy's and Otter Tail's North Dakota ratepayers will be associated with the MISO allocation, which represents approximately less than five percent of the costs, and not necessarily track the precise investment. Below, Applicants provide a more detailed discussion of the projected impacts on each of them.

1. Impact on Xcel Energy Ratepayers

Xcel Energy plans its generation and transmission systems as an integrated whole to serve all customers across the five state jurisdictions in which it operates. The costs of transmission and generation improvements are allocated across all customers generally in proportion to customer usage in each jurisdiction. Approximately 5% of Xcel Energy's system generation and transmission costs are allocated to North Dakota customers.

Based on the MISO cost allocation for the Group 1 Projects (explained in detail in Appendix C), Xcel Energy estimates that the MISO charges it will incur due to the Group 1 Projects will necessitate additional annualized North Dakota jurisdictional revenue requirements in the range of $9-10 per year. This represents approximately $40-60 million of investment by the CapX2020 Utilities allocated to our North Dakota customers. As described in Appendix C, the amount includes certain allocated costs that are currently under review and may change. However, this amount provides a high-case scenario for the Commission's consideration.

2. Impact on Otter Tail Ratepayers

Otter Tail, too, plans its generation and transmission systems as an integrated whole to serve all customers across the three state jurisdictions in which it operates. The costs of transmission and generation improvements are allocated across all customers generally in proportion to customer usage in each jurisdiction. Approximately 41% of Otter Tail's system generation and transmission costs are allocated to North Dakota customers.

Based on the MISO cost allocation for the Group 1 Projects (explained in detail in Appendix C), Otter Tail estimates that the MISO charges it will incur due to the Group 1 Projects will necessitate additional annualized North Dakota jurisdictional revenue requirements in the range of $7-7.5 million per year. This represents approximately $35-40 million of investment by the CapX2020 Utilities allocated to our North Dakota customers. As described in Appendix C, the amount includes certain allocated costs that are currently under review and may change. However, this amount provides a possible worst-case scenario for the Commission's consideration.

VII. COMMUNICATIONS AND SERVICE

Applicants respectfully request that the following persons be placed on the Commission's official service list for all official communications in this case:

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VIII. CONCLUSION

The Group 1 Projects are essential to the continued reliable and economic operation of the electrical system serving North Dakota and the rest of the upper Midwest. Without them, a growing list of equipment failures could result in system failures. Growing demand and renewable energy policies are causing significant generation expansion in the region. The Projects have been configured to meet reliability concerns and future growth needs in a reasonable and prudent manner. The Group 1 Projects have been designed to support generation growth in North Dakota and throughout the region and are a necessary foundation to any further expansion of the system in the future. For the reasons discussed above, Applicants respectfully request

that the Commission grant our request for an ADP for our proposed investment in the Group 1 Projects.

Dated: September 17, 2009

Northern States Power Company,
a Minnesota Corporation

Otter Tail Power Company,
a Minnesota Corporation

Respectfully submitted,

JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION

DEAN PAWLOWSKI
PROJECT MANAGER

2389650v10

XCEL ENERGY APPENDIX A

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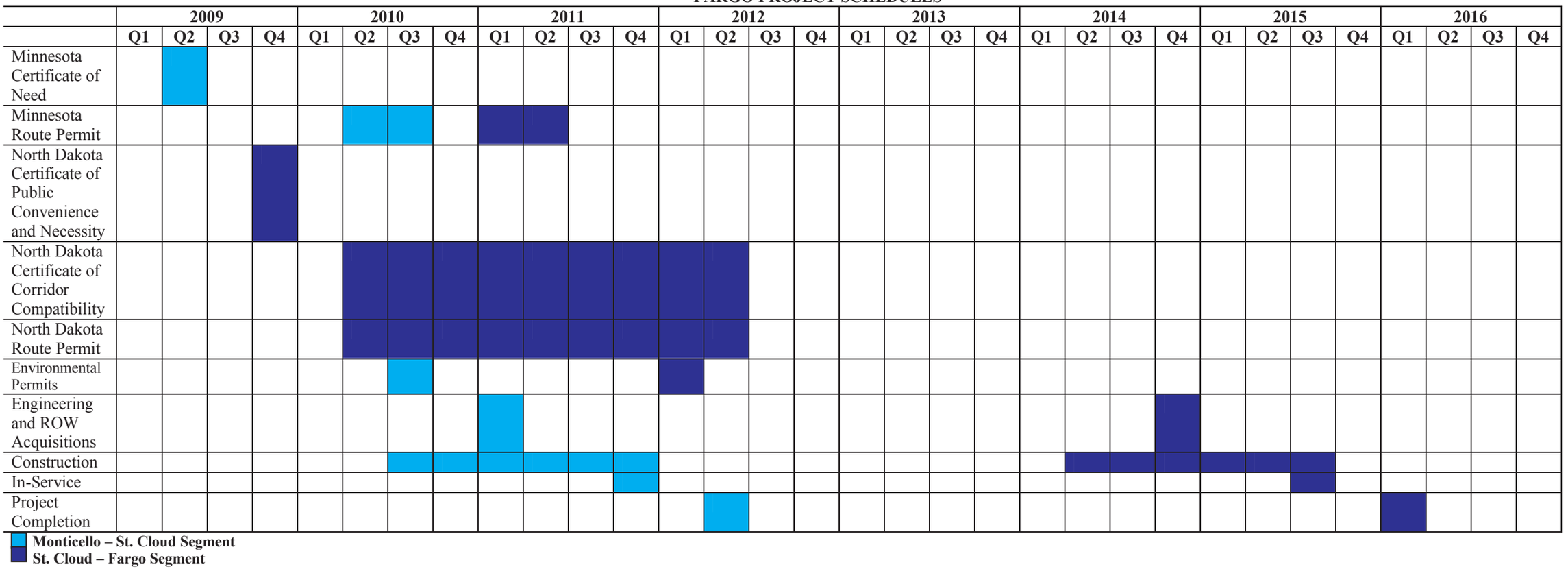
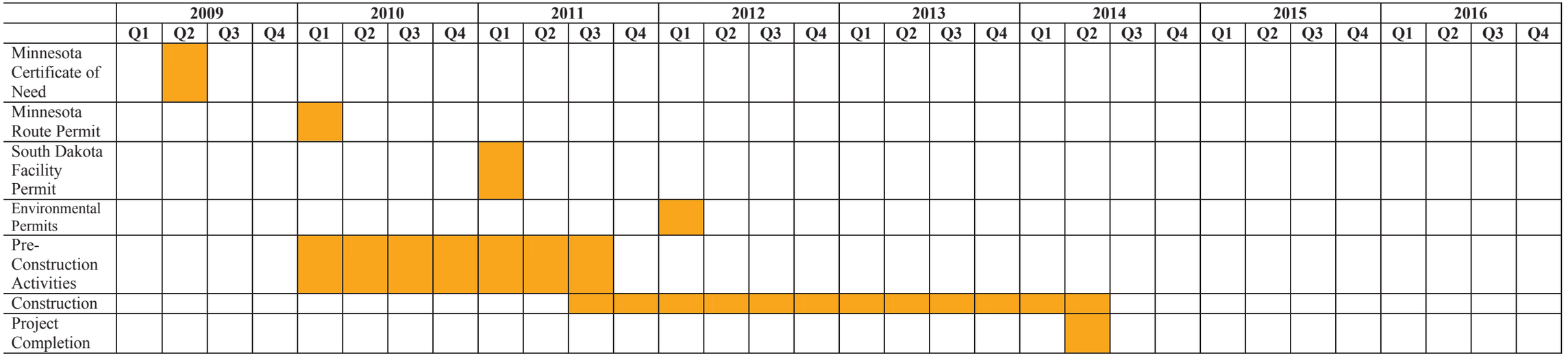
JOINT APPENDIX B

Project Construction Schedules

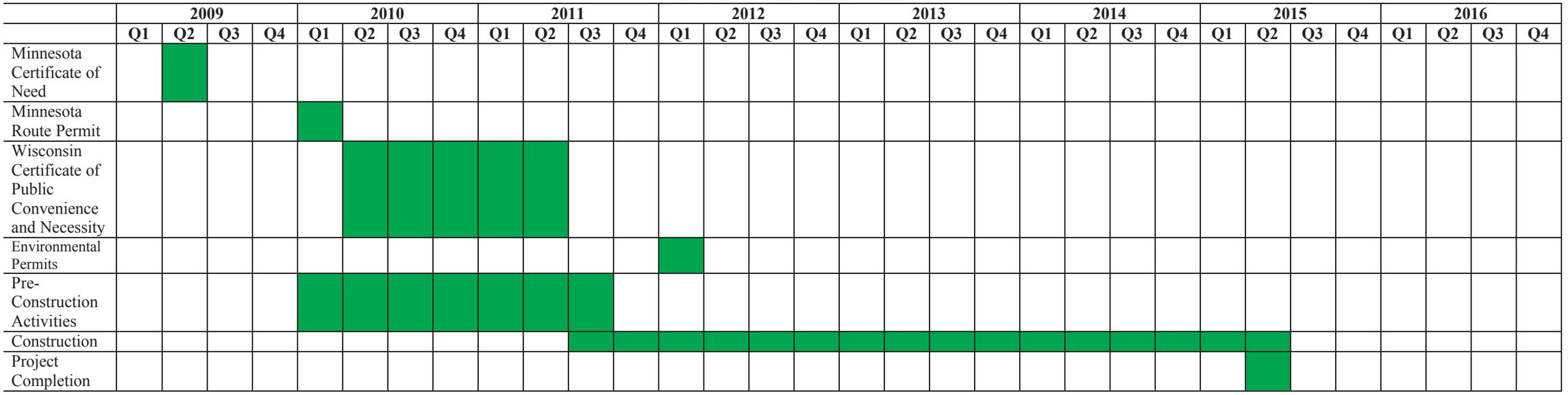
FARGO PROJECT SCHEDULES



BROOKINGS PROJECT SCHEDULES



LA CROSSE PROJECT SCHEDULES



BEMIDJI PROJECT SCHEDULES

	2009				2010				2011				2012				2013				2014				2015				2016			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Minnesota Certificate of Need																																
DEIS																																
FEIS																																
Minnesota Route Permit																																
Other Federal/State Permits																																
Project Construction																																
Project In-Service																																

Joint Appendix C

CapX2020 Group 1 Projects

MISO Cost Allocation Methodology

Summary

This Appendix is provided in connection with Applicants' Application for an Advanced Determination of Prudence and addresses issues concerning ratepayer impact arising out of the CapX2020 Group 1 Projects (hereinafter referred to collectively as either "CapX2020 Group 1 Projects" or "Group 1 Projects" and each individually as Project).

In an effort to provide the North Dakota Public Service Commission ("Commission") with meaningful information regarding potential cost-allocation scenarios, Applicants have attempted to work through the Midwest Independent Transmission System Operator, Inc. ("MISO") cost allocation process pursuant to Attachment FF[1] of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"). As will be discussed in this Appendix, there are various approaches to the allocation of transmission costs within the MISO Transmission System. Allocation of costs for those CapX2020 Group 1 Projects that are designated by MISO as "Baseline Reliability Projects" (the Fargo – Twin Cities 345 kV Project ("Fargo Project") and the Bemidji – Grand Rapids 230 kV Project ("Bemidji Project") and portions of La Crosse – Twin Cities 345 kV Project ("La Crosse Project")) is fairly straight forward. Cost allocation for the Brookings County – Twin Cities 345 kV Project ("Brookings Project") is likely to be more complex and will likely evolve over time.

In spite of these challenges and uncertainties, Applicants have attempted to estimate how costs of the CapX2020 Group 1 Projects will be allocated to the users of the MISO Transmission System, and in particular to Applicants. While the evolving rules and protocols make precise calculations difficult, some summary conclusions can be drawn. In the event that MISO develops cost allocation mechanisms that treat all four of the Group 1 Projects in a substantially similar fashion, the estimated cost to their respective North Dakota jurisdictional customers

[1] Attachment FF is sometimes referred to as "RECB," which stands for Regional Expansion and Criteria Benefits and was the name of the Midwest ISO stakeholder task force that developed the cost inclusion and allocation criteria.

for each Applicant will be the MISO charges on approximately $40-60 million of investment for Xcel Energy and $35-40 million of investment for Otter Tail.[2]

The following chart breaks this estimate down by Project:

	Xcel Energy	Otter Tail
Fargo Project*	$13-16 million*	$20-22 million*
Bemidji Project %	$1-2 million%	$5-7 million%
La Crosse Project+	$9-11 million+	$75,000+
Brookings Project^	$22-27 million^	$11-13 million^
Total investment attributable to ND	$40-60 million	$35-40 million
Approximate levelized revenue requirement per year in ND	$9-10 million	$7-7.5 million

*Assumes MISO cost allocation applicable to Baseline Reliability Projects applies.

% Assumes a combination of the MISO formula applicable to Baseline Reliability Projects and portion of Project designated non-MISO not subject to recovery of revenue requirements under the MISO Tariff.

+Assumes a combination of the MISO formula applicable to Baseline Reliability Projects and MISO Attachment O allocation for aspects of projects not eligible for cost sharing.

[2] As with any project that is still in the permitting stages, the final costs of the CapX2020 Group 1 Projects will not be known until they are completed. Applicants' submittal of costs estimated for this Application, pursuant to N.D.C.C. §49-05-16, and discussed herein are, therefore, estimates. These approximate totals are based on the estimated project costs in 2007 dollars and are subject to adjustment based on final route selection, timing of construction and the potential for unforeseen circumstances. Applicants will provide the Commission with updates on the costs and will advise the Commission of material changes in costs or material changes in MISO's treatment of the costs.

^Assumes MISO cost allocation applicable to Generator Interconnection Project applies. This assumption creates a high-cost "conservative" scenario for use in this proceeding. However, it is likely the Brookings Project's costs will be allocated by some different (yet to be developed) methodology. As discussed below, MISO, Applicants and stakeholders are actively working to develop different allocation mechanisms for the Brookings Project.

Cost Recovery and Allocations

A. Recovery of Capital Costs

As members of MISO, Applicants will recover their respective capital costs of each of the Group 1 Projects pursuant to the MISO Tariff (i.e., the segments of each Project that are eligible, under MISO Attachment FF, to receive cost-sharing, as discussed below). Those final eligible costs of ownership, pursuant to the final Ownership Agreements negotiated amongst the utilities participating in the CapX2020 Initiative (the "CapX2020 Utilities"), will be submitted by Applicants pursuant to MISO Attachment GG, the revenue requirements formula. For those segments of the Group 1 Projects without an eligible cost-sharing RECB designation, MISO will compute each MISO transmission owner's MISO revenue requirements and transmission charges pursuant to Attachment O of the MISO Tariff. The non-MISO transmission owners will determine their own requirements and charges under their respective open access transmission tariffs.

It is expected that 100% of the Fargo and Brookings Projects will be part of the MISO Transmission System[3] and subject to the cost allocation and cost recovery provisions of the MISO Tariff given that it is anticipated that all owners will be MISO

[3] For purposes of this Appendix C, Transmission System is defined pursuant to the MISO Tariff as: "The transmission facilities owned or controlled by entities that have conveyed operational control to the Transmission Provider that are used to provide Transmission Service under Module B of this Tariff. The Transmission System includes facilities, the operational control of which has been transferred to the Transmission Provider subject to Commission approval under Section 203 of the Federal Power Act. In addition, the Transmission System includes other facilities booked to transmission accounts that are not controlled or operated by the Transmission Provider but are facilities that the Transmission Owners, by way of the Agency Agreement, have allowed the Transmission Provider to use in providing service under this Tariff. While not part of the Transmission System, service over Distribution Facilities is available through the execution of a Service Agreement pursuant to Schedule 11 of this Tariff. The term Transmission System shall include the Transmission System (Michigan)."

transmission-owning members. Approximately 80% of the La Crosse Project and 68.5% of the Bemidji Project will be part of the MISO Transmission System. Companies that are not transmission-owning members of MISO will own the remainder of these Projects and obtain cost recovery from their ratepayers. CapX2020 Utilities that are transmission-owning members of MISO will recover their respective share of each Group 1 Project from charges MISO imposes on the users of the MISO Transmission System, including Applicants.

Table 1, below, shows the expected ownership share of each of the Group 1 Projects. These values represent the ownership percentages if all participants were to elect to invest at maximum specified levels. Because final ownership proportions have not yet been agreed on, these allocations are subject to change.

Table 1

Expected Ownership Shares of CapX2020 Projects (%)

Transmission Owner	Twin Cities - Fargo 345 kV Project	Twin Cities - Brookings County 345 kV Project	Twin Cities - La Crosse 345 kV Project	Bemidji - Grand Rapids 230 kV Project
Central Minnesota Municipal Power Agency (“CMMPA”)		2.2%		
Dairyland Power Cooperative (“DPC”)			11.0%	
Great River Energy (“GRE”)	25.0%	16.5%		13.0%
Minnesota Power (“MP”)	14.7%			9.3%
Minkota Power Cooperative (“MPC”)				31.5%
Missouri River Energy Services (“MRES”)	11.0%	5.1%		
Otter Tail Power Company (“OTP”)	13.2%	4.1%		20.0%
Rochester Public Utilities (“RPU”)			9.0%	
Southern Minnesota Municipal Power Agency (“SMMPA”)			13.0%	
WPPI Energy (“WPPI”)			3.0%	
Xcel Energy	36.1%	72.1%	64.0%	26.2%
Total	100.0%	100.0%	100.0%	100.0%

B. MISO Cost Allocation

Most of the CapX2020 Utilities are transmission-owning members of MISO. As a general matter, MISO calculates a revenue requirement for the recovery of costs for the owners of the transmission facilities under the MISO Tariff and charges *users* of the MISO Transmission System in order to collect and remit to the MISO transmission *owners* their cost recovery on their transmission assets. Therefore, CapX2020 Utilities that are members of MISO will, in general, recover their capital costs for their ownership of the Group 1 Projects from MISO.

As noted above, in order to pay the *owners* of the transmission in the MISO footprint, MISO charges the *users* of the transmission facilities in the MISO footprint for their use of those transmission facilities. Thus, MISO CapX2020 Utilities, as users of transmission facilities in the MISO footprint, will pay a portion of those charges. It is these charges to use the transmission in the MISO footprint, including the CapX2020 Group 1 Projects, for which CapX2020 Utilities will incur costs and which will be recovered from the ultimate benefactors of this use, the CapX2020 Utilities' ratepayers.

1. MTEP Analysis

Each year, MISO reviews all of the transmission expansion plans proposed by the MISO transmission owners and independently determines those projects that are to be included in what is know as "Appendix A" of the Midwest Transmission Expansion Plan ("MTEP"). Appendix A projects are projects that have satisfied MISO's factors to be the preferred solution to an identified reliability, policy or other need, or to achieve an identified cost savings or other benefit and that have been approved by the MISO Board of Directors. The project justification process includes consideration of a variety of factors including urgency of need and comparison from amongst alternatives of operating performance, initial investment costs, robustness of the solution, longevity of the solution provided, and performance against other economic metrics. Projects in Appendix A may be generated from the Baseline Planning process, or from the Generator Interconnection or Transmission Service Request study processes. Projects in Appendix A may be eligible for regional cost sharing per provisions in Attachment FF of the Tariff.

MISO's cost allocation process is outlined in Attachment FF, Section III of its Tariff. At the present time, MISO assigns costs based on four different categories.

Baseline Reliability Projects ("BRP")

Generation Interconnection Projects ("GIP")

Transmission Delivery Service Projects

Regionally Beneficial Projects ("RBP")

The CapX2020 Group 1 Projects have been designated either as a BRP or GIP. Therefore, this discussion focuses on those two categories.

Baseline Reliability Projects are defined as projects that serve a documented need for baseline reliability, and are eligible for MTEP cost sharing if they: 1) have a total cost of $5M or more; or 2) have a project cost below $5M, but a total cost that is 5% or more of the transmission owners net plant as established according to Attachment O.

All costs for BRPs with a rated voltage of 100 kV through 344 kV are allocated to Transmission Customers in designated sub-regional pricing zones. The subregions and pricing zones are determined on a case-by-case basis using the Line Outage Distribution Factor methodology (LODF).[4] MISO then models the LODF for each pricing zone for each new transmission facility. LODF is used because it is considered by MISO planners as a way to determine the added benefit of a new transmission facility to each of the pricing zones. Generally, pricing zones in close proximity to the proposed transmission facility have the greatest LODF cost allocation and those furthest away have little to no cost allocation from the LODF method thus this benefit assignment approach is defined as being sub-regional.

For BRPs of 345 kV or higher, the RECB criteria defines some of the benefit of the proposed transmission facility as being for system-wide reliability. Therefore a portion of the costs of the proposed facility (20%) is assigned to all pricing zones in MISO on what is known as a "postage stamp" basis. Postage stamp cost allocation spreads cost responsibility proportionally to the load in the pricing zones of MISO

[4] LODF is an engineering calculation of the change of flows on the Transmission System created by the addition of a new transmission facility. MISO uses computer software to measure and model the LODF of all facilities within the MISO Transmission System for each new facility added to the system.

thus this benefit assignment approach is defined as being regional. The remaining 80% of the project costs are allocated sub-regionally to all Transmission Customers within designated pricing zones. As before, the sub-regions and pricing zones are determined on a case-by-case basis using the LODF process as previously described.

