2003 MINNESOTA BIENNIAL TRANSMISSION PROJECTS REPORT

NOVEMBER 3, 2003

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EAST RIVER ELECTRIC POWER COOPERATIVE
GREAT RIVER ENERGY
HUTCHINSON UTILITIES COMMISSION
INTERSTATE POWER AND LIGHT COMPANY
L & O POWER COOPERATIVE
MARSHALL MUNICIPAL UTILITIES
MINNESOTA POWER
MINNKOTA POWER COOPERATIVE
MISSOURI RIVER ENERGY SERVICES
NORTHERN STATES POWER COMPANY D/B/A XCEL ENERGY
OTTER TAIL POWER COMPANY
ROCHESTER PUBLIC UTILITIES
SOUTHERN MINNESOTA MUNICIPAL POWER AGENCY
WILLMAR MUNICIPAL UTILITIES

2003 Minnesota Biennial Transmission Projects Report

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ATTACHMENTS[1]

Attachment No. 1	MAPP Regional Plan 2002
Attachment No. 2	MAPP Load and Capability Report 2002

[1] Because of their voluminous size, Attachments Nos. 1 and 2 are being provided only with the copies of the report being filed with the Minnesota Public Utilities Commission and Department of Commerce. Persons who would like a copy of these documents should contact one of the utility contact persons listed in the report or contact the Mid-Continent Area Power Pool directly at (651) 632-8400.

ELECTRIC TRANSMISSION: BACKGROUND

The 2003 Minnesota Biennial Transmission Projects Report ("Report") is the second biennial report required by the Minnesota Energy Security and Reliability Act (the "Act")[2] and is the first submitted under the Minnesota Public Utilities Commission's ("PUC" or "Commission") recently adopted biennial transmission planning rules (the "Rules").[3] This Report lists inadequacies in Minnesota's transmission system, both those currently affecting reliability within the state and those projected to affect reliability within the state over the next ten years. The high voltage transmission lines[4] ("HVTLs") or other facilities being considered to address existing or projected inadequacies over the next ten years are described in as much detail as possible, given current information. Where sufficient information is available, alternative means of addressing each inadequacy are identified, with a general description of the economic, environmental, and social issues raised by each alternative. In a few situations, the preferred solution had been decided on prior to the writing of this Report, and the project is in the stage of securing required government approvals. In some instances, there is enough information to recommend a preferred alternative. In other instances, the current information available allows only the identification of potential alternative solutions, with no recommendation yet for the preferred solution. In many cases, future inadequacies may be anticipated, but studies needed to identify and evaluate alternative solutions or identify impacts are ongoing and not yet completed.

This report has been developed by the joint cooperation of fifteen electric utilities (investor-owned, cooperative, municipal and municipal power agencies) that own and operate transmission facilities in Minnesota. Contact information for each utility can be found in Appendix I. As required by the Rules, this Report was prepared after extensive outreach efforts and transmission planning public meetings held in each of Minnesota's six transmission planning zones (the "Planning Zones"), as identified in the second section of this Report. Approximately 125 members of the public attended the planning meetings. Details regarding the outreach efforts and planning meetings are provided in Appendix III-VII of this Report. Appendix VI contains an affidavit documenting the utilities' compliance with all requirements in the Rules regarding meeting notice, content, and follow-up. Required materials concerning the public meetings are being retained by the utilities for ten years.[5]

No utility is seeking certification through this Report of any HVTL project described herein. Also, some projects discussed here do not otherwise require Commission approval as they fall outside the jurisdictional size and type. This should allow the Commission and other interested parties to review the Report in a notice and comment proceeding rather than a contested case. This also means that any HVTL project required to be certified by the Commission prior to the 2005 Minnesota Biennial Transmission Projects Report would be

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[2] Minnesota Laws 2001, Chapter 212, codified at Minn. Stat. § 216B.2425.

[3] Minnesota Rules Chapter 7848.

[4] A high-voltage transmission line (HVTL) is defined as "(a) Any transmission line with capacity of 200 kV or more, or (b) any transmission line with capacity of 100 kV or more with more than 10 miles of its length in Minnesota or that crosses a state line. Minnesota Rules, § 7848.0100, subp. 5.

[5] Minn. Rules, §7848.1200

proposed under the Commission's certificate of need (sometimes referred to herein as "CON") rules for transmission lines.[6]

Appendix VII is a map that shows the general location of the existing HVTLs in Minnesota, by Planning Zone. The existing transmission facilities of these utilities are highly interconnected, and a utility may own transmission facilities in a Zone where it has no (or few) retail customers or that is outside its exclusive service area. A single transmission line may also cross several Planning Zones, and different utilities may have ownership and maintenance responsibilities for different segments of the same line within a Planning Zone or within different zones. Maps showing the location of possible new HVTLs (or other transmission facilities) are included in the Report for the specific Planning Zone. The location of the HVTLs are intended as preliminary only; actual routing may vary significantly.

THE MINNESOTA ENERGY SECURITY AND RELIABILITY ACT

The Act, which became law in 2001, established comprehensive energy legislation that addressed a wide range of energy issues, including energy planning, conservation, be consistent and infrastructure. The biennial state transmission planning report process, codified at Minn. Stat. § 216B.2425 (the "Statute"), is designed to provide increased public participation early on in the process and, as a result, result in a more overall expeditious review and certification of transmission projects, providing an alternative to the traditional certificate of need process. In June 2003, the PUC developed new biennial transmission planning rules to govern the transmission planning process contemplated under the Act.

The Statute and the biennial transmission planning rules do the following:

- require that transmission-owning utilities file reports every two years on the status of the state electric transmission system;
- provide utilities the option to request certification of new HVTLs as part of the biennial transmission projects reports rather than seek PUC approval through the existing CON process; and
- provide for increased public and local government involvement in transmission planning.

The biennial report process is meant to enable the PUC to review transmission projects in the overall context of other regional transmission projects being considered. Where a request for certification satisfies a number of factors required by the rules, including an evaluation of feasible and prudent alternatives, the PUC is required to place the project on its "priority electric transmission list" ("Priority List"). Placement on the Priority List certifies the need for the HVTL and allows the utility to construct the HVTL without seeking a separate CON for that facility.

[6] Minnesota Rules Chapter 7849.

The Report is being submitted by the following electric utilities: Dairyland Power Cooperative ("DPC"), East River Electric Power Cooperative ("East River"), Great River Energy ("GRE"), Hutchinson Utilities Commission ("HUC"), Interstate Power and Light Company ("IPL"), L&O Power Cooperative ("L&OPC"), Minnesota Power ("MP"), Marshall Municipal Utilities ("MMU"), Minnkota Power Cooperative ("MPC"), Missouri River Energy Services ("MRES"), Northern States Power Company d/b/a Xcel Energy ("Xcel Energy"), Otter Tail Power Company ("OTP"), Rochester Public Utilities ("RPU"), Southern Minnesota Municipal Power Agency ("SMMPA"), and Willmar Municipal Utilities ("WMU"). Collectively these utilities own and operate more than 6,500 miles of high voltage transmission lines in the state, representing an investment in the state of more than three-quarters of a billion dollars.

The remainder of this section describes the electric transmission system and how it works, provides some factual background on the condition of the transmission and generation system in Minnesota, describes federal, regional, and state oversight of the system, describes the regional transmission planning process, and discusses other pertinent state and regional developments.

THE REGIONAL TRANSMISSION SYSTEM

The regional electric transmission grid is designed principally to carry electricity from generating plants to areas where electricity is used. The fundamental purpose of the high voltage transmission system is to connect generation plants owned by utilities and independent power producers to the utility distribution systems that serve retail electric consumers. The transmission system also connects utilities together to enhance reliability and provide a means to exchange electricity capacity reserves and energy in order to reduce costs, and thus rates, to energy consumers. The transmission system in Minnesota is interconnected with – and an integral part of – the regional transmission grid operated on a coordinated basis with other interconnected transmission systems throughout the Upper Midwest, Canada, and the entire Eastern United States. This grid is referred to as the "Eastern Interconnection." The Minnesota grid, as part of the regional grid, serves a critical reliability role under the auspices of the North American Electric Reliability Council ("NERC"), the Mid-Continent Area Power Pool ("MAPP") - as the NERC regional reliability council for the upper Midwest region, and the individual NERC-certified electrical control areas in Minnesota.[7]

A map of the regional transmission system as prepared by MAPP is included as Appendix VIII.

The interconnected transmission system improves efficiency of the system by allowing utilities to:

- share capacity resources and reduce capacity reserve costs;
- minimize duplication of facilities;

[7] The DPC, GRE, IPL, MP, OTP, SMMPA and Xcel Energy control areas each serve portions of Minnesota within the MAPP region.

- improve reliability; and
- lower costs by trading in economically dispatched energy supplies.

This interdependence also means changes to or disturbances on one utility's transmission system may affect operating conditions on neighboring transmission systems, even those in another state. The recent August 14, 2003 blackout in the northeastern United States and parts of Canada is an example of the interdependence of transmission systems and how a disturbance can impact a large region. As a result, a number of regional and national governing bodies provide oversight and guidance of the electrical transmission network.

As described in more detail later on, federal regulation of the transmission system and the wholesale power market, along with state policies favoring rapid development of wind and other renewable generation are having profound impacts on the regional grid. Beginning with the federal Public Utilities Regulatory Policies Act in 1978 and the Energy Policy Act of 1992, followed by a series of rulemakings by the Federal Energy Regulatory Commission ("FERC"), there are more transactions and flows on the Minnesota and regional grid than ever before. Originally constructed to interconnect neighboring utilities, the grid is now being used as a "super highway" for electricity transfers. Much like automobile highways, the increased traffic has increased both system strain and congestion.

MINNESOTA'S TRANSMISSION SYSTEM

Minnesota's electric transmission system has historically been very reliable but, like the grid generally, is experiencing unprecedented demands. Portions of Minnesota's transmission system are 35 to 50 years old, and others date back as far as 80 years. Minnesota's last major transmission facility addition was constructed in coordination with the Sherburne County No. 3 generating plant, which went into service in late 1987, nearly twenty years ago. More recent investments, such as the 1992 Minnesota-Manitoba Transmission Upgrade ("MMTU") project and numerous smaller projects, involved more focused investments designed to preserve reliability and provide incremental improvements in transmission efficiency by taking advantage of new technologies (e.g., capacitor banks to maintain voltage).

With the exception of dedicated transmission facilities connecting large baseload power plants (large power plant facilities that generate at a nearly constant level of output) located in North Dakota, and dedicated facilities connecting large hydropower facilities located in Manitoba, Minnesota's generation supply was originally located in Minnesota and Wisconsin. As a result, the state has relatively few large "interstate" interconnections critical in maintaining reliability. This limited expansion of the transmission system over the last two decades has resulted in:

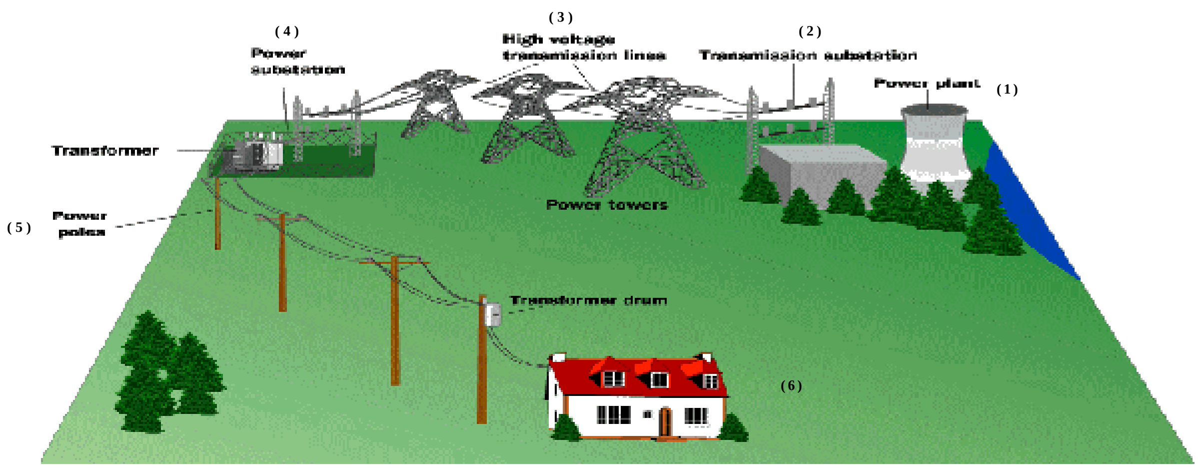
- portions of the system being at or near capacity,
- the system being unable, without more capacity, to handle load growth; and
- problems associated with interconnecting and delivering the output of new generation facilities.

While the capabilities of the physical transmission system have increased only incrementally over the last two decades, electricity usage in Minnesota has grown steadily. Between 1989 and 2001, Minnesota's electricity usage grew at an annual rate of 2%.[8] Some areas of the state have recently experienced annual load growth of greater than 10%.[9]

Yet while more is being expected of the transmission system, investment in transmission has remained essentially flat or in some cases is declining. For instance, transmission investments in 1999 were less than half of what they were in 1979.[10] One reason for the shortfall is the often contentious and protracted need and siting proceedings for proposed transmission facilities. The 2001 Minnesota Legislature passed the Act, in part, to streamline some of these processes.

HOW THE SYSTEM WORKS

The U.S. electric system is comprised of an interconnected network of generating plants, transmission lines, and distribution facilities. The transmission system is a network of high voltage power lines that deliver electricity from generating plants to substations that, in turn, deliver electricity to the consumer through lower voltage distribution lines. The transmission system also connects utilities together to enhance reliability and provide a means to exchange electricity. The following graphic provides a simple visual explanation of how the transmission system delivers electricity from generation to consumers.



Electricity is generated at a power plant (1) and its voltage is "stepped-up" at a substation adjacent to the plant (2). The electric energy travels along the high voltage transmission grid (3), which is interconnected with other high voltage transmission systems. The high voltage electricity is decreased, or "stepped down" at an electrical substation (4), and then is carried by distribution lines (5), is transformed to an even lower voltage at a transformer, where it is then consumed in your home or business (6).

In reality, the system is much more complicated. In Minnesota, the transmission system connects more than 175 electric generating plants, sized from a few megawatts to more than

8 Source: RDI Platts Powerdat – Dataset: Utility Retail Sales by State.

9 The area served by Crow Wing Power, for instance a distribution member of GRE, has experienced growth of 15% in 2001 and 14% in 2002.

10 Source: Edison Electric Institute.

1,100 MW and located both within and outside Minnesota to serve the state's more than five million inhabitants. The transmission system is also interconnected to utilities in other states and Canada in all directions.

A unique thing to understand about the electric transmission system is that there is no practical way to provide a specific, "contract" transmission path from a particular electricity generating plant to a particular customer or "load," except in the cases where the transmission line is constructed just for that purpose, and in that case then, the "radial" line is not considered part of the overall transmission grid. Because electric transmission systems are interconnected, in effect every generator is connected to every customer on the system. This means that all the electricity entering the transmission system is commingled, regardless of the source or destination. This is why events or disturbances on neighboring systems in other states can impact the reliability of electric service in Minnesota, and vice versa.

Another unique thing about the system is that electricity cannot be stored easily or economically – it flows from supplier to customer instantaneously. Electricity must be generated at the very moment it is needed.

Transmission systems are extremely complex to operate. Utilities constantly monitor their transmission systems to assure that generation is balanced with customer demands on an almost instantaneous basis, and to assure that line and facility loadings are kept within proper voltage, frequency, thermal, and stability limits. There must be sufficient reserve transmission network capability to insure the system remains secure and can provide reliable delivery service from generators to loads during contingencies (e.g., an unplanned outage or other loss of a transmission line, generator or other transmission facility).

MINNESOTA GENERATION TRENDS

Over 175 utility-owned generating plants serve Minnesota's electric load. However, no new significant baseload units have been added within the last 16 years. While no base load Plants have been added, the State has seen a significant amount of intermediate and peaking generation (typically natural gas-fired combustion turbines) and wind generation projects come on-line in recent years. Much of this new generation is owned by independent power producers who sell the output to Minnesota utilities through power purchase agreements (PPAs). The utilities deliver the power to residential and business customers.

Since 1993, more than 350 MW of wind generation have been connected to Minnesota's transmission system, primarily in Southwestern Minnesota on the Buffalo Ridge. The existing wind generation on Buffalo Ridge already exceeds the generation outlet capacity of the transmission system in the area, and Xcel Energy is under Commission order to contract for up to 850 MW of total wind generation. As discussed below, wind generators have submitted interconnection requests for more than 5,000 MW of additional wind generation into the interconnection queue administered by the Midwest Independent Transmission System Operator, Inc. ("MISO"), which administers the open access transmission tariff ("OATT") applicable to the IPL, MP, OTP and Xcel Energy systems in Minnesota. Even if many of these wind generation projects are not constructed, there will clearly be a need to dramatically increase investment in the transmission system in order to connect the new wind generation to load centers.

In addition to wind generation located far from load centers, a counter trend is distributed generation ("DG") - electricity generated and sited near end users. DG projects can reduce transmission line losses, boost local area voltage support (reactive power) on the electric grid, and may also be able to offset the need for additional or upgraded transmission lines. However, integration of DG units can also complicate the operation of utility transmission and distribution networks if the DG unit is operated in parallel to the utility system. The Commission is now conducting a proceeding to establish uniform DG tariffs and service agreements for all jurisdictional utilities (Docket No. E-999/CI-01-1023), and the Minnesota CON process requires the consideration of distributed generation as an alternative to a new or upgraded transmission line of 100 kV or above.

FEDERAL AND REGIONAL OVERSIGHT

1. FERC Regulation of Transmission

The FERC is granted federal jurisdiction over regulation of various aspects of the transmission system in Minnesota under the Federal Power Act ("FPA"). Although FERC does not have direct FPA jurisdiction over planning or construction of transmission facilities, numerous recent changes in federal energy policy have affected how the transmission system is used, which in turn impacts transmission planning and future construction.

In 1992, Congress passed the Energy Policy Act, which provided for increased competition wholesale power sales markets by (1) authorizing creation of independent power producers ("IPPs") and exempt wholesale generators ("EWGs") who could sell wholesale power in competition to traditional utilities, and (2) authorizing FERC to order public utilities to provide transmission service to third parties under Section 211 of the FPA.

In response to claims that utilities were providing themselves with preferential access to their transmission lines and denying access to others and thus inhibiting wholesale competition by not providing comparable service, FERC in 1996 enacted its landmark Order No. 888. Order No. 888 requires all transmission owners to (1) offer comparable open-access transmission service for wholesale transactions under an open access transmission tariff ("OATT") of general applicability on file at FERC and (2) take transmission service for their own wholesale sales under the same OATT. All FERC jurisdictional utilities serving Minnesota (IPL, MP, OTP and Xcel Energy) were required to submit a compliance OATT consistent with the pro forma OATT in the final rule. Order No. 888 affects transmission planning in Minnesota because the final rules and pro forma OATT include an obligation by all public utilities to construct new transmission facilities if needed to fulfill a request for firm transmission service by an eligible wholesale customer. Order No. 888 also encourages utilities to transfer operational control of their transmission systems to an Independent System Operator ("ISO").

In late 1999, FERC issued Order 2000 to further encourage competition in the wholesale power supply market, this time by encouraging transmission-owning utilities to voluntarily join large Regional Transmission Organizations ("RTOs"). In May 2002, the MPUC issued orders approving applications by IPL, MP, OTP and Xcel Energy to transfer functional control of their high voltage (100 kV and above) transmission systems in Minnesota to MISO, the first FERC-approved RTO. MISO began interim operations under its OATT on file with FERC on February 1, 2002. Access to and wholesale uses of the transmission systems of these utilities are now subject to the MISO OATT.

The MISO organizational documents include a regional transmission planning process in which all MISO transmission owners must participate, and the MISO OATT includes a MISO-administered process by which all new generation interconnection requests to member transmission systems must be conducted. Both processes will impact future transmission planning and construction in Minnesota. The impact of MISO formation and the MISO OATT are discussed in detail later in this section.

In August 2003, FERC published Order No. 2003, which adopted final rules governing the interconnection of large generators (20 MW and above) to the transmission systems of all public utilities.[11] The final rules mandate a new standardized process for processing interconnection requests and a new standard interconnection agreement form, and establish "default" rules for allocation of the costs of interconnection facilities and transmission "network upgrades" required as a result of new generator interconnection requests. All public utilities are required to submit a compliance filing by January 20, 2004. The MISO compliance filing will establish the access and cost allocation process applicable to the IPL, MP, OTP and Xcel Energy systems in Minnesota.

These and other FERC orders, policy statements and other rulings[12] significantly impact the transmission system in Minnesota and throughout the region. The historic regulatory view of the transmission system existing to deliver a utility's self-owned generation to its retail native load customers to meet a state "obligation to serve" has been replaced with a federal regulatory construct of open, competitive access to the interstate system, with a federal obligation to provide access (including construction) and service on a comparable basis.

11 104 FERC ¶ 61, 103, July 24, 2003, Docket No. RM02-1-000.

12 In July 2002, FERC issued a Notice of Proposed Rulemaking (NOPR) on Standard Market Design ("SMD"). This NOPR, and the subsequent SMD "white paper" released in April 2003, set forth FERC's vision for a future wholesale energy market based on centralized RTO dispatch and locational marginal cost ("LMP") pricing. FERC's proposed SMD rules would require RTOs to develop a periodic regional transmission plan. The regional transmission plan is intended to assist state and local siting authorities in evaluating the impact of new generation, transmission, energy efficiency, and demand response on regional reliability and resource adequacy. At this time, in is uncertain when the final SMD rules may be placed in effect. However, as noted above, the MISO Agreement already establishes a regional planning process. MISO filed a proposed Transmission and Energy Markets Tariff ("TEMT") in July 2003 to establish an energy market similar to that proposed by the SMD rules. In October 2003, MISO filed to withdraw the TEMT after numerous protests by MISO members and state commissions.

2. North American Electric Reliability Council and National Electric Safety Code

Reliability standards for electric transmission planning are established by the North American Electric Reliability Council ("NERC"). NERC is a self-regulating, non-government agency created after the 1965 widespread power failure in the northeastern United States. Since its formation in 1968, NERC has operated primarily as a voluntary organization based on reciprocity and mutual self-interest. Its primary purpose is to maintain electric system reliability and adequacy in North America by establishing standards applicable to generators, transmission systems and electrical control areas.

As currently constituted, NERC is a not-for-profit corporation made up of ten Regional Reliability Councils ("RRCs") throughout the country. RRC members come from all segments of the industry and account for virtually all the electricity supplied in the United States and Canada. The RRCs were organized after the 1965 blackout to coordinate reliability practices and avoid or minimize future outages. The RRCs are voluntary organizations of transmission-owning utilities and in some cases power cooperatives, power marketers, and non-utility generators. There are ten major RRCs plus the Alaska Systems Coordinating Council. The Mid-Continent Area Power Pool is the RRC that encompasses Minnesota and serves as one of the NERC's Regional Reliability Councils.

As a voluntary, non-government organization, NERC presently lacks authority to enforce its standards. The growth of wholesale supply competition and the structural changes taking place in the industry (e.g., formation of RTOs and independent transmission-only entities) are causing NERC participants to re-examine the current system. NERC is presently working to incorporate an enforcement mechanism by way of contracts among the ten Regional Councils. It is also seeking to transform itself into "NAERO" – the North American Electric Reliability Organization ("NAERO"). Like NERC, NAERO's principal mission would continue to be the development and implementation of reliability standards throughout North America. Federal legislation has also been proposed that would provide NAERO with statutory, as opposed to contractual, authority to enforce reliability standards among all market participants.

NERC's planning standards apply primarily to the "bulk" electric system – i.e., the electric generation resources, transmission lines, and interconnections generally operated above 100kV. These systems must be capable of performing under a wide-variety of expected system conditions and must be planned to withstand probable forced maintenance outages and other service interruptions known as "contingencies." The standards are designed to keep the interconnected system planned, designed, and operating to withstand a number of contingencies caused by the loss of a generation unit, transmission line, or other system failures. The standards require companies to continually keep the system in a secure state (able to withstand the next contingency) even after one or more contingencies have already occurred.

NERC's reliability standards can be found on its website, http://www.nerc.com/standards.

A second national standard for transmission planning is found in the National Electric Safety Code ("NESC"). The NESC governs the design, construction and operation of electric utility transmission facilities to ensure public and employee safety.

The NESC was well defined by the 1920's and is currently revised every five years following extensive research and review. The NESC and related information can be found at http://standards.ieee.org/nesc/newssites.html.

Minnesota Rules part 7826.0300 requires all Minnesota utilities to comply with the NESC standards when constructing or investing capital in new facilities, including transmission facilities.

REGIONAL TRANSMISSION PLANNING UNDER MAPP AND MISO

Until recently, all planning and analysis for transmission facilities located in Minnesota has been coordinated by MAPP. As discussed below, however, some historic MAPP planning functions applicable to Minnesota public utilities (IPL, MP, OTP and Xcel Energy) transferred to MISO with the start-up of interim MISO operations under the MISO OATT in February 2002. However, the planning functions under MISO remain in a transition period and, as a result, MAPP and MISO continue to coordinate their activities. The following describes the MAPP and MISO planning functions.

1. MAPP Transmission Planning

Organized in 1972, MAPP is a voluntary association of electric utilities and other electric industry participants that operates under contract to facilitate the pooling of generation and transmission services. MAPP is also the NERC Regional Reliability Council for the upper Midwest region, including Minnesota. All Minnesota electric utilities belong to MAPP, whose offices and control center are in St. Paul. (See Appendix I for MAPP contact information.)

The goal of MAPP is to ensure that the regional interconnected electric system is operated securely and efficiently and that the economic benefits of power pooling are equitably shared through coordination, consistent standards, and enforcement. MAPP has approximately 107 members, including investor-owned utilities, electric cooperatives, municipal utilities and public power districts, a federal power marketing agency, private power marketers, regulatory agencies, and independent power producers.

Under the Restated MAPP Agreement (the contract among MAPP members and a rate schedule filed with FERC under the FPA), MAPP is responsible for:

- the safety and reliability of the bulk electric system, including system-wide planning functions;
- facilitating open access of the transmission system under Schedule F to the Restated MAPP Agreement, as required by the FERC and Order No. 888; and

- providing a power and energy market where MAPP members and non-members may buy and sell electricity on the wholesale market.

The process of regional transmission planning and analysis begins with each MAPP member that owns and/or operates transmission facilities. Pursuant to MAPP's Restated Agreement, these MAPP members are required to prepare and maintain comprehensive plans for their transmission facilities that conform to reliability and transmission assessment standards established by NERC and implemented on a regional basis by MAPP. At a minimum, these plans assess the following:

- the member's current and expected transmission requirements to serve its retail and wholesale customers;
- its present and future network and firm transmission service (i.e., wheeling service) obligations;
- its coordination with neighboring utilities' plans; and
- other contractual or regulatory obligations that in any way affect its transmission facilities.

Once completed, individual MAPP member plans are submitted to Subregional Planning Groups ("SPGs"). MAPP has established four SPGs[13] to facilitate regional planning. The SPGs provide a forum to coordinate the individual member plans and to incorporate the planning expertise of the members' planning staff. The SPGs also facilitate the coordination of plans among SPGs and neighboring non-member utility systems.

Each SPG assesses the adequacy of proposed member plans to best meet the needs of the subregion. The SPG then develops a coordinated subregional transmission plan for the ensuing ten years, including alternatives, for all transmission facilities in the subregion at a capacity of 115 kV or greater. Subregional plans are designed to:

- identify load serving problems;
- identify transfer capability limitations within the subregion and with neighboring subregions and regions;
- identify transmission needs for new generation based on requests of generation owners;
- propose and study transmission expansion alternatives;
- recommend preferred alternatives;
- address subregional deficiencies identified by MAPP's Regional Plan (discussed below); and
- provide assessment of impacts of MAPP's Regional Plan on the subregion.

[13] The four SPGs currently recognized by MAPP are the Iowa Transmission Working Group ("ITWG") SPG; the Nebraska ("NEB") SPG; and the SPG (affecting Minnesota's transmission system – the Missouri Basin ("MB") SPG); and the Northern MAPP ("NM") SPG.

The completed subregional plans are then submitted biennially on or before June 1 to MAPP's Transmission Planning Subcommittee ("TPSC"), a subcommittee of the Regional Transmission Committee ("RTC").

Using both the individual and subregional plans as a basis, the TPSC develops a regional transmission plan for all transmission facilities 115 kV and higher in the MAPP region (the "MAPP Regional Plan" or "Regional Plan"). The Regional Plan is based on a ten-year rolling forecast and is intended to enable the transmission needs of MAPP members and the region generally to be met on a consistent, reliable, environmentally responsible, and economical basis. In addition, the TPSC ensures that projects proposed in one subregion are consistent with and do not undermine or duplicate projects proposed in another subregion. The TPSC also studies and quantifies transfer capability across the MAPP region, identifying "flow-gates[14], which act to limit the transfer of power for either exports or imports. These studies are then used as a basis to assess future regional projects.

The Regional Plan compares projects against alternative projects based on costs, reliability concerns and benefits, contractual and other obligations of the affected utilities, permitting concerns, and other factors. Once adopted by the RTC as a necessary and prudent plan, MAPP typically relies on the most affected utility(ies) to use their best efforts in supporting and implementing the projects.

The most current Regional Plan approved by MAPP is the 2002 Regional Plan, 2002 through 2011, dated December 6, 2002. Attachment No. 1 is a copy of the MAPP 2002 Regional Plan. A copy of this plan is also available on the MAPP web site, at www.mapp.org. This plan recommends the construction of certain transmission facilities over the planning period.

An important part of the MAPP transmission planning process is the use of modeling to assess regional grid reliability that (1) the system is operating as it was designed and (2) it will not be adversely affected by new generation, transmission facilities or end-use load. Many sources of information are used in the modeling of system reliability, including load reports and forecasts, real-time operating data on voltage and power flows, operating reliability standards, and physical system and hardware improvements.

MAPP committees and individual utilities use the models in their study of load serving adequacy, future transfer capability, generation interconnection and impact studies, and other system enhancement impacts. Information from these models may also be used to develop other regional and subregional models.

[14] The ability to transfer power from numerous source points to points of delivery depends on the relative impact that the resulting power flow has upon its components and key defined interfaces, known within MAPP as flowgates. A flow-gate is one or more elements that act as a proxy for an operating security limit. An operating security limit can be determined by transient or voltage stability, unacceptable voltage levels or thermal restrictions, whichever is most limiting. Flowgates have been identified for known system "bottlenecks" which limit transfer of power.

Computer software is used to simulate the response of the regional transmission network under the various systems intact or outage conditions. Equipment current carrying capability, system voltages, transient stability, small signal stability, and voltage stability all may be analyzed in these simulations. The output from the computer programs is compared against the appropriate criteria (i.e., NERC, MAPP, and local utility). Among other things, the analysis is designed to locate system inadequacies. Alternatives are then developed that attempt to address the inadequacies. The alternatives are then placed into the models and the computer analysis is rerun to determine the effectiveness of each of the alternatives. Review of these simulations and consideration of other factors will generally result in a "recommended" transmission alternative. MAPP and its various planning committees incorporate the results into a study report where they are then evaluated.

The MAPP Design Review Subcommittee ("DRS") must approve a facility before a utility or other entity can construct or interconnect a new generating plant or transmission facility, or upgrade an existing facility. The DRS reviews the model information and other data to ensure the new generating or transmission facility will not negatively impact reliability on the member utility's system or the systems of neighboring utilities in MAPP. If a negative impact is determined, the entity seeking DRS approval must install facilities or establish procedures (such as an operating guide) that will mitigate the impact and preserve regional reliability.

2. Transmission Planning Under MISO

As discussed above, FERC Order No. 2000 encouraged FERC-jurisdictional electric transmission owners to voluntarily participate in an RTO. RTOs are organizations comprised mostly of electric utilities that own, operate, or control facilities for the transmission of electric energy in interstate commerce over large geographic regions. The goals of these organizations are to facilitate electricity transmission on a regional basis, to ensure the reliable operation of the transmission grid system, and to promote economic efficiencies in the electric industry. In the Midwest, the FERC in December 2001 approved the Midwest Independent System Operator ("MISO") as complying with Order No. 2000.

According to the MISO Transmission Owner's Agreement (the "MISO Agreement"), MISO is a non-stock, not-for-profit Delaware corporation. Participating transmission owners are required to transfer to the MISO functional control over all "network" transmission facilities – generally those transmission facilities above 100 kV, subject to the procedures in the MISO Agreement. MISO is authorized to provide non-discriminatory open access transmission service over the transmission systems of its members, to receive and distribute transmission revenues, and to be responsible for regional system reliability. MISO's primary responsibilities include ensuring reliability of the transmission system and administering a single, system-wide OATT. MISO will have functional control over the operation of the transmission system, which means that the member utilities will continue to own and physically operate the facilities, subject to MISO's direction.

The MISO's corporate headquarters and transmission control center is located in Carmel, Indiana. Under an agreement between MISO and MAPP, the MAPP control center in St. Paul operates as a subregional control center for MISO members in the historic MAPP region and for the remaining members of MAPP. When MISO became operational on an interim basis as of December 15, 2001, and began providing services under its OATT on February 1, 2002, it assumed the responsibility for many of the transmission operations and planning function previously performed by MAPP. Currently, eight of the fifteen members responsible for this report have either joined the MISO or filed conditional applications for membership. [15]

a. MISO Transmission Planning Responsibilities

Under the MISO Agreement and OATT, MISO has the responsibility for regional transmission planning and has direct responsibility and authority over the process to add or expand generation connected to the MISO transmission system. The MISO transmission planning process functions similar to the process undertaken by MAPP and its members. Like MAPP's development of the Regional Plan, MISO is required to develop a long-range plan that will address both short-term and long-term regional transmission needs. Schedule N to the MISO OATT provides a mechanism for funding voluntary transmission expansions, but MISO would not directly construct and own new facilities, and MISO does not presently have authority to order a member to construct new transmission facilities.

The first MISO Transmission Expansion Plan ("MTEP") was released on June 19, 2003. The goal of the MTEP is to promote the efficient expansion of the transmission system under the control of the MISO and is the result of a collaborative process with MISO members, transmission customers, regulatory agencies, and other interested parties. MISO terms its process as a "bottom up, top down" approach. In this regard, transmission owners continue to have primary responsibility for developing their system-specific plans, which are then consolidated by MISO to develop the overall MTEP. Much like MAPP's regional planning, the MISO planning process allows for all projects with regional and interregional impact to be analyzed for their combined effects. A copy of the 2003 MTEP is available at the MISO website at www.midwestiso.org/plan_inter/expansion.shtml.

The MISO develops the overall regional and inter-regional plan by incorporating, and modifying if appropriate, plans generated from multiple sources, including:

- transmission owners and regional planning groups, such as the MAPP SPGs;
- plans developed through studies associated with requests by customers for firm transmission service;

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15 IPL, MP, OTP and Xcel Energy are currently members of MISO pursuant to the May 9, 2002 MPUC orders in the "MISO Transfer" cases. Missouri River Energy Services is also a MISO member. GRE, DPC and SMMPA have signed conditional MISO membership applications. On April 25, 2002, FERC approved the further transfer of functional control of the IPL and Xcel Energy systems to TRANSLink Transmission Company LLC ("TRANSLink"), a proposed independent transmission company member of MISO. IPL, Xcel Energy, DPC, GRE, SMMPA, and RPU are presently working toward indirect MISO membership through participation in the TRANSLink ITC. On June 26, 2003, the PUC deferred action on the IPL and Xcel Energy requests to participate in TRANSLink, pending submission of additional information.

- plans developed through studies associated with requests for interconnection of generators;
- plans developed by MISO to meet intra-regional needs; and
- plans developed with other RTOs to meet inter-regional needs.

Once a plan is proposed, MISO staff seeks technical input from member stakeholders through its Planning Support Group. The Planning Support Group is an advisory group of MISO members that advise, guide, and provide recommendations to MISO. The proposed plan, modified as appropriate, is then presented to the MISO Planning Advisory Committee ("PAC") for further input. The PAC consists of one member from each of the following groups:

- transmission owners;
- transmission-dependent utilities;
- IPPs and EWGs;
- power marketers and brokers;
- end-use customers;
- state regulatory authorities;
- consumer groups; and
- environmental groups.

