BRIGGS
BRIGGS AND MORGAN

2200 IDS Center
80 South 8th Street
Minneapolis MN 55402-2157
tel 612.977.8400
fax 612.977.8650

October 8, 2010

**Zeviel Simpser**
(612) 977-8865
zsimpser@briggs.com

**VIA FEDEX**

Darrell Nitschke
Executive Secretary
North Dakota Public Service Commission
Department 408
600 East Boulevard Avenue
Bismarck, ND 58505-0480

**Re: In the Matter of the Application of Northern States Power Company, a Minnesota corporation, for a Certificate of Public Convenience and Necessity for a 345 kV Transmission Line in the Fargo/West Fargo Metropolitan Area Case No. PU-10-_____**

Dear Mr. Nitschke:

Enclosed please find Applicant Northern States Power Company's, a Minnesota corporation ("Xcel Energy"), Application for a Certificate of Public Convenience and Necessity for a 345 kV Transmission Line in the Fargo/West Fargo Metropolitan Area ("Fargo Project") for filing. You will find an original, three unbound and seven 3-ring bound copies of the application. In addition, you will find a CD containing the complete filing in a searchable PDF format.

Applicant expects that Otter Tail will also file its Application for a Certificate of Public Convenience and Necessity for the Fargo Project today. Xcel Energy and Otter Tail have coordinated their Applications and they are substantively identical but for the description of the Applicant. To that end, Xcel Energy respectfully requests that the Commission consolidate these matters for review.

1 PU-10-607 Filed 10/11/2010 Pages: 143
Application
Northern States Power Company
Zeviel Simpser, Briggs&Morgan, P.A.

Please feel free to contact me if you have any questions.

Sincerely,

BRIGGS AND MORGAN, P.A.

Zeviel Simpser
ND Bar ID# 06794
Counsel for Northern States Power Company,
a Minnesota corporation

ZS/rlh
Enclosures
cc: M. Loftus
J. Alders

**STATE OF NORTH DAKOTA**

**PUBLIC SERVICE COMMISSION**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A 345 KV TRANSMISSION LINE IN THE FARGO/WEST FARGO METROPOLITAN AREA | **CASE NO. PU-10-____** |

## APPLICATION FOR CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

## I. INTRODUCTION

Pursuant to North Dakota Century Code Chapter 49-03, Northern States Power Company, a Minnesota corporation ("Xcel Energy" or the "Company") respectfully submits this application to the Public Service Commission of the State of North Dakota ("Commission") for a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate a 345 kilovolt ("kV") transmission line and associated facilities from the North Dakota/Minnesota border to a substation in the Fargo Area (this "Application").[1] The segment proposed in this Application is part of a regional transmission line project from Fargo to the North Dakota/Minnesota border, through Alexandria, St. Cloud and terminating at Monticello, Minnesota (the "Fargo Project" or "Project").

The Fargo Project will provide for community service reliability in the Fargo and greater Red River Valley area, as well as enable additional energy exports from North Dakota to load centers to the south and east. The Fargo Project also provides additional transmission capacity for expected growth in system-wide demand for electricity.

---

[1] On November 13, 2007, Xcel Energy, notified the Commission of its intent and the intent of the other utilities participating in the CapX2020 Initiative to construct the North Dakota portion of the Fargo Project.

The Company respectfully requests the Commission find the standards for granting a certificate of public convenience and necessity are satisfied.

The remainder of this Application will provide additional support for Xcel Energy's request for a CPCN. This Application will address:

- Standard of Review
- Description of the Company
- The CapX2020 Initiative
- Description of the Project
- Project Need

## II. STANDARD OF REVIEW

The statutory provisions governing the requirement for a public utility to file for and obtain a CPCN are as follows:

> **N.D.C.C. § 49-03-01. Certificate of public convenience and necessity - Secured by electric public utility.** No electric public utility henceforth shall begin construction or operation of a public utility plant or system, or of an extension of a plant or system, except as provided below, without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction and operation. This section does not require an electric public utility to secure a certificate for an extension within any municipality within which it has lawfully commenced operations. If any electric public utility in constructing or extending its line, plant, or system, unreasonably interferes with or is about to interfere unreasonably with the service or system of any electric public utility, or any electric cooperative corporation, the commission, on complaint of the electric public utility or the electric cooperative corporation claiming to be injuriously affected, after notice and hearing as provided in this title, may order enforcement of this section with respect to the offending electric public utility and prescribe just and reasonable terms and conditions.

**49-03-01.1. Limitation on electric transmission and distribution lines, extensions, and service by electric public utilities.** No electric public utility henceforth shall begin in the construction or operation of a public utility plant or system or extension thereof without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction and operation, nor shall such public utility henceforth extend its electric transmission or distribution lines beyond or outside of the corporate limits of any municipality, nor shall it serve any customer where the place to be served is not located within the corporate limits of a municipality, unless and until, after application, such electric public utility has obtained an order from the commission authorizing such extension and service and a certificate that public convenience and necessity require that permission be given to extend such lines and to serve such customer.

**49-03-02. Prerequisites to issuance of certificate of public convenience and necessity.** Before any certificate may issue under this chapter, a certified copy of the articles of incorporation or charter of the utility, if the applicant is a corporation, or a certified copy of the articles of organization of the utility, if the applicant is a limited liability company, shall be filed with the commission. At the hearing of said application upon notice as provided in this title, the utility shall submit evidence showing that such applicant has received the consent, franchise, permit, ordinance, or other authority of the proper municipality or other public authority, if required, or has or is about to make application therefor. The commission shall have the power, after notice and hearing to:

1. Issue the certificate prayed for;

2. Refuse to issue such certificate;

> 3. Issue it for the construction or operation of a portions only on the contemplated facility, line, plant, system, or extension thereof; or
>
> 4. Issue it for the partial exercise of the right or privilege sought, conditioned upon the applicant's having secured or upon the applicant's securing the consent, franchise, permit, ordinance, or other authority of the proper municipality or other public authority, and may attach to the exercise of the of the rights granted by any certificate such terms and conditions as in its judgment the public convenience and necessity may require.
>
> Notwithstanding any of the foregoing provisions, the commission may grant a certificate if no interested party, including any local electric cooperative, has requested a hearing on said applicant after receiving at least twenty days' notice of opportunity to request such hearing.

Under these statutes, the overall standard applied by the Commission is whether the proposed system addition is needed under all the circumstances and whether the applicant is qualified to implement the proposed system addition. As demonstrated in this Application, all needs are well documented, the Fargo Project is the most prudent method to address these needs and Xcel Energy is capable of constructing the Fargo Project. The Fargo Project will serve a number of needs for North Dakota:

- The Fargo Project will: (i) meet community service reliability needs in the greater Red River Valley area; (ii) increase system capacity to facilitate the transmission of North Dakota's rich energy resources; and (iii) provide additional transmission infrastructure to meet growing regional demand for electricity. As demonstrated in this Application, all three needs are well documented and the Fargo Project is the most prudent method to address these needs.

- The Fargo Project also provides a flexible platform for future system growth.

- Xcel Energy is an experienced electric utility who owns and has constructed many miles of transmission facilities of various size. Xcel Energy has successfully constructed transmission facilities in North Dakota. Xcel Energy's experience evidences its ability to construct the Fargo Project.

The Commission has indicated that it considers ten factors in determining whether to grant a CPCN for a new electric facility.[2]

These factors further support the Commission's standard of review as to whether the proposed facility is needed and whether an applicant is the appropriate utility to implement it. Xcel Energy provides the following responses to each of these factors:

- *From whom does the customer prefer electric service?*

  No specific customer requested the construction of the Fargo Project, and the Fargo Project does not provide direct retail service. Rather, the Fargo Project provides bulk transmission service that can be used by many utilities and, ultimately, their retail customers.

- *What electric suppliers are operating in the general area?*

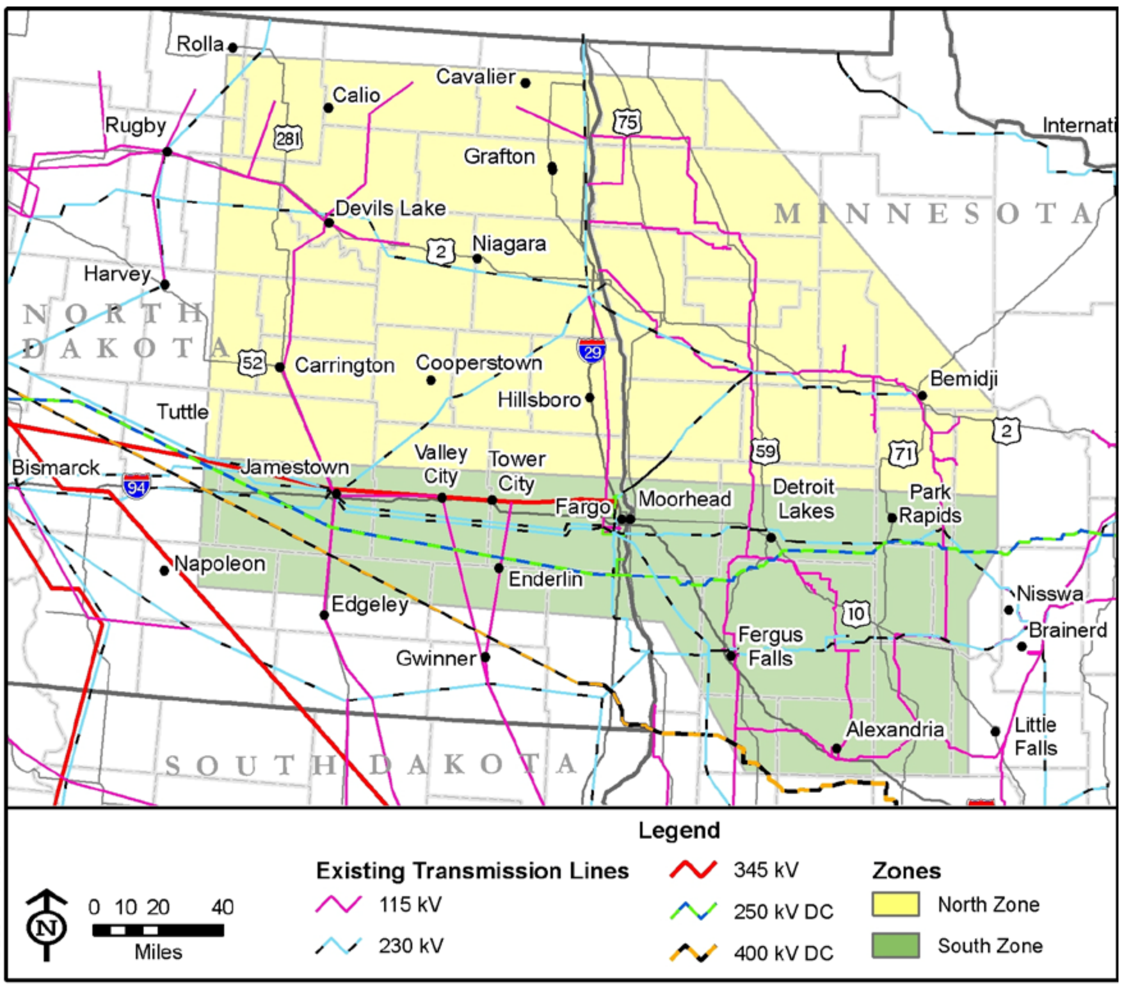
  Xcel Energy serves Fargo and Grand Forks, the major population centers of the Red River Valley area. The Fargo Project will not provide direct retail service in competition with any other retail electric suppliers in the area, but rather ensures reliable service to all.

[2] See testimony of Jerry Lein of the Commission staff, presented to the Interim Electric Industry Competition Committee, April 24, 2000.

- *What electric supply lines exist within a two-mile radius of the locations to be served and when were they constructed?*

  Figure 1 depicts the high voltage transmission lines near the proposed location of the North Dakota segment of the Fargo Project. The transmission system in this area was developed over many decades.

**Figure 1 HVTLs in North Dakota**




- *What customers are served by electric suppliers within at least a two-mile radius of the location to be served?*

  The North Dakota segment of the Fargo Project will not provide direct retail service. The Fargo Project will improve the reliability of electric service in the greater Red River Valley area. Customers in the vicinity of this line are served by Xcel Energy, Otter Tail Power Company, and Cass County Electric Cooperative.

- *What are the differences, if any, between the electric suppliers available to serve the area with respect to reliability of service?*

  Additional high voltage transmission is needed to enhance reliability in the region. The Fargo Project, which was developed collaboratively as part of the CapX2020 Initiative, will assist all electricity suppliers in the greater Red River Valley area to provide more reliable service.

- *Which of the available electric suppliers will be able to serve the location in question more economically and still earn an adequate return on its investment?*

  The Fargo Project will not provide direct retail electric service. Regional utilities have joined together to plan and propose essential transmission system improvements including the Fargo Project.

- *Which supplier's extended electric service would best serve orderly and economic development of electric service in the general area?*

  The Fargo Project will not extend retail electric service. The Fargo Project is part of the orderly and economic development of regional transmission facilities needed to preserve electric service reliability in North Dakota and the neighboring states.

- *Would approval of the application result in wasteful duplication of investment or services?*

  No. A consortium of utilities conceived and planned the Fargo Project in a collaborative effort to identify and meet regional transmission needs in a coordinated, efficient fashion to reduce wasteful duplication of investment and services.

- *Is it probable that the location in question will be included within the corporate limits of a municipality within the foreseeable future?*

  The North Dakota segment of the Fargo Project will be located in the greater Fargo metropolitan area and parts of it could conceivably be located within incorporated Fargo or West Fargo depending on the final route approved.

- *Will the service by either of the electric suppliers in the area unreasonably interfere with the service or system of the other?*

  No. The Fargo Project will not provide retail service, and will not interfere with any other transmission lines in the area.

In summary, the Fargo Project satisfies the relevant criteria. Xcel Energy will also apply for the necessary Certificate of Corridor Compatibility and Route Permit, which are required to route and construct the Fargo Project pursuant to N.D.C.C. Ch. 49-22.

## III. DESCRIPTION OF APPLICANT

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 Company is an experienced electric generation, transmission and distribution utility with the expertise and resources to construct the Fargo Project. The full name and address of Xcel Energy is:

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

Xcel Energy presently serves approximately 86,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. Xcel Energy owns approximately 3,700 miles of transmission lines of voltage 115 kV and above, of which 250 miles of transmission lines and 12 substations are located in North Dakota. Xcel Energy's corporate documents were filed with the Commission in Case No. PU-09-664 and are incorporated herein by reference.

## IV. THE CAPX2020 INITIATIVE

The CapX2020 Initiative ("CapX2020") was formed to establish a framework for the development of transmission infrastructure to meet the increasing demand for electricity in the upper Midwest. 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 Wisconsin Public Power, Inc., Northern State Power Company, a Wisconsin corporation, and Xcel Energy (collectively the "CapX2020 Utilities"). CapX2020 has established a coordinated regional approach to addressing both regional and community reliability needs, and longer term growth.

The CapX2020 Initiative was designed to plan for and construct additions to the regional network of transmission lines to meet regional needs. The Project is critical because in the near future, the transmission network serving a number of communities in North Dakota and the surrounding states will be inadequate. At the same time, significant new generation must be added to the system to meet the growing demand for electricity throughout the region as well as a variety of state policies. The study efforts undertaken by the CapX2020 study group are described in more detail at www.capx2020.com.

Transmission planning engineers estimated that the electrical system serving the region is expected to grow by 4,500 to 6,300 MW by 2020. Planning engineers analyzed system improvements to address emerging regional needs, recognizing that the performance of the transmission system depends not only on the demand for power by consumers, but also on the location of the generation to meet consumer demand.

Based on the studies conducted by the CapX2020 Utilities, four transmission projects were identified as common to any reasonable future scenario, including the Fargo Project.[3]

---

[3] The three 345 kV projects and one 230 kV project add increments of transmission capacity to the network to support the continuing development of new generation. They are (i) Fargo - Twin Cities 345 kV (the "Fargo Project"); (ii) Twin Cities – La Crosse, Wisc. 345 kV (the "La Crosse Project"); (iii) Twin Cities – Brookings County, S.D. 345 kV (the "Brookings Project"); and (iv) Bemidji – Grand Rapids 230 kV (the "Bemidji Project") (collectively the "Group 1 Projects"). Additional discussion of each of these four projects and the status of the regulatory proceedings can be found at www.capx2020.com.

## V. DESCRIPTION OF THE PROJECT

### A. Project Development

Currently, Xcel Energy, Otter Tail Power Company ("Otter Tail"), Great River Energy ("Great River"), Missouri River Energy Services ("MRES"), and Minnesota Power (the "Participating Utilities") expect to have ownership interests in the Fargo Project. In February of 2007, the Participating Utilities entered into a Project Development Agreement for the Fargo Project.

Through the Project Development Agreement, Xcel Energy and the other Participating Utilities have agreed to determine the interconnection/termination points of the Fargo Project; determine the recommended alignment of the proposed configuration; determine the scope of the Fargo Project; estimate the cost and schedule; obtain the required state and federal regulatory approvals and consents; and engage in other necessary project studies or analyses. Each participant has agreed to absorb a specified percentage of development costs associated with the Fargo Project.

In the Project Development Agreement, the Participating Utilities have agreed to certain maximum project investment percentages for the portion of the Fargo Project each participant may eventually own. Great River has agreed to a 25% share of the Fargo Project, Minnesota Power has agreed to a 14.7% share, MRES has elected an 11% share, Otter Tail has elected a 13.2% share and Xcel Energy has elected a 36.1% share. Each utility has the right (but not the obligation) to take ownership up to the identified percentage, choose to invest in a lower percentage, or choose not to invest in the Fargo Project at all. If a utility ultimately declines to take ownership to its designated level, the excess is offered to the other participants.

The Participating Utilities have decided to elect ownership in the Fargo Project in two stages.

On August 18, 2010, Xcel Energy and the other project owners executed the Project Participation Agreement ("Ownership Agreement") and other project agreements for the segment of the Fargo Project from Monticello, Minnesota to St. Cloud, Minnesota ("Fargo Phase 1"). The utilities who are committing themselves to funding and eventual ownership of the completed

Project are: Xcel Energy, Great River Energy, Western Minnesota Municipal Power Agency ("WMMPA")[4], ALLETE, Inc., d/b/a Minnesota Power, and Otter Tail (collectively "Project Owners"). Collectively, the agreements create a binding obligation that each owner will fund construction, operation and maintenance of the Fargo Phase 1 Project up to their allocated share.

The Ownership Agreement governs most of the rights and obligations of the Project Owners, as funders of the construction of the project facilities and as owners of the completed and energized facilities. Except for the Monticello Substation and Quarry Substation assets, the Project Owners of Fargo Phase 1 will own all property interests in the Facilities (defined as the transmission lines and associated real property) as tenants-in-common in undivided ownership interests. The assets of Quarry Substation and Monticello Substation will be owned individually by Xcel Energy.

The Project Owners have elected the following ownership percentages in Fargo Phase 1:

| | |
|---|---|
| Xcel Energy | 36.1% |
| Great River Energy | 25.0% |
| Minnesota Power | 14.7% |
| Otter Tail Power | 13.2% |
| WMMPA | 11.0% |

The Project Owners have begun construction activities on this Project and are expected to meet a 4th quarter of 2011 in-service date.

The second ownership election will be for the segment of the Fargo Project from St. Cloud, Minnesota to the Fargo area in North Dakota ("Fargo Phase 2"). The decision whether or not to invest in the construction of this segment of the Fargo Project will be made after all major permits necessary to begin construction of Fargo Phase 2, including this CPCN, have been obtained.

[4] Missouri River Energy Services ("MRES") has been a participating CapX2020 utility from the commencement of these proceedings. Under the Project Development Agreement, MRES held rights to as much as 11% of the Fargo Project. MRES chose to assign its rights to its affiliate, WMMPA. While WMMPA will be the owner of a share of Phase 1, it will continue to be affiliated with MRES and the overall utility operations are unchanged.

Terms for the construction, management, ownership, operations and maintenance of Fargo Phase 2 are likely to be similar to those for Fargo Phase 1.

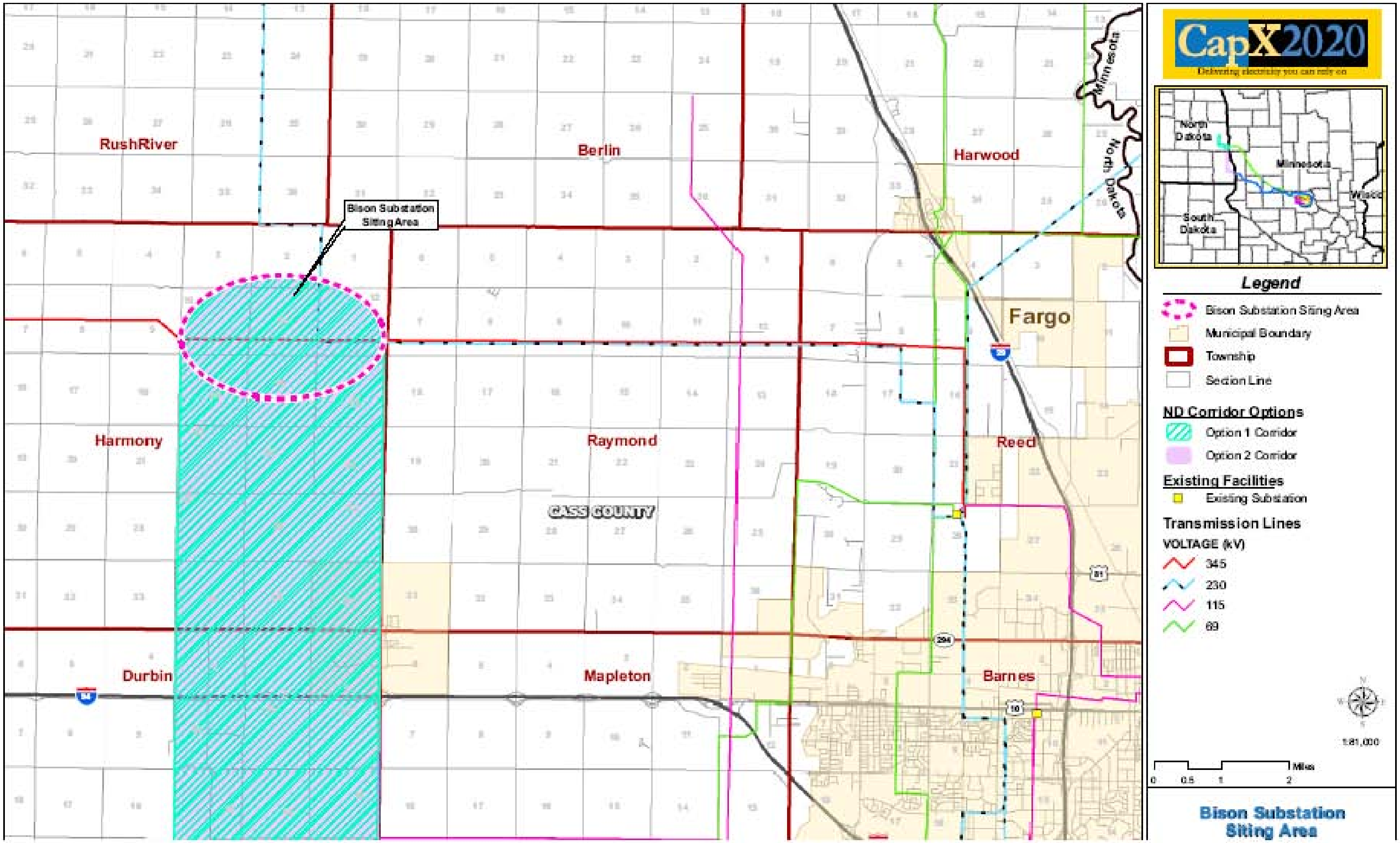
## B. The Fargo Project

The overall length of the Fargo Project will be approximately 210 to 270 miles with anywhere from seven to sixty miles in North Dakota depending on the route selected. The Participating Utilities intend to construct the Fargo Project in segments from South to North. Xcel Energy will comply with all requirements of N.D.C.C. Ch. 49-22 for the routing of the North Dakota segment of the Fargo Project and siting of the new Bison Substation in the Fargo/West Fargo area.

The first segment of the Fargo Project will include a 345 kV circuit between Monticello Substation on the Monticello Power Plant site in Monticello, Minnesota to a new substation (Quarry Substation) on the western side of St. Cloud, Minnesota routed through an expanded substation in the Alexandria, Minnesota area (Alexandria Substation). This segment will be approximately 90-120 miles long depending on how it is routed.

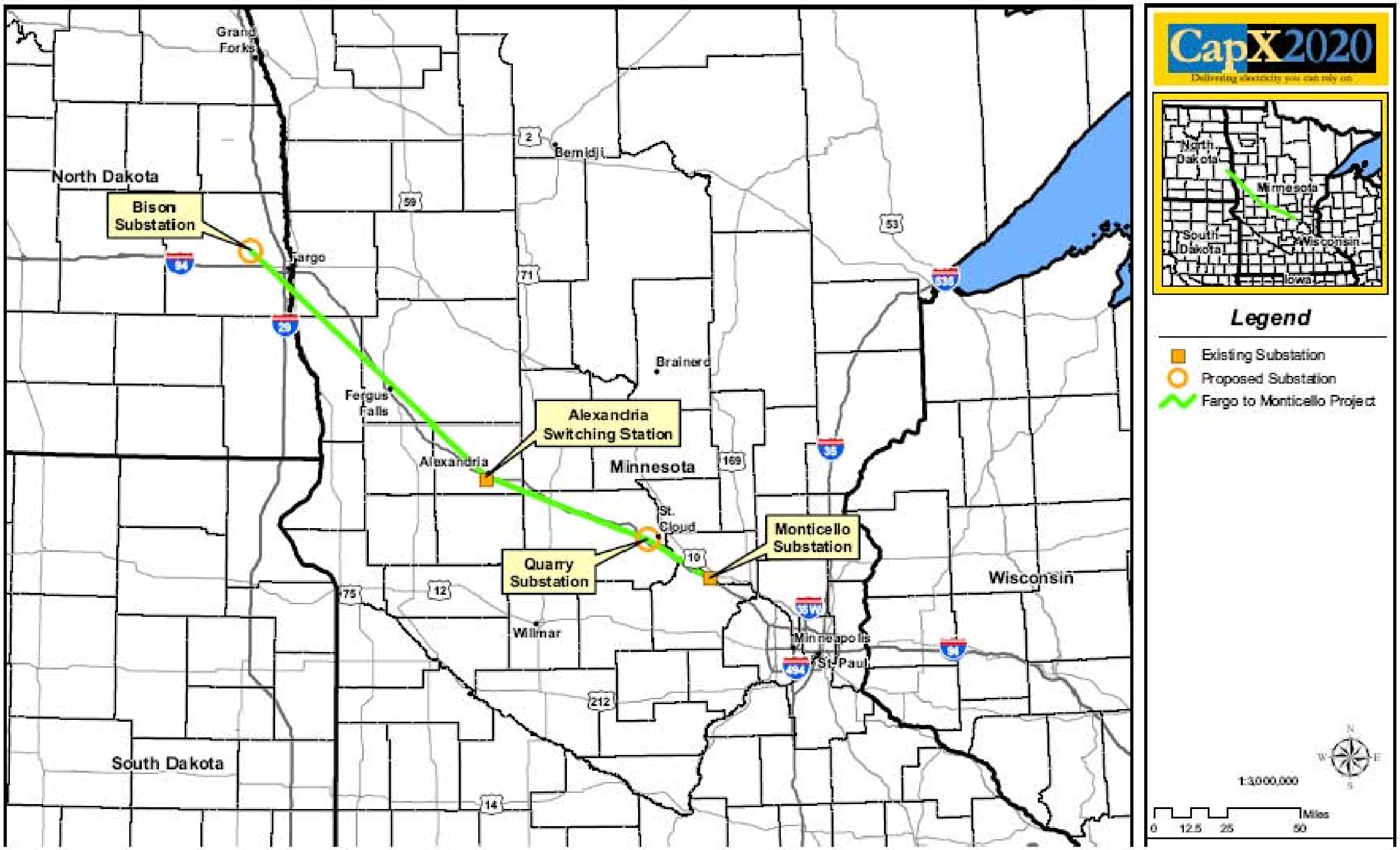
The second segment will be a 345 kV circuit between the Quarry Substation and a new substation in the Fargo area (Bison Substation). The Company respectfully request that any CPCN issued from this Application include authority to construct the Bison Substation in the Fargo area. This segment will be approximately 120-150 miles long depending on how it is ultimately routed. Figure 2 depicts the general location for the proposed new Bison Substation.

Figure 2 Bison Substation Location



The Participating Utilities plan to construct all segments of the Fargo Project in a "double-circuit compatible" configuration. The double-circuit compatible configuration will consist of a single 345 kV circuit on steel single pole structures capable of accepting a second 345 kV circuit in the future. This "upsizing" or "double circuit compatible" approach will maximize the use of rights-of-way and will offer a cost-effective way to increase future capacity. The double-circuit compatible configuration will also allow for future capacity additions to the bulk power network on existing structures within existing rights-of-way instead of on new structures in new corridors. This helps to mitigate proliferation of transmission 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 Participating 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, subject to Commission approval. The Fargo Project is depicted in Figure 3.

**Figure 3 Fargo – Twin Cities Project Map**



### C. Project Timing and Costs

The Fargo Project is scheduled to be constructed sequentially from the south to north. It is anticipated that the Monticello to St. Cloud segment will be in service in 2011; the St. Cloud to Alexandria segment in 2013 and the Alexandria to Fargo segment in 2015. These dates are approximate and subject to change depending on permitting and other contingencies. The cost of the entire line is estimated at approximately $500 to $750 million.

## VI. PROJECT NEED

The CapX2020 Utilities have identified three needs that will be met by the Fargo Project. First, the Fargo Project will enhance community service reliability in the Fargo and greater Red River Valley area which includes substantial parts of eastern North Dakota. Second, the Fargo Project will increase transmission capacity to facilitate generation additions in North Dakota. Third, the Fargo Project will provide necessary transmission facilities for the projected increase in the demand for electricity in the region.

In developing this proposed transmission addition, Xcel Energy and the other CapX2020 Utilities relied on the Vision Study as well as the conclusions of a regional study, the Red River Valley Area/Northwest Minnesota Load-Serving Transmission Study 2006 ("TIPS Update"), that was conducted by the CapX2020 Initiative. The Vision Study assessed the system from a high level and helped develop proposals for larger regional needs. The TIPS Update analyzed specific load serving issues. It analyzed several alternatives to the Fargo Project and determined that the Fargo Project is the best configuration to meet all identified needs. The Alternatives Analysis and the TIPS Update are attached as Appendix A. The TIPS Update provides the primary engineering support for the Fargo Project.[5] Together with the Vision Study, the TIPS update supports the overall Fargo Project as a necessary and important addition to the regional transmission system.

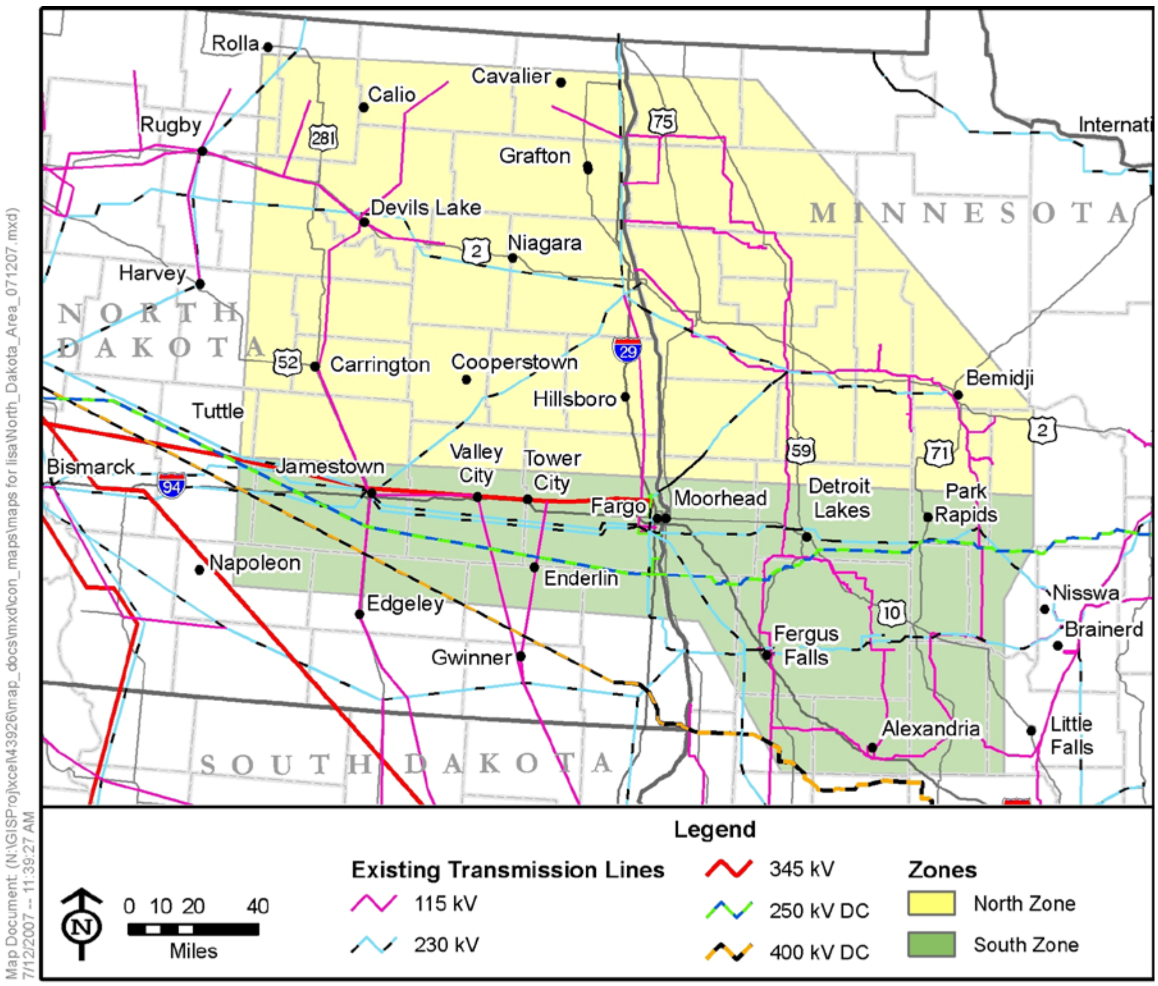
---

[5] The TIPS Update is one of several studies performed by the CapX2020 Utilities as a refinement of the CapX2020 Vision Study ("Vision Study"). The Vision Study is attached as Appendix B. Based on the Vision Plan, the CapX2020 Utilities concluded that a series of new transmission lines are needed to maintain the reliability of the electrical system as the demand for electricity grows.

## A. Community Reliability Needs

In the TIPS Update, planning engineers examined the performance of the electrical system serving the Red River Valley area. Geographically, that system serves not only the immediate Red River Valley area, but encompasses parts of North Dakota extending west to Jamestown and Devil's Lake, and parts of Minnesota as far east as Bemidji, Park Rapids, and Alexandria. Figure 4 shows a general depiction of the electrical service area of the Red River Valley.

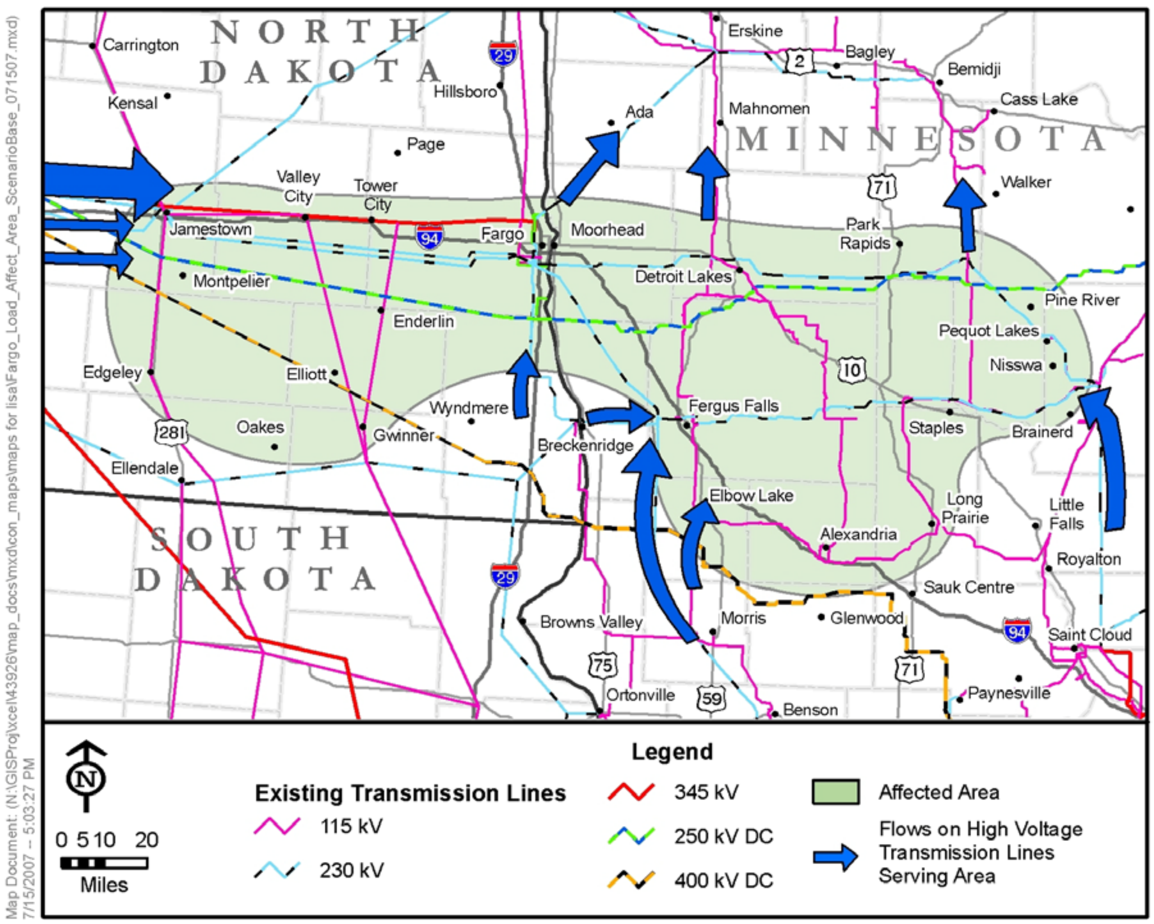
**Figure 4 Red River Valley Area**




The ability to meet community service reliability needs justifies the granting of a CPCN for the Fargo Project. As the population increases, over reliance on the few high voltage transmission lines in the area will not provide consistent, high quality electric service to eastern North Dakota. This is especially true should a contingency, like the loss of a transmission line, occur.