Under the current MISO Tariff, all upfront costs for GIPs are paid by the Interconnection Customer. For generation resources that are qualified as designated Network Resources of have a purchase power agreement of one year or more with a MISO Load, the Interconnection Customer may be repaid up to 50% of the costs of the GIP which is allocated among the pricing zones using the same methodology applicable to BRPs. The remaining 50% is directly assigned to the Interconnection Customer. The only exception is that all facilities classified as Transmission are considered for allocation purposes (i.e., cost allocation is not cut off at 100 kV).

If the initial screening criteria of RECB determines that the benefits of a proposed transmission facility is local in nature, then the assignment of costs for that facility is left to the local pricing zone of the owner of the facility. For example, a proposed transmission facility that serves a single customer on a radial line would be directly assigned for the benefit of that customer. Similarly, a proposed transmission facility that primarily benefits a local load center or even a load center that is not part of the MISO system would be assigned for the benefit of that local load center.

2. Revenue Requirement and Cost Allocation

For the costs for existing transmission or new transmission that is not eligible for cost sharing, the affected transmission owner will generally incorporate the costs of those facilities in its rate base as calculated pursuant to Attachment O of the MISO Tariff. As described below, portions of the La Crosse Project are not eligible for cost sharing under the MISO Tariff; thus those costs are included into the transmission owners' (including Applicant Xcel Energy) MISO rate base calculated pursuant to Attachment O.

MTEP projects that qualify for cost sharing are reported through MISO Attachment GG revenue requirement and rates calculations. The Attachment GG information is used for tracking costs and in-service dates of approved MTEP cost shared projects and for distributing the revenues associated with such charges. Schedule 26 of the MISO Tariff provides the rate recovery mechanism by which the MISO collects the Attachment GG revenue requirements. If a new transmission

facility qualifies for MISO cost sharing (pursuant to Attachment FF of the MISO Tariff and as described above), the revenue requirements are determined through Attachment GG of the Tariff and the subsequent recovery of those revenue requirements are assessed under Schedule 26 of the MISO Tariff.

C. Cost Allocations and Ratepayer Impacts of the Group 1 Projects

The Fargo Project and the MISO portion of the Bemidji Project have been designated as BRPs in the 2006 and 2008 MTEPs. The segment of the La Crosse Project from North Rochester to La Crosse has also been designated as a BRP in the 2008 MTEP. The Hampton Corner to North Rochester 345 kV segment of the La Crosse Project and both 161 kV circuits of the La Crosse Project were screened as local facilities under the RECB criteria because the primary benefit of these facilities are for the load of two non-MISO CapX2020 Utilities (Dairyland Power Cooperative ("DPC") and Rochester Public Utilities ("RPU")). Similarly, a portion (31.5%) of the Bemidji Project is assigned to a non-MISO CapX2020 Utilities (Minnkota Power Cooperative). Thus, that portion is not treated as a BRP by MISO. Finally for the Brookings Project, MISO has stated that this line is primarily a GIP under RECB (no near term BRP benefit and no RBP benefit). MISO is still working through the specific cost allocation of the Brookings Project costs attributable to the generators that require the Brooking Project for their interconnection.

In summary each of the CapX2020 Group 1 Projects have been designated for cost responsibility as follows under the RECB criteria:

Fargo Project – All of the cost responsibility assigned as a BRP with 20% through postage stamp to all MISO pricing zones and 80% through the LODF method.

Bemidji Project – 68.5% of the cost responsibility assigned as a BRP through the LODF method (as applicable to 100 kV through 344 kV projects) and 31.5% of the cost of the project that non-MISO transmission owner Minnkota Power Cooperative will incur are not assigned to any MISO members.

La Crosse Project – All of the cost of the Hampton to North Rochester portion of this project along with the 161 kV lines from North Rochester into the Rochester area are assigned locally to the owners of this segment of the line. This approach is defined as "Market Participant Funding" for non-BRP facilities. Further, the cost of the project that non-MISO transmission owners DPC and RPU will incur are not assigned to any MISO members. Finally, the cost of the

remaining portion of the project is assigned as a BRP with 20% through postage stamp to all MISO pricing zones and 80% through the LODF method.

Brookings Project – 100% of the cost responsibility initially assigned to the generators that require the project for their interconnection (yet to be finalized). Any further cost responsibility assignment has not been finalized and will be discussed later in this document.

A more detailed discussion of the cost allocation results for each of these projects is contained in the following discussion.

1. The Fargo Project

The entire length of the Fargo Project has been designated as a Baseline Reliability Project in the 2008 MTEP. As a 345 kV Baseline Reliability Project, 20% of the costs for use of the Fargo Projects will be allocated to all pricing zones as a postage stamp rate. The remaining 80% of the costs of the Fargo Project will be allocated to pricing zones based on the LODF allocation method. Table 2 shows the estimated cost of the Fargo Project to each MISO pricing zone that contain CapX2020 Utilities load (after both the Postage Stamp and LODF allocations) based on the budgeted costs for the Project.

Table 2

Allocation of Fargo Project Costs to Midwest ISO Pricing Zones (million $)

Midwest ISO Pricing Zone	Twin Cities - Fargo 345 kV Project
ALTW (ITCM)	$6.9
American Transmission Co.	$17.6
GRE	$17.8
MP	$54.3
Northern States Power Co.	$298.9
OTP	$94.4
SMMPA	$0.3
All Other MISO Pricing Zones	$86.1
Total	$576.2

Pricing Zones Containing CapX Members	**$490.1**

Non-CapX Members Pricing Zones	$86.1

The next step in the process of allocating costs is to allocate these charges to the load in each pricing zone. These last charge assignments are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing

zone. Table 3 provides estimates of charges that CapX2020 Utilities will incur on a pricing zone basis for the Fargo Project.

Table 3

Allocation of Fargo Charges to Owners for CapX2020 Projects ($1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Twin Cities - Fargo 345 kV Project
GRE	ALTW (ITCM)	$213
	GRE	$15,793
	MP	$4,889
	NSP	$25,404
	OTP	$10,190
MP	MP	$47,863
Xcel Energy	ALTW (ITCM)	$14
	GRE	$1,209
	MP	$54
	NSP	$261,808
	OTP	$26,041
OTP	OTP	$48,214
SMMPA	ALTW (ITCM)	$69
	GRE	$783
	NSP	$4,782
	SMMPA	$334
CMMPA	ALTW (ITCM)	$62
	NSP	$1,793
DPC	ATC	$53
	NSP	$5,081
MRES	ALTW (ITCM)	$117
	NSP	$5,081
	OTP	$9,907
WPPI	ATC	$1,055
	NSP	$1,793
Total		$472,600

Non-CapX Member Pricing Zones	$86,083
Non-CapX Members in CapX Member Pricing Zones	$17,517

Total Project Costs	$576,200

Therefore, some Project costs will be recovered through MISO charges paid by all MISO transmission owners through the postage stamp rate and the remainder will be recovered from MISO customers that more directly benefit from the Project as determined by MISO's LODF methodology.

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have an approximate cost responsibility of $289,126,000 for the Fargo Project and that Otter Tail will have an approximate cost responsibility of $48,214,000 for the Fargo Project. Of those MISO charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers. 41.3% of those charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Fargo project to their respective North Dakota jurisdictional customers for each Applicant, as represented in the MISO charges each Applicant will incur, is the MISO revenue requirements on approximately $13,357,621 of investment for Xcel Energy and approximately $19,864,168 of investment for Otter Tail.

2. The Bemidji Project

The Bemidji Project was designated as a Baseline Reliability Project in the 2006 MTEP. As a Baseline Reliability Project less than 345 kV, all of the CapX2020 Utilities who are MISO members' share of the Bemidji Project (68.5% of the costs of the Bemidji Project) will be allocated on a pricing zone basis to those pricing zones that benefit from the Bemidji Project based on MISO's LODF calculation (sub-regional basis). Table 4 shows the estimated charges on a pricing zone basis for the Bemidji Project.

Table 4

Allocation of Bemidji Project Costs to Midwest ISO Pricing Zones (million $)

Midwest ISO Pricing Zone	Bemidji - Grand Rapids 230 kV Project
ALTW (ITCM)	$0.4
American Transmission Co.	$3.6
GRE	$1.5
MP	$21.0
Northern States Power Co.	$26.7
OTP	$29.0
Total	$82.2

The remaining 31.5% of the Bemidji Project is expected to be owned by Minnkota Power Cooperative, which is not a transmission owning member of MISO. The costs to Minnkota of owning its respective portion of the Bemidji Project will be recovered by its ratepayers.

As noted above, the charges allocated to each pricing zone are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing zone. Table 5 provides estimates of charges that Applicants will incur on a pricing zone basis for the Bemidji Project.

Table 5

Allocation of Bemidji Charges to Owners for CapX2020 Projects ($1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Bemidji - Grand Rapids 230 kV Project
GRE	ALTW (ITCM)	$11
	GRE	$1,339
	MP	$1,889
	NSP	$2,266
	OTP	$3,130
MP	MP	$18,475
Xcel Energy	ALTW (ITCM)	$1
	GRE	$103
	MP	$21
	NSP	$23,350
	OTP	$7,988
OTP	OTP	$14,798
SMMPA	ALTW (ITCM)	$4
	GRE	$66
	NSP	$426
	SMMPA	$0
CMMPA	ALTW (ITCM)	$3
	NSP	$160
DPC	ATC	$11
	NSP	$453
MRES	ALTW (ITCM)	$6
	NSP	$169
	OTP	$3,043
WPPI	ATC	$219
	NSP	$160
Total		$78,090

Table 5
(continued)

Allocation of Bemidji Charges to Owners for CapX2020 Projects ($1000)

Non-CapX Member Pricing Zones		$64
Non-CapX Members in CapX Member Pricing Zones		$4,046
Non MISO Owners		
	MPC	$37,800
Total Non BRP		$37,800

Total Project Costs	$120,000

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have a cost responsibility for $31,500,000 of investment for the Bemidji Project and that Otter Tail will have a cost responsibility for $14,800,000 of investment for the Bemidji Project. Of those charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers. 41.3% of those charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Bemidji Project to their respective North Dakota jurisdiction for each Applicant, as represented by the MISO charges each Applicant will incur, is the MISO revenue requirement on approximately $1,454,000 of investment for Xcel Energy and approximately $6,112,000 of investment for Otter Tail.

3. The La Crosse Project

As mentioned above, it is expected that 80% of the La Crosse Project will be owned by CapX2020 Utilities who are transmission owning members of MISO. The

other 20% will be owned by RPU (9%) and DPC (11%). The non-MISO 20% of the La Crosse Project will be recovered by RPU and DPC from their ratepayers.

The 345 kV segment of the La Crosse Project from North Rochester to North La Crosse has been designated as a Baseline Reliability Project in the 2008 MTEP. Therefore, the costs for this segment will be allocated similarly to the costs of the Fargo Project. Twenty percent of the costs for use of this segment of the La Crosse Projects will be allocated to all pricing zones as a postage stamp rate. The remaining 80% of the costs of this segment of the La Crosse Project will be allocated to pricing zones based on the LODF allocation method.

The Hampton Corner to North Rochester 345 kV segment of the La Crosse Project and both 161 kV circuits of the La Crosse Project were not designated as a RECB Project. Therefore, the transmission charges for this segment will be determined based on the MISO Attachment O formula and incorporated into the applicable pricing zone rate in proportion to each MISO transmission owning member's ownership share.

Table 6 shows the estimated cost of the La Crosse Project to each MISO pricing zone based on the budgeted costs for the Project and anticipated ownership shares.

Table 6

Allocation of La Crosse Project Costs to Midwest ISO Pricing Zones (million $)

Midwest ISO Pricing Zone	Twin Cities - La Crosse 345 kV Project
ALTW (ITCM)	$25.1
American Transmission Co.	$36.8
GRE	$3.7
MP	$3.9
Northern States Power Co.	$135.0
OTP	$0.4
SMMPA	$18.1
All Other MISO Pricing Zones	$30.1
Total	$253.0

Pricing Zones Containing CapX Members	**$222.9**

Non-CapX Members Pricing Zones	$30.1

As noted above, the charges allocated to each pricing zone are then paid by the utilities serving load in each pricing zone in proportion to their load in that pricing zone. Table 7 provides estimates of charges that Applicants will incur on a pricing zone basis for the La Crosse Project.

Table 7

Allocation of La Crosse Charges to Owners for CapX2020 Projects ($1000)

CapX2020 Transmission Owners	MISO Pricing Zone	Twin Cities - La Crosse 345 kV Project
GRE	ALTW (ITCM)	$777
	GRE	$3,287
	MP	$348
	NSP	$11,472
	OTP	$39
MP	MP	$3,398
Xcel Energy	ALTW (ITCM)	$50
	GRE	$252
	MP	$4
	NSP	$118,092
	OTP	$100
OTP	OTP	$185
SMMPA	ALTW (ITCM)	$251
	GRE	$163
	NSP	$2,159
	SMMPA	$18,146
CMMPA	ALTW (ITCM)	$226
	NSP	$810
DPC	ATC	$110
	NSP	$2,294
MRES	ALTW (ITCM)	$426
	NSP	$135
	OTP	$38
WPPI	ATC	$2,208
	NSP	$810
Total		$165,781

Table 7
(continued)

Allocation of La Crosse Charges to Owners for CapX2020 Projects ($1000)

Non-CapX Member Pricing Zones	$30,141
Non-CapX Members in CapX Member Pricing Zones	$57,128

Non MISO Owners		
	DPC	$47,157
	RPU	$38,583
Non-BRP		
	SMMPA	$14,610
	WPPI	$3,372
	Xcel Energy	$71,928
Total Costs Not Assigned through BRP		$175,650

Total Project Costs	$428,700

Therefore some Project costs will be recovered through MISO charges paid by all MISO transmission owners through the postage stamp rate. The remainder will be

recovered by MISO members who serve load in affected pricing zones as determined by MISO's LODF methodology and as incorporated into each owner's MISO pricing zone pursuant to Attachment O methodologies.

Based on the expected MISO charges allocated to Applicants pursuant to the foregoing formula, it is expected that Xcel Energy will have a cost responsibility for $190,426,000 of investment for the La Crosse Project and that Otter Tail will have a cost responsibility for $185,000 of investment. Of those charges to Xcel Energy, 4.62% will be allocated to Xcel Energy's North Dakota jurisdictional customers and 41.3% of the charges to Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the La Crosse Project to their respective North Dakota jurisdictional customers for each Applicant, as represented by the MISO charges each Applicant will incur, is the MISO revenue requirements on approximately $8,797,681 of investment for Xcel Energy and approximately of investment $76,220 for Otter Tail.

4. The Brookings Project

In MTEP 2008, MISO determined that the Brookings Project is considered a GIP. As stated above, GIPs are those additions to the MISO transmission system necessary for the interconnection of new or the upgrading of existing generation ("Network Upgrades").[5] This decision is currently being discussed and analyzed and, as described below, MISO is in the process of a public stakeholder process designed to determine whether and how the Tariff might be changed to address stakeholder concerns over this designation.

The MISO cost allocation process for GIP facilities requires the affected generators to pay 100% of the cost of such facilities and allows for up to 50% of the initial assignment of cost responsibility to be passed back to the CapX2020 Utilities who are MISO transmission owners depending on the ultimate use of the generation.

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[5] In the case of the Brookings Project, MISO has identified a group of nineteen generators under study for interconnection to the MISO system consisting of 1,300 MW of generating capacity. These studies have identified the Brookings Project as a necessary Network Upgrade for the reliable interconnection of the proposed generation projects. Specifically, these nineteen generators have a measurable contribution to system overloading if the Brookings Project is not built. Therefore, MISO's starting position for allocation of the generation portion of the costs of the Brookings Project should be assigned to the generators making up the 1,300 MW of capacity studied.

This designation creates a number of difficult complications in the case of the Brookings Project:

The generators who will actually use the Brookings Project are currently unknown.

Even those 19 generators identified by MISO do not have signed interconnection agreements or power purchase agreements.

It is too early to specify how much of the potential 50% cost of the Brookings Project will actually be passed back to the CapX2020 Utilities who are MISO transmission owners under the MISO Tariff.

The timing of the construction of the transmission as compared to the timing of the completion of the generation does not fit well under the Tariff.

The Tariff requirement that generation projects fund 100% the Brookings Project is problematic since such generator projects do not yet exist and are not available to provide such funding.[6]

In light of all of these issues, Applicants and others have raised concerns with MISO on the need to address this situation in some fashion in order to provide an allocation mechanism that is workable. In light of those concerns, there are several activities going on within MISO and/or in the MISO area that could affect the ultimate cost assignment methodology for the Brookings Project. MISO has convened a public stakeholder process to develop potential proposals for Tariff revisions. And MISO has reconvened its RECB task force to address possible solutions.[7]

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[6] The GIP Cost Allocation process is based on the premise that interconnection facilities are built in response to approved interconnection requests for which the generator has a signed interconnection agreement and generation commitment. In the case of the Brookings project, this sequence could be backwards where completion of the transmission facilities may precede the completion of the generation.

[7] On another front that affects the Brookings Project, the Upper Midwest Transmission Design Initiative ("UMTDI") is evaluating the transmission needs, including cost allocation issues, for a five state region including CapX2020 Group 1 Project states. Initial expectations of this group are that the Brookings Project is a foundational transmission facility required in order to achieve any of the increased transmission supply capability objectives of the group. Thus there is analysis underway to determine if it is appropriate for the Brookings project to be included in the cost allocation treatment that may come out of the UMTDI work efforts.

As a result of the RECB task force process, MISO submitted to FERC a proposal to modify the cost allocation methodology contained in its Tariff for the costs associated with generators interconnection to its Transmission System on July 9, 2009. In its filing, MISO proposed changing the 50%/50% cost share for the costs of Network Upgrades by allocating 90% of the costs of Network Upgrade facilities in a voltage class of 345 kV or higher to the generators and 10% of the costs to the users of the MISO Transmission System. The costs of the 10% of the Network Upgrades allocated to users of the MISO Transmission System would be allocated on a postage stamp basis to all MISO pricing zones. The outcome of this process may result in changes to the way the costs for the Brookings Project will be allocated to Applicants and other MISO members. These changes could result in substantially lower impacts to all of our ratepayers. Applicants will keep the Commission informed on this process and of the impact any revised Tariff procedure may have on this proceeding.

Since MISO's current position is that the Brookings Project is to be treated as a GIP, for purposes of this filing, Applicants have provided the calculation of the cost allocation under that category. Table 8 shows the estimated investment costs for the CapX2020 Utilities responsible for the Brookings Project.

Table 8

Investment Costs of Brookings Project Owners for CapX2020 Projects ($1000)

Transmission Owner	Twin Cities - Brookings County 345 kV Project
CMMPA	$15,346
GRE	$115,088
MRES	$35,572
OTP	$28,598
Xcel Energy	$502,898
Total	$697,500

As shown in Table 4 above, it is expected that Xcel Energy will have an initial cost responsibility of approximately $502,898,000 for the Brookings Project and that Otter Tail will have an initial cost responsibility of approximately $28,598,000 for the Brookings Project. Of those charges to Xcel Energy, revenue requirements for 4.62% of that investment will be allocated to Xcel Energy's North Dakota jurisdictional customers. Revenue requirements for 41.3% of those investments by Otter Tail will be allocated to Otter Tail's North Dakota jurisdictional customers. Therefore, the estimated cost of the Brookings Project, as represented by MISO charges to be paid by each Applicant, to their respective North Dakota jurisdictional customers for each Applicant is the MISO revenue requirements on approximately $23,233,888 of investment for Xcel Energy and approximately $11,810,974 for Otter Tail.

As noted above, under the current MISO Tariff, these costs are to be initially funded by the affected generators, subject to refund of up to 50% depending upon the circumstances. But currently the generators are not in place to utilize and pay for these transmission improvements. The MISO Tariff does not resolve how funding is to be treated in such a circumstance and this issue creates a significant difficulty in developing and constructing transmission facilities for use by future generation. Until that and other issues relating to cost allocation have been resolved, it is unclear how these costs will be absorbed or recovered. For example, if the CapX2020 Utilities choose to move forward with the Brookings Project without generators, the utilities

would potentially need to fund the transmission improvements and would need to recover these costs from their retail customers until costs are re-assigned under the MISO Tariff. This is among the issues being considered by MISO.

Applicants would like to emphasize that these complex issues of cost responsibility are being discussed with stakeholders with the objective of reaching a workable solution by the end of the year. Many possible outcomes exist and stakeholders have many divergent points of view on the situation. Since the outcome is not yet known, we have simply allocated the jurisdictional portion of applicants' investment to North Dakota, without any adjustments, as an estimate of impact in the North Dakota. This provides the Commission with a potential worst case scenario for consideration.

5. Total Impact of CapX2020 Projects

For all of the CapX2020 Projects, the estimated cost to their respective North Dakota jurisdiction for each Applicant will be the MISO charges on approximately $47 million of investment for Xcel Energy and approximately $37 million of investment for Otter Tail. This ultimate cost responsibility represents an approximate annual levelized North Dakota jurisdictional revenue requirement of $9.5 million per year for Xcel Energy and $7.5 million for Otter Tail. However, Applicants will expend the costs of the CapX2020 Group 1 Projects over time through the final costs expected to be made in 2015.

