

RECEIVED

JUN 10 2010

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

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

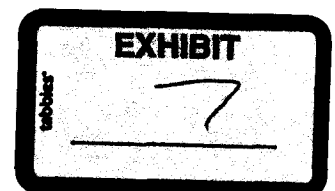
INTRODUCTION AND SUMMARY

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").

56 PU-09-678 Filed 06/10/2010 Pages: 40
Exhibit 7
Emineth & Associates Court Reporters

57 PU-09-676 Filed 06/10/2010 Pages: 40
Exhibit 7
Emineth & Associates Court Reporters



(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.

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]ommission 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.

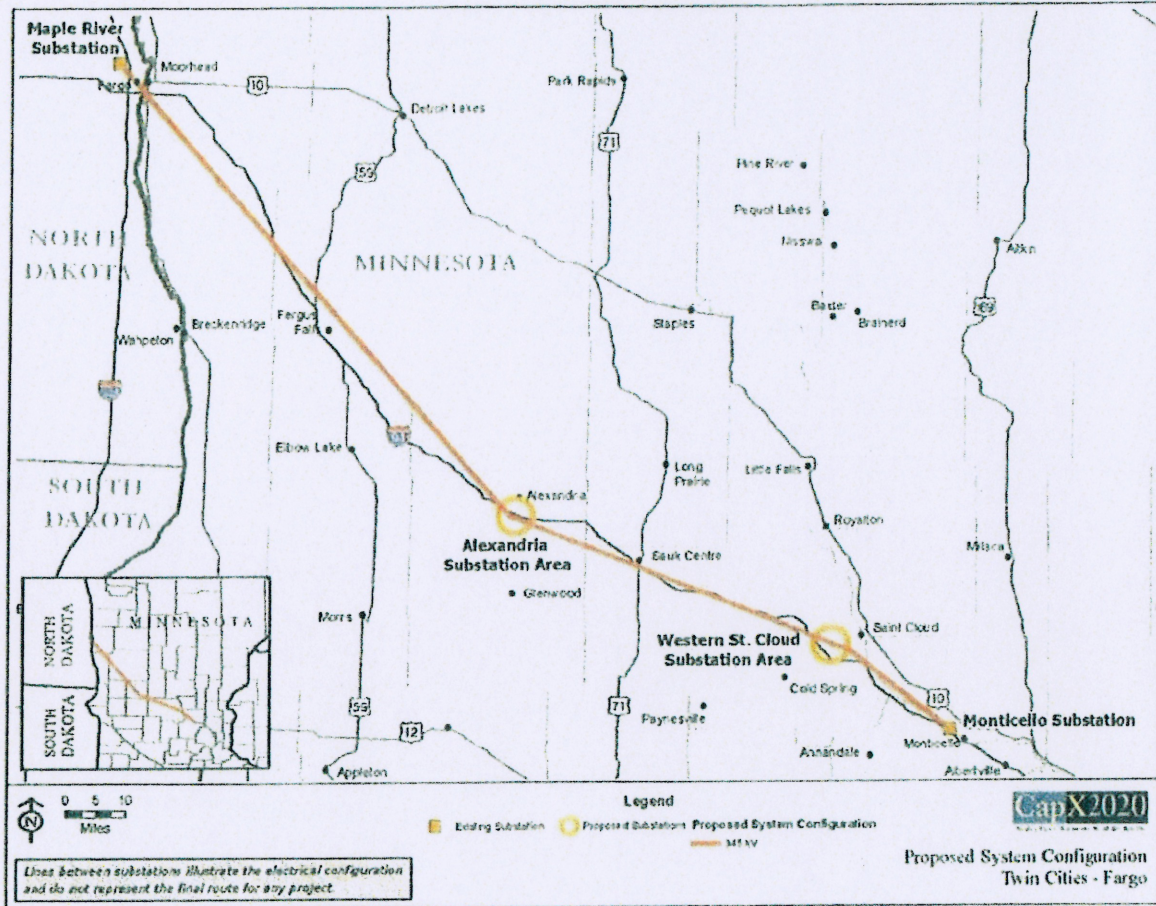
1. *The Fargo Project*

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
Fargo 345 kV Project



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.