Approximately 15 high voltage transmission lines are located in the southern Red River Valley area. The primary power source in the area is the 345 kV Center – Jamestown – Maple River transmission line, which connects generation-rich central North Dakota with the load centers in the eastern part of the State. The remaining 14 high voltage transmission lines are 115 kV and 230 kV. Figure 5 conceptually depicts the power flows associated with the southern zone of the Red River Valley area. The loss of the Center – Jamestown portion of the Center – Jamestown – Maple River 345 kV line severely limits the capacity of the transmission system in the Red River Valley area as it is the only 345 kV connection between generators in central North Dakota and the communities of eastern North Dakota.

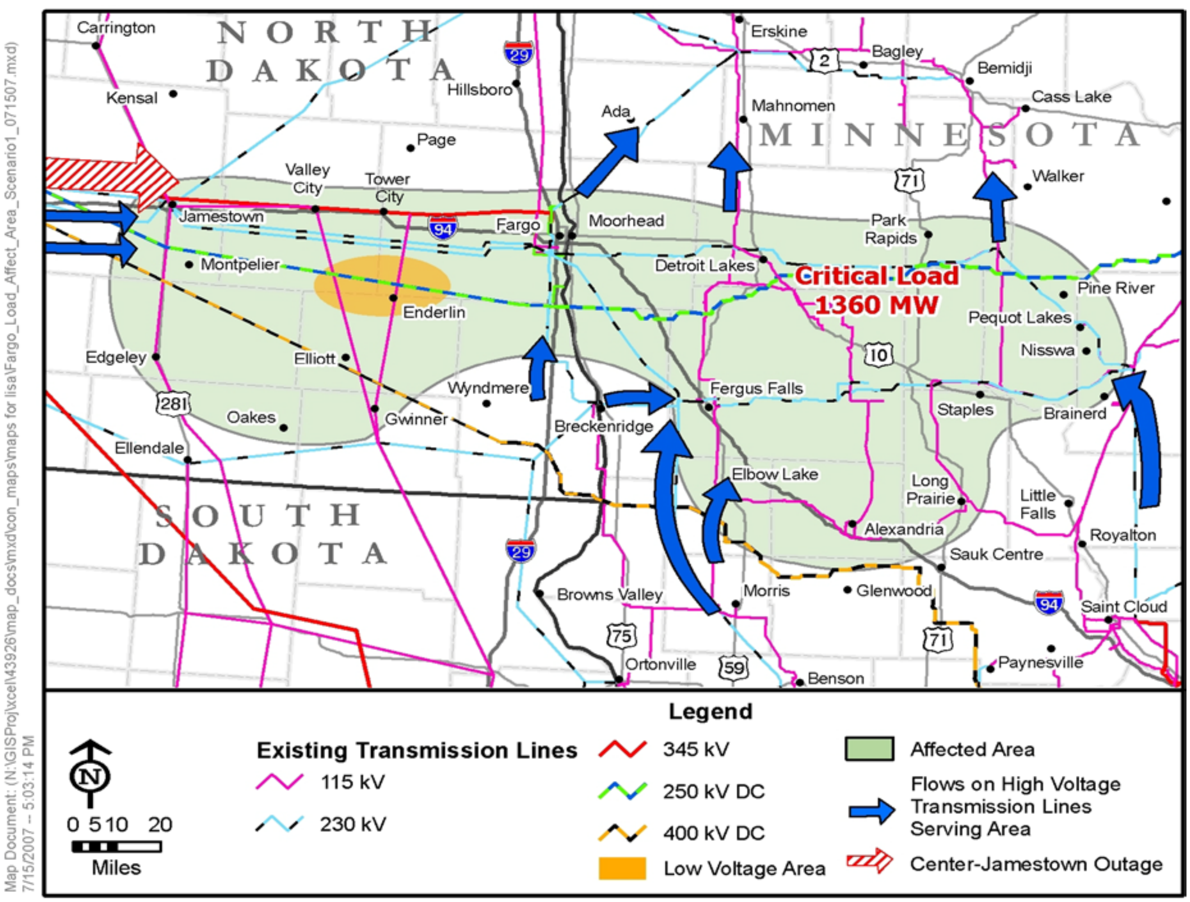
**Figure 5 South Zone of the Red River Valley area and Flows on High Voltage Transmission Lines**




With the Center – Jamestown – Maple River 345 kV line out of service, all load in eastern North Dakota must be served by the existing 230 kV network, which will not be able to reliably support the additional power flow. The TIPS Update found that placing more than 1,360 MW of power on the 230 kV and 115 kV lines causes unacceptably low voltages to occur in the vicinity of Enderlin, North Dakota. In addition, the loss of the 345 kV line causes overloads on the Fargo – Sheyenne 230 kV line. As the system is currently configured, when load surpasses the critical level and contingencies occur, system operators will be forced to mitigate these overloads and voltage issues by running local peaking generation in smaller towns and interrupting service to customers. Service interruptions typically could affect the eastern portion of the state, including Fargo and the surrounding area.

Figure 6 shows the electrical system in the area and the resulting low voltage area when the Center – Jamestown 345 kV connection is lost. The low voltage area depicted is the approximate area that results under contingency when the South Zone of the Red River Valley area reaches about 1,360 MW of peak load. If the capacity of the existing transmission infrastructure is not improved, the resulting low voltage area will continue to increase in size.

**Figure 6 Center – Jamestown 345 kV Contingency**



The need for the Fargo Project is further demonstrated by the fact that the Red River Valley area has experienced unplanned loss of the Center – Jamestown segment multiple times in the past. In 2005, the line was down for 34 hours on November 28-29, 2005, during a three-day snow and ice storm that moved through the Upper Midwest bringing freezing rain mixed with snow and wind gusts up to 50 miles per hour. The three-day storm caused outages on 57 different lines and caused service interruptions to nearly 50,000 customers in North Dakota, Minnesota and South Dakota, including forced interruptions made to reduce loading on overloaded facilities. In 2006, there were 17 outages of the Center – Jamestown segment. In March of 2007, there was an unplanned outage of the Center – Jamestown segment which occurred because of a problem with the Center 345/230 kV transformer.

Reliability in the Red River Valley area will also be impacted by load growth. The southern portion of the Red River Valley area has experienced population growth that has increased the demand for electricity. For example, according to the U.S. Census, the population of the Fargo-Moorhead Metropolitan Area, the largest load center in the Red River Valley area, has grown from 145,000 people in 1985 to 187,000 in 2006, a 28% increase. This trend is expected to continue beyond the next decade. In the foreseeable future, the demand for electric power in the Red River Valley area of North Dakota and Minnesota will reach levels that cannot be reliably supported by existing transmission lines.

The capability of the electrical system serving the southern Red River Valley area, a winter peaking area, was studied in the TIPS Update. Planning engineers began their evaluation with the actual system peak in the southern Red River Valley area in the 2003/2004 winter period, which occurred on January 30, 2004. On that date, the system loadings reached 1,030 MW with 350 MW of demand identified beyond the system peak. At this same time, 50 MW of load was interrupted as part of utility load management programs. In other words, the total demand on the system was approximately 1,080 MW until service was reduced by 50 MW, lowering the total demand to 1,030 MW. Planning engineers then calculated the maximum load that could be supported. The TIPS Update concluded that the transmission system could reliably serve an additional 330 MW of demand beyond the peak observed in 2004 or approximately 1,360 MW total.

The Transmission system must meet the highest possible peak demand for power. If the system has adequate capacity under peak conditions, it can operate reliably during periods of lower demand. To determine peak demand, planning engineers gathered actual individual substation peak loads for 2002 - 2006 and forecasted individual substation peak loads through 2020. To estimate annual system peak loads in the southern Red River Valley area, a 77% adjustment was applied ("Load Adjustment Factor") to the sum of the individual substation peak loads consistent with the relationship between the sum of the peak substation loads and the 2003/2004 system peak. This Load Adjustment Factor was developed by planning engineers who gathered the actual system coincident peak loads in the southern Red River Valley area for 2003/2004 and compared them to the individual substation peak loads. The mathematical relationship between the actual 2003/2004 southern Red River Valley area coincident system peak (with interruptible loads interrupted) and the sum of the individual peak loads was 77%. In other words, the system peak load was 77% of the sum of the individual peak loads.

Appendix C shows the actual annual peak demand for power at each substation in 2005 and provides a forecast of annual peak demand at each southern Red River Valley area substation for 2010, 2015, 2019 and 2020 and forecast southern Red River Valley area coincident peak load (South Zone of the Red River Valley area Winter Peak Load Total with Load Adjustment Factor). The forecast confirmed the TIPS Update's conclusion that the southern Red River Valley area could exceed the electrical system capabilities in the 2016 to 2019 timeframe. Absent further transmission infrastructure improvements, the communities in the area will be at risk of service interruptions when demand will outstrip the capabilities of the existing transmission infrastructure. Applicants' double-circuit compatible configuration allows for further capacity to be added to the transmission system as demand continues to grow beyond the 2020 time horizon.

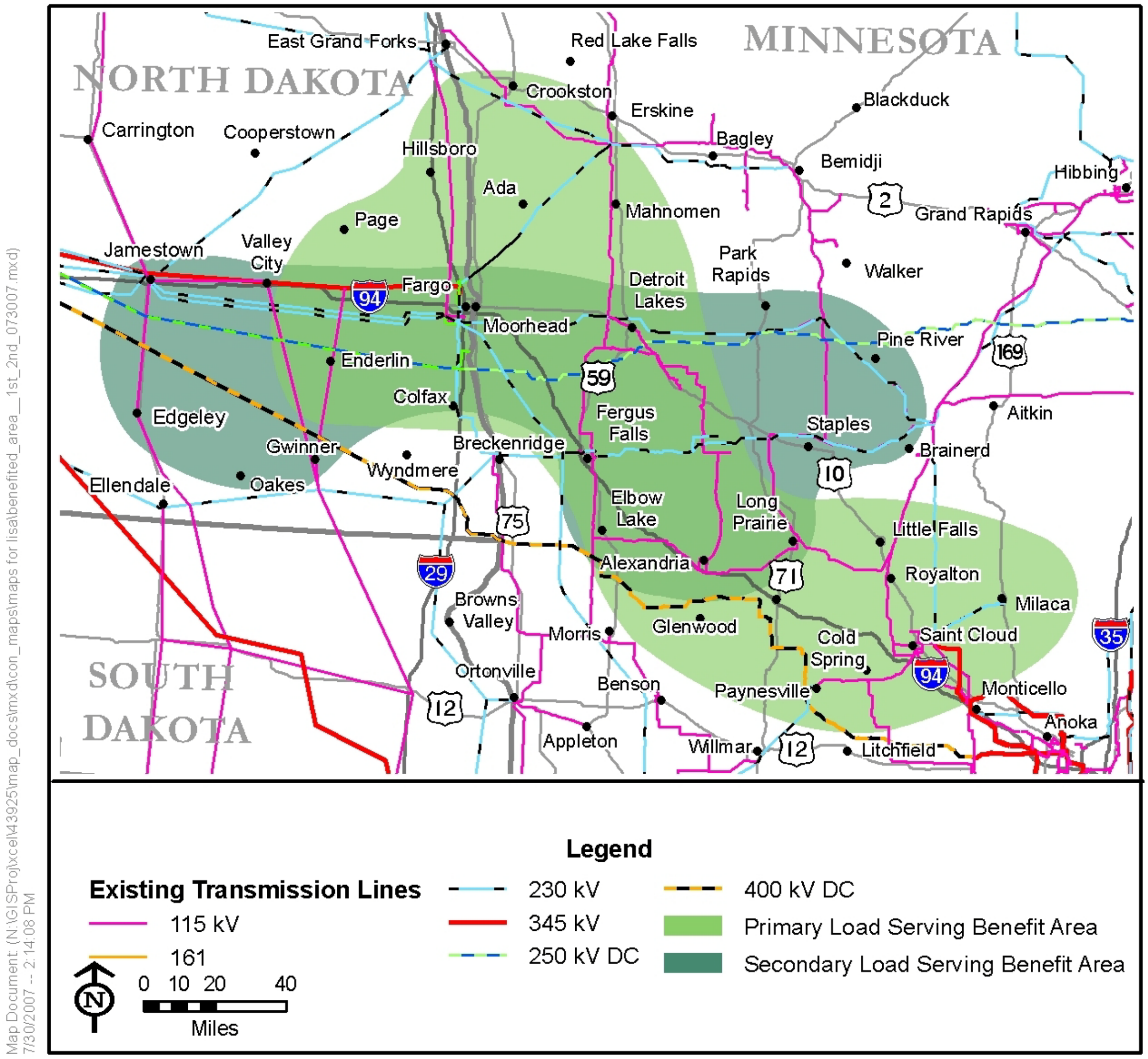
The Fargo Project will allow approximately 350 MW of additional load to be reliably served in the Red River Valley area.

The configuration of the Fargo Project was determined based on the need to provide reliability benefits to the Red River Valley area. An endpoint at a Fargo area substation was chosen because a 345 kV connection to a Fargo area substation provides reliability benefits to the Red River Valley area by providing an additional bulk-power transmission source into the region to protect against projected deficiencies caused by contingencies such as the loss of the Center – Jamestown – Maple River 345 kV transmission line. The loss of Center – Jamestown – Maple River 345 kV transmission line limits transfer capability into the eastern portion of the North Dakota from the generation in the central portion of the state.

The selection of the Minnesota endpoint for the Fargo Project was partly based on the reliability benefits to the Red River Valley area. A 345 kV source from the east will enable generation from the east to flow to the Fargo area. This will relieve the stress placed on the 230 kV network in North Dakota to deliver all of the power necessary to serve the Red River Valley area, particularly under contingency conditions.

The Fargo Project will provide community reliability benefits in the Red River Valley area and surrounding communities. Figure 7 shows the areas that will be benefited.

**Figure 7 Fargo – Twin Cities 345 kV Load Serving Benefit Areas**




## B. Generation Outlet and Support

The TIPS Update indicates that the Fargo Project will provide approximately 350 MW of outlet capacity for new generation, thus facilitating the expansion of North Dakota based generation resources. The Fargo Project will create additional generator outlet capacity in North Dakota, a state that has significant generation development potential. The double-circuit compatible configuration of the Fargo Project will also allow for future expansion of this system capacity.

### 1. *Increasing North Dakota Export ("NDEX") Limit*

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. The ability to export generation out of North Dakota is constrained by limits on the existing system.

Currently, transmission outlet capacity from North Dakota is limited in part by the NDEX limit – a continuous electrical boundary around northwestern Minnesota, southeastern North Dakota, a part of South Dakota and Montana that has a maximum generation outlet capability. The NDEX limit establishes the maximum amount of power that can be exported from North Dakota without adversely affecting system reliability. The electrical boundary between North Dakota, Minnesota and South Dakota has been identified by the Department of Energy as a congested area.[6] Additional generation cannot be developed without additions to the NDEX limit.

The Fargo Project is expected to increase transfer capability across the NDEX by approximately 350 MW or more depending on the size and location of generation. When the Fargo Project is combined with the development of the other CapX2020 Group 1 Projects, the transmission development by the CapX2020 Initiative should result in an overall incremental increase to NDEX of 700-800 MW.[7] This increase in the NDEX limit 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 transmission system further east by several hundred megawatts.

The Fargo Project is an integral component of the Group 1 Projects, which are designed to work together to link the western portions of the upper Midwest to regional energy markets in the east. The Fargo and Bemidji Projects work together with other system additions that make up the Group 1 Projects to increase outlet capability from North Dakota. The Fargo Project's ability to increase the NDEX limit will allow access to and support for generation located in North Dakota, which is needed to help meet growing demand region wide.

---

[6] National Electric Transmission Congestion Study, Executive Summary, p.3, U.S. Department of Energy (Aug. 2006).

[7] The Bemidji Project is expected to increase NDEX by 100 MW. The combination of building both the Fargo Project and the Bemidji Projects result in an approximately 550 MW of NDEX increase. The Brookings Project will result in further increases to NDEX.

Further, the Fargo Project (in conjunction with the other Group 1 Projects) is a necessary prerequisite for subsequent transmission projects that will further increase the capacity of the system to receive even larger amounts of generation from North Dakota. The Fargo Project also provides for future additional increases to the NDEX limit due to its double-circuit compatible configuration.

### *2. North Dakota Generation*

The additional generation outlet provided by the Fargo Project will help facilitate development of North Dakota generation. North Dakota has substantial capacity to increase its generation portfolio if it has sufficient transmission capacity to export the generation to regional load centers. Among its many types of available generation, the U.S. Department of Energy describes North Dakota's wind resources as good to excellent and consistent with utility scale production. North Dakota has an unparalleled opportunity to develop its wind energy potential if additional transmission is built.

Developing North Dakota's wind resource will be a significant vehicle for economic development in the State. A report prepared for the North Dakota Division of Community Services concluded that North Dakota is motivated to become a leader in wind-generated electricity. This motivation includes an opportunity to contribute to the general economic development in the state with short- and long-term jobs, investments, landowner income, operation, maintenance and manufacture.[8] In fact, in April 2005, North Dakota passed legislation designed to accelerate production of wind energy and other renewable resources, as well as to enhance transmission infrastructure necessary to get the energy to market. The Fargo Project can be considered a good first step in expanding the transmission infrastructure necessary for the development of generation in the state.

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.

---

[8] PanAero Corporation, *Wind Energy in North Dakota*, Executive Summary (1999).

The Fargo Project is a significant step in the development of further transmission capacity in North Dakota and for the development of wind based generation. Moreover, the double-circuit compatible configuration provides a base for the next step for additional outlet capacity by allowing additional expansion of the Fargo Project in the future.

## VII. COMMUNICATIONS AND SERVICE

Xcel Energy requests that the following persons be placed on the Commission's official service list for all official communications in this case:


James Alders
Manager of Regulatory Projects
Xcel Energy
414 Nicollet Mall, 7th Floor
Minneapolis, MN 55401
Phone: (612) 330-6732
Fax: (612) 330-7601
Email: james.r.alders@xcelenergy.com

Matthew Loftus
Assistant General Counsel
Xcel Energy
5th Floor
414 Nicollet Mall
Minneapolis, MN 55401
Phone: (612) 215-4501
E-mail:
matthew.p.loftus@xcelenergy.com

Zeviel Simpser
Briggs and Morgan, P.A.
2200 IDS Center
80 South Eighth Street
Minneapolis, MN 55402
Phone: (612) 977-8656
E-mail: zsimpser@briggs.com


## VIII. CONCLUSION

The public convenience and necessity call for the construction of the Fargo Project. The Fargo Project will provide: (1) community reliability benefits for eastern North Dakota; (2) a significant step in providing additional generation outlet to support North Dakota's development of its wind and other generation resources; and (3) support to the expected increase in the demand for electric energy forecasted for the eastern portion of North Dakota.

The Company respectfully requests that the Commission grant a Certificate of Public Convenience and Necessity for the Fargo Project. The Company further requests, pursuant to N.D.C.C. § 49-03-02, that the Commission grant the requested CPCN not more than 20 days after a notice of opportunity for hearing issued in this proceeding, if no party requests a hearing.

**[SIGNATURE PAGE FOLLOWS]**

Respectfully Submitted,

James R. Alders
Director of Regulatory Administration
Xcel Energy Services Inc. on behalf of
Northern States Power Company

# APPENDIX A

CapX 2020
A Vision for Transmission Infrastructure Investments for Minnesota

# Red River Valley/Northwest Minnesota Load-Serving Transmission Study (TIPS Update)

(Evaluation for the CapX 2020 Vision Study)

Prepared by:

Excel Engineering, Inc.

February 13, 2006

Appendix A-3
Application for Three 345 kV Projects
E-002/CN-06-1115

CapX 2020
A Vision for Transmission Infrastructure Investments for Minnesota

# Red River Valley/Northwest Minnesota Load-Serving Transmission Study (TIPS Update)

## (Evaluation for the CapX 2020 Vision Study)

(Generation Alternative Evaluation
to be Provided in Separate Study Report)

Sponsored by:

Great River Energy
Otter Tail Power
Minnesota Power
Missouri River Energy Services
Xcel Energy

Prepared by:


Excel Engineering, Inc.

Richard Gonzalez, PE
Michael Cronier, EIT
Mary Melvin, PE
Pam Bagley, PE
Jeffrey Norman, EIT
Mythili Chaganti


Appendix A-3
Application for Three 345 kV Projects
E-002/CN-06-1115

## Table of Contents

## Appendices
(supplied on CD)

## Certification

I hereby certify that this plan, specification, or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the Laws of the State of Minnesota

Richard Gonzalez
Registration Number 18938
February 13, 2006

## 1.0 Executive Summary

The northern portion of the Red River Valley electric transmission system (Diagram 4.0.A), specifically the Bemidji/Cass Lake vicinity, needs transmission improvements in the near term. During winter peak load conditions, the area will be deficient within the next few years with respect to first contingency (N-1) and is currently deficient for second contingency (N-2) load-serving capability. The deficiency is based on the identified inability to maintain post-contingent voltages above applicable criteria, primarily in the Bemidji/Cass Lake vicinity, during N-1 conditions. This study concluded that the addition of a Bemidji-Boswell 230 kV line is the transmission alternative that provides the best long-term solution for these deficiencies. A separate study is being conducted to evaluate the ability of additional local generation to eliminate these deficiencies. In the interim, the addition of reactive capability in the Bemidji area--such as a Static VAR Compensator (SVC) or possibly fast-switched shunt capacitors--will support voltages until a long-term solution (a transmission line or generator addition) can be constructed and placed in service. These reactive supply additions will continue to provide useful dynamic voltage regulation following the 230 kV line addition.

The Grand Forks portion of the Red River Valley has adequate amounts of reactive power supply capability, but during second contingency (N-2) conditions, the existing capacitor banks at the Prairie substation are too large to ensure successful transition to a sustainable post-contingency condition. The addition of a moderate-sized SVC at the Prairie Substation would enhance the existing capacitors' effectiveness at preventing voltage collapse under such conditions. Like the Bemidji area reactive support, this Prairie SVC would also provide long-term regional load-serving and dynamic stability benefits in addition to the immediate local benefits. Both SVCs are envisioned to be of approximately $\pm 60$ MVAR rating, but more-detailed analysis will be required to properly size and coordinate these reactive installations with the existing transmission system.

The southern portion of the Red River Valley needs shunt capacitor additions in the Audubon/Hubbard Minnesota; Jamestown, North Dakota; and Alexandria, Minnesota vicinities to help support post-contingent voltages during single contingency conditions, until a long-term transmission improvement can be added. The most effective long-term solution is a Fargo-St. Cloud 345 kV line, as it provides a new high-capacity transmission source to the Red River Valley in general, and to the Alexandria load center in particular. The Bemidji-Boswell 230 kV line, if constructed first, would also help augment Southern Region load-serving capability until the 345 kV line can be built into the area. Ultimately, both new lines are recommended for developing and maintaining adequate N-1 and N-2 load-serving capability in the Red River Valley.

The Fargo-St. Cloud 345 kV line provides significant load-serving capability for the Red River Valley, the Alexandria, and the St. Cloud load centers. In addition to providing a much needed bulk supply source for Alexandria, it also would satisfy St. Cloud load-serving requirements if routed along the west side of St. Cloud and terminated at Monticello or Sherburne County Generating Station ("Sherco"). Based on other studies, this St. Cloud load-serving benefit is significant since the St. Cloud 115 kV loop is known to be in need of reinforcement.

In addition to the improved load-serving capabilities provided by the recommended Bemidji-Boswell 230 kV line, the Fargo-St. Cloud 345 kV line, and the Wilton and Prairie SVCs, these transmission facilities also yield an incidental increase in the North Dakota Export ("NDEX") stability limit. However, it should be understood that the need for these transmission lines is based on load-serving requirements and that the increase in NDEX is a secondary benefit of the project.

## 2.0 Background & Scope of Study

The CapX 2020 planning effort has undertaken two technical studies on major transmission facilities needed in Minnesota. The "Vision Study" provided a conceptual framework for coordinated statewide transmission improvements, while the "Red River Valley Study" is intended to provide detailed information on integrating specific components of the Vision Study's overall findings in the context of the specific local load-serving needs and other relevant considerations. The basis of this study is the Red River Valley / West Central Minnesota Transmission Improvement Planning Study (RRV / WMN TIPS, hereafter referred to as the "TIPS" study) that was initiated during the year 2000. The TIPS study revealed load-serving reliability issues in west-central Minnesota and eastern North Dakota in the near future. In addition, the recent MISO Northwest Exploratory and WAPA Dakotas Wind studies touched upon this region in their evaluation of future bulk transmission options and existing generation outlet capability. Diagram 4.0 A shows the Red River Valley electric transmission system that was evaluated for this study.

This present study is an update and extension of the TIPS study. This study was performed as a load-serving study to identify the electric transmission system improvements that would be required to accommodate future load growth in the Red River Valley (RRV) and Northwestern Minnesota; principal load centers include:

- Alexandria, MN
- Bemidji, MN
- East Grand Forks, MN
- Moorhead, MN
- Park Rapids, MN
- Walker, MN
- Devils Lake, ND
- Fargo, ND
- Grand Forks, ND
- Jamestown, ND

This study's analysis goes further than the TIPS study by identifying, in greater detail, transmission improvements to the power system to reliably supply future load growth. A separate study is being conducted to determine whether the addition of local area generation can eliminate the need for the transmission additions identified in this study in a reliable, cost-effective manner. The technical analysis and report compilation was performed by the staff of Excel Engineering, Inc, on behalf of its non-affiliated clients, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power, and Xcel Energy, which are the contracting parties representing the group of area power suppliers.

The steady-state analysis was performed using a MAPP 2004 Series 2009 summer peak model along with a winter peak powerflow model developed for this analysis. The winter peak model has a high negative (south-to-north) Manitoba Hydro Export ("MHEX") of -700 MW, consistent with past planning studies used to establish power system design criteria.

Power system performance was evaluated with respect to meeting steady-state performance criteria of the NERC Reliability Standards' Categories A-C. This corresponds with the generally recognized utility practice of ensuring satisfactory performance (ability to reliably serve all firm load) during system intact and first-contingency ("N-1") conditions, with some localized planned loss of load or generation re-dispatch being acceptable for subsequent disturbances (second contingency -- "N-2") or "breaker failure" type occurrences. NERC Category C Standard allows for some dropping of load, but that was not invoked for this study.

Incremental demand (MW) losses were tabulated, to identify whether significant increases or decreases in electrical losses might arise from any of the transmission additions under evaluation.

The dynamic stability analysis was performed using the 2003 Northern MAPP Operating Review Working Group (NMORWG) Winter / Summer stability package which used both a winter peak model with northward transfers and a summer off-peak model with high southeastern transfers, consistent with northern Mid-Continent Area Power Pool (MAPP) planning and operating criteria

## 3.0 History

The bulk electric transmission system in the Red River Valley / northwestern Minnesota area consists of a 230 kV network, nearly all of whose power supply is from remote generation sources. The nearest generation resources from an electrical perspective consist of baseload generation in the North Dakota coalfields and in Manitoba. Due to this geography, power flows through the Red River Valley region are typically west-to-east and north-to-south. However, heavy south-to-north flows are possible during adverse hydrologic conditions, particularly during the winter season, when Manitoba loads are at their highest. Long-term power purchase and capacity exchange agreements between Manitoba Hydro and U.S. power suppliers require that adequate transmission capability be maintained to enable both northward and southward power transfers at all times of the year.

Load-serving capability in the Red River Valley (RRV) region is presently constrained primarily by post-contingent voltage conditions (rather than line or transformer loadings) for both local and remote transmission contingencies. These include the following:

Contingency within Red River Valley:

Wilton-Winger 230 kV Line Outage

Contingencies of the local lines that connect to the generation located to the north and west:

North: Letellier-Drayton-Prairie 230 kV Line Outage
West. Balta-Ramsey-Prairie 230 kV Line Outage
Jamestown-Pickert-Grand Forks-Prairie 230 kV Line Outage
Jamestown-Fargo 230 kV #1 & 2 Line Outage
Center-Jamestown-Buffalo-Maple River 345 kV Line Outage

Remote contingency:

Dorsey-Roseau Co-Forbes 500 kV Line Outage

The most severe local single contingency is the outage of the Center-Jamestown-Buffalo-Maple River 345 kV line, which is the highest-capacity tie to the coalfields, while the relevant remote contingency is outage of the Dorsey-Roseau Co-Forbes 500 kV line. Outage of this 500 kV circuit during northward flow conditions impresses significant "throughflow" on the Red River Valley's transmission system. This resultant step increase in Red River Valley line loadings during this and other severe contingencies cause large increases in reactive power consumption, which can lead to voltage collapse if insufficient reactive power supplies are available

The Manitoba-Minnesota Transmission Upgrade (MMTU) Project (1995) addressed the "post-500 kV outage" condition with extensive shunt capacitor installations at the Prairie Substation (Grand Forks, ND; 12 x 40 MVAR), the Sheyenne Substation (Fargo, ND; 5 x 40 MVAR), and the Ramsey Substation (Devils Lake, ND; 2 x 30 MVAR). These facilities provided the reactive support necessary in the Red River Valley to establish a 500 MW northward transfer capability. However, by the late 1990s continued load growth in the Red River Valley area had caused a degradation of this northward capability, as had been predicted by the MMTU studies

The Harvey-Glenboro 230 kV project (2002) established a new Manitoba-U.S. interconnection from central North Dakota (Harvey) to southwestern Manitoba (Glenboro). This additional 230 kV interconnection between Manitoba and the United States enabled an increase in the northward transfer limit to 700 MW[1] since there are now three 230 kV tie lines to support the total U.S.→Manitoba interface loading following loss of the Dorsey-Roseau Co.-Forbes 500 kV line

The Harvey-Glenboro development also included the addition of the Balta Switching Station at the intersection of the new Harvey-Glenboro 230 kV line and the existing McHenry-Ramsey 230 kV line, and the Rugby 230/115 kV transformation approximately 20 miles north of Balta. The Balta switching station improves sectionalizing capability of the transmission system and includes three 60 MVAR shunt capacitor banks, which help in supporting transmission system voltage during heavy loading conditions.

Although the Harvey-Glenboro project did not bring a new transmission source into the Red River Valley, it indirectly improved the Red River Valley load-serving capability by

- providing an additional parallel path for the northward throughflow following a loss of the 500 kV line;
- improving the sectionalization of the 230 kV system;
- adding the Rugby 230/115 kV transformation;
- adding reactive power supply at Balta.

The TIPS study concluded that load growth in the Red River Valley renders the existing transmission system inadequate to satisfy local load-serving needs. The study report's short-term recommendations included improvement of distribution system power factor, installation of additional 115 kV shunt capacitor banks, and installation of additional 230/115 kV transformer capacity. Most of these recommended "short-term" projects are under way or completed, most notably: the Hubbard 115 kV capacitor bank; the 2nd Maple River 230/115 kV transformer; the 2nd Wilton 230/115 kV transformer; the reconductoring of the 115 kV line between Grant County and Douglas County substations; and the reconductoring of the Fargo 115 kV system.

The TIPS study further concluded that long-term power supply needs would require addition of new bulk power transmission lines into the Red River Valley area The study specifically identified a Bemidji (Wilton)-Boswell 230 kV line and a Fargo-Alexandria-St. Cloud 345 kV line as being the most promising developments. These two lines were identified as principal features of the recommended long-range plan because they would satisfy Red River Valley regional reliability needs, while also addressing the more localized load-serving deficiencies specific to the Bemidji, Alexandria, and St. Cloud load centers.

[1] Although the northward Design Transfer Capability (DTC) was 700 MW, MISO has recently implemented a scheduling limit of 850 MW. The study effort described in this report examined power system performance at the 700 MW northward transfer level; testing of performance at the 850 MW level would yield higher post-contingent loadings and higher reactive power requirements

The CapX 2020 Vision Study identified a need for over 8000 MW of generation additions during the 2009-2020 time period in order to satisfy generating capacity requirements arising from continued load growth in Minnesota and electrically adjacent areas. That study concluded that a Fargo-St. Cloud 345 kV and a Bemidji-Boswell 230 kV line were both among the conceptual bulk transmission facilities common to all the different future generation scenarios examined, because they were effective in providing the desired generation outlet while also addressing the identified local load-serving reliability needs. It is important to note that the CapX 2020 transmission analysis examined only bulk (230 kV and above) system upgrades and did not attempt to determine detailed characteristics of optimal transmission configurations to address every identified load-serving deficiency.

This present Red River Valley/Northwestern Minnesota load-serving study is intended to build upon the results of the TIPS analysis, to determine the details of load-serving transmission improvements for this region, while utilizing the valuable findings derived from the CapX 2020 study effort with respect to bulk power system development considerations. This study addresses the following topics:

- Identification of the existing transmission system's inadequacies;
- Formulation of transmission improvement options;
- Evaluation of transmission options' effectiveness, cost, and practicality;
- Development of Recommended Plan

**Appendix A-3**
Application for Three 345 kV Projects
E-002/CN-06-1115

## 4.0 Analysis

### 4.1 Data Collection

This study was broken into three study areas, which consist of the northern region (North Zone), southern region (South Zone), and the entire Red River Valley / Northwestern Minnesota region (Combined Zone) as shown in Diagram 4.0.A. In order to refine the standard MAPP models, a data collection effort was designed to review historical powerflow data at summer peak and winter peak conditions within each zone. Real-time powerflow data was received from the various utilities for the time period between October 2003 and October 2004 to more accurately calibrate the available powerflow models against real-world conditions. This data consisted of tie-line flows and generation data for each zone on an hourly basis. This information enabled determination of the peak load and losses for both the winter peak and summer peak time periods.

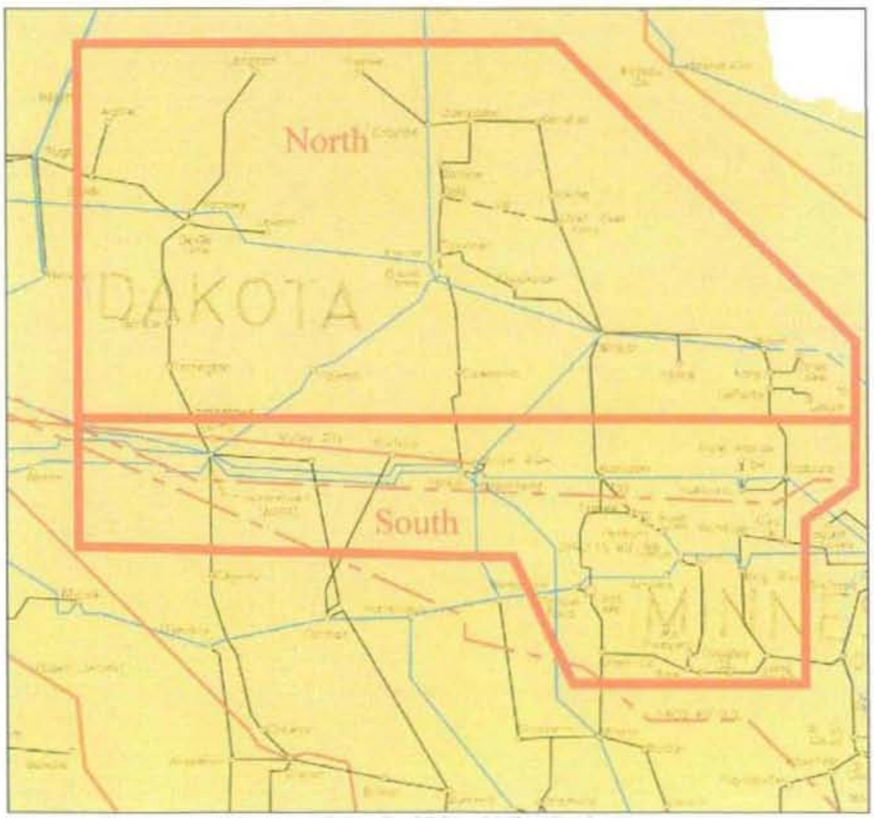



Diagram 4.0.A – Red River Valley Study Area

Below is a listing of all tie-lines for each of the study zones. These boundaries were selected in consideration of the natural electrical divisions existing in the Red River Valley / Northwestern Minnesota study area.