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE NO. PU-_____

IN THE MATTER OF THE APPLICATION FOR
AN ADVANCE DETERMINATION OF
PRUDENCE FOR THE CAPX2020
GROUP 1 TRANSMISSION PROJECTS

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

JAMES R. ALDERS, being first duly sworn on oath, deposes and says that he is the Director of Regulatory Administration for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation in the above captioned matter, that he has read said application, knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

James Alders
JAMES R. ALDERS

Subscribed and sworn to before me this 1 day of October, 2009.

Anne Johnson
Notary Public
My Commission Expires: Jan. 31. 2012

ANNE R. JOHNSON
Notary Public
State of Minnesota
My Commission Expires January 31, 2012

2409356v1

Direct Testimony and Schedule
Laura McCarten

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE NO. PU-_____

OTTER TAIL POWER COMPANY

CASE NO. PU-_____

IN THE MATTER OF THE APPLICATION
FOR AN ADVANCE DETERMINATION OF
PRUDENCE FOR THE CAPX2020
GROUP 1 PROJECTS

TESTIMONY OF

LAURA MCCARTEN

On Behalf of

APPLICANTS

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION,
AND

OTTER TAIL POWER COMPANY

September 17, 2009

Joint Exhibit A

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND YOUR BUSINESS ADDRESS.

A. My name is Laura McCarten and my business address is 414 Nicollet Mall, Minneapolis, Minnesota 55401.

Q. BY WHOM ARE YOU EMPLOYED, WHAT IS YOUR POSITION AND RESPONSIBILITIES?

A. I am employed by Northern States Power Company, a Minnesota corporation ("Xcel Energy"), as the Director of Regional Transmission Development. In this position, I am the Co-Executive Director of the CapX2020 Transmission Expansion Initiative ("CapX2020 Initiative"). My current job responsibilities include working with all of the utilities participating in the CapX2020 Initiative to develop the transmission projects that are under consideration in this proceeding, as well as the overall business relationship among the utilities. My resume is attached as Schedule 1.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I received a Bachelor of Science in Nuclear Engineering from the University of Wisconsin-Madison in 1979. Thereafter I began my career at Northern States Power Company in its nuclear power area. While in this area, I worked in several different capacities starting with analytic support for the Monticello and Prairie Island nuclear power facilities and concluding as a project manager for the Monticello spent fuel shipping campaign and the Prairie Island on-site dry spent fuel storage project.

In 1992, I moved to Northern States Power Company's regulatory department where I worked on the Certificate of Need proceeding for the Prairie Island Dry Spent Fuel Storage Installation, coordinated resource plan filings and worked with external parties interested in resource planning issues. From there I took the position of Regional General Manager and was responsible for utility operations for Xcel Energy's Minnesota service area outside of the Minneapolis/St. Paul metro area.

In 1997, I took the position of Director of Community Services in Minnesota and was responsible for managing Xcel Energy's relationships with local governments and communities across Minnesota. I held that position until 2006 when I assumed my current position as Co-Executive Director of the CapX2020 Transmission Expansion Initiative.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am testifying on behalf of Xcel Energy and Otter Tail Power Company ("Otter Tail"), the joint Applicants for the Application of Advance Determination of Prudence in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to (i) describe the Group 1 Projects; (ii) provide a status of the current regulatory posture for the Group 1 Projects; (iii) describe the CapX2020 Initiative, the relationship among the entities participating in the CapX2020 Initiative and their related business arrangements; and (iv) introduce Applicants' witnesses who are providing direct testimony in support of the Application.

Q. WHAT IS BEING PROPOSED IN THIS APPLICATION?

A. Applicants seek an advance determination of prudence for their investment in and resultant transmission charges related to the construction of the following four transmission line projects: 1) The Fargo Project; 2) The Brookings Project; 3) The La Crosse Project; and 4) The Bemidji Project (hereinafter referred to collectively as the "Group 1 Projects").

Applicants, as members of the CapX2020 Initiative (described below) are constructing the Group 1 Projects to meet several regional needs that can be best met by a substantial investment in additional transmission facilities by many utilities in the Upper Midwest. The identified needs are overall system reliability, community service reliability and generation outlet. Further, Applicants believe that the Group 1 Projects will provide a robust foundation upon which to build additional transmission facilities to meet the needs of the upper Midwest in the future. The need for and benefits of the Group 1 Projects are described in more detail in the testimony of Mr. Timothy J. Rogelstad.

Applicants believe that the Group 1 Projects are a reasonable and prudent way to meet these identified needs. Applicants, and the other CapX2020 Utilities, explored several alternatives to the Group 1 Projects and concluded that the Group 1 Projects were the best solution to these needs. The alternatives explored are discussed in the Application. Further, Applicants believe that their participation in the CapX2020 Initiative is a reasonable and prudent approach to achieve efficient development of transmission infrastructure. By identifying regional needs and developing transmission infrastructure to meet these needs, the CapX2020 Initiative allows regional utilities to avoid building duplicative facilities, makes permitting the projects simpler and allows for economies of

scale to provide savings in the procurement and construction of the Group 1 Projects.

Q. HOW WILL THIS PROPOSAL IMPACT NORTH DAKOTA RATEPAYERS?

A. Applicants are also Transmission Owning members of the Midwest Independent Transmission System Operator, Inc. ("MISO") and as such will recover their investments in the Group 1 Projects pursuant to the MISO Transmission, Energy Markets and Operating Reserves Tariff ("Tariff") through charges assessed by MISO on users of the transmission system under its functional control. It is the increase in MISO transmission charges due to the investment in the Group 1 Projects by members of the CapX2020 Initiative that will impact our North Dakota customers. Because Applicants both plan and allocate costs on a multi-jurisdictional, system-wide basis, the impacts to our North Dakota customers from the Group 1 Project will be a small percentage of our overall investment in and subsequent additional transmission charges resulting from the Group 1 Projects. The costs and ratepayer impacts of the Group 1 Projects are described in more detail in the testimony of Mr. Paul J. Lehman.

Applicants, in the instant Application, are respectfully requesting that the Commission determine that Applicants participation in the development and construction of the Group 1 Projects is reasonable and prudent.

II. DESCRIPTION OF THE CAPX2020 INITIATIVE AND THE GROUP 1 PROJECTS

Q. WHAT IS THE CAPX2020 INITIATIVE?

A. The CapX2020 Transmission Expansion Initiative is an agreement of regional utilities that the planning, coordination and identification of transmission upgrades and additions necessary to serve increased customer demand can be performed most effectively in a joint and collaborative manner due to the regional nature of the transmission grid. The primary purpose of the CapX2020 Initiative is to study, develop, permit and construct transmission infrastructure needed to implement long-term and cost-effective solutions for customers and the upper Midwest region of this country.

It has been nearly three decades since the electrical network serving the upper Midwest had been expanded by a significant degree, and at the same time the demand for power has continued to grow. Thus, in 2004, a group of regional utilities, including Applicants, began conducting engineering studies to establish a comprehensive plan for the development of transmission infrastructure to meet the increasing demand for electricity in the upper Midwest through the year 2020. The Group 1 Projects are a result of their joint efforts.

Q. DO THE REGIONAL UTILITIES SEE AN ADVANTAGE TO WORKING TOGETHER INSTEAD OF DEVELOPING SEPARATE TRANSMISSION SOLUTIONS TO MEET THEIR OWN INDIVIDUAL NEEDS?

A. Yes. By working together, the CapX2020 Utilities believe they are able to better develop improvements to the regional transmission system than would have occurred by each utility developing piecemeal solutions to meet only their needs.

Further, a joint approach creates efficiencies in the regulatory process so that each utility does not have to submit separate filings for separate projects that could at times work at cross purposes. The joint approach also allows may different utilities to share the costs involved with such large projects. Last, joint sourcing of services and materials is likely to allow the CapX2020 Utilities to take advantage of certain economies of scale which would not be available to each utility separately. It is likely that absent the joint approach taken by the CapX2020 Initiative, the development of a system-wide solution to meet all identified needs would not have been possible.

Q. WHO ARE THE CAPX2020 PARTICIPANTS?

A. Currently, there are 11 utilities that are participating in the CapX2020 Group 1 Projects. They are listed below, along with the transmission projects in which they are participating:

- Central Minnesota Municipal Power Agency (Brookings Project);
- Dairyland Power Cooperative (La Crosse Project);
- Great River Energy (Brookings, Bemidji and Fargo Projects)
- Minnkota Power (Bemidji Project);
- Minnesota Power (Fargo and Bemidji Projects);
- Missouri River Energy Services (Fargo and Brookings Projects);
- Otter Tail Power Company (Fargo, Bemidji and Brookings Projects);
- Rochester Public Utilities (La Crosse Project);
- Southern Minnesota Municipal Power Agency (La Crosse Project);
- Wisconsin Public Power, Inc. (La Crosse Project);
- Northern States Power Company, a Wisconsin corporation (La Crosse Project); and

- Northern States Power Company, a Minnesota corporation (all Group 1 Projects).

Q. PLEASE DESCRIBE EACH OF THE GROUP 1 PROJECTS THAT ARE THE SUBJECT OF THIS PROCEEDING.

A. The proposed Fargo Project is an approximately 250-mile long, 345 kV transmission line from a connection near Fargo, North Dakota to Alexandria, St. Cloud and ending at the Monticello Substation in Monticello, Minnesota. All of the line segments to this Project will be constructed as double circuit compatible.

The proposed Brookings Project is an approximately 200-mile long, 345 kV transmission line from the Brookings County Substation in South Dakota to the new Hampton Substation southeast of the Twin Cities, with intermediate connections near Marshall, Franklin, New Prague, and Apple Valley, Minnesota. The Project also includes a related 35-mile long, 345 kV transmission line between Marshall and Granite Falls, Minnesota. All of the line segments to this Project will be constructed either as double circuits initially or as double circuit compatible as described in more detail in the Application.

The proposed La Crosse Project is an approximately 150-mile long, 345 kV transmission line from the Hampton Substation southeast of the Twin Cities through Rochester, Minnesota, to La Crosse, Wisconsin, with two related 161 kV transmission lines connecting the new 345 kV transmission line with the Rochester, Minnesota area. All of the 345 kV portions of this project in Minnesota will be constructed as double circuit compatible. Whether the portions in Wisconsin will be constructed as double circuit compatible is under

discussion with the Wisconsin regulators and CapX2020 planners, and will be influenced by potential route options in Wisconsin.

The proposed Bemidji Project is an approximately 68-mile long, 230 kV transmission line from Bemidji, Minnesota to Grand Rapids, Minnesota.

Q. WHAT IS A DOUBLE CIRCUIT COMPATIBLE CONFIGURATION?

A. The "double circuit compatible" configuration means that the segments of the Fargo, Brookings and La Crosse Projects will be built on structures sufficient to accommodate a second 345 kV circuit at some point in the future. Only one circuit would be strung upon construction. We would obtain whatever regulatory approvals may be required to string the second circuit, at such future time as the second circuit is required.

Q. WHAT ARE THE BENEFITS OF UTILIZING THE DOUBLE CIRCUIT COMPATIBLE CONFIGURATION?

A. There are a number of benefits associated with the double circuit compatible configuration. First, constructing the Fargo, Brookings and La Crosse Projects in a double circuit compatible configuration rather than in a single circuit configuration is a more efficient approach to meeting the region's long-term transmission needs, in that it results in a more robust system that can better accommodate future growth and anticipated long-term needs. When additional capacity is required in the future, a second circuit can be strung on the existing structures at lower cost than rebuilding the structures to accommodate two circuits. Another benefit is that building the line as double circuit capable at time of initial construction should reduce landowner impacts in the future at the time the second circuit is strung.

The CapX2020 Utilities are currently exploring the cost, technical, and potential regulatory issues surrounding whether it would be more appropriate to install the davit arms and conductor for the second circuit of the Three 345 kV Projects at the time of initial construction. The lines would be operated as a single circuit until future circumstances and regulatory approvals deem the second circuit necessary. CapX2020 planners are analyzing the installation of all davit arms as part of initial construction which may be a lower cost approach because it would mitigate the need for larger structures and would avoid expensive and complex construction on the poles after the first circuit has been energized. As part of the analysis, CapX2020 planners are also considering the potential impacts of installing the second set of conductors as part of initial construction. The potential benefits may include: (i) less impact to landowners because of a single construction period, (ii) lower line losses and operating costs because of the additional conductor and (iii) avoiding complex and perhaps costly construction methods to add a second circuit to structures holding a "live" circuit. The CapX2020 Utilities will continue to analyze the impacts, costs and regulatory issues associated with concurrent installation and will provide additional information in the future.

Q. WHAT PROCESS WAS UNDERTAKEN TO DETERMINE THAT THE GROUP 1 PROJECTS ARE NEEDED?

A. The CapX2020 Utilities undertook various studies including the CapX2020 Vision Plan, that supported the conclusion that the region's electrical system would need a series of bulk transmission additions over an extended period of time to maintain reliability over the coming years in light of expected growth in

customer demands predicted by the year 2020. The testimony of Timothy Rogelstad provides additional testimony regarding the Vision Plan.

Resulting from these studies was a determination that the Group 1 Projects are needed, as discussed below.

Q. DID THE STUDY PROCESS DESCRIBED ABOVE REVEAL WHY THE GROUP 1 PROJECTS ARE NEEDED?

A. Yes. The overall study process revealed that the construction of these projects is needed for a number of reasons.

- First, the Group 1 Projects will strengthen regional transmission by increasing the reliability of the region's transmission system as a whole. This improvement in regional reliability allows the Group 1 Projects to create a foundation for future regional transmission build-out.
- Second, the Group 1 Projects will alleviate specific reliability concerns on a community level in North Dakota, Minnesota and Wisconsin where the demand for electrical power has reached a level that can no longer be reliably supported by existing transmission lines.
- Third, the Group 1 Projects will support system-wide growth in demand for electricity. The regional transmission system has not been significantly expanded for decades while load and generation growth has increasingly used up the capability created by the major transmission expansion projects of the 1950s-1970s. New transmission infrastructure is needed to meet this growth and enable Applicants and the other CapX2020 Utilities to meet all their customer's demands and regulatory requirements.
- Fourth, the Group 1 Projects will increase the capacity for outlet of additional generation sources in the region, allowing for the continued

development of new generation, including renewable-based generation. Additional generation is needed to meet growing regional demand. The Group 1 Projects will allow the rich generation resources in the western portion of the CapX2020 Study Region to meet load centers in the central and eastern portions of the upper Midwest.

Q. DID THE STUDY PROCESS IDENTIFY ANY BENEFITS RESULTING FROM THE CONSTRUCTION OF THE GROUP 1 PROJECTS?

A. Yes. The overall study process revealed that the construction of the Group 1 Projects will provide a number of benefits. These include enhanced regional reliability, added export capability, improved access to the MISO market by generators in the western portion of the MISO Transmission System, enhanced valuation of existing generation, increased potential for generation development and added economic development opportunities. Mr. Rogelstad provides testimony further explaining these benefits.

Q. DESCRIBE THE ECONOMIC DEVELOPMENT OPPORTUNITIES THAT WILL BE CREATED BY THE GROUP 1 PROJECTS.

A. The Group 1 Projects will provide necessary infrastructure to accommodate regional population growth and the economic development that come with such growth.

For example, construction of the Fargo Project will result in between 36 and 86 miles of a new high voltage transmission line in North Dakota as well as new 345 kV substation in the Fargo area. This represents an estimated value of $77 to $151 million of new infrastructure which would yield on the order of $1.5 to $3 million, total, in state and local taxes for the first four years the line is in-

service. In subsequent years, the Project will yield an estimated $10,000 to $20,000 per year in state and local taxes. An estimated 130,000 to 200,00 hours of construction labor will be required, over approximately 20 to 32 months, to complete the work in North Dakota, and these construction workers will have a positive impact the local economy during this time. Further, enhancement of existing generation will strengthen the North Dakota energy industry and the industries that supply fuel and supplies to North Dakota generators. Lastly, the Group 1 Projects will help to spur development of new generation in North Dakota to take advantage of its rich traditional fuel resources and excellent wind conditions.

Developing North Dakota's wind resources will be a significant vehicle for economic development in the State. A report prepared for the North Dakota Division of Community Services concluded that North Dakota is motivated to become a leader in wind-generated electricity. This motivation includes an opportunity to contribute to the general economic development in the state with short- and long-term jobs, investments, landowner income, operation, maintenance and manufacture. In fact, in April 2005, North Dakota passed legislation designed to accelerate production of wind energy and other renewable resources, as well as to enhance transmission infrastructure necessary to get the energy to market. The Group 1 Projects are a significant first step in expanding the transmission infrastructure necessary for the development of this rich resource.

The Group 1 Projects, by providing additional energy infrastructure in the region, can provide significant support for economic development in North Dakota.

Q. WHAT ARE THE CURRENT ESTIMATES FOR THE COST OF THE GROUP 1 PROJECTS?

A. The CapX2020 Utilities have currently estimated the Group 1 Projects to cost between:

$500 and $750 million for the Fargo Project;

$650 and $800 million for the Brookings Project;

$400 and $500 million for the La Crosse Project; and

$100 and $130 million for the Bemidji Project.

These estimates include the costs of configuring segments of certain projects as double circuit compatible.

As with any project in the middle of permitting stages, the final costs of the Group 1 Projects will not be known until the Projects are completed. The projected costs listed above are simply estimates. Given the size and scope of the Group 1 Projects, the largest regional transmission project in the upper Midwest in decades, there are novel and unique issues that still need to be resolved in order to better estimate Project costs.

Q. WHAT IS THE REGULATORY STATUS OF THE GROUP 1 PROJECTS?

A. On August 16, 2007, Xcel Energy and Great River Energy, on behalf of themselves and the other CapX2020 Utilities, filed an Application for Certificates of Need with the Minnesota Public Utilities Commission, to construct he Fargo, Brookings and La Crosse Projects in Minnesota. On May 22, 2009, the Minnesota Public Utilities Commission ("Minnesota Commission" or "MPUC")

granted Certificates of Need for the Fargo, Brookings and La Crosse Projects in the double circuit compatible configuration and imposed conditions upon the Certificate of Need for the Brookings Project. The conditions, modified on July 14, 2009 at the MPUC's agenda meeting to hear the parties' requests for reconsideration, require Xcel Energy and Great River Energy to:

- Enter into power purchase agreements or commit to utility-owned renewable generation projects within the timeframe of the Minnesota Renewable Energy Standard milestones, coordinated with the proposed in-service dates of each segment of the Brookings Project unless such action fails to conform to Xcel Energy's and Great River Energy's resource requirements as accepted or approved in their most recent Integrated Resource Plan or the Renewable Energy Standard report and is excused by a future order of the MPUC.
- Commit to submit network (firm) transmission service requests to MISO's Open Access Same Time Information System ("OASIS") for the amount of new renewable generation purchased under the first condition, above.
- Make a compliance filing detailing the projected amount of the new transmission capacity by Xcel Energy and Great River Energy and addressing how much capacity will be enabled by the Brookings Project and the type of MISO Transmission Service being sought to serve the renewable generated

electricity to be carried by the Brookings Project. The filing should recognize that MISO allocation and restriction of MISO managed transmission capacity is beyond the scope and authority of the Minnesota Public Utilities Commission.

- Designate the renewable commitments as Network Resources pursuant to the MISO Tariff, as necessary for the compliance of these conditions.

(collectively referred to as the "Brookings Project Conditions"). No written order on the parties' requests for reconsideration has been issued as of the date of this Direct Testimony. Applicants will update the Commission as more information becomes available.

Otter Tail Power Company, Minnesota Power and Minnkota Power Cooperative, on behalf of themselves and other CapX2020 Utilities, filed applications with the Minnesota Commission for a Certificate of Need (March 17, 2008) and Route Permit (June 4, 2008) for the Bemidji Project. As part of those proceedings, a joint federal/state Environmental Impact Statement is being developed by the Rural Utilities Services of the U.S. Department of Agriculture and Office of Energy Security of the Minnesota Department of Commerce. The MPUC approved the certificate of need for the Bemidji Project on July 14, 2009 and is expected to approve the route permit by June 2010.

On December 29, 2008, Great River Energy and Xcel Energy, on behalf of themselves and other CapX2020 Utilities, filed an Application with the Minnesota Commission for a route permit for the Brookings Project. Great River Energy and Xcel Energy anticipate filing an application for a Facilities

Permit with the South Dakota Public Utilities Commission for the South Dakota portion of the Brookings Project in the near future.

On April 8, 2009, Xcel Energy and Great River Energy, on behalf of themselves and other CapX2020 Utilities, filed an Application for a Route Permit for the Monticello to St. Cloud, Minnesota portion of the Fargo Project with the Minnesota Public Utilities Commission. Xcel Energy and Great River Energy anticipate filing Route Permit Applications for the remainder of the Fargo Project later in 2009.

Applicants anticipate that the North Dakota filing of the application for a Certificate of Public Convenience and Necessity as well as applications for Corridor Compatibility and Route Permits to the North Dakota Public Service Commission will be made soon.

Applicants anticipate that an application for a Certificate of Public Convenience and Necessity, which address both need and routing for the Wisconsin portion of the La Crosse Project, will be filed with the Wisconsin Public Service Commission in late 2009.

Applicants will provide updates regarding the current status of all regulatory filings to the Commission and additional updates as further regulatory filings are made for each of the Group 1 Projects.