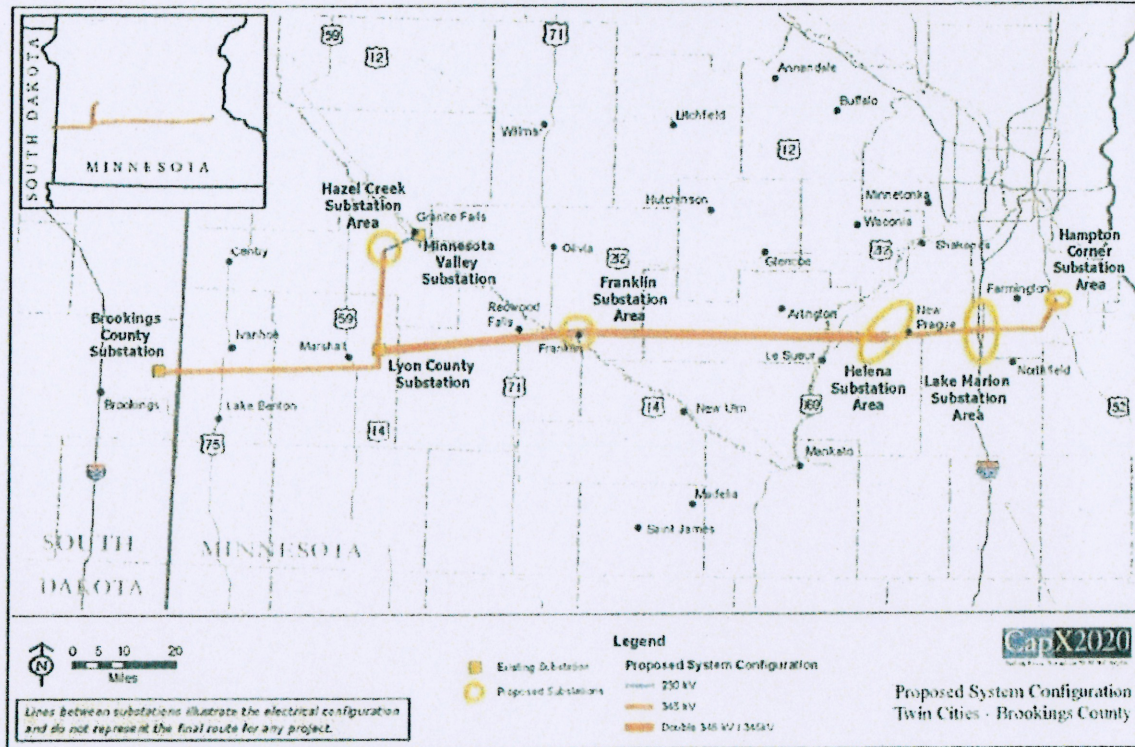
The western-most segment will be a 345 kV circuit between the Brookings County Substation and the Lyon County Substation. This segment will be approximately 50 to 55 miles long and will be constructed in a double-circuit compatible configuration by using structures capable of supporting a second circuit 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