In summary, the MISO planning process - like the MAPP planning process - is intended to ensure that the overall MISO transmission plan will receive the proper scrutiny and review from all interested parties and that the Midwest transmission system continues to be highly reliable.

b. MISO Generation Interconnection Process

The MISO procedures for administering generation interconnections also impact transmission planning and construction in Minnesota.

As discussed above, FERC has authority over transmission rates, services and tariffs under the FPA. FERC has determined that interconnection of new generation at transmission voltage is a form of transmission service subject to its jurisdiction under the FPA. (See e.g., *Tennesse Power Company*, 90 FERC ¶ 61, 238 (2002).

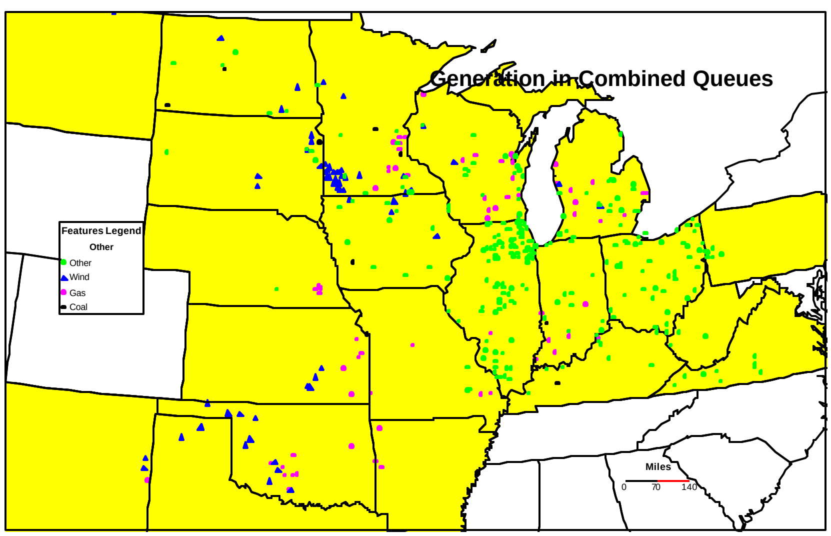
Under the MISO OATT, any eligible entity that wishes to interconnect a new generation facility or to increase generating capacity at a facility already connected on the MISO transmission system must submit a request for interconnection on the MISO Open Access Same-time Information System ("OASIS"), pursuant to Attachment R to the MISO OATT. The request is then placed in the MISO generation interconnection queue ("interconnection queue"). The interconnection queue is a list of generation interconnection requests, grouped by study region. Within each study region, the requests are studied in sequential order based on the date of the request. The studies are administered based on procedures set out in Attachment R to the MISO OATT. The MISO Generation Interconnection Procedures and Agreement are available on the MISO website at www.midwestiso.org/plan_inter/generator.shtml.

MISO then arranges for an interconnection study, and affected transmission owners are asked to participate in ad hoc study groups for each interconnection request. The studies determine system impact of the proposed generation and the transmission system facilities that might be necessary to support the interconnection. In many cases MISO will arrange with the expected interconnecting transmission owner to perform the study for MISO

The interconnection study is performed under the assumption that all prior generation requests and their associated transmission additions will be built and must be accommodated by the transmission system before the new request can be analyzed. The results of the study provide the requester the capability of the transmission system to accept power at the point of interconnection, the cost to provide the direct interconnection facilities and the likely transmission facilities that will be required to allow the delivery of power away from the interconnecting site.

The following graphic shows the general location of proposed generation projects seeking interconnection within the MISO region. At this time, there are more than 113 requests pending in the MISO queue, representing proposed generation of 26028 MW. Because of the regional and interconnected nature of the transmission system, even projects in distant states could affect the need for planning and construction of transmission facilities in Minnesota.

New generating requests in MISO Queue



It is also important to note that approval of an interconnection request does not grant the requestor the ability to transmit power to its intended market. Transmission service is received by making a second, separate transmission service request on the MISO OASIS, which establishes the priority (queue position) of the transmission service request in relation to all other transmission service requests from both new and existing generation sources. An existing generator, or a wholesale customer seeking to purchase power supplies from a different source, can also submit a transmission service request. MISO can grant the transmission service request only if sufficient available transmission capacity ("ATC") exists on the existing transmission system. If MISO determines the need for a study prior to granting the request, it then arranges for a system impact study. Transmission service can only be granted once all required transmission facilities impacted by the transmission service request (including those of high queued requests) are constructed or removed from the service queue.

Requests for new transmission services under the MISO OATT could also impact future transmission planning in Minnesota. As noted above, Schedule N to the MISO OATT provides a mechanism for funding voluntary transmission expansions needed to satisfy new transmission service requests under the OATT. Although this Report does not propose construction of any new transmission facilities to satisfy a transmission service request under the MISO OATT, such projects are possible in Minnesota under a future MTEP.

STATE AND LOCAL OVERSIGHT

1. State

Two state agencies provide primary state regulatory oversight of Minnesota's transmission system. The PUC is the central authority over the state's transmission system. The PUC has authority over the Biennial Transmission Projects Plan process under Minn. Stat. § 216B.2425 and Certificates of Need under Minn. Stat. § 216B.243. The Minnesota Environmental Quality Board ("EQB") has authority over routing and the environmental impact of transmission lines. Both the PUC and EQB have extensive public participation processes.

An HVTL certified by the PUC pursuant to the state transmission plan process under the Statute (or a Certificate of Need under Minn. Stat. § 216B.243) must also receive a route permit from the EQB prior to commencing construction. The EQB routing process requires landowner notification, provisions for public hearings, and further analysis of the environmental, social and economic considerations of alternative routes. The EQB provides three options for submitting and processing a route permit application. The "full process" requires the applicant to identify a preferred and one alternative route. The EQB prepares an environmental impact statement and holds a contested case hearing administered by an administrative law judge. The "alternative review" process, available for certain smaller-size transmission lines, requires the preparation of an environmental assessment and the EQB holds a public hearing. For certain transmission projects, the proponent may opt for the "local review" option, where a local unit of government conducts the environmental review and public participation process.

In addition to the need and environmental regulatory oversight of the PUC and EQB, the Minnesota Department of Commerce ("DOC") has the responsibility to collect energy data, develop a statewide energy policy plan, approve and monitor the conservation improvement programs ("CIP") of public utilities, and advocate for electric utility regulation before the PUC. The Minnesota Office of Attorney General - Residential Utilities Division ("OAG") advocates before the PUC on behalf of residential and small business customers on a number of energy issues. The Minnesota Pollution Control Agency ("PCA") also advocates before the PUC on environmental and pollution control issues.

2. Local

A state transmission line route permit, issued by the EQB, supersedes and preempts all zoning, building, or land use rules, regulations, or ordinances promulgated by regional, county, and local government for routing transmission lines. However, a utility has the option of applying for a transmission line route permit for certain high voltage transmission lines to those local units of government that have jurisdiction over the route for approval to build the project. In these instances, if local approval is granted, a route permit is not required from the EQB.

3. The Opportunity for Public Participation In Transmission Planning

The Rule requires Minnesota's transmission-owning utilities to follow an extensive public participation process. This is the first year in which transmission planning public meetings were held in each of the six transmission Planning Zones in the state. These meetings were held between June 10, 2003 and August 20, 2003. A summary of each meeting can be found in Appendix III and also on www.minnelectrans.com, under the link for each Planning Zone.

Prior to each meeting, a notice was mailed to each county government and tribal government in the zone and a display ad published in leading newspapers in each county. In addition, notices of each meeting, and a request that recipients designate a liaison to the utilities for transmission issues, were mailed to the League of Minnesota Cities, the Association of Minnesota Counties, the Minnesota Association of Townships, the Minnesota Environmental Quality Board, the Minnesota Department of Commerce, the Minnesota Department of Agriculture, the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, the U.S. Fish and Wildlife Service, and the U.S. Park Service. Notice of each meeting was also mailed to the U.S. Environmental Protection Agency, all state legislators in the zone, Minnesota's U.S. Senators and Congressional Representatives for each zone, and to appropriate state agencies in adjoining states. Notices of upcoming meetings were also mailed to all who had signed an attendance register at any of the meetings and to any person who had requested to be placed on the utilities' transmission planning mailing list.

Another significant effort to solicit public input and public participation in the meetings and transmission planning process was the development by the State's transmission owners of a web site, www.minnelectrans.com, addressing Minnesota's transmission planning process and issues. Notice of each zone's public meeting, a summary of each meeting, background information, and links to other related sites are posted on this web site. The web site includes an on-line form to submit comments or questions, and to request inclusion on the utilities' transmission planning mailing list.

Each transmission planning public meeting began with an overview of the regional and Minnesota's transmission systems. A representative of each utility considering a future transmission project in the zone then discussed the inadequacies in the zone's transmission system that need to be addressed in the next ten years, and alternative ways of solving the identified inadequacies.

Questions and comments were encouraged during the public meetings. Forms were provided for those present to submit written questions or comments. Some 123 members of the public attended the transmission planning meetings.

Appendix VI contains an affidavit addressing the utilities' compliance with all state requirements for meeting notice, content, and follow-up. Required written materials concerning the meetings[16] will be retained by the utilities for ten years. Appendix II of this report is a summary of outreach efforts used to obtain public participation in transmission planning; Appendix IV contains a summary of public input in the 2003 biennial transmission planning process; and Appendix V is a summary of local and tribal government input.

The slide presentations given at each meeting are posted on www.minnelectrans.com. In addition, a summary of each meeting presentation, including public input received and how the public input has influenced the utilities' decision-making process are contained in Appendix III, are posted on www.minnelectrans.com, and have been mailed to the transmission planning mailing list and all transmission liaisons designated by local and state government units.

4. Consideration of Environmental, Social and Economic Issues Affecting Transmission Planning

The development and construction of transmission line projects involve consideration of many important and sometimes competing environmental, social and economic factors. Utility environmental experts analyze and focus on the key transmission line routing factors that would apply to each proposed transmission line project. After identifying and mapping these key routing factors within the project area, utility representatives develop routing alternatives that attempt to minimize potential environmental and social impacts and maximize the reliability and economic benefits of the proposed transmission project.

The transmission project may create conflicts, requiring a balancing of factors, when one attempts to minimize all potential impacts and maximize all possible benefits. For example, a possible conflict with environmental routing factors may occur with developing a route through an area populated with agricultural fields (center-pivot irrigation and homes) and sensitive wetlands. Should the route avoid the developed agricultural area at the expense of potentially impacting the fragile wetlands? Further, should many expensive angle structures be proposed to minimize the total impact to natural resources (wetlands) and human settlement (homes and developed farmland use) at the expense of increased economic cost (increased construction cost)?

There also may be a need for balancing routing factors for transmission line upgrade projects. For example, homes may have been constructed near the rights-of-way of a lower voltage transmission line. The existing line may also have been constructed across a river, which

[16] Minnesota rules, §7848.1200

subsequently was provided special protection status. There is then a conflict between use of an existing established corridor and the potential social (human settlement) and environmental (protected riverways) impacts.

A listing of the many environmental, social and economic factors considered by utilities as alternative routes are developed includes:

- Topography, construction and maintenance accessibility;
- Protected river ways;
- Human settlement – residential, suburban areas and rural households;
- Public lands, tribal lands;
- Wetlands;
- Recreational and tourist areas;
- Archeological and historic sites;
- Land based economies – e.g., mining, agriculture, managed forests, etc;
- Natural areas, wildlife refuges;
- Upgrading, double-circuiting existing transmission lines; using other existing linear corridors – such as pipelines, roads and railroads;
- Airports; and
- Exclusion areas – national wilderness areas, state or national parks, state scientific and other protected areas.

The environmental, economic and social impacts of individual transmission projects are discussed in Section II of this Report. As noted previously, this Report does not seek certification of any HVTL for a Commission Priority List. As such, the evaluation of these impacts is not provided at the level of detail a utility would include for an HVTL project where Commission certification was requested.

OTHER STATE AND REGIONAL DEVELOPMENTS

1. Lignite Vision 21 Project

The Lignite Vision 21 Project ("LV21P") is an Industry/Government partnership created by the North Dakota Industrial Commission ("NDIC") in 2000. The goal of the LV21P is construction of one or more state of the art lignite-fired baseload generation facilities in western North Dakota that would utilize the latest generation and best available environmental control technologies. The LV21P is intended to provide low cost energy to meet the energy growth demands of the region.

The Upper Great Plains Transmission Coalition ("UGPTC") is a broad-based coalition formed in May of 2003 with the assistance of the NDIC. The UGPTC is comprised of coal, wind, and transmission interests in the Upper Great Plains region of North Dakota, South Dakota, and Minnesota. The mission of the UGPTC is to resolve the transmission export constraints so that wind - and lignite - produced electrical energy can be transmitted to remote markets within the region.

LV21P conducted some limited, conceptual-type transmission studies to analyze the effects of adding generation in North Dakota and possible system improvements to mitigate transmission constraints. The UGPTC has reviewed existing regional transmission studies to assess whether the new facilities studied would provide the transmission required for wind and coal development in the Upper Great Plains. MISO's 2003 MTEP also looked at some transmission concepts for increased coal and wind development in this area. The UGPTC has started discussions with MISO to determine whether their upcoming expansion plan, MTEP 2004, could meet the needs of the UGPTC and other stakeholders for a more detailed analysis of the transmission required for additional generation development.

2. Mesaba Project

Excelsior Energy Company has proposed to build a 1,000 – megawatt coal gasification power plant – known as the Mesaba Project – at the site of the former LTV Steel Mining Company, near Hoyt Lakes, Minnesota.

Laws of Minnesota Chapter 212, Article 4 (2003) provides the Mesaba Project certain exemptions from procedures applicable to other generating projects. For example, the Mesaba Project is exempted from the PUC's certificate of need process and from the need to bid to met a specified need in Xcel Energy's PUC-approved resource planning process.

The size and location of the proposed plant on the Iron Range in northern Minnesota would require significant additional transmission facilities to deliver the electric power produced at the Mesaba Project load centers such as the Twin Cities area. If the Mesaba Project proceeds, it would significantly impact future transmission planning and construction needs in Minnesota and probably neighboring states.

3. AWEA Wind "Pipeline" Proposal

In September 2003, the America Wind Energy Association ("AWEA") announced a proposal for phased construction of two wind "pipeline" systems from high wind generation areas in the Great Plains to large load centers to the east and west. One of the wind pipeline systems would be the Trans-Prairie project, and would deliver wind energy from North Dakota, South Dakota, Wyoming and Montana to Chicago, Milwaukee, and St. Louis. The second wind pipeline system would be the Interior West system from Wyoming, Montana, North Dakota, and South Dakota to Denver, Salt Lake City, and the Pacific Northwest region. The AWEA proposal states that the Trans-Prairie project would also strengthen transmission and allow wind development in neighboring states like Minnesota. The AWEA concept description for this proposal may be found at the AWEA website at http://www.awea.org/policy/documents/WindPipeline.pdf.

AWEA estimates the cost of the two "wind pipeline" systems at between $11 and $21 billion, and estimates the two projects could allow installation of between 30,000 and 60,000 MW of additional wind generation. If the Trans-Prairie project were to proceed as proposed by AWEA, it would significantly impact future transmission planning in Minnesota.

4. EMF

EMF exists wherever there is a flow of electric current. Common sources of EMF include electrical wiring in homes, offices and other buildings, electric equipment and appliances, and electric power distribution and transmission lines. As the Commission is aware, since the late 1970's, hundreds of scientific studies have been conducted in the U.S. and other countries to examine whether exposure to power frequency EMF adversely affects human health. This large body of research has been reviewed by many scientific panels and organizations. Most recently, the EMF research has been reviewed by the U.S. National Academy of Sciences,[17] the U.S. National Institute of Environmental Health Sciences,[18] the California EMF Program,[19] the U.K. National Radiological Protection Board,[20] and the International Agency for Research on Cancer.[21]

The prevailing view of these recent reviews of EMF is that while there remains a possible relationship between EMF and cancer, principally childhood leukemia, the evidence to date is insufficient to conclude a relationship between power frequency EMF and any disease or illness. Which is why the industry as a whole continues to be involved in research and study on the health and other effects of EMF. This includes all areas of public concern, including studies on leukemia, breast cancer, neurodegenerative and cardiovascular diseases and methodological modeling of biophysical processes, among others. Other research continues to investigate technologies that will help lower exposures even further. Minnesota's utilities are committed in their continued funding, monitoring and research review on EMF and will continue to incorporate EMF into the planning and operation of transmission facilities. Work will also continue on providing information to the public, interested customers and employees.

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[17] *Research on Power Frequency Fields Completed Under the Energy Policy Act of 1992,* Committee to Review the Research Activities Completed Under the Energy Policy Act of 1992, Board on Radiation Effects Research, Commission on Life Sciences, National Research Council. National Academy Press, 1999.

[18] *NIEHS Report on Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields, Prepared in Response to the 1992 Energy Policy Act (PL 102-486, Section 2118).* National Institute of Environmental Health Sciences, National Institutes of Health, NIH Publication No. 99-4493, 1999.

[19] *An Evaluation of the Possible Risks from Electric and Magnetic Fields (EMFs) from Power Lines, Internal Wiring, Electrical Occupations and Appliances*, Draft 3 for Public Comment, April 2001. California EMF Program, 2001.

[20] *ELF Electromagnetic Fields and the Risk of Cancer, Report of an Advisory Group on Non-ionizing Radiation*. National Radiological Protection Board, Vol. 12, No. 1, 2001.

[21] *Static and Extremely Low Frequency Electric and Magnetic Fields – IARC Monographs on the Evaluation of Carcinogenic Risks to Humans.* IARC, Vol. 80, in preparation, summary statement on IARC web-site.

MINNESOTA'S TRANSMISSION PLANNING ZONES: SYSTEM INADEQUACIES AND ALTERNATIVE SOLUTIONS

INTRODUCTION

Minnesota is divided geographically into six Transmission Planning Zones: Northwest, Northeast, West Central, Twin Cities, Southwest, and Southeast. A map showing the location of the Planning Zones and the high voltage transmission lines in the state is located in Appendix VII. Transmission systems in one zone are highly interconnected with those in other zones and with regional transmission systems. A particular utility may own transmission facilities in a Zone that is outside its exclusive service area, or where it has no (or few) retail customers. Different segments of the same transmission line may be owned and/or operated by different utilities. A transmission line may span more than one Planning Zone; transmission projects and studies may involve more than one zone.

This section of the report discusses each Planning Zone separately, beginning with a general description of the zone and its transmission system, a list of the utilities that own high voltage transmission facilities in the zone, and a discussion of the participation of the utilities in that zone in regional transmission planning.

Each Planning Zone section then addresses specific transmission inadequacies in the zone, lists possible alternatives intended to solve the identified inadequacies, and provides an overview of economic, environmental, and social issues associated with each alternative. Lastly, the Report provides a recommendation regarding the preferred alternative.

In some instances, there is not enough information available yet to identify a preferred alternative. Where this is the case, the Report identifies the studies that are ongoing or planned to further address these inadequacies.

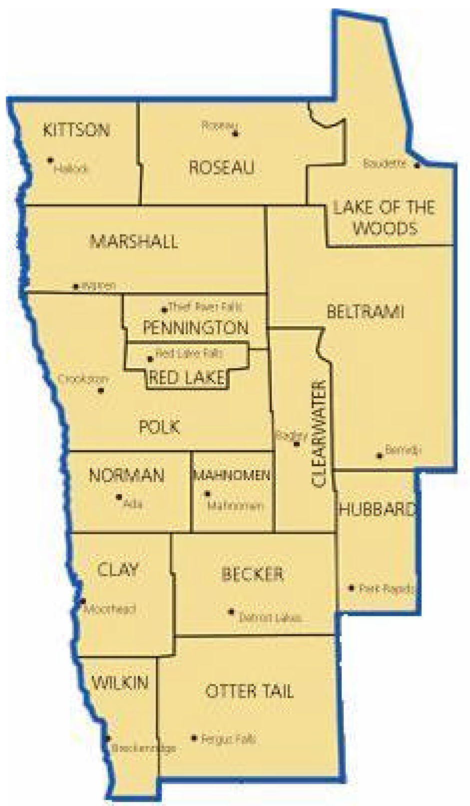
The next Biennial Transmission Projects Report will be filed on November 1, 2005. Any HVTL projects required to be certified by PUC prior to that date would go through the PUC certificate of need process for transmission lines (Minnesota Rules Chapter 7849).

Northwest Transmission Planning Zone

I. Introduction

The Northwest Planning Zone is located in northwestern Minnesota and is bounded by the North Dakota border on the west and the Canadian border to the north. Otter Tail and Wilkin counties are the southernmost counties in the zone, while Beltrami, Hubbard, Lake of the Woods, and Otter Tail are the easternmost counties in the zone. The Northwest Planning Zone includes the counties of Becker, Beltrami, Clay, Clearwater, Hubbard, Kittson, Lake of the Woods, Mahnomen, Marshall, Norman, Otter Tail, Pennington, Polk, Red Lake, Roseau, and Wilkin.

Northwest Transmission Planning Zone



A land use map is located in Appendix IX. The land in the Northwest Planning Zone is primarily sparsely populated and classified as cultivated, hay-pasture-grassland, forested, bog-marsh-fen with hundreds of lakes located in the southern part of the zone. Some densely populated areas exist near the Fargo/Moorhead and Grand Forks/East Grand Forks metropolitan areas.

Primary population centers in the Northwest Planning Zone (population greater than 10,000) include the cities of Bemidji, Fergus Falls, and Moorhead.

Primary users of the transmission system in the zone are residential, farming, oil/gas pipeline pumping stations, wood product processing, industrial/manufacturing, and agricultural processing plants.

A major portion of the transmission system that serves northwestern Minnesota is located in eastern North Dakota. Two 230 kV lines and one 345 kV line reach from western North Dakota to substations in Fargo, North Dakota. Similarly, three 230 kV lines run into Grand Forks, North Dakota, one of which originates in Manitoba. From the 230/115 kV substation in Fargo, four 230 kV lines extend out to Audubon, Morris and Winger in Minnesota and Wahpeton, North Dakota. The Wahpeton line turns easterly towards Fergus Falls, Henning, Wing River, and eventually Riverton. The Fargo-Audubon 230 kV line continues east to Hubbard and Badoura. The Grand Forks 230 substation has one 230 kV line extending easterly to the Winger substation. From the Winger substation, a 230 kV radial line continues east to Bemidji.

The 230 kV system supports the underlying 115 kV system. The northernmost part of the Northwest Planning Zone is served on a 115 kV loop. This loop serves the Minnesota cities of Crookston, Donaldson, Falconer, Karlstad, Oslo, Thief River Falls, Viking, and Warsaw. The 230 kV sources that feed this 115 kV loop are located Drayton, North Dakota (substation), Grand Forks, North Dakota, and Winger, Minnesota. The 230/115 kV substation near Bemidji feeds a 115 kV system that extends west to the Winger 230/115 kV substation and south to the Badoura 230/115 kV substation. A 115 kV line stretches south from Winger, to Audubon, Frazee, and finally Fergus Falls. From Fergus Falls, a 115 kV system extends south into Grant County.

69 kV and 41.6 kV subtransmission lines serve much of the load in the Northwest Planning Zone. The 230 kV and 115 kV systems serve this subtransmission system. In some areas of the Northwest Planning Zone, the 69kV and 41.6 kV subtransmission network is becoming unable to support local area load growth. Some of the solutions to theses problems involve the construction of new 230 kV and 115 kV transmission facilities.

A map showing the 100 kV and above transmission facilities located in Minnesota is located in Appendix VII. This map also identifies the Northwest Planning Zone and the other State Planning Zones.

II. Utility Contacts and Regional Transmission Organization Participation

The utilities which own transmission facilities within the Northwest Planning Zone include Great River Energy ("GRE"), Minnkota Power Cooperative ("MPC"), Missouri River Energy Services ("MRES"), Otter Tail Power Company ("OTP"), and Xcel Energy. Contact information for these utilities can be found in Appendix I.

The MISO is a FERC recognized RTO. MISO provides non-discriminatory, open access to transmission service and serves as the regional hub for the flow of electric energy in a 15-state area, including Minnesota. More information on MISO and its role can be found in the first section of this Report. In order to insure continued reliability of the regional transmission system and continued access to competitive electric energy, MISO has developed a regional transmission expansion plan. A copy of this plan, the *Midwest ISO Transmission Expansion Plan – 2003 (MTEP-03)* can be found on the MISO web site, at www.midwestiso.org/plan_inter/expansion.shtml. Although not all of the transmissions owners in the Northwest Planning Zone are members of MISO, the expansion plan has included data from all the owners.

All of the transmission-owning utilities in the Northwest Planning Zone participate in the MAPP is a regional transmission reliability group. MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the *Regional Load and Capability Report* produced by MAPP can be found on the MAPP web site, at www.mapp.org. More information on MAPP can be found in the first section of this report.

The *2003 Minnesota Biennial Transmission Projects Report* includes updates to the *MAPP 2002 Regional Plan* that will be incorporated into the 2003 update to the MAPP regional plan. A copy of the MAPP *2002 Regional Plan* can be obtained directly from MAPP (see Appendix I for contact information).

III. Transmission System Inadequacies and Alternative Solutions

This section provides information on the future inadequacies that have been identified in the Northwest Planning Zone's transmission system over the next ten years. It also provides information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental and social issues associated with each alternative.

BADOURA AREA

The Badoura 115/34.5 kV Substation is located near the border between the Northwest Planning Zone and the Northeast Planning Zone. This substation serves as the normal source for the Tripp Lake area, and for Backus, Hackensack, Pleasant Lake, Wabedo and surrounding rural areas that are located in the Northeast Planning Zone. It also serves as an alternative source for loads normally served out of the Pequot Lakes Substation, which is also located in the Northeast Planning Zone.

The electric loads served by both the Badoura and Pequot Lakes substations have been growing and will reach the point where the existing facilities will be incapable of supporting the area between Badoura and Pequot Lakes by 2008 to 2010. Planning engineers hope to be able to address issues associated with the loads served by the Badoura Substation and issues in the Pequot Lakes area with one project.

Since the majority of additional transmission facilities required to address these inadequacies would be located in the Northeast Planning Zone, this issue will be addressed in detail in the Northeast Planning Zone section of this Report.

HUBBARD-BADOURA AREA

The Hubbard-Badoura system consists of the 34.5 kV system that ties the 115/34.5 kV sources between Badoura and Hubbard together. This 34.5 kV system consists of one outlet at Badoura and two outlets at Hubbard, defined as follows:

- Badoura 515 Line, which serves GRE loads of Park Rapids and Mantrap;
- Hubbard 515 Line, which serves MP loads in the Park Rapids area; and
- Hubbard HP line (523 Line), which serves GRE loads of the RDO potato plant, Osage, and Pinepoint.

In addition, a 115 kV line provides a tie between Hubbard and Badoura and also provides service to the GRE Palmer Lake substation.

A. Inadequacies

There are many concerns that occur before 2006 in this area, including the overload of the transformers at Badoura and Hubbard, line overloads of the 34.5 kV lines to Park Rapids from Hubbard and Badoura, and critical system intact voltages at GRE Park Rapids and Mantrap substations. During contingency analysis, the low voltages resulted in many unsolvable cases or were so low that load would not be able to be served at these levels. The deficiencies are noted below:

Overloads in 2006

Line Segments	Rating MVA	2006 MVA
Badoura –515-520 Tie	17	18.5
Hubbard-Hubbard Tap	35	34.3
Osage MP-Osage Tap	22.7	23.1
Hubbard Transformer #1	33.6	48.7
Hubbard Transformer #2	33.6	49.8
Badoura Transformer #1	33.6	38.4
Badoura Transformer #2	33.6	38.1

Voltage Deficiencies in 2006-System Intact

Substation	2006 %
GRE Park Rapids	86.9
GRE Mantrap	85.3
GRE Pinepoint	91.0
GRE Osage	92.3

B. Alternative Solutions

Based on the deficiencies discussed above, the area utilities will proceed with development of a Park Rapids (a.k.a. Long Lake) 115/34.5 kV source currently planned to be installed in 2004. The 34.5 kV HP line from Hubbard up to the Park Rapids area is already built for 115 kV. This line will be operated at its 115 kV level with the Osage, RDO potato plant and Pinepoint loads being moved to the 515 line. Voltage concerns with serving all of the load in the area on the 34.5 kV system remain; therefore, the large RDO potato plant load is proposed to be converted to the 115 kV line in 2005 by constructing a short radial line, about 1.5 miles, from the newly converted HP line. Since these projects fall below the threshold levels (i.e., generally 115 kV and 10 miles of line construction) requiring a certificate of need, GRE plans to seek permits through a local government review process and has not requested any Commission certification through this biennial plan.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The majority of the HP line is already built to 115 kV standards, so major construction activity will not be needed. Minor line construction will be needed on the HP line to bring the 115 kV line to the proposed Long Lake substation site. GRE will have to remove one of the 34.5 kV taps on the HP line when converted to 115 kV. The proposed 1.5 mile RDO 115 kV line is presently planned to be cross-country and should have relatively little social impact. Environmentally, a river crossing on the Fishhook River will be needed, although this may allow the abandonment of the 34.5 kV crossing of the Straight River, which is a state classified trout stream.

D. Recommendation

The recommended plan to resolve the system inadequacies is installation of a 115/34.5 kV source in the Park Rapids vicinity and the transferring of the large RDO potato plant load to the new 115 kV.

LUND 230/69 KV SUBSTATION

Minnkota Power Cooperative (MPC) plans to construct the Lund substation near Baudette, Minnesota. The Lund substation will tap the Running–Moranville 230 kV transmission line that runs between Littlefork and Warroad. MPC owns almost all of the Running–Moranville line. The substation will be located approximately five miles from Baudette.

A. Inadequacies

The Lund substation is needed to provide reliable service to the existing MPC loads served from the 69 kV system between Littlefork and Warroad. The total load served in this area is approximately 20 MW at winter peak.

B. Alternative Solutions

The preferred solution (adding the Lund substation) for the inadequacy of the 69 kV system between Littlefork and Warroad had been identified prior to the writing of this report. Construction of the Lund substation will require a half-mile of 230 kV line. This line will be built from the substation site to a tap point on the Running-Morvanville 230 kV line. The substation will consist of a 30 MVA 230/69 kV transformer, a 230 kV circuit breaker, and three 69 kV circuit breakers.

By tapping the Running-Moranville 230 kV line near Baudette, MPC will be able to provide another source of power into its 69 kV system between Littlefork and Warroad. Another source of power is needed for this area to provide continuity of electric service during outages of 69 kV lines.

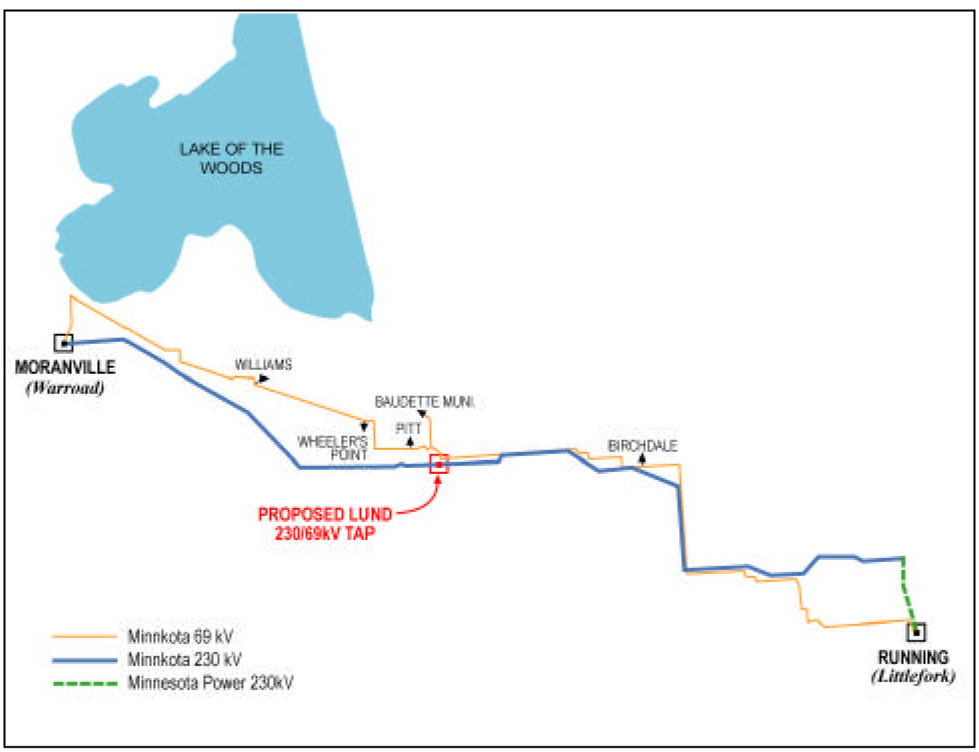
C. Economic, Environmental, and Social Issues Associated with Each Alternative

There will be little economic, environmental, and social effects associated with the construction of the Lund substation. There is no requirement for a certificate of need from the PUC for the additional half-mile of 230 kV line. However, the routing of this line will require EQB approval. Minnkota has the approval of the route by the landowner and has an option to purchase the substation site. The substation will need only local permitting. The half-mile of transmission line and the substation will likely be constructed by Minnkota personnel.

D. Recommendation

As noted above, the preferred solution to the inadequacy of the 69 kV system between Littlefork and Warroad is the addition of the Lund 230/69kV substation.

Proposed Lund 230/69kV Substation



NORTHERN VALLEY AREA

The Northern Valley Area consists of the northernmost part of the Northwest Planning Zone and also northeastern North Dakota. OTP and MPC serve this region. The Northern Valley area specifically includes the communities of Donaldson and Karlstad in Minnesota and Hensel and Langdon in North Dakota. A *Northern Valley Load Serving Study* is presently in progress by OTP.

A. Inadequacies

Historical data show that loads in the area have grown. As a result of increased load, concerns have arisen regarding transformer loading capability, transmission and subtransmission line loading capability, and low voltage. This area is winter peaking and thus the transmission system is most stressed during the winter months.

B. Alternative Solutions

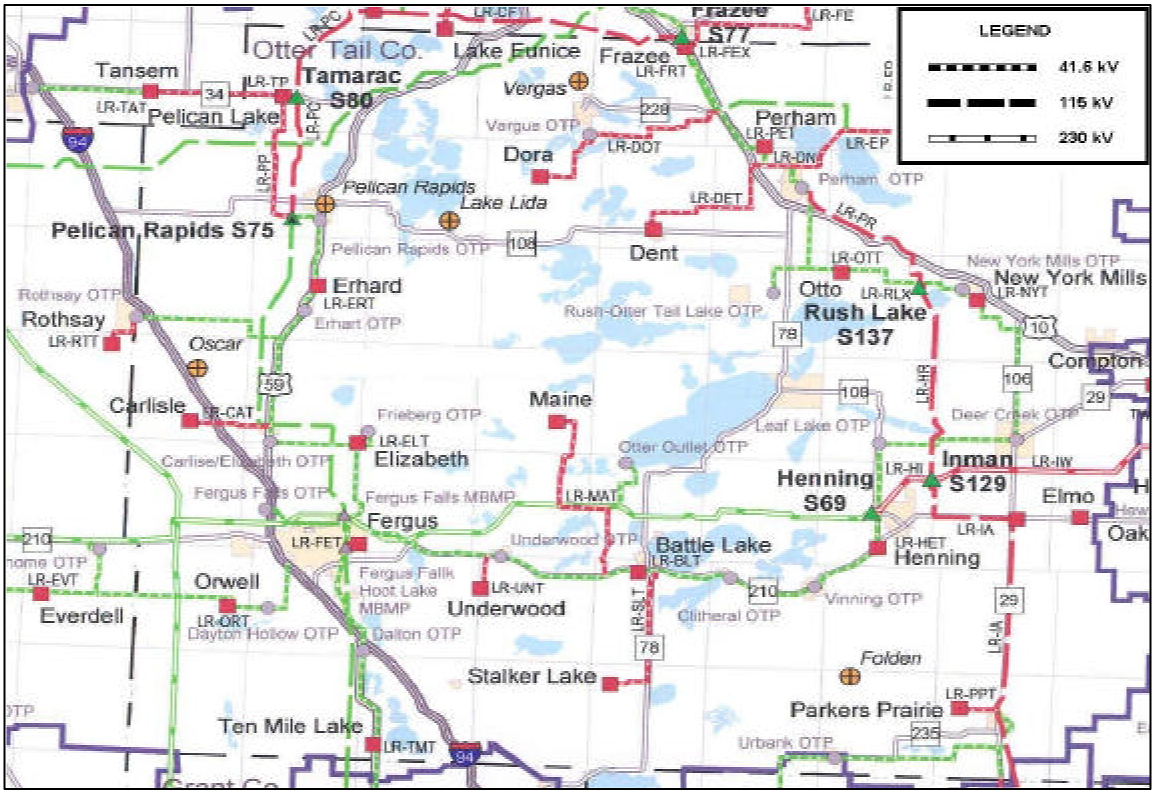
At the present time, no alternatives have been identified for the Northern Valley area. Specific problems have yet to be identified. As mentioned above, the *Northern Valley Load Serving Study* is underway to determine whether there are specific system inadequacy issues. Once these issues are identified, further steps can be taken to determine what, if any, system upgrades are required.