**"North Zone" Boundary**

| From | To (System) | Voltage (kV) |
|---|---|---|
| Balta | Ramsey | 230 |
| Rugby | Leeds | 115 |
| Letellier | Drayton | 230 |
| Badoura | La Porte | 115 |
| Ulrich | Mahnomen | 115 |
| Maple River | Winger | 230 |
| Fargo | Caledonia | 115 |
| Jamestown | Pickert | 230 |
| Jamestown | Carrington | 115 |

**"South Zone" Boundary**

| From | To (System) | Voltage (kV) |
|---|---|---|
| Carrington | Jamestown | 115 |
| Pickert | Jamestown | 230 |
| Caledonia | Fargo | 115 |
| Winger | Maple River | 230 |
| La Porte | Badoura | 115 |
| Badoura | Badoura | 115/34.5 |
| Riverton | Badoura | 230 |
| Riverton | Merrifield | 115 |
| Pequot Lake | Pequot Lake | 115/69 |
| Pequot Lake | Pequot Lake | 115/34.5 |
| Riverton | Baxter | 115 |
| Riverton | Wing River | 230 |
| Little Falls | Blanchard | 115 |
| Blanchard | Blanchard | 115/34.5 |
| Morris | Grant Co | 115 |
| Morris | Moorhead | 230 |
| Wahpeton | Fergus Falls | 230 |
| Wahpeton | Maple River | 230 |
| Forman | Gwinner | 115 |
| Forman | Valley City | 115 |
| Oakes | Oakes | 230/41.6 |
| Edgeley | Jamestown | 115 |
| Weber | Jamestown | 230 |
| Bismarck | Jamestown | 230 |
| Garrison | Jamestown | 230 |
| Center | Jamestown | 345 |

**"Combined Zone" Boundary**

| From | To (System) | Voltage (kV) |
|---|---|---|
| Balta | Ramsey | 230 |
| Rugby | Leeds | 115 |
| Letellier | Drayton | 230 |
| Badoura | Badoura | 115/34.5 |
| Riverton | Badoura | 230 |
| Riverton | Merrifield | 115 |
| Pequot Lake | Pequot Lake | 115/69 |
| Pequot Lake | Pequot Lake | 115/34.5 |
| Riverton | Baxter | 115 |
| Riverton | Wing River | 230 |
| Little Falls | Blanchard | 115 |
| Blanchard | Blanchard | 115/34.5 |
| Morris | Grant Co | 115 |
| Morris | Moorhead | 230 |
| Wahpeton | Fergus Falls | 230 |
| Wahpeton | Maple River | 230 |
| Forman | Gwinner | 115 |
| Forman | Valley City | 115 |
| Oakes | Oakes | 230/41.6 |
| Edgeley | Jamestown | 115 |
| Weber | Jamestown | 230 |
| Bismarck | Jamestown | 230 |
| Garrison | Jamestown | 230 |
| Center | Jamestown | 345 |

From the actual flow data that was provided by the various utilities, the following was determined as the coincident peak demand levels for the time periods of interest. These actual inputs to each zone represent the total load being served plus the line losses. The detailed flow data can be found in Appendix B.

Winter Peak (Load + Losses)

- North Zone: 877.3 MW @ 01/28/04 6:00 AM
- South Zone. 1086.0 MW @ 01/30/04 8:00 AM
- Combined Zone: 1903.7 MW @ 01/30/04 8:00 AM

Summer Peak (Load + Losses)

- North Zone: 683.8 MW @ 07/21/04 4:00 PM
- South Zone: 944.6 MW @ 09/02/04 3:00 PM
- Combined Zone: 1638.1 MW @ 07/20/04 4:00 PM

As shown in the above listing, "Combined Zone" load doesn't equal the sum of the "North" and "South" loads because the two zones' peak demands are not coincident; the peak demand of the "North" zone did not occur at the same time there was a peak demand in the "South" zone.

The following tables are a breakdown of the loads by utility in each zone. The substation load totals do not equal the figures cited above (which are total zonal load + losses) due to line losses. For example, the North Zone substation load total is 849.9 MW, and the zonal transmission losses are 27.4 MW, yielding a grand total of 877.3 MW, as shown above for the winter peak demand level for the North zone.

Winter Peak

North Zone (Grand Forks/Bemidji)

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 849.9 | 28.6 | 0.0 | 20.9 | 0.0 | 390.8 | 5.0 | 221.8 | 71.7 | 111.0 |
| | % | 100.0 | 3.4 | 0.0 | 2.4 | 0.0 | 46.0 | 0.6 | 26.1 | 8.4 | 13.1 |

South Zone (Fargo/Jamestown/Alexandria)

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 1029.7 | 10.2 | 151.3 | 0.0 | 66.8 | 219.0 | 96.1 | 161.4 | 96.9 | 228.0 |
| | % | 100.0 | 1.0 | 14.7 | 0.0 | 6.5 | 21.3 | 9.3 | 15.7 | 9.4 | 22.1 |

Combined Zone

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 1820.3 | 38.1 | 143.1 | 20.8 | 63.5 | 596.0 | 95.8 | 374.2 | 162.9 | 325.9 |
| | % | 100.0 | 2.1 | 7.9 | 1.1 | 3.5 | 32.7 | 5.3 | 20.6 | 8.9 | 17.9 |

Summer Peak

North Zone (Grand Forks/Bemidji)

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 655 6 | 20 4 | 0 0 | 22 6 | 0 0 | 221 9 | 4 6 | 213 1 | 67 5 | 105 5 |
| | % | 100.0 | 3.1 | 0.0 | 3.4 | 0 0 | 33 9 | 0 7 | 32 5 | 10.3 | 16.1 |

South Zone (Fargo/Jamestown/Alexandria)

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 893.9 | 9.7 | 164 0 | 0 0 | 63 5 | 120 2 | 90.9 | 161 4 | 90.3 | 193.9 |
| | % | 100.0 | 1.1 | 18.3 | 0.0 | 7.1 | 13.5 | 10.2 | 18.0 | 10.1 | 21.7 |

Combined Zone

| Loads | | Total | BEPC | GRE | MMPA | MP | MPC | MRES | OTP | WAPA | Xcel |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW | 1558 6 | 29 9 | 168 5 | 22 0 | 65 0 | 339 6 | 97 8 | 375 4 | 158 5 | 302 0 |
| | % | 100 0 | 1 9 | 10 8 | 1 4 | 4 2 | 21 8 | 6 3 | 24 0 | 10 2 | 19 4 |

Additional tables showing output from the powerflow models reporting North Dakota (ND) load (referred to as "Zone 90") and OTP control area load can be found in Appendix C along with the changes made to the base powerflow models.

## 4.2 Steady-State Procedure

The steady-state analysis was based on the Winter 2003 – Summer 2004 transmission system and focused on the Red River Valley area. The 2009 Summer Peak model from the latest available MAPP Models (2004 Series) was used as the basis for the powerflow analysis. This model had no new transmission line additions from today's existing system because none are presently committed in the Red River Valley region for the 2005-2009 period. Consequently, this model was determined to be the appropriate starting Summer Peak model; the load and generation were then scaled to match the observed real-time conditions.

The winter peak model was developed from the summer peak model. This was done by setting the load pattern in the Red River Valley study area (see Diagram 4.0.A) to match the pattern in the NMORWG package winter case. The loads were then scaled to match the observed real-time conditions. MAPP loads outside of the Red River Valley were scaled as a whole to match those in the NMORWG winter case. Also, the NDEX and MHEX interface loadings were adjusted to the desired levels.

Summer 2009 Peak Case with 2003/4 RRV loads (RRV-SUpk09)

- MHEX 1800 MW South
- NDEX 650 MW

Winter 2009 Peak Case with 2003/4 RRV loads (RRV-WIpk09)

- MHEX 700 MW North
- NDEX -80 MW

The goal of this analysis was to identify any transmission facilities' overloads and voltage deficiencies as a result of future Red River Valley load growth and to determine what transmission improvements will help the area. Power system performance was examined with the PSS/E Revision 30 digital computer powerflow and stability simulation program. Three different analyses were performed to help identify the limiting facilities.

The first part performed was Transfer Limit Table Generator (TLTG) analysis to incrementally increase the load in the three regions to reveal upcoming overloads ("thermal limits") for each region for "system intact" and "first contingency" conditions. TLTG ignores voltages and focuses on overloads.

Power-Voltage (P-V) analysis was then performed to show the voltage profile of all RRV buses 115 kV and above as load is incrementally increased. The incremental load-serving capabilities for each outage were evaluated by the following two criteria:

- The MW level at which the first bus reaches 0.90 p.u. voltage, or
- 90 % of amount of the theoretical MW load-serving limit, as determined from the P-V curve's point of voltage collapse (the "nose" of the curve).

This analysis shows the locations that are most susceptible to voltage issues.

Voltage-Reactive Power (V-Q) analysis was then performed on several buses identified from the P-V analysis to allow examination of the reactive margins.

A sensitivity analysis was then performed, using the results of all three analyses, on the winter peak model to evaluate the effects of the MHEX level over a range of 1000 MW North flow to 1000 MW South flow at 100 MW increments.

At the end, an automated sequential contingency analysis routine ("ACCC") was then used to verify that the long-term system improvements identified are adequate for the amount of load growth in the region.

Throughout the TLTG and ACCC analyses, the following input parameters were utilized:

Monitored facilities:

- All transmission lines and transformers 69 kV and above included in the following control areas:

| | | |
|---|---|---|
| GRE | MP | OTP |
| WAPA | XCEL | |

Contingencies studied:

- All single contingencies 69 kV and above in RRV region, which include the following transmission owners:

| | | |
|---|---|---|
| GRE | MP | MPC |
| MRES | OTP | WAPA |
| XCEL | | |

- Multiple-circuit lines in the standard MAPP 2004 Contingency File, which includes facilities for the following entities.

| | | |
|---|---|---|
| GRE | MP | MPC |
| MRES | OTP | WAPA |
| XCEL | | |

Source facilities:

Incremental source generation used for the analyses involving increased load levels was presumed to be from all directions outside the Red River Valley except for Manitoba. Accordingly, the incremental generation sources were:

| | |
|---|---|
| Antelope Valley #1 | Big Bend #1-8 |
| Boswell #4 | Coyote #1 |
| Monticello #1 | |

Allocation of generation increases to each unit was in proportion to that unit's size relative to the total set of "incremental" generators.

Sink facilities:

The sink was the "seasonal" load of the three Red River Valley regions. Local generation, "Constant Firm" load (such as pipeline pumping stations), and "Conditional/Station Service" load were all held constant during the analysis

Appendix D contains all input data files describing the above facilities used during this study.

Power system performance was evaluated against the NERC Planning Standards, with respect to acceptable system performance following Category A, B, and C contingencies.

Category A relates to "system intact" conditions
Category B relates to first contingency ("N-1") conditions
Category C relates to 1) Outage of multiple elements, due to a single initiating event [loss of double-circuit line, breaker failure, or bus fault], or
2) Loss of one element, with an intermediate adjustment period, followed by a subsequent outage.

Performance was judged to be acceptable if

1. "system intact" loadings were within the continuous ratings of transmission system facilities and post-contingent loadings were within the applicable emergency ratings;
2. voltage levels were within the applicable system intact and post-contingent criteria.

## 4.3 Dynamic Stability Procedure

The dynamic stability performance of the transmission system was examined on the 2003 NMORWG stability study package using PSS/E Revision 29. The dynamic stability analysis was used to confirm that the bulk power system dynamic stability performance is acceptable for all long-term transmission solutions. The two base cases that were used to evaluate initial performance were the following:

Summer 2003 Off-Peak Case
(000-so03aa.uzvV4V4)

- MHEX 2176 MW South
- NDEX 1951 MW
- MWSI 1480 MW

Winter 2003 Peak Case
(000-wp03aa.ZNZ0Y4W)

- MHEX 700 MW North
- NDEX -69 MW
- MWSI -63 MW

The summer off-peak case with high simultaneous transfers was used as the starting case for the evaluation of long-term transmission solutions' effect on the NDEX stability limit. Both cases have the North Dakota Coalfields generation at traditional "cruise" output levels, which are slightly below the maximum attainable ("URGE") levels.

The following disturbances were reviewed for this study:

| | |
|---|---|
| AG1 | Single line to ground fault with breaker fail at Leland Olds on the Ft. Thompson 345 kV line |
| AG3 | Three phase fault at Leland Olds on the Ft. Thompson 345 kV line |
| EI2 | CU DC Permanent Bipole Fault with tripping of both Coal Creek units. |
| EQ1 | Single line to ground fault with breaker fail at Coal Creek on CU DC pole 1 with cross-trip of Coal Creek unit #2 |
| PCS | Single line to ground fault with breaker fail at King with 8P6 stuck |
| PYS | Single line to ground fault with breaker fail at Prairie Island with 8H9 stuck |
| PCT | Eau Claire-Arpin 345 kV line trip without a fault |
| PYT | Prairie Island-Byron 345 kV line trip without a fault. |
| NAD | 4 Cycle 3 phase fault on the Dorsey to Forbes 500 kV line D602F at Forbes. |
| NBZ | 3.5 Cycle 3 phase fault on the Chisago Co-Forbes 500 kV line D601C at Chisago County. |
| OAS | Single line to ground fault with breaker fail at Dorsey with 602L stuck. |
| PAS | Single line to ground fault with breaker failure at Forbes with 602L stuck. Trip D602F. |
| MTS | Single line to ground fault with breaker failure at Monticello |
| MQS | Single line to ground fault with breaker failure at Sherco with cross trip of Sherco Unit 3, Sherco-Benton County 345 kV line and 230/345 kV tx at Benton County |
| TAZ | 4 Cycle 3 phase fault on the Sherco-Coon Creek #1 345 kV line at Sherco. |
| MAD | 4 cycle 3 phase fault at Dorsey 500 kV. Clear the Dorsey-Forbes 500 kV line. This disturbance is required only when USA - Manitoba flow is north |
| QA3 | 5 cycle 3 phase fault at Blackberry. Clear the Blackberry-Riverton 230 kV line |
| RXS | Single line to ground fault with breaker fail at Boswell with 951 stuck. |

Note: Proposed revisions to the Forbes 500 kV bus configuration would modify the "NBZ" disturbance scenario to be that represented by the "NMZ" scenario, in which the Forbes SVS remains online following the disturbance. Simulation of the NMZ disturbance was not found necessary for this study because

- NBZ performance was determined to be satisfactory, and NMZ performance would be somewhat better,
- To date, no commitments have been made toward the implementation of the Forbes 500 kV bus configuration improvement.

# 5.0 Results

The three defined zones of the Red River Valley/Northwest Minnesota study area were evaluated to determine their ability to reliably supply future load levels. The load-serving capabilities were evaluated by reviewing system intact, first-contingency (N-1), and second-contingency (N-2) simulation results, focusing primarily on the P-V and V-Q analysis for the Winter Peak condition. All powerflow modeling within the study area was performed on base cases with load levels adjusted to match the actual loadings experienced during the winter of 2003/2004. Consequently, there has already been two years' load growth since that time, and it is likely that several more years will elapse before any significant transmission facilities can be placed in service. The following paragraphs summarize the results of the "existing system" load-serving evaluation.

In order to evaluate the North and South zones of this region, three analyses were undertaken. These included independent analysis of load growth in each of the North and South zones. The third analysis evaluated system performance as load was simultaneously increased in both zones.

The North Zone of the RRV can support almost 500 MW of incremental load during system intact conditions. (This is of only theoretical or academic interest, since load-serving capability is determined by contingent capability.) The first-contingency (N-1) incremental load-serving capability is approximately 112 MW (13% load growth), limited by outage of the Jamestown-Center 345 kV line overloading the Hankinson-Wahpeton 230 kV line, which has a winter rating of 320 MVA. A voltage-related N-1 limit of 150 MW, or 17% above the Winter 2003/2004 load levels is observed due to the post-contingent voltage in the Bemidji/Cass Lake area dropping below criteria following the Dorsey-Forbes 500 kV outage.

The outage of the Winger-Wilton 230 kV line is also a significant outage for the Bemidji/Cass Lake area and is shown in the V-Q graphs for the Wilton 115 kV bus (discussed later). This marginal N-1 performance is despite the multiple recent capacitor additions in the Bemidji area on the 115 kV system, and the addition of the Solway generation, all of which were modeled.

The North Zone's N-2 performance is limited by the Winger-Wilton 230 kV/Badoura-La Porte 115 kV outage combination to 0 MW of incremental load-serving capability. This is based upon the studied load levels that correspond to the peak loads experienced during the Winter 2003/2004 season.

The South Zone of RRV can support almost 600 MW of incremental load growth in the region during system intact conditions. During first contingency (N-1) conditions, the region can only support approximately 330-340 MW of incremental load, the limiting considerations being overload of the Sheyenne-Fargo 230 kV line and voltage adequacy in the Enderlin vicinity following outage of the Center-Jamestown 345 kV line. This 330 MW corresponds to a 32% increase in load over the Winter 2003/2004 levels modeled.

The South Zone can only support about 150 MW of load growth (14%) for second contingency (N-2) conditions. The most critical outage combination for this zone is loss of the North 500 kV line (Dorsey-Forbes) and the Center-Jamestown 345 kV line.

This zonal summary does not take into account localized load-serving problems, such as the Alexandria load center, nor the adjacent St. Cloud area's load-serving deficiencies.

For the Combined analysis of both zones, 885 MW of incremental load growth could theoretically be supported during system intact conditions. For N-1 conditions, the limiting consideration (at 312 MW or 13% load growth) is outage of the Audubon 230/115 kV transformer causing overload of the Hoot Lake-Edge Tap 115 kV line, whose winter rating is 100 MVA. A voltage-related N-1 limit of 440 MW (24%) of incremental load is observed for loss of the North 500 kV line.

The Combined Zone incremental load-serving capability is then reduced to 0 MW for N-2 conditions due to the Winger-Wilton 230 kV/Badoura-LaPorte 115 kV outage. If this limiter were addressed, the next N-2 load-serving limit is encountered at about 300 MW (16%) of incremental load (North 500 kV and Center-Jamestown 345 kV outage).

The preceding results are summarized in the following table

Table 5.0.A
Existing System
Incremental load-serving capabilities
(% load increase beyond Winter 2003/2004 level)

| RRV Zone | Base (existing) Load Level | Incremental load-serving capability, MW System Intact | | N-1 | | N-2 | |
|---|---|---|---|---|---|---|---|
| Northern | 849.9 MW | 490 | 56% | 112 | 13% | 0 | 0% |
| Southern* | 1029.7 MW | 590 | 54% | 330 | 32% | 150 | 14% |
| Combined* | 1820.3 MW | 885 | 48% | 312 | 17% | 0 | 0% |

* Alexandria & St Cloud sub-regional deficiencies are more near term than "total zone" need

To address the above-described existing or impending load-serving deficiencies, four possible new transmission sources into the Red River Valley / Northwestern Minnesota area were evaluated:

| | Approx. miles |
|---|---|
| • a 230 kV line from Harvey to Prairie ("West Source"), | 145 |
| • a second 230 kV line from Letellier to Drayton to Prairie ("North Source"), | 110 |
| • a 230 kV line from Boswell to Wilton ("East Source")*, and | 65 |
| • a 345 kV line from Benton Co to Alexandria to Maple River ("South Source").** | 165 |

* Known as the Bemidji to Boswell 230 kV line
** Known as the Fargo to St Cloud 345 kV line

A fifth option of a 230 kV line from Fargo to Grand Forks (referred to as "Internal RRV" or "Other") was also evaluated as an option for improving load-serving capability in the region.

Although this 65-mile line does not represent the addition of a new transmission source into the Red River Valley, it was hypothesized that it may re-distribute power flows and improve voltage profiles within the RRV.

Table 5.1.B shows a comparison of the five options' performance relative to "existing system" performance considering Winter Peak conditions. The load-serving limits are based on a P-V Analysis for N-1 conditions. A full set of tables and graphs of the source comparisons (including N-2 conditions) is provided in Appendices H and I. The following paragraphs summarize the results observed from the N-1 and N-2 load-serving analysis.

### 5.0.1 North Zone P-V Results

Referring to Table 5.1.B, the West Source (Harvey-Prairie 230 kV) helps slightly with an incremental load-serving capability of 210 MW for N-1 conditions and about 60 MW for N-2 conditions. The North Source (Letellier-Drayton-Prairie 230 kV) helps less with an incremental load-serving capability of 175 MW for N-1 conditions and only 10 MW for N-2 conditions.

The South Source (Fargo-St. Cloud 345 kV) is more effective, providing over 225 MW of incremental load-serving capability for N-1 conditions and 60 MW for N-2 conditions. These incremental load-serving limits are due to the loss of the Maple River-Winger 230 kV line, which results in separating the new South Source from the North Zone.

These estimates exclude the N-2 loss of Winger-Wilton 230 kV and Badoura-La Porte 115, for which all transmission options except for the East Source (Bemidji-Boswell 230 kV) fail to provide any additional support to the Bemidji area.

The East Source (Bemidji-Boswell 230 kV) helps significantly for all North Zone critical outages, as it provides another transmission source to the Bemidji area--where it is most needed. It provides about 415 MW of additional load-serving capability for N-1 conditions and 300 MW for N-2 conditions. The short-term option of an SVC at Wilton also helps with supporting the voltages in the Bemidji area during N-1 and N-2 outage conditions, whereas a Prairie SVC is too distant from Bemidji to provide the necessary Bemidji vicinity voltage support for critical outage conditions.

### 5.0.2 South Zone P-V Results

For the "existing system" and "line addition" scenarios, the Hubbard/Audubon area and Jamestown/Enderlin 115 kV voltages are the limiting considerations for incremental load-serving capability because they experience the largest voltage decline with the incremental load growth. Great River Energy's recent addition of a 27 MVAR capacitor at Hubbard (which was not modeled) addresses part of this requirement. Additional capacitor banks at Audubon and Jamestown would help raise bus voltages during N-1 conditions, thereby being an effective short term solution.

The Jamestown-Center 345 kV line outage is the N-1 critical contingency for all transmission options, while Jamestown-Center 345 kV line/North 500 kV line is the N-2 critical contingency.

The West Source slightly improves the South Zone incremental load-serving capability by an additional 60 MW for N-1 and N-2 conditions Its effectiveness is limited by its length (and resultant impedance) and the reality that the Harvey "source" is far from being an "infinite bus".

The Northern Source improves N-1 incremental load-serving capability for the South Zone by approximately 10 MW, but actually reduces incremental capability by approximately 10 MW in the South Zone for N-2 conditions. This result is obtained because the new line encourages additional south-north throughflow in the Red River Valley.

The East Source provides about 100 MW of additional incremental N-1 load-serving capability and approximately 190 MW for N-2 conditions.

The South Source provides approximately 250 MW of additional incremental N-1 load serving capability and approximately 320 MW for N-2 conditions.

### 5.0.3 Combined Zone P-V Results

Considering the Combined Zone under N-2 conditions, the West Source helps slightly with incremental load growth (75 MW), while the North Source actually reduces the load-serving capability during N-2 by about 5 MW.

The effectiveness of both the East and South Sources is restricted by the finding that they become part of the critical contingencies during N-2 conditions: loss of the north 500 kV line (Dorsey-Forbes) and the new line becomes the limiting condition for the Combined Zone. Despite this characteristic, the East and South improvements provide for approximately 300 MW and 400 MW, respectively, of load growth considering N-2 conditions The corresponding N-1 increment for the East Source is 300 MW, while the South Source provides 425 MW of incremental load-serving capability.

### 5.0.4 Overall Results

Considering the N-1 and N-2 performance data obtained with the various transmission additions studied, it is concluded the "East" and "South" line additions consistently provide the largest amounts of incremental load-serving capability.

The "East Source" is the Bemidji-Boswell 230 kV line. It addresses two important needs:

- The need for another transmission source to the Bemidji sub-area of the North Zone, where currently a radial 230 kV transmission line is the only bulk supply. Failure of this line leaves only two 115 kV transmission lines attempting to supply the Bemidji load center. Recent additions of the Solway generation and 115 kV capacitor banks have helped extend the existing system's load-serving capability, but in the near term these additions will be insufficient.
- The need for a new transmission source for the North Zone as a whole.

The Bemidji-Boswell 230 kV line is the most effective transmission option studied with respect to satisfying these two needs. Since it also involves considerably fewer miles of new line construction than any other option studied, it would reasonably be expected to have the lowest installed cost.

The "South Source" is the Fargo-St. Cloud 345 kV line. This is the longest and presumably most expensive transmission option, but it also

- yields the highest Red River Valley/Northwest Minnesota incremental load-serving capabilities;
- provides a new transmission source to the Alexandria sub-area, where one is needed;
- provides a long-term solution to the St. Cloud area load-serving issues, especially if the new 345 kV line terminates at Monticello or Sherco rather than Benton Co.;
- establishes an increased NDEX transfer limit;
- yields a significant loss reduction (nearly 20 MW), and
- based on CapX Vision Study results, this line is needed in the future under all generation patterns studied.

The Alexandria and St. Cloud sub-areas merit special attention because they need an additional transmission supply, and none is available in the immediate vicinity. "Existing system" analysis shows the Alexandria sub-area to have N-1 load-serving capability of only 4% above the 2004 summer peak load level. The limiting contingency is outage of the Grant County-Elbow Lake 115 kV line. Currently, MRES is a planning to add two 25 MVAR capacitor banks in the Alexandria area prior to Summer 2007 as a short-term solution until a new transmission line can be built into the Alexandria sub-area.

Similarly, the St. Cloud load center is also in need of load-serving assistance, primarily due to N-1 conditions relating to the existing St. Cloud 115 kV loop. The St. Cloud load-serving deficiencies consist of both severe thermal (line overload) and reactive power (low voltage) problems and therefore cannot be addressed by the classic short-term strategies of capacitor additions or line reconductors; a new transmission source is required, preferably on the west or northwest side of the existing 115 kV loop

The near-term Alexandria and St Cloud load-serving needs make the Fargo-St. Cloud 345 kV development attractive because the other transmission options examined would require additional lines to address the Alexandria and St. Cloud load-serving deficiencies. Such a development would most likely consist of a 230 or 345 kV line extension from Sherco or Monticello, to St. Cloud and Alexandria. Consequently, if the Fargo-St. Cloud 345 kV line were not chosen as part of the regional transmission plan, a significant portion of a Fargo-St. Cloud 230 or 345 kV development would need to be implemented regardless, to address Alexandria and St. Cloud load-serving needs

The following table compares the transmission options' effectiveness with regard to

- the degree to which they address the identified load-serving deficiencies:
- approximate NDEX increase achieved; and
- approximate demand loss reduction achieved

"Yes" indicates the transmission option provides a long-term solution to the deficiency; "part" (partial) indicates that additional transmission facilities would be required for that source to be fully effective, or that it is a short-lived solution, providing for less than 25% load growth from "existing" (2003/2004) levels. "No" indicates the facility is not effective at addressing the load-serving deficiency.

Considering the relatively long lead time associated with transmission line additions, some short-term improvements are likely needed to maintain system reliability in the interim. Two short-term improvements were identified as desirable for the North Zone and two for the South Zone, with all four improvements also evaluated for the Combined Zone. The two North Zone improvements are an SVC at the Prairie Substation and an SVC at the Wilton Substation. The two short-term improvements evaluated for the South Zone consist of shunt capacitor additions at 230 kV buses at Hubbard/Audubon and additional capacitors at the Jamestown (WAPA) 115 kV or 230 kV bus. GRE has added reactive capability at Hubbard, partially addressing that need, while MRES has plans to add reactive capability in the Alexandria area.

Table 5.1.A

| | | | Load-serving deficiencies addressed? | | | | | NDEX | MW | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | line | North | South | Bemidji | Alexandria | St | increase | loss reduction | |
| Option | | miles | Zone | Zone | sub-area | sub-area | Cloud | MW | Winter | Summer |
| West: | Harvey-Prairie 230 kV | 145 | part | part | no | no | no | 0 | 7 | 3 |
| North | Letellier-Drayton-Prairie 230 kV #2 | 110 | part | no | no | no | no | 0 | 0 | 6 |
| East | Bemidji-Boswell 230 kV | 65 | yes | part | yes | no | no | 100 | 22 | 5 |
| South | Fargo-St. Cloud 345 kV | 165 | part | yes | no | yes | yes | 350 | 20 | 12 |
| Internal: | Fargo-Grand Forks 230 kV | 65 | part | no | no | no | no | 0 | 4 | 0 |
| Wilton SVC | | 0 | part | no | part | no | no | 0 | 0 | 0 |
| Prairie SVC | | 0 | part | no | no | no | no | 0 | 0 | 0 |
| East + South + Wilton Reactive support & Prairie SVC (Recommended Plan) | | 230 | yes | yes | yes | yes | yes | 550 | 36 | 17 |

The above-listed performance benefits are described in further detail in various sections of this report.

Table 5.1.B
PV N-1 Winter Peak Comparison Table
(Incremental Load-Serving Capabilities (MW) with respect to Winter 2003/4 Actual Load Level)

NORTH ZONE

| | EXISTING | WEST SOURCE | NORTH SOURCE | EAST SOURCE | SOUTH SOURCE |
|---|---|---|---|---|---|
| Condition | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) |
| System Intact | 490 | 515 | 500 | 750 | 540 |
| Drayton 66752 - Letellier 67557 230 KV outage | 420 | 475 | 495 | 660 | 475 |
| Ramsey 63047 - Balta 63056 230 KV outage | 450 | 490 | 460 | 560 | 480 |
| Ramsey 63047 - Prairie 66755 230 KV outage | 450 | 490 | 450 | 700 | 470 |
| Maple River 66754 - Winger 66758 230 KV outage | 355 | 400 | 375 | 650 | 370 |
| Jamestown 66444 - Pickert 66759 230 KV outage | 415 | 465 | 450 | 635 | 440 |
| 500kV North outage | 146 | 355 | 320 | 575 | 405 |
| 500kV South outage | 475 | 505 | 480 | 710 | 525 |

SOUTH ZONE

| Condition | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) |
|---|---|---|---|---|---|
| System Intact | 590 | 625 | 600 | 675 | 760 |
| Prairie 66755 - Winger 66758 230 KV outage | 570 | 600 | 580 | 665 | 770 |
| Wahpeton 63329 - Maple River 66754 230 KV outage | 600 | 635 | 610 | 680 | 780 |
| Jamestown 63369 - Center 66791 345 KV outage | 340 | 402 | 390 | 440 | 585 |
| Badoura 61610 - Riverton 61612 230 KV outage | 550 | 580 | 555 | 650 | 740 |
| 500kV North outage | 360 | 475 | 420 | 620 | 710 |
| 500kV South outage | 550 | 595 | 560 | 630 | 760 |

Combined Zone

| Condition | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) | Limit (MW) |
|---|---|---|---|---|---|
| System Intact | 885 | 950 | 910 | 1090 | 1140 |
| Drayton 66752 - Letellier 67557 230 KV outage | 750 | 850 | 900 | 1025 | 1025 |
| Ramsey 63047 - Balta 63056 230 KV outage | 800 | 900 | 840 | 995 | 1040 |
| Jamestown 63369 - Center 66791 345 KV outage | 580 | 665 | 605 | 750 | 910 |
| Badoura 61610 - Riverton 61612 230 KV outage | 770 | 820 | 790 | 1040 | 1030 |
| 500kV North outage | 440 | 430 | 575 | 960 | 675 |
| 500kV South outage | 840 | 900 | 870 | 1010 | 1120 |

Example Calculation: For the North Zone, the East Source increases the incremental load-serving capability to 560 MW. This compares to 146 MW for the existing system, for a net increase of 414 MW (560-146 = 414 MW).

## 5.1 Wilton Reactive Support

Reactive support is especially needed in the Bemidji vicinity during Winter Peak conditions when loads are highest and Solway generation would not typically be producing real power due to its relatively high energy production costs. The Solway unit does have the ability to run as a synchronous condenser, thereby providing reactive power to support local voltages. However, the analysis performed shows that even with the Solway unit on line as a synchronous condenser, post-contingent voltage violations occur in the Bemidji area following outage of the Winger-Wilton 230 kV line, or several different N-2 contingencies.

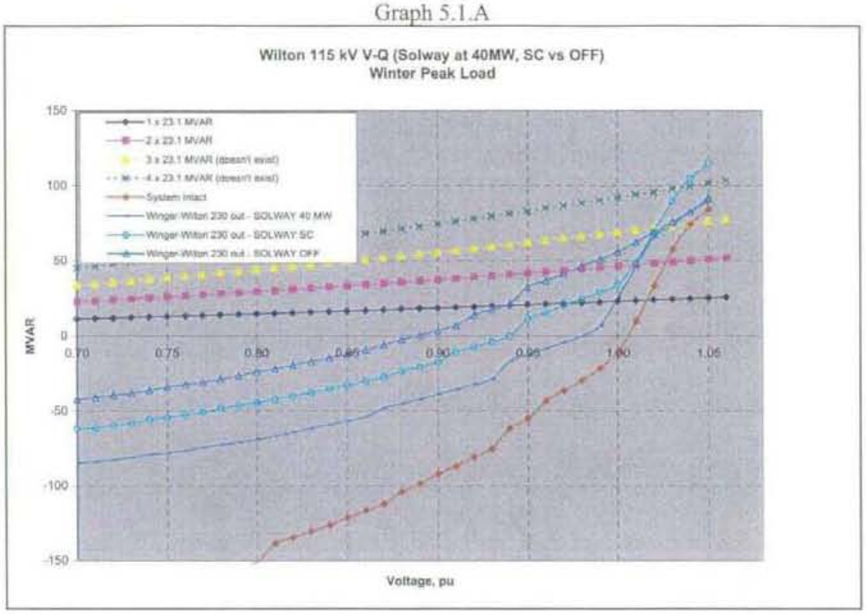
The MHEX and NDEX transfer levels don't affect the post-contingent voltages dramatically in the Wilton/Bemidji area due to the load being supplied radially during most of the relevant contingencies. The most limiting N-1 condition is the loss of the Winger-Wilton 230 kV line. A second 230/115 transformer recently was added to Wilton Substation; this addresses the concern over the possibility of a long-duration transformer outage, but still leaves the Bemidji sub-area supplied by only one 230 kV line. Graph 5.1.A shows the situation for the Winger-Wilton 230 kV line outage, for all three possible Solway generation scenarios: Solway generation on line at 40 MW, operating as a synchronous condenser (SC), and off line.

Graph 5.1.B shows that today the Bemidji/Wilton area cannot withstand the "N-2" outage of both the Winger-Wilton 230 kV and the Badoura-La Porte 115 kV line; voltage collapse would occur if loads were at or near peak levels. This is observed by noting that the reactive requirement curve for this N-2 condition is higher than the reactive output available from the two existing 23 MVAR Wilton capacitors without any load shed. This is regardless of whether the Solway generation is online at 40 MW, as synchronous condenser (SC), or off line. Having Solway generation online at 40 MW helps the Bemidji/Wilton area the greatest because it's producing real power to offset some of the local load and its reactive power output also helps provide voltage control.

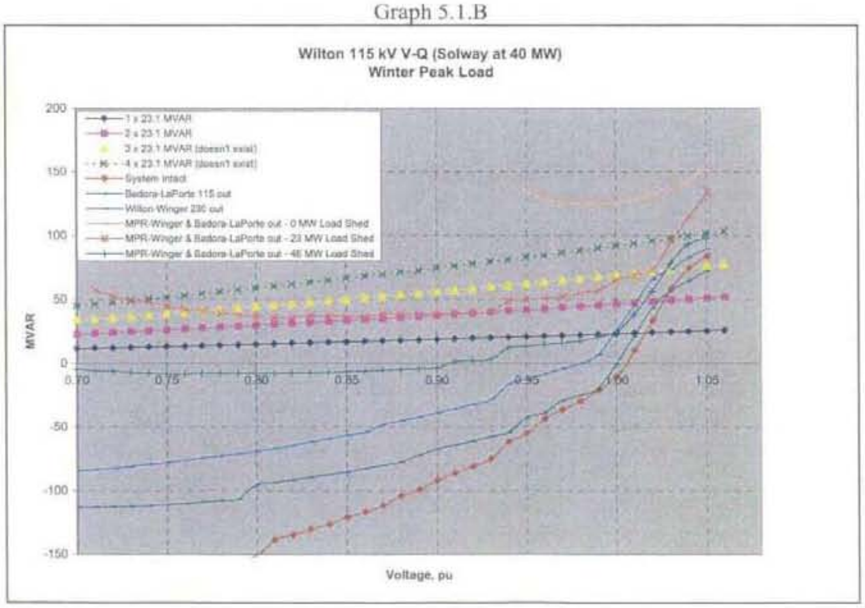
From these graphs it is observed that the addition of more blocks of conventional shunt capacitors is not a very feasible option primarily because the number of capacitors required in the immediate post-contingency condition generally exceeds the number that can be on line during system intact conditions without causing excessively high voltages. More-detailed study work would need to be performed to further investigate the feasibility of addressing the Bemidji reactive needs with shunt capacitor bank additions. Such a study would address speed of switching required, development of suitable control schemes, and evaluation of methods of achieving rapid capacitor bank re-energization capability.

In contrast to the challenges of additional shunt capacitor banks, an SVC in the Wilton area can easily both keep the pre-contingent voltages at desired levels and ensure adequate post-contingent voltages. Capacitor switching frequency will also be reduced because the SVC (if properly sized) will handle most of the variability in reactive injection required to achieve effective voltage regulation. A detailed SVC characterization study would be required in order to determine the recommended MVAR rating of the SVC and to determine the optimal connection configuration.