Brookings 345 kV Project



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

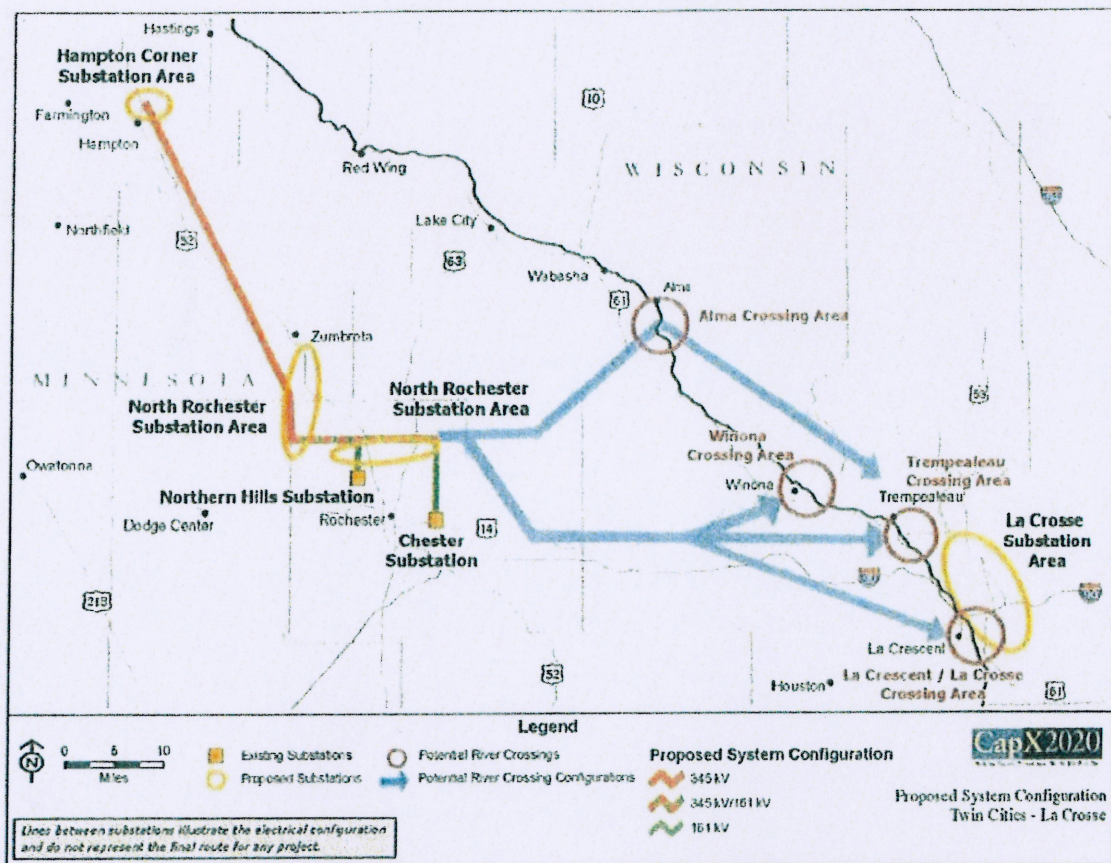
area, the Chester and Northern Hills Substations. The North Rochester – Northern Hills 161 kV transmission line will be approximately 10 – 15 miles long. The North Rochester – Chester 161 kV transmission line will be approximately 20 to 30 miles long.