OTTER TAIL COUNTY AREA

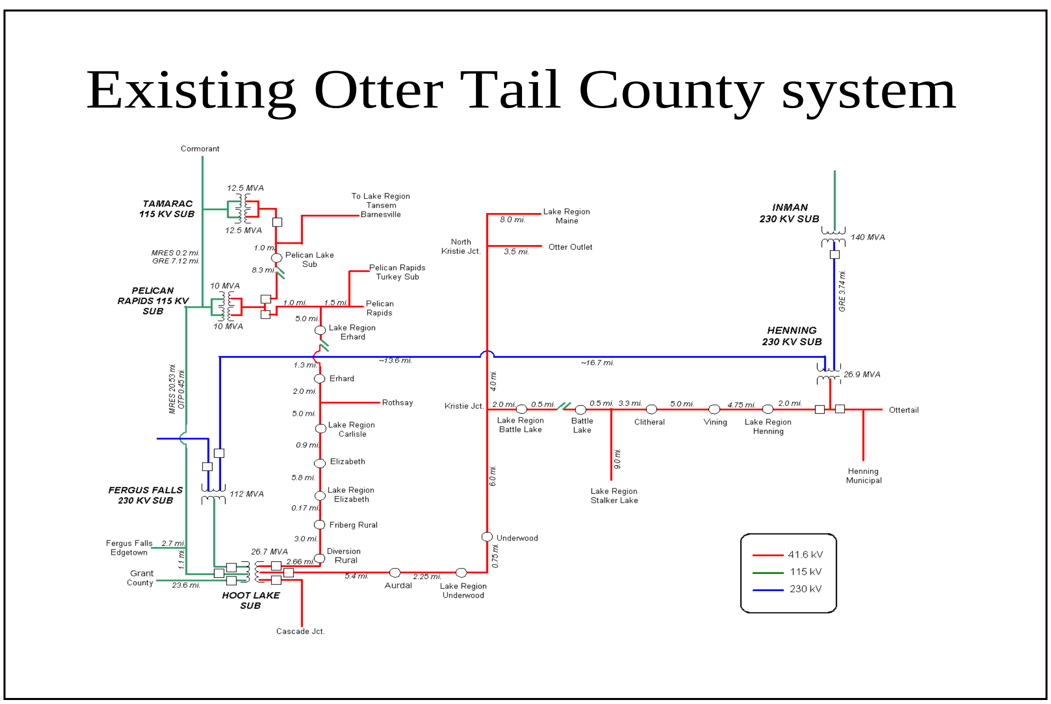
Great River Energy, Missouri River Energy Services, and Otter Tail Power Company serve loads in the Otter Tail County area.

Two recent studies of the transmission system in Otter Tail County are the *Great River Energy Long-Range Transmission Plan*, and the *Otter Tail County Load Serving Study* (study performed by Otter Tail Power Company).

Otter Tail County Study Area



A. Inadequacies



The transmission and subtransmission system in Otter Tail County cannot adequately serve the area load under summer peak contingency scenarios. Under present load conditions, contingency events cause transformer loading violations, line loading violations, and under-voltage violations. During summer peak conditions, 10 different contingencies on the 41.6 kV system between Fergus Falls and Henning violate system-operating criteria. Loss of the Pelican Rapids to Pelican Rapids tap results in under-voltage violations at the Pelican Rapids Turkey Plant substation and the Pelican Rapids town substation. In addition, load within Otter Tail County is increasing at a rate of 2.1% annually. The increase in future electrical power usage, combined with existing problems, will require the Otter Tail County electrical network to be upgraded.

B. Alternative Solutions

A number of different alternatives were considered for system improvements to the Otter Tail County transmission and subtransmission system. The Otter Tail County system consists of two separate subsystems. These subsystems are the Fergus Falls-Pelican Rapids 41.6 kV system, and the Fergus Falls-Henning 41.6 kV system. Both of these subsystems possess operating concerns that need to be addressed.

FERGUS FALLS TO PELICAN RAPIDS SUBSYSTEM

1. Fergus Falls-Pelican Rapids Alternative #1: Pelican Rapids 115 kV Load Conversion

This option involves converting the OTP Pelican Rapids load to 115 kV operation. Moving the load to 115 kV system unloads the 41.6 kV subtransmission system. This results in an improved 41.6 kV voltage profile and reduced transformer loading.

2. Fergus Falls-Pelican Rapids Alternative #2: 41.6 kV System Improvement

This option involves replacing the two Pelican Rapids 115/41.6 kV transformers with larger, load tap changing transformers. It also requires building a second 41.6 kV line from Pelican Rapids to the Pelican Tap. The second 41.6 kV line from Pelican Rapids to the Pelican Tap will eliminate criteria violations for the worst contingency which is the outage of the first line from the Pelican Rapids source.

3. Fergus Falls-Pelican Rapids Alternative #3: New 115/41.6 kV Substation at Erhard, MN

This option involves establishing a new 115/41.6 kV substation at Erhard. Erhard is located approximately halfway between Fergus Falls and Pelican Rapids. The new 115/41.6 kV substation at Erhard would provide voltage support and line loading relief.

The following table lists the estimated cost for each of the options listed above.

Option	Estimated Capital Investment
P1: Pelican Rapids 115 kV Load Conversion	$1,197,000
P2: 41.6 kV System Improvement	$2,888,000
P3: New 115/41.6 kV Source at Erhard	$1,810,000

FERGUS FALLS TO HENNING SUBSYSTEM

1. Fergus Falls-Henning Alternative #1: New 230/41.6 kV substation between Fergus Falls and Henning

This option involves establishing a new 230/41.6 kV substation between Henning and Fergus Falls to serve the 41.6 kV subtransmission system. The new 230/41.6 kV substation would provide voltage support and relieve line loading problems. The new substation (Silver Lake 230/41.6 kV) would be located near Battle Lake, Minnesota.

2. Fergus Falls-Henning Alternative #2: Fergus Falls to Henning 41.6 kV to 115 kV line upgrade

This option involves building a new 115 kV line from Fergus Falls to Henning. A new 115 kV circuit would allow for increased line loading and an improved voltage profile. Implementation of a 115 kV upgrade would also require all of the 41.6 kV distribution substations to be upgraded to 115 kV. Upgrading these distribution substations would be very costly.

The following table lists the estimated cost for each of the options listed above.

Alternative	Estimated Capital Investment
H1: New 230/41.6 kV Source	$ 3,021,000
H2: Henning to Fergus Falls 115 kV Upgrade	$17,243,000

INTEGRATION OF SUBSYSTEMS

Although the Fergus Falls to Pelican Rapids and Fergus Falls to Henning 41.6 kV subtransmission networks are separate subsystems, a final option was developed that integrates the two subsystems together. By combining the infrastructure improvements of the two different subsystems, it was possible to delay transmission improvements while maintaining a reliable system.

1. Integration Alternative #1: New Pelican Rapids Turkey 115 kV Circuit and Silver Lake 230/41.6 kV substation; with capacitor additions

This option calls for immediate construction of a new 115 kV line (2.5 miles) to serve the large turkey processing plant in Pelican Rapids. This line would be initially operated at 41.6 kV. Operating at 41.6 kV defers the cost associated with upgrading the Pelican Rapids turkey distribution substation from 41.6 kV to 115 kV. The turkey plant is now fed on a dedicated breaker within the Pelican Rapids 115/41.6 kV substation. Moving the load to a new breaker eliminates the worst-case contingency in the area which is loss of the Pelican Rapids to Pelican Rapids 41.6 kV line. The new line will be shielded, therefore increasing the reliability of service to the Pelican Rapids turkey plant. The new circuit will need to be operated at 115 kV once loading reaches projected 2017 levels.

This plan also calls for the immediate installation of capacitor banks within the 41.6 kV distribution substations between Fergus Falls and Henning. These capacitor banks improve the voltage profile on the Fergus Falls to Henning 41.6 kV subtransmission system. Once projected 2011 loading levels are reached, a new 230/41.6 kV substation will need to be constructed between Fergus Falls and Henning. This substation (Silver Lake 230/41.6 kV) is proposed to be located near Battle Lake, Minnesota.

The following table lists the estimated cost for this option.

Alternative	Estimated Capital Investment
F1: Pelican Rapids 115 kV upgrade, Silver Lake 230/41.6 sub; with capacitor additions	$2,651,100

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The recommended construction of the new 115 kV line (2.5 miles) should have relatively little environmental or social impact. This also holds true for the addition of the new Silver Lake 230/41.6 kV substation. The substation will require a plot of land at the intersection of the existing 230 kV line and the 41.6 kV line. Other than the 2.5 miles of line needed for the Pelican Rapids turkey plant circuit, no additional transmission lines will be built. Upgrading the infrastructure will result in a positive economic impact in the form of reduced system losses.

D. Recommendation

The recommended plan to resolve the Otter Tail County system inadequacies is Integration Alternative 1. This alternative provides the following system benefits:

eliminates voltage and loading problems past projected 2020 loading levels;
new system facilities reduce line exposure and increase system reliability;
most economic solution;
allows for the deferment of more substantial new transmission facilities until absolutely required; and
requires minimal property acquisitions to support new transmission facilities.

RED RIVER VALLEY AND WEST CENTRAL MINNESOTA AREAS

A. Inadequacies

Recent studies have demonstrated that the Red River Valley and West Central Minnesota Areas are in need of significant electrical facility upgrades. While load in the region has continued to grow, transmission and electrical facility additions have been minimal. Many electrical facilities are reaching their allowable operating limits. Under contingency scenarios, both line and transformer overloads exist, along with low voltage concerns. If regional load continues to grow, and sufficient electrical improvements are not implemented, the Red River Valley and West Central Minnesota could potentially face voltage security issues. This includes the possibility of voltage collapse, which could result in partial or regional system blackouts.

In addition to maintaining adequate voltage security, major facility additions are required to insure the ability to adequately deliver bulk power to the load centers in the Red River Valley and West Central Minnesota. These load centers include Alexandria, Bemidji, East Grand Forks, Moorhead, and St. Cloud in Minnesota and Fargo and Grand Forks in North Dakota. As load continues to grow, it will become more difficult to adequately and reliably serve these load centers.

B. Alternative Solutions

The proposed alternatives for addressing system inadequacies in the Red River Valley and West Central Minnesota are identified in the *Red River Valley/Western Minnesota Transmission Improvement Planning Study* ("TIPS"). This study has been broken down into three different phases. The phases include a base improvement plan, a wires study, and a generation alternatives study. The base improvement plan identifies existing facilities that need to be upgraded. These facilities are in violation of system operating standards in the near-term planning horizon.

The base improvement plan of the TIPS is complete and has been published. Preliminary analysis for the wires study has been performed but has not yet been released. The generation alternatives phase of the study is scheduled to begin in early 2004, and therefore no generation alternatives are available for this report. The TIPS base improvement plan and the entire TIPS study, when completed, may be viewed and downloaded at the www.minnelectrans.com web site.

The wires study examines new transmission alternatives to maintain future reliability of the electrical system. The generation alternatives study will seek to find generation solutions comparable to the transmission facilities identified in the wires study.

The base improvement plan of the TIPS study has identified the following facility improvements to maintain acceptable system operating conditions for near term loading conditions:

- Increase capacity of 115 kV lines between:
  - Grant County–Elbow Lake–Brandon–Alexandria–Douglas County; and
  - Bagley–Winger.
- Increase transformer capacity at:
  - Maple River (Fargo) 345/230 kV and 230/115 kV substations;
  - Winger 230/115 kV substation; and
  - Wilton (Bemidji) 230/115 kV substation.

The wires phase of the TIPS study identified eight alternatives for potential transmission projects to strengthen the electrical network in western Minnesota and eastern North Dakota. These alternatives include:

- Boswell—Wilton (Bemidji) 230 kV line;
- Coal Creek—Underwood—Harvey—Prairie (Grand Forks) 345 kV line;
- Garrison—Max—Logan—Minot—Rugby—Drayton 230 kV line;
- Bismarck—Jamestown—Fargo 345 kV line;
- Dorsey(Winnipeg)–Karlstad—Winger 345 kV line;
- Fargo—Morris—Granite Falls—Blue Lake (Twin Cities) 345 kV line;
- Benton County (St. Cloud)—Alexandria—Maple River 345 kV line; and
- Watertown—Granite Falls—Blue Lake 345 kV line.

The following table identifies line lengths and estimates construction costs for the above eight alternatives:

Alternative	Length (Miles)	Cost (Millions)
1	85	$23.8
2	235	$99.3
3	258	$74.2
4	183	$76.9
5	194	$82.7
6	282	$119.8
7	195	$81.6
8	191	$80.4

Preliminary study results indicate that the combination of Alternative 1 and Alternative 7 provide the most robust, economic, and efficient transmission infrastructure enhancements for the Red River Valley and Western Minnesota regions. Further analysis will need to be completed to insure that these two alternatives are the optimal transmission system enhancements.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

Presently the environmental and social impacts caused by the proposed projects of the TIPS study have not been quantified. Upgrading the transmission infrastructure will result in a positive economic impact in the form of reduced system losses. The approximate project costs are listed above.

D. Recommendation

The wires and generation alternatives phases of the TIPS study are not yet complete. As a result, there are no recommended alternatives at this time.

IV. Studies in the Northwest Planning Zone

The following studies pertain to the transmission system in the Northwest Planning Zone.

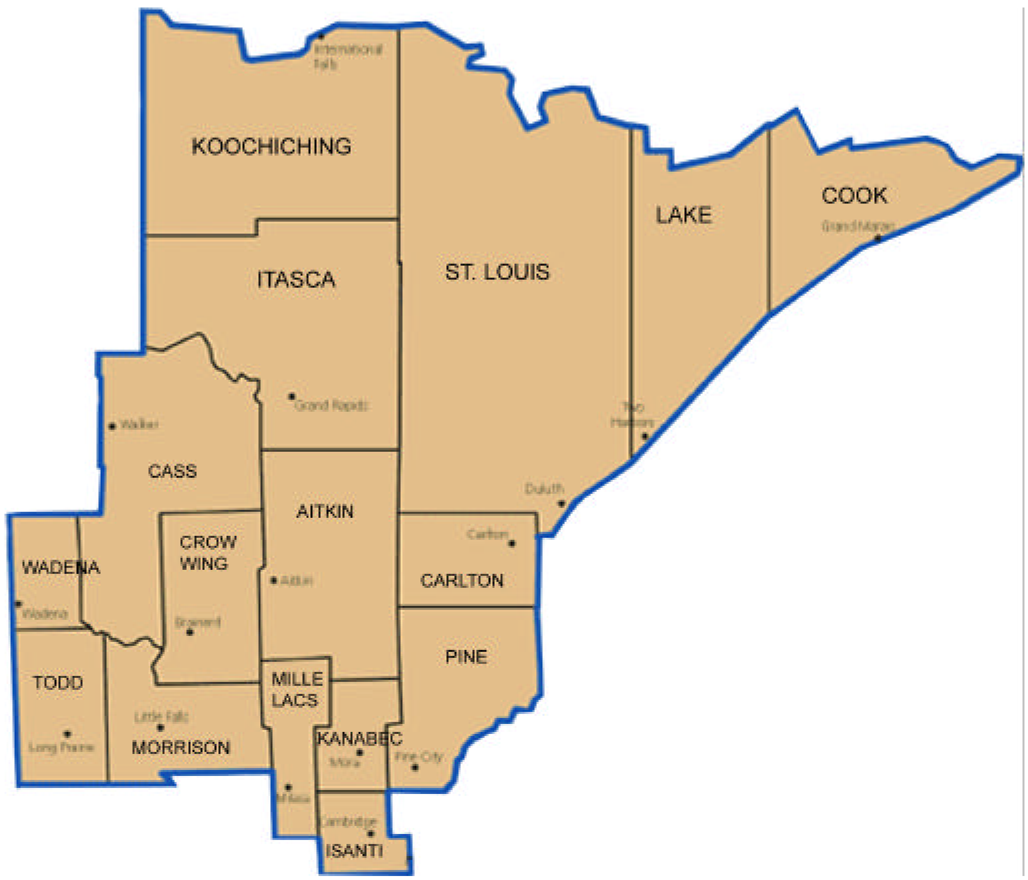
- *Northern Valley Load Serving Study* (in progress);
- *Great River Energy Long-Range Transmission Plan* (complete);
- *Otter Tail County Load Serving Study* (complete); and
- *Red River Valley/Western Minnesota Transmission Improvement Planning Study (TIPS)* (in progress).

Northeast Transmission Planning Zone

I. Introduction

The Northeast Planning Zone covers the area north of the Twin Cities suburban area to the Canadian border and from Lake Superior west to the Walker and Verndale areas. The zone includes the counties of Aitkin, Carlton, Cass, Cook, Crow Wing, Isanti, Itasca, Kanabec, Koochiching, Lake, Mille Lacs, Morrison, Pine, St. Louis, Todd, and Wadena counties.

Northeast Transmission Planning Zone



A land use map is located in Appendix IX. As can be seen from this map, the primary land use in the central and northern areas of the Northeast Planning Zone is forest land. The southern and western portions of the Zone have significant amounts of cultivated land and pockets of forest. The Iron Range includes a strip of land running from Grand Rapids to Babbitt used for mining operations. The zone also includes bogs, brush land and numerous lakes. The zone also includes both urban and rural development.

The primary population centers in the Northeast Planning Zone include the cities of Brainerd, Cambridge, Cloquet, Duluth, Ely, Grand Rapids, Hermantown, Hibbing, International Falls, Little Falls, Long Prairie, Milaca, Pine City, Princeton, Verndale, Virginia, and Walker.

The recent electric load growth in the zone has been in the numerous lake and recreational areas as cabins are converted to year-round residences, and population increases. Loads in the zone consist mainly of iron ore/taconite, timber and paper production. These loads have been cyclic as they are responsive to world fluctuation in supply and demand. Agriculture and tourism are also dominant industries in the zone. The southern boundary of the zone has seen increased residential growth as urban development expands north from the Twin Cities.

The transmission system in the Northeast Planning Zone consists mainly of 230 kV, 138 kV and 115 kV lines that serve lower voltage systems comprised of 69 kV, 46 kV, 34.5 kV, 23 kV and 14 kV. The 230 kV system is used as an outlet for generation and to deliver power to the major load centers within the zone. From the regional load centers, 115 kV lines carry power to lower voltage substations where it is distributed to outlying areas. In a few instances, 230 kV lines serve this purpose.

A +/- 250 kV DC line runs from central North Dakota to Duluth and serves as a generator outlet for lignite-fired generation located in North Dakota. In addition, a 500 kV line and a 230 kV line provide interconnections with Manitoba and a 115 kV line interconnects with Ontario at International Falls. The interconnections with Canada provide for generation resource sharing as well as seasonal and economic power interchanges between Minnesota and Canada.

A map showing the 100 kV and above transmission facilities located in Minnesota is located in Appendix VII. This map also identifies the Northeast Planning Zone and the other State Planning Zones.

II. Utility Contacts and Regional Transmission Organization Participation

The utilities which own transmission facilities within the Northeast Planning Zone include Great River Energy ("GRE"), Minnesota Power ("MP"), Minnkota Power Cooperative ("MPC"), Southern Minnesota Municipal Power Agency ("SMMPA") and Xcel Energy. Contact information for these utilities can be found in Appendix I.

The Midwest Independent Transmission System Operator, Inc. is a FERC recognized RTO. Midwest Independent Transmission System Operator, Inc. provides non-discriminatory, open access transmission service and serves as the regional hub for the flow of electric energy in a 15-state area, including Minnesota. More information on Midwest Independent Transmission System Operator, Inc. and its role can be found in the first section of this Report. In order to insure continued reliability of the regional transmission system and continued access to competitive electric energy, Midwest Independent Transmission System Operator, Inc. has developed a regional transmission expansion plan. A copy of this plan, the *Midwest ISO Transmission Expansion Plan – 2003 (MTEP-03)* can be found on the Midwest Independent Transmission System Operator, Inc. website (www.midwestiso.org/plan_inter/expansion.shtml). Although not all of the transmissions owners in the Northeast Planning Zone are members of Midwest Independent Transmission System Operator, Inc., this expansion plan has included data from all the owners.

All the utilities in the Northeast Planning Zone participate in the MAPP, a NERC regional transmission reliability group. MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the *Regional Load and Capability Report* produced by MAPP may be requested from MAPP (see Appendix I for MAPP contact information). More information on MAPP and its role can be found in the first section of this Report.

The *2003 Minnesota Biennial Transmission Projects Report* includes updates to the *MAPP 2002 Regional Plan* that will be incorporated into the 2003 update to the MAPP regional plan. A copy of the *MAPP 2002 Regional Plan* can be found on the MAPP website, at www.mapp.org.

III. Transmission System Inadequacies and Alternative Solutions

This section will provide information on the future inadequacies that have been identified in the Northeast Planning Zone transmission system over the next ten years. It will also provide information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy and economic, environmental and social issues associated with each alternative.

TOWER-ELY-BABBITT AREA

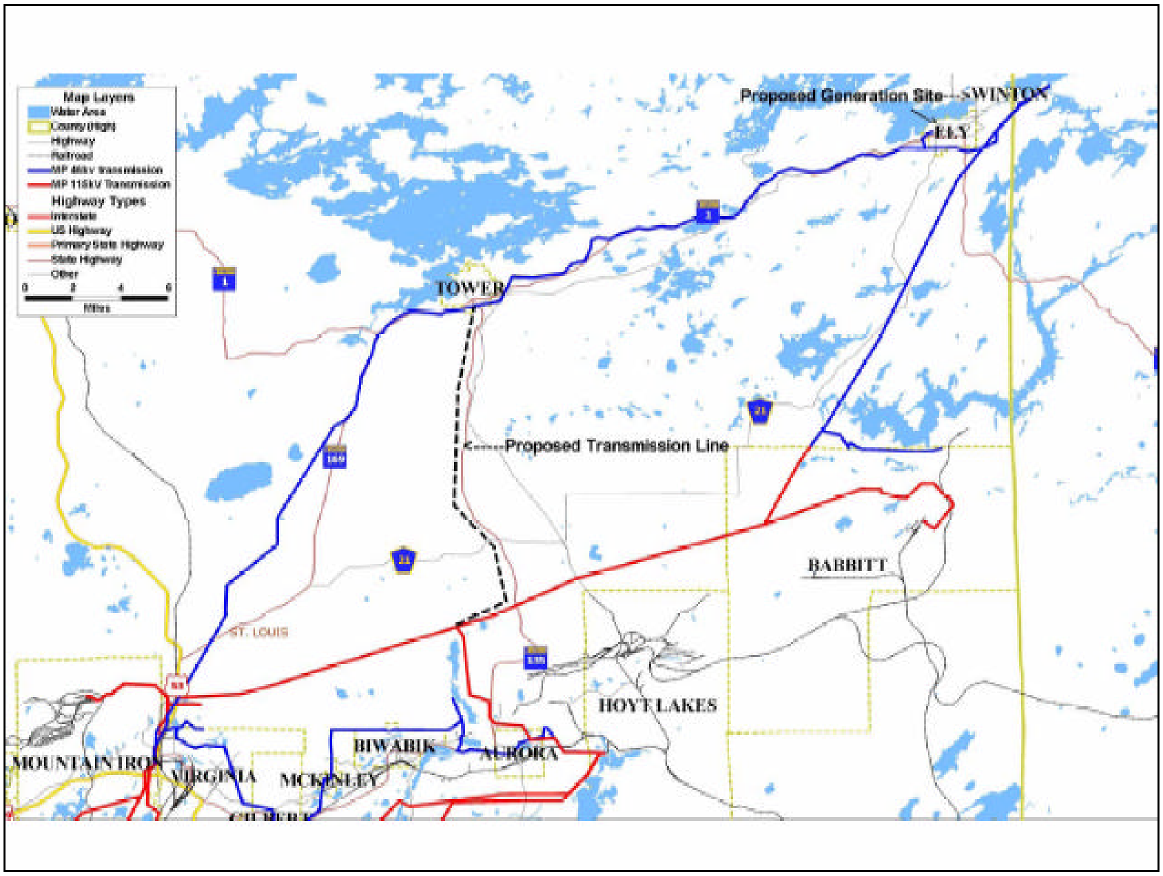
A. Inadequacies

This area is served by a 75-mile long 46 kV transmission loop with 115 kV sources located at Virginia and Babbitt. There is also 4 MW of hydro generation located at Winton. Load has been growing slowly and by 2006-2008 is expected to reach the point that acceptable voltage cannot be maintained if one of the two 115 kV sources is lost during peak load periods. During some past disturbances the Winton generation has been lost and, if this generation is not available due to unplanned outages or maintenance, the time periods when voltages cannot be maintained at acceptable levels will increase. In order to maintain reliable electric service to this area, this voltage issue will need to be addressed. A map of the area showing the 46 kV loop and its 115 kV sources located at Virginia and Babbitt is shown below.

B. Alternative Solutions

The voltage issues in this area have been studied extensively over the past few years. These studies included steady state analysis and transient analysis to evaluate dynamic voltage remediation systems ability to support the area's voltage post disturbance. This analysis included transient analysis of the response of Winton generation to area disturbances and of the benefits a Superconducting Magnetic Energy Storage (SMES) device and additional generation may provide. Results of this analysis indicated that with the addition of capacitors, acceptable post-contingent voltage could be maintained until approximately 2006-2008, depending on load growth. These capacitors were added to the Ely substation in 1991. This analysis also showed that a SMES device could delay the need for new transmission into the area, but due to its high cost, it would be uneconomical. Based on this analysis, three alternative means of addressing this voltage issue beyond the 2006-2008 timeframe have been developed and studied. Two alternatives include construction of new substations and power lines; a third alternative evaluated distributed generation located at Ely or Winton.

Tower-Ely-Babbitt Area 46 kV Loop



1. Tower-Ely-Babbit Area Alternative #1: Construct a 115 kV line between the Minnesota Power (MP) 115 kV Line #34 and Tower

Alternative 1 would include the following transmission components:

- Approximately 17 miles of 115 kV transmission line;
- Development of a 115 kV switching station near Embarrass on MP Line #34; and
- Development of a 115/46 kV substation near Tower.

This alternative would provide an additional 115 kV source to the Tower area that would tie directly into the 75-mile long 46 kV loop that serves this area. This source will be capable of supporting the area voltage for the foreseeable future. It will also improve reliability to the area by sectionalizing the 46 kV line between Virginia and Ely into a Virginia-Tower line section and a Tower-Ely line section. Lastly, it will improve the performance of Line #34 since it would also be sectionalized at the 115 kV switching station. The line would need to be routed from near Embarrass to the Tower area, a distance of approximately 17 miles. There is an existing road, County Highway 135, which may provide a transmission line routing corridor. The above area map shows one possible corridor for routing the line and the locations of the substations. These locations should be considered as preliminary only.

2. Tower-Ely-Babbit Area Alternative #2: Construct a 46 kV line between the MP 115 kV Line #34 and Tower

Alternative 2 would include the following transmission components:

- Approximately 17 miles of 46 kV transmission line;
- Development of a 115/46 kV substation station near Embarrass on MP Line #34; and
- Development of existing 46 kV substation located near Tower.

This alternative would provide a third 115 kV source into the existing 46 kV loop via a 17-mile long 46 kV tie from the Embarrass area to the Tower area. As with Alternative 1, this new source will be capable of supporting the area voltage for the foreseeable future. It will also improve reliability to the area by sectionalizing the 46 kV line between Virginia and Ely. Last, it will improve the performance of Line #34 since it would also be sectionalized at the point where the 115/46 kV substation would be constructed. As with Alternative 1, the line would be approximately 17 miles long and would need to be routed from near Embarrass to the Tower area. There is an existing road, County Highway 135, which may provide a routing corridor. The area map shows one possible corridor for routing the line and the locations of the substations.

3. Tower-Ely-Babbit Area Alternative #3: Install 48 MW of diesel generation in the Ely or Winton area

Alternative 3 would include the following components:

- Two to four diesel generators and associated facilities (4-8 MW); and
- Ties into existing 46 kV loop.

This alternative would delay the need for additional electric power lines into the area for 10 years or perhaps longer depending on load growth. Due to the high cost of diesel-derived electric energy, this generation would likely only be dispatched during emergencies, planned maintenance or periods when the price for electric energy was high. Because this generation may not be on-line during unplanned disturbances, electric service to the area may be lost during some disturbances until the generation can be started. Starting this generation and restoring service would be expected to take approximately 10 minutes. The above area map identifies two possible generation sites.

C. <u>Economic, Environmental and Social Issues Associated with Each Alternative</u>

Preliminary routing analysis has revealed two distinct options – a "County No. 135" option and a "cross country" option. A "County No. 135" option would potentially have greater social impacts due to the presence of homes and businesses adjacent to the road, but less environmental impact due to corridor sharing and the need to clear less vegetation. A "cross country" option would have less potential social impact, but greater environmental impact due to creating a new right-of-way through a forested area. Alternative 1, the 115kV option, would require approval by the Minnesota PUC.

All alternatives would create positive economic impacts by improving the capacity and reliability of the electric supply network.

D. Recommendation

The utilities have not selected a preferred alternative. At this time, Alternative 1 would likely be ranked last since it is the highest cost and its performance is not significantly better, at expected load levels, than Alternative 2. If a large increase in load were to occur, the ranking of Alternative 1 would likely increase. Alternative 2 is higher cost than Alternative 3 and requires construction of 17 miles of power line and associated environmental impacts, but it would be capable of supporting the area for the foreseeable future. Alternative 3 does not require construction of any transmission facilities and is the least cost alternative. Since the generation can be added in 2 MW units, the additions can more closely coincide with need as compared to Alternatives 1 and 2. It may also provide benefits to the Ely Municipal system if located in Ely. However, Alternative 3 also has some disadvantages. First, it would not eliminate the need for future transmission facilities to serve the area, only delay them. Second, adding local diesel generation would not be as reliable as the other alternatives. This is because it takes time to get the generation on-line and there would be occasional disturbances where the area would be without power until the generators can be started. Comments from local area residents and regulatory agencies will be helpful in assisting the utilities in determining the appropriate alternative.

WRENSHALL-MAHTOWA AREA

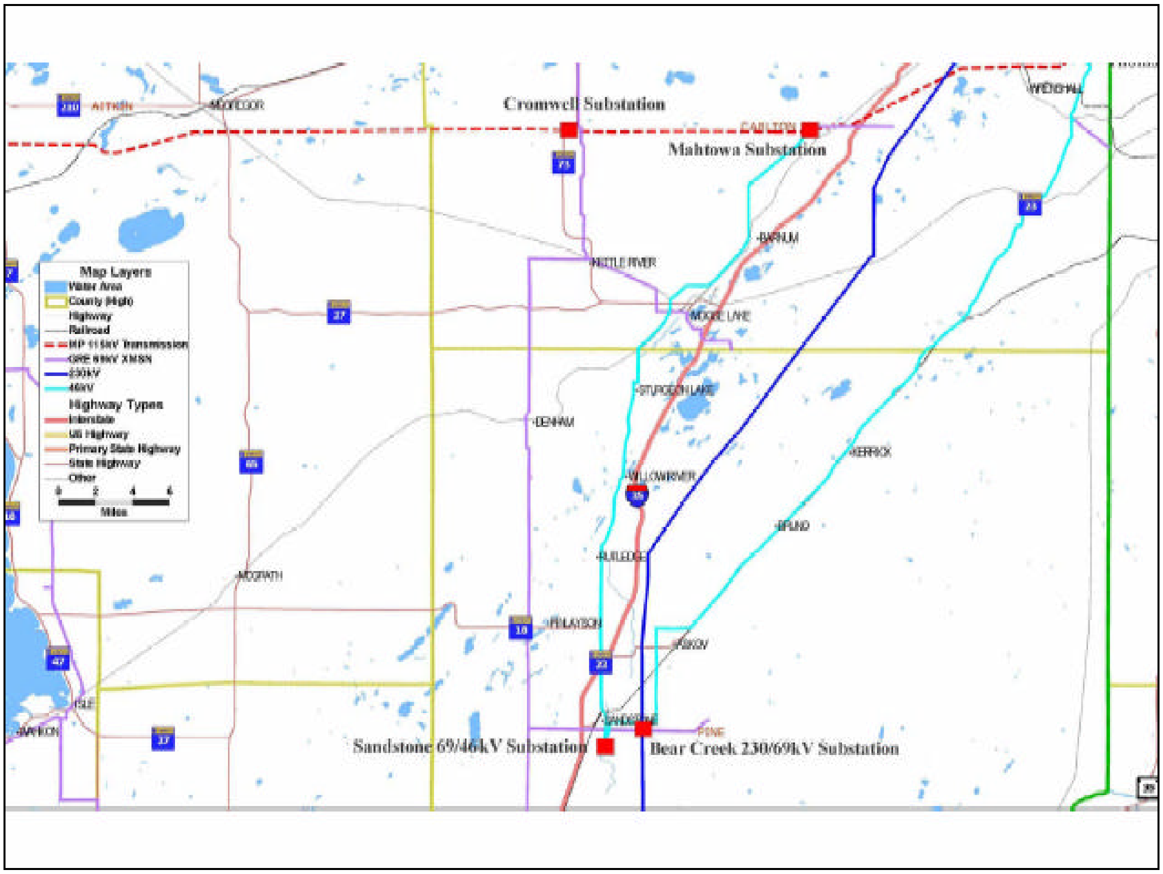
A. Inadequacies

This area is supplied by a 90-mile 115 kV line running between 115 kV sources located at the Riverton substation near Brainerd and the Thompson substation located south of Duluth. A 46 kV loop runs south from the Thompson 115 kV source to Sandstone and from Sandstone to Mahtowa, where it again connects with the 115 kV line running between Thompson and Riverton. Due to the distances between the two 115 kV sources and the total load served, the voltage in the Mahtowa and Wrenshall area is approaching unacceptable levels during loss of the Thompson source. If this problem is not addressed, it is expected that voltage cannot be maintained at or above acceptable levels by the 2007 timeframe at current load growth rates.

B. Alternative Solutions

Studies to determine the best method to support this area are scheduled to commence in late fall or winter 2003. The primary alternative to be studied will make use of GRE's new Bear Creek 230/69 kV substation located near Sandstone and the existing MP/GRE Sandstone 69/46 kV substation (see area map below). The Bear Creek substation would be capable of providing an alternate source to support the area during loss of the Thompson 115 kV source. This could be accomplished by opening and closing switches in the Wrenshall and Mahtowa area such that the 46 kV system would be sourced from the Bear Creek 69 kV source. Studies need to be completed to verify that Bear Creek substation is capable of providing this alternative source.

Wrenshall-Mahtowa Area



C. **Economic, Environmental and Social Issues Associated with Each Alternative**

Routing options have not yet been examined for these potential projects. Upgrading existing lower voltage lines would potentially have less environmental and social impacts than developing a new route. However, location of the existing lines is important. Lower voltage lines originally routed through areas that are environmentally sensitive or that have experienced residential growth near the right-of-way may not be good options for future high voltage transmission line routes. Again, the construction of a new 115 kV line designed to improve the reliability and capacity of the electric delivery network would have positive economic impacts. If construction of a 115 kV transmission line is necessary to support the area, approval by the PUC would be required.

D. **Recommendation**

Minnesota Power proposes to verify that the Bear Creek 69 kV source will be able to support the load in this area. If studies determine that the Bear Creek 69 kV source is not capable of supporting the area, more alternatives would need to be developed. These would likely include bringing a new 115 kV source into the area, upgrade of existing 46 kV circuits to higher voltage operation or the addition of local distributed generation. Minnesota Power and GRE will be working together to determine the best method to support this area. If additional transmission facilities are required, it's possible that a request for certification of a project would be included in the 2005 Biennial Report. If conditions warrant and if upgrades would need to be completed sooner, owners would likely seek approval through a certificate of need application.