Graph 5.1.A




Graph 5.1.B

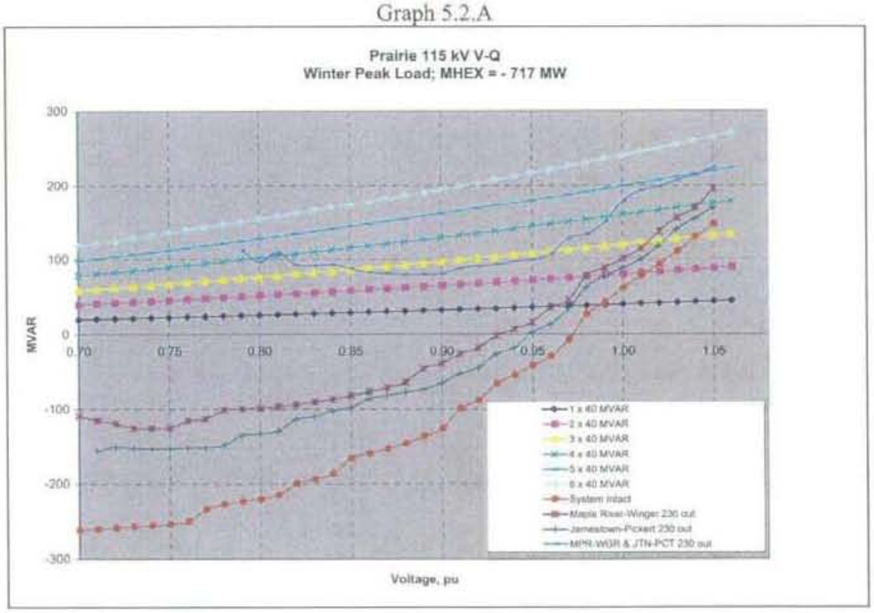


## 5.2 Prairie Reactive Support

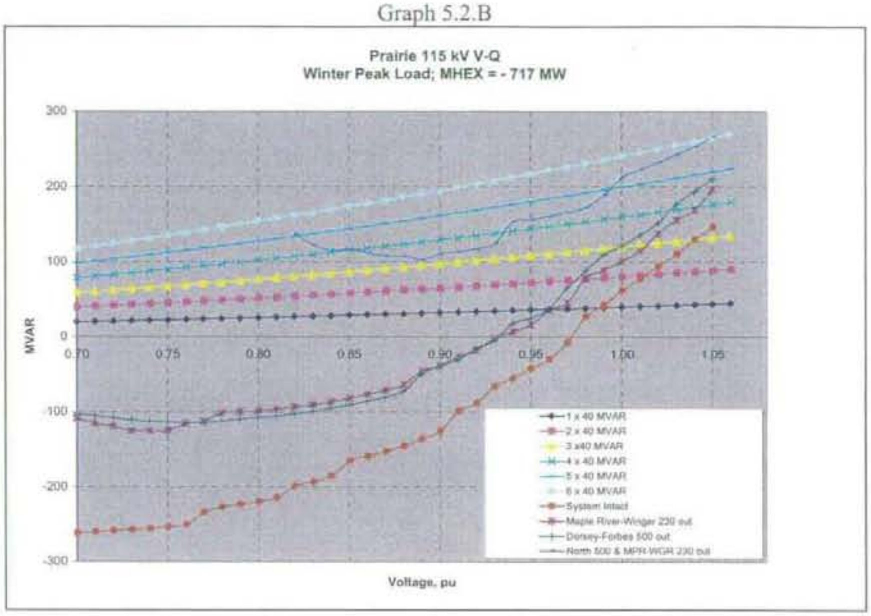
Presently, the Prairie 230/115 kV substation has 480 MVAR of reactive capability consisting of twelve 40 MVAR 115 kV fast-switched capacitors. These capacitors supply the large amounts of reactive capability needed to support high post-contingent throughflows, which can occur during high transfer conditions, particularly high northward transfers into Manitoba following outage of the Dorsey-Forbes 500 kV line. The issue with the Prairie capacitors is that for local N-2 conditions (such as Maple River-Winger 230 kV and Jamestown-Pickert 230 kV contingency shown in Graph 5.2.A) the critical voltage is relatively high, and the system reactive requirement curve is nearly parallel to the capacitor output curves. The ramifications of this system characteristic are:

- "hunting" or "toggling" can occur because switching of one capacitor causes a relatively large change in voltage. The excessive change in voltage causes overshoot or undershoot of the bus voltage, resulting in a capacitor being switched on or off; this cycle is then repeated; and
- trip-out of one capacitor can cause voltage collapse.

Graph 5.2.A



Graph 5.2.B




An SVC at Prairie keeps the pre-contingent voltages at desired levels and ensures adequate post-contingent voltages. Capacitor switching frequency is also reduced because the SVC (if properly sized) will handle most of the variability in reactive injection required. The SVC could also have some inductive capability, which would be helpful during light load conditions and to control voltage during system restoration following catastrophic events. Presently there is no inductive capability in the Prairie vicinity; this presents challenges in re-energizing long 230 kV lines.

The Prairie SVC will also help improve dynamic stability performance following regional disturbances; this contributes toward an improvement in NDEX limit, and also improves relay margins for the Letellier-Drayton 230 kV out-of-step relaying, which is one of the many limiting factors for the Manitoba-U.S. interface (MHEX) loadability limit.

## 5.3 Bemidji-Boswell 230 kV Line

The Bemidji–Boswell 230 kV line addition is shown in Diagram 5.3.A. This line will actually connect the Wilton 230 kV bus and Boswell 230 kV bus. This diagram also shows what was determined to be the load benefit area for this line addition. This line adds an Eastern Source to the Red River Valley from Northeastern Minnesota.

The Bemidji–Boswell 230 kV line isn't the answer for all load-serving needs in the Red River Valley / Northwestern Minnesota area, but is very effective in supporting the Northern zone, especially the Bemidji area, which needs near-term reinforcement, and also increases load-serving capability throughout the Red River Valley, primarily the northern section.

Compared to the other long-term regional transmission options, this line is anticipated to have the lowest construction cost because it is at least 40% shorter than any other long-term transmission line studied.

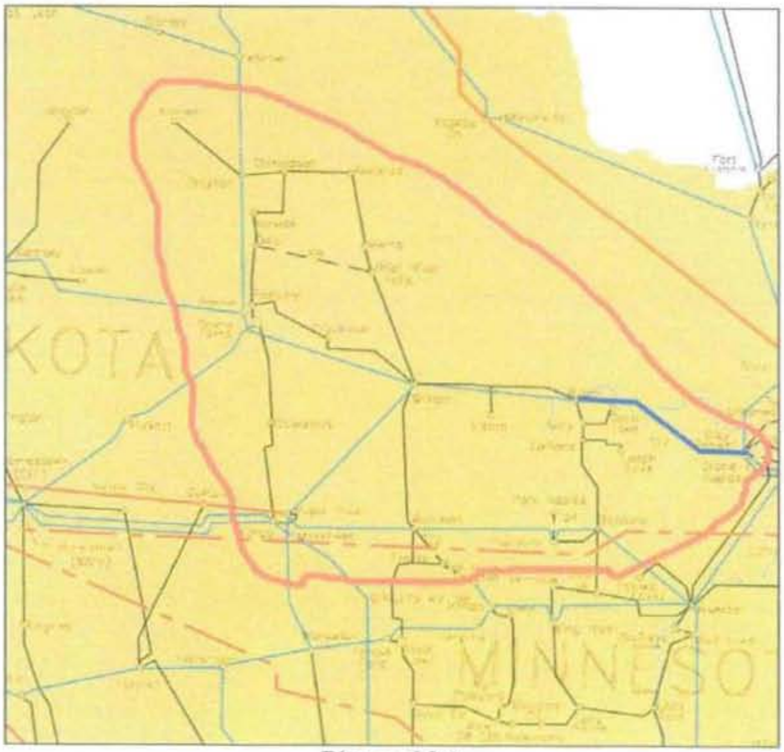



Diagram 5.3.A
Load Benefit Area for the Bemidji-Boswell 230 kV Line Addition

## 5.3.1 TLTG Analysis

Table 5.3.A summarizes the results of a "TLTG" analysis which revealed the transmission overloads encountered when incrementing the load in each zone (from the base 2003/2004 load level) while supplying power from various generation units in the MAPP Region as detailed in the Analysis Section. There are several localized sub-transmission overloads that need to be addressed that are not listed in this table, which can be found in Appendices F and G.

The table shows the effect of the Bemidji-Boswell 230 kV line addition on the thermally-limited load-serving capabilities of all three zones. Although most of the load-serving limits increase as expected, it observed that the Bemidji-Boswell 230 kV line addition can cause a reduction in two of the load-serving limits. This result is obtained because the Bemidji-Boswell 230 kV line addition provides access to a very strong source (Boswell), which redirects power flows throughout the region.

These two potentially-adverse effects of the Bemidji-Boswell 230 kV line addition are easily avoided. Addition of a second Winger 230/115 kV transformer (which was recommended in the original TIPS study) addresses the North Zone Winter Peak concern, while the South Zone Winter Peak concern is easily addressed by upgrading the terminal equipment on the Hankinson-Wahpeton 230 kV line, and would be further relieved by the anticipated Fargo-St Cloud 345 kV line addition.

Table 5.3.A
TLTG Analysis Incremental Load-Serving Capability
(Thermal-based Limits)

| | Existing System | | | Bemidji-Boswell 230 kV Addition | | |
|---|---|---|---|---|---|---|
| | MW | Limiting Element | Contingency | MW | Limiting Element | Contingency |
| **North Zone** | | | | | | |
| Winter Peak | **112** | Hankinson-Wahpeton 230 | Jamestown-Center 345 | **16** | Winger 230/115 tx | Grand Forks-Falconer 115 |
| Summer Peak | **170** | Drayton 230/115 tx #1 | Drayton 230/115 tx #2 | **226** | Drayton 230/115 tx #1 | Drayton 230/115 tx #2 |
| **South Zone** | | | | | | |
| Winter Peak | **328** | Sheyenne-Fargo 230 | Jamestown-Center 345 | **225** | Hankinson-Wahpeton 230 | Jamestown-Center 345 |
| Summer Peak | **342** | Sheyenne-Fargo 230 | Jamestown-Center 345 | **432** | Sheyenne-Fargo 230 | Jamestown-Center 345 |
| **Combined Zone** | | | | | | |
| Winter Peak | **312** | Hoot Lake-Edge Tap 115 | Audubon 230/115 tx | **553** | Coyote-Center 345 | Multi lines of Jamestown 230 |
| Summer Peak | **467** | Sheyenne-Fargo 230 | Jamestown-Center 345 | **613** | Sheyenne-Fargo 230 | Jamestown-Center 345 |

Table 5.3.B
PV Analysis Incremental Load-Serving Capability
(Voltage-based Limits)

| | Existing System | | | Bemidji-Boswell 230 kV Addition | | |
|---|---|---|---|---|---|---|
| | MW | Limiting Voltage | Contingency | MW | Limiting Voltage | Contingency |
| **North Zone** | | | | | | |
| Winter Peak | **146** | Cass Lake 115 | Forbes-Dorsey 500 | **560** | Langdon 115 | Ramsey-Balta 230 |
| Summer Peak | **635** | Cass Lake 115 | Letellier-Drayton 230 | **585** | Hensel 115 | Ramsey-Balta 230 |
| **South Zone** | | | | | | |
| Winter Peak | **340** | Enderlin 115 | Jamestown-Center 345 | **440** | Enderlin 115 | Jamestown-Center 345 |
| Summer Peak | **455** | Alexandria 115 | Jamestown-Center 345 | **480** | Alexandria 115 | Jamestown-Center 345 |
| **Combined Zone** | | | | | | |
| Winter Peak | **440** | Hubbard 115 | Forbes-Dorsey 500 | **750** | Enderlin 115 | Jamestown-Center 345 |
| Summer Peak | **655** | Enderlin 115 | Jamestown-Center 345 | **720** | Alexandria 115 | Jamestown-Center 345 |

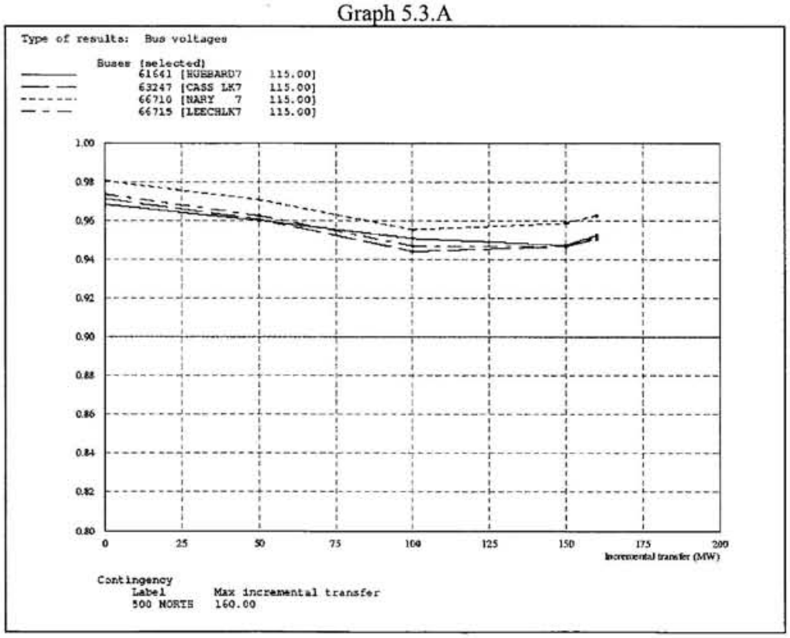
### 5.3.2 P-V Analysis

This analysis is for the purpose of determining the load levels at which voltage violations are encountered as load is increased within each study zone. Table 5.3.B shows how the addition of the Bemidji-Boswell 230 kV line affects the incremental load-serving capability of the three zones. As shown in the table, Cass Lake 115 kV voltages are the limiting consideration for North Zone for both Winter and Summer Peak conditions. Graph 5.3.A shows existing system incremental load capability for North Zone during Winter Peak conditions for the outage of the North 500 kV line.

For Winter Peak conditions, the North Zone load can be increased dramatically after the Bemidji–Boswell 230 kV line has been added. From Table 5.3.B it is observed that the load serving capability for N-1 conditions increases from 146 MW to 560 MW, while the N-2 load serving limit increases from 0 MW to 300 MW.

During Summer Peak conditions, the Bemidji–Boswell 230 kV line helps with the Bemidji area voltages but also encourages more flow southward through the Red River Valley via the Letellier-Drayton 230 kV line. The result is that the Drayton/Hensel area voltage becomes the limiting condition at an incremental load value of 585 MW. This interesting result isn't the most limiting condition, since Winter Peak has a slightly lower incremental load value (560 MW). More-detailed results can be found in Appendices H and I.

Graph 5.3.A

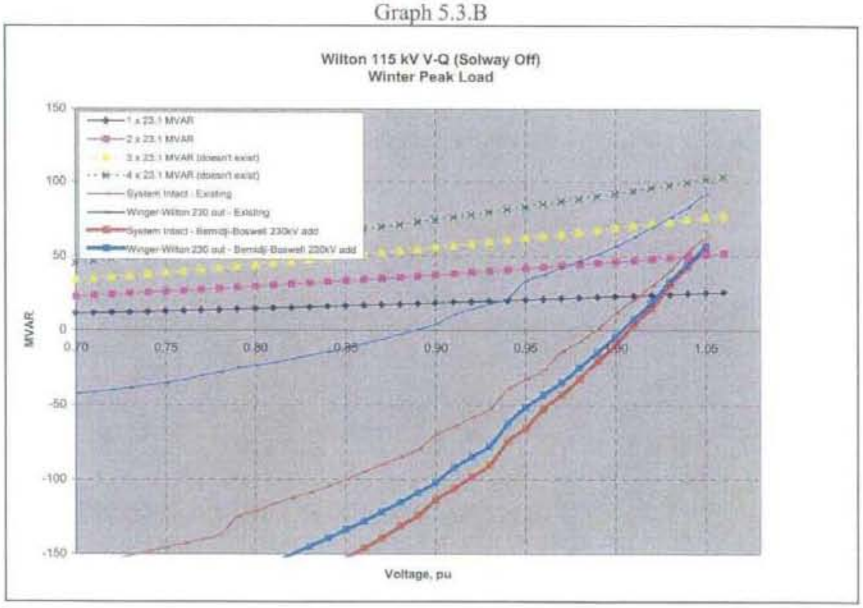


### 5.3.3 V-Q Analysis

V-Q analysis was then performed at a few critical buses within the Red River Valley region based on the results of the previously mentioned TLTG and PV analysis. Graph 5.3.B shows Wilton 115 kV bus reactive needs for system intact & N-1 in before and after the Bemidji-Boswell 230 kV line addition with the Solway generator off-line.

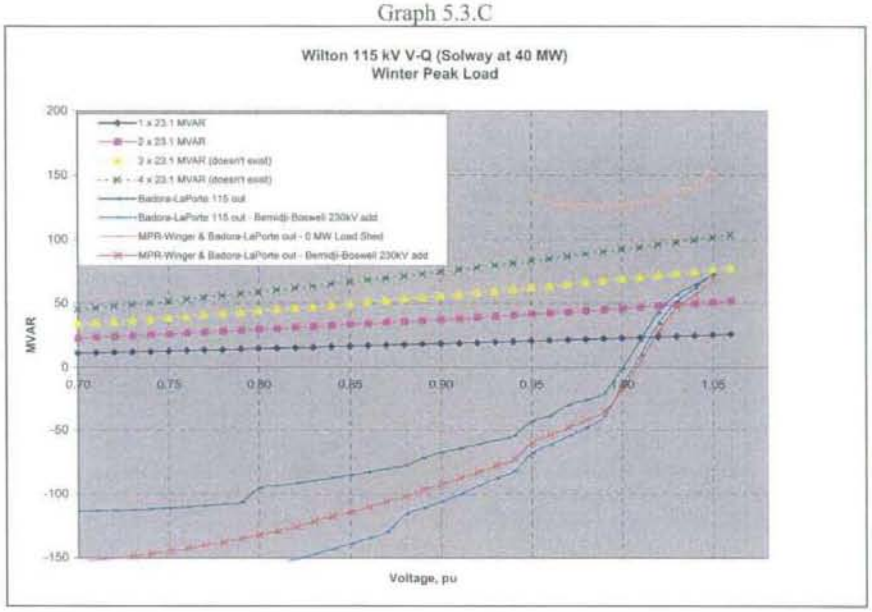
V-Q analysis was then performed at a few critical buses within the Red River Valley region based on the results of the previously mentioned TLTG and PV analysis. Graph 5.3.B shows Wilton 115 kV bus reactive needs before and after the Bemidji-Boswell 230 kV line addition with the Solway generator off-line. While Graph 5.3.C shows Wilton 115 kV bus reactive needs for the Badoura-LaPorte 115 kV line and the N-2 outage of both Badoura-LaPorte 115 kV line and Winger-Wilton 230 kV line for both before and after the Bemidji-Boswell 230 kV line addition with the Solway generator at 40 MW. As shown in these graphs, during both system intact conditions, N-1 conditions and N-2 conditions, the reactive need at the Wilton 115 kV bus is reduced when the new Bemidji–Boswell 230 kV line is added because it brings a new source into the Bemidji region.

Graph 5.3.B



Graph 5.3.C shows Wilton 115 kV bus reactive needs for N-1 and N-2 conditions both with and without the Bemidji-Boswell 230 kV line addition. As in Graph 5.3.B, the relevant N-1 contingency is outage of Winger-Wilton 230 kV. The relevant N-2 contingency is Winger-Wilton 230 kV & Badoura-LaPorte 115 kV. This graph shows that the winter peak reactive requirement during N-2 conditions is significantly beyond the existing Wilton capacitors' output capability (there are two capacitor banks, but the reactive requirement exceeds that of four). Furthermore, the critical voltage for this condition is unacceptably high (over .95 pu.).

Graph 5.3.C




Addition of the Bemidji-Boswell 230 kV line is seen to be very effective at addressing the Bemidji area voltage security challenge. This result is obtained because the Bemidji-Boswell 230 kV brings a new source into the Bemidji area.

### 5.3.4 ACCC Analysis

ACCC analysis was performed for each of the three RRV zones at the incremental MW load levels suggested in the N-1 PV analysis in Section 5.0. Table 5.3.C confirms the North Zone performance that would be obtained at the 560 MW load increment level with the Bemidji–Boswell 230 kV line addition. Similar analyses were performed at the, 440 MW and 750 MW load increments for the South and Combined Zones, respectively. The complete output of the ACCC analyses can be found in Appendix K.

Table 5.3.C
Performance with North Zone Winter Peak Load Increased by 560 MW

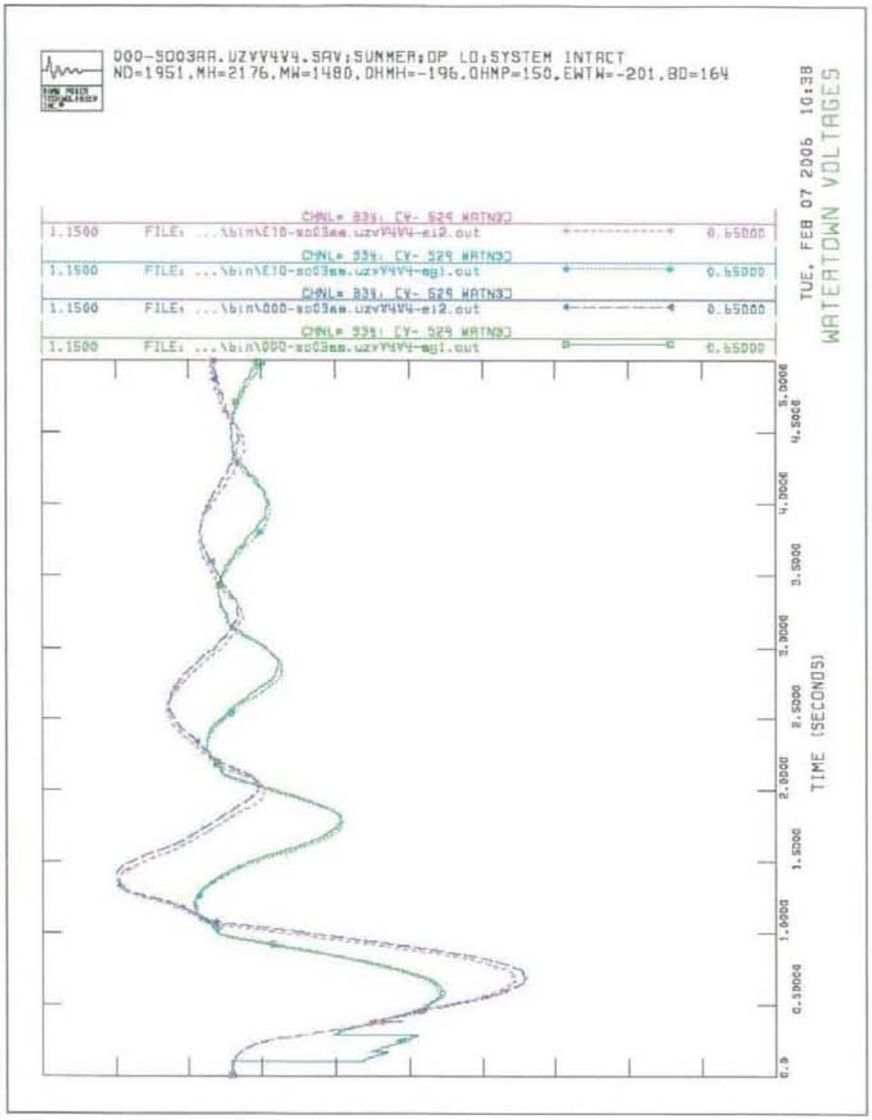
| Monitored Element | Contingency | Rating | Facility Loading MVA | Loading% |
|---|---|---|---|---|
| Winger 230 / 115 kV transformer | System Intact | 140 | 152 6 | **109.0** |
| Winger 230 / 115 kV transformer | Letelier-Drayton 230 kV line | 140 | 157 1 | 112 2 |
| Winger 230 / 115 kV transformer | Balta-Ramsey 230 kV line | 140 | 151 9 | 108.5 |
| Carrington-Jamestown 115 kV | Balta-Ramsey 230 kV line | 80 | 86 1 | 105.4 |
| Jamestown-Pickert 230 kV | Balta-Ramsey 230 kV line | 319 | 323 9 | 101 2 |
| Leeds-Rugby 115 kV | Balta-Ramsey 230 kV line | 120 | 136 6 | **114.5** |
| Jamestown-Pickert 230 kV | Maple River-Winger 230 kV line | 319 | 325.6 | 101.3 |
| Winger 230 / 115 kV transformer | Jamestown-Pickert 230 kV line | 140 | 157.4 | 112.4 |
| Carrington-Jamestown 115 kV | Jamestown-Pickert 230 kV line | 80 | 86 9 | 105.5 |
| Fargo 230 / 115 kV transformers | Jamestown-Pickert 230 kV line | 100 | 110 6 | 110.6 |

This ACCC analysis summary shows that the Winger 230/115 kV transformer loading (system intact) and the Leeds-Rugby 115 kV line loading (post-contingent) will limit the North Zone load-serving capability to a level lower than the 560 MW suggested by the PV analysis.

### 5.3.5 Dynamic Stability Analysis

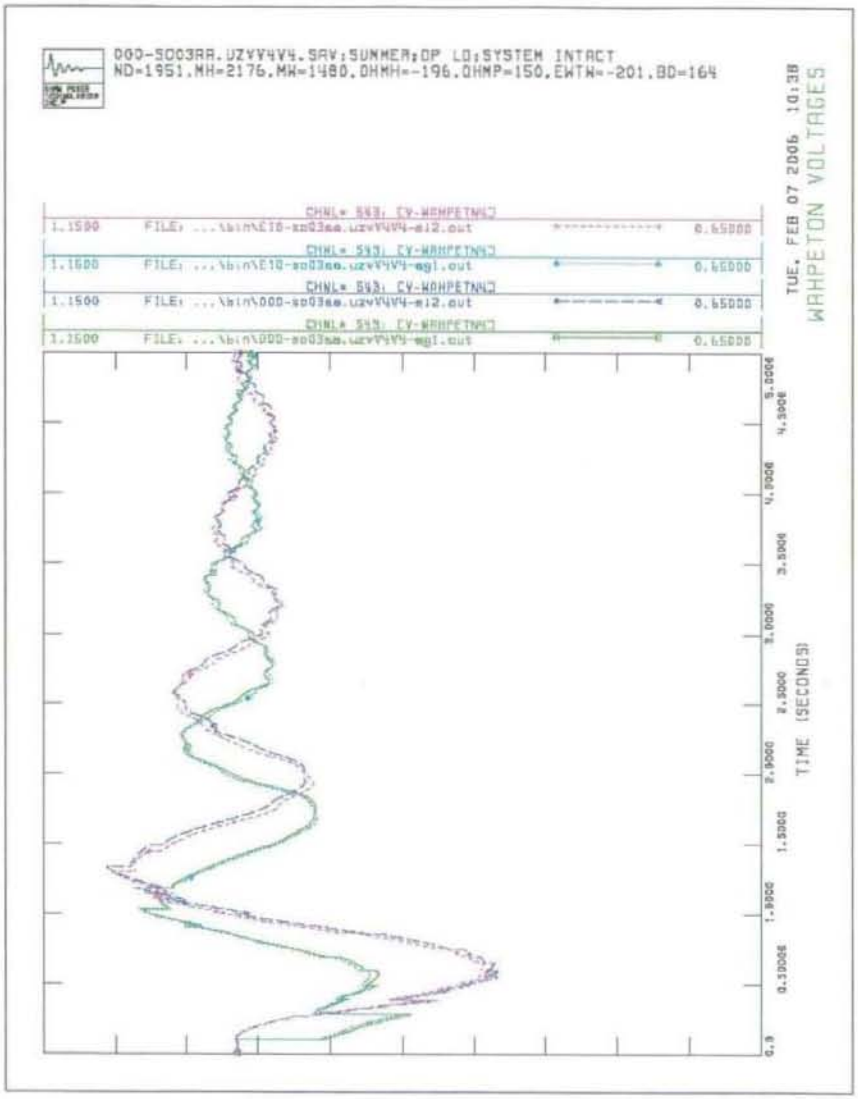
Dynamic stability analysis shows that the long-term solution of the Bemidji-Boswell 230 kV line (represented in simulations with case names beginning with "E10-") improves system damping and voltage performance compared to the existing system ("RRV-"). This is shown in the Watertown and Wahpeton voltage plots below and in more detail in Appendices M and N.

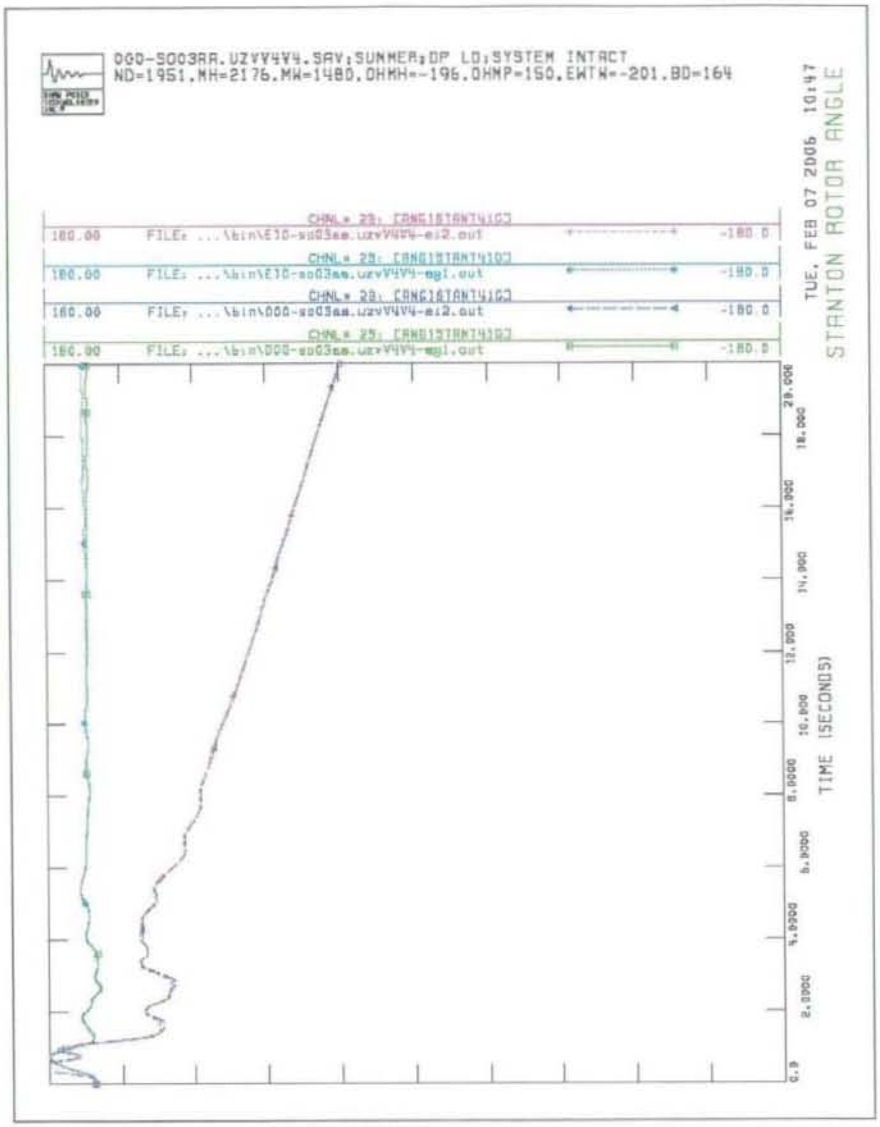
From these plots, it is determined that in addition to the local and regional load-serving benefits achieved, the Bemidji-Boswell 230 kV line addition also appears to improve power system dynamic performance sufficiently to yield approximately 100-150 MW of incremental capability on the NDEX interface






Appendix A-3
Application for Three 345 kV Projects
E-002/CN-06-1115


000-S003AA.UZVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
TUE, FEB 07 2006 10:38
WAHPETON VOLTAGES
TIME (SECONDS)


OGO-SOO3AA.UZVV4V4.SAV;SUMMER;DP LD;SYSTEM INTACT
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
TUE, FEB 07 2006 10:47
STANTON ROTOR ANGLE
TIME (SECONDS)

## 5.4 *Fargo-St. Cloud 345 kV line*

The Fargo-St. Cloud 345 kV line would connect the transmission system from eastern North Dakota to the 345 kV system in the northwestern Twin Cities. During the majority of this study, this line was modeled as extending from the Maple River 345 kV bus to the Benton County 345 kV bus with a tap and step-down transformer in Alexandria. However, additional analyses (Appendix A) were performed to examine the relative merits of the Benton County termination and alternate southern termini (Sherco and Monticello) for the proposed 345 kV line with regard to its effectiveness in providing St. Cloud area load-serving capability.

Diagram 5.4.A shows the region that was determined to be the principal load benefit area for this 345 kV line addition.

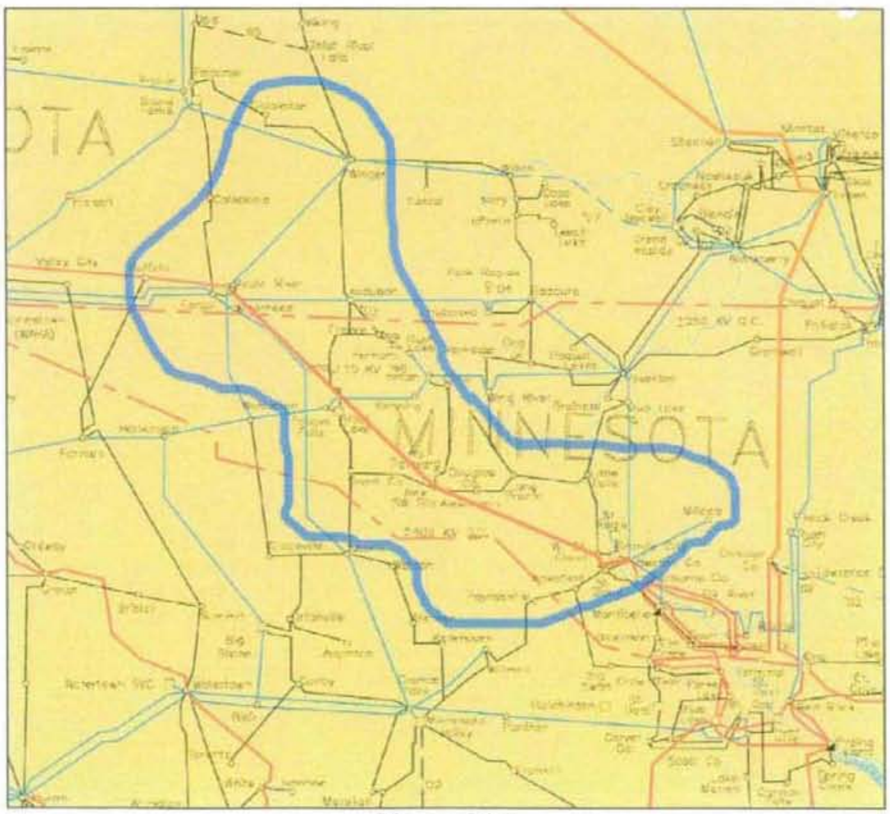



Diagram 5.4.A
Load Benefit Area for the Fargo-St. Cloud 345 kV Line Addition

### 5.4.1 TLTG Analysis

Based on the study results, the Fargo-St. Cloud 345 kV line is the transmission option which provides the greatest load-serving benefit to the South Zone of the Red River Valley. It also significantly helps the Combined Zone if the local Bemidji area load-serving issues are separately addressed. Without the Bemidji area fix (presumably Bemidji-Boswell 230 kV), the Fargo–St. Cloud 345 kV line has the undesirable characteristic of encouraging flow on the Badoura–LaPorte 115 kV line for the Maple River–Winger 230 kV outage

Table 5.4.A compares bulk transmission overloads (in terms of incremental load MW beyond the base 2003/2004 peak levels) for the "existing system" and the "Fargo- St. Cloud 345 kV line addition" scenarios; more detail can be found in Appendices F and G. From this table it is concluded that the Fargo-St Cloud 345 kV line yields a large increase in the incremental South Zone thermal load-serving limit, but is not capable of independently addressing the North Zone limitations. Furthermore, the limitations encountered for South Zone load serving are relatively easily addressed following addition of the new 345 kV line, by reconductoring short 230 kV and 115 kV line segments, adding 230/115 kV transformer capacity, or by tapping the new 345 kV line at the Sheyenne substation.