III. CAPX2020 INITIATIVE BUSINESS ARRANGEMENTS

Q. WHAT IS THE BUSINESS RELATIONSHIP AMONG THE CAPX2020 PARTICIPANTS?

A. Currently, there are 11 utilities that are participating in the Group 1 Projects. Nine of those utilities have formalized their commitment to the overall CapX2020 Initiative through the execution of a Participation Agreement, discussed below. The CapX2020 Utilities are working together in a collaborative manner to jointly develop each of the Projects. Their relationship to one another during the development phase is memorialized in Project Development Agreements ("PDAs"), also discussed below.

Q. WHAT IS THE PURPOSE OF THE PARTICIPATION AGREEMENT?

A. The purpose of the Participation Agreement is to memorialize the agreement of nine regional utilities that planning, coordination and identification of transmission upgrades and additions necessary to serve increased customer demand and regional energy policies can be performed most effectively in a joint and collaborative manner due to the regional nature of the transmission grid. The Participation Agreement reflects their formalized commitment to the CapX2020 Initiative.

Q. WHAT IS THE PURPOSE OF THE PROJECT DEVELOPMENT AGREEMENTS?

A. The purpose of the Project Development Agreements, or PDAs, is to memorialize the agreement of the signatories to the PDAs to jointly develop and fund the development work for the three 345 kV transmission line projects and one 230 kV transmission line project in a collaborative manner ("Development Phase"). There are four PDAs – one for each Project. During the Development

Phase, the Participants for each Project have agreed to determine the recommended alignment of the proposed Project configuration; determine the scope of a given project; estimate the cost and schedule; obtain the required State and Federal regulatory approvals and consents; and engage in other necessary project-related studies and analyses. Each signatory has agreed to absorb a specified percentage of the development costs associated with a given Project. The Participants have designated a "lead" utility or a "Development Manager" responsible for obtaining major permits and developing and implementing the project if construction is authorized for each project. Great River Energy serves as Development Manager for the Brookings Project; Otter Tail serves as Development Manager for the Bemidji Project; and Xcel Energy serves as the Development Manager for the Fargo and La Crosse Projects.

As Development Managers, Xcel Energy, Otter Tail and Great River Energy will determine the conceptual design, determine the recommended interconnection/termination points, determine the recommended configuration, determine the scope and estimate project cost and schedule, obtain permits and make or undertake necessary related studies and analyses. Other utilities may assist the Development Managers in some of the duties outlined above. The Development Managers will report progress to each project's Management Committee, which consists of one representative from each project's participating utilities. It is anticipated that the Development Manager will become the Construction Manager and execute the implementation plan developed during the development phase.

Q. DO THE PROJECT DEVELOPMENT AGREEMENTS REQUIRE PARTICIPANTS TO OWN THE PROPOSED TRANSMISSION FACILITIES?

A. No. The PDAs address only the terms and conditions involving the Development Phase of the Group 1 Projects. The PDAs do not create commercial arrangements that result in the ownership of the transmission lines. The PDAs have, however, established a procedure through which the CapX2020 Utilities may elect ownership of individual Projects at the end of the Development Phase. Once State, Federal and other regulatory decisions are made pertaining to each Project, each signatory will have the right to invest in (and correspondingly own) a particular Project up to the level of its specified percentage. If a Participant does not elect to invest in a Project, the PDAs have established procedures by which other participants, including third parties, may take on the non-elected investment share.

Q. SO PARTICIPATING CAPX2020 UTILITIES MAY ELECT NOT TO OWN ANY PART OF THE GROUP 1 PROJECTS?

A. Yes. Any of the CapX2020 Utilities, including Applicants, has the opportunity to assess its investment position at the end of the regulatory approval process and elect not to own any portion of the Projects for which it has entered into a PDA. The other CapX2020 Utilities that are participating in that particular Project may then elect to assume ownership of the ownership share of the CapX2020 Utility electing not to take an ownership stake in that Project.

Q. DO XCEL ENERGY AND OTTER TAIL EXPECT TO PARTICIPATE IN ALL OF THE GROUP 1 PROJECTS?

A. Xcel Energy intends to participate in all four Group 1 Projects. Otter Tail plans to participate in the Fargo, Bemidji and Brookings Projects. It has elected,

however, not to participate in the La Crosse Project. Otter Tail chose not to invest because it prefers to own facilities closer to its already existing transmission facilities. Because each utility has a finite amount of resources available for investments in the Group 1 Projects, Otter Tail has determined that it would spend its available resources on the Projects closest to its customers.

That said, because Otter Tail serves load in the MISO pricing zones to which the costs of the La Crosse Project will be allocated, Otter Tail will incur costs and receive benefits from the La Crosse Project. Paul Lehman provides a more in-depth discussion of MISO's cost allocation methodologies in his Direct Testimony.

Q. HOW WAS THE INVESTMENT LEVEL DETERMINED IN EACH PROJECT?

A. Through a consensus-based and collaborative process, each owner was given the opportunity to invest in one or more of the Projects. Generally, each utility desired to achieve a total investment percentage comparable to what it would end up paying to MISO for use of the lines. In addition, each entity had different criteria for which projects they wanted to invest in.

Q. How important is it to know how much each company is investing in each project?

A. It is important to make sure there is enough capital to complete a particular Project. But, it is more important that there is enough capital to complete all of Group 1 Projects. As Mr. Lehman will discuss, the customers of the utilities will be assigned the charges through which the CapX2020 Utilities that are Transmission Owning Members of MISO will recover their costs of each of the

projects pursuant to MISO's cost allocation process, which is independent of who invest in the particular project.

Q. IDENTIFY THE CURRENT POTENTIAL OWNERSHIP PERCENTAGES FOR THE GROUP 1 PROJECTS.

A. The current potential project development percentages, which are non-binding ownership percentages at this stage, are set forth below:

Table 1

Expected Ownership Shares of the CapX2020 Group 1 Projects

Transmission Owner	Fargo Project	Brookings Project	La Crosse Project	Bemidji Project
Central Minnesota Municipal Power Agency ("CMMPA")		2.2%		
Dairyland Power Cooperative ("DPC")			11.0%	
Great River Energy ("GRE")	25.0%	16.5%		13.0%
Minnesota Power ("MP")	14.7%			9.3%
Missouri River Energy Services ("MRES")	11.0%	5.1%		31.5%
Otter Tail Power Company ("OTP")	13.2%	4.1%		20.0%
Rochester Public Utilities ("RPU")			9.0%	
Southern Minnesota Municipal Power Agency ("SMMPA")			13.0%	
Wisconsin Public Power, Inc. ("WPPI")			3.0%	
Xcel Energy	36.1%	72.1%	64.0%	26.2%
Total	100.0%	100.0%	100.0%	100.0%

Q. HAVE THE CAPX2020 PARTICIPANTS ENTERED INTO ANY CONTRACTUAL COMMITMENTS TO CONSTRUCT, OWN, AND/OR OPERATE AND MAINTAIN THE GROUP 1 PROJECTS?

A. No. The CapX2020 Utilities are in the process of negotiating the terms and conditions relating to construction management, ownership, and operations and maintenance of the Group 1 Projects. Participants will elect ownership and sign final agreements after State, Federal and other regulatory decisions relating to each Project have been made.

V. WITNESSES

Q. YOU HAVE IDENTIFIED SEVERAL INDIVIDUALS WHO ARE PROVIDING TESTIMONY IN THIS PROCEEDING. COULD YOU PROVIDE A SUMMARY OF THE TESTIMONY THEY ARE PROFFERING IN THIS PROCEEDING?

A. Witnesses providing testimony in support of the Application are:

Laura McCarten: Testimony regarding the Group 1 Projects, the CapX2020 Initiative, the relationship among the entities participating in the CapX2020 Initiative and their related business arrangements;

Tim Rogelstad: Testimony regarding the regulatory context, principles of transmission planning and the study work that has been done and is currently underway in connection with the CapX2020 Initiative, as well as regional and North Dakota specific benefits of the Group 1 Projects; and

Paul Lehman: Testimony regarding cost allocation and cost recovery of transmission facilities through the MISO Tariff.

Our witnesses adopt those portions of the Application that fall within their areas of competence and are available to answer questions relating to those areas.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Laura McCarten

Experience

2006–2008 Xcel Energy Minneapolis, MN

Director, Regional Transmission Development

- Serves as staff to the CapX Participation Organization Vision Team
- Responsible for anticipating changes in and developing responses to transmission and related energy policy, and coordinating and directing inter-utility teams that support planning, policy and project needs

1997–2005 Xcel Energy Minneapolis, MN

Director, Minnesota Community Services

- Led a dispersed team which managed relationships with local governments and communities across the state to which Xcel Energy provides electric and natural gas service; provided economic development assistance to community-based organizations and individual businesses; and promoted and supported community service and cultural art organizations

1994–1997 Xcel Energy Mankato, MN

Regional General Manager

- Responsible for the electric construction and community service functions for Northern State's Power's Minnesota regional operations outside of the Twin Cities metropolitan area

1992–1994 Northern States Power Minneapolis, MN

Manager Regulatory Affairs

- Responsible for interfacing with the Minnesota Public Utilities Commission and Department of Public Service on issues related to the company's nuclear power plants and resource planning
- Primary media spokesperson regarding need for spent fuel storage

1988–1991 Northern States Power Minneapolis, MN

Project Manager, Spent Nuclear Fuel Projects

- Project Manager for Prairie Island Spent Fuel Storage Installation.
- Project Manager for Monticello Spent Fuel Shipping Campaign.

1979–1988 Northern States Power Minneapolis, MN

Engineer, Nuclear Generation

- Responsible for nuclear fuel and cycle design analyses
- Responsible for nuclear plant outage coordination

Education

1979 University of Wisconsin Madison, WI

- Received a Bachelor of Science in Nuclear Engineering

Professional Development

- Xcel Energy Leadership Advantage Program (2004)
- University of Michigan Business School, Strategic Marketing Planning (1998)
- University of Minnesota, Carlson School of Management, Minnesota Management Institute (1996)
- Kidder, Peabody & Co. Inc., Seminar on Corporate Finance for the Utility Industry (1992)

Community Service

- Board of Directors of Park Square Theatre, Saint Paul MN; former Board Chair (Current)
- Greater Minneapolis Chamber of Commerce, Public Policy Committee
- Sanford Middle School E-mentor
- Minnesota Science Bowl Moderator
- Board of the Minnesota Zoo
- Board of the Eastwood Development Corporation, Mankato MN
- Board of the Greater Mankato United Way

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY,
A MINNESOTA CORPORATION

CASE NO. PU-_____

OTTER TAIL POWER COMPANY

IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 TRANSMISSION PROJECTS

CASE NO. PU-_____

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

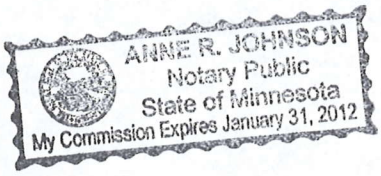
LAURA MCCARTEN, being first duly sworn on oath, deposes and says that she is Director of Regional Transmission Development for Applicant Northern States Power Company, a Minnesota corporation, in the above captioned matter, that the testimony and schedules submitted in the above captioned matter under her name were prepared under her direction, that she knows the contents thereof, and that the same is true and correct to the best of her knowledge and belief.

[SIGNATURE PAGE FOLLOWS]

Laura McCarten

LAURA MCCARTEN

Subscribed and sworn to before me this 17 day of September, 2009.



Anne Johnson

Notary Public

My Commission Expires: Jan 31. 2012

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION	**CASE NO. PU-_____**
OTTER TAIL POWER COMPANY	**CASE NO. PU-_____**

IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 PROJECTS

TESTIMONY OF

TIMOTHY J. ROGELSTAD

On Behalf of

APPLICANTS

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION,

AND

OTTER TAIL POWER CORPORATION

September 17, 2009

Joint Exhibit B

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND EMPLOYMENT ADDRESS.

A. My name is Timothy J. Rogelstad and my business address is 215 South Cascade Street, Fergus Falls, Minnesota 56537.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Otter Tail Power Company ("Otter Tail") and my current position is Manager of Delivery Planning.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from North Dakota State University in 1989 with a Bachelor Degree in Electrical and Electronics Engineering. I am currently a registered professional engineer in the states of Minnesota, North Dakota, and South Dakota. I have been an employee with Otter Tail for the past 19 years. I started with the company in 1989 as a substation design engineer in the System Engineering Department. In 1992, I transferred to the Transmission Planning Department as a Planning Engineer. In 1998, I was promoted to supervisor of Transmission Planning, and in 2002 I was promoted to Manager of Delivery Planning. My current job responsibilities include managing transmission planning, transmission contracts and capital budget development.

For most of my professional career, I have been involved with transmission planning. My experience ranges from being involved in building models for transmission studies and completing transmission studies, to acting as project manager for a 100-mile, 230 kV transmission project, to managing a

department that is responsible for transmission planning at Otter Tail. I have been involved in a number of planning activities at the regional level with the Mid-Continent Area Power Pool ("MAPP"), the Midwest Independent Transmission System Operator ("MISO") and with other organizations, including: MAPP Model Building Working Group, MAPP Transmission Reliability Working Group, MAPP Line Loading Relief Working Group, MAPP Design Review Subcommittee, MAPP Planning Committee, former chair of the MAPP Red River Valley Subregional Planning Group, MISO Planning Subcommittee, CapX2020 Technical Team, CapX2020 Tariff Team, Upper Great Plains Transmission Coalition, and Chair of the Minnesota Transmission Owners. My resume is attached as Schedule 1.

Q. WHAT HAS YOUR INVOLVEMENT BEEN IN THE CAPX2020 INITIATIVE?

A. I have been involved in CapX2020 since the beginning stages of this initiative, including the first meeting held in 2004 where utilities discussed the need for a joint planning initiative. From that point on, I have been actively leading and participating in the technical planning studies that have resulted in the CapX2020 transmission proposals. I have also been involved in cost allocation discussions related to CapX2020 as well as participating and representing Otter Tail Power in the Vision Team and Management Committee meetings for the CapX2020 Initiative.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy"), and Otter Tail Power Company ("Otter Tail"), the joint Applicants in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide the following information:

- An explanation of the transmission planning process utilities engage in to determine system needs;
- The current regulatory environment applicable to constructing and permitting new transmission facilities;
- An overview of the CapX2020 participating utilities' coordinated transmission planning efforts which resulted in the proposed Group 1 Projects, including the CapX2020 Vision Plan (as discussed in the Pre-Filed Direct Testimony of Ms. Laura McCarten); and
- Why the Group 1 Projects are needed at this juncture and the benefits the Projects will provide to the upper Midwest region, in particular North Dakota.

Q. WERE YOU INVOLVED IN THE PREPARATION OF THE APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE IN THIS PROCEEDING?

A. Yes. I provided information to the Applicants in their preparation of the Application. The Application was prepared with my participation, using information that I provided as well as the type of information that is regularly relied upon by professionals in the ordinary course of business.

II. TRANSMISSION PLANNING GENERALLY

Q. WHAT IS THE PURPOSE OF TRANSMISSION PLANNING BY UTILITIES?

A. The overall goal of transmission planning is to ensure the reliable operation of the transmission system to meet the demand for power by a utility's customers at the lowest reasonable cost. Planning involves a number of objectives, including planning for increased customer service requirements (often referred to as local load growth), taking into account generators' interconnection requests, assessing the need for system maintenance and upgrades, assessing ways to eliminate constraints on the system, and taking into consideration a utility's compliance with applicable policy and regulatory goals. Generally, transmission planning is an ongoing, continuous process of ensuring that the electrical system under review is operated in a reliable and economic fashion.

Q. PLEASE DESCRIBE GENERALLY HOW A UTILITY'S TRANSMISSION PLANNING IS DONE.

A. Transmission planners for utilities use sophisticated computer models that simulate the operation and performance of the transmission grid under various scenarios. Typically, the planners attempt to determine how the system will perform under peak load and high transfer situations, although normal operating conditions and off-peak conditions are also examined. The planners also look at how the system will operate under contingency situations, such as when a transmission line or generation facility is taken out of service by a storm or other unexpected occurrences or during planned maintenance outages. In addition to the modeling results, utilities also have to take into account such factors as costs, environmental impacts, social impacts,

and national standards. The time horizon used in developing assumptions that are used in the modeling can typically range from 1 to 25 years.

Q. ARE A UTILITY'S PLANNING EFFORTS EVER REDUCED TO FORMAL STUDIES?

A. Yes. There are generally three categories of studies that transmission planners can create during the transmission planning process: vision studies, mid-term studies; and specific studies.

Q. PLEASE EXPLAIN EACH OF THESE CATEGORIES OF TRANSMISSION PLANNING STUDIES.

A. Vision studies look at long-range needs and goals and include the following characteristics: a high level, 50,000-foot, review of the electrical system; a blue print for the future; a 10- to 25-year time horizon; and broad assumptions.

Mid-Term studies have the following characteristics: a mid-level, 25,000-foot, review of the electrical system; identified needs; a seven- to 15-year time horizon; and more certainty in assumptions.

Specific studies, which may include load-serving studies and interconnection studies, have the following characteristics: a shorter-term, 5,000-foot, review of the electrical system; needs for a specific circumstance; a one- to 10-year time horizon; and more certainty in assumptions.

Q. DOES A UTILITY GENERALLY WORK WITH OTHERS IN ITS TRANSMISSION PLANNING EFFORTS?

A. Yes. Transmission planners for the various utilities work together with MISO, regulatory agencies, and other interested persons to develop plans to conduct their transmission planning to ensure the continued reliable and economical operation of the transmission system. MAPP and MISO also maintain various committees, including Subregional Planning Groups ("SPGs") and other transmission planning groups, to focus on the need for transmission infrastructure in the region. Much of this planning is conducted in an open forum, including regulatory staff participation from North Dakota.

Q. DO UTILITIES REPORT THE WORK OF THEIR TRANSMISSION PLANNERS?

A. The planning activities of the utilities are generally reported to the public and to regulators. The reports are made available in various forms, from presentations at SPG meetings, to posting the study results on websites.

Q. HOW ARE TRANSMISSION STUDIES CONDUCTED?

A. The first step in conducting a transmission study is to develop a scope of work. The scope of work identifies the problem that is trying to be solved in a transmission study. Once we identify the problem to be solved, we then develop assumptions that can be used in modeling. The Transmission Planners in this region use software called PSSE (Power System Simulator for Engineering). This software is used to model the power system, including generators, transmission lines and loads. With the model we can develop different scenarios (varying load levels, new generation additions, new transmission additions, etc.) based on the problem we are trying to solve. The

analysis portion of a study involves running hundreds of simulations to understand the performance of the power system under different assumptions. From this analysis, planning engineers can then analyze the results from the various simulations and make recommendations as to what the best solution is for solving the problem that was identified in the initial study scope.

Q. HOW DO UTILITIES DETERMINE THE ASSUMPTIONS TO USE FOR PLANNING AND STUDY PURPOSES?

A. Engineers use their engineering judgment to narrow the number of assumptions and the number of scenarios. Studies look at a wide range of assumptions. However, they cannot cover every possible scenario because there would be an infinite number. Therefore, transmission planners use their engineering judgment to assess what types of scenarios and assumptions are prudent to evaluate in transmission studies. Engineering judgment is also used when transmission planners are called upon to assess variations or modifications of prior studies. Transmission planners use their experience and training to assess situations and provide their professional opinions on the particular situation.