PEQUOT LAKES-BADOURA AREA

A. Inadequacies

The Minnesota Power (MP) Pequot Lakes 115/34.5 kV substation is supplied by a single 115 kV source via a Riverton-Pequot Lakes transmission line. The substation 34.5 kV feeders serve both MP and GRE electric loads in the towns of Nisswa, Pequot Lakes and Pine River and in the surrounding rural areas. A 34.5 kV feeder connects the Pequot Lakes 115/34.5 kV substation to the MP Badoura 115/34.5 kV substation, which is located in the Northwest Zone (see map below). This feeder is normally open at Pine River and can be closed to provide an alternative source to the area loads during maintenance or unplanned outages. A second 34.5 kV feeder runs between the Pequot Lakes substation and the MP Baxter 115/34.5 kV substation and is operated normally-open between Nisswa and Gull Lake. This feeder also serves as an alternative source to the Pequot Lakes area loads. GRE serves load from Pequot Lakes via a 69 kV line.

The load served out of the Pequot Lakes substation has been growing at an average annual rate of approximately 3% since 1996, and slightly higher during the last couple of years. This load growth is resulting in near-term voltage concerns. In the long term, the alternative sources supplied by the 34.5 kV connections to Badoura and Baxter will no longer be able to support the area during loss of the single 115 kV Pequot Lakes source. Based on historic load growth, this inadequacy will need to be rectified by the 2008 timeframe or sooner.

The Badoura substation, which is located in the Northwest Planning Zone, normally serves the loads to the west of Pine River on the 34.5 kV feeder, which runs between the Pequot Lakes substation and the Badoura substation. This includes the towns of Tripp Lake, Hackensack, Backus, and the surrounding rural areas. The Badoura substation also supplies Pleasant Lake and Wabedo, which are served from the GRE's Birch Lake 69/34.5 kV substation located near Hackensack. These loads have also been growing and, like the Pequot Lakes area, have both short-term voltage issues and long-term (2010 timeframe) issues associated with the ability to support the area if the primary source is lost. Transmission planning engineers intend to address both the Badoura and the Pequot Lakes long-term inadequacies with one project.

A. Alternative Solutions

At this time, transmission upgrades to support this area are not expected to be needed until the 2008 timeframe. Both MP and GRE serve load in this area and will be working together to find the best solution. As mentioned above, an immediate issue in this area is the voltage performance of the 34.5 kV system, which has experienced considerable growth in the last few years. This short-term deficiency will be addressed with the addition of 3.0 MVAR of capacitors at the Birch Lake 69/34.5 kV substation and two 3.0 MVAR capacitors at the Pine River 34.5 kV substation.

The long-term deficiency is primarily due to the radial aspect of the Pequot Lakes 115 kV substation and the multiple switching events needed to get a secure system in place on loss of the Riverton-Pequot Lakes 115 kV line. Considering the growth potential in the Pequot Lakes area, a second 115 kV source into Pequot Lakes appears to be the best method to address this concern. MP and GRE have both done preliminary studies and have identified the following alternatives to accomplish this.

1. Pequot Lakes–Badoura Area Alternative #1: Badoura-Pequot Lakes 115 kV line with Birch Lake 115/69 kV source

This alternative would develop a new 115 kV line between the Badoura and Pequot Lakes substations, a distance of approximately 30 miles. This option would convert portions of the existing 34.5 kV feeder #507, which runs between Badoura and Pequot Lakes, to 115 kV operation. This upgrade would allow the load at Tripp Lake to be converted to 115 kV and would provide for a 115 kV source to be extended to the GRE Birch Lake substation. A 115/69 kV transformer would be added at Birch Lake to support the Wabedo and Walker areas. The remaining loads between Badoura and Pequot Lakes would continue to be served at 34.5 kV via an underbuild of the proposed 115 kV line.

2. Pequot Lakes–Badoura Area Alternative #2: Pine River 230/115/34.5 kV source

This option would establish a source to Pine River from the nearby 230 kV line (see area map). The short-term solution is to get the Pine River load off the existing system to free up 34.5 kV capacity. This can be done by establishing a 115/34.5 kV source at the MP Pine River substation. Eventually, Pequot Lakes would require a second 115 kV source. This could be obtained by rebuilding the 34.5 kV line between Pine River and Pequot Lakes to 115 kV. The GRE Pine River load would then be moved to the 115 kV system. A 115 kV tie to the Hackensack and Birch Lake area would also be required in the future. This could be accomplished by extending a line from the Pine River 115 kV substation into Birch Lake and/or Hackensack in a similar fashion as Alternative 1.

3. Pequot Lakes–Badoura Area Alternative #3: Add local generation and delay second 115 kV source into Pequot Lakes

Generation would be attractive on the low side of the Pequot Lakes substation, which could be used to unload the transformers and reduce the total load that must be served by alternative sources if the 115 kV Pequot Lakes source is lost. This would delay, but not eliminate the need for a second 115 kV into Pequot Lakes. To address the issues in the Badoura, Hackensack and Birch Lake areas, additional generation would also be needed at these locations.

C. Economic, Environmental and Social Issues Associated with Each Alternative

Routing options have not been examined for any of the potential projects. Upgrading existing lower voltage lines would potentially have less environmental and social impacts than developing a new route. However, location of the existing lines is important. Lower voltage lines, originally routed through environmentally sensitive areas or that have experienced residential growth near the right-of-way, may not be good options for future high voltage transmission line routes. The density of lakes and other recreational areas in the project area would create a routing challenge for a new 115 kV line. Again, the construction of a new transmission line designed to improve the reliability and capacity of the electric delivery network would have positive economic impacts. Alternative 1 and Alternative 2 would require PUC approval.

D. Recommendation

Additional studies and economic analysis need to be completed. At this point, it appears that Alternative 1 would provide the best performance and the best options to address future area needs. Alternative 2 would delay the construction of a 115 kV transmission line between Pequot Lakes and Badoura, but requires construction of a 230 kV substation, which is much more costly than 115 kV facilities. An economic analysis will be required to determine if delaying these upgrades provides an economic advantage over Alternative 1. Last, since the load in this area is growing at a modestly rapid rate, it is unlikely that Alternative 3 would delay the need to obtain a new source into Pequot Lakes and support for Birch Lake long enough to be an economical solution.

MP and GRE will be working together to determine the best option to increase the reliability to this area. Present schedules are to request project certification in the 2005 Biennial Report. Again, if the area experiences an unexpected increase in load growth, the utilities may need to pursue a separate certificate of need application.

CENTRAL LAKES AREA

A. Inadequacies

The Central Lakes is defined as the area around Brainerd and west to the Baxter area. The Central Lakes Area electric system consists of the 34.5 kV lines that connect the area 115 kV sources together. The 115 kV sources are located at the Brainerd, Baxter and Dog Lake 115/34.5 kV substations. The following are the MP 34.5 kV lines that support the load in this area:

- 503 Line from Dog Lake;
- 531 and 534 Line from Baxter; and
- 504 Line from Brainerd.

This area also has two hydroelectric stations: one at Pillager and one at Sylvan. From Sylvan a normally open line, the 502 Line, goes to the Blanchard area.

GRE is presently in the process of establishing a new 115 kV source to the Baxter area. Loads in the Southdale area near Brainerd have been growing so rapidly that the 34.5 kV system is near the limits of its capability to continue to serve the load. GRE has proposed the construction of a radial 115 kV line by June 2004, from the Brainerd substation to Southdale and converting the Southdale load to 115 kV. This line is being permitted through the local permit process. This is only a short-term solution, as the 115 kV system serving this area will also become a concern in the near future because the loads will soon reach the point when the existing 115 kV system will not be able to supply the electric energy necessary to maintain service if a line is lost or removed from service for maintenance.

B. Alternative Solutions

To correct the area deficiencies, GRE and MP are proposing further 115 kV line development by the 2006-2007 timeframe from Southdale to either of the MP 115 kV lines identified as the 24 Line or 30 Line, which are located on the north side of Baxter. This will create a looped 115 kV system with a third source being provided to the Brainerd substation from the west.

Depending on the route of the Baxter-Southdale 115 kV line, a 115 kV breaker may be added at Dog Lake along with a short (1/2 mile) 115 kV extension of the 24 Line to eliminate the Dog Lake 115 kV tap. This would avoid a four-terminal line and is beneficial in reducing outage exposure to Thomastown and Verndale.

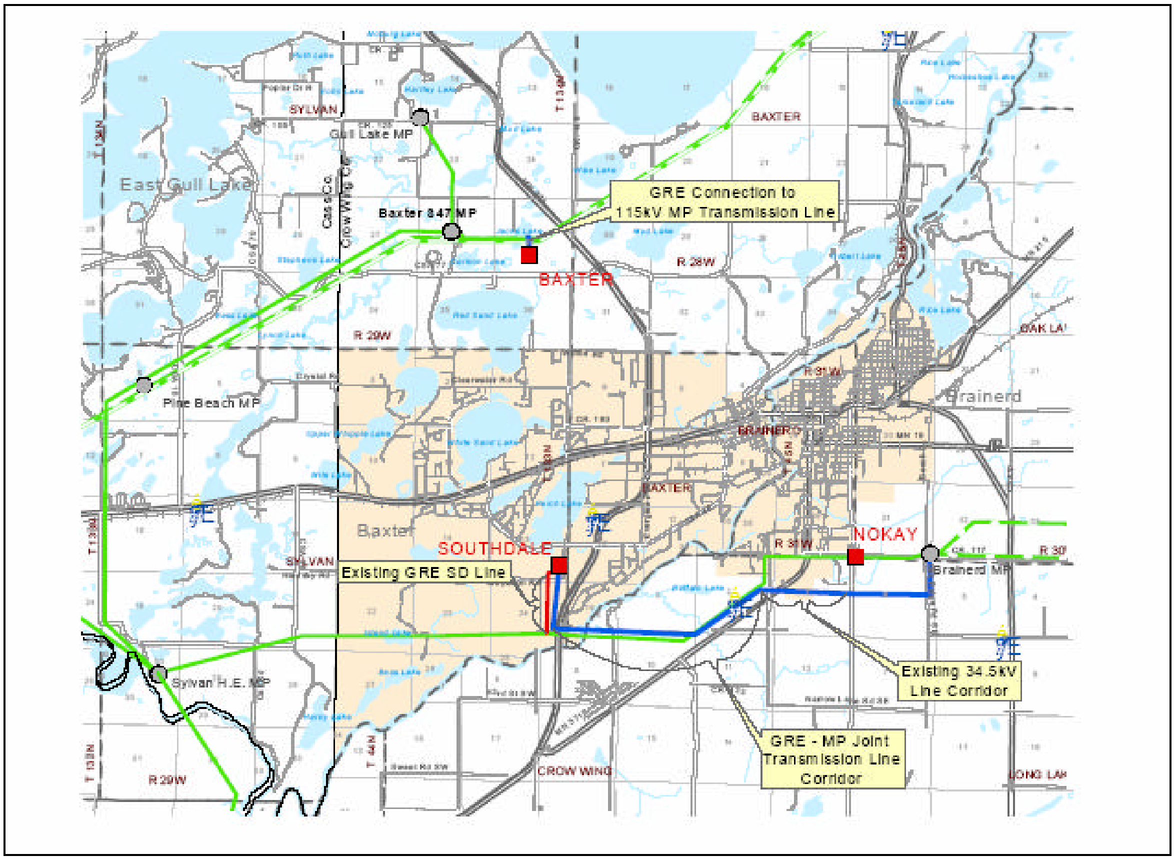
C. Economic, Environmental and Social Issues Associated with Each Alternative

The only other viable transmission voltage in the area is 115 kV due to the limited capability of the 34.5 kV system and the rapid growth in the Central Lakes area. GRE and MP will be using mostly existing transmission line routing corridors on the initial phase of this project. The second phase, which will create the 115 kV loop, will involve some impacts in the populated areas. GRE and MP are coordinating development of an overall plan to address all of the needs in the area.

D. Recommendation

A 115 kV loop will provide a long-term solution to the Central Lakes area and allow load to be moved from the 34.5 kV system to the 115 kV system. MP and GRE will be working together to determine which 115 kV line (the 24 Line or 130 Line) will provide the best overall solution. Since this project may also be capable of providing support to the Brainerd Public Utilities electric system, MP and GRE have also been seeking their input. Plans are to request project certification in the 2005 Biennial Report, or proceed with a local review process if the project does not require certification.

Central Lakes Area



PIERZ-GENOLA AREA

A. Inadequacies

The Pierz-Genola system consists of a 34.5 kV system that ties the 115/34.5 kV sources between Blanchard and Little Falls together. One 34.5 kV outlet, the 511 Line, exists at Blanchard and another outlet, the 526 Line, from Little Falls. The two outlets meet with the 5261 FDR line, which ties the system together as a looped system. The electric load in this area has been growing slowly but has already reached the point where both lines will overload and voltage violations are a concern. The table below lists line overloads and voltage deficiencies.

Overloads

Facility	Rating MVA	Outage	2001 MVA
Royalton Tap-Royalton 34.5 kV line	18	MP Little Falls-GRE Little Falls 34.5 kV line	18.5
Royalton 34.5 kV Regulator	10	MP Little Falls-GRE Little Falls 34.5 kV line	18.5
Pierz 34.5 kV Regulator	10	MP Little Falls-GRE Little Falls 34.5 kV line	10.4

Facility	Rating MVA	Outage	2001 MVA
526-529 Tie -GRE Little Falls	17	Blanchard-Royalton 34.5 kV line	21.2
GRE Little Falls-526-5261Tie 34.5 kV line	17	Blanchard-Royalton 34.5 kV line	17.2

Voltage Deficiencies

Substation	2001 %	Outage
Genola (MP)	87.0	MP Little Falls-GRE Little Falls 34.5 kV line
Lastrup (GRE)	88.0	Blanchard-Royalton 34.5 kV line

Backfeeding the Lastrup substation is currently an option for removing load from the system. This procedure is used when the Little Falls source is out and will also be needed for other faults as load grows within the area. The GRE Little Falls-526-529 tie line segment will still remain overloaded even with the Lastrup load removed. This indicates an immediate need in the area. GRE and MP are in the process of permitting and constructing a 115/34.5 kV substation near Langola (located in the West Central Zone) that will address the immediate concern. This substation will also allow the Royalton and Rice loads to be removed from the Little Falls substation and will eliminate the short-term concerns with line overloads and low voltage. Long-term, low voltages near Genola and surrounding area are expected to be a concern again by 2011.

B. Alternative Solutions

As mentioned above, the short-term inadequacies in the area will be addressed by development of a new 115/34.5 kV substation near Langola. In the long-term, two alternative solutions are currently being considered.

1. Pierz–Genola Area Alternative #1: Little Falls-Genola 115 kV line operated at 34.5 kV

Building a 9-mile long, 795 ACSR, 115 kV line, operated at 34.5 kV, from Little Falls to Genola will improve the system voltage and service during the loss of the existing Little Falls source and during other outages. The line will be built for 115 kV capability such that it will be a potential 115 kV outlet for a future Pierz 230/115/34.5 kV source.

2. Pierz–Genola Area Alternative #2: Local Generation

Generation would be attractive in the Buckman area since it would place a voltage source in the middle of the system. The concern is that this generation may not be able to resolve the voltage drop on the transmission lines, leading to continued voltage problems on the large loads located near the transmission sources.

C. Economic, Environmental and Social Issues Associated with Each Alternative

The proposed 115 kV line, operated at 34.5 kV, would be a long-term solution in the Little Falls area. A 34.5 kV line will meet the load-serving issue requiring the line. However, it is proposed that the line be built to 115 kV construction standards to provide the Little Falls area with a future third 115 kV line connected to a 230/115 kV source in the Pierz area. The line would be routed through rural areas. Due to the significant expense of the line, GRE will continue to look at alternatives to delay this new construction.

D. Recommendation

GRE will continue to monitor this long-term need and determine when a when a project will be required. At this time, load forecasts indicate that an upgrade of the area electric system will be needed by 2011. From analysis completed to date, it appears that Alternative 1 would be the least cost alternative and provide the best solution to the long-term deficiencies in this area.

TACONITE HARBOR-GRAND MARAIS AREA

A. Inadequacies

The Taconite Harbor-Grand Marais system consists of the 115/69 kV transformer at Taconite Harbor and a 50-mile long, radial 69 kV line that extends up the north shore of Lake Superior to serve loads at Schroeder, Lutsen, Grand Marais Municipal, Maple Hill and Colvill. The load served by this line has been growing at a rate of approximately 3% per year and includes both GRE and SMMPA load. The chart below lists line loading concerns for this 69 kV line:

Line Overloading

Line Segment	Mileage	Rating MVA	Year (est.)	Action	2006 MVA	2011 MVA	2026 MVA
Taconite Harbor-Schroeder	1.5	10.6	2005	Temperature Uprate	8.8	11.1	18.4
Schroeder-Lutsen	10.98	10.6	2007	Temperature Uprate	7.4	9.0	15.2
Lutsen-Cascade	~9.0	10.6	2026	Temperature Uprate	4.8	6.6	10.6

The line ratings are based on the existing 120^{o} F thermal rating of the conductor. It may be possible to increase the thermal rating of the conductor to a 170^{o} F maximum operating temperature. If this can be achieved, the rating of these lines will be 31 MVA, which will meet long-term needs for summer loading. However, if inspection of the existing line reveals that it needs to be rebuilt to increase its thermal rating, then it would be recommended that replacement should be 477 ACSR, 115 kV construction with lightning protection.

Voltage Deficiencies

Substation	Year (est.)	2006 %	2011 %	2026 %
Colvill	2006	95.5	92.6	85.9
Maple Hill	2007	95.9	93.1	86.5
Grand Marais	2008	96.3	93.6	87.3
Cascade	2012		95.6	90.4
Lutsen	2022		97.8	94.0

These are system intact voltages as there are no contingencies that create a worse voltage for the area. The criteria is to have 95% voltage during system intact conditions, which means sometime between 2006 and 2011 the voltage will be below acceptable levels without an upgrade.

B. <u>Alternative Solutions</u>

With the radial aspect of this system and the load growth that is projected, another source to the area would enhance the system greatly. However, establishing a new line to this area could have undue environmental impacts. Some of the line options considered include establishing a new source to the area from the Ely area or from Thunder Bay, Ontario. Both of these possibilities would require over 70 miles of line to be built, which would not be economical or offer the voltage support needed due to voltage drop across long lines. For new line construction it would seem that building from the existing Taconite Harbor substation would be the most feasible. However, if this was proposed, a different line corridor would need to be established.

The emergency transformer for this area is also a concern because it will not be large enough once the load reaches 16.1 MVA. This limit is based on 125% of the tertiary winding of the 138/115 kV transformer at Taconite Harbor. Action will depend upon the availability of a GRE mobile transformer, which is being reviewed for budget submittal. If the mobile transformer is not available, a second Taconite Harbor 115/69 kV transformer will be needed when the load reaches 16.1 MVA. If the mobile is available, the second transformer will be needed when the load reaches 28 MVA. The need and capacity of the second transformer will be dependent on projected growth and whether new generation has been added on the radial line. For this analysis, it will be assumed that the transformer will be added as the cost of generation running in this area may not be economical.

Portions of the existing 69 kV line serving the area were built between 1956 and 1958 and are becoming age-limited. It is expected that all portions of the line built before 1960 will need to be replaced by 2015.

The following are alternatives that were considered.

1. Taconite Harbor–Grand Marais Alternative #1: Build second loop from Taconite Harbor

To provide an independent source to the area, with some separation from the existing line, GRE looked at a westerly route to the Grand Marais tap. This line would be about 45 miles long. For loss of the Taconite Harbor-Schroeder line or the new line, voltage support would be needed.

The following is the estimated timeline for Alternative 1 installations:

Alternative 1A: Assuming 69 kV construction

Year (est.)	Facility
2003	Establish GRE reserve transformer
2005	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 69 kV (1.5 miles)
2006	Establish Taconite Harbor-Grand Marais Tap, 477 ACSR, 45 mile, 69 kV line
	Taconite Harbor 69 kV termination
2007	Rebuild Schroeder-Lutsen to 477 ACSR, 69 kV (10.98 miles)
	5.0 MVAR capacitor at Lutsen
2012	Install 2-3.0 MVAR capacitor at Colvill
2015	Rebuild Lutsen-Cascade-Grand Marais Tap-Maple Hill to 477 ACSR, 69 kV (22.09 miles)
	Second Taconite Harbor 30 MVA, 115/69 kV transformer

Alternative 1B: Assuming 115 kV construction

Year (est.)	Facility
2003	Establish GRE reserve transformer
2005	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 69 kV (1.5 miles)
2006	Establish Taconite Harbor-Grand Marais Tap, 477 ACSR, 45 mile, 115 kV line
	Grand Marais Tap 30 MVA, 115/69 kV source
	Taconite Harbor 115 kV termination
2007	Rebuild Schroeder-Lutsen to 477 ACSR, 69 kV (10.98 miles)
2012	Install 2-3.0 MVAR capacitor at Colvill
2015	Rebuild Lutsen-Cascade-Grand Marais Tap-Maple Hill to 477 ACSR, 69 kV (22.09 miles)
2021	Install 2-3.0 MVAR capacitor at Maple Hill

2. Taconite Harbor–Grand Marais Alternative #2: Rebuild to 115 kV to Grand Marais Tap

This alternative would replace the aging 69 kV line with new 115 kV construction and move the Taconite Harbor transformer to the Grand Marais Tap. This will remove some of the load that flows through the 115/69 kV transformer and put a voltage controlling device at the Grand Marais Tap, which will help the voltage at the distant Colvill substation. The new line would be constructed with 477 ACSR and consist of 31.3 miles of new 115 kV construction.

This alternative does not resolve the radial aspect of the line, meaning that a contingency at Taconite Harbor will still black-out the load. The cost investment for this facility is estimated to be $6.5 million.

Year (est.)	Facility
2003	Establish GRE reserve transformer
2005	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 115 kV line operated at 69 kV (1.5 miles)
2006	Install 2-3.0 MVAR capacitor at Colvill
2007	Rebuild Schroeder-Lutsen to 447 ACSR, 115 kV line operated at 69 kV (10.98 miles)
2015	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 115 kV line operated at 69 kV (0.35 miles)
	Rebuild Schroeder-Lutsen to 477 ACSR, 115 kV line operated at 69 kV (0.55 miles)
	Rebuild Lutsen-Cascade-Grand Marais Tap to 477 ACSR, 115 kV line (17.93 miles), operate from Taconite Harbor to Grand Marais at 115 kV
	Rebuild Grand Marais Tap-Maple Hill to 477 ACSR, 69 kV (4.16 miles)
	Move Taconite Harbor 115/69 kV transformer to Grand Marais tap
	Convert Schroeder, Lutsen, and Cascade to 115 kV

3. Taconite Harbor–Grand Marais Alternative #3: Add Capacitors to maintain voltage

Maintaining voltage as the load grows seems to be the most critical aspect of this area. This option looks at capacitor installation to assure a 95% voltage is maintained at all of the load-serving distribution substations. The addition of capacitors will not resolve the radial line issues, but would delay major investments in transmission.

Year (est.)	Facility
2003	Establish GRE reserve transformer
2005	Rebuild Taconite Harbor-Schroeder to 477ACSR at 69 kV (1.5 miles)
2006	Install 2-3.0 MVAR capacitor at Colvill
2007	Rebuild Schroeder-Lutsen to 477 ACSR at 69 kV (10.98 miles)
2015	Second Taconite Harbor 30 MVA, 115/69 kV transformer
	Rebuild Lutsen-Cascade-Grand Marais Tap-Maple Hill to 477 ACSR, 69 kV (22.09 miles)
2017	Install 2-3.0 MVAR capacitor at Maple Hill

4. Taconite Harbor–Grand Marais Alternative #4: Add Generation

Generation is an attractive alternative for this radial transmission system because it might have less environmental impact than a new 45-mile long transmission line or reconstructing the existing line with taller 115 kV construction. It will also provide a second source into the area. Based on the load projections, GRE estimates that the load in this area will be about 35 MW by winter of 2026. Ideally, generation should be sized such that it will be capable of serving future load, provide voltage support, and operate in an island condition (i.e., disconnected or isolated from the transmission system) which would occur during planned or unplanned outages of the radial 69 kV line serving the Taconite Harbor-Grand Marais Area.

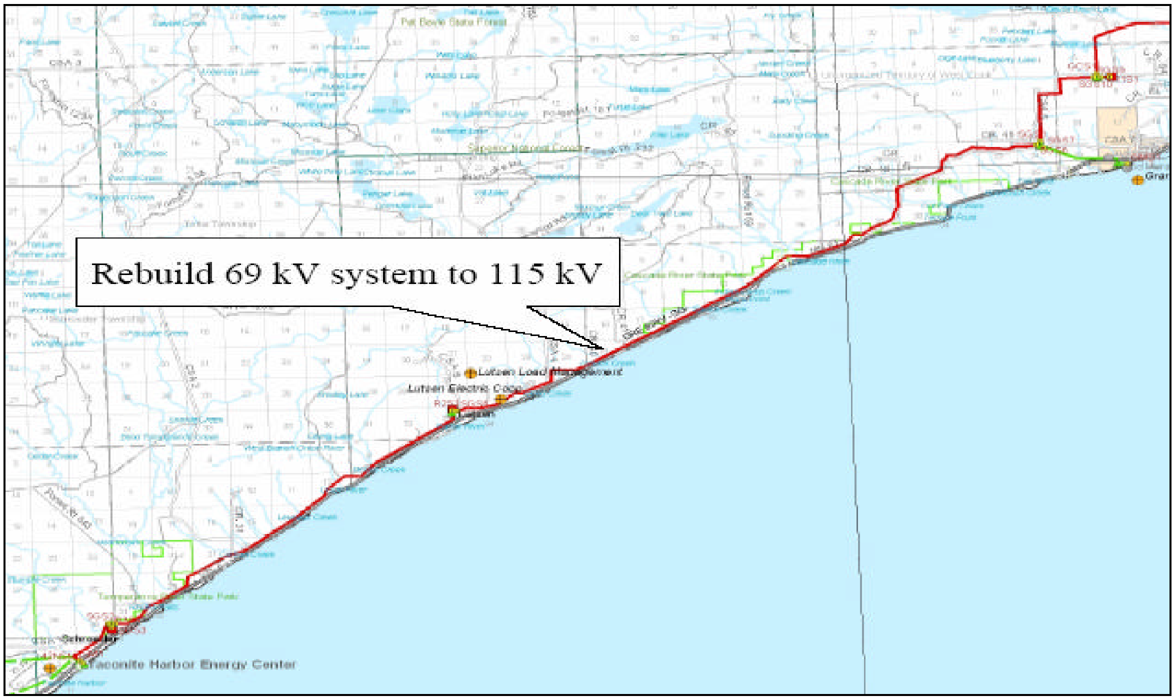
C. Economic, Environmental and Social Issues Associated with Each Alternative

If generation (Alternative 4) is not a viable option, then GRE will need to re-evaluate Alternatives 1 and 2. Alternative 2 will have the least environmental impact because it uses the existing routing corridor. GRE suggests that it continue to monitor the load growth in this area, and re-evaluate the system as needed. Alternative 2 will also allow for greater long-term growth than Alternative 3 because Alternative 3 will continue to have voltage issues as load grows.

D. Recommendation

Construction cost analysis indicated that establishing a second source into the area is not economical as presented in Alternative 1A and 1B. This further supports the desire to establish some generation in the Grand Marais area instead of building new transmission. However, sizing a generator unit may be difficult, as load is projected to continue to increase and the goal is for the generator to pick up the majority of the load when the system is isolated. The addition of generation also does not address the need to rebuild the existing 69 kV line due to its age. Based on overall cost, combined with the condition of the existing 69 kV line and load forecasts, Alternative 2 will likely become the recommended alternative. However, since the initial upfront design and construction steps of Alternative 3 are the same as Alternative 2, both alternatives remain viable solutions, as does the generation alternative. Additional analysis will be needed to confirm that Alternative 2 is the best solution; however, the limited capability or age of the existing 69 kV line will ultimately set the timing of its replacement with a new 115 kV or 69 kV line. GRE expects to provide an updated analysis in the 2005 Biennial Report.

Taconite Harbor – Grand Marais Area



MILLE LACS AREA

A. Inadequacies

The Mille Lacs area consists of the load served between Riverton and Milaca. This area is served by a GRE 69 kV line that loops around Mille Lacs Lake. The loads around the lake have continued to grow and are expected to grow in the future, especially on the lake's northwest side where the major load, the Mille Lacs Casino, is served from the Vineland substation. The annual load growth in the area is projected to be approximately 3.5%.

Assuming that the lines in this area are capable of operation at 170^{o} F, the following overloads are projected:

Overloads at 170^{o} F

Facility	Rating MVA	Year (est.)	2011 MVA	2026 MVA
Riverton 115/69 kV transformer	56	2015	63.1	87.6
Riverton-Oak Lawn Tap 69 kV line	45.5	2015	39.8	60.6

Facility	Rating MVA	Year (est.)	2011 MVA	2026 MVA
Oak Lawn Tap-Pine Center Tap 69 kV line	45.5	2019	34.9	52.8
Ogilvie-Isle 69 kV line	24.3	2017	19.5	30.0
Ogilvie-Milaca 69 kV line	36.2	2013	32.6	51.3
Onamia-Rum River Tap 69 kV line	45.5	2026	30.0	45.5
Glen-Spirit Lake Switch 69 kV line	27.7	2022	16.0	31.9
Milaca-Rum River Tap 69 kV line	36.2	2008	32.7	39.3

Voltage Deficiencies

Substation	Year (est.)	2001 %	2006 %
Oak Lawn	<2001	91.0	88.8
Wilson Lake	2002	92.9	90.3

To resolve the voltages at Oak Lawn and Wilson Lake, a 7.0 MVAR and a 9.6 MVAR capacitor will be added at the Vineland and Isle substations, respectively. These capacitors will delay any major transmission addition. Eventually another source will be needed in the area to eliminate voltage issues and for line overloadings.

Voltage Deficiencies-Post Capacitors

Substation	Year (est.)	2006 %	2011 %
Oak Lawn	2008	94.8	89.7
Wilson Lake	2008	94.1	89.4

B. Alternative Solutions

A new source needs to be established in the area. Two alternatives will be examined for the Mille Lacs area.

1. Mille Lacs Area Alternative #1: Kimberly 115/69 kV, 60 MVA source with line to Glen

A Kimberly-Glen line would provide another north side source, although it will be further away from the load center. It would lead to a potential common source at Kimberly to resolve some issues in the Floodwood Area. Another concern is the strength of the Riverton-Thomson 115 kV line, which can be fairly weak, especially during the loss of the Thomson-Wrenshall 115 kV line. Even with this line addition, the load in the Wilson Lake area causes voltage problems and overloads. The Mud Lake-Wilson Lake source will still be needed as indicated with the following deficiencies:

Overloads

Facility	Rating MVA	Year (est.)	2026 MVA
Riverton 115/69 kV transformer	56	2026	69.6
Riverton-Oak Lawn Tap 69 kV line	45.5	2025	45.8

Voltage Deficiencies

Substation	Year (est.)	2011 %	2026 %
Oak Lawn	2017	96.7	85.7
Wilson Lake	2019	95.4	89.7

Alternative 1A: Assume new Kimberly source

Year (est.)	Facility
2008	Kimberly 115/69 kV, 60 MVA source
	Kimberly-Glen 13.3 mile, 336 ACSR, 69 kV line
	Wilson Lake Breaker Station
2017	Mud Lake-Wilson Lake 12.0 mile, 477 ACSR, 115 kV line
	Wilson Lake 115/69 kV, 60 MVA source
	Mud Lake line termination and breaker

Alternative 1B: Assume Kimberly source already available for resolving Floodwood Area Issues

Year (est.)	Facility
2008	Kimberly 69 kV line termination
	Kimberly-Glen 13.3 mile, 336 ACSR, 69 kV line
	Wilson Lake Breaker Station
2017	Mud Lake-Wilson Lake 12.0 mile, 477 ACSR, 115 kV line
	Wilson Lake 115/69 kV, 60 MVA source
	Mud Lake line termination and breaker

2. Mille Lacs Area Alternative #2: Wilson Lake 115/69 kV, 90 MVA substation with 115 kV line from Mud Lake

Extending a 12-mile, 477 ACSR, 115 kV line from Mud Lake to the load center at Wilson Lake would put a strong source where it is needed. The source would have an outlet to the Spirit Lake Switch and Pine Center Tap. The 115 kV line will need to avoid the Oak Lawn-Pine Center Tap line because common right-of-way may lead to common failure, leading to a worst case situation.

Year (est.)	Facility
2008	Mud Lake-Wilson Lake 12.0 mile, 477 ACSR, 115 kV line
	Wilson Lake 115/69 kV, 90 MVA source
	Mud Lake 115 kV line termination and breaker

3. Mille Lacs Area Alternative #3: Local Generation

A fairly large generator located at the Wilson Lake substation can meet the needs in the area. The generation will have to continue to serve future load growth, so expansion may have to be examined.

C. Economic, Environmental and Social Issues Associated with Each Alternative

The new line proposed in Alternative 2 would be in a predominantly rural area that is dotted by many recreational lakes. A future proposed transmission line route would follow road corridors wherever possible.

D. Recommendation

A cost analysis was performed on each alternative with line losses evaluated using Alternative 2 as the benchmark for loss savings. Based on the present-worth values, Alternative 2 is the preferred plan. The Kimberly source may become a valid option in the Floodwood Area.

Alternative 2 provides a new source in the load center, allowing for the existing sources to be used more efficiently and as a backup for failure of this new source. Another advantage to this option is the strength of the 115 kV source, which is emanating from the MP Mud Lake 230/115 kV source. The Kimberly source offers a new source to the Glen area; however, this area is not projected to see the growth that will occur between Wilson Lake and Riverton.

NASHWAUK AREA

A. Inadequacies

The GRE Nashwauk and Crooked Lake loads are served from a 23 kV MP distribution feeder on a radial line that has a regulator to maintain voltage in system intact conditions. The load at these two substations has continued to grow, resulting in voltage and capacity issues. Load projections indicate that the load served from this system will continue to grow at an annual rate of approximately 4%.

Studies indicate that the line section between the Nashwauk Regulator and the Crooked Lake Tap will become overloaded by 2006. The tap to Crooked Lake is projected to become overloaded by 2011. Voltage will also become an issue in this area during the same timeframe.

Voltage support upon loss of the Nashwauk voltage regulator is a concern at this time. Upon the loss of the Nashwauk regulator, the system voltage collapses, leading to blackout of some load. It is estimated that only 1.4 MW of total load can be served from the Nashwauk and Crooked Lake substations, which is 47% of the 2001 summer peak and 36% of the 2001 winter peak. This indicates that even during off-peak times, some load shedding may have to be implemented to maintain voltage. Even with the regulator in service, the voltage drop on the line will lead to low voltages during system peaks.

B. Alternative Solutions

The existing line was built in 1958 with #2 ACSR and consists of 11.3 miles of line from the Nashwauk regulator station to Crooked Lake tap to Crooked Lake. The MP Nashwauk 115 kV substation is about 1.5 miles from the Nashwauk regulator station. Based on the weakness of the 23 kV system and the projected load growth, GRE will look at bringing 115 kV transmission into the area and proposing a new, 115 kV distribution substation two miles west of the existing Nashwauk substation. This will allow GRE to shorten the 115 kV line construction by not having to rebuild the whole 23 kV system. The GRE connection to the MP system is proposed as a 3-way switch tapping either the MP 45 or 14 Line just outside of the MP Nashwauk 115 kV substation.

The following are the proposed transmission system additions:

Year (est.)	Facility
2006	MP Nashwauk-GRE Nashwauk 9.37 miles, 336 ACSR, 115 kV line and 3-way 115 kV switch
2006	New LCP Nashwauk distribution substation

Generation is not an attractive option based on the limitations of the existing system.