Table 5.4.A
TLTG Analysis Incremental Load-Serving Capability
(Thermal-based Limits)

| | Existing System | | | Fargo-St. Cloud 345 kV Addition | | |
|---|---|---|---|---|---|---|
| | MW | Limiting Element | Contingency | MW | Limiting Element | Contingency |
| **North Zone** | | | | | | |
| Winter Peak | 112 | Hankinson-Wahpeton 230 | Jamestown-Center 345 | 168 | Winger 230/115 tx | Grand Forks-Falconer 115 |
| Summer Peak | 170 | Drayton 230/115 tx #1 | Drayton 230/115 tx #2 | 173 | Drayton 230/115 tx #1 | Drayton 230/115 tx #2 |
| **South Zone** | | | | | | |
| Winter Peak | 328 | Sheyenne-Fargo 230 | Jamestown-Center 345 | 422 | Sheyenne-Maple River 230 | Maple River-RedRiver 115 |
| Summer Peak | 342 | Sheyenne-Fargo 230 | Jamestown-Center 345 | 453 | Maple River 230/115 #1 | Maple River 230/115 #2 |
| **Combined Zone** | | | | | | |
| Winter Peak | 312 | Hoot Lake-Edge Tap 115 | Audubon 230/115 tx | 299 | Hoot Lake-Edge Tap 115 | Audubon 230/115 tx |
| Summer Peak | 467 | Sheyenne-Fargo 230 | Jamestown-Center 345 | 472 | Maple River 230/115 #1 | Maple River 230/115 #2 |

Table 5.4.B
PV Analysis Incremental Load-Serving Capability
(Voltage-based Limits)

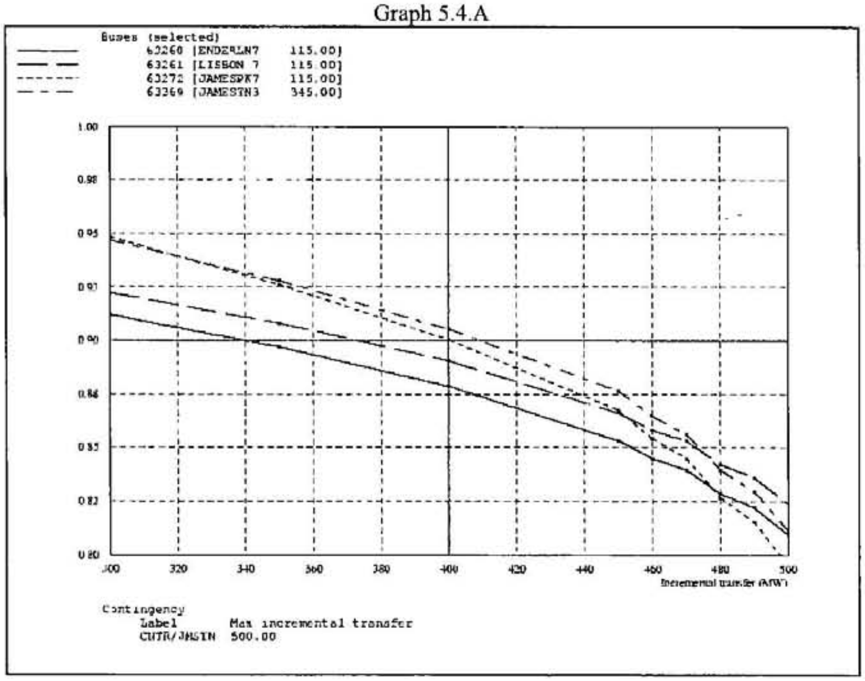
| | Existing System | | | Fargo-St. Cloud 345 kV Addition | | |
|---|---|---|---|---|---|---|
| | MW | Limiting Voltage | Contingency | MW | Limiting Voltage | Contingency |
| **North Zone** | | | | | | |
| Winter Peak | 146 | Cass Lake 115 | Forbes-Dorsey 500 | 370 | Cass Lake 115 | Maple River-Winger 230 |
| Summer Peak | 635 | Cass Lake 115 | Letellier-Drayton 230 | 645 | Hensel 115 | Ramsey-Balta 230 |
| **South Zone** | | | | | | |
| Winter Peak | 340 | Enderlin 115 | Jamestown-Center 345 | 585 | Enderlin 115 | Jamestown-Center 345 |
| Summer Peak | 455 | Alexandria 115 | Jamestown-Center 345 | 685 | Enderlin 115 | Jamestown-Center 345 |
| **Combined Zone** | | | | | | |
| Winter Peak | 440 | Hubbard 115 | Forbes-Dorsey 500 | 875 | Enderlin 115 | Forbes-Dorsey 500 |
| Summer Peak | 655 | Enderlin 115 | Jamestown-Center 345 | 950 | Enderlin 115 | Jamestown-Center 345 |

## 5.4.2 P-V Analysis

Table 5.4.B shows the Fargo-St. Cloud 345 kV line addition's effects on the three zones' incremental load-serving capability based on voltage adequacy considerations. It is observed that the Fargo-St. Cloud 345 kV line improves voltage performance throughout the Red River Valley/northwest Minnesota study area, particularly for winter peak conditions, which are the most limiting conditions with heavy Manitoba imports. This performance improvement is achieved because the new line provides a low-impedance transmission path into the RRV from the strong Sherco/Monticello source, thereby raising voltages throughout the Red River Valley for most regional outages. Graph 5.4.A shows existing system incremental load-serving capability for the South Zone during Winter Peak conditions for the outage of the Jamestown-Center 345 kV line.

The South Zone load serving capability for N-1 conditions increases from 340 MW to 585 MW, while the corresponding limit for N-2 conditions increases from 155 MW to 320 MW. More detailed results can be found in Appendices H and I.

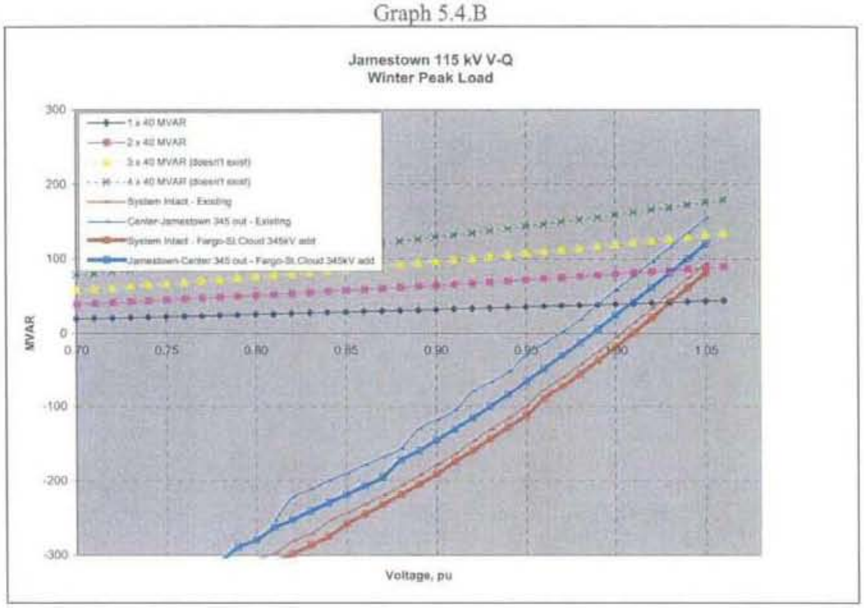
Graph 5.4.A



## 5.4.3 V-Q Analysis

V-Q analysis was performed for a few critical buses in the Red River Valley region. These buses were selected based upon study participants' experience and judgment, and the results derived from the PV analysis. Graph 5.4.B shows the reactive requirements found for the WAPA Jamestown 115 kV bus before and after the Fargo-St. Cloud 345 kV line addition. During both system intact and outage of the Center-Jamestown 345 kV line, the reactive needs at the WAPA Jamestown 115 kV bus are reduced by addition of the Fargo-St. Cloud 345 kV line.

Graph 5.4.B



### 5.4.4 ACCC Analysis

ACCC analysis was performed for each of the three RRV zones at the incremental MW load levels suggested in the N-1 PV analysis in Section 5.0. The complete output of the ACCC analysis can be found in Appendix K. Table 5.3.C confirms the performance in the region that would be obtained with the Fargo-St. Cloud 345 kV line addition with approximately 585 MW of addition load in the South Zone. Also, 370 MW and 875 MW load increments was modeled in the North and Combined Zones, respectively.

Table 5.4 C
Performance with South Zone Winter Peak Load Increased by 585 MW

| | | | Facility Loading | |
|---|---|---|---|---|
| Monitored Element | Contingency | Rating | MVA | Loading% |
| Hoot Lake-Edge tap 115 kV | System Intact | 96 | 115.8 | **118.1** |
| Fargo 230 / 115 kV transformers | System Intact | 100 | 131.0 | **131.0** |
| Hoot Lake-Edge tap 115 kV | Prairie-Winger 230 kV line | 96 | 116 2 | **119.0** |
| Hoot Lake-Edge tap 115 kV | Maple River-Wahpeton 230 kV line | 96 | 127 4 | **131.0** |
| Pelican Rapids-Edge tap 115 kV | Maple River-Wahpeton 230 kV line | 96 | 102 0 | **105.2** |
| Hoot Lake-Edge tap 115 kV | Center-Jamestown 345 kV line | 96 | 118 5 | **125.8** |
| Hoot Lake-Edge tap 115 kV | Badoura-Riverton 230 kV line | 96 | 127 2 | **130.6** |
| Pelican Rapids-Edge tap 115 kV | Badoura-Riverton 230 kV line | 96 | 101 8 | **104.9** |

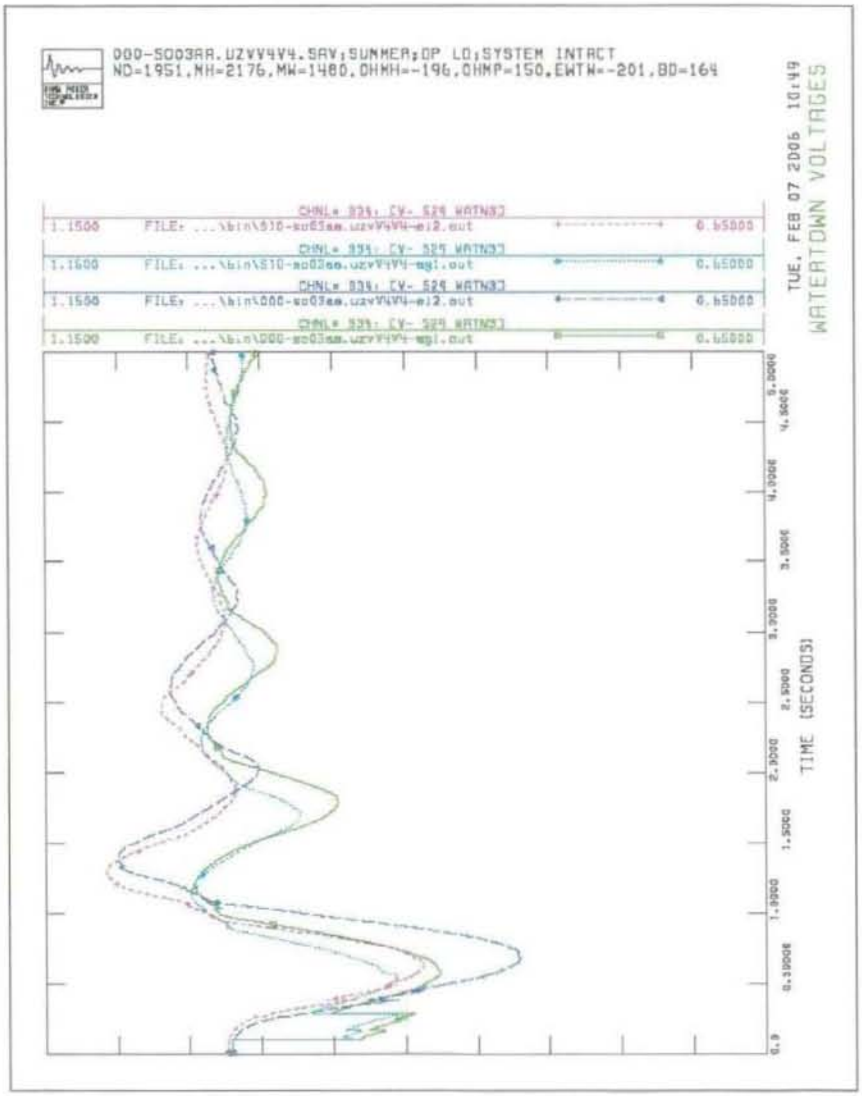
This ACCC summary suggests that two line and transformer upgrades would be required in order to achieve the 585 MW load-serving increment indicated by the P-V analysis. However, the Fargo 230/115 kV transformers are already scheduled for replacement with larger units sometime during the next few years—long before a load increment of 585 MW would be experienced. Consequently, the only additional system upgrade required in order to achieve the 585 MW load-serving increment would be the Hoot Lake-Edge Tap 115 kV reconductor.

### 5.4.5 Dynamic Stability Analysis

Testing the long-term solution of the Fargo-St Cloud 345 kV line addition ("S10-") shows that power system dynamic stability performance improves with respect to the critical measures of system damping and dynamic voltage performance compared to the existing case ("RRV-"). The Fargo-St. Cloud 345 kV line is shown to reduce the reactive outputs required at the existing Watertown and Fargo SVCs This is shown in the Watertown and Wahpeton Voltage Plots (Figure 5.4.5) and in more detail in Appendices M and N.

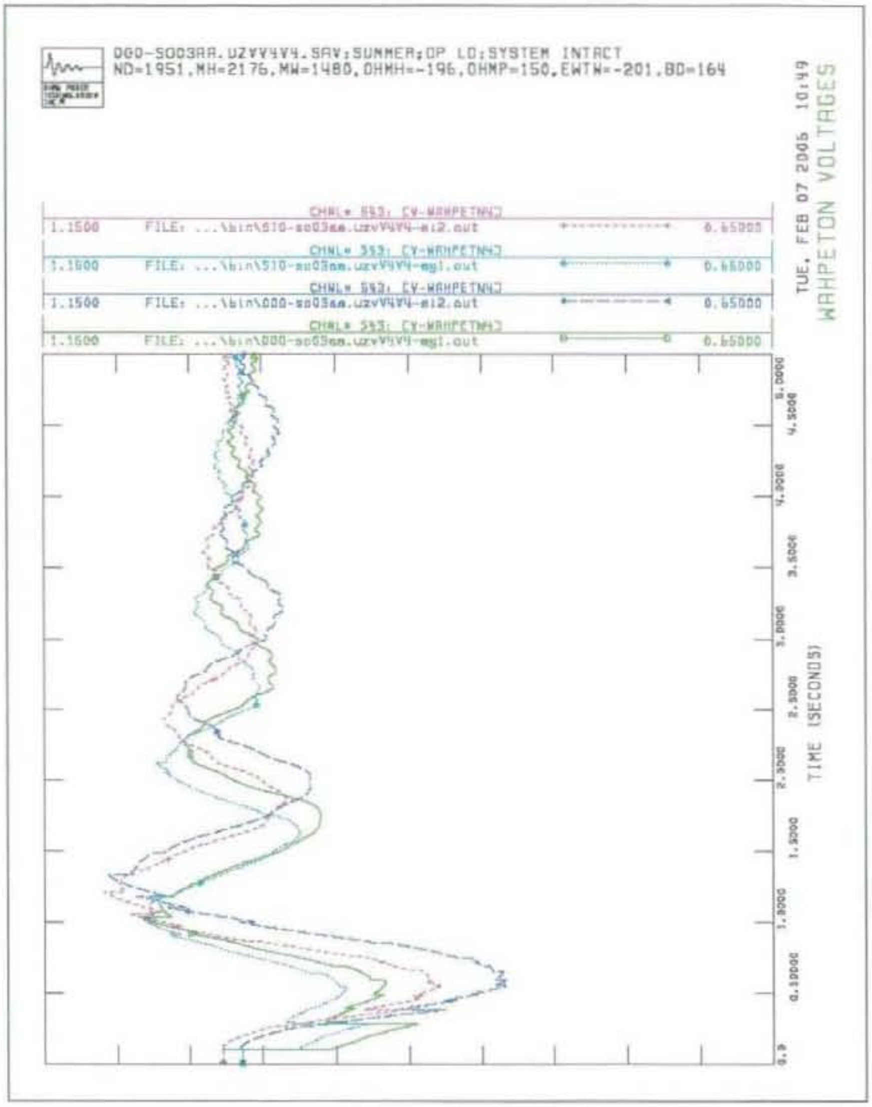
The observed improvement in dynamic stability performance indicates that, in addition to the important load-serving benefits, the Fargo-St. Cloud 345 kV line addition is also anticipated to yield approximately 350 MW of additional NDEX capability. Stability simulations at this higher NDEX transfer level are provided in Appendix M.

When testing both long-term solutions (Bemidji-Boswell 230 kV and Fargo-St. Cloud 345 kV lines) along with the short-term reactive improvements (Wilton SVC and Prairie SVC), the achievable NDEX capability as measured by the dynamic stability limit, increases by a total of approximately 550 MW, to 2500 MW, based on an existing recognized NDEX dynamic stability limit of 1950 MW.



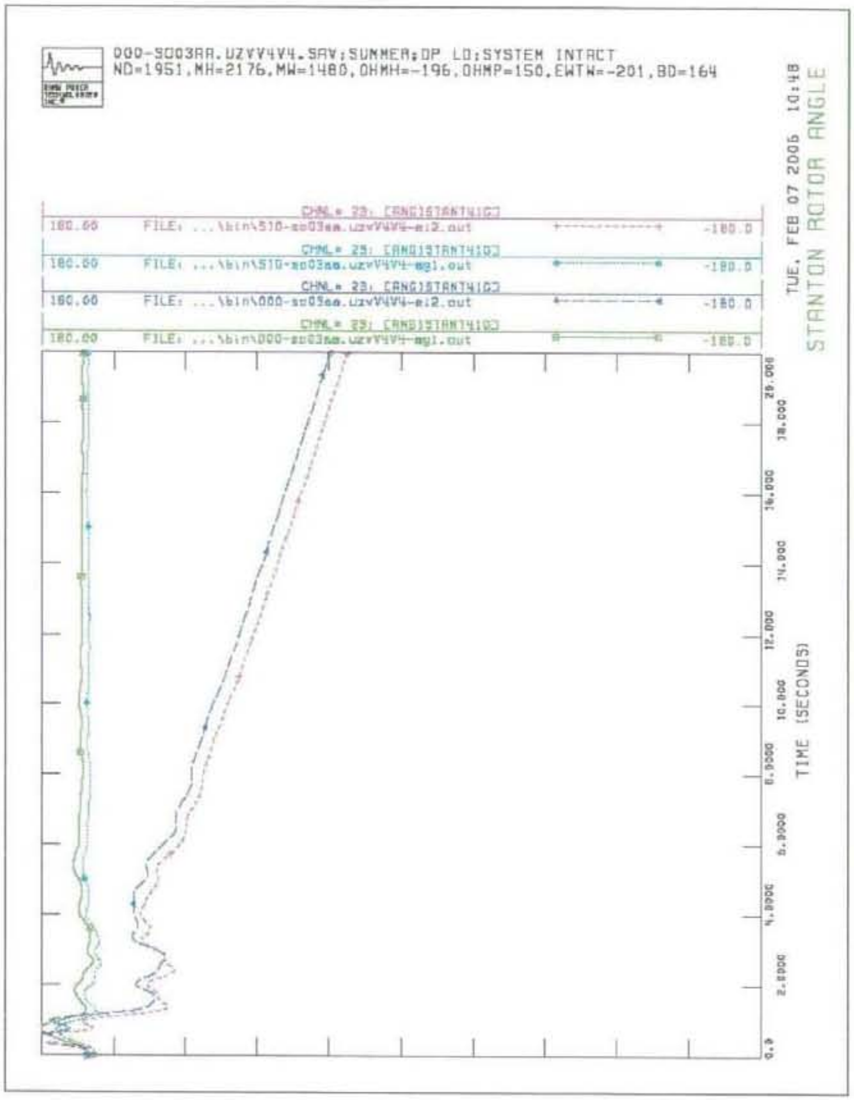



Appendix A-3
Application for Three 345 kV Projects
E-002/CN-06-1115






**Appendix A-3**
Application for Three 345 kV Projects
E-002/CN-06-1115



OOO-SOO3AA.UZVV4V4.SAV;SUMMER;OP LO;SYSTEM INTACT
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
CHNL= 23: [ANG]STANT4[G]
180.00 FILE: ...\bin\510-so03aa.uzvV4V4-e;2.out -180.0
180.00 FILE: ...\bin\510-so03aa.uzvV4V4-mgl.out -180.0
180.00 FILE: ...\bin\000-so03aa.uzvV4V4-e;2.out -180.0
180.00 FILE: ...\bin\000-so03aa.uzvV4V4-mgl.out -180.0
TUE, FEB 07 2006 10:48
STANTON ROTOR ANGLE
TIME (SECONDS)

**Appendix A-3**
Application for Three 345 kV Projects
E-002/CN-06-1115

# 6.0 Loss Analysis

Transmission losses consist of demand (MW) and energy (MWh) losses. The demand loss analysis (Section 6.1) is performed by examining the powerflow simulations' loss data for the conditions of interest. The annual energy losses for the transmission options (Section 6.2) are calculated from the demand loss values by means of an annual loss factor. Derivation of this loss factor is also described in Section 6.2.

A 20-year cumulative present worth economic evaluation of the transmission options' demand and energy loss reductions is provided in Section 6.3.

## *6.1 Demand losses*

Table 6.1.A shows the winter peak losses for the relevant combinations of system conditions for the "Total System" and the different control areas in the Red River Valley vicinity. The "Total System Losses" figures in this tabulation are the demand (MW) losses for the entire North American Eastern Interconnection for the configuration and loading condition studied. This table shows results for only the Bemidji-Boswell 230 kV and Fargo-St Cloud 345kV options, as they result in the largest loss reductions. Subsequent tables include results for all transmission options studied.

Table 6.1.A
Transmission Losses, MW
Winter Peak (with actual 2003/4 RRV Loads)
(MHEX = -717 MW, NDEX = -77 MW)

| | Losses, MW | | | | | |
|---|---|---|---|---|---|---|
| | **Total System** | **GRE** | **MP** | **OTP** | **WAPA** | **Xcel** |
| **Existing System** | 11963.0 | 99.6 | 105.5 | 72.5 | 170.8 | 204.6 |
| **Add Bemidji-Boswell 230 kV** | 11941.1 | 98.1 | 91.7 | 73.5 | 164.4 | 202.2 |
| Reductions: (MW) | 21.9 | 1.5 | 13.8 | -1.0 | 6.4 | 2.4 |
| (% of total) | 100 | 7 | 63 | -5 | 29 | 11 |
| **Add Fargo-St Cloud 345 kV** | 11943.4 | 97.8 | 100.3 | 71.6 | 165.9 | 195.7 |
| Reductions: (MW) | 19.6 | 1.8 | 5.2 | 0.9 | 4.9 | 8.9 |
| (% of total) | 100 | 9 | 27 | 5 | 25 | 45 |
| **Add Bemidji-Boswell 230 kV& Add Fargo-St Cloud 345 kV** | 11927.2 | 96.8 | 89.1 | 72.1 | 161.4 | 194.7 |
| Reductions: (MW) | 35.8 | 2.8 | 16.4 | 0.4 | 9.4 | 9.9 |
| (% of total) | 100 | 8 | 49 | 1 | 26 | 28 |

From this table it is seen that loss reductions are present in nearly every control area for either transmission addition. The only exception is the Otter Tail control area for the Bemidji-Boswell 230 kV addition, which is due to the new line being modeled entirely in the OTP control area. This result would not be obtained if the new line were instead modeled in the MP control area.

The 21.9 MW total loss reduction achieved by the Bemidji-Boswell 230 kV line is notable, considering no special effort such as consideration of alternative conductor sizes has been made to optimize its performance and that the much-longer Fargo-St Cloud 345 kV addition yields only a 19.6 MW total loss reduction.

Economic evaluation of the demand (MW) losses was not performed based on the Table 6.1.A values because they reflect winter peak conditions. Although the load regions of interest are winter peaking, and the resultant loss reductions will generally be highest during winter peak conditions, the Midwestern U.S. is strongly summer peaking. Consequently, winter season generating capacity is of relatively low incremental value because adequate generating capacity is installed to satisfy the higher summer capacity requirements. Table 6.1.B shows both the summer and winter demand loss reductions

Table 6.1B
Demand Loss reductions, MW
(Total Eastern Interconnection)

| | Winter | Summer |
|---|---|---|
| West Source (Harvey-Prairie 230 kV) | 7.0 | 3.4 |
| North Source (Letellier-Drayton-Prairie 230 #2) | 2.4 | 5.7 |
| East Source (Bemidji-Boswell 230 kV) | 21.9 | 5.3 |
| South Source (Fargo-St. Cloud 345 kV) | 19.6 | 12.1 |
| Internal (Fargo-Grand Forks 230 kV) | 4.0 | 0.3 |
| Bemidji-Boswell 230 & Fargo-St. Cloud 345 kV | 35.8 | 17.1 |

From Table 6.1.B it is seen that all transmission options except for the "North Source" have significantly lower loss reductions during summer peak than winter peak. The North Source differs from all other options by having higher loss reduction during summer peak conditions because this option establishes a new Manitoba-U.S. interconnection: the new line relieves loading on the other Manitoba-U.S. interconnections, which are heavily loaded during the summer condition

Based on the summer demand loss reductions, the transmission options yield the following annual demand-related savings, based on the assumption that the capacity savings represents an avoided installation of generation peaking capacity having an installed cost of $400/kW and an annual fixed charge rate of 15%:

Table 6.1C
Annual Demand Loss Savings, $1,000's
(Total Eastern Interconnection)

| | | |
|---|---|---|
| West Source | (Harvey-Prairie 230 kV) | $ 235 |
| North Source | (Letellier-Drayton-Prairie 230 #2) | 393 |
| East Source | (Bemidji-Boswell 230 kV) | 366 |
| South Source | (Fargo-St. Cloud 345 kV) | 835 |
| Internal | (Fargo-Grand Forks 230 kV) | 21 |
| Bemidji-Boswell 230 & Fargo-St. Cloud 345 kV | | 1,180 |

Note: above values are based on 115% of actual MW loss reduction, because reserve sharing pool capacity obligation is 115% of load and losses.

## 6.2 Energy Losses

Annual energy loss savings are calculated from the winter demand losses by use of an annual loss factor. The loss factor was computed using the real-time line loading data provided for the study. As a Combined Zone, each hourly demand (load + losses) was normalized to the peak demand of 1903.7 MW. The average of these normalized values is the load factor; it was determined to be 63.1%

The normalized hourly demand values were then squared. The average of these squared normalized values is the annual loss factor; it was determined to be 41.5%.

The following table shows all the load factors and loss factors for the study zones

Table 6.2.A
Load and Loss Factors, %

| Zone | Load Factor | Loss Factor |
|---|---|---|
| North | 63.4 | 42.2 |
| South | 59.4 | 36.8 |
| Combined | 63.1 | 41.5 |

The "Combined Zone" factors don't equal the average of the North and South Zones' factors even when adjusted for the differing amounts of load in the two zones, due to the non-coincident nature of the two zones' peak loads. In fact, the two zones' peak loads occurred on different days during the winter studied (2003-2004).

Annual Energy Loss Savings were obtained by multiplying the on-peak winter MW loss reduction by the Loss Factor and by the number of hours per year (8760). The resultant annual MWh figures were then converted to corresponding dollar values by multiplying by an assumed average annual energy cost of $25/MWh. This $25/MWh energy cost is an estimated average cost of replacement energy from the existing regional generation resources. This value is representative of present-day energy costs. No effort was made to reflect possible future energy cost escalation.

Table 6.2.B
Evaluation of Energy Losses
(At $25/MWh energy value)

| | | Peak Loss Reduction MW | Loss Factor % | Loss Savings Avg MW | Annual Losses MWh | Annual Savings $ 1,000's |
|---|---|---|---|---|---|---|
| West Source | (Harvey-Prairie 230 kV) | 7.0 | 41.5 | 2.9 | 25,400 | 635 |
| North Source | (Letellier-Drayton-Prairie 230 #2) | 2.4 | 41.5 | 1.00 | 8,760 | 219 |
| East Source | (Bemidji-Boswell 230) | 21.9 | 41.5 | 9.1 | 79,700 | 1,990 |
| South Source | (Fargo-St. Cloud 345 kV) | 19.6 | 41.5 | 8.1 | 71,000 | 1,780 |
| Internal | (Fargo-Grand Forks 230 kV) | 4.0 | 41.5 | 1.7 | 14,900 | 373 |
| Bemidji-Boswell 230 & Fargo-St. Cloud 345 kV | | 35.8 | 41.5 | 14.9 | 131,000 | 3,280 |

Table 6.2.B shows the annual energy loss savings resulting from the "East" and "South" sources are the highest (nearly $2 million), while addition of *both* the Bemidji–Boswell 230 kV and the Fargo–St. Cloud 345 kV line yields an annual energy loss savings of approximately $3.3 million.

### 6.3 Preliminary Present Value Economic Analysis

The present value economic analysis described in this section was performed to assist in determining whether the transmission options' loss differences are significant relative to their capital-related revenue requirements. It is important to keep in mind that this analysis was performed utilizing indicative facility costs and estimated quantities, in conjunction with economic parameter values and assumptions that were considered by the study group to be appropriate for this preliminary type of analysis.

More-detailed analyses, which will be performed at a later date by individual transmission entities or groups of project participants, will employ data derived from better-defined line routes, refined substation configurations, and company-specific economic parameters. Consequently, the installed costs, associated revenue requirements, and calculated present values will likely differ somewhat from those presented in this preliminary analysis. Recognizing these limitations, the values presented in this present analysis are suitable and appropriate for their intended use in identifying differences among the transmission options' economic performance.

The cumulative lifetime economic value of the demand and energy loss reductions was evaluated for each transmission option by assuming a 20-year period for the duration of the loss differences, and a discount rate of 6.0%/yr, resulting in a 11.47 "present value of annuity" factor.

Transmission system economic analyses are ordinarily conducted with longer study periods, typically 30 to 50 years. However, a 20-year study period was selected in this instance because the loss differences change over time as transmission system additions are made and as use of the transmission system is modified due to both changes in generation patterns and changes in load levels and locations. Use of a 20-year term ensures that the calculated loss values will tend to be conservative (low compared to actual results obtained).

Table 6.3.A shows, for each transmission option, the 20-year cumulative present value of the demand and energy losses.

Table 6.3.A
Economic Evaluation of Demand and Energy Losses:
Annual and 20-Year Cumulative Present Value of Loss Reductions

| | | Annual Savings ($1,000's) | | | Cumulative |
|---|---|---|---|---|---|
| | | Demand | Energy | Total | ($ Millions) |
| West Source | (Harvey-Prairie 230 kV) | 235 | 635 | 870 | 10.0 |
| North Source | (Letellier-Drayton-Prairie 230 #2) | 393 | 219 | 612 | 7.0 |
| East Source | (Bemidji-Boswell 230) | 366 | 1,990 | 2,356 | 27.0 |
| South Source | (Fargo-St. Cloud 345 kV) | 835 | 1,780 | 2,615 | 30.0 |
| Internal | (Fargo-Grand Forks 230 kV) | 21 | 373 | 394 | 4.5 |
| Bemidji-Boswell 230 & Fargo-St. Cloud 345 kV | | 1,180 | 3,280 | 4,460 | 51 2 |

From Table 6.3.A it is evident that the Bemidji-Boswell 230 kV and the Fargo-St. Cloud 345 kV transmission options yield significantly higher loss savings than any of the other options. Also notable is that the "Combined" option of installing both the Bemidji-Boswell 230 kV and the Fargo-St. Cloud 345 kV line yields a 20-year present worth loss savings of over $51 million.

To put the loss savings in perspective relative to the transmission options' costs, Table 6.3.B provides a rough comparison of the cumulative loss savings (from Table 6 3 A) to the transmission projects' 35-year lifetime ownership costs. The transmission options' "cumulative present worth of revenue requirements" estimate is based on the following:

- Approximate line mileages, per Table 6.3.B
- Installed cost of $500,000/mile for 230 kV and $800,000/mile for 345 kV line
- Substation costs are $2,000,000 per substation involved
- Fixed Charge Rate for transmission of 16%
  (This is the factor used to compute the Levelized Annual Revenue Requirement [LARR])
- Discount rate = 6%/yr
- Term = 35 years (assumed life of transmission facility)

The resultant "present value of annuity" factor for the 35-year term is 14.50.

The transmission line and substation installed cost estimates derived from these assumptions are admittedly very approximate, as they are developed from generic per-mile and per-site cost values, without benefit of detailed site or route investigations, or specific facility designs. However, cost estimates of this type are adequate for the purpose of determining for each transmission option whether the cumulative present value of the loss savings is significant compared to the cumulative present value of the transmission option's revenue requirements.

Table 6.3.B
Computation of 20-yr Loss Savings as a % of
Transmission Options' Cumulative Present Worth of Revenue Requirements

| | | | $ Millions | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Installed cost | | | | Cum PW | | % |
| | | Miles | line | subs | total | LARR | xmsn | losses | |
| West Source | (Harvey-Prairie 230 kV) | 145 | 73 | 6 | 79 | 12.6 | 183 | 10.0 | 5 |
| North Source | (Letellier-Drayton-Prairie 230 #2) | 110 | 55 | 6 | 61 | 9.8 | 142 | 7.0 | 5 |
| East Source | (Bemidji-Boswell 230) | 65 | 33 | 4 | 37 | 5.9 | 86 | 27.0 | 31 |
| South Source | (Fargo-St. Cloud 345 kV) | 165 | 132 | 8 | 140 | 22.4 | 325 | 30.0 | 9 |
| Internal | (Fargo-Grand Forks 230 kV) | 65 | 33 | 4 | 37 | 5.9 | 86 | 4.5 | 5 |
| Bemidji-Boswell 230 & Fargo-St. Cloud 345 | | 230 | 165 | 12 | 177 | 28.3 | 411 | 51.2 | 12 |

Examination of Table 6.3.B reveals that

- The Bemidji-Boswell 230 kV option's loss savings is equal to approximately 31% of its capital-related revenue requirements.
- The corresponding figure is 9% for the Fargo-St. Cloud 345 kV transmission option, while all other individual options are at only 5%.
- The "combined" Bemidji-Boswell/Fargo-St. Cloud option yields a 12% value.

From this information it is concluded that the Bemidji-Boswell 230 kV option's loss savings is significant relative to its capital-related revenue requirements. Even with the conservative assumptions employed, approximately 1/3 of the Bemidji-Boswell 230 kV line's revenue requirements are expected to be offset by the demand and energy savings resulting from its installation.

## 7.0 Conclusions

The Northern region of the Red River Valley needs transmission improvements in the near term. During winter peak load conditions, with northward flow across MHEX, this area in the near term will be deficient with respect to first contingency (N-1) and is currently deficient for second contingency (N-2) load-serving capability. The deficiency is based upon the identified inability to maintain post-contingent voltages above criteria, primarily in the vicinity of Bemidji.

The short-term improvement of additional Wilton reactive support would help with voltages in the Bemidji area until a long-term transmission addition, such as the Bemidji-Boswell 230 kV line, could be placed in service. The reactive support would then have ongoing value in supporting the new source's effectiveness in load-serving and would provide regional dynamic stability benefits if it were an SVC or equivalent device.

The Fargo-St. Cloud 345 kV transmission option is not particularly effective at providing load-serving support to the northern RRV sub-area because the Maple River-Winger 230 kV outage isolates this new transmission source from the northern RRV load center. However, it very effectively addresses the existing St. Cloud and imminent Alexandria N-1 load-serving deficiencies while improving N-1 and N-2 load-serving capability for the region as a whole.

The Southern region needs additional shunt capacitor additions to support post-contingent voltages, until a long-term transmission improvement can be implemented. These capacitor additions would be in the Jamestown (WAPA) and Hubbard/Audubon vicinities in addition to those recently completed. The most effective long-term transmission solution for the Southern region is the Fargo-St. Cloud 345 kV line, as it brings a new source into the Alexandria and Fargo load centers, and could also be developed in a way that could provide support to the Audubon/Hubbard vicinity. The Bemidji-Boswell 230 kV line, if constructed first, would also help augment Southern Region load-serving capability as an interim step, until the 345 kV line could be built into the area.

Ultimately, both the Bemidji-Boswell 230 kV and the Fargo-St. Cloud 345 kV lines or equivalent local generation additions are necessary for developing and maintaining adequate N-1 and N-2 load-serving capability into the Red River Valley / Northwestern Minnesota. In addition to load-serving benefits, the lines also appear to provide some increase in transfer capability across NDEX and reduce transmission losses. An additional study is under way to determine whether addition of local area electric generation is a reasonable alternative to the construction of new transmission lines.

# A St. Cloud 345 kV Sensitivity

<u>Background</u>

A sensitivity analysis was performed to evaluate various possible termination points of the proposed 345 kV line addition from Fargo to the northwestern corner of the Twin Cities 345 kV loop, with a presumed tap in the St. Cloud area. These three options were evaluated:

- The 345 kV line terminating at Benton Co. (what was used in this study outside of this sensitivity analysis), being routed north of St. Cloud, tapping the West St. Cloud-Little Falls 115 kV line and then crossing the Mississippi River before reaching the Benton Co. Substation.
- The 345 kV line terminating at Sherco, being routed south and west of St. Cloud (conceptually following the I-94 corridor) with a tie into the St Cloud 115 kV loop at or near the Sauk River or West St Cloud Substations and then crossing the Mississippi River to reach the Sherburne Co. Substation.
- The 345 kV line terminating at Monticello, being routed south and west of St. Cloud (conceptually following the I-94 corridor) with a tie into the St Cloud 115 kV loop at or near the Sauk River or West St Cloud Substation and then terminating at the Monticello Substation. No Mississippi River crossing is involved, as the Monticello Substation is located on the west bank of the river.

The following Table A.1 summarizes the three termination options' performance with respect to the amount of incremental St. Cloud metro area load that can be supported within the applicable loading criteria. Some shunt capacitor additions may be required to achieve these thermal limits; however, the economic impact of such differences between the termination options will be relatively minor compared to those of the thermal limits.