III. NORTH DAKOTA'S TRANSMISSION SYSTEM

Q. DESCRIBE THE TRANSMISSION SYSTEM THAT SERVES NORTH DAKOTA.

A. North Dakota's transmission system is part of the Eastern Interconnection, which is one of three subsystems that the continental United States electric

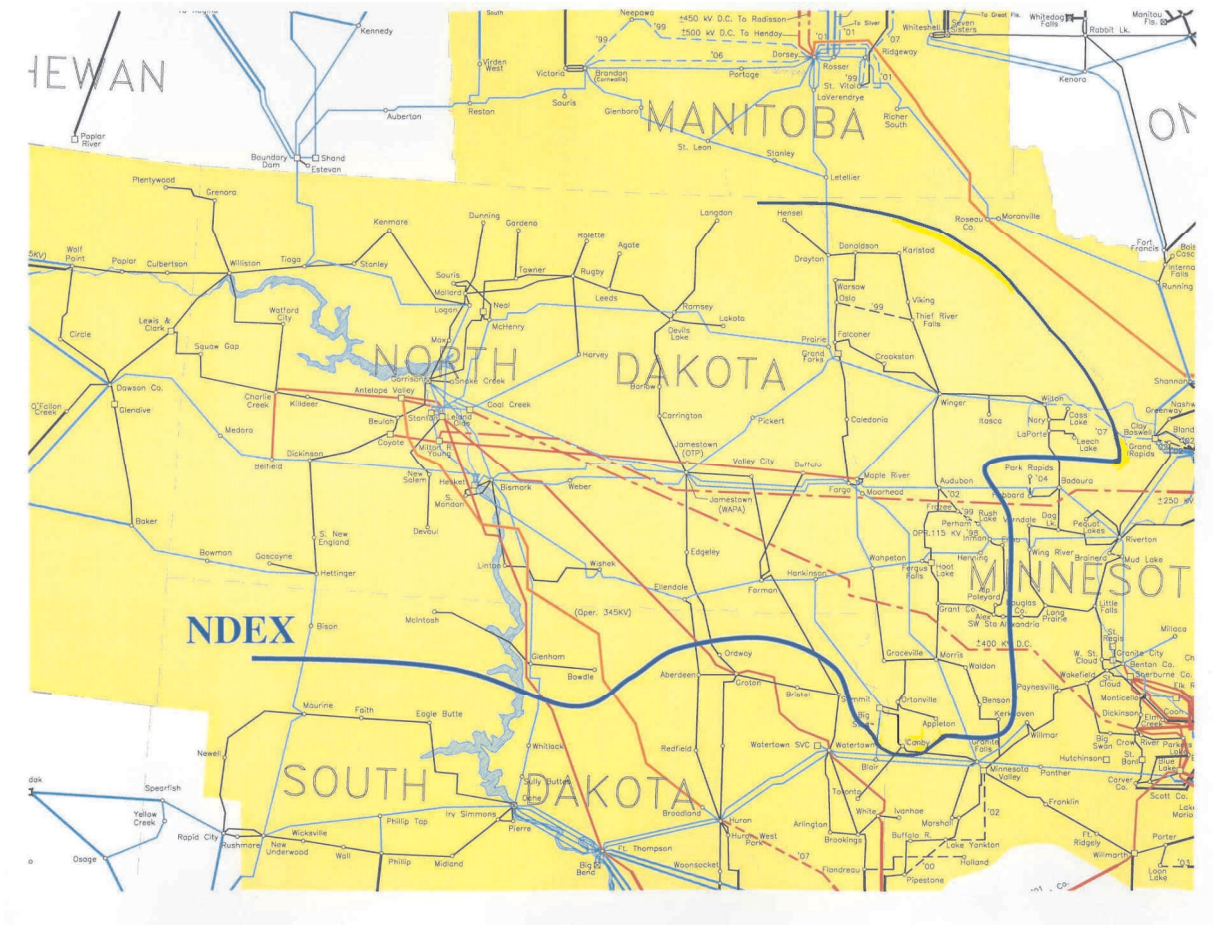
transmission grid is divided into, and therefore interconnected with the systems serving South Dakota, Minnesota, Iowa, Wisconsin, and all of the states and Canadian provinces in the eastern two-thirds of North America. The entire electric system in the Eastern Interconnection operates as a single integrated electrical machine. Therefore, the operation of electrical generators and transmission facilities in Ohio or Nebraska can potentially impact the reliability of electric service to customers in North Dakota.

The transmission system in North Dakota consists of series of 41.6 kV, 69 kV, 115 kV, 230 kV and 345 kV alternating current transmission lines and two direct current transmission lines into Minnesota. In North Dakota, the transmission system is serving two primary purposes, the first is to reliability serve North Dakota retail load customers and, second to export power out of the region. Even under peak load conditions, North Dakota has more generation than load. At lower load levels within the State, there becomes substantial generation that is available to be exported out of the State. In a situation where North Dakota exports large amounts of power to load centers remote from North Dakota, like the Twin Cities, the electrical system in the region has the potential to become unstable, and the ability to transfer power is limited by the phenomenon known as instability, which is a characteristic of generators that are located long distances from large loads through long transmission lines. The addition of strategically located transmission infrastructure can help to alleviate the possibility of the instability and increase the amount of electricity that can be exported out of North Dakota.

Historically, the limitations on transmission outlet capability from North Dakota is referenced by a phrase known as the North Dakota Export Limit ("NDEX") – which is an electrical boundary around northwestern Minnesota, southeastern North Dakota, a part of South Dakota and Montana that has a maximum generation outlet capability related to transmission lines that cross the boundary. The NDEX boundary has a maximum amount of power that can be exported from North Dakota and part of Minnesota and South Dakota without adversely affecting regional system reliability. This is significant because, as mentioned previously, even under peak load conditions, there is more generation than load within the NDEX boundary leading to exports of power to load centers like the Twin Cities and points east. If large amounts of generation were developed without a simultaneous increase in transmission capacity, the generation would effectively be trapped in North Dakota. Figure 1 shows the NDEX boundary.

Figure 1

NDEX



Q. WHEN WAS THE LAST SIGNIFICANT UPGRADE TO NORTH DAKOTA'S TRANSMISSION SYSTEM?

A. The Harvey – Glenboro 230 kV transmission line was the last major network transmission project in North Dakota. It was placed into service in 2002. There are several other projects currently under development to address load serving needs as a result of the expansion of oil production activities in the oil rich portions of North Dakota. In addition, there have been several other transmission projects that have been constructed to allow the interconnection of wind generation to the transmission system. These facilities have generally been "radial" lines that connect the wind farms to the transmission grid.

These types of facilities do not increase the ability export power out of North Dakota.

IV. REGULATORY ENVIRONMENT

Q. DESCRIBE THE REGULATORY STRUCTURE WITHIN WHICH ELECTRIC SERVICE PROVIDERS MUST SERVE ITS CUSTOMERS.

A. Because of the importance of providing safe, adequate and reliable service to customers and the important role electric transmission plays in that service, matters pertaining to electric transmission are highly regulated. Regulatory oversight of transmission in the state of North Dakota occurs at several levels and by several different state and federal regulatory bodies. These regulatory bodies and their roles are described below.

North Dakota Public Service Commission

The Commission provides plenary oversight over many aspects of the electric system pursuant to Chapter 49 of the North Dakota Century Code. For investor owned public utilities, such as Applicants, the Commission has regulatory control over all aspects of the provision of retail electric service to customers. The Commission reviews and approves the rates, charges and service provisions of public utilities, as well as matters pertaining to the quality of service, affiliated interests and a variety of other types of transactions. The Commission also has permitting authority over the construction and routing of transmission facilities through its powers to issue Certificates of Public

Convenience and Necessity, Certificates of Corridor Compatibility and Route Permits.

Federal Energy Regulatory Commission ("FERC")

The FERC has authority over the transmission of electric energy in interstate commerce and wholesale sales of electricity, including regulating transmission rates and practices and authorizing and overseeing the operation of regional transmission organizations. The FERC is also responsible for oversight of mandatory electric reliability standards and for designating the Electrical Reliability Organization ("ERO") for the United States. In 1996 FERC mandated the functional separation of transmission from generation to ensure equal access to the transmission grid, thereby requiring that transmission planning and development be prepared to meet the needs of all regional market participants rather than just those of an individual utility's customers or a specific generation resource type.

Regional Transmission Organizations ("RTOs")

RTOs, including MISO, oversee and coordinate regional transmission planning and regional transmission services and manage access to the transmission grid to facilitate fair and competitive wholesale electric markets. Applicants are transmission-owning members of MISO and both are subject to the terms and conditions of MISO's Open Access Transmission, Energy Markets and Operating Reserves Tariff ("Tariff").

As part of its transmission function, MISO also undertakes studies of the transmission system and recommends proposed transmission projects that are

necessary to meet the needs of end use customers and new generators and improve electric power grid performance throughout the Midwest. MISO then reports on those recommended projects in its annual Midwest ISO Transmission Expansion Plan ("MTEP") report.

MISO also operates a centralized regional wholesale energy market, known as the "Day 2" market. Under the MISO Tariff, short-term and spot market transactions are available to utilities to acquire energy supply to meet load demands at lower cost than operating their own longer-term resources. Under the MISO Tariff, participating utilities are required to purchase and sell energy within the MISO Day-Ahead and Real Time markets. These transactions are conducted through MISO through those markets. MISO uses a security constrained economic dispatch that employs Locational Marginal Pricing ("LMP") that is intended to take into account the costs of resources and capacity limitations (referred to as "congestion") on the transmission system to use the least cost available generation to serve loads on a regional basis within MISO.

North American Electric Reliability Corporation ("NERC")

NERC, designated as the ERO by FERC, sets standards for grid planning and operations and monitors compliance with reliability standards, which recently became mandatory. The standards apply to the planning, construction, operation, and maintenance of electric utilities' electric systems in the upper Midwest.

Midwest Reliability Organization ("MRO")

MRO is a regional entity that implements the NERC standards for Minnesota and the surrounding region. MRO is designed to develop standards, monitor compliance, enforce standards, and assess reliability of the bulk power system in the Midwest. MRO operates independently of the entities subject to its jurisdiction, thereby ensuring that the reliability standards developed and enforced by NERC are fair.

V. THE CAPX2020 PLANNING AND STUDY EFFORTS

Q. DESCRIBE GENERALLY THE CAPX2020 INITIATIVE'S STUDY EFFORTS.

A. In 2004, Xcel Energy, Great River Energy, Minnesota Power and Otter Tail agreed to conduct the engineering studies they believed were needed to establish a framework or comprehensive plan for the development of transmission infrastructure to meet the increasing demand for electricity in the upper Midwest. As the momentum of the planning effort grew, additional utilities joined the Initiative and its study efforts. The CapX2020 Initiative recognized a need to develop a long range transmission plan that also addressed short term transmission needs for customer service requirements. As a result, the CapX2020 Initiative launched multiple transmission planning study efforts to address both long and short term needs of the system.

To evaluate long-term needs, the CapX2020 Vision Plan was initiated to develop a long-term transmission plan to ensure that load in the region could be served reliably under different generation scenarios. This study was

intended to be a high level study that would provide a blue-print for future transmission development in the region.

In addition to the Vision Plan, there were other studies initiated to address the short term needs. These studies, the Southeastern Minnesota and Southwestern Wisconsin Reliability Enhancement Study, the Red River Valley/Northwest Minnesota Load-Serving Transmission Study (TIPS Update), and the Southwest Minnesota – Twin Cities EHV Development Electric Transmission Study, were initiated to address the increasing load-serving capability and generation outlet needs in the Red River Valley and other areas in the CapX2020 Study Region, described further below. These study efforts were launched in parallel to address the needs of each of these areas.

Q. IS IT IMPORTANT THAT SHORT-TERM AND LONG-TERM TRANSMISSION PLANS ARE COORDINATED?

A. Yes. As transmission planners, we strive to develop a reliable and cost effective transmission system. One way this is accomplished is through coordinated planning. Coordinated planning is accomplished in several different ways, including working collaboratively with different utilities, working with MISO, and engaging other interested individuals and parties during the study process.

There are many assumptions that go into developing transmission plans, and those plans change over time. Since it takes time to plan, permit and construct transmission infrastructure, the passage of time will affect the

assumptions that went into the planning. But at some point, planners must make a decision on what facility to build and move forward. Otherwise, nothing would ever get built and the process would get bogged down in what is sometimes termed "analysis paralysis." With the CapX2020 Initiative planning effort, we have developed a long range plan to address regional reliability in the future under different generation scenarios and in addition, we have developed a short-term plan that addresses the immediate load-serving capability needs of specific areas within our region's system.

Q. PLEASE DESCRIBE THE CAPX2020 VISION PLAN IN MORE DETAIL.

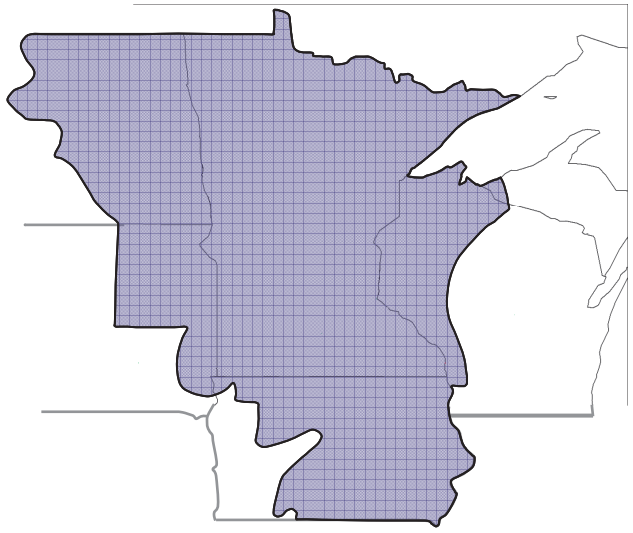
A. In any transmission study there are key assumptions that are made prior to conducting the study analysis. Key assumptions in the modeling of the CapX2020 Vision Plan are in the areas of: (1) Study region, (2) load and (3) generation.

Q. DESCRIBE THE STUDY REGION ESTABLISHED FOR THE VISION PLAN.

A. The CapX2020 study region was designed to examine the implications of growth in the demand for power on the systems of those utilities serving customers in the region. The CapX2020 Initiative addresses important needs in all areas of the CapX2020 Study Region, including North Dakota. Figure 2 is an illustration of the geographic area.

Figure 2

CapX2020 Study Region



While this footprint was the primary area of focus, transmission is regional in nature, and, as a result, we included modeling of a region larger than the primary study area.

Q. WHAT LOAD ASSUMPTIONS WERE USED FOR THE VISION PLAN?

A. The goal of the Vision Plan was to develop a long range plan for serving load out through the year 2020; therefore, we wanted to have loads in models that represented the projected load in 2020. The initial planning models used in the Vision Plan represented a 2009 Summer peak load. As a result, we needed to adjust the load estimates to represent 2020 load. In order to make the load adjustments in the models, we used several sources of information to compare the load levels between 2009 and 2020. We then adjusted the load in the models to represent this change. There were two load levels that were studied. The first load level indicated a 6,300 MW increase in peak demand between what was assumed in 2009 planning models and aggregated 2020 forecasts.

This 6,300 MW increase reflects load growth from 20,201 MW in 2009 to 26,488 MW in 2020, based on the forecast described above.

We also wanted to study a load level that represented a lower load growth as well. As a result we included a second load level scenario reflecting a growth of 4,500 MW, from 20,201 MW in 2009 to 24,701 MW in 2020. This "slow growth" forecast scenario, approximately 30 percent lower, was a check or validation of the planning effort to assess system needs under conditions substantially different than the base planning assumptions. The load growth projections utilized in the Vision Plan were intended to act as a reasonable proxy for expected customer demand growth over the next decade or more.

Q. DESCRIBE HOW THE CAPX2020 INITIATIVE ESTIMATED THE PROJECTED GENERATION THAT WOULD BE ADDED TO THE ELECTRICAL SYSTEM.

A. One of the more difficult assumptions to make in transmission planning is determining the location of projected future generation. This is a difficult assumption to make because of all of the uncertainties associated with the development of and interest in generation projects. We determined that, given the uncertainty in where generation will develop, we would create multiple generation scenarios, or biases, and test our transmission plan around each scenario. Accordingly, planning engineers developed and studied three generation scenarios: a Minnesota bias, a western bias and an eastern bias.

Q. PLEASE DESCRIBE HOW THE THREE GENERATION SCENARIOS WERE DEVELOPED.

A. Planning engineers developed the three generation scenarios based on input from resource planners and independent power producers. Planning engineers reviewed the MISO interconnection queue, comparing the queue with wind maps showing the best wind resources. Representative generation locations were developed by engineers through this broad data gathering process. Based on the data gathering, it became apparent there were common geographic locations, or regions, where generation was likely to develop. These regions were categorized into southwestern Minnesota, southeastern Minnesota, North Dakota, South Dakota, Manitoba and Wisconsin. It is unlikely that all generation to meet future load would come from one region, therefore generation scenarios were developed that included generation from each region. These scenarios were described as the Minnesota bias, the western bias and the eastern bias. Once the amount of generation from each region was approximated, representative sites were selected based on the data that we had gathered during the data gathering phase of the study. The assumptions of generation additions in North Dakota for each of the scenarios is listed in the table below.

Scenario	North Dakota Generation
Western Bias	1050 MW
Eastern Bias	550 MW
Minnesota Bias	550 MW

Q. DOES THE FUEL TYPE OF THE VARIOUS GENERATION OPTIONS YOU MODELED HAVE ANY BEARING ON YOUR STUDY WORK?

A. No. Fuel type has no bearing on our work in power flow analysis. We did not model specific generation proposals. The Vision Plan examined the impact on the transmission system associated with different geographic patterns of generation injecting power into the transmission network that serves customers throughout the upper Midwest.

Q. HOW WERE THE GENERATION SCENARIOS USED IN THIS STUDY?

A. Planning engineers developed a transmission plan around each of the three generation scenarios or biases. These three transmission plans were then compared to determine whether there were transmission facilities common to each scenario. The common facilities that were identified through this process are listed below:

Facility Name			
From	**To**	**Volt (kV)**	**Miles**
Alexandria	Benton County	345	80
Alexandria	Maple River	345	126
Antelope Valley	Jamestown	345	185
Arrowhead	Chisago	345	120
Arrowhead	Forbes	345	60
Benton County	Chisago County	345	59
Benton County	Granite Falls	345	110
Benton County	St. Boni	345	62
Blue Lake	Ellendale	345	200
Chisago County	Prairie Island	345	82
Columbia	North La Crosse	345	80
Ellendale	Hettinger	345	231
Rochester	North La Crosse	345	60
Jamestown	Maple River	345	107
Prairie Island	Rochester	345	58

Q. WHAT IS THE SIGNIFICANCE OF THE COMMON FACILITIES TABLE?

A. This table identifies the transmission facilities that are common to all three generation scenarios, which means that regardless of which generation scenario actually develops, these transmission facilities are needed. The Group 1 Projects are a subset of these common facilities. The Fargo Project is identified in the table above as two line sections Alexandria – Benton County and Alexandria – Maple River. The Brookings Project is a portion of the Ellendale – Blue Lake line in the table above, and the La Crosse Project is identified as Prairie Island – Rochester and Rochester – North La Crosse in the table above. The Bemidji Project is not included in the table above, because it is not a 345 kV project, but rather a 230 kV project.

Q. WHAT IMPACT DID THE LOW LOAD GROWTH SCENARIO HAVE ON THE TRANSMISSION PLANS?

A. The plan changed very little as a result of changing the load growth assumption from 6,300 MW to 4,500 MW. The common facilities listed above were found to be needed in both growth scenarios.

Q. PLEASE DESCRIBE IN MORE DETAIL THE SHORT TERM STUDIES THAT WERE UNDERTAKEN AS PART OF THE CAPX2020 INITIATIVE.

A. To address the short term needs, identified as community load serving needs and generation outlet needs, three detailed transmission studies were then conducted. Each study had a specific study scope and is briefly summarized below.

- Southeastern Minnesota and Southwestern Wisconsin Reliability Enhancement Study: This study addressed the load serving needs of the Rochester, Minnesota and La Crosse, Wisconsin communities.
- Red River Valley/Northwest Minnesota Load-Serving Transmission Study (TIPS Update): This study addressed the load serving needs of the Red River Valley and the Bemidji areas.
- Southwest Minnesota – Twin Cities EHV Development Electric Transmission Study: This study addressed the need to increase the ability to interconnect and deliver generation from the Buffalo Ridge area.

(collectively referred to as the "Short Term Studies")

Q. WHY WERE THE GROUP 1 PROJECTS SELECTED FROM THE COMMON FACILITIES TABLE?

A. The CapX2020 Initiative decided to proceed with the Group 1 Projects first because the Short Term Studies identified projects that were necessary to address short term needs of the system, were also common to any future reasonable transmission system development scenario, and provide the most expansive foundation for any future reasonable expansion of the transmission system.

Q. IDENTIFY THE NEEDS THAT WILL BE ADDRESSED BY THE GROUP 1 PROJECTS.

A. There are multiple needs that will be met by the Group 1 Projects. These include: 1) improving regional system reliability and meeting demand growth through 2020; 2) meeting specific community reliability needs; and 3)

providing outlet for added generation throughout the region; and 4) creating a robust platform for future development.

Q. PLEASE DESCRIBE THE SYSTEM RELIABILITY NEED.

A. As explained earlier in my testimony, the utilities participating in the Group 1 Projects are obligated under federal and state law to provide reliable service to all of their customers in all their service areas. The ability to meet this obligation is projected to be, at risk in the near future. There are several areas within the region where the transmission system is constrained or is exceeding the level at which customers can be reliably served. Studies undertaken as part of the CapX2020 Initiative confirmed that the Group 1 Projects will be able to address this need by providing an increment of additional regional transmission infrastructure which will substantially improve the future reliability of electric service in those areas.

Q. ARE ANY OF THE AREAS OF CONCERN LOCATED IN NORTH DAKOTA?

A. Yes. The Red River Valley is identified as an area where the transmission system is projected to be at risk in the near future and reliable service to customers in that area is a concern.

Q. DESCRIBE THE TRANSMISSION SYSTEM CURRENTLY SERVING THE RED RIVER VALLEY.

A. Geographically the transmission system serves not only the Red River Valley, but encompasses parts of North Dakota extending west to Jamestown and Devils Lake, and parts of Minnesota as far east as Bemidji, Park Rapids and Alexandria.

The bulk electric transmission system in the Red River Valley primarily consists of a 230 kV network with a single 345 kV connection between the Red River Valley and western North Dakota. Nearly all of the power supply to the Red River Valley is from remote generation sources. Power typically flows through the Red River Valley region from west-to-east and north-to-south. However, long term power purchase and capacity exchange agreements between Manitoba Hydro and United States power suppliers require that adequate transmission capability be maintained to enable both northward and southward power transfers at all times of the year.