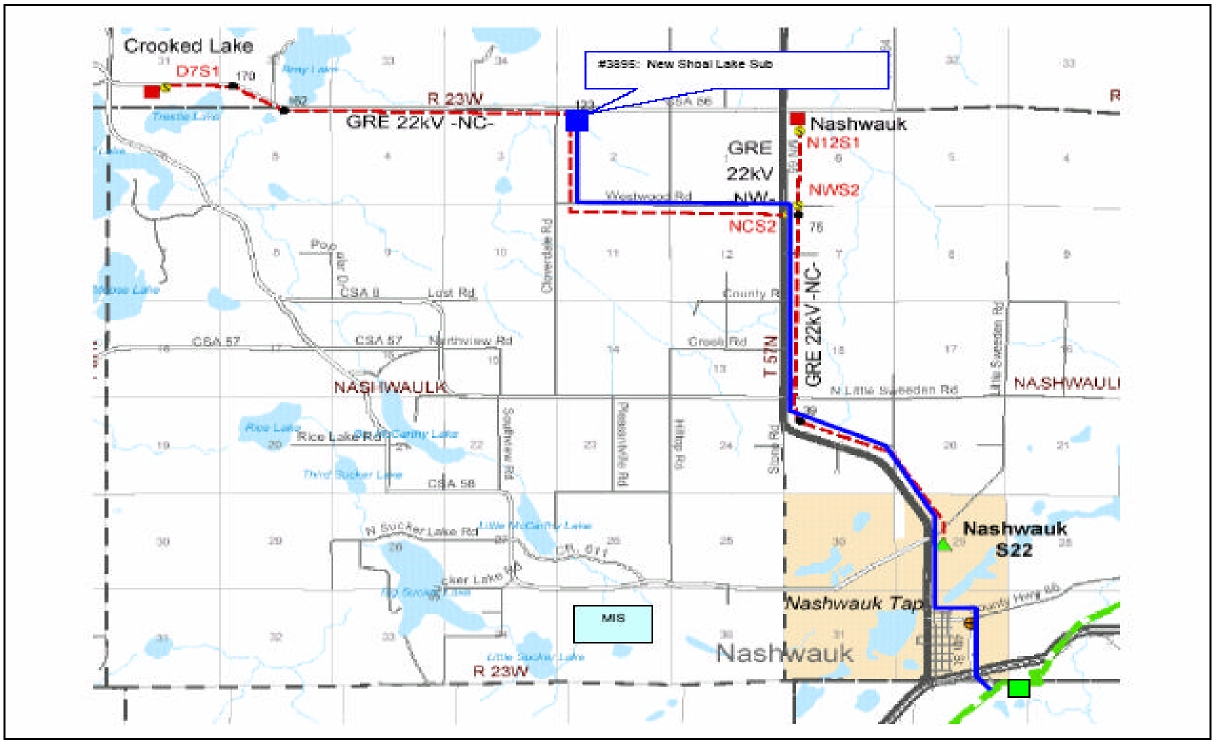
C. Economic, Environmental and Social Issues Associated with Each Alternative

Due to the limited capability of 23 kV lines, 115 kV is the only other viable transmission voltage in the area. The proposed project will be mostly using existing 23 kV transmission line routing corridor. Due to the cost of the project for a relatively small amount of load, GRE is continuing to look at alternatives to delay major transmission cost.

D. Recommendation

Development of 115 kV transmission in this area will allow for long-term growth. However, GRE will continue to study this inadequacy to determine if there are ways for delaying or lowering its cost.

Nashwauk Area Recommendation



V. Other Zone-Specific Issues

System inadequacies in the Red River Valley and western Minnesota can impact the entire regional transmission system, including the Northeast Planning Zone. These issues are being studied by the area utilities through the Northern MAPP SubRegional Planning Group. This study, called the *Red River Valley-West Central Minnesota Transmission Improvement Planning Study*, or TIPS, has been broken down into three different phases. These phases include a base improvement plan, a wires study, and a generation alternatives study. One alternative being considered, which affects the Northwest Planning Zone, is a 230 kV transmission line from Boswell (Cohasset) to Wilton (Bemidji). A more complete discussion of the TIPS study can be found in the Northwest Planning Zone section of this report.

VI. Studies in the Northeast Planning Zone

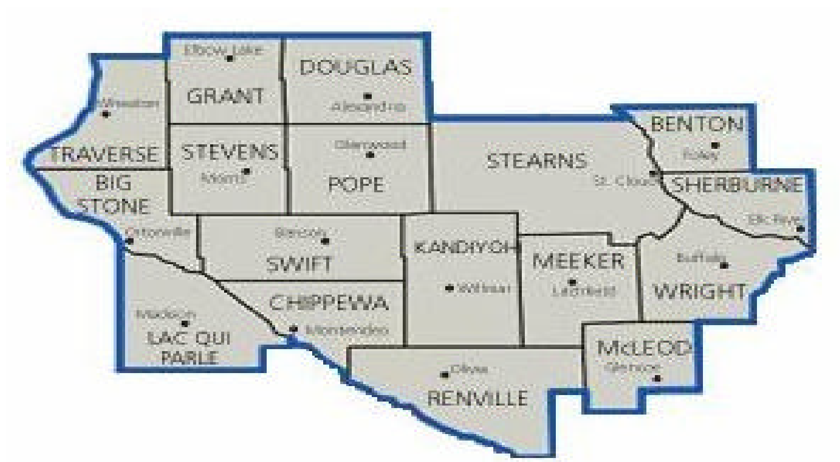
- *Red River Valley-West Central Minnesota Transmission Improvement Study (TIPS)*; and
- *GRE 2003 Long Range Transmission Plan*.

West Central Transmission Planning Zone

I. Introduction

The West Central Transmission Planning Zone extends from Sherburne and Wright counties on the east, to Traverse and Big Stone counties on the west, bordered by Grant and Douglas counties on the north and Renville county to the south.

West Central Transmission Planning Zone



A land use map of the area is located in Appendix IX. The primary land use in the West Central Planning Zone is cultivated agriculture with some hay/pasture/grassland present in the northern portion of this zone. Numerous lakes are scattered throughout the zone.

The primary population centers in the zone include the cities of Alexandria, Buffalo, Elk River, Hutchinson, Sartell, Sauk Rapids, St. Cloud, St. Michael, and Willmar. The cities of Glencoe, Hutchinson, Litchfield, St. Cloud, and Willmar provide commercial, regional City centers for their respective areas.

Commerce in the region is predominantly agricultural and includes large cash-crop farms. Many small and large commercial industries, many of which support the agriculture businesses, are also present. Agricultural processing plants (beets, soybean and ethanol) are also large loads on the electrical system in this region.

This transmission system in the West Central Planning Zone is characterized by a 115 kV line loop from the Grant County – Alexandria – West St. Cloud – Paynesville – Willmar – Morris – Grant County. These 115 kV transmission lines provide a hub from which 69 kV subtransmission lines provide transmission to loads in the zone. The 345 kV and 230 kV lines from Sherburne County and Monticello generating plants connect the two base load generating plants to the Twin Cities. The 345 kV line from Sherburne County to St. Cloud and the 115 kV and 230 kV lines from Monticello to St. Cloud provide the primary transmission supply to St. Cloud and much of the eastern half of this zone. There are also 115 kV lines to the east of the 115 kV line from Dickinson to Carver County and another one from Wakefield to Big Swan to Crow River that provides transmission service to the Hutchinson – Glencoe – Waconia area.

Two additional 230 kV lines are in the area - 230 kV from Granite City to McLeod to the Black Dog generating plant in the Twin Cities; and a 230 kV line from Granite Falls to Willmar. These lines provide the primary transmission service to the southern part of this zone.

A map showing the 100 kV and above transmission facilities located in Minnesota is in Appendix VII. This map also identifies the West Central Planning Zone and the other State Transmission Planning Zones.

Some of the 69 kV "subtransmission" network is becoming inadequate for supporting the growing load in the area. Solutions to the 69 kV transmission inadequacies may involve construction of new 115 transmission lines. Therefore, discussions about the inadequacy of the existing system will include an analysis of parts of the existing 69 kV subtransmission system.

II. Utility Contacts and Regional Transmission Organization Participation

The utilities which presently own transmission facilities of voltages greater than 100 kV within the West Central Planning Zone include Great River Energy ("GRE"), Hutchinson Utilities Commission ("HUC"), Missouri River Energy Services ("MRES"), Otter Tail Power Company ("OTP"), Southern Minnesota Municipal Power Agency ("SMMPA"), Willmar Municipal Utilities ("WMU"), and Xcel Energy. Glencoe Light and Power Commission, the municipal utility for the City of Glencoe, is proposing constructing a new 115 kV line by late 2005.

Contact information for these utilities can be found in Appendix I.

The Midwest Independent Transmission System Operator, Inc. is a FERC recognized RTO. Midwest Independent Transmission System Operator, Inc. provides non-discriminatory, open access transmission service and serves as the regional hub for the flow of electric energy in a 15-state area, including Minnesota. More information on Midwest Independent Transmission System Operator, Inc. and its role can be found in the first section of this Report. In order to insure continued reliability of the regional transmission system and continued access to competitive electric energy, Midwest Independent Transmission System Operator, Inc. has developed a regional transmission expansion plan. A copy of this plan, *The Midwest ISO Transmission Expansion Plan – 2003 (MTEP-03)* can be found on the Midwest Independent Transmission System Operator, Inc. web site (www.midwestiso.org/plan_inter/expansion.shtml). The *2003 Minnesota Biennial Transmission Projects Report* here includes updates to the MTEP-03 that are in the process of getting incorporated in the Midwest Independent Transmission System Operator, Inc. update to the Midwest Independent Transmission System Operator, Inc. Transmission Expansion Plan.

The transmission owning utilities in the West Central Planning Zone also participate in the MAPP, a regional transmission reliability group. Among other things, MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the most recent *Regional Load and Capability Report* can be found on the MAPP web site, at www.mapp.org. More information on MAPP can also be found in the first section of this Report.

The *2003 Minnesota Biennial Transmission Projects Report* includes updates to the *MAPP 2002 Regional Plan* that will be incorporated into the 2003 update to the MAPP Regional Plan. A copy of the *2002 MAPP Regional Plan* can be obtained from MAPP (see Appendix I for the MAPP contact information).

III. Transmission System Inadequacies and Alternative Solutions

This section provides information on the inadequacies that have been identified in the West Central Planning Zone transmission system over the next ten years. It also provides information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental and social issues associated with each alternative.

WIND GENERATION OUTLET

A. Inadequacies

Wind generation developments on the Buffalo Ridge area in southwestern Minnesota have become one of the main drivers for future transmission needs in the southern half and the west central part of the state. The inadequacies of the West Central Planning Zone relative to the need for wind generation outlet are discussed in the Southwest Planning Zone section of this report.

Recent completed studies pertinent to this issue include:

- *Plan 1H, In the matter of the application of Northern States Power Company d/b/a Excel Energy for certificate of need for four large high voltage transmission line projects in southwestern Minnesota, Docket No. E002/CN-01-1958;*
- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission Outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW) Volume 1 and 2 November 13, 2001;* and
- *Preliminary results of an interconnection study for 36-130MW of wind generation near Chanarambie, Minnesota, January 11, 2001.*

A study of the next stage transmission wind generation outlet from the southwest Minnesota region is also planned. Details of the study scope are not yet developed.

B. Alternative Solutions

Discussion of the basic wind development alternatives is found in the wind generation part of the Southwest Planning Zone section of this report. Several transmission components in the West Central Planning Zone require upgrading in order to meet the needs of the wind generation outlet. These specific components, all Xcel Energy projects, are discussed below.

Wind outlet related projects in West Central area (425 MW capacity)

- Alexandria—Douglas County 115 kV line: reconductor 11 miles;
- Willmar 115/69 kV 84 MVA transformer: replace with 112 MVA unit;
- Minnesota Valley 230/115 kV 50 MVA transformers: replace with 100 MVA units;
- Troy switching station: new 69 kV breaker station;
- Franklin-Henryville tap-Bird Island 69 kV: rebuild 16.6 miles;
- Minnesota Valley-Redwood Falls 115 kV: reconductor 27.2 miles; and
- Willmar-Kerkhoven tap 115 kV: rebuild 14.7 miles.

Wind outlet related projects in West Central Planning Zone (425-825 MW capacity)

- Paynesville-Munson tap 69 kV: reconductor 11.6 miles;
- Paynesville-Wakefield 115 kV: rebuild 15 miles; and
- Redwood Falls-Franklin 115 kV: reconductor 13 miles.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The projects proposed to address wind generation outlet in this zone all use existing lines to improve the system. These projects are already approved as Option 1H. The rebuilds and reconductors minimize impact on the environment by limiting the line work to existing transmission line routes.

D. Recommendation

At this time, no addition projects, beyond Option 1H, are required to obtain wind generation outlet capacity up to 825 MW. If additional wind generation outlet capacity (above 825 MW) is required, further study and additional projects will be required, including new projects in the West Central Planning Zone.

MCLEOD-GLENCOE-WACONIA AREA

The McLeod-Glencoe-Waconia Area is bounded by Delano on the northeast, Carver County substation on the southeast, the McLeod substation on the southwest, and Lester Prairie on the northwest. It includes the cities of Glencoe, Waconia, Watertown, Young America, and several smaller communities. These communities are on the fringe of the metropolitan area and include some light industry. It is recognized that rapid load growth may continue to develop in this area within the next 10 years, as has been observed in other similarly situated communities on the fringe of the Twin Cities metropolitan area.

The McLeod-Waconia Area load is served from 69 kV transmission lines that are supplied by two 115-69 kV, 70 MVA transformers: one at the St. Bonifacius substation and one at the Carver County substation. The City of Glencoe, GRE and Xcel Energy have distribution substations on the 69 kV transmission lines in this area.

Analysis of the transmission system in this area was done through a *Glencoe Area Load Serving Transmission Study* that was completed in June 2002. Further discussion of the inadequacies, alternative solutions, social and economic analysis and the recommendations can also be found in the Carver County—Waconia Area discussion in the Twin Cities Planning Zone section of this Report.

The recommended alternative for the Carver County–Waconia Area includes a project that traverses a portion of the McLeod–Waconia area of the West Central Planning Zone. This project consists of a new 115 kV transmission line from Glencoe to the McLeod substation, approximately 9.5 miles. This project will be constructed by the Glencoe Light and Power Commission and will be permitted through local government authorities.

STATE HWY 10/I-94 CORRIDOR, MONTICELLO-ST. CLOUD

This corridor runs on either side of the Mississippi River between St. Cloud and Monticello. There are three major transmission lines in this corridor: a 345 kV line from Sherburne County Generating Plant (“Sherco”) to the Benton County substation; a 230 kV line from the Monticello Generating plant to the Benton County substation; and a 115 kV line from the Monticello Generating plant to the St. Cloud substation. Study of this area is documented in *Preliminary Steady State Results of an Interconnect Study for 120 MW of Additional Generation in Sherburne County, Minnesota* (February 24, 2003).

A. Inadequacies

For loss of Benton County-Sherco 345 kV line, during 2004 winter peaking conditions, the existing Monticello 345/230 kV transformer loads to 152.1% of its 336 MVA rating. By 2006, the Monticello-St. Cloud 115 kV line will exceed acceptable limits for the same outage. Outage of the Benton County 115 kV double circuit can also cause excessive overloads by 2004.

B. Alternative Solutions

Two alternatives were developed to address this deficiency.

1. Hwy 10/I-94 Corridor Alternative #1: New 345/115 kV transmission source at the Sherco substation and rebuild the Twin Cities-St. Cloud 115 kV line

This alternative proposes construction of a new 345/115 kV transmission source at the Sherco substation in the far northwestern suburbs of Minneapolis and the reconstruction to increase the capacity of the 22 miles of existing 115 kV line between the Sherco substation, the Twin Cities, and the city of St Cloud. This project is needed to mitigate unacceptable transmission line loadings under transmission line outage conditions in both summer and winter peak loadings.

The main components of this plan include:

- New 115 kV tie to the Sherco substation with less than one mile of double circuit (795 ACSS) from the Monticello–Salida Crossing 115 kV line;
- New 345/115 kV 448 MVA transformer at the Sherco substation to tie in new 115kV line;
- Rebuild the Monticello–St Cloud 115 kV line to 795 ACSS (22 miles); and
- Bus work at St Cloud and Salida.

The cost of Alternative 1 is approximately $12.4 million.

2. State Hwy 10/1-94 Corridor Alternative #2: Second 345/230 kV transformer at Monticello

A viable alternative is adding a second 345/230 kV transformer at Monticello. However, as this was being studied, it was determined that the 115 kV line from Monticello to St. Cloud would still need to be upgraded to 795 aluminum conductor steel supported ("ACSS"), with additional need to reconductor the 230 kV line from Monticello-Benton County. This alternative has an estimated cost of $18,480,000.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

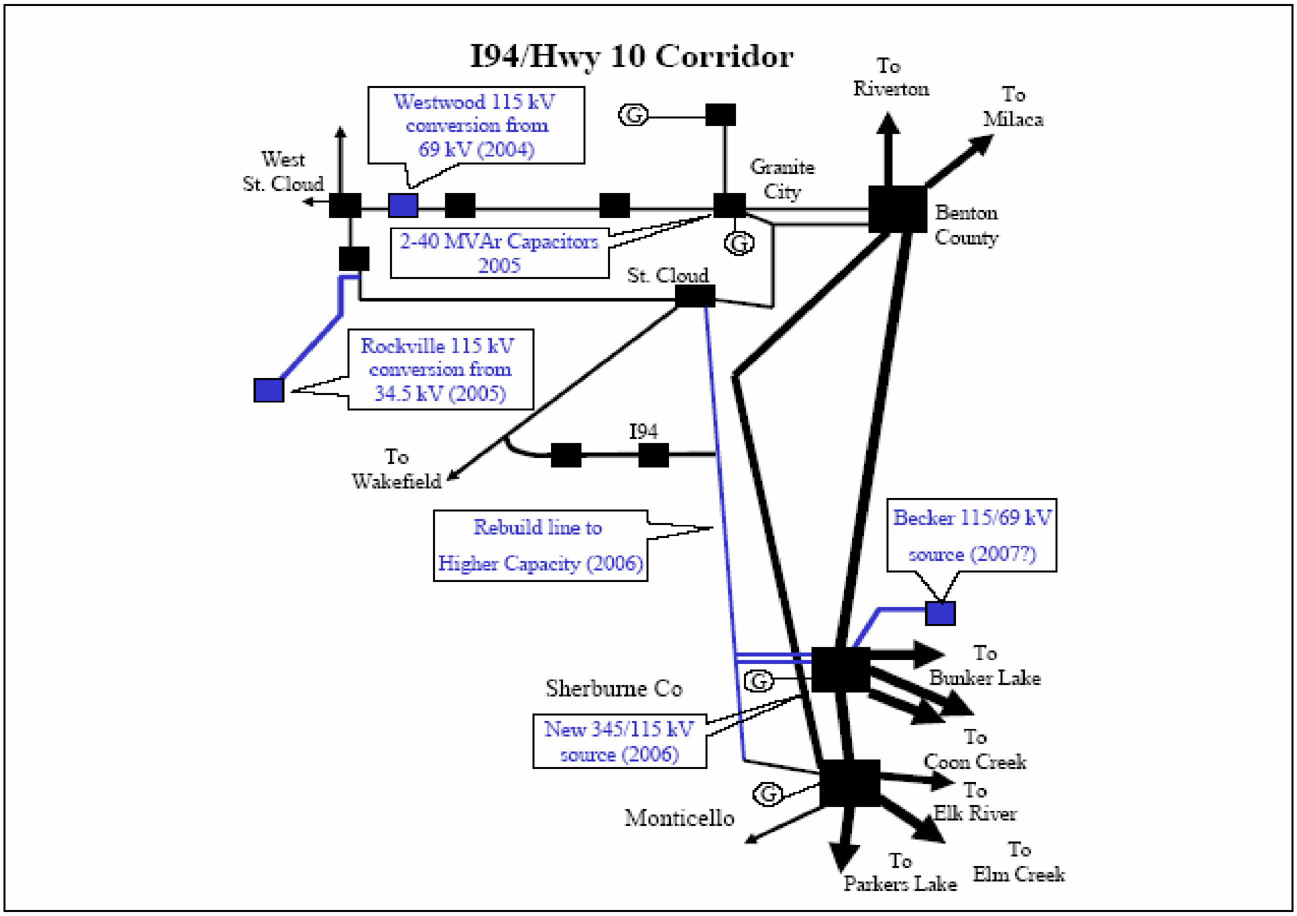
Alternative 1 would upgrade an existing 115 kV transmission line and use an existing substation to provide a new source. The expansion of the Sherco substation will occur on Xcel Energy property. Using existing facilities should have minimal environmental impact.

Alternative 2 also includes the expansion of an existing substation. The reconductoring of the two transmission lines should have minimal environmental impact. No major social issues have been identified for either option.

The cost of Alternative 1 is estimated at approximately $12.4 million. The cost of Alternative 2 is approximately $18 million.

D. Recommendation

The recommended plan is to construct a new 115 kV tie to the Sherco substation and to upgrade 22 miles of existing 115 kV lines from Monticello to St. Cloud. The estimated cost of this plan is approximately $6 million less than Alternative 2. This plan also provides a new 115 kV source near Salida Crossing near where GRE has identified the need for a new mid-system, 69 kV voltage source. (See the Elk River-Becker area for discussion on this need). Final decisions on this project are expected late this year. Any required PUC approval would be requested in a separate proceeding.



ST. CLOUD AREA

The St. Cloud area includes the city of St. Cloud and surrounding suburbs. The area is bounded by Benton County, Granite City, St. Regis, West St. Cloud to the west and Monticello, Paynesville and Sherco to the south.

The St. Cloud area load is served by the Xcel Energy transmission system. The primary source for the 115 kV loop is the Benton County 345/230/115 kV transformers. Alternate and much weaker sources are located at the St. Cloud and West St. Cloud substations.

The City of St. Cloud is continuing to experience load growth and the growth rate is expected to increase as farm land is converted to residential and light industrial uses. The 2001 load in the St. Cloud area was about 350 MVA.

A. Inadequacies

Outage of either of the Benton County 230/115 kV 187 MVA transformers results in excessive loading of the remaining transformer. These transformers also overload upon loss of the Monticello 230 kV or 115 kV sources, loss of any of the 345 kV lines from Sherco, loss of the Wakefield 115 kV source and loss of West St. Cloud-Little Falls 115kV line.

Outage of the Benton County-Granite City double circuit results in low voltages in and around St. Cloud and much of central Minnesota. This also results in unacceptable loading on the Monticello-St. Cloud, and St. Cloud-Sauk River-West St. Cloud 115 kV lines. The two Benton County 230/115 kV 187MVA transformers have been identified for loss of the Monticello 230 kV or 115 kV source, loss of any of the 345 kV lines from Sherco, loss of the Wakefield 115 kV source, and loss of the West St. Cloud-Little Falls 115kV.

A fundamental issue is that the entire St. Cloud area and much of central Minnesota relies on the single source of the Benton County substation and the single 115 kV double circuit line from Benton County. Total load exceeds the capability of the 115 kV loop to supply the area during a contingency. Within 10 years some form of additional bulk power supply will be needed into St. Cloud and central Minnesota.

Xcel Energy and GRE anticipate the need to perform a long term load serving study, within the next two to three years, of the transmission system in the St. Cloud Area along with a overall review of the transmission system in the West Central Planning Zone.

The short-term needs are addressed in the *2003 St. Cloud Short-Term Transmission Study*.

B. Alternative Solutions

The Benton County transformer loading issue is addressed by replacing the 230/115 kV 187 MVA transformers with 336 MVA transformers. This project is in the early stages of construction with a projected 2005 in-service date.

There are two relatively inexpensive, short-term alternatives for outage of the double-circuit 115 kV line from Benton County.

1. St. Cloud Area Alternative #1 (short-term): Capacitor Banks at Granite City

The first short-term alternative is the installation, in 2005, of two 40 MVAR capacitor banks at Granite City configured in such a way that the banks remains in service during the outage of the Benton County - Granite City 115 kV double circuit line. This assumes retention of the present operating procedure to start the Granite City generators before reenergizing the transmission source to the St. Regis substation.

2. St. Cloud Area Alternative #2 (short-term): New 115 kV line from Benton County to Granite City

The second and less expensive alternative is a new five-mile long 115 kV line from Benton County to Granite City. However, the only route is on the same 100-foot right-of-way as the existing double circuit. Any event likely to result in the outage of the double circuit would also likely result in the outage of the new line, reducing the reliability benefit of this alternative. However, the long-range usefulness of this line is unknown.

3. St. Cloud Area Alternative #3 (long-term): New High Voltage Transmission Source

The long-range plan is to bring a new high voltage transmission source into this area. The high voltage source has not yet been identified.

4. St. Cloud Area Alternative #4: Transformer upgrade

The transformer overload will be addressed by replacing the 230/115 kV, 187 MVA transformers with 336 MVA transformers in 2005.

C. Economic, Environmental and Social Issues Associated with Each Alternative

The cost of installing the two 40 MVAR capacitor banks at Granite City is approximately $2.5 million and the cost of the five mile long 115 kV line from Benton County to Granite City is also approximately $2.5 million. Installation of capacitor banks at Granite City will have minimal impact since the work will be located at an existing site. The new five-mile Benton County to Granite City 115 kV line could parallel an existing double circuit transmission line. However, there is limited right-of-way available and the construction and location of the line may be difficult.

D. Recommendation

Replacing the two Benton County 230/115 kV transformers with higher capacity is already under construction.

Given the almost identical project costs, the short-term recommendation for this subarea is to install two 40 MVAR capacitor banks at Granite City 115 kV in 2005. This is a less intrusive transmission line alternative and is the recommended choice. Also, the capacitors will likely have more value to the long-range transmission needs for the St. Cloud area than the parallel 115 kV line. Final decision to proceed is expected late 2003.

A long-term solution to serving the St. Cloud area still needs to be identified. A major regional study to address the long-range supply of both the city of St. Cloud and west central Minnesota is anticipated within the next couple of years.

HUTCHINSON-MCLEOD AREA

There are several transmission projects underway in the Hutchinson area as a result of the *West Central Minnesota Transmission Study* that was completed in September 1999. This study was a joint effort of GRE, HUC, SMMPA, WMU and Xcel Energy. This study was conducted to develop alternatives to correct the low voltages in the area during system normal and system contingency conditions. Reliability concerns, due to extremely long 69 kV lines, were also addressed in the study.

The following projects were recommended in the *West Central Minnesota Transmission Study*. The status of the projects (in-service date) is included in parenthesis.

- Litchfield 69 kV breaker additions (in-service);
- McLeod 230/115 kV substation (in-service);
- Hutchinson-McLeod 115 kV transmission line (in-service);
- Hutchinson 115/69 kV substation (in-service);
- Victor 69 kV breaker station (November 2003); and
- Big Swan-Hutchinson 115 kV line (June 2004).

A. Inadequacies

The completion of the projects mentioned above will correct the existing transmission system deficiencies: primarily the low voltage and overloads in the Hutchinson area with the Hutchinson generation off-line.

Outages of the new 115/69 kV transformer at the Hutchinson substation will still require that Hutchinson generation be run to prevent overloading of the Big Swan 115/69 kV, 47 MVA transformer during peak loading conditions. In 2006, the Big Swan transformer will load to 103% of rating for this outage; by 2011, the load goes up to 113% of rating. This is within criteria (maximum loading during contingency is 125% of rating) but if load in the area grows faster than projected, the loading of this transformer will be of concern.

Another long-term deficiency in this area will be low voltage (91.6%) at the Litchfield 69 kV bus beginning in 2006 summer (with Litchfield generation off-line).

B. Alternative Solutions

1. Hutchinson-McLeod Area Alternative #1: Hutchinson Generation

Outages of the new 115/69 kV transformer at the Hutchinson substation will still require that Hutchinson generation be run to prevent overloading of the Big Swan 115/69 kV, 47 MVA transformer during peak loading conditions. In 2006, the Big Swan transformer will load to 103% of rating for this outage; by 2011, the load goes up to 113% of rating. This is within criteria (125%) but if load in the area grows faster than projected, the loading of this transformer will be of concern. Operating the Hutchinson generation can alleviate this overload.

2. Hutchinson-McLeod Area Alternative #2: Litchfield Capacitor Bank, Big Swan to Litchfield 115 kV line

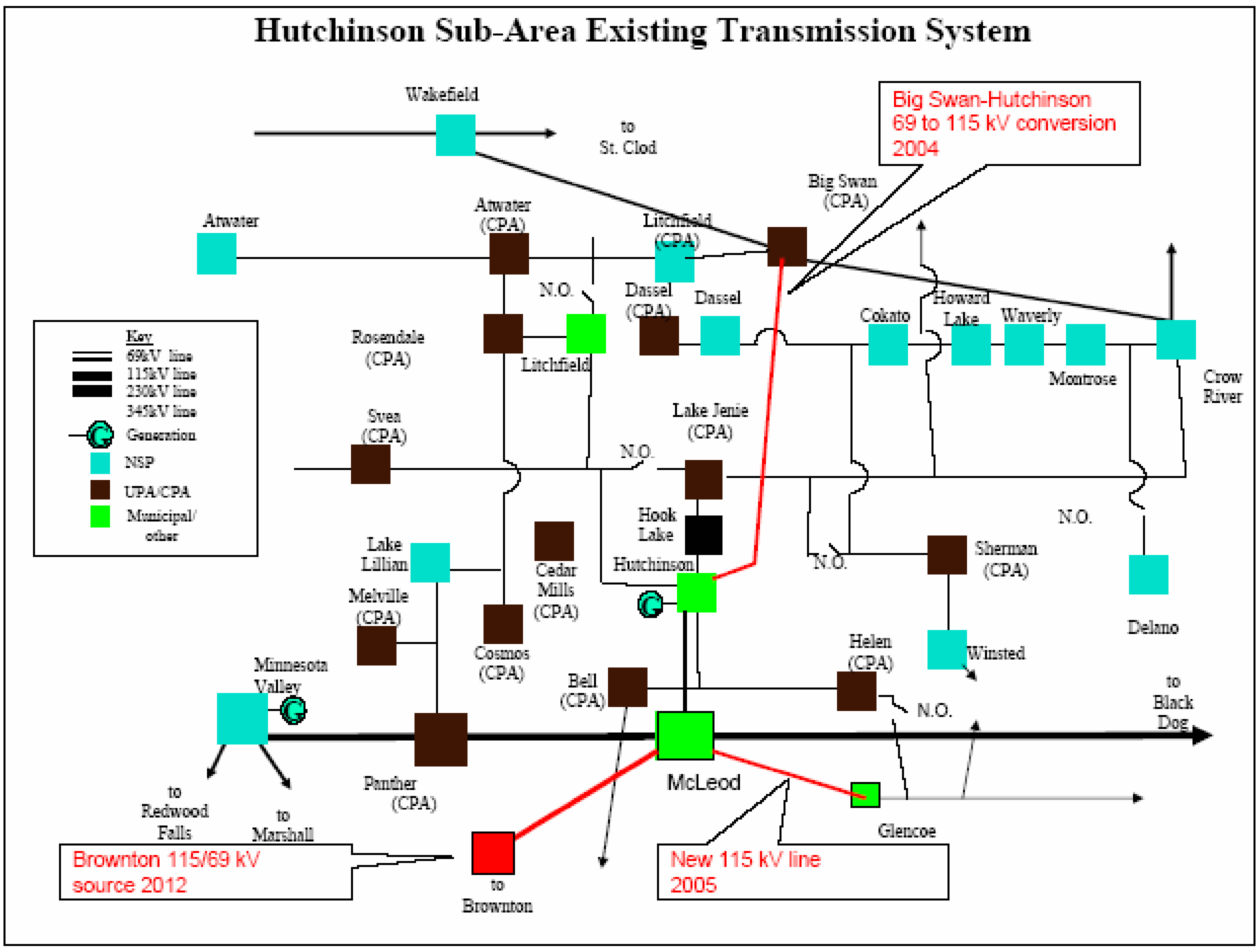
The low voltage (91.6%) deficiency at the Litchfield 69 kV bus, beginning in the summer of 2006 (with Litchfield generation off-line), can be addressed by adding a 7.2 MVAR capacitor bank at Litchfield, which will delay further transmission additions until the summer of 2013 when a new, second Big Swan-Litchfield 69 kV line is recommended. It is recommended that this new line be constructed at 115 kV to allow for the future option of converting the Litchfield load to 115 kV operation. These two projects will likely be constructed by SMMPA, which has the responsibility to supply the Litchfield load.

C. Economic, Environmental and Social Issues Associated with each Alternative

The environmental impacts of the above projects should be minimal since existing rights-of-way will be used. Environmental assessments will be made where appropriate and/or required. The continued availability of reliable electricity to the area in and around Hutchinson is essential to the continued social and economic development in the area.

D. Recommendation

Most of the projects described above are in-progress. The additional transmission line from Big Swan to Litchfield is planned to be in-service in 2013. Additional studies will be conducted prior to that time. These studies will analyze and compare the above proposed alternatives with any new alternatives that may be proposed.



ELK RIVER-BECKER AREA

This area is served by two 230/69 kV sources at Elk River and Benton County. The total mileage for the 69 kV transmission lines is 44 miles.

A. Inadequacies

Currently, the loss of either the Elk River source or the Benton County source causes overload problems in the area between Elk River and Benton County. In 2006, there are low voltages in the Big Lake and Becker area during the loss of the Elk River source. In addition, during the outage of the Lake Pulaski 115/69 kV transformer an emergency tie switch is closed to this system to support the Linn Street load. This causes strain on the 69 kV system between Elk River and Benton County.

B. Alternative Solutions

Three alternatives were developed as solutions to the problems that occur in this area with installation proposed for the 2006-2007 time period.

1. Elk River-Becker Area Alternative #1: 115/69 kV source at Becker

This option involves establishing a new 115/69 kV source at Becker to provide voltage support and loading relief to the 69 kV system during the contingency of either the Elk River or the Benton County sources.

2. Elk River-Becker Area Alternative #2: 115/69 kV source at Monticello

This option involves establishing a new 115/69 kV source at Monticello and building a 69 kV line from Monticello to Thompson Lake. The 115/69 kV source at Monticello will provide voltage support and loading relief to the 69 kV system during the contingency of either the Elk River or the Benton County sources. In addition, the Monticello source will connect to the Xcel 69 kV system to support the Linn Street area.

3. Elk River-Becker Area Alternative #3: 230/69 kV source at Thompson Lake

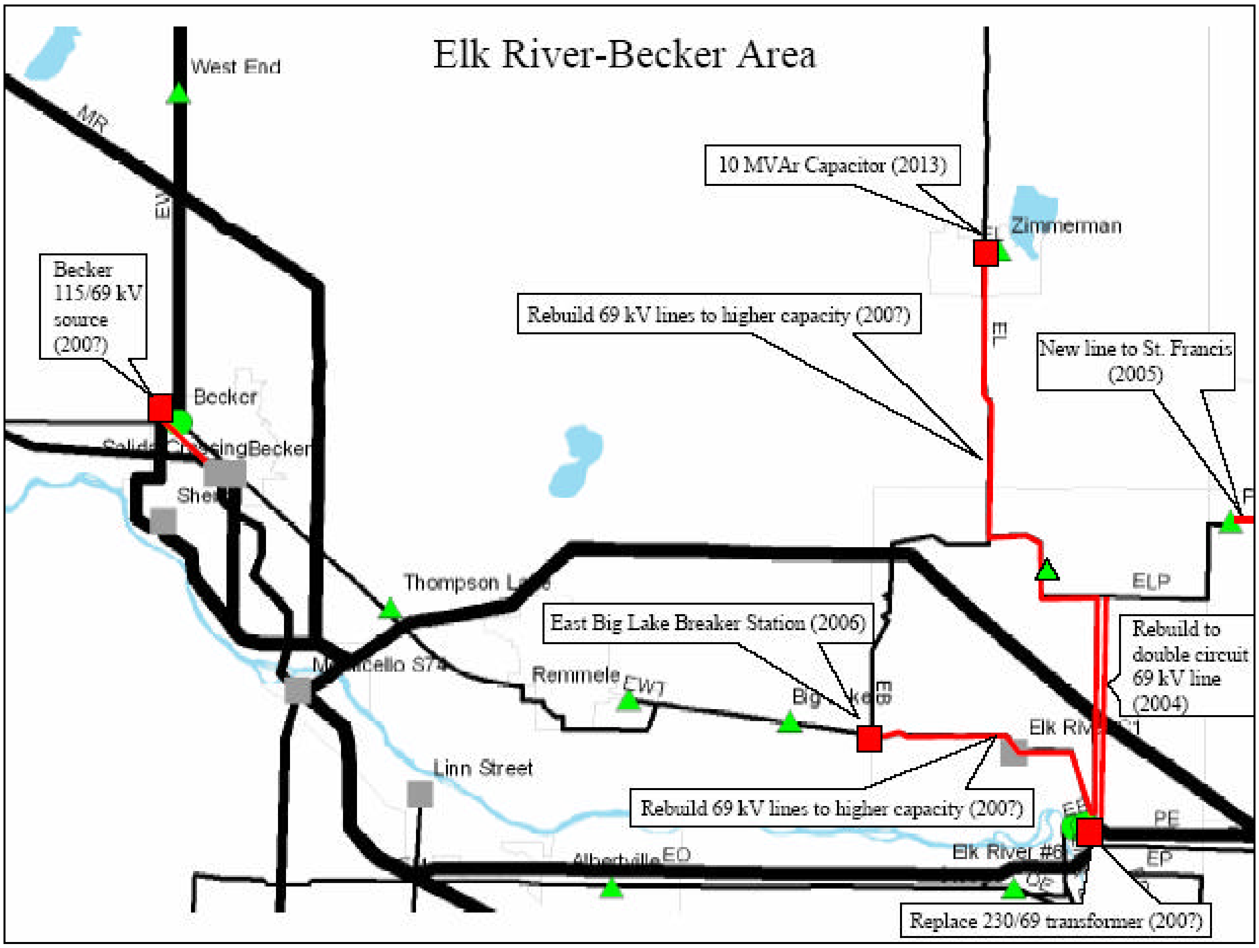
This option involves establishing a new 230/69 kV source at Thompson Lake in 2004. The 230/69 kV source at Thompson Lake will provide voltage support and loading relief to the 69 kV system during the contingency of either the Elk River or the Benton County sources.