Table A.1
St. Cloud Double Contingency Comparison
For the Three Termination Options
(Incremental St. Cloud Metro Area Load, MW)

| <------ LIMITING ELEMENT ------> <---- FROM ----> <---- TO ---->CKT 110% OR 125% OF RATING | RATING | ------ CONTINGENCY DESCRIPTION ------ | BENTON | MONTI | SHERCO |
|---|---|---|---|---|---|
| Monticello 345/230 kV tx #6 | 336 | Sherco - St. Cloud Tap 115 kV line<br>Sherco - Benton 345 kV line | -20 | | |
| Monticello 345/230 kV tx #6 | 336 | Sherco - Benton 345 kV line<br>"SOURCE" - West St. Cloud Tap 345 kV line | | 246 | 246 |
| Monticello 345/230 kV tx #6 | 336 | Sherco - Benton 345 kV line<br>West St Cloud Tap 345/115 kV tx #1 | | 269 | 268 |
| Benton - Monticello 230 kV line | 383 | Sherco - St. Cloud Tap 115 kV line<br>Sherco - Benton 345 kV line | 232 | | |
| Benton - Monticello 230 kV line | 383 | Sherco - Benton 345 kV line<br>West St Cloud Tap 345/115 kV tx #1 | | 515 | 521 |
| Benton 230/115 kV tx # 5 or 6 | 336 | Benton 230/115kV tx # 6 or 5<br>W St. Cloud - West St. Cloud Tap 115 kV line | 284 | | |
| Benton 230/115 kV tx # 5 or 6 | 336 | Benton 230/115kV tx # 6 or 5<br>West St Cloud Tap 345/115 kV tx #1 | 318 | 318 | 321 |
| West St Cloud Tap 345/115 kV tx #1 | 448 | Benton 230/115kV tx # 5<br>Benton 230/115kV tx # 6 | 486 | 453 | 421 |
| Benton 230/115kV tx # 5 or 6 | 336 | Benton 230/115kV tx # 6 or 5<br>"SOURCE" - West St. Cloud Tap 345 kV line | 430 | 434 | 435 |
| Benton 345/230 kV tx #1 or 2 | 336 | Benton 345/230 kV tx # 2 or 1<br>West St Cloud Tap 345/115 kV tx #1 | 527 | 493 | 510 |
| Benton 345/230 kV tx #1 or 2 | 336 | Benton 345/230 kV tx # 2 or 1<br>Sherco - Monticello 345 kV line | 1221 | 343 | 968 |

All three termination options are conceptually similar with respect to the St. Cloud region because they provide a new transmission source to the West St. Cloud region. However, when terminating at Benton Co., the St. Cloud region doesn't receive an additional transmission source from the south (Sherco/ Monticello area). This greatly restricts the incremental load-serving capability of the region during N-1 conditions, particularly for loss of the Sherco-Benton Co 345 kV line. To solve this problem, a second 345 kV circuit would need to be added between the St. Cloud area and the Sherco/Monticello system.

There is little difference between the Monticello and Sherco terminations except for loss of the 345 kV tie between Monticello and Sherco. When this tie is lost, the phase angle between the machines at Monticello and Sherco becomes great enough to result in more power flowing from Sherco to St. Cloud than from Monticello to St. Cloud.

<u>Detailed comparison of termination options</u>
For the option of terminating the new line at the Benton Co. substation, no additional load-serving capability is achieved unless a second Monticello 345/230 kV transformer is added. With the addition of a second Monticello 345/230 kV transformer, the Benton Co option is limited to approximately 232 MW due to the overload of the Monticello-Benton Co. 230 kV line upon loss of the Sherco-Benton Co 345 kV. Reconductoring the 22-mile Monticello-Benton Co. 230 kV line would alleviate this problem, but the next limiter is encountered at 284 MW.

In contrast, the Monticello and Sherco termination options immediately achieve 246 MW of incremental load-serving capability. Addition of a second Monticello 345/230 kV transformer increases the incremental load-serving capability to approximately 320 MW, at which point addition of a second 345/115 kV transformer is required at the new St. Cloud area 345/115 kV substation.

Following the addition of the second transformer at the new St Cloud area 345/115 kV substation, the Monticello and Sherco options differ in performance. The Monticello option is limited to 343 MW by the outage of the Sherco-Monticello 345 kV line in conjunction with outage of one Benton Co 345/230 kV transformer. The Sherco option does not have this limitation; its next limiter is at 435 MW of incremental St. Cloud metro load. This difference arises because for the Monticello termination option, following the Sherco-Monticello 345 kV outage the two southern paths (Sherco-Benton and the new Monticello-West St. Cloud Tap) do not share the loading proportionately as a result of the phase angle difference between Sherco and Monticello. This causes the remaining Benton Co 345/230 kV transformer to overload. The remedy for this condition is to add three 345 kV breakers at Monticello to enable loop-in of the Sherco-Coon Creek line that currently bypasses (but is adjacent to) the Monticello Substation. Alternatively, the Benton Co 345/230 kV transformers could be replaced with larger units. Selection of the preferred course of action for this future improvement would be dependent on the results of dynamic stability studies, since the Monticello 345 kV loop-in would likely have significant stability ramifications.

Both the Monticello and the Sherco options offer better electrical performance than that achieved with the Benton Co. option while requiring fewer additional transmission improvements. In particular, the reconductor of the Monticello-Benton Co 230 kV is not required. From a routing perspective, the Monticello option has the advantage of not involving a Mississippi River crossing, although it results in the greatest mileage of new 345 kV line (approximately 5-7 miles more than would be the case for terminating at Sherco).

Another favorable characteristic of a Monticello termination is that performance for NERC Reliability Criteria "Category D" disturbances (extreme disturbances beyond the scope of this study) would be better than that for a Sherco termination. This result would be obtained because the "loss of entire substation" scenario is more severe for a Sherco occurrence than for Monticello due to the much larger amount of generation present at Sherco, the loss of which is a very severe contingency. Consequently, the reliability improvement achieved for Category D disturbances would be greater for a Monticello termination of the new line than for a Sherco termination.

Conclusion

Considering the electrical performance characteristics of the three termination options, it can be logically concluded that the Monticello and Sherco termination options yield the highest St Cloud area load-serving capabilities while also requiring the fewest additional transmission system improvements.

The Monticello termination option also has the desirable feature of not requiring a new crossing of the Mississippi River, and would yield the best Category D performance.

Considering all relevant factors, the Monticello termination is preferred, with Sherco being next-best, and Benton Co being the least desirable.

# APPENDIX B

# CapX 2020 Technical Update: Identifying Minnesota's Electric Transmission Infrastructure Needs

October 2005


## EXECUTIVE SUMMARY

### Background

Minnesota's electric transmission infrastructure, a network of transmission lines of 230 kilovolts and higher, primarily was designed and built during the 1960s and 1970s. As explained in CapX 2020's December 2004 interim report, the system is adequate to meet today's needs. But to support customers' growing demand for electricity, this high-voltage transmission system in Minnesota and neighboring states requires major upgrades and expansion during the next 15 years.

To ensure that this backbone transmission system is developed and available to serve growing demand for electricity and to plan for major capital expenditures. Minnesota's largest transmission-owning utilities—Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Southern Minnesota Municipal Power Agency, and Xcel Energy—initiated the CapX 2020 project.

CapX 2020's mission is to:

- Create a joint vision of required transmission infrastructure investments needed to meet growing demand for electricity in Minnesota and the region.
- Work to create an environment that allows these projects to be developed in a timely, efficient manner, consistent with the public interest.

The utilities have completed a draft study that defines a vision for transmission infrastructure investments needed in Minnesota through 2020. That technical study, which meets the first part of CapX 2020's mission, is described in this report. Studies will continue to determine which facilities will need to be built first. As other regional transmission studies are completed, they will be integrated into the CapX 2020 study. A report that describes progress on the second part of CapX 2020's mission, including pending legislation, is planned for this summer

### Study overview

In developing this long-range plan for major new construction, the CapX 2020 technical team considered two potential scenarios for growth in electricity demand:

1. Anticipated load growth of 2.49 percent annually from 2009 through 2020, for an increase of 6,300 megawatts. This is based on load projections for utilities with customers in Minnesota, published by the Mid-Continent Area Power Pool (MAPP) in the *2004 MAPP Load and Capability Report* and in recent utility resource plan filings. Load growth of 6,300 MW would require over 8000 MW of new generation, given losses that occur when transmitting.
2. Slower load growth—about two-thirds of the published load projections—of 4,500 MW.

Based on information from independent power producers, wind developers, utility resource planning staff, and the Midwest Independent Transmission System Operator's generation interconnection queue, the team also worked out three generation scenarios, each including 2,400 MW of renewable energy, to illustrate potential locations of new electric generating plants or wind farms.

The goals were to identify new transmission *independent* of where plants are located *and* to identify new transmission *specific* to particular electric generation scenarios. The team considered planning requirements for meeting the Minnesota Renewable Energy Objective, addressed issues related to relieving transmission congestion, and focused on high-voltage solutions that best addressed the three different generation scenarios.

**Results: The CapX 2020 Vision Plan**

Facilities common to two of the three generation scenarios were identified as the cornerstone of the CapX 2020 Vision Plan—1,620 miles of 345 kV transmission lines that total $1.215 billion, about 80 percent of the cost of each scenario individually. The following table identifies these facilities. Any long-range vision plan also will have to include additional unique facilities for each scenario.

| Facility Name | | | | |
|---|---|---|---|---|
| **From** | **To** | **Volt (kV)** | **Miles** | **Cost ($M)** |
| Alexandria, MN | Benton County (St. Cloud, MN) | 345 | 80 | 60 |
| Alexandria, MN | Maple River (Fargo, ND) | 345 | 126 | 94.5 |
| Antelope Valley (Beulah, ND) | Jamestown, ND | 345 | 185 | 138.75 |
| Arrowhead (Duluth, MN) | Chisago County (Chisago City, MN) | 345 | 120 | 90 |
| Arrowhead (Duluth, MN) | Forbes (northwest Duluth, MN) | 345 | 60 | 45 |
| Benton County (St. Cloud, MN) | Chisago County (Chisago City, MN) | 345 | 59 | 44.25 |
| Benton County (St. Cloud, MN) | Granite Falls, MN | 345 | 110 | 82.5 |
| Benton County (St. Cloud, MN) | St. Bonifacius, MN | 345 | 62 | 46.5 |
| Blue Lake (southwest Twin Cities, MN) | Ellendale, MN | 345 | 200 | 150 |
| Chisago County (Chisago City, MN) | Prairie Island (Red Wing, MN) | 345 | 82 | 61.5 |
| Columbia | North LaCrosse | 345 | 80 | 60 |

| | | | | |
|---|---|---|---|---|
| Ellendale, ND | Hettinger, ND | 345 | 231 | 173.25 |
| Rochester, MN | North LaCrosse | 345 | 60 | 45 |
| Jamestown, ND | Maple River (Fargo, ND) | 345 | 107 | 80.25 |
| Prairie Island (Red Wing, MN) | Rochester, MN | 345 | 58 | 43.5 |
| | **Total miles 1620** | | **Total cost $1,215 ($M)** | |

**Conclusion**

The CapX 2020 technical team believes the results documented here to be the basis for additional studies to better identify the transmission needs of the study region. The following report details the technical study behind this update. Section headings are:

- Base model assumptions
  (about loads and generation and how scenarios were determined, biases).
- Analysis
  (of study assumptions such as system conditions, contingencies, Big Stone II, and other sensitivities).
- Scenario analysis
  (of existing system performance, transmission alternatives, and line flows on interface and tie lines).
- Slow growth analysis.
- Common facilities.
- Conclusion and next steps.
- CapX 2020 Technical Team members.
- Appendices.

Although the existing transmission system is adequate to meet the reliability needs of customers today, the CapX 2020 study shows that the study region will experience specific and numerous transmission overloads, outages, and voltage problems if we make no transmission additions between now and 2020. Collaborative efforts and plans, such as those identified in this report, are necessary to reduce the risk of investing in new transmission infrastructure and to preserve electric reliability for customers.

## 1. Base Model Assumptions

The CapX study region encompasses the service territories of electric utilities that have load-serving responsibilities for Minnesota consumers. This region is represented in Diagram 1 below.

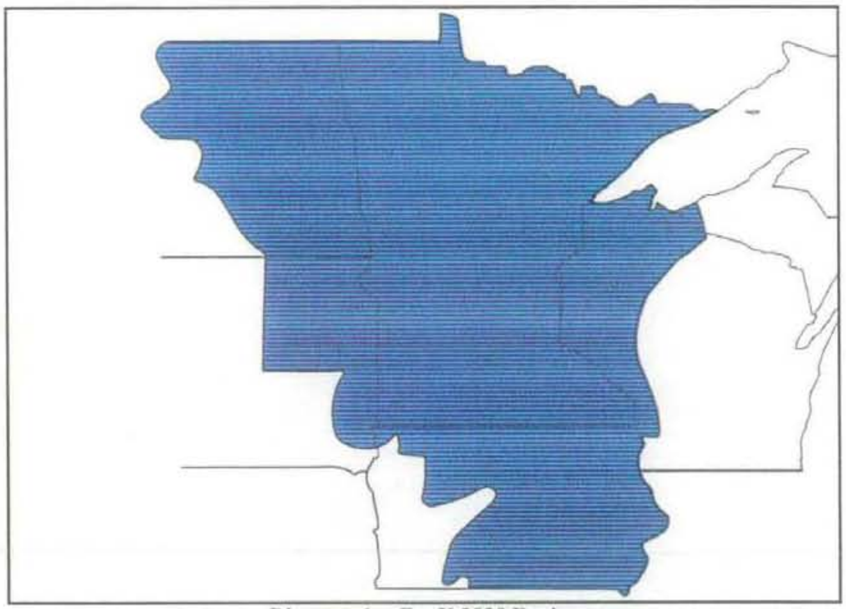


**Diagram 1 – CapX 2020 Region**

### 1.1 Loads

The CapX 2020 technical team chose the MAPP 2004 Series, 2009 summer peak model, as the base model to begin scaling loads to the anticipated 2020 load level. To accurately model 2020 loads, the technical team used individual company load growth from the *2004 MAPP Load and Capability Report* for the following control areas: Alliant Energy (west), Xcel Energy (north), Southern Minnesota Municipal Power Agency, Otter Tail Power Company, and Dairyland Power Cooperative.

Note that each control area contains not only load belonging to the control area operator, but also that of other companies. For example, Missouri River Energy Services has load in the Alliant Energy (west), Minnesota Power, Otter Tail Power Company, Western Area Power Administration, and Xcel Energy (north) control areas).

Minnesota Power and Great River Energy's loads were scaled based on their most recent resource plan filings. The growth results are in Table 1

| Control area | 2009 load level (2004 MAPP Series) (MW) | Yearly growth rate (%) | Calculated 2020 load level (MW) |
|---|---|---|---|
| ALT (West) | 3265.3 | 1.60 | 3888.2 |
| Xcel Energy (North) | 9632.6 | 2.68 | 12885.1 |
| MP | 1507.3 | 1.70 | 1814.4 |
| SMMPA/RPU | 330.0 | 2.70 | 442.4 |
| GRE | 2833.5 | 3.27 | 3943.2 |
| OTP/MPC | 1677.2 | 2.70 | 2248.3 |
| DPC | 954.7 | 2.60 | 1266.2 |
| Total | 20200.6 | Ave. = 2.49% | 26487.8 |

**Table 1 – CapX 2020 Anticipated Area Growth**

Table 1 shows an anticipated load growth of approximately 6300 megawatts (MW) in the CapX 2020 region for the period from 2009 to 2020. The technical team also studied historical loads for Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy to determine whether anticipated load growth was consistent with historical load growth in the region. Load growth for these companies averaged 2.64 percent during the period 1980 to 2004. Diagram 2 shows the variability of load growth as well as the continuing upward growth in load for the region. The technical team's forecast from 2009 through 2020 is a slower growth curve than the actual growth in the early 2000's (2.49 percent vs. 2.64 percent).

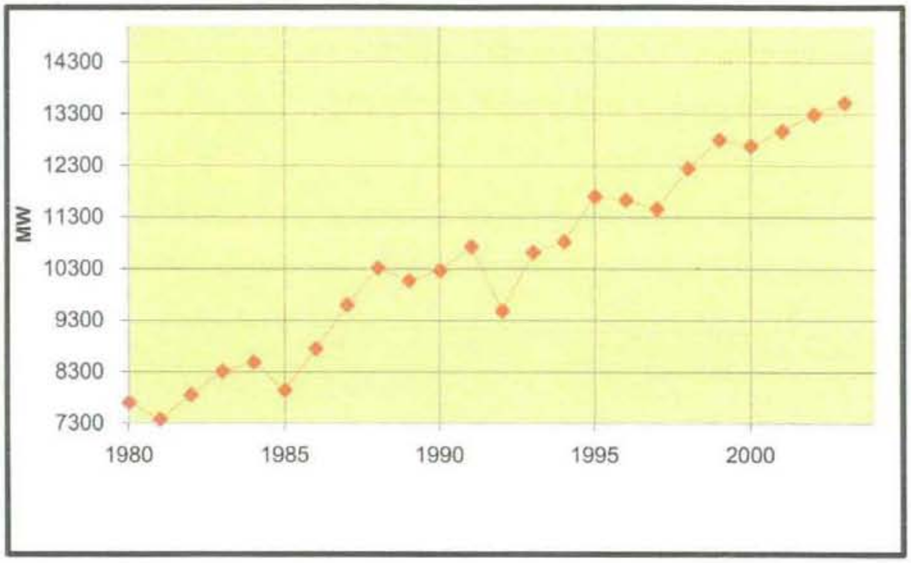



**Diagram 2 – Historical Growth**

### 1.2 Generation

The CapX 2020 technical team assumed that the generation modeled in the 2009 summer model would still exist in 2020 and would continue to serve the load modeled in 2009. To address anticipated load growth of 6,300 MW, the technical team solicited information from independent power producers (including wind developers), resource planning entities within various organizations, and the Midwest Independent System Operator's (MISO) generation interconnection queue.

Diagrams 3 and 4 are maps of potential generation addition locations that have been identified either from the MISO queue (Diagram 3) or from Wind on the Wires (which is a wind advocate organization) potential wind sites (Diagram 4).

The technical team combined this information to form potential generation development nodes, independent of fuel type, which they used in the modeling process to supply load increases.


**Diagram 3 – Potential Generation Areas**

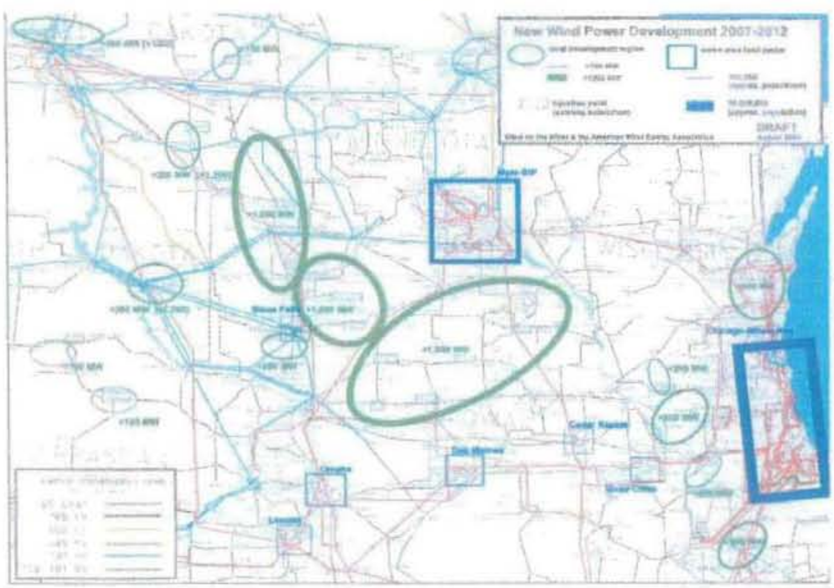



**Diagram 4 – Potential Wind Generation Areas**

The CapX 2020 technical team mapped the locations of these resources and identified five generation regions: Northern Minnesota, Dakotas (North Dakota and South Dakota), Southern Minnesota/Northern Iowa, Wisconsin and the Metro (Twin Cities Metropolitan) area. These regions are shown in Diagram 5.

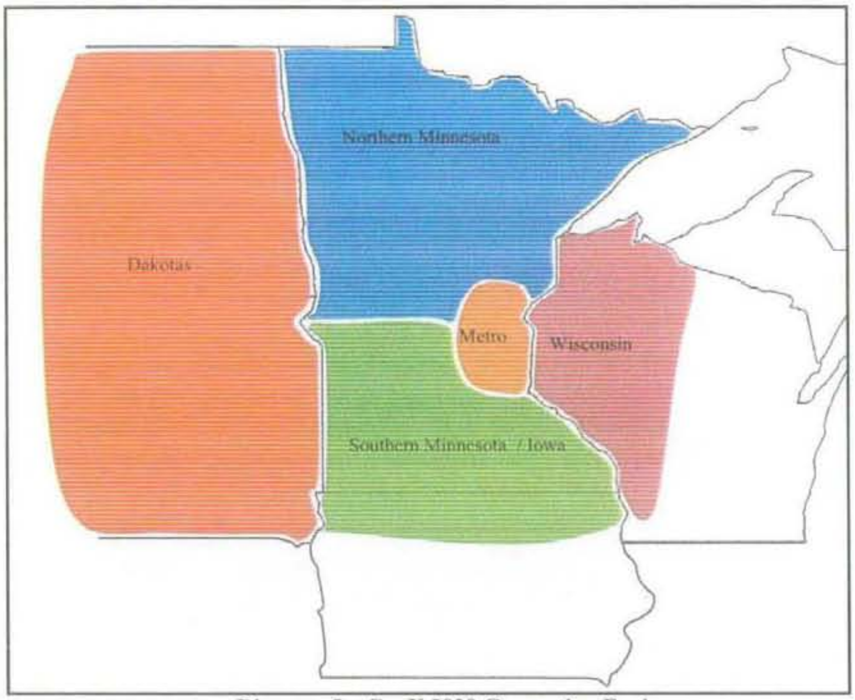


**Diagram 5 – CapX 2020 Generation Regions**

### 2.3 Scenario determination

The team modeled three generation scenarios to address the anticipated load growth of 6,300 MW from 2009 to 2020. Each of the scenarios includes sufficient renewable resources to address the Minnesota Renewable Energy Objective of the CapX 2020 participants.

The three generation scenarios consist of a North/West bias, a Minnesota bias, and an Eastern bias. These three generation biases reflect potential generation development that might influence electric power flows on the regional grid and thus indicate the size and location of new transmission infrastructure needed to deliver the generation to customers.

Each of the scenarios includes generation resources from several of the regions. See Table 2.

| Generation areas | North /West Bias | Scenario<br>Minnesota Bias | Eastern Bias |
|---|---|---|---|
| Northern MN | 1700[1] | 1250 | 550 |
| Dakotas | 2100 | 1000 | 1600 |
| Southern MN/ Iowa | 1875 | 1875 | 2175 |
| Metro | 650 | 2200 | 1000 |
| Wisconsin | 0 | 0 | 1000 |
| Total | 6325 | 6325 | 6325 |

**Table 2 – Generation Scenarios**

Diagrams 6, 7, and 8 provide geographical representation of the regions for which generation will be modeled in each scenario.

### 2.3.1 North/West Bias Generation

In the north/west bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Manitoba, North Dakota, South Dakota, and Iowa.

The generation mix includes 2275 MW to meet Minnesota's Renewable Energy Objective: 975 MW from Minnesota and 1300 MW from outside of Minnesota. It also includes 1950 MW of other Minnesota generation and 2100 MW of other generation from outside of Minnesota.

Chart 1 below illustrates the north/west generation mix.

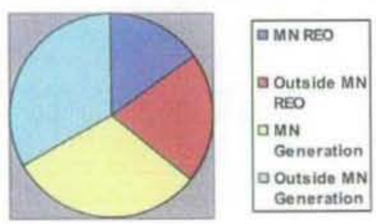



**Chart 1 - North/West Bias Generation Mix**

[1] This 1700-MW total includes a 1000-MW import from Manitoba.

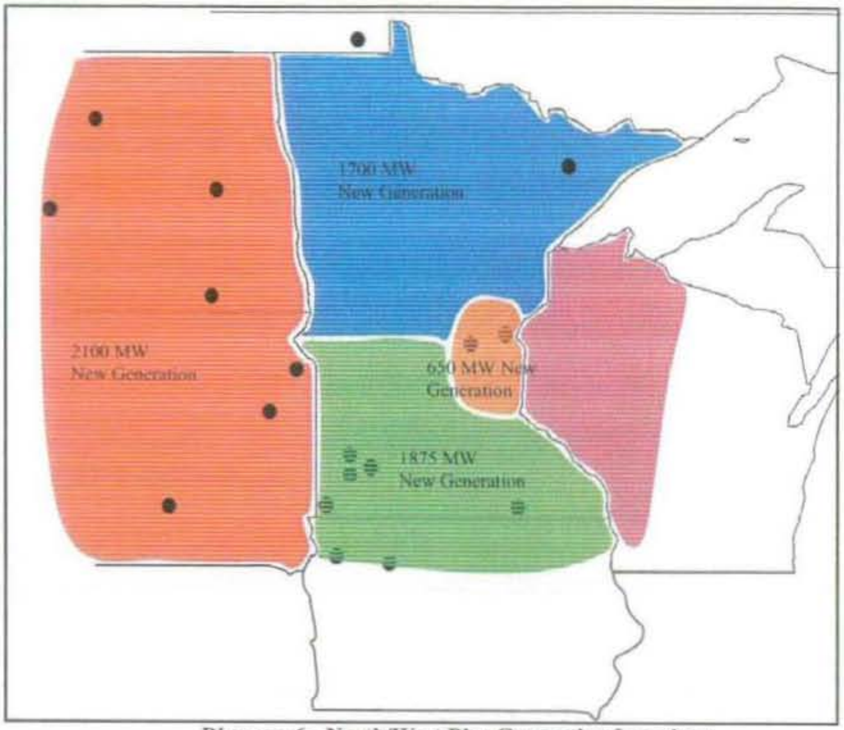



**Diagram 6 - North/West Bias Generation Locations**

### 2.3.2 Minnesota Bias Generation

In the Minnesota Bias Generation case all new generation outside of Minnesota (North Dakota, South Dakota, and Iowa) is modeled as 1300 MW of wind generation (REO). The generation modeled inside of Minnesota is a mixture of REO, peaking, and base load generation.

The generation mix includes 2275 MW of Renewable Energy Objective and 4050 MW of Minnesota generation.

Chart 2 below illustrates the Minnesota bias generation mix.

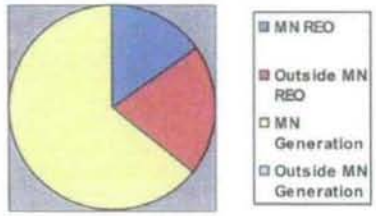



**Chart 2 - Minnesota Bias Generation Mix Chart**

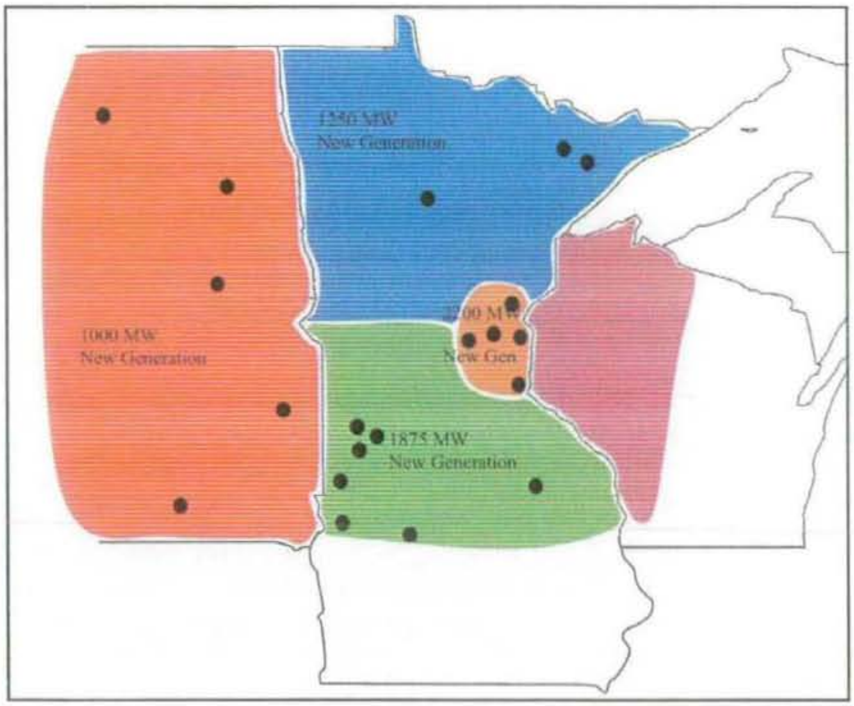



**Diagram 7 - Minnesota Bias Generation Locations**

### 2.3.3 Eastern Bias Generation

In the Eastern Bias generation case the new generation modeled is more heavily based on importing generation into Minnesota from Wisconsin and Iowa with 1000 MW new generation modeled in Wisconsin and 1050 MW of new generation modeled in Iowa.

The generation mix includes 2275 MW of Renewable Energy Objective (975 MW of Minnesota REO and 1300 MW from outside of Minnesota REO), 1700 MW of generation from inside of Minnesota, and 2350 MW of generation from outside of Minnesota.

Chart 3 below illustrates the Eastern bias generation mix.

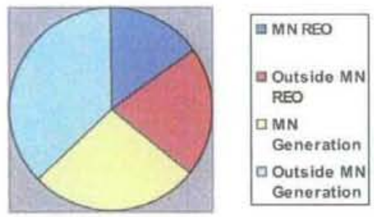



**Chart 3 - Eastern Bias Generation Mix**

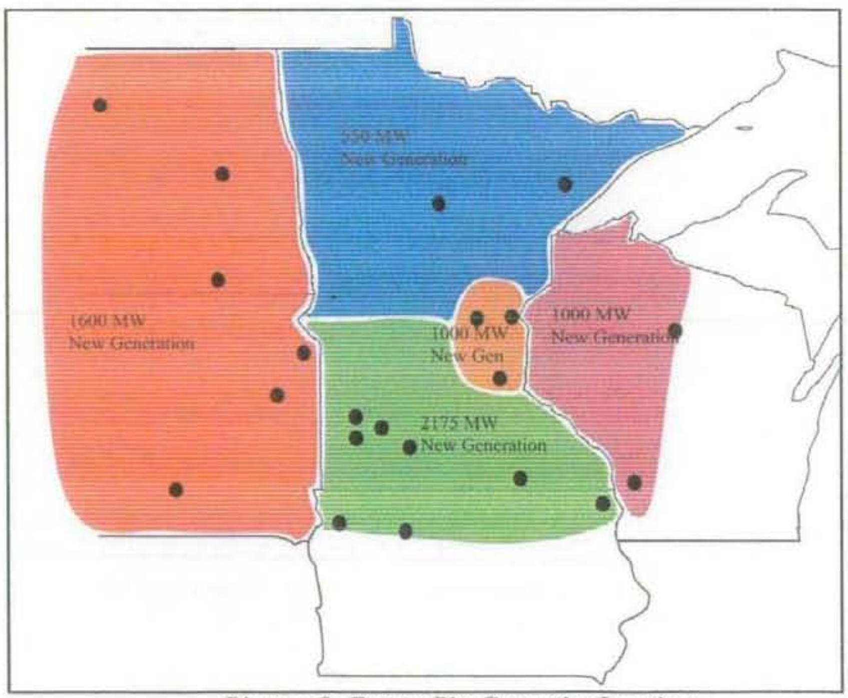



**Diagram 8 - Eastern Bias Generation Locations**

## 3 Analysis

The CapX 2020 technical team's primary goal was to create a common transmission backbone that could sustain system growth based on the three generation scenarios. In the future as specific generation is built, other transmission facilities will be required to tie the generation to the transmission backbone system and tie the load-serving centers to the local-serving distribution substations.

With this goal in mind, the team developed an initial list of possible transmission facilities. These facilities are shown in Diagram 9. Diagram 9 was created using inputs from various regional Midwest Independent System Operator (MISO) exploratory studies, the 2004 MISO Transmission Expansion Plan (MTEP '04), as well as input from utility transmission planners in the study area. The team purposely kept lines vague, leaving the routes and endpoints to be determined as study work progressed. Transmission alternatives were limited to facilities 345 kilovolts and larger for the purpose of this vision study of the high voltage bulk transmission study.

The technical team incorporated transmission alternatives identified in on-going studies in conjunction with transmission plans identified by various transmission stakeholders. The goals were to identify transmission improvements that connect remote generation to the load-serving centers in the region and to develop a transmission backbone that supports continued load growth in the various load centers. The transmission improvements focused on high voltage solutions (345 kV lines and 500 kV lines) that best addressed the load areas and the various generation scenarios.

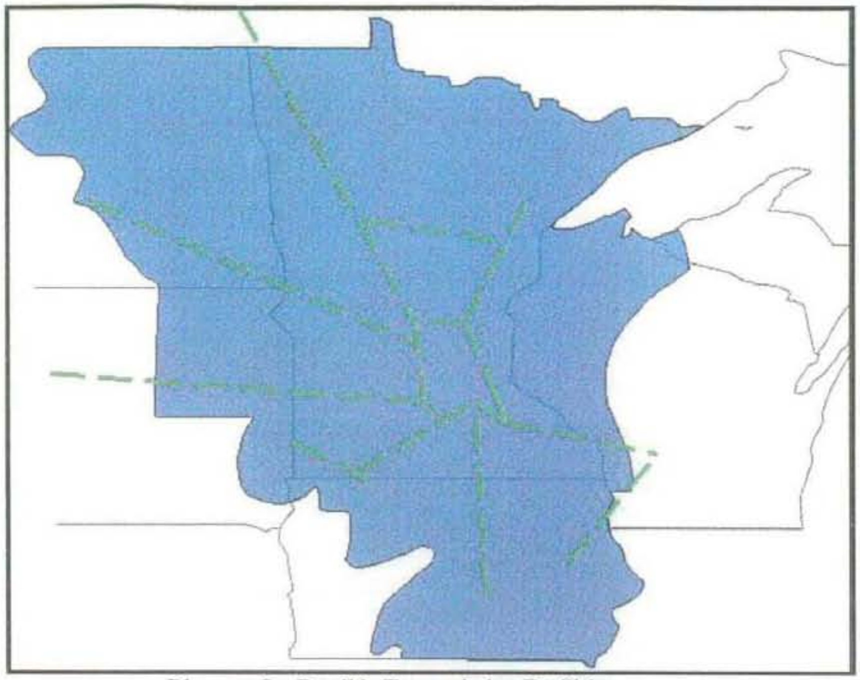


**Diagram 9 – Possible Transmission Facilities**

As a starting point, the technical team utilized the most probable transmission options from the exploratory studies already underway in the MISO/MAPP footprint, most notably the Southwest Minnesota/ Northern Iowa study and the Northwest Exploratory study. These transmission options are shown below:

- A 345 kV line from the North Dakota coal fields to Fargo and continuing to near St. Cloud, Minnesota
- A 345 kV line from Prairie Island, near Red Wing, Minnesota, to Rochester, Minnesota, and continuing to southwest Wisconsin
- Two 345 kV lines into central Iowa
- A 345 kV or 500 kV line from Manitoba into near St. Cloud, Minnesota.
- Generation outlet transmission facilities presently under study through MISO.

Once these lines were placed on the map, the technical team analyzed the system for the best regional method to tie all these study results together, while maximizing load-serving potential for the entire region well into the future. The team also created a second 345 kV transmission ring around the wider Twin Cities metro area, with "spokes" leading out to the smaller load and/or generation pockets in the region.

A complete list of the potential transmission facilities is included in Appendix A.

### 3.1 Study Assumptions

#### 3.1.1 System Condition Assumptions

The CapX 2020 study was based on a system snapshot with the best-known 2020 state of the transmission system as of August 2004 for the MAPP region. Since August 2004, very few changes have been made to the base case model. In the last ten months, load, generation and transmission modeling may have been modified in other studies, which the CapX 2020 study does not reflect.

#### 3.1.2 Contingency Analysis Assumptions

The technical team tested several transmission solutions for each generation scenario and performed steady-state powerflow analysis (first contingency simulations) to determine which transmission solution eliminates thermal overloads on transmission lines 161 kV and higher in the region. Because the intent of this study was bulk level load serving, the technical team decided to model all generation on the highest voltage bus available local to the generation, and to run the contingency simulations on a limited list of facilities, namely 161 kV and above.

***When reviewing the results of this study, note that only the bulk system overloads and solution are represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure was studied.***

#### 3.1.3 Big Stone II Inclusion in the CapX 2020 Vision Study

Interconnection steady-state results from the Big Stone II generation study were completed in the late fall 2004 and, therefore, were included in the CapX 2020 Vision Study. Big Stone II was modeled in the north/west and eastern biases. In the north/west bias, the generator was modeled along with the outlet options that included:

- Big Stone – Canby new 230 kV line
- Canby – Granite Falls 115 kV line converted to 230 kV
- Big Stone – Willmar new 230 kV line

The eastern bias included the generator along with outlet options that included:

- Big Stone – Canby, Minnesota, new 230 kV line
- Canby – Granite Falls, Minnesota, 115 kV line converted to 230 kV
- Big Stone – Ortonville, Minnesota, new 230 kV-line
- Ortonville – Johnson Jct. - Morris, Minnesota, 115 kV line converted to 230 kV

Because the Minnesota bias focused on generation located within state boundaries with the exception of wind resources, Big Stone II, which is a potential coal-fired plant in South Dakota, was not included in this generation bias.

Based on the results from this vision study, the Minnesota and north/west generation biases include a new 345 kV line from Granite Falls, Minnesota, to Benton County (St. Cloud), Minnesota, and all three generation scenarios include a new 345 kV line from Ellendale, North Dakota, to Blue Lake (Mpls/St. Paul), Minnesota, regardless of whether Big Stone II was included. These lines could be instrumental to wind outlet in the North Dakota and South Dakota.

### 3.1.4 Sensitivities to Current Area Study Work

- Big Stone II was partially included in this vision study as described in section 3.1.3 above. Because the Big Stone II interconnection study was completed during the CapX 2020 technical study timeframe, variations of the interconnection study results were included in the CapX 2020 study. When a certificate of need (CON) is filed for Big Stone II, a vision study sensitivity will be completed to determine how the Big Stone II project proposed facilities fit into the timeline for the CapX 2020 vision study facility additions.
- Buffalo Ridge Incremental Study conducted by Xcel Energy in the winter of 2004 through spring 2005 had no public results available to include during the CapX 2020 case development time. In addition, the Buffalo Ridge study is a lower voltage study than the CapX 2020 focus.