Q. HAS THE TRANSMISSION SYSTEM SERVING THE RED RIVER VALLEY BEEN STUDIED RECENTLY?

A. Yes. Building on the Vision Plan, which I described above, and a 2002 effort of the Red River Valley Subregional Planning Group (the "RRV-SPG") – which was made up of area utilities, generation developers, MISO and MAPP staff, state regulatory staff – CapX2020 planners undertook the Red River Valley/Northwest Minnesota Load-Serving Transmission Study (the "TIPS Update") in 2006 to examine community service reliability needs for the electrical system serving the Red River Valley.

For the TIPS Update, planning engineers began their evaluation with the actual system peak for the 2003/2004 winter period. The study found that load serving capability in the Red River Valley becomes constrained when one transmission line is out of service. There were also voltage concerns for both local and remote transmission contingencies. The most severe contingency of

local lines connecting the Red River Valley to the generation from the west and north is outage of the Center – Jamestown – Buffalo – Maple River 345 kV transmission line, which is the highest capacity transmission tie between the Red River Valley area and the baseload generation sources to the west. The most severe remote contingency for the Red River Valley is outage of the Dorsey – Forbes transmission line. Outage of this 500 kV circuit during northward flow conditions causes significant power to flow through the Red River Valley's transmission system. This "throughflow" results in high reactive power losses, contributing to the risk of voltage collapse.

Q. WHAT DID THE TIPS UPDATE CONCLUDE?

A. Consistent with previous studies, the TIPS Update confirmed that the most robust, economic and efficient upgrades to improve local load serving capability of the Red River Valley area and local load centers within it are the Bemidji Project (North Zone) and the Fargo Project (South Zone). In reaching this conclusion, the TIPS Update considered several other options including increasing reactive power sources in the area and other transmission line options.

The TIPS Update also identified community service reliability needs in the Alexandria, Minnesota area and St. Cloud, Minnesota area that can be met with the Fargo Project. Improving reliability in these communities also will help North Dakota communities located in the Red River Valley. The Fargo Project will assist in maintaining voltage levels and prevent overloads to the transmission lines serving the Red River Valley, including those serving North Dakota communities.

Q. WILL THE GROUP 1 PROJECTS SERVE THE RELIABILITY NEEDS OF OTHER COMMUNITIES?

A. Yes. The Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study of 2006 identified community service reliability needs in the Rochester, Minnesota and La Crosse, Wisconsin areas that can be met by the La Crosse Project. The Southwest Minnesota – Twin Cities EHV Development Electric Transmission Study identified community service reliability needs in many of the communities that lie within the area affected by installation of the Brookings Project. The Brookings Project will help to meet these identified needs.

It is important to understand that while the La Crosse and Brookings Projects are not located in North Dakota, they will help address the needs of North Dakota. For example, the La Crosse Project will provide an outlet for new generation in the west, including generation proposed to be built in North Dakota, to access markets serving large load centers located in the east; and the Brookings Project will alleviate a congestion bottleneck that limits the amount of generation that can be delivered out of North Dakota. Both of these projects provide significant benefits to North Dakota for purposes of generator outlet and overall system reliability.

Q. DESCRIBE THE SYSTEM WIDE GROWTH NEED.

A. One of the drivers for the Group 1 Projects is current and future predicted demand for electricity. The utilities participating in the CapX2020 Initiative studied the peak demand of the regional transmission system generally and the

peak demand of particular communities. Their analysis concluded that the Upper Midwest will experience several thousands of megawatts in demand growth between now and 2020.

The regional transmission system, however, has not kept pace with current or projected load and generation growth. Current growth has increasingly used up the capability created by major transmission expansions in the 1950s, 1960s, and 1970s. In addition, the capacity stemming from the other transmission expansion projects that Applicants and other CapX2020 Utilities are currently constructing are expected to be fully used by the time the Group 1 Projects are placed in service. For the electrical system to continue to deliver power safely and reliably to Applicants' customers, additional transmission infrastructure must be built.

Q. HOW WILL THE GROUP 1 PROJECTS ADDRESS SYSTEM WIDE GROWTH?

A. As part of the Vision Plan, planners looked at the overall electrical system in light of both the current and future predicted demand for electricity and generation. The Vision Plan identified fifteen facilities necessary to meet this demand. The Group 1 Projects were identified as those system improvements that would satisfy immediate needs and also provide a platform for meeting the needs of anticipated regional growth.

Q. DESCRIBE THE GENERATION OUTLET NEED.

A. To serve growing demands of customers in the upper Midwest, large amounts of new electric generation, both renewable and nonrenewable, will need to be installed. CapX2020 studies estimate that 5700 to 8000 MW of generation will

be needed by 2020 to meet power demands. Without expansion of the bulk transmission network, the current transmission system serving the upper Midwest will not be able to support the addition of this amount of new generation.

Recently enacted legislation in several states in the CapX2020 Study Region is also driving the need for additional generation outlet. Several states are requiring retail electric providers to supply a certain percentage of their retail electricity from renewable sources. For example, both the North Dakota and Minnesota legislatures passed renewable energy legislation in 2007. North Dakota passed the Renewable and Recycled Energy Objective that established the goal of achieving ten percent of retail electric sales from renewable and recycled energy sources by 2015. N.D.C.C. § 49-02-28. Minnesota passed the Renewable Energy Standard that mandates that twenty-five percent of retail electric sales come from renewable sources by 2025 (Xcel Energy must provide 30% of it retail electrical sales from renewable energy by 2020). Minn. Stat. § 216B.1691. In addition, a federal renewable standard appears to be on the horizon. These legislative initiatives create a need for additional renewable generation to come on line sooner rather than later.

Oftentimes, large scale generation projects are not constructed near the load which will consume the electricity generated. For example, North Dakota currently generates substantial generation based on traditional fuels and has rich wind resources that can be developed so that utilities can meet their state mandated renewable energy requirements. However, North Dakota's loads are too small to absorb all of the electricity that is and can be generated within

the State. Additional transmission will allow an outlet for new generation to reach remote areas where it can be used.

Q. WILL THE GROUP 1 PROJECTS ADDRESS THIS NEED?

A. Yes. The Group 1 Projects are designed to work together to provide outlet for generation. The Fargo and Bemidji Projects will increase the capacity and support for generation created in North Dakota, as well as exported out of North Dakota, including renewable generation. The Brookings Project will allow the continued development of renewable generation in Minnesota and eastern South Dakota and alleviate some strain on the transmission system in North Dakota by creating an additional path for North Dakota based generation. The La Crosse Project will provide additional capacity to transmit generation produced in North Dakota into the MISO Market providing access to the eastern portion of the MISO footprint thereby increasing the number of available purchasers for generation produced in North Dakota.

The Vision Plan analyzed different possible, fuel neutral, generation scenarios to determine the type of additional transmission infrastructure would be necessary to support the needed additional generation on the bulk transmission system. The Vision Plan and the additional studies performed concluded that the Group 1 Projects are common facilities reasonably necessary to serve any future generation scenario for our region.

Q. DESCRIBE THE NEED FOR A ROBUST PLATFORM FOR FUTURE DEVELOPMENT.

A. The Group 1 Projects are needed to establish a common foundation for future development across the system. This will allow for regional generation to access the wider MISO market. By building the Group 1 Projects, the CapX2020 Utilities will effectively balance immediate and future needs. Further, the Group 1 Projects, by providing a foundation for future system build-out, are a prudent way for the CapX2020 Utilities to cost-effectively meet additional system-wide needs in the future. Finally, North Dakota is a net-exporting State and is dependent upon a robust transmission system to access regional markets for excess generation. The ability to export North Dakota generation is already constrained and new transmission is needed to enhance that access.

Q. DID CAPX2020 PLANNING ENGINEERS EVALUATE ALTERNATIVES TO THE GROUP 1 PROJECTS TO MEET THE NEEDS YOU DESCRIBED?

A. Yes. CapX2020 planning engineers analyzed other alternatives to constructing the Group 1 Projects including upgrades to currently built facilities, double-circuiting existing facilities, adding localized generation and using higher or lower voltage transmission lines. CapX2020 planning engineers determined that these alternatives did not adequately meet the multiple needs identified for these projects. Many of the alternatives considered by Applicants are described in the Application. The Group 1 Projects' ability to meet multiple needs simultaneously make them the most prudent option for maintaining the reliability of the regional transmission system.

IX. BENEFITS OF THE CAPX2020 GROUP 1 PROJECTS

Q. WHAT BENEFITS WILL BE PROVIDED BY THE GROUP 1 PROJECTS TO NORTH DAKOTA?

A. The Group 1 Projects will provide the following benefits to Applicants' North Dakota customers and the state as a whole: 1) enhanced reliability throughout the region including North Dakota; 2) added export capacity to the transmission system within North Dakota; 3) improved access to the MISO market for North Dakota based generation; 4) increase the value of generation currently located in the state; 5) create opportunities for the development of new generation, including wind based generation; and 6) stimulate economic development in North Dakota.

Q. HOW WILL THE GROUP 1 PROJECTS ENHANCE REGIONAL RELIABILITY?

A. Regional reliability is related to the shared importance of an efficient and reliable transfer of bulk power across regions and between regions. By constructing the Group 1 Projects, the regional interconnected transmission system is benefited as a whole because those additional connections provide for a more robust transmission system that is able to better withstand system contingencies. A more robust bulk power system also enhances efficient transfer of power across and between regions. Efficient regional power transfers promote and support fair and competitive wholesale electric markets thereby assisting in meeting the needs of all regional market participants, rather than just those of the individual utility's customers or a specific generation resource type.

Q. HOW WILL THE GROUP 1 PROJECTS IMPROVE EXPORT CAPABILITY?

A. The Group 1 Projects will enhance the export capability of all generation in North Dakota by alleviating some of the constraints of the NDEX boundary and facilitate MISO dispatch of North Dakota generation into the MISO energy markets.

Q. HOW WILL THE GROUP 1 PROJECTS ADDRESS THE CURRENT NDEX CONSTRAINT?

A. The Group 1 Projects will provide additional export capability for North Dakota Generation. The Fargo and Bemidji Projects will together increase NDEX limits by approximately 550 MW. The addition of the Brookings Project should further increase NDEX. Depending upon the size and location of new generation, the combination of the Fargo, Bemidji and Brookings Projects could increase NDEX by 700-800 MW. Applicants' Proposal provides for future additional increases to the NDEX limit because it utilizes the double-circuit compatible configuration.

Q. HOW WILL THE GROUP 1 PROJECTS IMPROVE MISO MARKET ACCESS?

A. In order to reliably operate the transmission system, generation and load must always be in balance. MISO operates as a centralized dispatcher of generation in the MISO foot print to make sure that the system remains in balance. Alleviating congestion on the system with an eastbound outlet, provided by all the Group 1 Projects, allows MISO to more efficiently dispatch generation from the generation rich western portion of the MISO footprint, especially North Dakota, into the load centers in the east. Without more eastbound

outlet, especially into the congested areas east of Minnesota, the generation in the western portion of the MISO footprint essentially becomes trapped. Any generation bid into the MISO market therefore effectively displaces existing generation instead of adding an incremental benefit to the system as a whole. An eastern outlet will enlarge the possible market for North Dakota based generation.

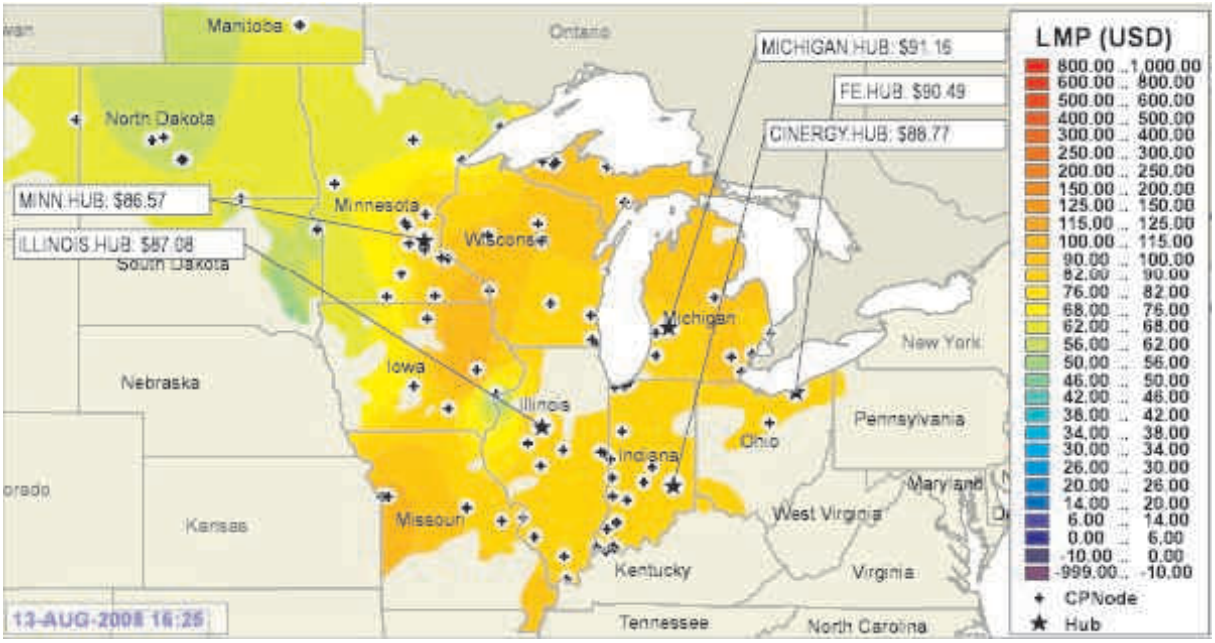
Q. WHY IS IT BENEFICIAL FOR NORTH DAKOTA GENERATORS TO HAVE ACCESS TO THE MISO MARKET?

A. MISO prices energy based on LMP which provides price signals that account for the additional costs of electricity caused by transmission congestion and line loss at various points on the electricity grid. Under the LMP pricing structure, areas on the grid which experience the least amount of congestion and have sufficient generation resources have the lowest prices for electricity.

Figure 3 is a representative map showing the LMP for the MISO footprint.

Figure 3

LMP



Source: MISO

As demonstrated in Figure 3; the LMP in Wisconsin and Michigan are higher than in North Dakota and Minnesota. A higher LMP signifies congestion in serving those areas with higher prices. The La Crosse Project will help to alleviate some of the congestion in serving Wisconsin. The La Crosse Project will complete the direct path provided by the Fargo Project, aided by the additional NDEX increase of the Brookings and Bemidji Projects, and the secondary path through the Brookings Project into those areas of the MISO footprint with higher LMPs. This access to the eastern portion of the MISO footprint enlarges the market for generation based in the western part of the CapX2020 study region, including North Dakota based generation.

Q. HOW WILL THE GROUP 1 PROJECTS ENHANCE THE EXISTING VALUE OF NORTH DAKOTA GENERATION?

A. The Group 1 Projects will allow for additional increments of outlet for North Dakota based generation and additional access to the MISO markets. This in turn will make the energy and capacity produced by North Dakota's current generation facilities more valuable. Since North Dakota is a net exporting state which has more generation than load to absorb it, North Dakota's generators need a robust transmission infrastructure to transport and sell their energy to load centers further east.

The Fargo, Brookings and Bemidji Projects will increase the NDEX limit, allowing more generation to physically leave the NDEX area without creating instability on the transmission system serving North Dakota's customers. The Brookings Project will alleviate some strain on the North Dakota transmission system and provide an additional path east for North Dakota based generation through transmission ties between North Dakota and South Dakota. The La Crosse Project will create a path into the MISO market creating additional opportunities for the marketing of North Dakota based generation. The ability to access loads east of North Dakota creates a larger market for North Dakota based generation thereby making it more valuable.

Q. WILL THE GROUP 1 PROJECTS INCREASE THE POTENTIAL FOR DEVELOPING NEW GENERATION IN NORTH DAKOTA?

A. Yes. Much the same way that the Group 1 Projects will enhance the value of existing North Dakota based generation, the Projects will also create a

transmission backbone which may be attractive to developers of new generation.

Q. IS THERE MUCH INTEREST IN DEVELOPING NEW GENERATION IN NORTH DAKOTA?

A. Yes. Based on my understanding of the rich wind resource available in North Dakota, I would assume that there is substantial interest in harnessing this resource. This assumption is borne out by the amount of generation waiting to interconnect in North Dakota.

Q. WHAT IS YOUR UNDERSTANDING OF NORTH DAKOTA'S POTENTIAL FOR RENEWABLE FUEL GENERATION.

A. According to the American Wind Energy Association, North Dakota ranks number one in the country for wind energy potential. The entire state has a class 3 (14 to 15 mph) or better wind resource, with several areas containing class 5 winds (16 to 18 mph). The U.S. Department of Energy describes North Dakota's wind resources as good to excellent and consistent with utility scale production. North Dakota has an unparalleled opportunity to develop its wind energy potential.

There is also significant regional demand for the energy produced by wind-based generation. In addition to assisting North Dakota in meeting its renewable energy goals, development of wind based generation in North Dakota will assist regional utilities in meeting Minnesota's Renewable Energy Standard which allows renewable energy not produced in the State to be counted towards a utility's requirements. As North Dakota develops its wind

resources, Minnesota and points east can be a substantial market for the energy produced.

Q. IS THE DEMAND FOR NORTH DAKOTA RENEWABLE GENERATION STARTING TO INCREASE?

A. Yes. The demand for North Dakota's wind resource is starting to grow. In fact, MISO's Interconnection Queue in North Dakota shows that 7,128 MW of wind energy has entered the queue as of June 28th, 2009, and the WAPA Interconnection Queue shows that 4857 MW of wind energy has entered that queue as of June 28th, 2009, and the Minnkota Power Cooperative Interconnection Queue shows 3067 MW as of June 28th, 2009.

Q. WILL THE GROUP 1 PROJECTS BENEFIT THE DEVELOPMENT OF RENEWABLE FUEL BASED GENERATION?

A. Yes. The Group 1 Projects will expand interconnection opportunities for generation development in eastern North Dakota and as a result help facilitate development of wind based generation in North Dakota.

Q. WHAT ABOUT NON-RENEWABLE GENERATION? WILL THE GROUP 1 PROJECTS BENEFIT THE DEVELOPMENT OF NON-RENEWABLE GENERATION?

A. Yes. The outlet capabilities provided by the Group 1 Projects and any additional transmission facilities which may expand on the platform provided by the Group 1 Projects may facilitate the development of traditional fuel based generation to meet growing system wide baseload demand. Planning studies are non-discriminatory in terms of generation sources.

Q. HAVE THERE BEEN OTHER TRANSMISSION STUDIES CONDUCTED IN THIS REGION THAT HAVE IDENTIFIED SIMILAR PROJECTS?

A. Yes. There have been several studies conducted over the years that identified the same projects or very similar projects. The most recent study completed prior to the CapX2020 transmission studies is the Northwest Exploratory Study. In this study, 345 kV transmission projects from North Dakota to the Twin Cities were identified. The Fargo Project and the Brookings Project represent a portion of those projects that were identified in that plan.

Q. WHAT WAS THE PURPOSE OF THE NORTHWEST EXPLORATORY STUDY?

A. The primary purpose of this study was to identify a transmission plan that would allow additional generation, approximately 2000 MWs, to be built in North Dakota and to deliver this power to loads outside of North Dakota.

Q. PLEASE SUMMARIZE THE RESULTS OF THE NORTHWEST EXPLORATORY STUDY.

A. The Northwest Exploratory identified two 345 kV transmission lines between western North Dakota and the Minneapolis area. These lines were necessary to add generation in North Dakota and deliver to the Minneapolis area. The Brookings Project and the Fargo Project represent portions of these two lines.

VI. MISO'S ROLE IN THE DEVELOPMENT OF THE GROUP 1 PROJECTS

Q. IDENTIFY THE OTHER REGIONAL TRANSMISSION STUDIES THAT HAVE BEEN PERFORMED?

A. MISO plays an important role in coordinating the transmission planning in its footprint, and has undertaken regional transmission planning efforts and publishes its results in the Midwest ISO Transmission Expansion Plan ("MTEP"). Other regional planning efforts include the North Dakota 10-year Plan filing requirements and the Upper Midwest Transmission Development Initiative ("UMTDI").

Q. DESCRIBE MISO'S MTEP EFFORTS.

A. The MTEP identifies projects required to maintain reliability for the next 10-year period, and provides a preliminary evaluation of projects that may be required to enhance market transactions up to 20 years in the future. A project's inclusion in the MTEP makes it eligible for different cost allocation treatment under the MISO tariff.

Q. DESCRIBE THE APPROACH TAKEN BY MISO WHEN DEVELOPING THE MTEP.

A. MISO uses a "bottom-up, top down" approach in developing the MTEP. The "bottom-up" portion relies on the ongoing responsibilities of the individual transmission owning members of MISO to continuously review and plan for reliably meeting the needs of their local systems. MISO then reviews these local planning activities with stakeholders and performs a top-down

review of the adequacy of and appropriateness of these local plans in meeting needs.

In addition, MISO considers together with stakeholders, opportunities for expansion that would reduce customer costs by providing access to new low cost resources that are consistent with and required by evolving energy legislative policies. MISO's planning process examines congestion that may limit access to the most efficient resources, and considers upgrades that may be needed to meet applicable statutory requirements.

Q. HAVE THE GROUP 1 PROJECTS BEEN EVALUATED BY MISO?

A. Yes, they have. The Group 1 Projects have been submitted to MISO and MISO has analyzed them for inclusion in the MTEP. MISO has designated the Fargo, Bemidji and parts of the La Crosse Projects as Baseline Reliability Projects and has included the Brookings Project in MTEP as well, but has not given the Brookings Project an MTEP designation.