C. Economic, Environmental and Social Issues Associated with Each Alternative

This area is presently under study. All three alternatives offer similar long-term solutions for this area. No adverse environmental impacts are expected with any of the three alternatives. This area is growing rapidly and the continued availability of reliable electric supply is important to the social and economic development of the area. GRE is also trying to coordinate its source needs with potential developments by Xcel Energy at Sherco and with future GRE distribution needs in the Becker Area.

D. Recommendation

GRE will continue to evaluate the feasibility of the above alternatives in order to bring forward a project that is appropriate for providing electric service to the area.



WILLMAR-PAYNESVILLE AREA

This area was included in the *West Central Minnesota Transmission Study* (September 1999), and the *GRE Long-Range Transmission Plan* (January 2003). An update to the *West Central Minnesota Transmission Study* is expected to start in 2004. Other studies, particularly generation outlet studies, also include analysis of this area within their scope. This is especially true for the study of wind generation additions on the Buffalo Ridge in southwest Minnesota.

The *West Central* Minnesota *Transmission Planning Study* (September 1999) recommended the conversion of the existing Paynesville-Willmar 115 kV line to 230 kV construction and operation. Construction of this project by Xcel Energy is presently underway. The purpose of this project is to improve the voltage support in the Paynesville area and reduce the loading on the Willmar 230/69 kV transformer.

Another project in this area is the reconductor of the Kerkhoven Tap-Willmar 115 kV line to meet the needs of the wind generation in the Southwest Planning Zone. For more information on this topic, see the section above discussing the Wind Generation Outlet.

A. Inadequacies

The GRE load in the Willmar area is served by a 69 kV loop, with both ends originating at the Willmar 230/69 kV substation. The worst loading and voltage conditions occur during the outage of either end of the loop. The following are some of the criteria violations that could have existed in 2001 had the contingency occurred during summer peak conditions. Although these are 69 kV problems (less that 100 kV) the solutions may involve future 115 kV transmission additions.

Bus/Line segment	Line rating (MVA) or Voltage criteria	Flow (MVA) Voltage (p.u.)	Contingency
Kandiyohi—Willmar 69 kV	13.3	19.6 (147%)	Sunburg—Willmar tap 69 kV
Sunburg—Willmar tap 69 kV	11.7	20.8(178%)	Kandiyohi—Willmar 69 kV
Willmar SW—Willmar tap 69 kV	13.3	29.8(224%) 17.2(130%)	Willmar—Willmar So 69 kV Kandiyohi—Willmar 69 kV
Kandiyohi 69 kV	0.92	0.888	Kandiyohi—Willmar 69 kV
Gravgaard 69 kV	0.92	0.903	Kandiyohi—Willmar 69 kV
Green Lake 69 kV	0.92	0.897	Kandiyohi—Willmar 69 kV

B. Alternative Solutions

The line overloads shown in the above table can be corrected by resagging the existing conductors to allow operation at higher operating temperatures. If resagging is not possible due to the design limitation or physical condition of the existing structures, consideration should be given to rebuild the lines with larger conductors and with a design spacing to allow for future operation at 115 kV.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

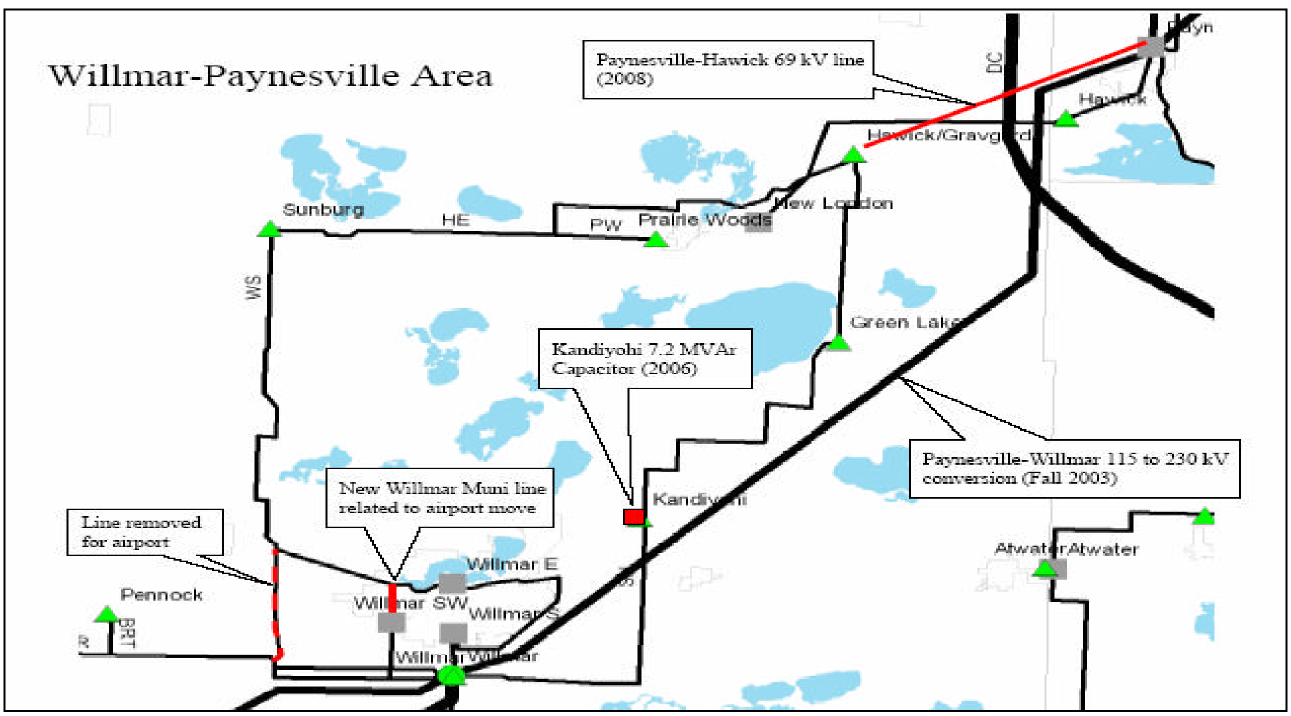
The following table contains a summary of the recommended projects for the Willmar area.

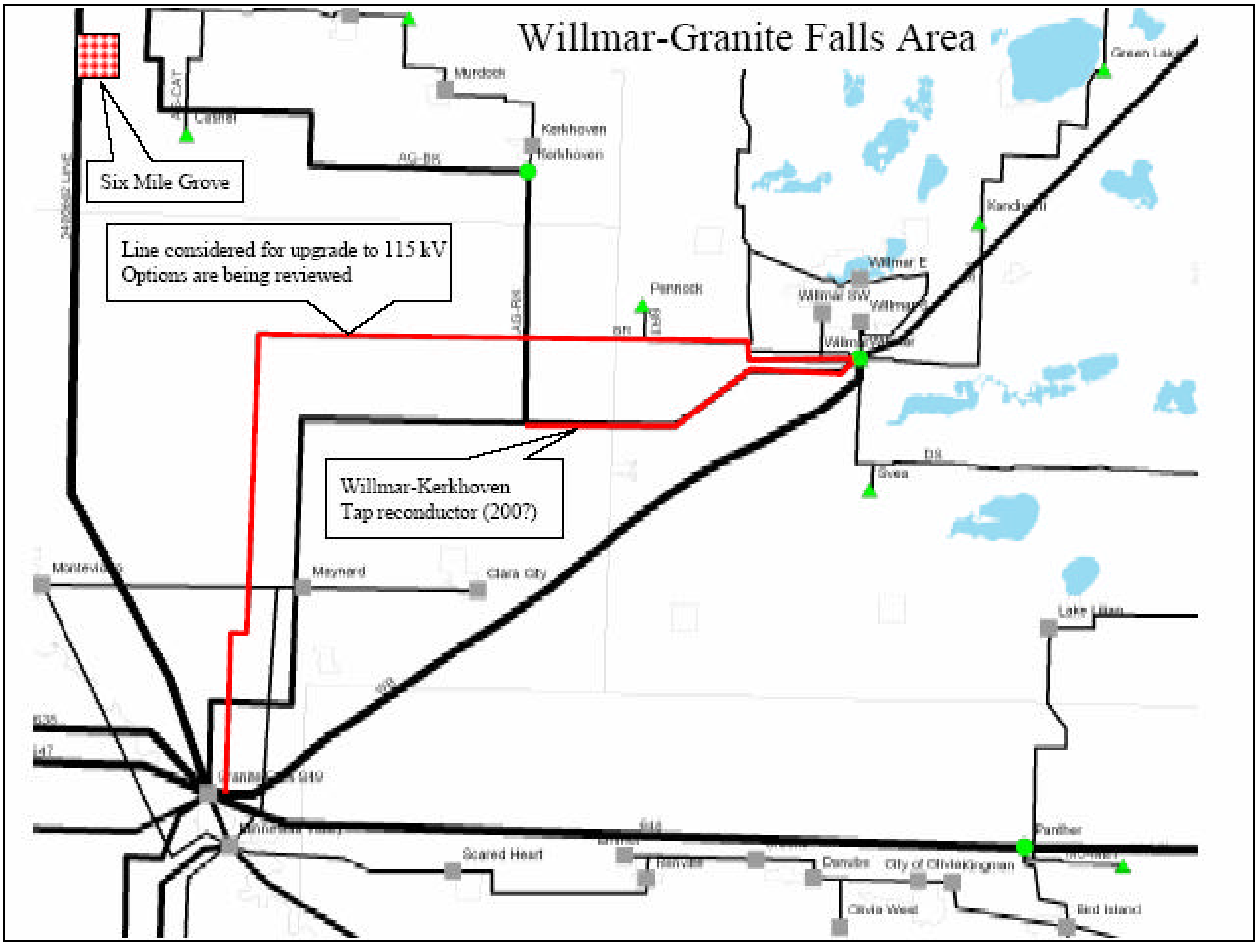
Year in-service	Project	Estimated Cost ($2002)
2003	Sunburg—Willmar: Upgrade 11.5 miles of 69 kV line	$ 230,000
2005	Kandiyohi—Willmar: Rebuild 9.9 miles of 69 kV line to 115 kV	$2,015,900
2005	Granite Falls—Willmar: Upgrade 43 miles of 69 kV line (consider rebuild to 115 kV)	$860,000
2006	Kandiyohi 7.2 MVAR, 69 kV capacitor bank	$100,000
2008	Hawick—Paynesville: Construct 18 miles of new 69 kV line	$3,516,000

The social and environmental impacts of these projects are expected to be minimal because existing transmission lines routes will be used; however, environmental impacts will be formally assessed when permits for the projects are requested.

D. Recommendation

The capability of the existing transmission lines will be determined through engineering surveys. If sufficient capacity is not available, utilities will look at constructing new transmission lines with higher capacities. Existing routes will be used wherever feasible.





PANTHER AREA

This area is located along the 230 kV transmission line from Minnesota Valley (Granite Falls) to the McLeod substation.

Xcel Energy plans to upgrade some of the existing transmission lines in this area to higher capacity due to the increased wind generation on the Buffalo Ridge and the increased load in this area. Also planned is a new 69 kV breaker station at the existing Troy tap to allow more flexibility in switching the transmission system to avoid overloads during contingencies and to provide better voltage support to the loads in the area around Olivia, Minnesota.

A. Inadequacies

This area is characterized by long 69 kV transmission lines from remote 115/69 kV sources with one 230/69 kV source (Panther) in the middle of the system. Although load growth in this area is slow, several relatively large spot loads are present near Danube and Olivia. During the loss of the Panther 230/69 kV source or one of the 69 kV lines emanating from Panther, bus low voltage and line overloads occur.

The following are typical of the deficiencies in this area that could be expected based on the 2001 summer peak conditions:

- The Crooks-Emmet 69 kV line is at 172% loading for the outage of the Bird Island-Kingman 69 kV line;
- The Olivia bus voltage drops to 62.1% for the outage of the Bird Island-Kingman 69 kV line;
- Brownton bus voltage drops to 88.2% for the outage of the Bird Island-Panther 69 kV line; and
- Hector bus voltage drops to 90.6% for the outage of the Panther 230/69 kV transformer.

B. Alternative Solutions

As mentioned, Xcel Energy plans to reconductor or rebuild the overloaded transmission lines and construct a new, 69 kV breaker station at the Troy tap. This new breaker station will provide voltage support to the Olivia bus by providing simultaneous connections from both the Franklin and Minnesota Valley 115/69 kV sources.

The remaining low voltages at Hector and Brownton can be corrected by the addition of a 7.2 MVAR capacitor bank at either the Hector or Buffalo Lake substations. In 2012, the voltage at Hector will again be marginally within criteria (92%). The recommendation is to add, in 2012, approximately nine miles of 115 kV line from Brownton to McLeod and to construct a 115/69 kV substation at Brownton. This will add a 69 kV source into the system closer to Panther and greatly improve the 69 kV voltage performance in the area.

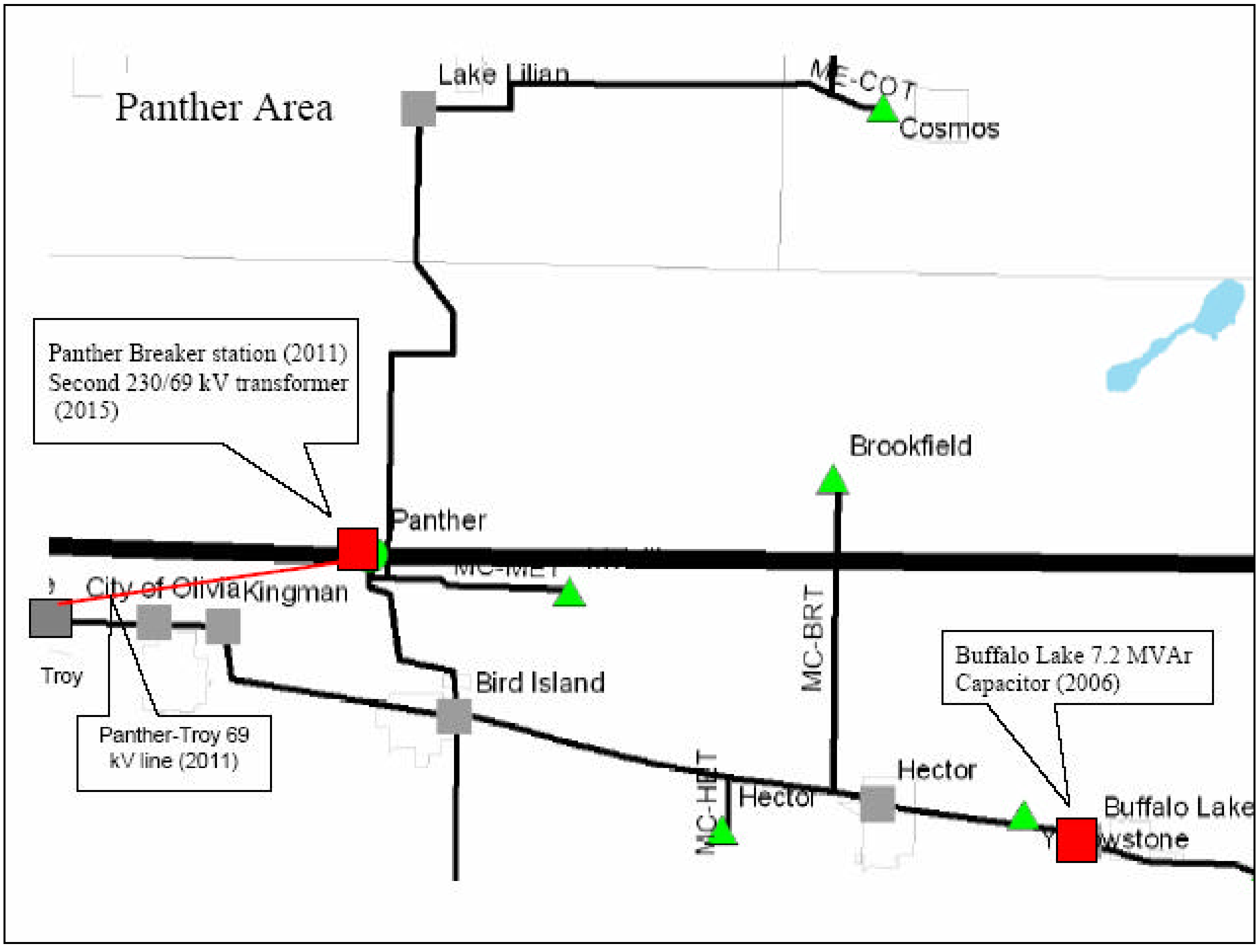
C. Economic, Environmental, and Social Issues Associated with Each Alternative

The capacitor additions and upgrades or rebuilds of existing lines will not have a significant impact due to the use of existing rights-of-way. The addition of the Brownton-McLeod 115 kV circuit will be reevaluated through additional transmission studies as the time for implementing the project gets closer.

D. Recommendation

The short term projects (capacitor additions and line rebuilds) should be implemented to alleviate the overload and voltage issues. Load growth in the area should be monitored and long-term alternatives should be restudied prior to implementing the addition of new transmission line rights-of-way.

Panther Area



DOUGLAS COUNTY - PAYNESVILLE - WAKEFIELD - WEST SAINT CLOUD AREA

This area is served by four 115/69 kV sources from Douglas County, Paynesville, Wakefield, and West St. Cloud. The total mileage for the 69 kV transmission line is 156 miles. There are 13 GRE distribution substations and 13 Xcel Energy distribution substations in this area. The following graph depicts the forecasted loads in MWs, in the area.

Season	2001	2006	2011	2026
Summer	102.3	123.8	136.5	193.7
Winter	97.0	116.8	128.6	179.6

A. Inadequacies

Currently, the Albany-Big Fish-Farming Tap 69 kV line overloads during system intact conditions. The Douglas County-Osakis line overloads during the outage of the Paynesville source. There are low voltages in the Black Oak area during the outage of either Douglas County or Paynesville sources. In 2005, the outage of the West St. Cloud transformer causes low voltages in the Albany area. There are severe low voltages and overload problems in the whole area during the outage of either source from Douglas County, Paynesville, Wakefield, and West St. Cloud in 2011.

B. Alternative Solutions

Two alternatives were developed as solutions to the long-range problems that occur in this area. Note that the short-term projects are common to all the options before 2011. The short-time projects include rebuilding the Albany-Big Fish-Farming Tap in 2003 and installing capacitor banks for voltage supports. The options are as follows:

1. Douglas County-Paynesville Alternative #1: 115 kV development

This alternative involves building a new 115 kV line from Alexandria to West St. Cloud. This option includes establishing a new 115/69 kV source at Albany and converting the Sauk Centre and the Melrose substations to 115 kV.

The following is the estimated timeline for Alternative 1 installations, assuming 115 kV development:

Estimated Year	Facilities	Cost
2001	Rebuild Albany - Big Fish - Farming Tap 69 kV line	$ 2,295,000
2003	Install 10 MVAR capacitor bank at Brockway Tap	$ 225,000
2004	Install 10 MVAR capacitor bank at Sauk Centre	$ 225,000
2005	Install 10 MVAR capacitor bank at Melrose	$ 225,000
2006	Rebuild Douglas Co. - Osakis 69 kV line	$ 153,000
2006	Install second 10 MVAR capacitor bank at Black Oak	$ 110,000
2011	115 kV, Alexandria—West St. Cloud	$20,200,000

2. Douglas County-Paynesville Alternative #2: 69 kV system improvement

This option involves improving the 69 kV system in the area. It includes establishing a new 115/69 kV source at St. Stephen and building three new 69 kV lines in the area.

The following is the estimated timeline for Alternative 2 installations:

Estimated Year	Facilities	Cost
2001	Rebuild Albany - Big Fish - Farming Tap 69 kV line	$2,295,000
2003	Install 10 M VAR capacitor bank at Brockway Tap	$ 225,000
2004	Install 10 MVAR capacitor bank at Sauk Centre	$ 225,000
2005	Install 10 MVAR capacitor bank at Melrose	$ 225,000
2006	Rebuild Douglas Co. - Osakis 69 kV line	$ 153,000
2006	Install second 10 MVA R capacitor bank at Black Oak	$ 110,000
2011	Establishing a 115/69 kV source at St. Stephen	$1,850,000
2011	Rebuild Osakis -Black Oak 69 kV line	$3,519,000
2011	Rebuild Black Oak - Albany 69 kV line	$2,601,000

Estimated Year	Facilities	Cost
2011	Rebuild Albany - St Stephen 69 kV line	$2,601,000
2011	Build Westport - Sauk Centre 69 kV line	$3,370,000
2013	Build Roscoe - Melrose 69 kV line	$3,980,000
2015	Build Bangor - Black Oak 69 kV line	$3,530,000

C. Economic, Environmental, and Social Issues Associated with Each Alternative

A cost analysis was performed on each alternative, with line losses evaluated for Douglas County-Paynesville-Wakefield-West St. Cloud area with Alternative 2 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Alternative	2006 Summer	2011 Summer	2026 Summer
1	-	0.74	1.41

For the loss allocations, the present worth is summarized as follows (in $1,000s):

Alternative	Cumulative Investment	Present Worth	Present Worth Loss Savings
1	$32,137	$43,961	$41,804
2	$33,952	$43,222	NA

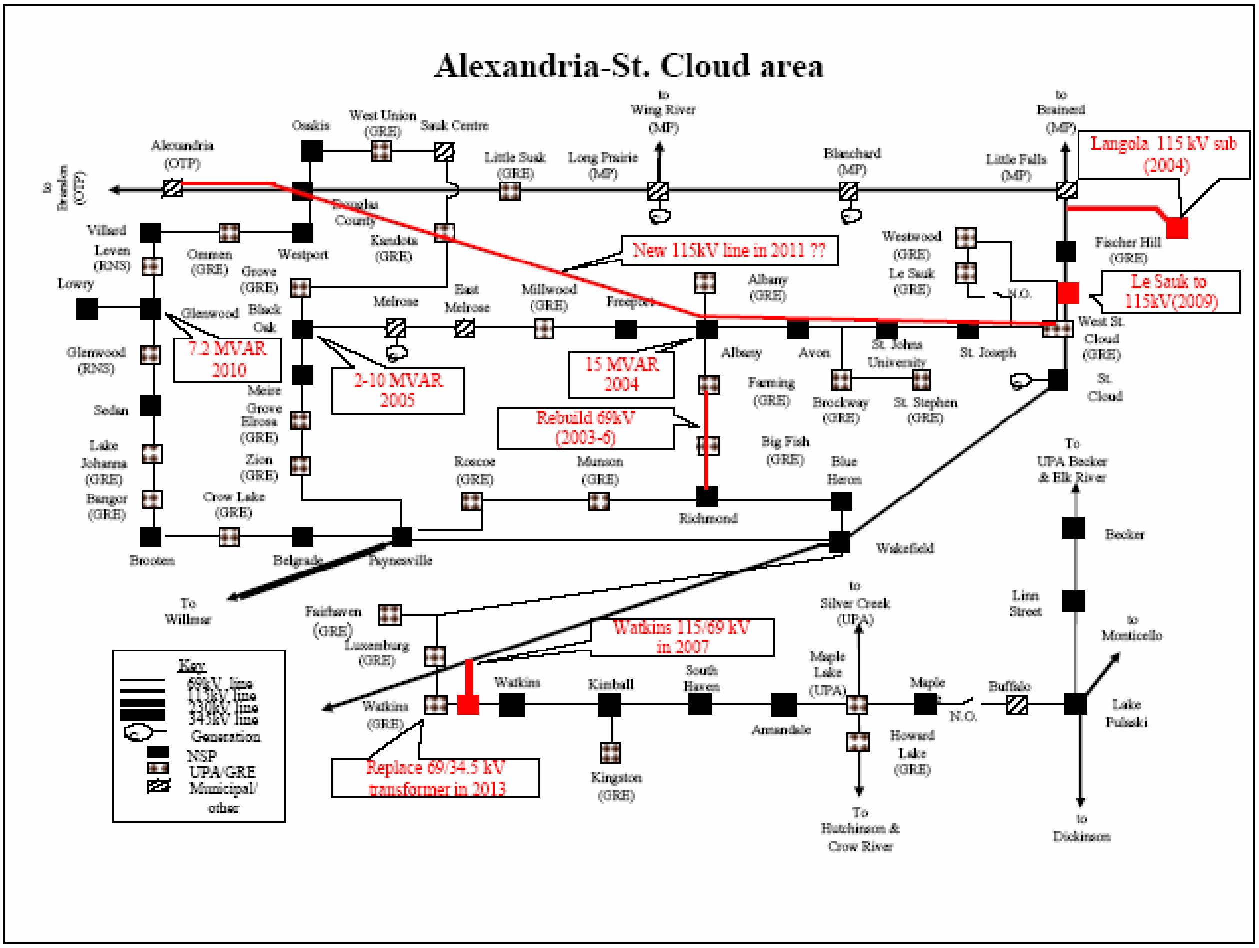
Alternative 1 is the least cost plan and involves the least amount of total investment.

Alternative 1 offers a long-term solution, as it provides potential sources for future load growth along I-94. Alternative 2 is only capable of serving this area if the load growth rate is low.

No environmental assessment has yet been made of the above alternatives.

D. Recommendation

Due to the significant commercial and residential development along the I-94 corridor between Alexandria and St. Cloud, this area needs further study to determine the appropriate expansion of the transmission system required to provide continued reliable electric service to the area.



WEST ST. CLOUD AREA

This area was studied during the preparation of the *GRE Long-Range Transmission Plan* (January 2003).

A. Inadequacies

The loss of the Wakefield source causes the West St. Cloud 115/69 kV transformer to overload in 2004. The loss of the West St. Cloud transformer causes low voltages in the area in 2004 and the Wakefield-Blue Heron line 69 kV to overload in 2006. The loss of the Douglas County 69 kV source causes the West St. Cloud transformer to overload in 2009.

B. Alternative Solutions

The recommended alternative to the overloading of the West St. Cloud 115/69 kV transformer is to convert the Le Sauk and Westwood loads to 115 kV in the years shown below. In the case of the Le Sauk substation load, it will require some reconstruction of the existing 69 kV line to 115 kV design standards.

Estimated Year	Facilities	Cost
2004	Convert the Westwood load to 115 kV	$620,000
2009	Convert the Le Sauk load to 115 kV	$620,000

C. Economic, Environmental, and Social Issues Associated with Each Alternative

No environmental or social issues have yet been evaluated. The impacts for converting the substations to 115 kV will be minimal due to use of existing substation sites and transmission line routes.

D. Recommendation

All new loads in the area should be connected to the 115 kV transmission system, if possible. Continued conversion of the existing loads to 115 kV is also highly recommended to avoid upgrading the existing 115/69 kV West St. Cloud transmission substation.

GRANT COUNTY-ALEXANDRIA RECONDUCTOR PROJECT

The Grant County-Alexandria 115 kV transmission line is located in West Central Minnesota from Elbow Lake to Alexandria. This line has a rating of 96.4 MVA and provides service to the 41.6 kV Alexandria Receiving, Brandon, and Elbow Lake substations.

A. Inadequacies

The Grant County-Elbow Lake section of the 115 kV line will overload with the outage of the Fergus-Henning 230 kV line. In studies conducted by MRES, the remainder of the line was also approaching thermal and clearance limitations. The entire 35.6-mile transmission line will need to be upgraded due to load growth in the area.

The overload of this line was identified in a number of regional studies including the *Buffalo Ridge 425 MW Outlet Study, the FibroMinn Interconnection Study, Griggs-Steele Wind Project, and Red River Valley-West Central Minnesota Transmission Improvement Plan Study (TIPS).* Additional studies conducted by MRES identified the remainder of the line as also approaching thermal and clearance limitations.

B. Alternative Solutions

The recommended alternative is to replace the existing 266 ACSR conductor with 795 ACSS conductor. The shield wire will also need to be replaced due to rusting. The substations along the route will be upgraded to accommodate the higher line rating of the new conductor. The rating of the line after the upgrade is anticipated to be 170 MVA. With additional improvements such as breaker replacement and raising structures to mitigate clearance violations, the transmission line can be rated up to 270 MVA. The project started in August 2003 and is expected to be completed in December 2003.

Additional options were studied, but the short-term nature of the solutions were uneconomical. Generation was also studied, but the economics of generation was not acceptable as a long-term solution.

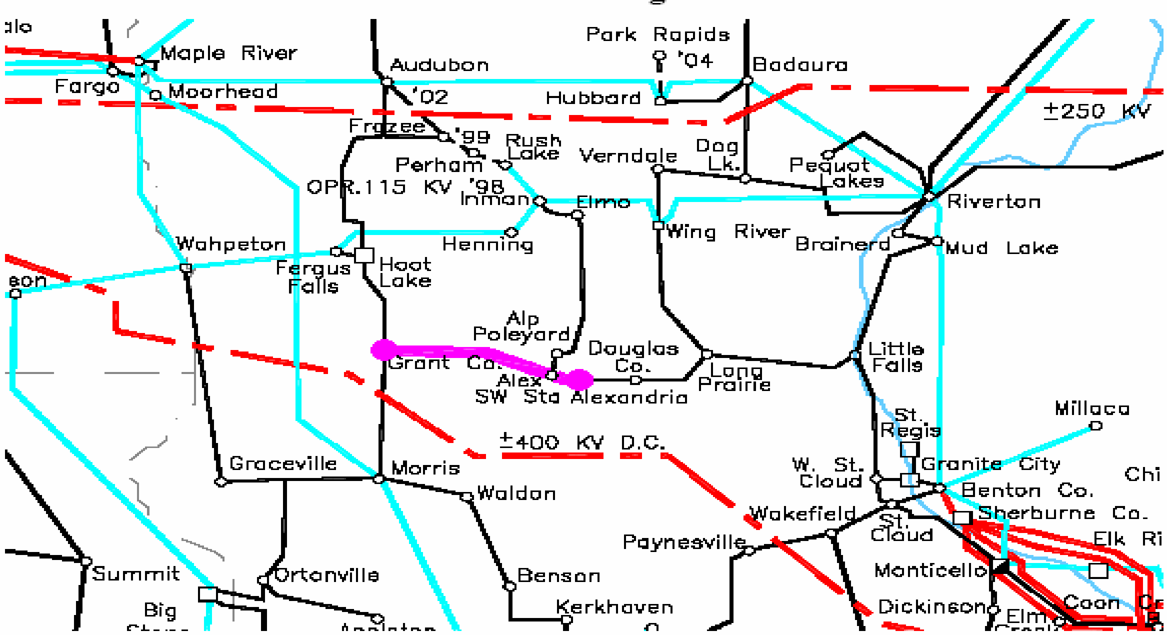
C. Economic, Environmental, and Social Issues Associated with Each Alternative

The cost of the reconductor project is estimated to be about $3,000,000. The reconductor cost is about half of the cost for a completed rebuild. The social and environmental impact of the project will be minimal since the line already exists and existing structures and right of way will be used. There will be minimal crop damage during construction and landowners will be reimbursed for any crop or land damage incurred.

D. Recommendation

MRES is replacing the existing 266 ACSR conductor with a 795 ACSS conductor. The shield wire will also be replaced due to rusting. The substations along the route will also have upgrades made to accommodate the higher line rating of the new conductor. The rating of the line after the upgrade is anticipated to 170 MVA. With additional improvements such as breaker replacement and raising structures of mitigate clearance violations, the transmission line can be rated up to 270 MVA.

Grant Co to Alexandria Receiving Substation Reconductor



ROCKVILLE AREA

This area was studied during the preparation of the *GRE Long-range Transmission Plan* (January 2003).

A. <u>Inadequacies</u>

The Rockville substation has experienced poor reliability performance in the past five years. The five-year average outage duration for this substation is 2.15 hours per year compared to GRE's 0.95 hours per year five-year average. In the first six months of 2002, the substation sustained four outages with a total outage of 2.4 hours for this substation.

B. <u>Alternative Solutions</u>

To improve the reliability for this substation, one alternative was developed as a solution to the long-range problems that occur in this area.

1. Rockville Area Alternative #1: 115 kV load conversion

This alternative involves converting the Rockville load to 115 kV by constructing approximately five miles of new 115 kV transmission line from the Rockville substation to the Sauk River substation. The 115 kV system will provide better reliability and greater capacity for future load growth.

C. <u>Economic, Environmental, and Social Issues Associated with Alternative Solution</u>

No environmental or social issues have yet been evaluated. The impacts for converting the substation to 115 kV are expected to be small due to use of existing substation sites and short-length transmission line routes.

D. <u>Recommendation</u>

Conversion of the Rockville load to 115 kV operation is recommended to improve the reliability of the transmission service to the existing load.

APPLETON-CANBY REBUILD

An Appleton-Canby area load serving study is presently in the process of being completed by Otter Tail Power Company.

A. <u>Inadequacies</u>

Load growth in the Appleton-Canby area has caused electrical facilities in this area to exceed allowable capacity. Under existing loading conditions, the Canby 115/41.6 kV transformer becomes overloaded during critical contingency situations. Fans have already been added to the existing transformer to fully maximize its thermal capacity. Continued load growth is expected in the city of Dawson, further supporting the need for upgraded electrical infrastructure. Depressed voltages are also a concern for the Dawson substation.

B. Alternative Solutions

The primary alternative for addressing the Appleton-Canby area is the upgrade of an existing 41.6 kV line from Appleton to Canby to 115 kV. This line serves the loads of Dawson, Lac Qui Parle, and Louisburg. To solve the identified system inadequacy, the existing 41.6 kV line will be upgraded to 115 kV. The existing 41.6 kV line between Canby and Dawson (21.3 miles) is already built to 115 kV standards. This consists of approximately one-half of the total line length. The existing Dawson-Appleton 41.6 kV line will need to be rebuilt to 115 kV standards. Once the line is upgraded to 115 kV, system reliability will increase. This is a result of adding shield wire to the new line. Shield wire protects against lightening related disturbances. The upgrade of the 115 kV line results in the following system benefits:

- Eliminates overload of the Canby 115/41.6 kV transformer;
- Improves the voltage profile at Dawson;
- Increases system reliability;
- Provides backup transmission service to Appleton; and
- Decreases system losses.

There were no other practical alternatives examined or available to solve this system inadequacy. Capacitors have already been placed in the Dawson substation to improve the voltage profile. Furthermore, fans have been added to the Canby 115/41.6 kV transformer to maximize thermal capacity.