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

La Crosse 345 kV Project

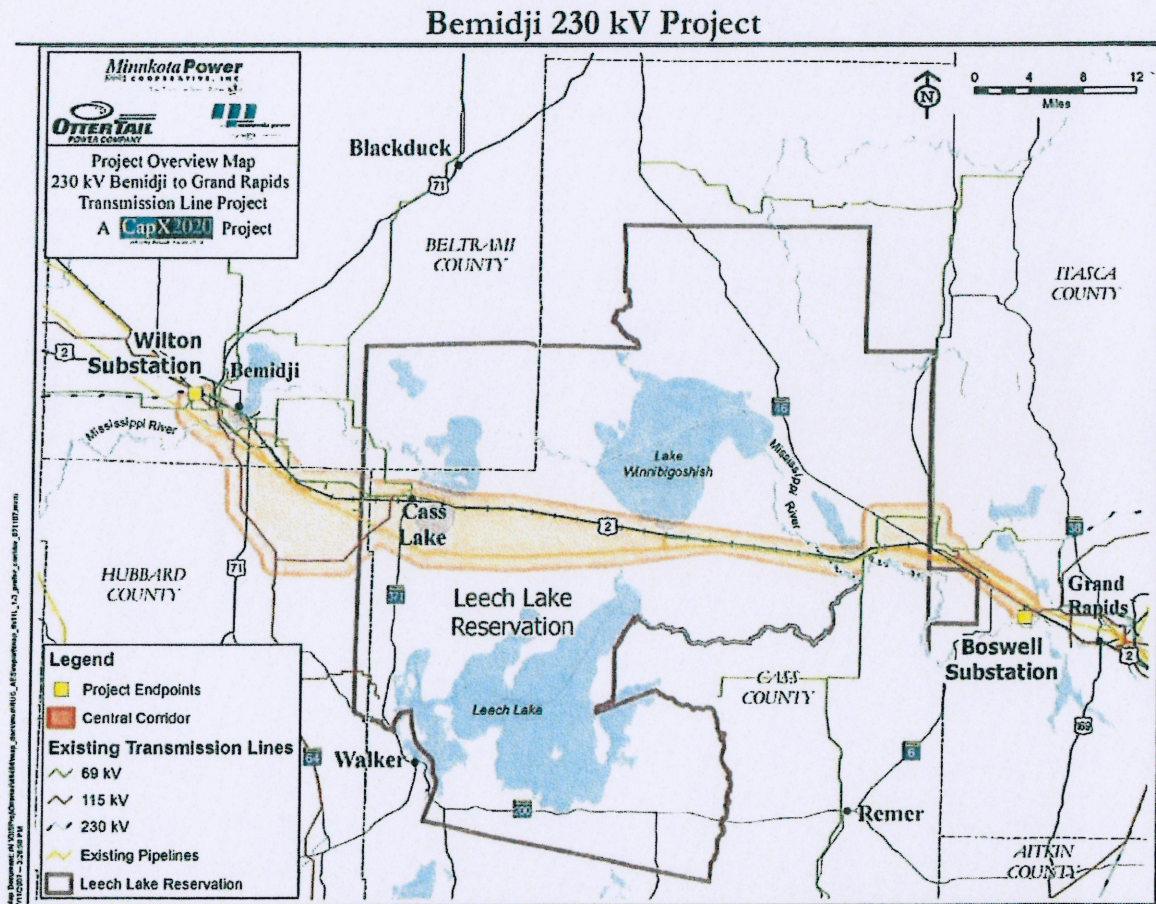


4. The Bemidji Project

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

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.

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.

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.

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.

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

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 up 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 demand (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

| <u>Project Name:</u> | <u>Fargo</u> | <u>La Crosse</u> | <u>Brookings</u> | <u>Bemidji</u> |
|---|--------------|------------------|------------------|----------------|
| 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.

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 disproportionately 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 indispensable 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:

James A. Alders
Director, Regulatory Administration
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

Dean Pawlowski
Project Manager
Otter Tail Power
215 S. Cascade St.
Fergus Falls, MN 56537

David H. Sederquist
Sr. Consultant, Regulation & Finance
Xcel Energy
2302 Great Northern Drive
Fargo, ND 58102

Bernadeen Brutlag
Manager, Regulatory Services
Otter Tail Power
215 S. Cascade St.
Fergus Falls, MN 56537

SaGonna Thompson
Records Specialist
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401

Mark Bring
Associate General Counsel
Otter Tail Corporation
215 S. Cascade St.
Fergus Falls, MN 56537

Priti Patel
Assistant General Counsel
Xcel Energy Services Inc.
414 Nicollet Mall, 5th Floor
Minneapolis, MN 55401

Michael C. Krikava
Attorney
Briggs and Morgan
2200 IDS Center
Minneapolis, MN 55402

Lawrence Bender
Attorney
Fredrickson & Byron, PA
200 North Third Street, Suite 150
Bismarck, ND 58501-3879

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

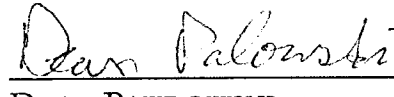
Northern States Power Company,
a Minnesota Corporation

Otter Tail Power Company,
a Minnesota Corporation

Respectfully submitted,



JAMES R. ALDERS
DIRECTOR, REGULATORY ADMINISTRATION



DEAN PAWLOWSKI
PROJECT MANAGER

(38)

2389650v10