Q. HAS MISO'S COST ALLOCATION TREATMENT FOR THE GROUP 1 PROJECTS BEEN ACCEPTABLE TO APPLICANT OTTER TAIL?

A. The discussion on page 36 of the Application adequately states Applicant Otter Tail's views with respect to its position within MISO and the impact of MISO's cost allocation methodology to it.

Q. DESCRIBE NORTH DAKOTA'S 10-YEAR TRANSMISSION INFRASTRUCTURE PLAN.

A. The Commission conducts its own planning oversight by requiring each utility which owns transmission infrastructure in the state to submit a ten-year plan.

This plan requires, among other things, that a utility provide information on the transmission facilities it plans to construct, keep in service or remove from service. Utilities are also required to inform the Commission of their efforts to coordinate with other utilities to provide a coordinated regional plan for meeting the needs of the region.

Q. HAVE THE GROUP 1 PROJECTS BEEN INCLUDED IN THE NORTH DAKOTA 10-YEAR PLAN?

A. Yes. The Group 1 Projects have been included in each Applicant's 10-year plan.

VII. OTHER REGIONAL TRANSMISSION INITIATIVES

Q. WHAT ARE SOME OF THE TRANSMISSION INITIATIVES FOCUSING ON THE DEVELOPMENT OF A TRANSMISSION SYSTEM THAT COULD DELIVER POWER TO LOADS OUTSIDE OF NORTH DAKOTA?

A. From the time that I have been involved with transmission planning, North Dakota has had an interest in seeing the development of more transmission that would allow generation export from North Dakota. Some of the more recent initiatives that North Dakota has been involved with include the Upper Great Plains Transmission Coalition ("UGPTC" or "Coalition") and the Upper Midwest Transmission Initiative (UMTDI).

Q. PLEASE DESCRIBE THE PURPOSE OF THE UGPTC?

A. The mission of the Coalition is to identify, publicize, and advocate solutions to increase the export of electricity from the upper Great Plains. The Coalition is made up of many different stakeholders including utilities such as Applicants Otter Tail and Xcel Energy; generation developers such as NextEra, Crown Butte Wind; and generation advocacy groups such as the North Dakota Lignite Energy Council, and Wind on the Wires. In addition to the actual members, there are other stakeholders that have participated in the Coalition, such as the North Dakota Industrial Commission, Western Area Power Administration and the regulatory agencies from North Dakota, South Dakota and Minnesota.

Q. DESCRIBE THE UMTDI.

A. The UMTDI is a regional transmission planning effort initiated by the governors of the states of North Dakota, Iowa, Wisconsin, Minnesota and South Dakota to promote regional electric transmission development and equitable cost sharing. The UMTDI was created due to the need for developing transmission infrastructure on a coordinated regional basis. The UMTDI will identify energy generation zones, transmission projects, and other infrastructure needed to support those resources in a cost-effective manner. The UMTDI held its first meeting in October of 2008 and is in the process of developing its work plan.

Q. HAVE THE GROUP 1 PROJECTS BEEN EVALUATED OR INCLUDED IN THE TRANSMISSION STUDIES THAT ARE BEING CONDUCTED FOR THE UMTDI INITIATIVE?

A. Yes, the UMTDI transmission studies have included Group 1 Projects. The base case models that are being used for the UMTDI transmission studies included the transmission facilities that were identified and approved in the MISO MTEP '08, which include all of Group 1 Projects, with the exception of the Brookings Project. However, all UMTDI transmission options that are under study include the Brookings Project or a similar variation of that project.. The UMTDI studies will identify additional facilities beyond the Group 1 Projects to integrate additional resources into the grid.

VIII. ONGOING TRANSMISSION PLANNING STUDY EFFORTS

Q. BEYOND THE STUDIES YOU HAVE DESCRIBED, ARE THE CAPX2020 UTILITIES CONDUCTING OR PARTICIPATING IN ANY ADDITIONAL TRANSMISSION STUDIES IN ORDER TO PLAN FOR FUTURE NEEDED TRANSMISSION DEVELOPMENT IN THE REGION BEYOND THE GROUP 1 PROJECTS?

A. Yes. There are several studies that we are either conducting ourselves or having active participation. These studies are being conducted to ensure a reliable electrical system in the region is developed while facilitating compliance with regulatory requirements and meeting important load-serving and reliability needs.

Q. WHY ARE THE CAPX2020 UTILITIES CONDUCTING TRANSMISSION STUDIES NOW FOR TRANSMISSION INFRASTRUCTURE THAT IS NOT ANTICIPATED TO BE NEEDED UNTIL 2025 OR BEYOND?

A. The CapX2020 Utilities are conducting these additional transmission studies now for the same reason that the Vision Plan was performed: to establish a comprehensive plan to guide near term transmission investments toward an efficient, well-coordinated goal. Due in part to the renewable energy standards established by the states in the Study Region, including North Dakota, significant generation additions above and beyond those modeled in the Vision Plan will be needed. In addition, there is significant discussion at the national level regarding a renewable energy standard that if enacted would require substantial transmission expansion. While 2020 and 2025 seem a long way away at this point, from a transmission planning perspective, it is time to begin looking at the system and planning the facilities that will need to be built to address customer needs in that timeframe.

Q. HAVE THERE BEEN OTHER TRANSMISSION STUDIES COMPLETED FOR THIS REGION SINCE THE CAPX2020 STUDIES?

A. In late March 2009, several of the regional utilities released three additional studies, the "RES Study," "Corridor Study" and the "Capacity Validation Study" ("CVS"). These studies provide insight into the development of the transmission system beyond the Group 1 projects and one of them in particular, the CVS provides additional insight with respect to the benefits of the Group 1 Projects.

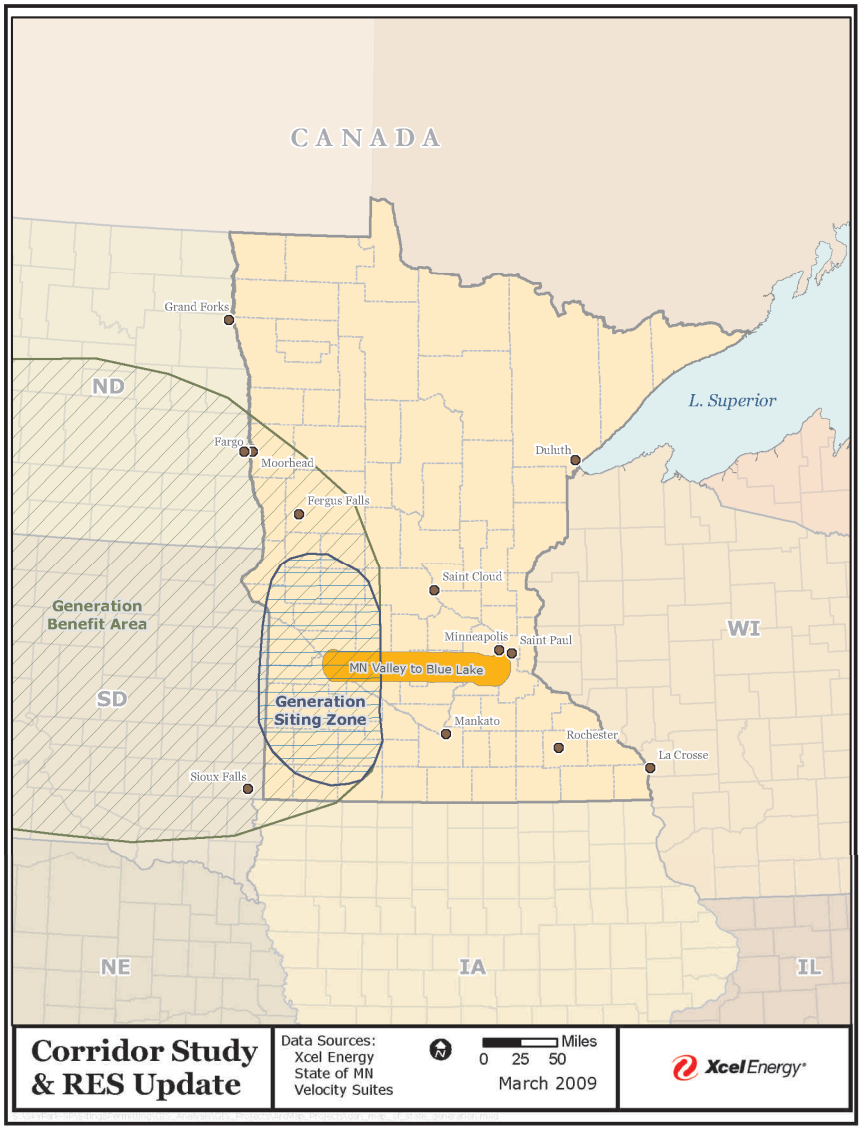
Q. PLEASE DESCRIBE THE OBJECTIVE AND SCOPE OF THE CORRIDOR STUDY.

A. The objective of the corridor study was to identify a solution for the transmission limitations that exist between western Minnesota and the Twin Cities. The results of the study indicate the rebuild of an existing 230 kV line between the Granite Falls area and the southwestern side of the Twin Cities should be rebuilt as a double circuit 345 kV line. This upgrade will create a substantial increase in transfer capability.

Q. WILL THE TRANSFER CAPABILITY IDENTIFIED IN THE CORRIDOR STUDY BENEFIT NORTH DAKOTA?

A. The transfer capability identified in the study enhances the ability of the regional transmission system to move generation from western Minnesota and points west to the Twin Cities. This not only helps generation additions in Minnesota, but also in the Dakotas. Figure 4 illustrates this point.

Figure 4



The gold line on the diagram shows the location of the "Corridor Project," and the hashed areas on the diagram show the areas where additional generation can be added to the system as a result of this transmission addition. Even though this line is physically located in Minnesota, it provides benefits for generation sited in the Dakotas. While more transmission facilities may also be necessary, without this line, it would be very unlikely that additional generation could be added and delivered to the Twin Cities or points further

east. The total capability added by this line is estimated to be an incremental 2000 MWs.

Q. WERE THERE OTHER FINDINGS IN THE CORRIDOR STUDY?

A. Yes, another important result from the Corridor Study was the identification of the need for a line in Wisconsin to allow generation development in Minnesota and the Dakotas to access load centers in the east. The study reveals that adding a line from La Crosse, Wisconsin to Madison, Wisconsin can increase the 2000 MW transfer capability created by the Corridor Project by an additional 1600 MWs, which will facilitate generation development in Minnesota and the Dakotas. This study demonstrates the benefits of regional transmission and how transmission constructed in a non-neighboring state has the potential to provide benefits to generators seeking to site in North Dakota.

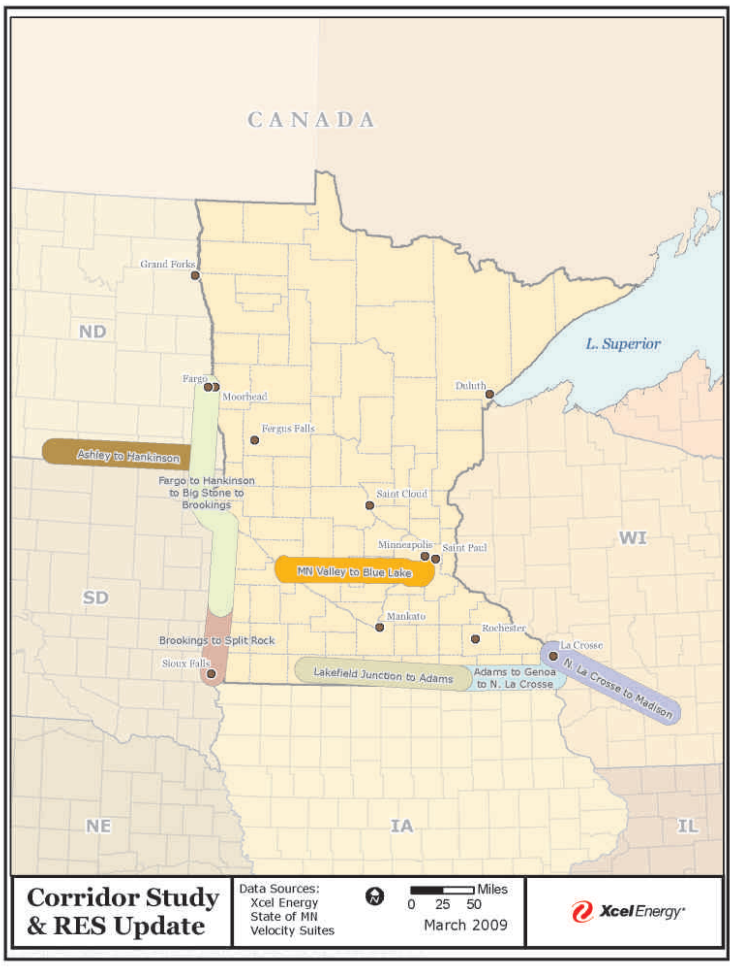
Q. PLEASE DESCRIBE THE OBJECTIVE AND SCOPE OF RES UPDATE STUDY.

A. The scope of the RES Update transmission study was to examine the transmission facilities necessary to meet the Minnesota Renewable Energy Standard beyond the Group 1 projects and the Corridor project. Transmission projects identified during this study would support renewable generation projects, and other generation projects necessary to maintain system reliability in the region. Similar to the CapX2020 Vision Plan, this study looked at various generation development scenarios, and looked for common transmission plans across the various scenarios.

Q. WHAT WERE THE RESULTS OF THE RES UPDATE STUDY?

A. Figure 5 illustrates the next likely set of transmission facilities that were identified in this study. A new double circuit 345 kV line from Fargo to Sioux Falls allows for a north-south tie for several major east-west transmission lines, therefore optimizing the performance of the Group 1 facilities and the Corridor project. The Ashley – Hankinson extension would allow several new wind projects to be integrated into the system. Furthermore, the transmission lines proposed in Southern Minnesota enable more generation outlet capability from the Buffalo Ridge area and points west.

Figure 5



Q. PLEASE DESCRIBE THE OBJECTIVE AND SCOPE OF THE CVS STUDY.

A. Most of the transmission studies that have been conducted for high voltage transmission projects have primarily been performed on an individual or small group basis, each using a different set of assumptions. The objective and scope of the CVS Study was to evaluate, at a high level various combinations of proposed projects with a common set of assumptions to identify the potential range of capability that may be achieved by a single project or a set of projects.

Q. PLEASE DESCRIBE THE RESULTS OF THE CVS STUDY.

A. Some key findings of the CVS Study were that the Group 1 projects provide more transfer capability together than each project individually. Following the construction of the Group 1 projects, the CVS Study concluded that the Corridor Project is the next logical development because it offers the most amount of incremental transfer capability at the lowest cost. The CVS Study also verified that a new line in Wisconsin greatly enhances power transfer through the system regardless of any combination of transmission projects. Furthermore, the CVS Study confirmed that the 500 kV line between Manitoba and Minnesota is the next major transmission constraint in the region.

Q. DOES THE CAPX2020 INITIATIVE HAVE PLANS FOR FURTHER TRANSMISSION PLANNING STUDIES?

A. Yes. Because transmission planning is an ongoing and evolving process, there will always be a need to continue to conduct additional studies. At this point, we expect that once the current phase of transmission studies are completed,

we would conduct additional studies in a similar fashion with updated assumptions.

Q. IS THERE ANYTHING ABOUT THE ONGOING TRANSMISSION STUDY WORK THAT CONTRADICTS THE NEED FOR MAJOR TRANSMISSION INFRASTRUCTURE IMPROVEMENTS IN THE REGION?

A. No, in fact, just the contrary. Each study that has been conducted, or is underway, continues to point to the conclusion that major improvements to the transmission system are needed and that significant improvements in the CapX2020 Study Region is necessary. The ongoing study work reinforces the need for major transmission line construction and the Group 1 Projects.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes.

Timothy J. Rogelstad
Otter Tail Power Company
215 S Cascade St
Fergus Falls, MN 56537

Professional Experience

Manager of Delivery Planning, Otter Tail Power Company 2002 to Present

- Accountable for managing Transmission Planning, transmission contracts, capital budget development and monitoring and overseeing the project management for Big Stone transmission.
- Ensure that Otter Tail has an adequate transmission system to reliably and economically serve its customers.
- Ensure compliance with NERC Planning Standards
- Negotiate transmission contracts.
- Represent Otter Tail on various industry working groups and committees.
- Manage the development and monitoring of Otter Tail Power capital spending.
- Manage the project management for Big Stone transmission.

Supervisor of Transmission Planning, Otter Tail Power Company 1998 to 2002

- Supervise Transmission Planning staff.
- Negotiate transmission contracts with neighboring utilities.
- Represent Otter Tail on key MAPP/MISO committees and working groups.
- Ensure compliance with NERC Planning Standards.
- Project Manager for a 100 mile 230 kV transmission project.

Planning Engineer, Otter Tail Power Company 1992 to 1998

- Conduct transmission studies.
  - Powerflow analysis
  - Stability analysis
  - Economic analysis
- Review transmission studies from neighboring utilities.
- Build and submit transmission modeling information.
- Participate in MAPP working groups regarding transmission planning issues.

Engineer, System Engineering, Otter Tail Power Company 1989 to 1992

- Conduct relay coordination and distribution coordination studies.
- Design transmission substation protection schemes.
- Field check-out and commissioning of new transmission substation installations and modifications.

Education

- Bachelors of Science, Electrical and Electronics Engineering, North Dakota State University, 1989.
- Registered professional engineer in the states of Minnesota (1994 to present), North Dakota (1994 to present), and South Dakota (1994 to present).
- Participated in numerous continuing education programs, and currently enrolled in an Accelerated Leadership Program for Otter Tail Coorporation.

Affiliations

- Member of the Institute of Electrical and Electronics Engineers (IEEE), past chair of Red River Valley Section
- Member of the Minnesota Society of Professional Engineers
- Former member MAPP Model Building Working Group
- Former member MAPP Transmission Reliability Working Group
- Former member MAPP Line Loading Relief Working Group
- Former member MAPP Design Review Sub-Committee
- Past chair of the MAPP RRV SPG (Red River Valley Sub-Regional Planning Group)
- Current participant MISO Planning Sub-Committee
- Current participant CAPX Technical Team
- Current participant CAPX Tariff Team
- Current participant Upper Great Plains Transmission Coalition
- Chair, Minnesota Transmission Owners

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION — **CASE NO. PU-_____**

OTTER TAIL POWER COMPANY

IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 TRANSMISSION PROJECTS — **CASE NO. PU-_____**

VERIFICATION

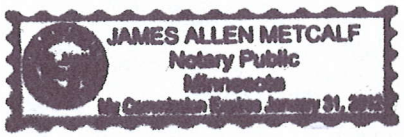
STATE OF MINNESOTA)
) ss.
COUNTY OF OTTER TAIL)

TIMOTHY J. ROGELSTAD, being first duly sworn on oath, deposes and says that he is Manager of Delivery Planning for Applicant Otter Tail Power Company in the above captioned matter, that the testimony and schedules submitted in the above captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

[SIGNATURE PAGE FOLLOWS]

TIMOTHY J. ROGELSTAD

Subscribed and sworn to before me this 10th day of September, 2009.



Notary Public
My Commission Expires: JAN. 31, 2012

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION	**CASE NO. PU-_____**
OTTER TAIL POWER COMPANY	**CASE NO. PU-_____**

IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 PROJECTS

TESTIMONY OF

Paul J Lehman
On Behalf of

APPLICANTS

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION,
AND
OTTER TAIL POWER COMPANY

September 17, 2009

Joint Exhibit C

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND EMPLOYMENT ADDRESS.

A. My name is Paul J. Lehman and my business address is 414 Nicollet Mall, Minneapolis, Minnesota, 55401.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Xcel Energy Services Inc., the service company provider for Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") and my current position is Manager, Regulatory Administration.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received a Bachelor of Science in Electrical Engineering from the University of Minnesota in 1977. Thereafter I began my career at Northern States Power Company as a Planning Engineer in its Power Supply Planning Department. While in that area, I worked on planning the transmission system expansion requirements for the Company.

In 1980, I became the Superintendent of Transmission Planning for Northern States Power Company – Wisconsin, responsible for all power supply planning efforts for the Company's transmission needs in Wisconsin. This included all regulatory reporting requirements for the Company Northern States Power Company – Wisconsin.

In 1984, I moved to the Energy Supply Planning Department of Northern States Power Company with various responsibilities and titles centered around

the planning activities associated with the Company's generating plants. This included life extension efforts, alternative fuel supply evaluations, negotiating contracts with non utility power suppliers under the Public Utilities Regulatory Policies Act ("PURPA"), capacity supply acquisition activities within the Mid-Continent Area Power Pool ("MAPP"), long term power supply planning and acquisition and regulatory reporting requirements associated with these various activities.

In 1990, I became the Manager of a new department within the Company, Power Contracts, with responsibility for all of the contracting activities for the power supply business needs of the Company.

In 1991, I became Manager, Electric Rate Design for Northern States Power Company responsible for all the retail electric rate design activities and requirements of the Company.