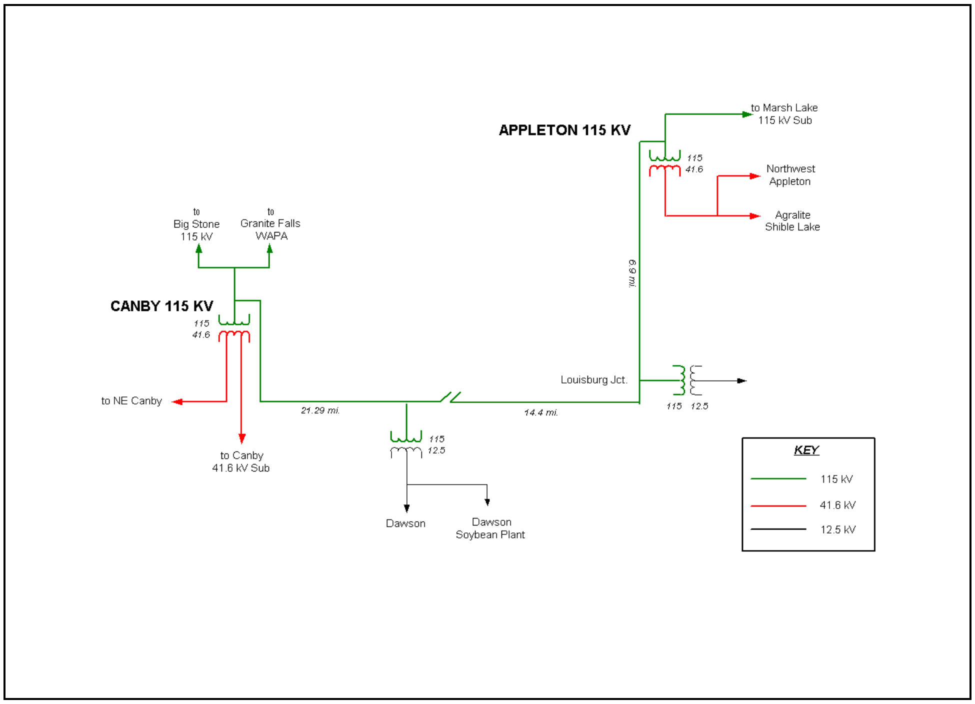
C. Economic, Environmental, and Social Issues

The cost of the project is estimated at $2,000,000. The recommended upgrade of the 41.6 kV line to 115 kV should have relatively little environmental or social impact. The upgraded line will follow existing line right-of-way and be on single-pole structures, similar to the existing line. Upgrading the line will result in a positive economic impact in the form of reduced system losses.

D. Recommendation

The recommended plan to solve the system inadequacy in the Appleton-Canby area is to upgrade the existing 41.6 kV line from Appleton to Canby to 115 kV.

Appleton-Canby Area



IV. Other Zone-Specific Issues

System inadequacies and growing transmission system loading in the Red River Valley and western Minnesota can impact the entire regional transmission system, including the West Central Planning Zone. These issues are being studied by the area utilities through the Northern MAPP Subregional Planning Group. This study, called the *Red River Valley-West Central Minnesota Transmission Improvement Planning Study*, or TIPS, has been broken down into three different phases. These phases include a base improvement plan, a wires study, and a generation alternatives study. The initial phase of the study, the base improvement plan, has been completed. The wires and generation portions of the study will begin in 2004. A more complete discussion of the TIPS study can be found in the Northwest Planning Zone section of this report.

Some of the alternative projects for the West Central Planning Zone that have been suggested in the TIPS study are:

- 345 kV line from Fargo to Morris to Granite Falls to Blue Lake (Twin Cities);
- 345 kV line from Benton County (St. Cloud) to Alexandria to Maple River (Fargo); and
- 345 kV line from Watertown to Granite Falls to Blue Lake.

V. Studies in the West Central Planning Zone

The following studies pertinent to the wind generation outlet issue have been completed:

- *Plan 1H, In the matter of the application of NSP D/B/A as Xcel Energy for Certificate of Need for four large High Voltage Transmission line projects in southwestern Minnesota"* (Docket No. E002/CN-01-1958);
- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission outlet Analysis for Southwest Minnesota* (Buffalo Ridge Area) *Generation Additions* (0-400 MW beyond initial 425 MW) *Volume 1 and 2* (November 13, 2001); and
- *Preliminary results of an interconnection study for 36-130 MW of wind generation near Chanarambie, Minnesota* (January 11, 2001).

A study of the next stage transmission wind generation outlet from southwest Minnesota is planned. Details of the study scope are not yet developed.

Other studies in the West Central Planning Zone include:

- *Glencoe Area Load Serving Transmission Study* (June 2002);
- *Preliminary Steady State Results of an Interconnect Study for 120 Megawatts of Additional Generation in Sherburne County, Minnesota* (February 24, 2003);
- *2003 St. Cloud Short-Term Transmission Stu*dy;
- *West Central Minnesota Transmission Stu*dy (September 1999);
- *GRE Long-Range Transmission Plan* (January 2003);
- *Buffalo Ridge 425 MW Outlet Study*;
- *FibroMinn Interconnection Study*;
- *Griggs-Steele Wind Project*; and
- *Red River Valley-West Central Minnesota Transmission Study* (TIPS).

Twin Cities Transmission Planning Zone

I. Introduction

The Twin Cities Planning Zone comprises the Twin Cities metropolitan area. It includes the counties of Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott and Washington.

Twin Cities Transmission Planning Zone

A land use map is located in Appendix IX**.** The Twin Cities Planning Zone has a wide variety of land uses: agricultural, commercial, industrial, and residential. Approximately 2.7 millions of people live and work in this zone.

Primary population centers in this zone are Bloomington, Minneapolis, St. Paul, and the surrounding suburbs. Primary users of the zone's transmission system are commercial, industrial and residential customers.

The transmission system in the Twin Cities Planning Zone is characterized by a 345 kV double circuit loop around the core Twin Cities and first tier suburbs. This loop also incorporates major generation plant outlet from the Sherburne County and Monticello plants in the northwest, the A.S. King plant to the east, the Prairie Island and Inver Hills plants to the southeast, and the Blue Lake plant to the southwest. In addition, there are bulk transmission facilities dedicated to bringing remote generation to the Twin Cities. The GRE DC line and 345 kV circuits tie into the northwest side of the 345 kV loop and are dedicated to bringing generation to Twin Cities and

Minnesota loads. Tie lines extend from the 345 kV loop to three 345 kV lines: one to eastern Wisconsin, one to southeast Iowa and one to southwest Iowa. The other tie is the Xcel Energy 500 kV line from Canada that is tied into the northeast side of the 345 kV loop.

Transmission service to the distribution substations internal to the 345 kV loop is via a high capacity, 115 kV transmission network. External to the 345 kV loop, the transmission system is characterized by a number of 115 kV lines extending outward from the Twin Cities bulk supply with much of the local load serving accomplished via lower capacity, 69 kV transmission lines.

Major generating plants are interconnected to the 345 kV transmission loop at the Sherburne County generating plant and the Monticello generating plant in the northwest, the A.S. King plant in the northeast and Prairie Island in the southeast. On the 115 kV transmission system in the Twin Cities Planning Zone there are three intermediate generating plants: Riverside (located in northeast Minneapolis), High Bridge (located in downtown St. Paul), and Black Dog (located in north Burnsville). There are also two peaking generating plants, Blue Lake and Inver Hills, interconnected on the southeast and the southwest, respectively.

A map showing the 100 kV and above transmission facilities located in Minnesota is located in Appendix VII. This map also identifies the Twin Cities Planning Zone and the other state Transmission Planning Zones.

II. Utility Contacts and Regional Transmission Organization Participation

GRE and Xcel Energy are the utilities which own transmission lines (115 kV and above) in the Twin Cities Planning Zone. Contact information for these utilities can be found in Appendix I.

The MISO is a FERC recognized RTO. MISO provides non-discriminatory, open access transmission service and serves as the regional hub for the flow of electric energy in a 15-state area, including Minnesota. More information on MISO and its role can be found in the first section of this Report. In order to insure continued reliability of the regional transmission system and continued access to competitive electric energy, MISO has developed a regional transmission expansion plan. A copy of this plan, *The Midwest ISO Transmission Expansion Plan – 2003 (MTEP-03)* can be found on the MISO web site (www.midwestiso.org/plan_inter/expansion.shtml). GRE and Xcel Energy are both MISO members. The *2003 Minnesota Biennial Transmission Projects Report* here includes updates to the MTEP-03 that are in the process of getting incorporated in the MISO update to the MISO Transmission Expansion Plan.

GRE and Xcel also participate in MAPP, a regional transmission reliability group. MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the most recent *Regional Load and Capability Report* can be found on the MAPP web site, at www.mapp.org. More information on MAPP can also be found in the first section of this Report.

The *2003 Minnesota Biennial Transmission Project Report* includes updates to the *MAPP 2002 Regional Plan* that will be incorporated into the 2003 update to the MAPP Regional Plan. A copy of the *MAPP 2002 Regional Plan* can be obtained directly from MAPP (see Appendix I for contact information).

III. Transmission System Inadequacies and Alternative Solutions

This section provides information on the transmission system inadequacies that have been identified in the Twin Cities Planning Zone over the next ten years. It also provides information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental and social issues associated with each alternative.

CARVER COUNTY–WACONIA AREA

The Carver County-Waconia Area is bounded by Delano on the northeast, the Carver County substation on the southeast, Glencoe on the southwest, and Lester Prairie on the northwest. It includes the cities of Glencoe, Waconia, Watertown, Young America, and several smaller communities. These communities are on the fringe of the metropolitan area and contain some light industry. It is recognized that rapid load growth could continue to develop in this area, as has been observed in other similarly situated communities on the fringe of the Twin Cities metropolitan area.

The Carver County-Waconia area load is served from 69 kV transmission lines that are supplied by two 115-69 kV, 70 MVA transformers, one at the St. Bonifacius substation and one at Carver County substation. Glencoe Municipal Utilities, GRE, and Xcel Energy have distribution substations on the 69 kV transmission lines in this area.

In June, 2002, a *Glencoe Area Load Serving Transmission Study* was completed. This study included a portion of the Twin Cities Planning Zone. The results of the study are included in the discussion below.

A. <u>Inadequacies</u>

At present, the outage of the Carver County to Glencoe 69 kV line requires switching the Lester Prairie and Plato loads to their alternate source and serving the Glencoe load with local municipal generation.

By 2003, outage of the Dickinson to St. Bonifacius 115 kV line results in violations of voltage criteria on some of the 115 kV and 69 kV busses in the area. Outage of the St. Bonifacius to West Waconia 115 kV line causes the St. Bonifacius 115/69 kV transformer to overload (2008). Outage of the St. Bonifacius to Waconia 69 kV line also results in greater than 115% loading of the Carver County 115/69 kV transformer (2000) and the 115 kV West Waconia to St. Bonifacius line loading up to greater than 110% of rating.

Outage of the 115/69 kV transformer at St. Bonifacius transfers much of the 69 kV load in the area to the Carver County 115/69 kV transformer. Presently this results in loadings that exceed planning guidelines (no more than 115% loading on transformers during a contingency). Outage of the 115/69 kV transformer at St. Bonifacius causes overloads of Young America to Carver County 69 kV and low voltages on the 69 kV busses at Watertown and Delano. Likewise, the outage of the 115/69 kV transformer at Carver County results in the St. Bonifacius 115/69 kV transformer being loaded greater than 115% and low voltage (less than 90%) at Glencoe, High Island, Lester Prairie, and Plato.

B. Alternative Solutions

Three alternatives were developed for the McLeod-Waconia area.

1. Carver County – Waconia Area Alternative #1: New 115 kV Line from McLeod to Glencoe

The first alternative involves building a new 115 kV line from Glencoe to McLeod in the mid 2000's, along with a second Carver County 115/69 kV transformer and a capacitor on the West Waconia 115 kV bus. The long-range strategy is to extend the 115 kV line to the east (assumed for study purposes to West Waconia) from Glencoe to West Waconia.

Alternative 1 consists of the following transmission components:

- Second 115/69 kV 70 MVA transformer at Carver County in 2004;
- Install a 30 MVAR capacitor bank at West Waconia in 2004;
- 9.9 miles of new 115 kV from McLeod-Glencoe in 2005;
- Second 115/69 kV 70 MVA transformer at Carver County in 2004;
- Install a 30 MVAR capacitor bank at West Waconia in 2004;
- Rebuild 6.9 miles of the Young America Tap-Glencoe Tap 69 kV to 115 KV in 2008;
- Rebuild 1 mile of the Carver County-Young America at 69 kV in 2008;
- Install a second 30 MVAR capacitor bank at West Waconia in 2010; and
- Install a 10 MVAR capacitor at Watertown 69 kV in 2010.

2. Carver County – Waconia Area Alternative #2: New second 69 kV Line from Carver County to Glencoe

The second alternative is a second 69 kV line from Carver County along with the second Carver County 115/69 kV transformer and a capacitor on the West Waconia 115 kV bus.

Alternative 2 consists of the following transmission components:

- Second 17.1 miles 69 kV from Carver County-Glencoe in 2005;
- Second 115/69 kV of the 70 MVA transformer at Carver County in 2004;
- Install 30 MVAR capacitor bank at West Waconia in 2004;
- Second 115/69 kV of the 70 MVA transformer at St. Bonifacius in 2004;
- Rebuild 6.9 miles of the Young America Tap-Glencoe Tap #1 at 69 kV in 2008;

- Install second 30 MVAR capacitor bank at West Waconia in 2010;
- Rebuild 1 mile of the Carver County-Young America line at 69 kV in 2008; and
- Install a 10 MVAR capacitor at Watertown 69 kV in 2010.

3. Carver County – Waconia Area Alternative #3: Second 69 kV Line from Glencoe to St. Bonifacius

The third alternative establishes a second 69 kV source to Glencoe from St. Bonifacius via New Germany. A new 69 kV line would be built from New Germany to Glencoe. The line from New Germany Tap to Plato would be operated normally open. Glencoe would have two simultaneous sources: one from St. Bonifacius and one from Carver County.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

Summary of Plan Economics

Description of Alternative	Base Cost	2003 NPV[22]
Alternative 1: 115 kV Glencoe—McLeod	$10,925,000	$9,300,000
Alternative 2: 2nd 69 kV Carver County-Glencoe	$9,940,000	$8,400,000
Alternative 3: 2nd 69 kV Glencoe—St. Bonifacius-Glencoe	$11,650,000	$10,000,000

Alternative 1 includes improvements to existing substations in addition to the new 9.9 mile, Glencoe to McLeod 115 kV transmission line. The Glencoe Light and Power Commission has applied for local approvals for the new transmission line. Alternatives 2 and 3 also require the construction of new transmission line. There are corridor sharing opportunities for all the options including existing transmission lines and roads. No major social issues have been identified.

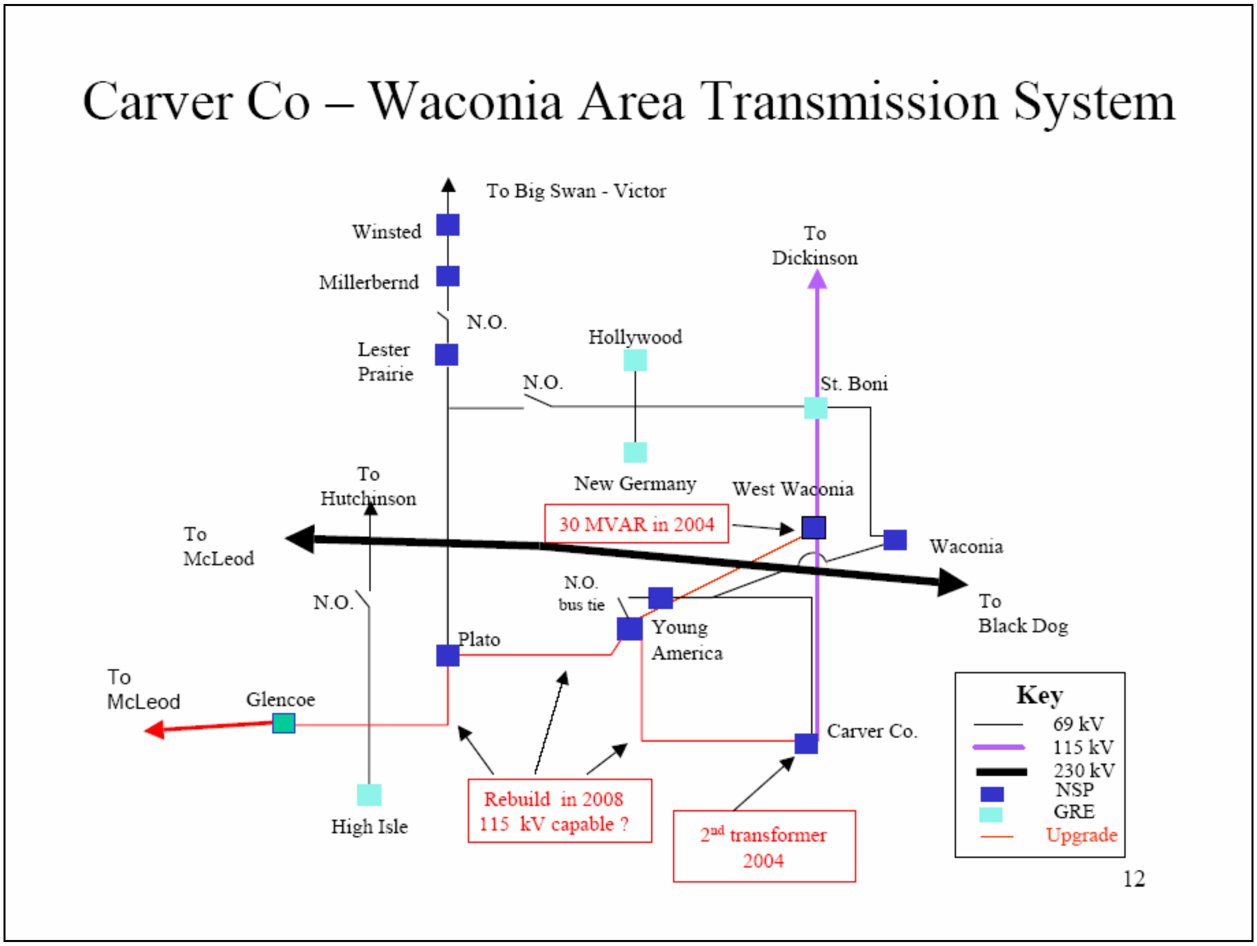
D. Recommendation

The recommendation is to implement Alternative 1. Xcel Energy is in the process of constructing the Carver County second transformer addition and the West Waconia capacitor addition. The Glencoe Light and Power Commission is constructing the new 115 McLeod-Glencoe line by the end of 2005. Final planning analysis is expected over the next year to confirm that the best long-range strategy is extending 115 kV from Glencoe to the east and to determine if it should be built to Carver County or the West Waconia substation. This involves building a new Glencoe-McLeod 115 kV line by the end of 2005.

The long-range strategy in this area is to extend this new 115 kV line from Glencoe to West Waconia by rebuilding some of the 69 kV transmission line in the area to 115 kV. The Young America tap to Glencoe tap 69 kV line could be rebuilt to 115 kV in 2008 when it overloads for outage of the new Glencoe to McLeod 115 kV.

[22] NPV=Net Present Value

Alternative 1 is recommended because, while not projected in the study, rapid load growth may develop in this area, as has been observed in other similarly situated communities on the fringe of the Twin Cities metropolitan area. The 115 kV plan is adaptable to such a change in load growth while the 69 kV development option is limited in the future growth potential.



EDEN PRAIRIE - MINNETONKA AREA

The Eden Prairie-Hopkins-Minnetonka Area is part of the Twin Cities metropolitan area. It is roughly defined by Minnetonka Boulevard on the north, the Minnesota River on the south, and Highway 169 on the east. The western boundary includes Lake Minnetonka and the area extending south from the west end of the lake. The area includes the cities of Chanhassen, Chaska, Eden Prairie, Hopkins, southern Minnetonka, and the small, south Lake Minnetonka communities of Deephaven, Excelsior, Greenwood, Shorewood, Tonka Bay and Victoria.

In the Eden Prairie-Minnetonka area, the Eden Prairie 345 kV substation is the primary bulk power source for the 115 kV system, with Scott County being a weaker, secondary 115 kV source. A 50 MVA peaking generation plant, operated by the City of Chaska, is located near the Chaska on this system.

An *Eden Prairie - Minnetonka Area Load Serving Study* was completed in 2003.

A. Inadequacies

Outage of the Scott County-Chaska 69 kV line causes overloading of the Westgate-Deephaven 69 kV line and one of the 115/69 kV 47 MVA transformers at Westgate in 2006. Outage of the Westgate source causes overloading on the Scott County-Excelsior 69 kV line in 2006. Loss of both Eden Prairie-Westgate 115 kV lines causes low bus voltages in the area by 2008.

B. Alternative Solutions

Two alternatives were developed for the Westgate-Deephaven area. Both alternatives involve upgrading existing 69 kV lines in the area to 115 kV.

1. Eden Prairie – Minnetonka Area Alternative #1: Upgrade Westgate-Glen Lake-Gleason Lake to 115 kV

The first alternative would be to upgrade the Westgate-Glen Lake-Gleason Lake 69 kV line to 115 kV using 795 ACSS conductor to yield 310 MVA capacity. This plan also involves expanding the existing Glen Lake substation and adding a second 115/13.8 kV substation north of the existing substation. Distribution engineers would design the distribution system to carry much of the new load growth in this area from the upgraded Glen Lake substation.

This alternative consists of the following transmission components:

- Rebuild 10 miles of the Westgate-Glen Lake-Gleason Lake 69 kV line to 115 kV using 795 ACSS conductor to yield 310 MVA capacity in 2006;
- Expand the existing Glen lake substation to install two 50MVA 115/13.8 kV transformers; and
- Build an outdoor 115/13.8 kV substation with two 50 MVA transformers north of existing substation.

This alternative has the advantage of enabling the transmission system at Glen Lake to be operated normally-closed. The Glen Lake transmission system is operated normally open with half the load served from the Gleason Lake and half the load served from Westgate. This configuration is required because the outage of the Parkers Lake-Eden Prairie 345 kV line would cause large power flows through the 69 kV system. This plan also defers the installation of a capacitor bank at Westgate to 2008.

2. Eden Prairie – Minnetonka Area Alternative #2: Upgrade Westgate-Deephaven-Excelsior-Scott County to 115 kV

The second alternative would be to upgrade the 15 miles of the Westgate-Deephaven-Excelsior-Scott County 69 kV line to higher capacity. The equipment at the substations would also need to be upgraded. With present load projections, this plan will work until 2012-2013, when the load at Deephaven and Excelsior would reach or exceed 84 MVA.

Alternative 2 consists of the following transmission components:

- Reconductor the Westgate-Deephaven-Excelsior-Scott County 69 kV line (15 miles) using 336 ACSS conductor to 107 MVA capacity in 2006. Substation equipment would limit rating of the circuit to 84 MVA;
- Install a 115 kV capacitor at Westgate in 2008;
- Rebuild 15 miles of the Westgate-Deephaven-Excelsior-Scott County 69 kV line to 115 kV using 795 SSAC conductor to yield 310 MVA in 2006; and
- Upgrade Westgate-Eden Prairie 115 kV #1 and #2 to 600MVA.

The advantage of this plan is that it defers having to invest about $3 million in 2006. It also has an advantage, from a distribution point of view, that the substation expansions will be closer to the immediate load center. When the 69 kV system can no longer supply the load growth, this line and the Excelsior and Deephaven substations would be expanded and upgraded to 115 kV and 310 MVA capacity, or the conversion identified in Alternative 1 would be followed. The choice would depend on where most of the future load was projected to develop.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

Summary of Plan Economics

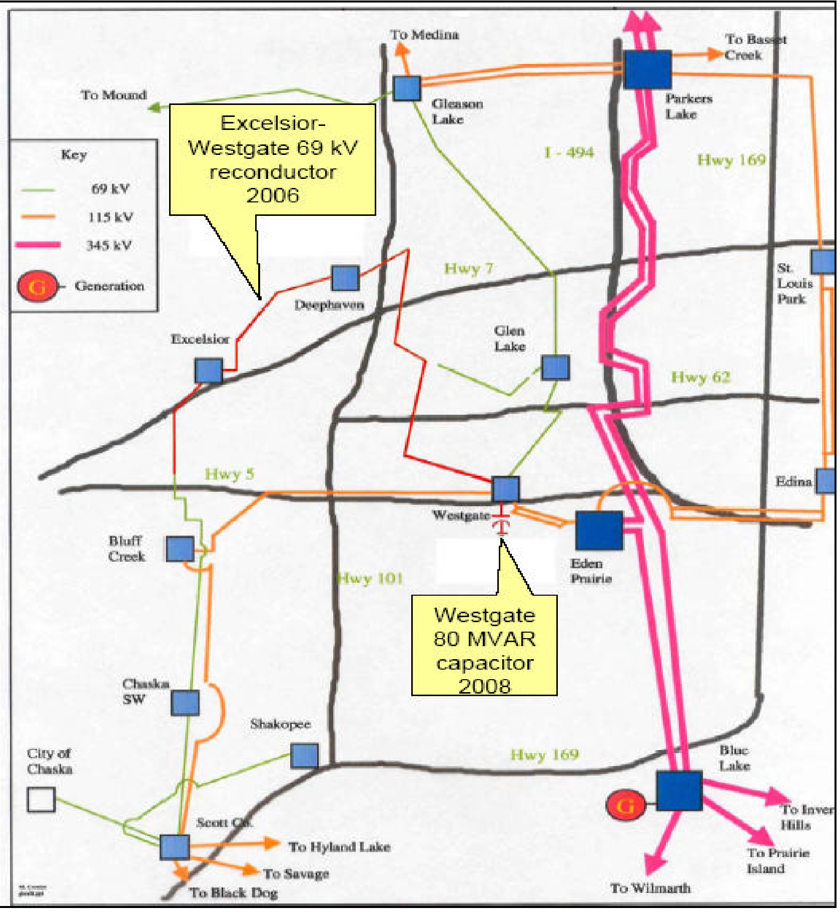
Description of Options	Base Cost	2003 NPV
Alternative 1: Rebuild 10 miles Westgate-Glen Lake- Deephaven 69kV to 115kV in 2006	$ 20,700,000	$16,000,000
Alternative 2: Reconductor 15 miles Westgate-Deephaven-Excelsior-Scott County 69kV to 107 MVA in 2006. Rebuild to 115 kV in 2011-2013	$ 19,200,000	$13,750,00

Both alternatives include the upgrade of existing transmission lines and substations, so there should be minimal new environmental impacts. The work will be conducted in an area where considerable residential and commercial development has occurred in recent years. Proposals that call for the rebuild of existing 69 kV transmission lines to 115 kV may require the existing right-of-way to be expanded. This in turn may require additional tree trimming for safe operation of the line.

D. Recommendation

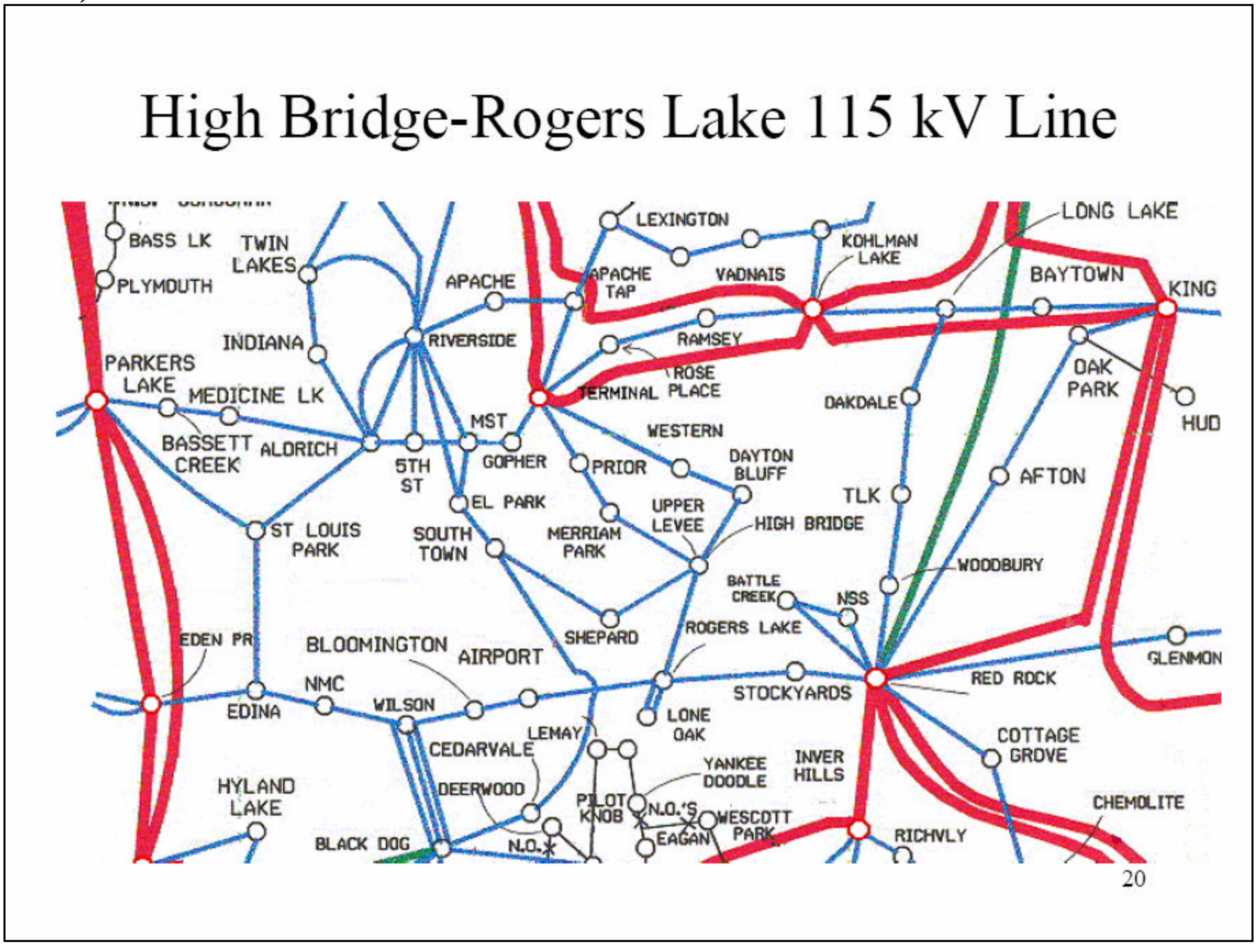
Alternative 2 has been proposed for implementation. Final decisions will be made late in 2003 to go forward with this plan. The advantage of this plan is that it defers having to invest about $3 million in 2006. It also has an advantage from a distribution point of view in that the substation expansions will be closer to the immediate load center. In addition it defers the decision to develop the major 115 kV upgrade plans until the load growth potential of the region is further developed (approximately 2011-2015), resulting in near term cost savings.

Eden Prairie-Minnetonka Transmission System



HIGH BRIDGE - ROGERS LAKE 115 KV LINE

This transmission line is located with the Twin Cities Planning Zone (see the diagram below).



A recent transmission planning study of the City of St. Paul area (*Ramsey County 36 MW Plant Addition, Transmission Assessment*, November 2002) identified a transmission issue in this area. The Midwest ISO is also presently studying the *High Bridge Metropolitan Emissions Reduction Project* ("MERP") generation upgrade project, which would utilize the same transmission system and may change the recommendations for this issue.

A. Inadequacies

During off-peak periods (defined as 70% of peak), the outage of either the King-Red Rock or the Elm Creek-Monticello 345 kV circuits causes the High Bridge-Rogers Lake 115 kV line to load to 111% of its emergency rating.

Outage of the Parkers Lake-Elm Creek and Parkers Lake 345 kV line results in the High Bridge-Rogers Lake 115 kV line reaching 140% of its maximum conductor limit. Similar loadings can occur with loss of the King-Chisago County 345 kV and King-Kohlman Lake 345 kV double circuit line.

B. Alternative Solutions

These overloads can be alleviated with generation redispatch. Use of generation redispatch to address this system inadequacy will be reviewed annually.

Informal review of alternatives to alleviate the overloads investigated a new line from Dayton's Bluff to Battle Creek and rebuilding or reconductoring portions of the High Bridge-Rogers Lake 115 kV line.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The analysis has not yet proceeded far enough to quantify the economics of the alternatives. Qualitatively, the new Dayton's Bluff-Red Rock line is expected to be more expensive than rebuilding the High Bridge-Rogers Lake line. Since no specific studies have begun on this issue, limited environmental review has been conducted. As the analysis progresses, one can expect that proposals in the highly populated and developed area may require modifications to the existing right-of-way, such as widening the right-of-way and additional tree clearing.

D. Recommendation

The conditions identified that create the inadequacy are infrequent and, along with the uncertainties associated with the MERP project at this time, the redispatch option is recommended. Xcel Energy will continue to monitor the situation.

LONG LAKE-OAKDALE-TANNERS LAKE-WOODBURY 115 KV LINE

This line is located in the suburbs just east of St. Paul, Minnesota. The area was last studied in the *NSP Long-Range Delivery System Study, Central Twin Cities Area* (February 2000).

A. Inadequacies

The outage of King-Baytown-Long Lake-Kohlman Lake 115 kV line results in the Tanners Lake-Woodbury 115 kV line loading to 112% of its 191 MVA rating in 2008. The Red Rock-Woodbury 115 kV line outage results in the Long Lake-Oakdale 115 kV line loading to 109% of its 239 MVA rating and the Oakdale-Tanners Lake 115 kV line to 115% of its 140 MVA rating in 2008.

B. Alternative Solutions

No operating procedures are available, as the overloaded lines are radial during the contingencies causing the overloads. The Woodbury-Tanners Lake 115 kV line may be reconductored with 795 ACSS to get a 310 MVA thermal rating. The Tanners Lake-Oakdale-

Long Lake 115 kV line may also be reconductored to 795 ACSS. Any other alternative would involve constructing a new 115 kV transmission line.

C. Economic, Environmental and Social Issues

The Long Lake-Tanners Lake 115 kV line reconductor is estimated to cost $650,000. The Woodbury-Tanners Lake 115 kV line reconductor is estimated to cost $450,000. The lines are located in highly populated areas, but the proposed reconductor projects will have minimal new environmental impact.

D. Recommendation

It is recommended to reconductor the thermally limited lines. The schedule will be determined during the coming year.

ALDRICH - ST LOUIS PARK 115 KV LINE

During the spring of 2003, an informal review of the adequacy of the Twin Cities transmission system identified a number of transmission issues in the southwest suburbs of Minneapolis. The "Parkers Lake #10 Bank Failure Operating Analysis" also found the same issues.

A. Inadequacies

In 2007, the outage of the double circuit, common structure Parkers Lake – St. Louis Park and Parkers Lake–Basset Creek lines causes the 115 kV line from Aldrich to St. Louis Park to load up to 175.6 MVA, or 123.6%, of its present 140 MVA maximum conductor rating.

The overload can be resolved by closing the Aldrich 115 kV, normally-open bus tie, which connects the Medicine Lake-St. Louis Park line to the other lines at Aldrich substation. However, this procedure creates a number of new concerns. There are four single contingencies and three double-circuit outages which overload the Aldrich-St. Louis Park line. The worst is outage of Edina-Eden Prairie 115 kV line, which loads the Aldrich – St. Louis Park line to 117% of its rating.

B. Alternative Solutions

Most of the issues are resolved by closing the Aldrich 115 kV normally-open bus tie. This does, however, cause new conditions which may overload the Aldrich-St. Louis Park 115 kV line. This can be addressed by a relatively inexpensive reconductor of the line to higher capacity. Any other alternative would require a more expensive new 115 kV line in this area.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The reconductor alternative will cost approximately $900,000. Reconductoring an existing transmission line will not create new environmental or social issues for this area.