## 4 Scenario Analysis

The preliminary base case model for the year 2020 includes the 6300 MW of anticipated load growth and the new generation to meet and serve the growth, however the base case doesn't contain any new necessary transmission facilities.[2] The CapX 2020 technical team's preliminary base case analysis of the three generation scenarios identified a significant number of transmission overloads that could occur if no additional transmission is built to serve the projected load growth and the new generation needed by 2020 to meet this growth. The team simulated the loss (outage) of single transmission elements (n-1 analysis) to help determine transmission alternatives to address potential violations of North American Electric Reliability Council criteria, such as low voltages and thermally overloaded facilities.

Power Technology's PSS/E program, Version 29, was used to perform this analysis. Within PSS/E, the activity called ACCC, or AC Contingency Checking, was used as a first check of the entire study area to find problems. ACCC sequentially examines all relevant single contingencies in the region of interest for a given load and transfer base case. Facilities identified in the ACCC outputs were considered limiters if they had line outage distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged.

For the more detailed analysis of each scenario, the team used a contingency program developed by Great River Energy. The contingency program uses the IPLAN programming language within PSS/E. It performs many functions on the user-defined model, including developing user-defined contingencies with appropriate line-switching procedures, monitoring files for bus voltage and line loading violations, and the output files are then easily imported into Microsoft Excel. Transmission facilities identified in the Excel outputs were considered limiters if they had power transfer distribution factors and/or line outage

[2] Exception: The north/west bias base 2020 case includes a 345 kV facility from Manitoba to near St Cloud, MN

distribution factors of 2 percent or greater. Bus voltages lower than 0.9 per unit were also flagged

For the n-1 analysis, the team ran transmission contingencies and monitored the transmission system in the following control areas:

| Control area | PSS/E area # |
|---|---|
| Alliant Energy West | 331 |
| Xcel Energy | 600 |
| Minnesota Power | 608 |
| Southern Minnesota Municipal Power Agency | 613 |
| Great River Energy | 618 |
| Otter Tail Power Company | 626 |
| Dairyland Power Company | 680 |

### 4.1 Existing System Performance / Base Case Analysis

The ACCC activity performs all contingencies in the area and, therefore, provides an excellent screening tool for determining as to when and where violations of the planning criteria occur.

Initially, the team ran ACCC on the existing system for the three generation scenario bias cases: Peak load with all the Minnesota bias generation on-line at the 2020 load levels, peak load with all the north/west bias generation on-line at the with 2020 load levels, and peak load with all the eastern bias generation on-line at the 2020 load levels. The team temporarily put aside base case results but eventually will compare them with the post-new facility results for each bias to find the most effective set of 345 kV and higher transmission infrastructure additions to meet the 6,300 MW of new load. The base case system n-1 results are included in Appendix B of this report for each bias case.

Table 3 shows the number of overloaded transmission facilities and voltage violations in the base case 2020 models. Sections 4.2 through 4.5 of this report will discuss the results for each scenario in further detail. Again, n-1 contingency output results are tabulated in Appendix B.

| Scenario | System Intact Overloads | n-1 Overload Violations[3] | Voltage Violations |
|---|---|---|---|
| North/West Bias[4] | 42 | 142 | 45 |
| Minnesota Bias | 42 | 187 | 14 |
| Eastern Bias | 42 | 197 | 33 |

**Table 3 – Base Case 2020 Transmission System Violations**

[3] Outages of individual facilities 161 kV and higher were simulated.

[4] Includes the addition of a 345 kV facility from Manitoba to near St. Cloud, Minnesota

### 4.2 Transmission Alternatives

As mentioned previously in this report, Appendix A of this report includes a complete list of all transmission facilities 345 kV and higher that the CapX 2020 technical team considered. The team analyzed each generation scenario separately to determine which of these facilities would most effectively solve thermal and voltage violations on the bulk (161 kV and higher) transmission system in the study area. To do this, the team inserted specific facilities or facility groups from Appendix A one at a time into the model to assess each facility's benefits.

The team selected facilities to insert into the model by determining the location of the need for system improvement. The team recommended as facility additions those facilities that had the greatest benefit to the system by reducing the thermal overload and/or solving voltage violations during n-1 contingency.

The results of the facility addition benefits are shown in Appendix B in the n-1 contingency output result tables for each generation scenario.

### 4.3 Minnesota Bias Scenario Results

#### 4.3.1 Recommended Transmission Vision Facilities

Diagram 10 shows the final compilation of recommended transmission facilities for the Minnesota bias based on the n-1 contingency analysis completed using the facilities in Appendix A and Table 4. All contingency analysis results and PSS/E automaps are included in Appendix B-1.

| Ref. Ref.# | Data Source | Facility name | | | | |
|---|---|---|---|---|---|---|
| | | From | To | Volt (kV) | Miles | Cost ($M) |
| F-02 | TIPS | Alexandria | Benton County | 345 | 80 | 60 |
| F-03 | TIPS | Alexandria | Maple River | 345 | 126 | 94.5 |
| F-06 | NW | Antelope Valley | Maple River | 345 | 292 | 219 |
| F-07 | CAPX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CAPX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CAPX | Benton County | Chisago County | 345 | 59 | 44.25 |
| F-10 | CAPX | Benton County | Granite Falls | 345 | 110 | 82.5 |
| F-11 | MH | Benton County | Riverton | 345 | 78 | 58.5 |
| F-12 | CAPX | Benton County | St. Boni | 345 | 62 | 46.5 |
| F-13 | CAPX | Blue Lake | Ellendale | 345 | 200 | 150 |
| F-17 | CAPX | Boswell | Forbes | 345 | 64 | 48 |

| | | | | | | |
|---|---|---|---|---|---|---|
| F-26 | CAPX | Chisago County | Prairie Island | 345 | 82 | 61.5 |
| F-28 | CAPX | Columbia | North LaCrosse | 345 | 80 | 60 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 173.25 |
| F-32 | CAPX | Forbes | Riverton | 345 | 114 | 85.5 |
| F-36 | SMNI | Rochester | North LaCrosse | 345 | 60 | 45 |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.5 |
| F-63 | CAPX | Lakefield Jct | Adams | 345 | 92 | 69 |
| | | | | **Total** | **1968** | **1,476** |

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

**Table 4 – Minnesota Bias Recommended Facilities**

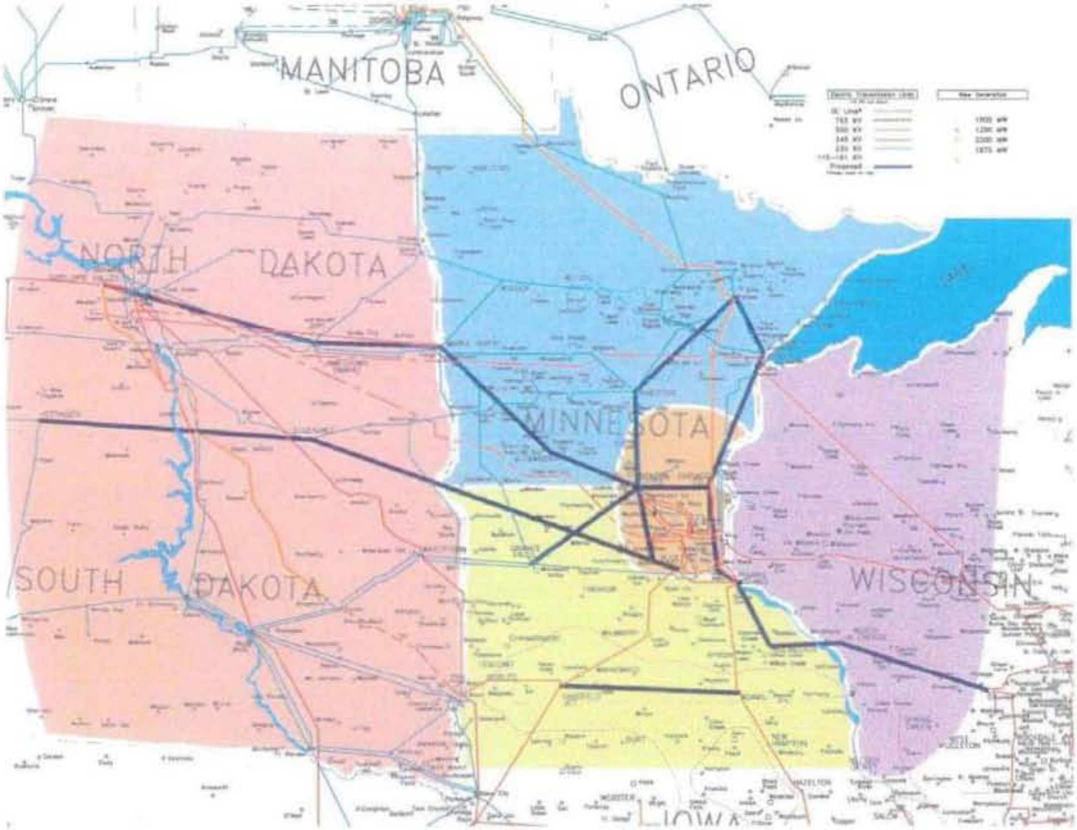



**Diagram 10 – Minnesota Bias Recommended Facilities**

### 4.3.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 5 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission. Table 5 shows that adding the facilities recommended for the Minnesota bias scenario mostly causes reductions in MW flow over these 230 kV and higher interfaces.

| LINE | kV Voltage Level | Base 6300 MW flow (MW) | 6300 mw UPGRADE scenario (MW) | Description |
|---|---|---|---|---|
| Forbes – Chisago | 500 kV | 870 | 687 | Northern Minnesota to Twin Cities loop |
| Riel – Roseau | 500 kV | 1418 | 1308 | Manitoba Hydro to northern Minnesota |
| Richer – Roseau | 230 kV | 170 | 183 | Manitoba Hydro to northern Minnesota |
| Letellier – Drayton | 230 kV | 325 | 300 | Manitoba Hydro to MN-ND border |
| Glenboro – Rugby | 230 kV | 18 | 2 | Manitoba Hydro – North Dakota (this and the 3 lines above are all that ties Manitoba and U.S. as planned of 2009) |
| Arrowhead – Stone Lake | 345 kV | 116 | 97 | Duluth area to northwestern Wisconsin (then to Weston) |
| Eau Claire – Arpin | 345 kV | 111 | 87 | West to central Wisconsin |
| Prairie Island – Byron | 345 kV | 116 | 320 | South of Twin Cities metro to west of Rochester |
| Adams – Hazelton | 345 kV | 127 | 50 | Southeastern Minnesota – eastern Iowa |
| Lakefield Jct. – Wilmarth | 345 kV | 768 | 594 | Southwestern Minnesota to Mankato area |
| Split Rock – Nobles County | 345 kV | 175 | 159 | North of Sioux Falls, SD, to northwest of Worthington, MN |
| Nobles County – Lakefield Jct. | 345 kV | 300 | 285 | Northwest of Worthington to Lakefield Jct. sub. (Minnesota) |
| Watertown – Granite Falls | 230 kV | 315 | 292 | Eastern South Dakota to western Minnesota |
| Blair – Granite Falls | 230 kV | 329 | 317 | Runs parallel with Watertown – Granite Falls |
| Granite Falls – Minnesota Valley | 230 kV | 263 | 220 | Western Minnesota |
| Fargo – Moorhead | 230 kV | 53 | 62 | Fargo, North Dakota, to Moorhead, Minnesota |
| Fargo – Sheyenne | 230 kV | 260 | 162 | North Dakota, Minnesota border |
| Maple River – Winger | 230 kV | 76 | 69 | Fargo area to northwestern Minnesota |
| Prairie – Winger | 230 kV | 138 | 84 | Grand Forks area to Winger |
| Wahpeton – Fergus Falls | 230 kV | 234 | 153 | ND-MN border east to Fergus Falls |
| Bear Creek – Rock Creek | 230 kV | 53 | 51 | South of Duluth toward the Twin Cities loop |
| Blackberry – Riverton | 230 kV | 220 | 114 | Northern Minnesota towards south |
| Mud Lake – Benton County | 230 kV | 10 | 26 | Coming from the north into St Cloud |
| Sheyenne – Audubon | 230 kV | 214 | 178 | Fargo area west into Minnesota |
| Genoa – Coulee | 161 kV | 263 | 204 | Western Wisconsin |
| Boswell – Blackberry Ckt 1 | 230 kV | 291 | 192 | Northern Minnesota |
| Boswell – Blackberry Ckt 2 | 230 kV | 283 | 187 | Northern Minnesota |

**Table 5 – Minnesota Bias Tie Line / Interface Flows**

### 4.4 North / West Scenario Results

#### 4.4.1 Recommended Transmission Vision Facilities

Diagram 11 shows the final compilation of recommended facilities for the North/West Bias based on the n-1 contingency analysis using the facilities in Appendix A and Table 6. All contingency analysis results and PSS/E automaps are included in Appendix B-2.

| Ref. Ref.# | Data Source | Facility Name | | | | |
|---|---|---|---|---|---|---|
| | | From | To | Volt (kV) | Miles | Cost ($M) |
| F-02 | TIPS | Alexandria | Benton County | 345 | 80 | 60 |
| F-03 | TIPS | Alexandria | Maple River | 345 | 126 | 94.5 |
| F-06 | NW | Antelope Valley | Maple River | 345 | 292 | 219 |
| F-07 | CAPX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CAPX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CAPX | Benton County | Chisago County | 345 | 59 | 44.25 |
| F-10 | CAPX | Benton County | Granite Falls | 345 | 110 | 82.5 |
| F-12 | CAPX | Benton County | St. Boni | 345 | 62 | 46.5 |
| F-13 | CAPX | Blue Lake | Ellendale | 345 | 200 | 150 |
| F-26 | CAPX | Chisago County | Prairie Island | 345 | 82 | 61.5 |
| F-28 | CAPX | Columbia | North LaCrosse | 345 | 80 | 60 |
| F-29 | MH | Dorsey | Karlstad | 345 | 134 | 100.5 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 173.25 |
| F-36 | SMNI | Rochester | North LaCrosse | 345 | 60 | 45 |
| F-45 | MH | Karlstad | Winger | 345 | 91 | 68 |
| F-40 | MH | Winger | Benton Co. | 345 | 162 | 121.5 |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.5 |
| | Total | | | | 2007 | 1,505 |
| | | | | | | |

**Table 6 – North/West Bias Recommended Facilities**

**Key for Table 6:**
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

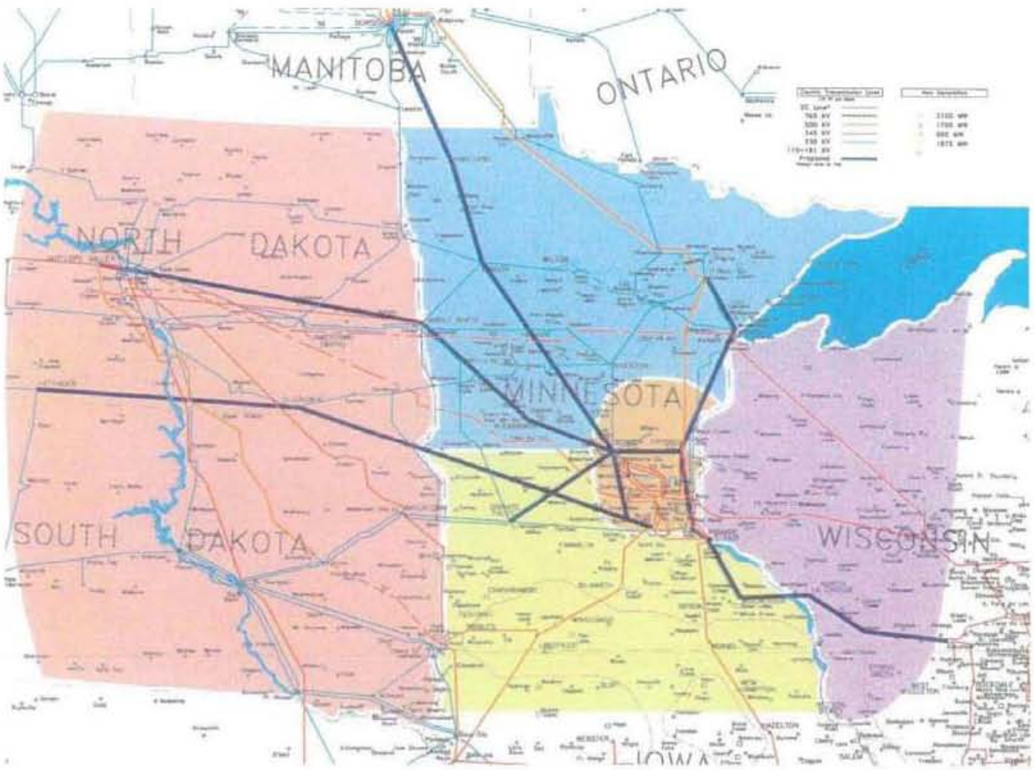



**Diagram 11 – North/West Bias Recommended Facilities**

### 4.4.2 Line Flows on Interface and Tie Lines

The Technical Team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 7 predominantly focuses on lines coming into and going out of Minnesota, including some lines internal to Minnesota connecting pockets of transmission.

The table shows that adding the facilities recommended for the north /west bias scenario causes about equal amounts of reductions and additions in MW flow over these 230 kV-and-higher interfaces. Note that in this north/west scenario the Manitoba Hydro flows are lower than in the slow growth scenario Manitoba Hydro export. The reason for this difference is that the CapX technical team has added the 345 kV line in the 6,300 MW load base case, which has 816 megavolt amperes flowing on it.

| LINE | kV Voltage Level | Base 6300 MW flow (MW) | 6300 MW UPGRADE scenario (MW) | Description |
|---|---|---|---|---|
| Forbes – Chisago | 500 kV | 1507.7 | 1343.3 | Northern Minnesota to Twin Cities loop |
| Riel – Roseau | 500 kV | 1591.8 | 1507.5 | Manitoba Hydro to northern Minnesota |
| Richer – Roseau | 230 kV | 219.2 | 212.8 | Manitoba Hydro to northern Minnesota |
| Letellier – Drayton | 230 kV | 286.5 | 303.7 | Manitoba Hydro to MN-ND border |
| Glenboro – Rugby | 230 kV | 64.4 | 10.6 | Manitoba Hydro – North Dakota (This and the 3 lines above are all that ties Manitoba and U.S. as planned through 2009.) |
| Arrowhead – Stone Lake | 345 kV | 271.0 | 295.4 | Duluth area to northwestern Wisconsin (then to Weston) |
| Eau Claire – Arpin | 345 kV | 148.4 | 71.0 | West to central Wisconsin |
| Prairie Island – Byron | 345 kV | 284.4 | 277.3 | South of Twin Cities metro to west of Rochester |
| Adams – Hazelton | 345 kV | 274.1 | 156.6 | Southeastern Minnesota – eastern Iowa |
| Lakefield Jct. – Wilmarth | 345 kV | 978.5 | 819.3 | Southwestern Minnesota to Mankato area |
| Split Rock – Nobles County | 345 kV | 350.7 | 261.6 | North of Sioux Falls, SD, to northwest of Worthington, MN |
| Nobles County – Lakefield Jct. | 345 kV | 500.7 | 409.9 | Northwest of Worthington to Lakefield Jct. sub (Minnesota) |
| Watertown – Granite Falls | 230 kV | 293.0 | 245.0 | Eastern South Dakota to western Minnesota |
| Blair – Granite Falls | 230 kV | 334.5 | 292.4 | Runs parallel with Watertown – Granite Falls |
| Granite Falls – Minnesota Valley | 230 kV | 455.5 | 404.4 | Western Minnesota |
| Fargo – Moorhead | 230 kV | 50.8 | 39.1 | Fargo, North Dakota to Moorhead, Minnesota |
| Fargo – Sheyenne | 230 kV | 286.6 | 230.0 | North Dakota, Minnesota border |
| Maple River – Winger | 230 kV | 64.3 | 20.9 | Fargo area to northwestern Minnesota |
| Prairie – Winger | 230 kV | 110.0 | 70.8 | Grand Forks area to Winger |
| Wahpeton – Fergus Falls | 230 kV | 277.8 | 213.4 | ND-MN border east to Fergus Falls |
| Bear Creek – Rock Creek | 230 kV | 89.6 | 90.0 | South of Duluth toward the Twin Cities loop |
| Blackberry – Riverton | 230 kV | 203.5 | 175.0 | Northern Minnesota towards south |
| Mud Lake – Benton County | 230 kV | 47.6 | 36.6 | Coming from the north into St.Cloud area |
| Sheyenne – Audubon | 230 kV | 265.4 | 233.0 | Fargo area west into Minnesota |
| Genoa – Coulee | 161 kV | 278.0 | 212.0 | Western Wisconsin |

| | | | | |
|---|---|---|---|---|
| Boswell – Blackberry Ckt 1 | 230 kV | 284.4 | 276.2 | Northern Minnesota |
| Boswell – Blackberry Ckt 2 | 230 kV | 277.6 | 269.7 | Northern Minnesota |

**Table 7 – North/West Bias Tie Line/Interface Flows**

### 4.5 Eastern Bias

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

#### 4.5.1 Recommended Transmission Vision Facilities

| Ref. # | Data Source | Facility Name From | To | Volt (kV) | Miles | Cost ($M) |
|---|---|---|---|---|---|---|
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.7 |
| F-64 | CAPX | Eau Claire | King | 345 | 84 | 63.1 |
| F-65 | CAPX | N. LaCrosse | Eau Claire | 345 | 73 | 55.1 |
| F-66 | CAPX | Genoa | N LaCrosse | 345 | 42 | 31.7 |
| F-67 | CAPX | Genoa | Columbia | 345 | 113 | 84.8 |
| F-68 | CAPX | Genoa | Nelson Dewey | 345 | 70 | 52.4 |
| F-69 | SMNI | Nelson Dewey | Salem | 345 | 34 | 25.6 |
| F-70 | CAPX | Genoa | Lansing | 345 | 21 | 15.8 |
| F-71 | CAPX | Lansing | Rochester | 345 | 89 | 66.8 |
| F-72 | CAPX | Ellendale | Big Stone | 345 | 194 | 145.8 |
| F-73 | CAPX | Big Stone | Blue Lake | 345 | 71 | 53.4 |
| F-02 | TIPS | Maple River | Benton Co | 345 | 206 | 154.5 |
| F-03 | NW | Antelope Va. | Maple River | 345 | 292 | 218.8 |
| F-07 | CapX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CapX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CapX | Benton Co | Chisago | 345 | 59 | 44.2 |
| F-10 | CapX | Benton Co | Granite Falls | 345 | 110 | 82.5 |
| F-12 | CapX | Benton Co | St Boni | 345 | 62 | 46.5 |
| F-26 | CapX | Chisago Co | Prairie Island | 345 | 82 | 61.5 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 218.8 |
| | | | Total | | 2071 | 1,600 |

**Table 8 – Eastern Bias Recommended Facilities**

**Key for Table 8:**
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study

SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

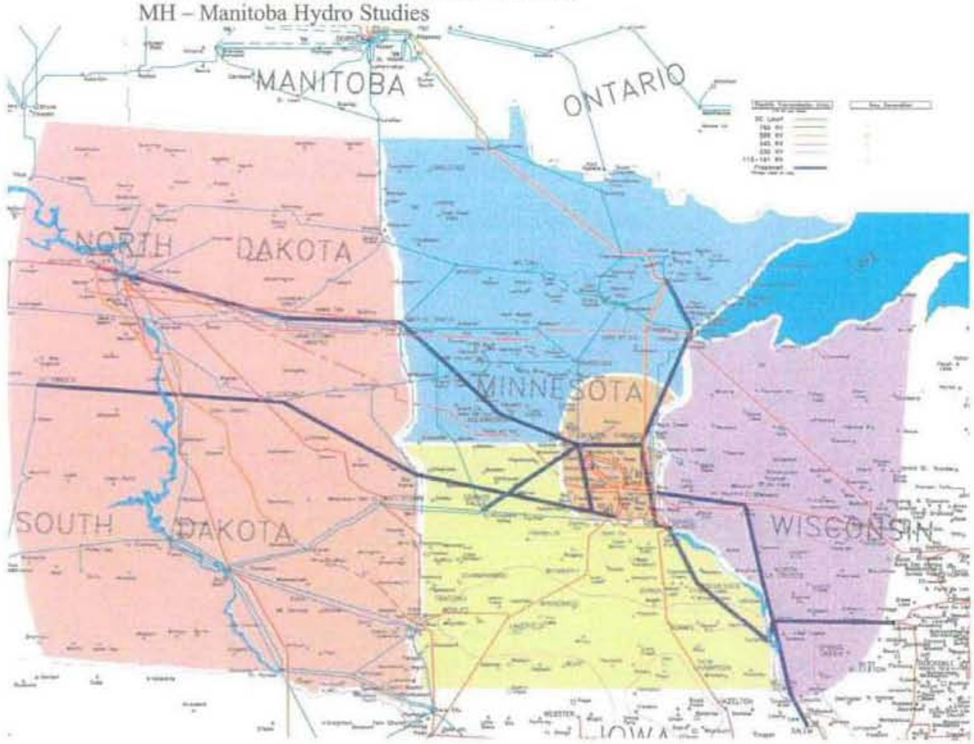



**Diagram 12 – Eastern Bias Recommended Facilities**

### 4.5.2 Line Flows on Interface and Tie Lines

The CapX 2020 technical team collected system intact line flows on a select set of tie lines and interfaces in and around the Minnesota system. Table 9 predominantly focuses on lines coming into and going out of Minnesota, including some lines inside Minnesota connecting pockets of transmission.

| LINE | kV Voltage Level | Base 6300 MW flow (MW) | 6300 MW UPGRADE scenario (MW) | Description |
|---|---|---|---|---|
| Forbes – Chisago | 500 kV | 1209.6 | 1191.7 | Northern Minnesota to Twin Cities loop |
| Riel – Roseau | 500 kV | 1344.9 | 1329.6 | Manitoba Hydro to northern Minnesota |
| Richer – Roseau | 230 kV | 178.8 | 177.7 | Manitoba Hydro to northern Minnesota |

| | | | | |
|---|---|---|---|---|
| Letellier – Drayton | 230 kV | 306.5 | 314.1 | Manitoba Hydro to MN-ND border |
| Glenboro – Rugby | 230 kV | -26.9 | -18.6 | Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.) |
| Arrowhead – Stone Lake | 345 kV | 177.1 | 174.5 | Duluth area to northwestern Wisconsin (then to Weston) |
| Eau Claire – Arpin | 345 kV | -174.1 | -41.8 | West to central Wisconsin |
| Prairie Island – Byron | 345 kV | -380.5 | -263.7 | South of Twin Cities metro to west of Rochester |
| Adams – Hazelton | 345 kV | -138.5 | -12.5 | Southeastern Minnesota – eastern Iowa |
| Lakefield Jct. – Wilmarth | 345 kV | 724.4 | 660.1 | Southwestern Minnesota to Mankato area |
| Split Rock – Nobles County | 345 kV | 97.9 | 81.1 | North of Sioux Falls, SD, to northwest of Worthington, MN |
| Nobles County – Lakefield Jct. | 345 kV | 279.4 | 265.4 | Northwest of Worthington to Lakefield Jct. sub. (Minnesota) |
| Watertown – Granite Falls | 230 kV | 234.2 | 224.2 | Eastern South Dakota to western Minnesota |
| Blair – Granite Falls | 230 kV | 276.8 | 269.9 | Runs parallel with Watertown – Granite Falls |
| Granite Falls – Minnesota Valley | 230 kV | 373.6 | 362.8 | Western Minnesota |
| Fargo – Moorhead | 230 kV | -23.1 | -21.4 | Fargo, North Dakota, to Moorhead, Minnesota |
| Fargo – Sheyenne | 230 kV | 305.9 | 297.2 | North Dakota, Minnesota border |
| Maple River – Winger | 230 kV | 91.5 | 88.5 | Fargo area to northwestern Minnesota |
| Prairie – Winger | 230 kV | 129.2 | 129.3 | Grand Forks area to Winger |
| Wahpeton – Fergus Falls | 230 kV | 242.6 | 234.9 | ND-MN border east to Fergus Falls |
| Bear Creek – Rock Creek | 230 kV | 93.1 | 92.5 | South of Duluth toward the Twin Cities loop |
| Blackberry – Riverton | 230 kV | 227.0 | 233.4 | Northern Minnesota towards south |
| Mud Lake – Benton County | 230 kV | 38.3 | 31.5 | Coming from the north into St.Cloud area |
| Sheyenne – Audubon | 230 kV | 230.6 | 222.3 | Fargo area west into Minnesota |
| Genoa – Coulee | 161 kV | 391.9 | 210.8 | Western Wisconsin |
| Boswell – Blackberry Ckt 1 | 230 kV | 279.9 | 280.3 | Northern Minnesota |
| Boswell – Blackberry Ckt 2 | 230 kV | 273.2 | 273.5 | Northern Minnesota |

**Table 9 – Eastern Bias Tie Line/Interface Flows**

## 4 Slow Growth Analysis

The CapX 2020 technical team performed a sensitivity analysis for a reduced load level of 4,500 MW to determine which facility additions are necessary at this slower growth load level. Assuming the 6,300 MW increased load level is reached in 2020 and using a linear load growth rate, the team determined that the 4,500 MW increased load level would be reached in the year 2016.

To model the 4,500 MW load level, the 6,300 MW load model was scaled down in each control area uniformly by scaling the load growth down by a factor of 2/3 (4500/6300). The scaled down load totals for each control area are shown in Table 10.

| Control area | Calculated 2020 load level (6300 MW) | Scaled load level (4500 MW) |
|---|---|---|
| Alliant Energy (West) (331) | 3888.2 | 3711.1 |
| Xcel Energy (North) (600) | 12885.1 | 11960.5 |
| Minnesota Power Co. (608) | 1814.4 | 1727.1 |
| Southern MN Municipal Power Agency (613) | 442.4 | 410.4 |
| Great River Energy (618) | 3943.2 | 3627.8 |
| Otter Tail Power (626) | 2248.3 | 2085.9 |
| Dairyland Power Co. (680) | 1266.2 | 1177.6 |
| Total | 26487.8 | 24700.6 |

**Table 10 – CapX 2020 Slow Area Growth**

The generation total also was reduced by scaling each generator down by a factor of 2/3 (4500/6300). Table 11 shows the reduced generation totals for each generation bias scenario.

| Slow Growth Analysis | | | | | | |
|---|---|---|---|---|---|---|
| | North/West | | Minnesota | | Eastern | |
| | 6300 MW | 4500 MW | 6300 MW | 4500 MW | 6300 MW | 4500 MW |
| Northern Minnesota | 1700 | 1214 | 1250 | 893 | 550 | 393 |
| Dakotas | 2100 | 1500 | 1000 | 714 | 1600 | 1143 |
| Southern MN/ Northern Iowa | 1875 | 1340 | 1875 | 1340 | 2125 | 1554 |
| Metro | 650 | 464 | 2200 | 1571 | 1000 | 714 |
| Wisconsin | 0 | 0 | 0 | 0 | 1000 | 714 |
| **Total** | **6325** | **4518** | **6325** | **4518** | **6325** | **4518** |

**Table 11 – Slow Growth Generation Scenario**

The results for each generation scenario at the slow growth load level will be discussed in detail in sections 5.1 – 5.3 of this report. The n-1 contingency output results tabulated in Appendices B-1 through B-3. For the slow growth n-1 analysis, the same contingencies from the anticipated growth study were run again and the transmission system was monitored in the following control areas:

| Control Area | PSS/E Area # |
|---|---|
| Alliant Energy West | 331 |
| Xcel Energy | 600 |
| Minnesota Power Co. | 608 |
| Southern Minnesota Municipal Power Agency | 613 |
| Great River Energy | 618 |
| Otter Tail Power Company | 626 |
| Dairyland Power Company | 680 |

### 5.1 Transmission Alternatives Considered for Slow Growth

For the slow growth sensitivity the CapX 2020 technical team began the analysis of each generation scenario with the facilities recommended for the 6300-MW vision study. The recommended facilities were individually removed to determine which of the facilities were also necessary at the 4,500 MW load/generation level.

For the Minnesota and North/West biases, the team determined that the majority of the facilities still were necessary even with the load reduced by 33 percent. For the eastern bias case at the slow growth level, there was less justification for some of the various recommended transmission lines. Although, higher voltage lines from the Wisconsin – Iowa border area towards the Twin Cities were still appropriate. It was also still clear that relief of existing facilities is needed on the system between the Dakotas and Minnesota. As explained in section 4.5, additional sensitivity work is still pending for the eastern bias case, both at the 6300 MW level and the slow growth scenario.