In 2000, I became an internal consultant providing services to other areas of the Company on pricing and regulatory issues. During this time, I served as the Company representative to the Federal Energy Regulatory Commission's ("FERC") during its rulemaking activities for the interconnection of generation to utility transmission systems including testifying on behalf of the Edison Electric Institute ("EEI") before FERC on technical challenges and issues associated with interconnection of wind to utility systems.

In 2008, I assumed my current position. My resume is attached as Schedule 1.

Q. FOR WHOM ARE YOU TESTIFYING?

A. I am providing testimony on behalf of Northern States Power Company, a Minnesota corporation ("Xcel Energy"), Otter Tail Power Company ("Otter Tail"), the joint Applicants in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to provide an overview of the cost recovery and allocation methodologies for the Group 1 Projects.

Q. WERE YOU INVOLVED IN THE PREPARATION OF THE APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE IN THIS PROCEEDING?

A. Yes. I provided information to the Applicants in their preparation of the Application. The Application was prepared with my participation, using information that I provided as well as the type of information that is regularly relied upon by professionals in the ordinary course of business.

II. COST RECOVERY AND ALLOCATIONS

Q. HOW WILL APPLICANTS RECOVER THE COST OF THEIR INVESTMENT IN THE GROUP 1 PROJECTS?

A. Applicants are both Transmission Owning Members of the Midwest Independent Transmission System Operator, Inc. ("MISO"). As such, Applicants' transmission facilities above 100 kV are operated by MISO. As a general matter, MISO calculates a revenue requirement for the recovery of costs for the owners of the transmission facilities it operates and charges users of the MISO Transmission System (those transmission facilities over which

MISO has functional control) in order to collect and remit to the MISO transmission owners their cost recovery on their transmission assets. Therefore, Applicants will, in general, recover their capital costs for their ownership of the Group 1 Projects from users of the MISO Transmission System.

Q. IF APPLICANTS WILL RECOVER THEIR CAPITAL COSTS FROM MISO, HOW ARE APPLICANTS' RATEPAYERS AFFECTED?

A. As noted in my previous answer, in order to pay the utility owners of transmission in the MISO footprint, MISO charges the utility users of the transmission facilities in the MISO footprint for their use of those transmission facilities to serve customers. Applicants, as users of transmission facilities in the MISO footprint, on behalf of their ratepayers, will pay a portion of those charges. It is these charges to use the transmission facilities in the MISO footprint, including the Group 1 Projects, for which Applicants will incur costs and which will be recovered from the ultimate benefactors of this use, the Applicants' ratepayers.

Q. HOW DOES MISO DETERMINE THE TRANSMISSION OWNER'S COST FOR EACH TRANSMISSION FACILITY?

A. Generally, the owner of a transmission facility will incorporate the costs of that facility in its rate base as calculated pursuant to Attachment O of the MISO Transmission, Energy Markets and Operating Reserves Tariff ("Tariff"). The Attachment O rate base is then used to calculate the Transmission Owner's revenue requirement and from that, a charge is calculated for the use of the transmission facilities within the Transmission

Owner's pricing zone, which is roughly equivalent to that Transmission Owner's transmission footprint.

However, some proposed transmission facilities are eligible for different cost allocation methodology because MISO characterizes them as providing certain regional and sub-regional benefits. For these projects, MISO attempts to allocate the costs to those users of the MISO Transmission System who benefit from these projects.

Therefore, Transmission Owning Members of MISO recover their costs of investment in transmission facilities either by the MISO Attachment O formula or through MISO's other cost allocation methodology.

Q. YOU SAID THAT THE PAYMENT FOR CERTAIN TRANSMISSION FACILITIES IN MISO ARE PAID FOR BY THOSE THAT BENEFIT FROM THE USE OF THE FACILITIES. PLEASE EXPLAIN HOW MISO DETERMINES THIS.

A. Yes. As a first step, MISO determines the resultant benefit of a proposed transmission addition. To do this, MISO uses several broad categories. One of these defines transmission facilities that provide an improvement in the overall reliability of the entire MISO transmission system ("Regional Basis"). A second benefit category defines how proposed transmission facilities have a more direct or local benefit to the transmission system ("Sub-Regional Basis"). A third benefit category is for the connection of generation to the MISO system ("Generation Interconnection Projects"). Finally, the fourth benefit category is for projects that have a high economic benefit to the MISO system as compared to their costs ("Regionally Beneficial Projects"). In some cases,

proposed transmission projects may have benefits in more than one of these benefit categories.

Q. HOW DOES MISO ACCOUNT FOR EACH OF THESE BENEFIT CATEGORIES WHEN DETERMINING ALLOCATION OF COST RESPONSIBILITY FOR TRANSMISSION ADDITIONS?

A. Each year, MISO reviews all of the transmission expansion plans proposed by the MISO Transmission Owners and identifies those projects that are to be included in what is know as "Appendix A" of the Midwest Transmission Expansion Plan ("MTEP"). For projects included in Appendix A and constructed?, MISO will collect the necessary funds to meet each of Applicant's revenue requirements through the cost allocation formula approved in its Cost Allocation Policy (FERC Docket No. ER06-18). This Policy allocates and recovers costs associated with new transmission projects and system upgrades within the MISO Transmission System using provisions developed by the Regional Expansion Criteria and Benefits ("RECB") Task Force. As expressed in the name of this task force, the provisions developed set the criteria for how the benefits of proposed transmission expansion facilities will be allocated to users of the MISO Transmission System.

As a first threshold, RECB criteria divides proposed transmission facilities between those that are more local or direct in benefit from those that are regional in benefit. Facilities that are regional in benefit are defined as Baseline Reliability Projects ("BRP" or "BRPs"). I'll address the more direct or local projects later, but for those transmission projects with BRP designations, MISO allocates some or all of their costs in one of two ways.

For transmission projects with voltages below 345 kV, MISO makes use of an analysis known as the Line Outage Distribution Factor ("LODF") method. LODF is an engineering calculation of the change of flows on the Transmission System created by the addition of a new transmission facility. MISO uses computer software to measure and model the LODF of all facilities within the MISO Transmission System for each new facility added to the system. MISO then models the LODF for each pricing zone for each new transmission facility. LODF is used because it is considered by MISO planners as a way to determine the added benefit of a new transmission facility to each of the pricing zones. Generally, pricing zones in close proximity to the proposed transmission facility have the greatest LODF cost allocation and those furthest away have little to no cost allocation from the LODF method, thus this benefit assignment is defined as Sub-Regional.

For transmission projects of 345 kV or higher, the RECB criteria defines some of the benefit of the proposed transmission facility as being for system wide reliability. Therefore a portion of the costs of the proposed facility (20 percent) is assigned to all pricing zones in MISO on what is known as a "postage stamp" basis. Postage stamp cost allocation spreads cost responsibility proportionally to the load in the pricing zones of MISO thus this benefit assignment approach is defined as being Regional. The remaining 80 percent of the cost of the proposed transmission facility is then assigned using the LODF method I just described.

One more factor that is included in the RECB criteria is if the proposed transmission facilities have been designated (through MISO studies) as necessary for interconnection of generation. If this is the case, then further

analysis is done to determine what portion of the transmission facilities are solely for the purpose of Generation Interconnection and which portion may have benefits from one of the other categories. The portion that is solely for Generation Interconnection is assigned to the generation that requires the facility for interconnection.

In the case of transmission facilities that have more purposes than just interconnection of generation ("Network Upgrades"), MISO's Generation Interconnection cost allocation provides for up to 50 percent of the cost responsibility to be passed back to the transmission owners and then ultimately to the transmission users. This assignment of other purposes is determined if the generation is either designated a "Network Resource" or is being sold to a "Network Customer" for more than one year. In either of these cases, the transmission facilities are serving a "network" purpose (in addition to their generation interconnection purpose). MISO's Tariff thus treats the portion of the transmission cost responsibility passed back to the transmission owner as BRP facility with cost allocation as described above. The other 50 percent of costs would be assigned to the generator.

On July 9, 2009, MISO submitted proposed Tariff revisions to FERC that would change the way costs for Generation Interconnection Projects are allocated. MISO has proposed changing the 50/50 percent cost share for the costs of Network Upgrades by allocating 100 percent of the costs of Network Upgrades in a voltage class below 345 kV to the generators. MISO also proposed allocating 90 percent of the costs of Network Upgrade facilities in a voltage class of 345 kV or higher to the generators and 10 percent of the costs to the users of the MISO Transmission System. The costs of the 10 percent

of the Network Upgrades allocated to users of the MISO Transmission System would be allocated on a postage stamp basis to all MISO pricing zones. MISO's proposed changes would apply to all generators, not just those that interconnect using Network Resource Interconnection Service.

Q. WHAT ABOUT THE LOCAL OR DIRECT BENEFIT TRANSMISSION FACILITIES YOU MENTIONED? PLEASE EXPLAIN WHAT HAPPENS WITH THE COST ASSIGNMENT OF THOSE FACILITIES.

A. If the initial screening criteria of RECB determines that the benefit of a proposed transmission facility is local in nature, then the assignment of costs for that facility is left to the local pricing zone of the owner of the facility. For example, a proposed transmission facility that serves a single customer on a radial line would be directly assigned for the benefit of that customer. Similarly, a proposed transmission facility that primarily benefits a local load center or even a load center that is not part of the MISO system would be assigned for the benefit of that local load center. This later consideration becomes important when looking at two of the CapX2020 lines which I will explain later.

Q. WILL ANY OF THE GROUP 1 PROJECTS HAVE A BRP DESIGNATION UNDER RECB?

A. Yes. The Fargo Project and most of the Bemidji Project have been designated as BRPs in the 2006 and 2008 MTEPs. The segment of the La Crosse Project from North Rochester to La Crosse has also been designated as a BRP in the 2008 MTEP. The Hampton Corner to North Rochester 345 kV segment of the La Crosse Project and both 161 kV circuits of the La Crosse Project were screened as local facilities under the RECB criteria because the primary benefit

of these facilities are for the load of two non-MISO CapX2020 Utilities (Dairyland Power Cooperative and Rochester Public Utilities). Similarly, a non-MISO member (Minnkota Power Cooperative) has a 31.5 percent ownership share of the Bemidji Project and thus that share in not treated as a BRP by MISO.

Finally, the Brookings Project has been designated as a Generation Interconnection Project ("GIP") under RECB. This decision is currently being discussed and analyzed and MISO has convened a public stakeholder process to determine whether and how the MISO Tariff might be changed to address stakeholder concerns over this designation.

In summary each of the Group 1 Projects have been designated for cost responsibility as follows under the RECB criteria:

The Fargo Project – All of the cost responsibility assigned as a BRP with 20 percent through postage stamp to all MISO pricing zones and 80 percent through the LODF method.

The Bemidji Project – 68.5 percent of the cost responsibility assigned as a BRP through the LODF method (as applicable projects under 345 kV).

The La Crosse Project – All of the cost of the Hampton to North Rochester portion of this project along with the 161 kV lines from North Rochester into the Rochester area are assigned locally to the owners of this segment of the line. Further, the cost of the project that non-MISO transmission owners DPC and RPU will incur are not assigned to any MISO members. Finally, the

cost of the remaining portion of the project is assigned as a BRP with 20 percent through postage stamp to all MISO pricing zones and 80 percent through the LODF method.

The Brookings Project – Initially, 100 percent of the line has been designated as being the responsibility of the generators that require the project for their interconnection (yet to be finalized). Under the existing MISO RECB process, the ultimate cost responsibility for the project would leave 50 percent assigned to the generators and potentially 50 percent assigned as a BRP with 20 percent of this half (10 percent of the total cost) through postage stamp to all MISO pricing zones and 80 percent of this half (40 percent of total cost) through the LODF method. I note, again, that this methodology is being reviewed and MISO has convened a stakeholder process to assess more appropriate ways to allocate the cost of the Brookings Project.

Q. UP TO THIS POINT YOU HAVE DESCRIBED THE ALLOCATION OF COST TO MISO PRICING ZONES. ONCE THOSE ALLOCATIONS HAVE BEEN MADE, HOW ARE THE CHARGES THAT HAVE BEEN ALLOCATED TO PRICING ZONES FURTHER ALLOCATED TO USERS OF THE MISO TRANSMISSION SYSTEM?

A. Charges allocated to each pricing zone are then paid for by the utilities serving load in each pricing zone (the users) in proportion to their load in that pricing zone. For example, Xcel Energy serves over 80 percent of the load in its pricing zone and therefore pays over 80 percent of the costs allocated to the Xcel Energy pricing zone.

Q. HAVE YOU CONDUCTED AN ANALYSIS THAT ACCOUNTS FOR ALL OF THE ASSIGNMENT OF COST RESPONSIBILITY FOR THE GROUP 1 PROJECTS SUCH

THAT YOU CAN QUANTIFY THE COST RESPONSIBILITY THAT HAS BEEN ASSIGNED TO THE APPLICANTS?

A. Yes. The analysis is reflected in Appendix C, attached to the Application.

Q. WOULD YOU PLEASE SUMMARIZE THE CONCLUSIONS OF THAT ANALYSIS?

A. The expected costs assigned to each Applicants' respective North Dakota jurisdiction will be equal to the revenue requirements for MISO charges reflecting an investment of $40-60 million for Xcel Energy and $35-40 million for Otter Tail in the Group 1 Projects. This ultimate cost responsibility will generate a North Dakota jurisdictional annual levelized revenue requirement of approximately $9.5 million per year for Xcel Energy and $7.5 million per year for Otter Tail.

Q. YOU MENTIONED THAT THE BROOKINGS PROJECT HAS BEEN DESIGNATED AS A GENERATION INTERCONNECTION PROJECT UNDER RECB AND THUS SUBJECT TO THE GENERATOR INTERCONNECTION PROJECT COST ALLOCATION METHODOLOGY DISCUSSED ABOVE. IS THIS SUBJECT TO CHANGE?

A. As of the date of this filing, both Applicants, Xcel Energy and Otter Tail, are transmission-owning members of MISO. However, Otter Tail and several other transmission-owning members of MISO are currently in discussions with MISO regarding modifications to the MISO GIP cost allocation methodology. Because of the location of Otter Tail's pricing zone, there is a large amount of generation in the MISO Queue that is seeking to interconnect to the MISO Transmission System within Otter Tail's pricing zone. Based on the GIP RECB cost allocation methodology currently in place, a substantial proportion of the cost of the Generator Interconnection Projects' cost to

build transmission facilities will be disproportionately borne by Otter Tail ratepayers. Otter Tail, Xcel Energy, and others are working with MISO to develop a better allocation of the costs of these GIPs to address these concerns.

As identified in the Application, as a result of this cost allocation issue, Otter Tail has submitted notice to MISO reserving its right to withdraw from MISO should the issue not be addressed to its satisfaction. The notice is a technical requirement under the Tariff so that Otter Tail may preserve all its rights in negotiations with MISO. Again, both Otter Tail and Xcel Energy are proactively working with MISO to resolve the uncertainty in cost allocation and reach a fair and reasonable solution among all stakeholders.
In an effort to address these concerns, MISO submitted to FERC the proposed modifications to its GIP cost allocation methodology that I described above. The outcome of this process may result in changes to the way the costs for the Brookings Project will be allocated to Applicants and other MISO members. Applicants will keep the Commission informed on this process and of the impact any revised Tariff procedure may have on this proceeding.

To that end, MISO's cost allocation methodology for Generation Interconnection Projects may change prior to construction of the Group 1 Projects. Applicants will update the Commission regarding any such changes.

Q. WHY IS MISO'S GENERATOR INTERCONNECTION PROJECT COST ALLOCATION METHODOLOGY PROBLEMATIC FOR THE STAKEHOLDERS IN THE BROOKINGS PROJECT?

A. The Generator Interconnection Project cost allocation methodology is based on the premise that interconnection facilities are built in response to approved interconnection requests for which the generator has signed an interconnection agreement and generation commitment. In the case of the Brookings Project, MISO has identified a group of nineteen generators under study for interconnection to the MISO Transmission System consisting of 1,300 MW of generating capacity. These studies have identified the Brookings Project as a necessary Network Upgrade for the reliable interconnection of the proposed generation projects. Therefore, MISO's starting position for allocation of the generation portion of the costs of the Brookings Project should be assigned to the generators making up the 1,300 MW of capacity studied.

MISO's starting position creates a number of difficult complications in the case of the Brookings Project. The nineteen generators identified by MISO do not have signed interconnection agreements or power purchase agreements. Therefore, the generators who will actually use the Brookings Project are currently not under contract. This creates several problems with the timing of the Brookings Project. First, the MISO Tariff requirement that generation projects fund 100 percent of the upfront costs of the Brookings Project is problematic since such generation projects do not yet exist and are not available to provide such funding. Second, under the current project schedule, we expect the Brookings Project to be completed prior to the completion of all of the generation projects. Such timing is not contemplated under the MISO Tariff. Last, because the 50/50 percent cost sharing provisions apply only to generators who are interconnecting with Network Resource Interconnection Service, the fact that the generators do not have

Interconnection Agreements makes it unclear how much of the potential 50 percent of the cost of the Brookings Project will actually be passed back to CapX2020 Utilities' ratepayers in the form of MISO charges.

In light of all of these issues and cost allocation uncertainty, Applicants and others have raised concerns with MISO on the need to address this situation in some fashion in order to provide an allocation mechanism that is workable.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.

MR. PAUL J LEHMAN
Manager, Regulatory Administration
414 Nicollet Mall, Minneapolis, Minnesota

CURRENT RESPONSIBILITIES (August 2008 – Present)

Manage regulatory projects related to transmission facilities for Xcel Energy.

PREVIOUS EMPLOYMENT (Northern States Power Company)

Pricing Consultant	2000 - 2008
Manager, Electric Rate Design	1991 – 2000
Manager, Power Contracts	1990 – 1991
Various positions, Energy Supply Planning Including Superintendent, Power Systems Development And Superintendent, Bulk Power Planning	1984 – 1990
Superintendent, Transmission Planning	1980 – 1984
Planning Engineer, Power Supply Planning and Transmission Planning	1977 – 1980

PREVIOUS TESTIMONY

Jurisdiction	Subject	Docket/Case No.
Minnesota	Rate Design	E002/GR-05-1428
Colorado	Rate Design	04S-164E
Minnesota	Rate Design and Cost Allocation	E002/GR-92-1185
Minnesota	Legislative Committee Hearings on Wind Generation	NA
Minnesota	Power Purchase and Cogeneration Litigation	E002/GR-91-001
Minnesota	Joint Petition of Dakota County and Winona County	E002/CG-88-489
North Dakota	Rate Design and Cost Allocation	PU-400-92-399
North Dakota	Rules Governing Cogeneration and Small Power Production	PU-439-89-374
Wisconsin	Advance Plan 5	05-EP-5
Wisconsin	Advance Plan 4	05-EP-4
Wisconsin	Advance Plan 3	05-EP-3

EDUCATION

University of Minnesota – Institute of Technology Bachelor of Science in Electrical Engineering	1977
University of Minnesota – Continuing Education and Extension Pricing for Profits Strategies and Tactics	1992
University of Minnesota – Carlson School of Management Strategic Pricing Program	1997
Professional Pricing Society Fundamentals and Advanced Workshops of the Professional Pricing Skills Certificate Program	1999
University of Wisconsin, Madison – College of Engineering EEI Transmission Pricing School	2001

PROFESSIONAL REGISTRATIONS AND ASSOCIATIONS

Registered Professional Engineer in Minnesota and Wisconsin
Member, Institute of Electrical and Electronic Engineers

ARTICLES OR PAPERS PUBLISHED OR PRESENTED

Paul J. Lehman, et al, "MAPP Bulk Transmission Outage Data Collection and Analysis", IEEE Transactions on Power Apparatus and Systems, Volume PAS-103, Number 1, January 1984, p. 213-221.

Paul J. Lehman, et al, "Effects of Pooling Weather Associated MAPP Bulk Transmission Outage Data on Calculated Forced Outage Rates", IEEE Transactions on Power Apparatus and Systems, Volume PAS-103, Number 8, August 1984, p. 2345-2351.

Paul J. Lehman, et al, "Analysis of Pooling 345 kV Transmission Outage Data Between the Mid-Continent Area Power Pool and Northeast Utilities", IEEE Transactions on Power Apparatus and Systems, Volume PAS-104, Number 9, September 1985, p. 2427-2435.

Paul J. Lehman, et al, "The Procedure Used in the Probabilistic Transfer Capability Analysis of the MAPP Region Bulk Transmission System", IEEE Transactions on Power Apparatus and Systems, Volume PAS-104, Number 11, November 1985, p. 3013-3019.

Paul J. Lehman, et al, "The Effects of Terminal Complexity and Redundancy on the Frequency and Duration of Forced Outages", IEEE Transactions on Power Apparatus and Systems, Volume PWRS-2, Number 4, November 1987, p. 856-863.

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION — **CASE NO. PU-_____**

OTTER TAIL POWER COMPANY

IN THE MATTER OF THE APPLICATION FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE CAPX2020 GROUP 1 TRANSMISSION PROJECTS — **CASE NO. PU-_____**

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

PAUL J. LEHMAN, being first duly sworn on oath, deposes and says that he is Manager of Regulatory Administration for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above captioned matter, that the testimony and schedules submitted in the above captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

[SIGNATURE PAGE FOLLOWS]

PAUL J. LEHMAN

Subscribed and sworn to before me this 11 day of September, 2009.

Notary Public
My Commission Expires: 1-31-2010