### 5.2 Minnesota Bias Scenario Slow Growth Results

#### 5.2.1 Recommended Facilities

| Ref. # | Data Source | Facility Name | | | | |
|---|---|---|---|---|---|---|
| | | From | To | Volt (kV) | Miles | Cost ($M) |
| F-02 | TIPS | Alexandria | Benton County | 345 | 80 | 60 |
| F-03 | TIPS | Alexandria | Maple River | 345 | 126 | 94.5 |
| F-06 | NW | Antelope Valley | Maple River | 345 | 292 | 219 |
| F-07 | CAPX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CAPX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CAPX | Benton County | Chisago County | 345 | 59 | 44.25 |
| F-10 | CAPX | Benton County | Granite Falls | 345 | 110 | 82.5 |
| F-11 | MH | Benton County | Riverton | 345 | 78 | 58.5 |
| F-12 | CAPX | Benton County | St. Boni | 345 | 62 | 46.5 |

| | | | | | | |
|---|---|---|---|---|---|---|
| F-13 | CAPX | Blue Lake | Ellendale | 345 | 200 | 150 |
| F-17 | CAPX | Boswell | Forbes | 345 | 64 | 48 |
| F-26 | CAPX | Chisago County | Prairie Island | 345 | 82 | 61.5 |
| F-28 | CAPX | Columbia | North LaCrosse | 345 | 80 | 60 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 173.25 |
| F-32 | CAPX | Forbes | Riverton | 345 | 114 | 85.5 |
| F-36 | SMNI | Rochester | North LaCrosse | 345 | 60 | 45 |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.5 |
| | | | | | | |
| | | | | **Total** | **1876** | **1407** |

**Table 12 – Slow Growth Load Level Minnesota Bias Recommended Facilities**

**Table 12 key:**
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

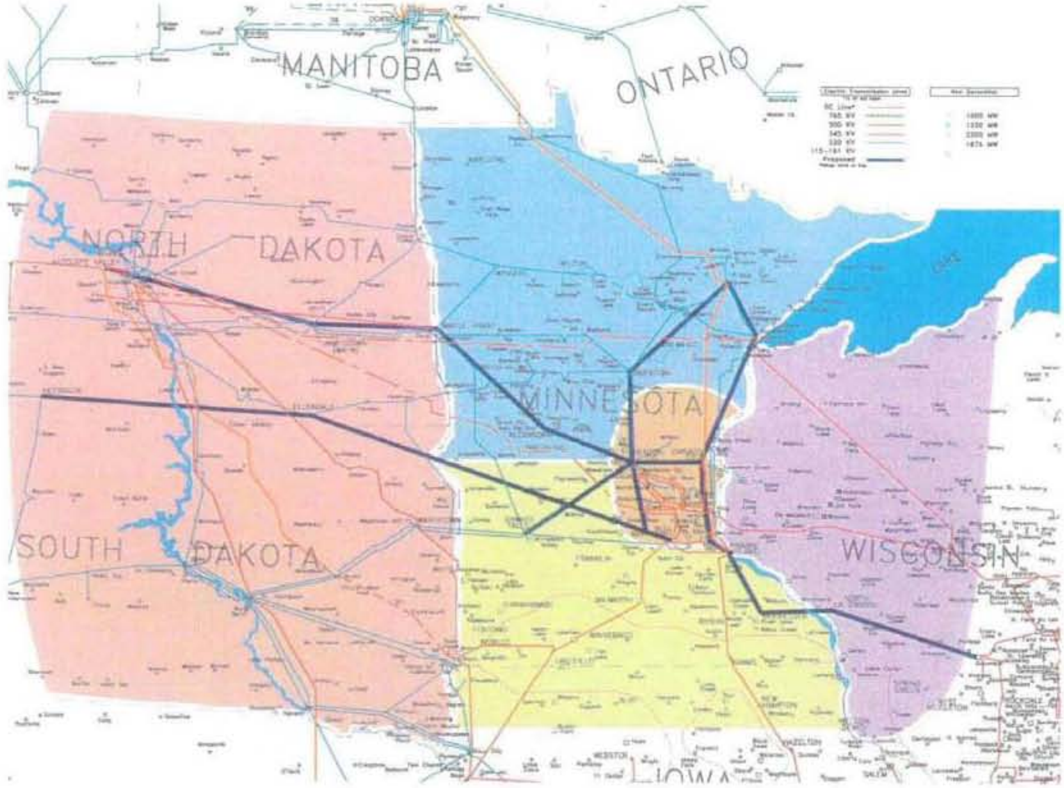



**Diagram 13 – Slow Growth Load Level Minnesota Bias Recommended Facilities**

### 5.2.2 Line Flows on Interface and Tie Lines

| LINE | kV Voltage Level | Base 4500 MW FLOW (MW) | 4500 MW UPGRADE scenario (MW) | Description |
|---|---|---|---|---|
| Forbes – Chisago | 500 kV | 1351 | 1187 | Northern Minnesota to Twin Cities loop |
| Riel – Roseau | 500 kV | 1228 | 1224 | Manitoba Hydro to northern Minnesota |
| Richer – Roseau | 230 kV | 180 | 184 | Manitoba Hydro to northern Minnesota |
| Letellier – Drayton | 230 kV | 363 | 340 | Manitoba Hydro to MN-ND border |
| Glenboro – Rugby | 230 kV | 17 | 38 | Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.) |
| Arrowhead – Stone Lake | 345 kV | 88 | 98 | Duluth area to northwestern Wisconsin (then to Weston) |

| | | | | |
|---|---|---|---|---|
| Eau Claire – Arpin | 345 kV | 206 | 146 | West to central Wisconsin |
| Prairie Island – Byron | 345 kV | 169 | 227 | South of Twin Cities metro to west of Rochester |
| Adams – Hazelton | 345 kV | 260 | 197 | Southeastern Minnesota – Eastern Iowa |
| Lakefield Jct – Wilmarth | 345 kV | 719 | 622 | Southwestern Minnesota to Mankato area |
| Split Rock – Nobles County | 345 kV | 175 | 129 | North of Sioux Falls, SD to northwest of Worthington, MN |
| Nobles County – Lakefield Jct | 345 kV | 220 | 128 | Northwest of Worthington to Lakefield Jct. sub. (Minnesota) |
| Watertown – Granite Falls | 230 kV | 302 | 272 | Eastern South Dakota to western Minnesota |
| Blair – Granite Falls | 230 kV | 317 | 297 | Runs parallel with Watertown – Granite Falls |
| Granite Falls – Minnesota Valley | 230 kV | 250 | 220 | Western Minnesota |
| Fargo – Moorhead | 230 kV | 54 | 64 | Fargo, North Dakota to Moorhead, Minnesota |
| Fargo – Sheyenne | 230 kV | 245 | 144 | North Dakota, Minnesota border |
| Maple River – Winger | 230 kV | 75 | 55 | Fargo area to northwestern Minnesota |
| Prairie – Winger | 230 kV | 137 | 78 | Grand Forks area to Winger |
| Wahpeton – Fergus Falls | 230 kV | 209 | 136 | ND-MN border east to Fergus Falls |
| Bear Creek – Rock Creek | 230 kV | 91 | 80 | South of Duluth toward the Twin Cities loop |
| Blackberry – Riverton | 230 kV | 227 | 156 | Northern Minnesota towards south |
| Mud Lake – Benton County | 230 kV | 1.2 | 34 | Coming from the north into St.Cloud area |
| Sheyenne – Audubon | 230 kV | 194 | 165 | Fargo area west into Minnesota |
| Genoa – Coulee | 161 kV | 268 | 206 | Western Wisconsin |
| Boswell – Blackberry Ckt 1 | 230 kV | 288 | 188 | Northern Minnesota |
| Boswell – Blackberry Ckt 2 | 230 kV | 281 | 183 | Northern Minnesota |

**Table 13 – Slow Growth Minnesota Bias Tie Line/Interface Flows**

### 5.3 North / West Scenario Slow Growth Results

#### 5.3.1 Recommended Facilities

| | | Facility Name | | | | |
|---|---|---|---|---|---|---|
| Ref. # | Data Source | From | To | Volt (kV) | Miles | Cost ($M) |
| F-02 | TIPS | Alexandria | Benton County | 345 | 80 | 60 |
| F-03 | TIPS | Alexandria | Maple River | 345 | 126 | 94.5 |
| F-06 | NW | Antelope Valley | Maple River | 345 | 292 | 219 |
| F-07 | CAPX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CAPX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CAPX | Benton County | Chisago County | 345 | 59 | 44.25 |
| F-10 | CAPX | Benton | Granite Falls | 345 | 110 | 82.5 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | County | | | | |
| F-12 | CAPX | Benton County | St. Boni | 345 | 62 | 46.5 |
| F-13 | CAPX | Blue Lake | Ellendale | 345 | 200 | 150 |
| F-26 | CAPX | Chisago County | Prairie Island | 345 | 82 | 61.5 |
| F-28 | CAPX | Columbia | North LaCrosse | 345 | 80 | 60 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 173.25 |
| F-36 | SMNI | Rochester | North LaCrosse | 345 | 60 | 45 |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.5 |
| | | | | | | |
| | | | **Total** | | **1620** | **1215** |

**Table 14 – Slow Growth Load Level North/West Bias Recommended Facilities**

**Table 14 key:**
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

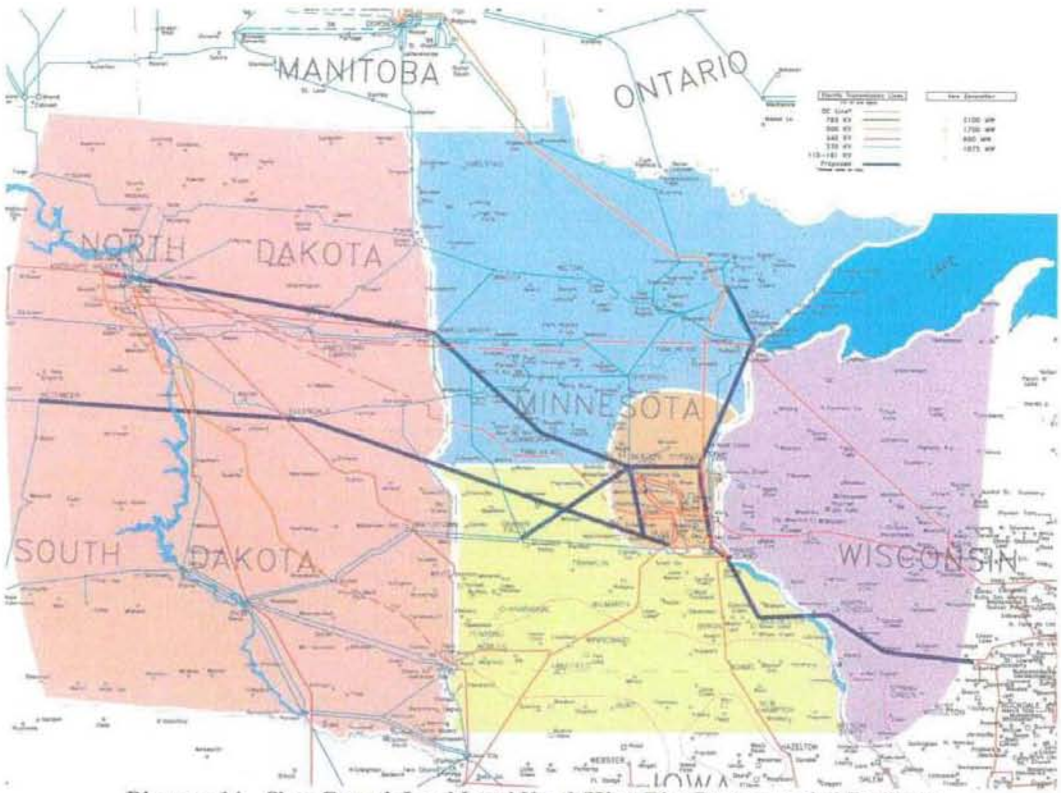



Diagram 14 – Slow Growth Load Level North/West Bias Recommended Facilities

### 5.3.2 Line Flows on Interface and Tie Lines

| LINE | kV Voltage Level | Base 4500 MW FLOW | 4500 MW UPGRADE scenario | Description |
|---|---|---|---|---|
| Forbes – Chisago | 500 kV | 1540.3 | 1398.6 | Northern Minnesota to Twin Cities loop |
| Riel – Roseau | 500 kV | 1842.1 | 1782.9 | Manitoba Hydro to Northern Minnesota |
| Richer – Roseau | 230 kV | 228.5 | 223.5 | Manitoba Hydro to Northern Minnesota |
| Letellier – Drayton | 230 kV | 392.3 | 405.6 | Manitoba Hydro to MN-ND border |
| Glenboro – Rugby | 230 kV | 34.1 | 81.1 | Manitoba Hydro – North Dakota (This and the three lines above are all that ties Manitoba and U.S. as planned through 2009.) |

| | | | | |
|---|---|---|---|---|
| Arrowhead – Stone Lake | 345 kV | 298.3 | 310.9 | Duluth area to northwestern Wisconsin (then to Weston) |
| Eau Claire – Arpin | 345 kV | 72.3 | 57.8 | West to central Wisconsin |
| Prairie Island – Byron | 345 kV | 165.4 | 185.3 | South of Twin Cities metro to west of Rochester |
| Adams – Hazelton | 345 kV | 173.9 | 92.9 | Southeastern Minnesota – eastern Iowa |
| Lakefield Jct. – Wilmarth | 345 kV | 746.1 | 602.3 | Southwestern Minnesota to Mankato area |
| Split Rock – Nobles County | 345 kV | 263.9 | 184.4 | North of Sioux Falls, SD, to northwest of Worthington, MN |
| Nobles County – Lakefield Jct. | 345 kV | 336.4 | 252.5 | Northwest of Worthington to Lakefield Jct. sub. (Minnesota) |
| Watertown – Granite Falls | 230 kV | 248.5 | 232.0 | Eastern South Dakota to western Minnesota |
| Blair – Granite Falls | 230 kV | 279.8 | 270.1 | Runs parallel with Watertown – Granite Falls |
| Granite Falls – Minnesota Valley tap | 230 kV | 375.4 | 288.3 | Western Minnesota |
| Fargo – Moorhead | 230 kV | 54.5 | 55.4 | Fargo, North Dakota, to Moorhead, Minnesota |
| Fargo – Sheyenne | 230 kV | 271 | 200.7 | North Dakota, Minnesota border |
| Maple River – Winger | 230 kV | 75.1 | 82.9 | Fargo area to northwestern Minnesota |
| Prairie – Winger | 230 kV | 168.3 | 139.6 | Grand Forks area to Winger |
| Wahpeton – Fergus Falls | 230 kV | 241.8 | 164.3 | ND-MN border east to Fergus Falls |
| Bear Creek – Rock Creek | 230 kV | 96.1 | 95.5 | South of Duluth toward the Twin Cities loop |
| Blackberry – Riverton | 230 kV | 232.8 | 216.5 | Northern Minnesota towards south |
| Mud Lake – Benton County | 230 kV | 63.6 | 23.9 | Coming from the north into St.Cloud area |
| Sheyenne – Audubon | 230 kV | 233.9 | 197.2 | Fargo area west into Minnesota |
| Genoa – Coulee | 161 kV | 249.8 | 189.1 | Western Wisconsin |
| Boswell – Blackberry Ckt 1 | 230 kV | 293.9 | 287.2 | Northern Minnesota |
| Boswell – Blackberry Ckt 2 | 230 kV | 286.9 | 280.4 | Northern Minnesota |

**Table 15 – Slow Growth North/West Bias Tie Line/Interface Flows**

In the eastern bias scenario, the CapX 2020 technical team added part of the additional generation to the east of Minnesota (part on the border of northeastern Iowa and southwestern Wisconsin, part central Wisconsin), in addition to having generation throughout Minnesota, northern Iowa, North Dakota, and South Dakota as in the other two scenarios.

### 5.4 East Scenario Slow Growth Results

### 5.4.1 Recommended Facilities

| Ref. # | Data Source | Facility Name | | | | |
|---|---|---|---|---|---|---|
| | | From | To | Volt (kV) | Miles | Cost ($M) |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.7 |
| F-64 | CAPX | Eau Claire | King | 345 | 84 | 63.1 |
| F-65 | CAPX | N. LaCrosse | Eau Claire | 345 | 73 | 55.1 |
| F-66 | CAPX | Genoa | N LaCrosse | 345 | 42 | 31.7 |
| F-67 | CAPX | Genoa | Columbia | 345 | 113 | 84.8 |
| F-68 | CAPX | Genoa | Nelson Dewey | 345 | 70 | 52.4 |
| F-69 | SMNI | Nelson Dewey | Salem | 345 | 34 | 25.6 |
| F-70 | CAPX | Genoa | Lansing | 345 | 21 | 15.8 |
| F-71 | CAPX | Lansing | Rochester | 345 | 89 | 66.8 |
| F-72 | CAPX | Ellendale | Big Stone | 345 | 194 | 145.8 |
| F-73 | CAPX | Big Stone | Blue Lake | 345 | 71 | 53.4 |
| F-02 | TIPS | Maple River | Benton Co | 345 | 206 | 154.5 |
| F-03 | NW | Antelope Va. | Maple River | 345 | 292 | 218.8 |
| F-07 | CapX | Arrowhead | Chisago | 345 | 120 | 90 |
| F-08 | CapX | Arrowhead | Forbes | 345 | 60 | 45 |
| F-09 | CapX | Benton Co | Chisago | 345 | 59 | 44.2 |
| F-10 | CapX | Benton Co | Granite Falls | 345 | 110 | 82.5 |
| F-12 | CapX | Benton Co | St Boni | 345 | 62 | 46.5 |
| F-26 | CapX | Chisago Co | Prairie Island | 345 | 82 | 61.5 |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 218.8 |
| | | | **Total** | | **2071** | **1,600** |

**Table 15– Eastern Bias Preliminary Recommended Facilities**

**Key for Table 15:**
CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies

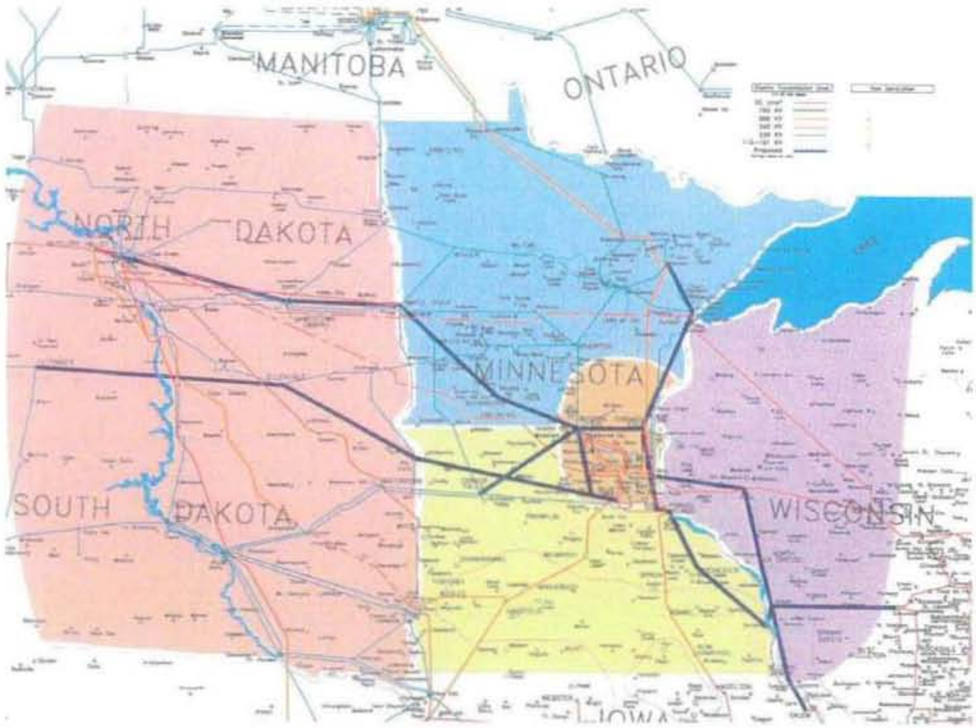



**Diagram 15 – Eastern Bias Preliminary Recommended Facilities**

## 6 Common Facilities

The CapX 2020 technical team's primary goal for this initial vision study was to identify a long-range transmission plan that would benefit Minnesota's electric reliability as load continues to grow over the next 15 years and beyond.

### 6.1 Common transmission alternatives between the Biases

The team found that the biases had 1620 miles of 345 kV transmission lines in common, for a total of $1.215 billion.[5] For comparison, that is a little more than 80 percent of the cost of each scenario individually. The common facilities are shown in Table 18.

[5] When reviewing the results of this study, note that only the cost of transmission line per mile is represented. None of the associated substation, generation interconnection facilities, or underlying lower-voltage (below 161 kV) transmission system infrastructure costs are determined or included in this vision study.

| Facility Name | | | | |
|---|---|---|---|---|
| From | To | Volt (kV) | Miles | Cost ($M) |
| Alexandria | Benton County | 345 | 80 | 60 |
| Alexandria | Maple River | 345 | 126 | 94.5 |
| Antelope Valley | Jamestown | 345 | 185 | 138.75 |
| Arrowhead | Chisago | 345 | 120 | 90 |
| Arrowhead | Forbes | 345 | 60 | 45 |
| Benton County | Chisago County | 345 | 59 | 44.25 |
| Benton County | Granite Falls | 345 | 110 | 82.5 |
| Benton County | St. Boni | 345 | 62 | 46.5 |
| Blue Lake | Ellendale | 345 | 200 | 150 |
| Chisago County | Prairie Island | 345 | 82 | 61.5 |
| Columbia | North LaCrosse | 345 | 80 | 60 |
| Ellendale | Hettinger | 345 | 231 | 173.25 |
| Rochester | North LaCrosse | 345 | 60 | 45 |
| Jamestown | Maple River | 345 | 107 | 80.25 |
| Prairie Island | Rochester | 345 | 58 | 43.5 |
| | **Total miles 1620** | **Total cost $1,215 ($M)** | | |

**Table 16 – Common Recommended Facilities**

### 6.2 Additional transmission facilities for each scenario

In addition to the common facilities in the above table, the Minnesota bias had three additional unique facilities for a total of 256 miles and $192 million. These facilities are a result of the high concentration of generation in the St Paul/Minneapolis metro area.

The north/west bias also had three unique facilities for a total of 387 miles and $290 million. These facilities are a direct result of the 1000-MW import from Manitoba Hydro, which is included in the north/west generation bias.

The East Bias has unique facilities due to the difficulties sending power from the East to West across minimal river crossings.

## 7 Conclusion and Next Steps

The CapX 2020 technical team believes these results to be the cornerstone of future studies to better identify the transmission needs of the study region. These results need to be integrated into the MISO Transmission Expansion Plan and ongoing utility load-serving studies.

The team envisions future study efforts to incorporate the results of adjoining regional study efforts, investigate how the bulk transmission solutions can support the load-serving transmission, and investigate how the impacts of new load forecasts and generation interconnections impact the transmission vision. Additional studies to consider include:

- Scaling the 2009 model's load to a point where transmission violations begin to occur and determining which transmission alternative best solves the problem. The study should continue this effort to determine sequence and/or combinations of transmission additions.
- Analyzing the lower voltage system (below 161 kV) for voltage violations and thermal overloads during n-1 contingency analysis.
- Conducting detail studies (including stability analysis) to support a certificate of need for facilities identified as being critical to meet the needs of the transmission customer.
- Identifying bulk substation locations that address overloads on the load-serving transmission system and preparing least-cost planning alternatives that meet the anticipated load growth in the area. Studies would involve detailed load scaling efforts to better model local load growth. The team would review short-term alternatives to address immediate concerns such as switched capacitors, reconductoring, and voltage upgrades on existing corridors.
- Investigating impacts of alternative transmission technology (DC, FACTS, phase shifting transformers, etc.)
- Reconsidering alternative generation locations in each of the biases to determine the sensitivity of generation location on the transmission vision.
- Updating study results based on new generation interconnect/delivery study results.
- Integrating results of adjoining regional and MISO study efforts to determine impacts on transmission vision.

**CapX 2020 Technical Team members:**

| | |
|---|---|
| Jared Alholinna | Great River Energy Company |
| Tami Anderson | Great River Energy Company |
| Richard Dahl | Missouri River Energy Services |
| Rick Hettwer | Southern Minnesota Municipal Power Agency |
| Amanda King | Xcel Energy |
| Mike Klopp | Minnesota Power Company |
| Gordon Pietsch | Great River Energy Company |
| Tim Rogelstad | Otter Tail Power Company |

**Appendices**

A. Composite List of Transmission Data

B. Tabulated Contingency Results, Load Flow Data and Automaps

B-1. MN Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-2. NW Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

B-3. Eastern Bias

- N-1 Output 6300 MW
- Automaps for 6300 MW Case
- N-1 Output 4500 MW
- Automaps for 4500 MW case

C. Transmission Characteristics and Cost Estimate Data

134

## Appendix A
### Composite List of Transmission Data – Recommended Facilities Include Facility Characteristics

| Ref. # | Data Source | Facility Name | | | | | Facility Characteristics | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | From Name | To Name | Volt (kV) | Miles | Cost ($M) | From Bus # | To Bus # | R | X | Bch | Rating (MVA) Summer | |
| F-01 | SMNI | Adams | Hayward | 345 | 34 | 25.3 | | | | | | | |
| F-02 | TIPS | Alexandria | Benton County | 345 | 80 | 59.9 | 67010 | 60142 | .00299 | .03276 | .559 | 1165 | |
| F-03 | TIPS | Alexandria | Maple River | 345 | 126 | 94.2 | 67010 | 66792 | .00506 | .05544 | .946 | 1165 | |
| F-04 | CAPX | Alma | Rock Elm | 345 | 60 | 45 | | | | | | | |
| F-05 | CAPX | Alma | Tremval | 345 | 40 | 30 | | | | | | | |
| F-06 | NW | Antelope Valley | Maple River | 345 | 292 | 219 | 67101 | 66792 | .01058 | .11592 | 1.978 | 1165 | |
| F-07 | CAPX | Arrowhead | Chisago | 345 | 120 | 90 | 61608 | 60199 | .00438 | .04718 | .80974 | 1303 | |
| F-08 | CAPX | Arrowhead | Forbes | 345 | 60 | 45 | 61608 | 61622 | .00191 | .02060 | .35357 | 1303 | |
| F-09 | CAPX | Benton County | Chisago County | 345 | 59 | 43.9 | 60142 | 60199 | .00269 | .02890 | .49602 | 1303 | |
| F-10 | CAPX | Benton County | Granite Falls | 345 | 110 | 82.7 | 60142 | 66797 | .00506 | .05449 | .93523 | 1303 | |
| F-11 | MH | Benton County | Riverton | 500 | 78 | 58.5 | 61620 | 60142 | .00361 | .000494 | .665 | 1303 | |
| F-12 | CAPX | Benton County | St. Boni | 345 | 62 | 46.6 | 60142 | 62655 | .00285 | .03068 | .52655 | 1303 | |
| F-13 | CAPX | Blue Lake | Ellendale | 345 | 200 | 150 | 60192 | 99990 | .014398 | .157752 | 2.6918 | 1166 | |
| F-14 | NW | Blue Lake | Franklin | 345 | 87 | 65.0 | | | | | | | |
| F-15 | NW | Blue Lake | Granite Falls | 345 | 127 | 95.4 | | | | | | | |
| F-16 | CAPX | Blue Lake | West Faribault | 345 | 50 | 37.5 | | | | | | | |
| F-17 | CAPX | Boswell | Forbes | 345 | 64 | 47.7 | 61628 | 61622 | .00292 | .03142 | .53926 | 1303 | |
| F-18 | TIPS | Boswell | Wilton County | 230 | 72 | 54.3 | | | | | | | |
| F-19 | SMNI | Burt | Webster | 345 | 50 | 37.3 | | | | | | | |
| F-20 | SMNI | Burt | Winnebago | 345 | 56 | 41.9 | | | | | | | |
| F-21 | SMNI | Byron | Rochester | 345 | 31 | 23.6 | | | | | | | |
| F-22 | SMNI | Byron | Wilmarth | 345 | 72 | 54.2 | | | | | | | |
| F-23 | SMNI | White | Franklin | 345 | 76 | 57.2 | | | | | | | |
| F-24 | SMNI | Chanarambie | White | 345 | 53 | 39.8 | | | | | | | |
| F-25 | CAPX | Chisago County | King | 345 | 52 | 39 | | | | | | | |
| F-26 | CAPX | Chisago County | Prairie Island | 345 | 82 | 61.2 | 60199 | 60105 | .00375 | .04031 | .69189 | 1303 | |
| F-27 | CAPX | Columbia | Genoa | 345 | 110 | 83 | | | | | | | |
| F-28 | CAPX | Columbia | North LaCrosse | 345 | 80 | 60 | 39157 | 92605 | .00316 | .04954 | .5371 | 1328 | |
| F-29 | MH | Dorsey | Karlstad | 345 | 134 | 100.5 | 67625 | 66750 | .00383 | .05688 | .89380 | 1295 | |
| F-30 | NW | Ellendale | Hettinger | 345 | 231 | 173.3 | 99990 | 67175 | .0092 | .1008 | 1.72 | 1165 | |
| F-31 | NW | Ellendale | Watertown | 345 | 131 | 98.2 | | | | | | | |

135

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| F-32 | CAPX | Forbes | Riverton | 345 | 114 | 85.4 | 61622 | 61620 | 00522 | .05622 | .96491 | 1303 | |
| F-33 | CAPX | Franklin | Granite Falls | 345 | 48 | 36 | | | | | | | |
| F-34 | CAPX | Franklin | Lyon County | 345 | 70 | 52 5 | | | | | | | |
| F-35 | CAPX | Franklin | Wilmarth | 345 | 60 | 45 | | | | | | | |
| F-36 | SMNI | Rochester | North LaCrosse | 345 | 60 | 44 9 | 69999 | 92603 | .00253 | .02717 | .46635 | 2110 | |
| F-37 | SMNI | Freemont | Rochester | 345 | 0 | 0 | | | | | | | |
| F-38 | NW | Granite Falls | Watertown | 345 | 93 | 69.9 | | | | | | | |
| F-39 | CAPX | Genoa | Lansing | 345 | 0 | 0 | | | | | | | |
| F-40 | MH | Winger | Benton Co | 345 | 162 | 121 5 | 66760 | 60142 | .00735 | .10920 | 1.7157 | 1295 | |
| | | | | | | | | | | | | | |
| F-42 | SMNI | Hayward | Winnebago | 345 | 56 | 41 9 | | | | | | | |
| F-43 | SMNI | Hazelton | Salem | 345 | 78 | 58 1 | | | | | | | |
| F-44 | NW | Jamestown | Maple River | 345 | 107 | 80 4 | | | | | | | |
| F-45 | MH | Karlstad | Winger | 345 | 91 | 114 | 66750 | 66803 | .00311 | .04623 | .72631 | 1295 | |
| F-46 | CAPX | King | Rock Elm | 345 | 50 | 37 5 | | | | | | | |
| F-47 | SMNI | Lakefield Junction | Winnebago | 345 | 64 | 47.9 | | | | | | | |
| F-48 | CAPX | Lansing | Rochester | 345 | 100 | 75 | | | | | | | |
| F-49 | CAPX | Lyon County | White | 345 | 50 | 37.5 | | | | | | | |
| F-50 | SMNI | Nelson Dewey | Salem | 345 | 35 | 25.9 | | | | | | | |
| F-51 | SMNI | Nelson Dewey | Spring Green | 345 | 67 | 50.2 | | | | | | | |
| F-52 | SMNI | Nobles | Wilmarth | 345 | 120 | 89.7 | | | | | | | |
| | | | | | | | | | | | | | |
| F-54 | SMNI | North LaCrosse | Spring Green | 345 | 105 | 78 8 | | | | | | | |
| F-55 | CAPX | North Lacrosse | Tremval | 345 | 55 | 41.3 | | | | | | | |
| F-56 | SMNI | Prairie Island | Rochester | 345 | 58 | 43.7 | 60105 | 6999 | .0046 | .0494 | .8479 | 2110 | |
| F-57 | MH | Riverton | Wilton County | 500 | 96 | 72 | | | | | | | |
| F-58 | SMNI | Rockdale | West Middleton | 345 | 36 | 26.7 | | | | | | | |
| F-59 | SMNI | Spring Green | West Middleton | 345 | 31 | 23.2 | | | | | | | |
| F-60 | CAPX | West Faribault | Wilmarth | 345 | 45 | 33 75 | | | | | | | |
| F-61 | MH | Wilton County | Winger | 345 | 66 | 49.5 | | | | | | | |
| F-62 | CAPX | Wilmarth | Rochester | 345 | 75 | 56 25 | | | | | | | |
| F-63 | CAPX | Lakefield Jct. | Adams | 345 | 92 | 69 | 60331 | 60102 | .00644 | 06916 | 1.187 | 1303 | |
| F-64 | CAPX | Eau Claire | King | 345 | 84 | 63.1 | | | | | | | |
| F-65 | CAPX | North LaCrosse | Eau Claire | 345 | 73 | 55.1 | | | | | | | |
| F-66 | CAPX | Genoa | North LaCrosse | 345 | 42 | 31.7 | | | | | | | |
| F-67 | CAPX | Genoa | Columbia | 345 | 113 | 84.8 | | | | | | | |
| F-68 | CAPX | Genoa | Nelson Dewey | 345 | 70 | 52.4 | | | | | | | |
| F-69 | SMNI | Nelson Dewey | Salem | 345 | 34 | 25.6 | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| F-70 | CAPX | Genoa | Lansing | 345 | 21 | 15.8 | | | | | | | |
| F-71 | CAPX | Lansing | Rochester | 345 | 89 | 66.8 | | | | | | | |
| F-72 | CAPX | Ellendale | Big Stone | 345 | 194 | 145.8 | | | | | | | |
| F-73 | CAPX | Big Stone | Blue Lake | 345 | 71 | 53.4 | | | | | | | |
| | | | | **Total** | **0** | **0** | | | | | | | |

CAPX – CapX Technical Team
NW – MISO Northwest Exploratory Study
TIPS – Transmission Improvement Plans Study
MH – Manitoba Hydro Studies
SMNI – MISO Southern Minnesota/Northern Iowa Exploratory Study

**For the rest of the Appendices please refer to www.capx2020.com for the electronic version of the Technical Update report.**

## Appendix C: Actual and Projected Substation Loads for Southern Red River Valley area (Winter Peak)

| Southern Red River Valley area Load Serving Substations | Actual | Forecast | | | |
|---|---|---|---|---|---|
| | Load MW 2005 | Load MW 2010 | Load MW 2015 | Load MW 2019 | Load MW 2020 |
| Aldrich | 2.7 | 3.2 | 3.6 | 4.0 | 4.0 |
| Alexandria (GRE) | 24.4 | 26.4 | 28.8 | 30.8 | 30.9 |
| Alexandria Nokomis | 12.9 | 14.2 | 15.4 | 16.2 | 16.5 |
| Alexandria Poleyard | 20.1 | 22.1 | 24.0 | 25.3 | 25.6 |
| Alexandria Southwest | 11.6 | 12.8 | 13.9 | 14.6 | 14.8 |
| Alice | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 |
| Audubon | 38.8 | 43.3 | 47.5 | 50.6 | 51.2 |
| Aviko | 5.5 | 5.9 | 6.3 | 6.6 | 6.7 |
| Badoura | 2.9 | 2.9 | 2.9 | 2.9 | 2.9 |
| Baxter | 17.4 | 22.6 | 24.8 | 26.6 | 26.7 |
| Brandon | 22.8 | 22.8 | 24.7 | 26.4 | 26.5 |
| Buffalo | 19.0 | 18.0 | 19.2 | 20.3 | 20.5 |
| Cass County | 90.0 | 99.1 | 106.6 | 112.7 | 114.3 |
| Cormorant | 7.0 | 8.2 | 9.2 | 10.0 | 10.0 |
| Detroit Lakes Industrial | 6.6 | 8.7 | 10.4 | 11.6 | 11.9 |
| Detroit Lakes Rud St. | 6.0 | 8.0 | 9.7 | 10.8 | 11.2 |
| Detroit Lakes West | 6.0 | 8.0 | 9.7 | 10.8 | 11.2 |
| Dog Lake | 14.4 | 11.2 | 12.3 | 13.2 | 13.2 |
| Eagle Valley | 0.0 | 7.6 | 8.1 | 8.4 | 8.5 |
| Edgeley Switching Station | 4.1 | 5.1 | 5.4 | 5.7 | 5.7 |
| Elbow Lake | 22.4 | 26.1 | 28.0 | 29.6 | 29.9 |
| Elmo | 7.4 | 8.7 | 9.7 | 10.6 | 10.6 |
| Enderlin | 9.8 | 13.6 | 14.5 | 15.2 | 15.4 |
| Fargo | 67.7 | 81.7 | 92.6 | 101.7 | 103.9 |
| Fergus Falls | 17.8 | 27.0 | 28.7 | 30.1 | 30.5 |
| Frazee | 45.3 | 50.6 | 55.2 | 59.0 | 59.3 |
| Gwinner | 8.4 | 8.8 | 9.4 | 9.9 | 10.0 |
| Henning | 21.9 | 26.4 | 28.5 | 30.2 | 30.5 |

| Southern Red River Valley area Load Serving Substations | Actual | Forecast | | | |
|---|---|---|---|---|---|
| | Load MW 2005 | Load MW 2010 | Load MW 2015 | Load MW 2019 | Load MW 2020 |
| Hoot Lake | 59.2 | 64.0 | 69.1 | 73.3 | 73.9 |
| Hoot Lake Generator #2 | 2.7 | 2.7 | 2.7 | 2.7 | 2.7 |
| Hoot Lake Generator #3 | 4.1 | 4.1 | 4.1 | 4.1 | 4.1 |
| Hoving Jct. | 8.6 | 12.4 | 13.1 | 13.7 | 13.9 |
| Hubbard | 45.4 | 28.3 | 30.3 | 32.0 | 32.2 |
| Jamestown | 27.8 | 37.4 | 39.3 | 40.9 | 41.3 |
| Jamestown (WAPA) | 0.8 | 0.8 | 0.8 | 0.8 | 0.8 |
| Jamestown Downtown | 10.8 | 9.7 | 10.3 | 10.8 | 10.9 |
| Jamestown Peaking (OTP) | 7.8 | 9.0 | 9.4 | 9.7 | 9.8 |
| Ladish | 12.1 | 15.8 | 16.8 | 17.7 | 17.9 |
| Lisbon | 8.7 | 9.1 | 9.7 | 10.2 | 10.3 |
| Little Sauk | 2.5 | 2.9 | 3.2 | 3.5 | 3.5 |
| Long Lake | 0.0 | 27.2 | 28.8 | 30.1 | 30.4 |
| Long Prairie | 29.5 | 23.0 | 24.4 | 25.6 | 25.9 |
| Maple River | 4.5 | 4.0 | 4.0 | 4.0 | 4.0 |
| Maple River | 93.4 | 109.7 | 124.2 | 136.3 | 139.3 |
| Mapleton | 0.0 | 11.5 | 12.3 | 12.9 | 13.0 |
| Merrfield | 4.2 | 5.3 | 6.0 | 6.5 | 6.5 |
| Miltona | 17.5 | 19.8 | 22.2 | 24.2 | 24.2 |
| MN Pipeline – Staples | 6.0 | 6.2 | 6.5 | 6.8 | 6.9 |
| Moderow | 24.2 | 32.0 | 36.3 | 39.9 | 40.8 |
| Moorhead Brookdale | 10.0 | 10.9 | 11.4 | 11.7 | 11.8 |
| Moorhead Southeast | 15.4 | 16.7 | 17.5 | 18.0 | 18.2 |
| Moorhead Centennial | 22.7 | 24.6 | 25.9 | 26.6 | 26.9 |
| Moorhead Northeast | 18.7 | 20.3 | 21.3 | 21.9 | 22.1 |
| North Jamestown | 5.4 | 5.8 | 6.2 | 6.5 | 6.6 |
| Oakes | 19.9 | 25.7 | 27.0 | 28.1 | 28.4 |
| Palmer Lake | 2.2 | 2.6 | 2.9 | 3.1 | 3.1 |
| Park Rapids | 37.2 | 45.1 | 50.6 | 55.0 | 55.0 |
| Pelican Rapids | 24.4 | 29.6 | 32.1 | 34.1 | 34.4 |
| Perham | 22.4 | 17.3 | 18.4 | 19.3 | 19.5 |
| Red River | 151.9 | 159.2 | 169.4 | 175.1 | 177.9 |
| Rush Lake | 10.4 | 28.2 | 30.4 | 32.3 | 32.5 |

| Southern Red River Valley area Load Serving Substations | Actual | Forecast | | | |
|---|---|---|---|---|---|
| | Load MW 2005 | Load MW 2010 | Load MW 2015 | Load MW 2019 | Load MW 2020 |
| Southdale | 9.5 | 11.0 | 12.6 | 14.1 | 14.5 |
| Tamarac Lake | 6.9 | 7.9 | 8.5 | 8.9 | 9.0 |
| Ulrich | 45.2 | 40.6 | 44.0 | 46.8 | 47.4 |
| Valley City | 13.4 | 13.4 | 13.4 | 13.4 | 13.4 |
| Valley City (MPC) | 17.5 | 19.5 | 22.0 | 24.5 | 25.0 |
| Verndale | 41.5 | 30.1 | 32.3 | 34.1 | 34.2 |
| **Total (MW)** | **1,357.5** | **1,536.7** | **1,668.5** | **1,773.6** | **1,795.2** |
| **Southern Red River Valley area Winter Peak Load Total (with Load Adjustment Factor)** | 1,044.3 | 1,182.2 | 1,283.6 | 1,364.0 | 1,381.0 |
| Critical Load Level = 1360 Megawatts of Load at Risk (rounded) | --- | ---- | ---- | 4.8 | 21.3 |

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

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR A CERTIFICATE OF PUBIC CONVENIENCE AND NECESSITY FOR A 345 KV TRANSMISSION LINE IN THE FARGO/WEST FARGO METROPOLITAN AREA

**CASE NO. PU-________**

## VERIFICATION

**STATE OF MINNESOTA** )
) ss.
**COUNTY OF HENNEPIN** )

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

James Alders
JAMES R. ALDERS

Subscribed and sworn to before me this 7th day of October, 2010.

Notary Public
My Commission Expires: ________

2736072v1

CYNTHIA D. HARRINGTON
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2015

2573297v3