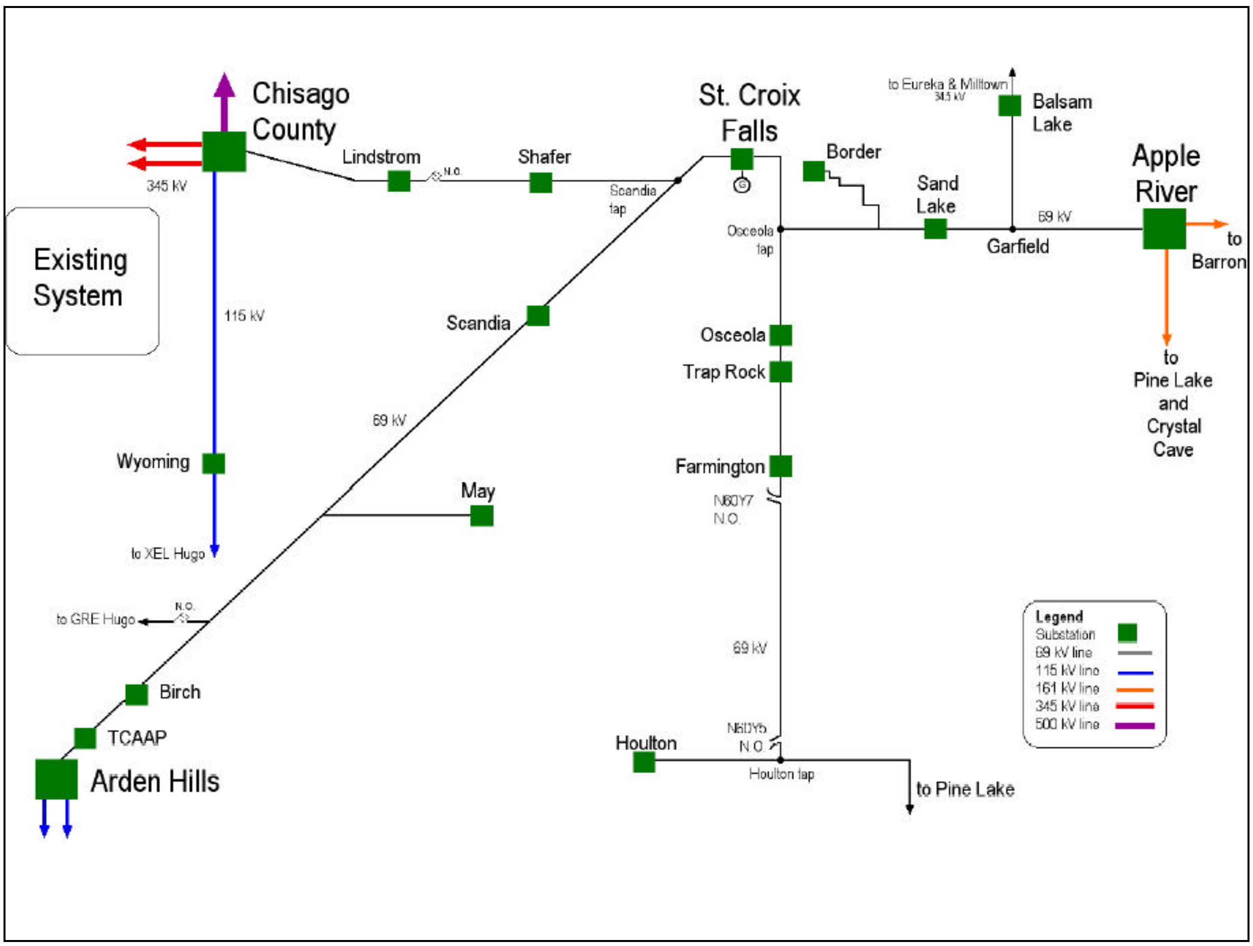
D. Recommendation

The short-term operating procedure and the reconductor option are under evaluation at this time. A decision is expected late Fall of 2003.

CHISAGO - APPLE RIVER AREA

The Chisago-Apple River project is located in east central Minnesota and northwestern Wisconsin. The area of concern in Minnesota is bounded by Arden Hills on the south and west, North Branch (Chisago County) to the north and Taylors Falls to the east. Specifically, the area served by the Arden Hills-St Croix Falls 69 kV line and the Chisago-Lindstrom-Scandia tap 69 kV line.

Chisago - Apple River Project



The following studies address this project:

- Advance Plan 7 Western Wisconsin Bulk Transmission Report (D23w) (1994);
- Chisago Electric Transmission Project Application,(1996);
- Minnesota Department of Public Service Information Request 33 (1999); and

- Chisago Electric Reliability Project Hybrid 115/161 kV Analysis (2001).

A. Inadequacies

Outage of the Apple River source to the Apple River-St Croix Falls 69 kV line results in overload of the TCAAP tap-Birch 69 kV line at 1997 load levels. At existing load levels, this outage results in the overload of the Arden Hills-TCAAP tap-Birch portion of the line. This outage also results in low voltage at the Scandia, Shafer, and Sand Lake substations in 2003. Outage of the Arden Hills source of the Arden Hills-St Croix Falls 69 kV line results in overload of the Apple River-Garfield section of the Apple River-St Croix Falls 69 kV line at existing load levels. Outage of the Chisago-Lindstrom 69 kV line results in the Lindstrom substation being without power until it can be transferred to the Arden Hills-St Croix Falls 69 kV line.

There was 64 MW of demand on the Arden Hills-St Croix Falls-Apple River 69 kV line in 2002. The Arden Hills source can serve 47 MVA of demand; and the Apple River source can serve 25 MVA of demand during summer peak conditions. The St. Croix Falls hydro plant averages 12 MW of output during a typical year. Therefore, this local area transmission system can serve 37 to 59 MVA of load during outage of either transmission source. This is less than the customer demand. Actual capability to serve load depends on water available to the St. Croix Falls hydro plant.

B. Alternative Solutions

The following alternatives were analyzed to address these load-serving issues:

1. Chisago – Apple River Area Alternative #1: Rebuild the Chisago-Apple River 69 kV line to a higher voltage

Alternative 1 makes the following transmission system upgrades:

- A Chisago-Lawrence Creek 115 kV line;
- A new Lawrence Creek substation;
- A Lawrence Creek-St Croix Falls-Border 161 kV line; and
- A Border-Apple River 161/69 kV double circuit line; single 795 ACSS on the 115 kV and 161 kV to Border substation; 954 ACSR used on Border-Apple River 161 kV line. This option would also require conversion of the Lindstrom, Shafer, and St Croix Falls substations to 115 kV, 115 kV, and 161 kV, respectively.

2. Chisago – Apple River Area Alternative #2: Rebuild the Chisago-Apple River 69 kV line at 69 kV to higher capacity

Alternative 2 has the following transmission upgrades:

- Chisago-St. Croix Falls-Apple River 69 kV line rebuilt at 69 kV using 795 ACSS;
- A new Lawrence Creek 161/115 kV substation; and

- Upgrade the Chisago 115/69 kV transformer.

3. Chisago – Apple River Area Alternative #3: Reconfigure the 69 kV system and add reactive support

Alternative 3 reconfigures the 69 kV system in east central Minnesota and northwestern Wisconsin; specifically, opening the Arden Hills-St. Croix Falls 69 kV line at St. Croix Falls, closing the normal open at Lindstrom, and replacing the Chisago 115-69 kV transformer to create a Chisago-Arden Hills 69 kV line. A 69 kV switching station would also be constructed in the Roberts or New Richmond area. The new substation would terminate the lines from River Falls, Apple River, Pine Lake, and Clear Lake. Reactive support would also be added at the Lindstrom, Scandia and Apple River substations.

4. Chisago – Apple River Area Alternative #4: Install distributed generation in the area

Alternative 4 makes no transmission system upgrades, but assumes that all future load growth will be served with distributed generation. The preliminary economics provided below assume 30 MW natural gas fired combustion turbines located at larger load centers.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

Xcel Energy and DPC are currently finalizing a certificate of need application for this project. The economics are still under review. Both Alternative 1 and Alternative 2 upgrade an existing 69 kV transmission line to address the load serving need. Environmental issues include routing of the line through more developed areas such as Lindstrom and Chisago City and through sensitive areas such as the St. Croix National Scenic Riverway.

Alternative 3 has less transmission line work as part of the project, but will require a new substation to be sited in Wisconsin. Alternative 4 would install distributed generation in the area. Since the location of the distributed generation is dependent upon who builds it, the impacts of the sites and the possible transmission line work that may be required for this alternative has not been addressed.

The economics analyzed an integrated plan, with additional system upgrades, that addressed east central Minnesota and western Wisconsin load serving needs through 2015. The proposed plan has small portion of transmission line underground near the St. Croix river. To compare options on a similar basis, it was assumed that similar portions would be underground for each option. The value of energy and capacity losses was calculated for each option. These are preliminary economics, as the technical analysis is not yet completed. The cumulative present value of revenue requirements for the options are as shown in the table below.

Economics with Underground Transmission near River (thousands of dollars)

Plan	UG	Investment	Escalated Investment	Investment Cumulative PV of RR	Cumulative PV of Loss Benefit	Net Cum. Present Value of RR
CA1 ug	Yes	$62,154	$70,686	$86,142	$15,643	$70,500
CA5 ug	Yes	$65,765	$74,712	$91,315	$15,556	$75,759
DF ug	Yes	$69,245	$82,234	$89,213	$3,623	$85,590
DG ug	Yes	$70,986	$80,416	$122,931	$7,608	$115,322
RBD ug	Yes	$68,542	$77,468	$96,581	$9,349	$87,232

To show the sensitivity of option economics to the cost of underground transmission, the economics were calculated assuming all overhead transmission.

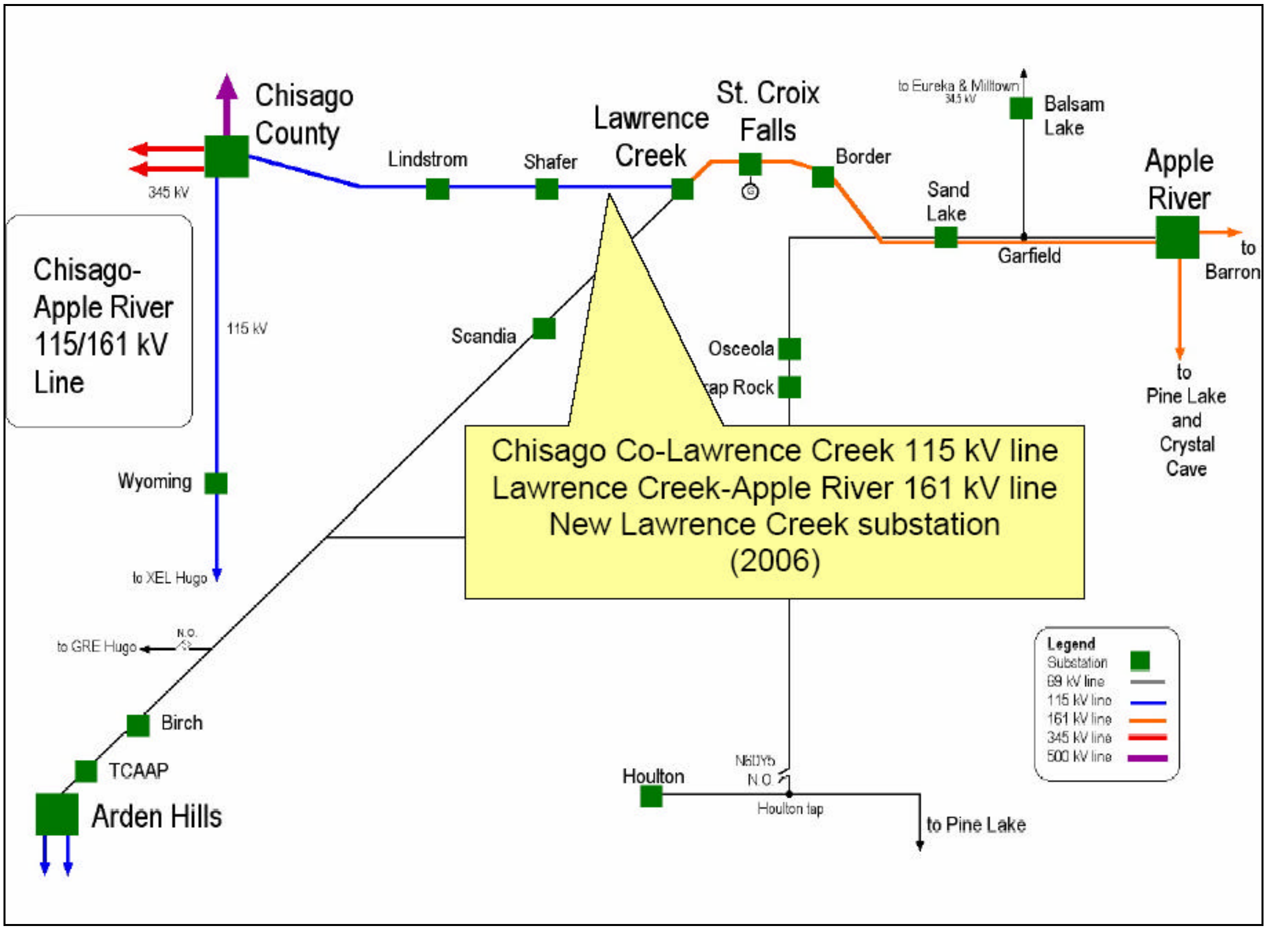
Economics with All Overhead Transmission (thousands of dollars)

Plan	UG	Investment	Escalated Investment	Investment Cumulative PV of RR	Cumulative PV of Loss Benefit	Net Cum. Present Value of RR
CA1	No	$48,375	$55,328	$66,408	$15,643	$50,765
CA5	No	$51,986	$59,354	$71,580	$15,556	$56,024
DF	No	$38,384	$45,134	$50,315	$3,623	$46,692
DG	No	$60,986	$69,270	$108,608	$7,608	$101,000
RBD	No	$44,031	$52,279	$56,781	$9,349	$47,432

D. Recommendation

The recommended plan is Alternative 1, which rebuilds the Chisago-St. Croix Falls-Apple River 69 kV line to a higher voltage. The higher voltage plan is a logical extension of the load serving 115 kV transmission system in the Twin Cities and provides 50% greater load serving capability than rebuilding it at 69 kV. A certificate of need application for this project is expected to be filed in late 2003 or early 2004.

Chisago—Apple River Area



TWIN CITIES 345/115 KV TRANSFORMER CAPACITY

There are nineteen 345/115 kV or 230/115 kV transformers in the Twin Cities. These transformers serve a majority of the Twin Cities load from remote generation from Xcel Energy's A.S. King, Monticello, Prairie Island and Sherburne County plants; GRE's plants in North Dakota; and hydro power from Manitoba.

Xcel Energy is planning to perform a Twin Cities 345/115 kV transformer capacity study in 2003-2004.

A. Inadequacies

Beginning with the mid 2000s, an outage of the Parkers Lake, Eden Prairie, or Red Rock 345/115 kV transformer results in an overload of its twin transformer. These overloads can be aggravated by reducing the amount of 115 kV generation in the Twin Cities metropolitan area (Black Dog, Blue Lake, High Bridge, Inver Hills, and Riverside plants).

B. Alternative Solutions

The primary alternative is to replace the existing transformers with a larger capacity units. The secondary alternative is to install additional units at substations with a single transformer.

C. Economic, Environmental and Social Issues Associated with Each Alternative

These issues have not yet been evaluated at this early stage of the planning process. It is expected that the environmental impacts will be limited where the transformer replacements do not require any substation expansion. If some of the projects require substation expansion, land use concerns may be raised if the substation is located in one of the more highly developed sites in the Twin Cities.

D. Recommendation

An evaluation of the size, in service dates, and best location for increasing the transformer capacity in the Twin Cities is expected during the upcoming year.

PLYMOUTH - MAPLE GROVE AREA

This suburban area northwest of the Twin Cities metro has seen significant residential and commercial development. GRE submitted a certificate of need application (Docket No. ET2/CN-02-536) in November 2002, which requested approval of a new 115 kV transmission line to serve the load in the area. Complete information regarding inadequacies, alternatives, environmental and social review and recommendations can be found in that document. The following sections summarize the information contained in the application.

A. Inadequacies

As early as the summer of 2004, the existing 69 kV transmission system will be inadequate during contingencies, to serve the growing load in this area. Additional load growth in this area is expected as commercial and residential development continues. Overload conditions will continue to worsen with the increased load.

B. Alternative Solutions

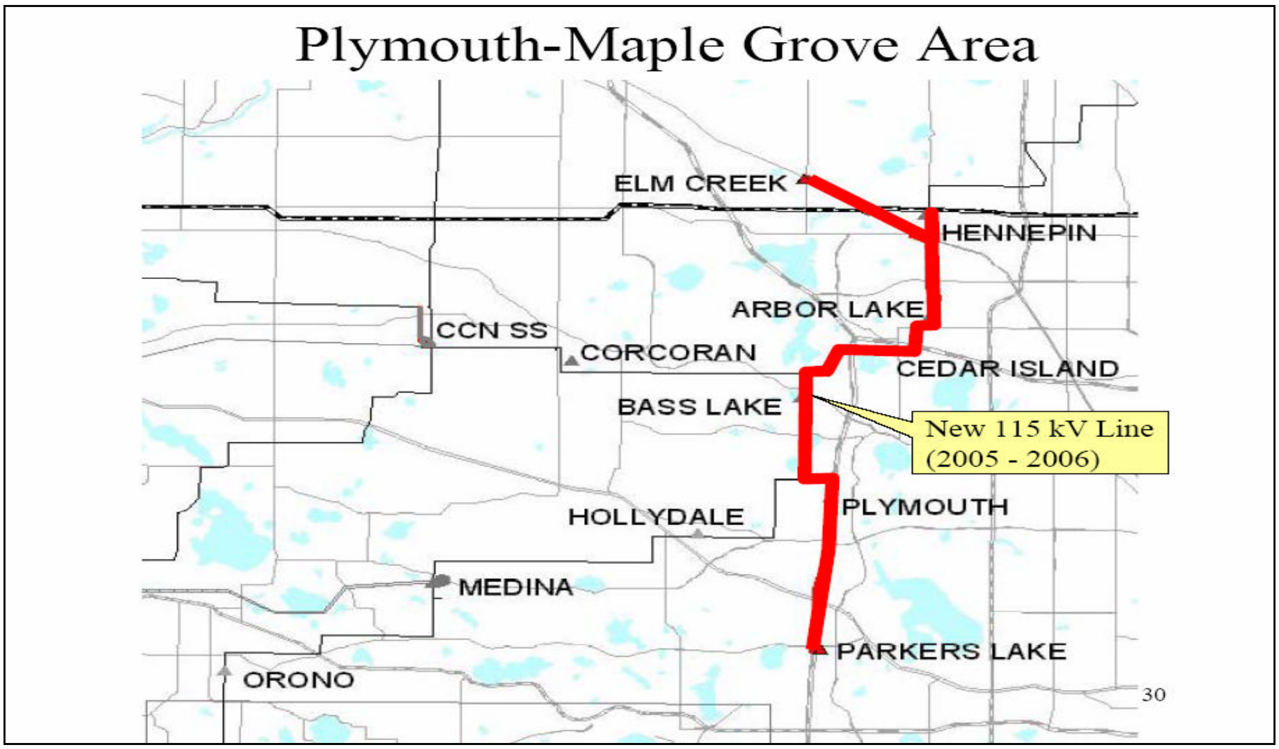
In its CON application, GRE evaluated several alternatives including distributed generation, rebuilding the existing transmission lines at 69 kV, adding a new 69 kV source in the area, and rebuilding the 69 kV transmission line to 115 kV using the existing right-of-way as much as possible.

C. Economic, Environmental and Social Issues Associated with Each Alternative

Adequate and reliable electric service is essential to the economic and social development in this area. The environmental impacts of the various alternatives were discussed in the CON application. Generally, the use of existing rights-of-way has the least amount of environmental impact.

D. Recommendation

The recommended project, as outlined in GRE's application, was 36 miles of new 115 kV transmission line from the Elm Creek substation to the Parkers Lake substation. Except for approximately 4.25 miles of new line, the line would be constructed using the existing 69 kV right-of-way. This project is needed to develop a transmission system that will provide support for future, continued load growth in the Plymouth-Maple Grove area.



RUSH CITY - FOREST LAKE – BLAINE AREA

This area is served by two 230/69 kV sources from Rush City and Blaine. The total mileage for the transmission lines in this area is 52 miles.

A. Inadequacies

Currently, the loss of either the Rush City or the Blaine source causes low voltages and overload problems in the area between Rush City and Blaine. Also, in 2010 the Rush City transformer will overload on the loss of the Blaine transformer. Similarly, the Blaine transformer will overload in 2011 on the loss of the Rush City transformers.

B. Alternative Solutions

Three alternate options were developed as solutions to the long-range problems that occur in this area. The alternatives are as follows:

1. Rush City – Forest Lake Area Alternative #1: 69 kV development

This option involves establishing a new 230/69 kV source at Linwood and building a 69 kV line from Martin Lake to Athens. The new source at Linwood will maintain voltages, relieve line overloads, and relieve transformer flow at Blaine and Rush City. The 69 kV line from Martin Lake to Athens will be needed to relieve line overloads in the area between Soderville and Cambridge.

2. Rush City – Forest Lake Area Alternative #2: 115 kV conversion

This option involves converting the 69 kV line between Rush City and Blaine to 115 kV. The 115 kV development will provide greater capacity for future load growth. This option will involve distribution substation conversions to 115 kV. Overall, this alternative would be very expensive.

3. Rush City – Forest Lake Area Alternative #3: 69 kV system improvement

This option involves rebuilding the 69 kV lines to carry a higher current-carrying conductor, and providing another transformer at the Rush City substation. Capacitors are added to maintain voltage. Similar to Alternative 2, this option would involve significant mileage of line being replaced, making it a rather expensive alternative. However Alternative 3 is less expensive than Alternative 2 because the distribution substations would not have to be reconstructed to a higher voltage.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

GRE will be evaluating each alternative for both land acquisition and environmental impacts. Alternative 1 would have the least amount of impact as construction would be limited to a single area, whereas, Alternatives 2 and 3 would have minimal new land acquisition, but would require 52 miles of potential line construction on an existing corridor. Alternative 1 is by far the least cost plan and provides the most reliable source. It establishes a breaker station in the middle 69 kV system with a strong 230/69 kV source. It also provides benefits to the Highway 65 corridor with a proposed 69 kV line to the Athens area, and will enhance the load serving capability that is needed in this area.

D. **Recommendation**

GRE is proposing Alternative 1 as the recommended plan.

ELK RIVER - RAMSEY - BUNKER LAKE AREA

This area is served by two 230/69 kV sources from Elk River and Bunker Lake. The total mileage for the 69 kV transmission line is 21 miles. The growth potential for this area is considered to be high due to the undeveloped land along Highway 10 in Ramsey.

A. **Inadequacies**

Based on projected growth, the loss of either the Elk River or the Bunker Lake sources causes overload problems in 2005 on the other 69 kV line from the other source.

B. **Alternative Solutions**

Three alternatives were developed as solutions to the long range problems that occur in this area. The alternatives are as follows:

1. **Elk River – Ramsey Area Alternative #1: 115/69 kV source at Enterprise Park**

This alternative involves establishing a 115/69 kV source at Enterprise Park. This option will relieve overloads and relieve transformer loadings at Elk River and Bunker Lake. In addition, this option will provide a loop-feed service to the existing radially fed Enterprise Park substation. The 115 kV line would be from the Crooked Lake 115 kV substation and involve about 3.5 miles of construction.

2. **Elk River – Ramsey Area Alternative #2: 115 kV conversion**

This alternative involves converting the 69 kV system between Elk River and Bunker Lake to 115 kV. This alternative will provide greater capacity for future load growth. In addition, this option will greatly relieve the transformer flow at Elk River and Bunker Lake. This alternative is considered to be very expensive, as the distribution substation would need to be converted to 115 kV and Elk River and Bunker Lake substation would need to be modified to establish 115 kV buses.

3. **Elk River – Ramsey Area Alternative #3: 69 kV system improvement**

This alternative involves rebuilding the 69 kV lines in the area. The overload problems would be eliminated. However, the major loads of Energy Park and Enterprise Park would continue to be served from a radial 69 kV system with no backup source.

C. Economic, Environmental, and social Issues Associated with Each Alternative

Alternative 1 would have the greatest land impact because a corridor would have to be established, although a railroad corridor through mainly industrial park areas does presently exists. Alternative 1 is the most reliable because it would establish a third source in the area. Alternative 2 is expensive and is not being pursued by GRE. Alternative 3 does not offer significant reliability improvements to the existing system, except that the newly rebuilt lines would have slightly better reliability.

D. Recommendation

Alternatives 1 and 3 are nearly equivalent in cost, but due to long-term potential to accommodate future growth and the reliability benefits, Alternative 1 is the preferred plan.

Enterprise Park 115/69 kV Substation

SOUTHEASTERN DAKOTA COUNTY

Southeastern Dakota County is experiencing rapid housing and commercial development, much of it near Lakeville and Farmington. The primary source of electrical service to this region is from the north via the Twin Cities transmission grid. Both 115 kV and 69 kV transmission lines are used to deliver power south to this area from the Twin Cities system, with the primary transmission substations of Black Dog 115 kV, Pilot Knob 115/69 kV and the Inver Hills 345/115 kV.

Lakeville is served from the Xcel Energy Air Lake 115 kV distribution substation, with the surrounding area served by the Dakota Electric Association's (DEA"), Lake Marion 69 kV and Dodd Park 115 kV distribution substations. The primary transmission source is the Black Dog-Riverwood-Burnsville-Dakota Heights-Lake Marion-Faribault 115 kV line and the Johnny Cake-Dodd Park-Air Lake-Lake Marion 115 kV line. Further east, the City of Farmington and its surrounding area is served by the Xcel Energy Farmington 69 kV substation and the DEA Farmington 69 kV substation. The primary transmission sources are the Lake Marion-Farmington and Pilot Knob-Farmington 69 kV lines.

This area was studied in 1999 by Xcel Energy as part of the southeast metro portion of their system studies. It was also studied by GRE as part of the Dakota county studies for the *GRE Long Range Transmission Plan–2003*. The distribution needs of Xcel Energy and DEA were studied in the individual studies for their respective companies. A significant amount of inter-utility communication has taken place over the last few years that has resulted in a combined distribution and transmission plan to provide electric service in the southeast Dakota County area.

A. Inadequacies

There are a number of electrical issues associated with the transmission and distribution systems in this area.

- The Xcel Energy Farmington distribution substation has physical restrictions;
- Reliable capacity of the Air Lake substation is 42 MVA - a load level expected within the next few years;
- The DEA Farmington distribution substation transformer cannot reliably back up other area substations. Within two to three years, the substation will exceed its normal loading capability;
- The Xcel Energy service territory between Rosemount and Farmington is sparsely developed, but has significant growth potential, with no nearby distribution sources;
- Outage of the Black Dog-Riverwood 115 kV line (primary source to the Lake Marion 115/69 kV station) in the early 2000s results in excessive loading of the Pilot Knob-Farmington 69 kV line, due partially to loads served further south of Farmington;
- Outage of the Lake Marion-Farmington 69 kV by late 2000s also loads the Pilot Knob–Farmington 69 kV alternate source above acceptable limits; and
- The 115 kV voltages at the Air Lake, Burnsville, and Lake Marion buses fall below criteria in 2007 during the outage of the Black Dock-Riverwood 115 kV line.

B. Alternative Solutions

1. Southeastern Dakota County Alternative #1: Air Lake to Empire 115 kV transmission line

The proposal for this area is a joint development plan among DEA, GRE and Xcel Energy. A new 115 kV distribution substation site will be developed near Farmington and used jointly by Xcel Energy and DEA. This site will be served from a new 115kV line between the Air Lake and Empire stations. Converting some of the existing loads to 115 kV and putting all new loads in this area on 115 kV will allow the 69 kV system loading to be reduced. This new source also corrects the low voltage and overloads on the northern portion of the Dakota County area transmission.

The steps are as follows:

- A new substation site (Vermillion River) will be developed for the DEA 115 kV distribution station. During construction, a new 115 kV line will be built from Vermillion River to Empire (located approximately five miles east of Farmington on the Rosemount-Cannon Falls 115 kV line). In 2004, the Air Lake-Farmington 69 kV line would be rebuilt as a double circuit 115 kV: one circuit from Air Lake to Vermillion River to Empire and one circuit from Lake Marion to Farmington. Xcel Energy will add its 115 kV Vermillion River distribution station during the mid-2000's.
- In the late 2000's, the plan calls for the addition of a second Inver Hills-Koch Refinery 115 kV line. This addresses possible outages of the existing Inver Hills-Koch Refinery 115 kV line or the Black Dog-Burnsville 115 kV line.

2. Southeastern Dakota County Alternative #2: Continue adding load to the 69 kV system

The main alternative to the proposed Air Lake to Empire 115 kV transmission line is to continue adding load to the 69 kV system. This would require a rebuild of the existing Pilot Knob-Farmington 69 kV line to higher capacity. A large capacitor bank would also be needed at Air Lake for voltage support to the area 115 kV. By 2009, the alternative would require either a second Black Dog-Burnsville or Inver Hills-Koch Refinery 115 kV line for outage of either the existing Inver Hills-Koch Refinery 115 kV line or the Black Dog-Burnsville 115 kV line. DEA would expand the existing Farmington substation and Xcel Energy would create a new area 69/13.8 kV substation.

The disadvantage of a 69 kV expansion is that it is not practical to add the necessary equipment at the existing 69 kV locations. Both the Pilot Knob and the Farmington substations are land-locked by existing roadways, houses and parks. Expansion of these sites would require complete relocation.

The Inver Hills-Koch Refinery second 115 kV line is one alternative, which will be further reviewed in the future along with other alternatives as the need gets closer.

DEA, GRE, and Xcel Energy are working together to develop the necessary permit applications for these facilities. Based on the existing routing and siting rules, the permits for the projects will be obtained under local jurisdiction.

C. Economic, Environmental and Social Issues Associated with Each Alternative

The fast growing area of southeastern Dakota County contains significant potential for continued economic and social development. The proposed alternative that develops a 115 kV transmission system will provide for the continued addition of new loads in this area and provide a step toward additional transmission expansion as may be necessary to meet future load growth.

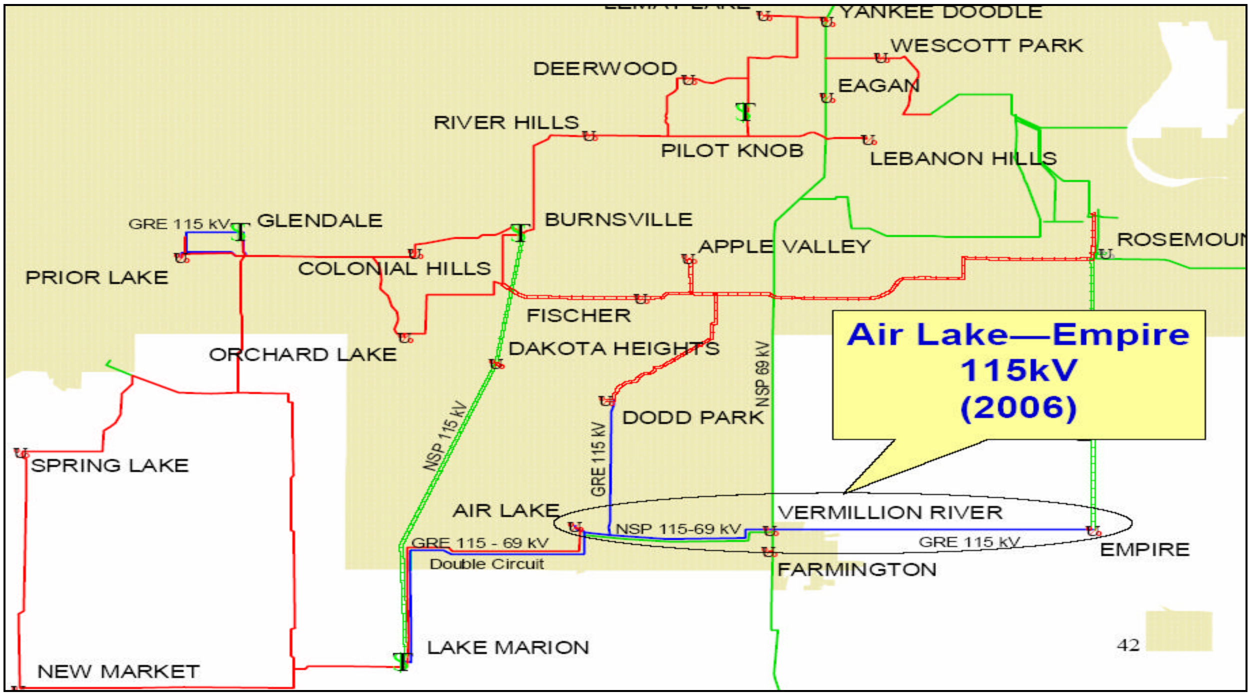
The development of the new Air Lake-Empire 115 kV line and the new Vermillion River substation, as a joint effort among the utilities, minimizes the environmental impact as compared to a plan where each utility develops independent facilities.

D. Recommendation

The recommendation is to construct Alternative 1, the Air Lake to Empire 115 kV transmission line (2005) and a new Vermillion River substation (2007). There are a number of reasons that support the need for this alternative:

- The immediate need of DEA to increase the capacity of its Farmington transformation (along with the need to rebuild the substation) allowing for conversion to 115 kV;
- The Xcel Energy near-term need to add a new substation to serve load and significant load growth in the area; and
- The 69 kV system is reaching the end of its capability (both age and capacity) and does not provide for any future expansion capability.

Air Lake – Empire 115 kV



MINNESOTA - WISCONSIN STABILITY INTERFACE

The Minnesota-Wisconsin Stability Interface ("MWSI") is a measure of the power flowing from or through the Twin Cities area to areas south and east. The MWSI is presently a regional constraint that limits the delivery of power in MAPP and MISO. To determine methods (either new construction or operating procedures) to alleviate the MWSI constraint, MISO is planning to start an exploratory study in the near future.

A. Inadequacies

The MWSI has transmission service reservations which exceed the capacity of the interface. This constraint limits the implementation of new wholesale transactions and the construction of new generation within Minnesota, even to serve Minnesota load, because parallel path flows (loop flows) often impact this interface.

B. Alternative Solutions

Alternative solutions will be determined by MISO's planned study of the MWSI constraint. A major regional study is required to investigate what options may be available to increase the interface capacity. Such a study would also be expected to include addressing load serving issues in southeast Minnesota as part of its scope.

IV. Studies of Issues in the Twin Cities Planning Zone

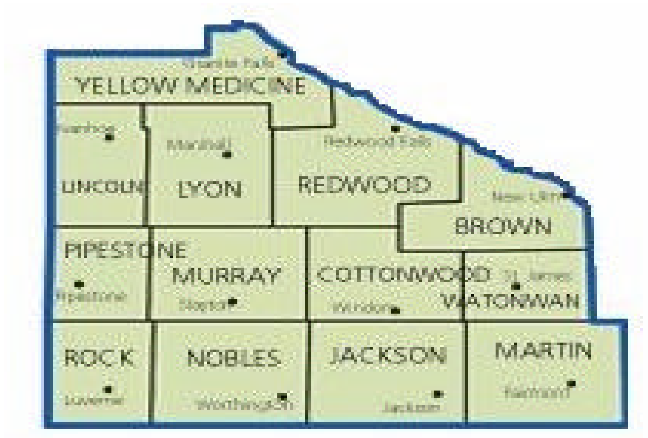
- *Glencoe Area load Serving Transmission Study* (June, 2002);
- *Eden Prairie - Minnetonka Area Load Serving Study* (2003);

- *Eden Prairie - Minnetonka Area Load Serving Study* (2003);
- *Ramsey County 36 MW Plant Addition, Transmission Assessment* (November 2002);
- (*High Bridge Metropolitan Emissions Reduction Project MERP)* (in progress);
- *NSP Long-Range Delivery System Study, Central Twin Cities Area* (February 2000);
- *Advance Plan 7 Western Wisconsin Bulk Transmission Report (D23w)* (1994);
- *Chisago Electric Transmission Project Application* (1996);
- *Minnesota Department of Public Service Information Request 33* (1999);
- *Chisago Electric Reliability Project Hybrid 115/161 kV Analysis* (2001);
- *Chisago Electric Reliability Project - Application Study* (in progress); and
- *GRE Long Range Transmission Plan–2003*.

Southwest Transmission Planning Zone

I. Introduction

The Southwest Transmission Planning Zone is located in southwestern Minnesota and is generally bounded by the Iowa border on the south, Mankato on the east, Granite Falls on the north and the South Dakota border on the west. It includes the counties of Brown, Cottonwood, Jackson, Lincoln, Lyon, Martin, Murray, Pipestone, Redwood, Rock, Watonwan, and Yellow Medicine.



Southwest Transmission Planning Zone

A map showing the 100 kV and above transmission facilities located in Minnesota is located in Appendix VII. This map also identifies the Southwest Transmission Planning Zone and the other Minnesota State Transmission Planning Zones.

A land use map is located in Appendix IX**.** The primary land use is cultivated land.

The primary population centers in the Southwest Planning Zone include the cities of Fairmont, Granite Falls, Jackson, Marshall, New Ulm, Pipestone, St. James, and Worthington.

Commerce in this zone is highly agricultural and includes large cash crop farms. Many small and large industries that support the agricultural industry, both pre-and post-production, are also located in this Zone. This includes seed production, farm equipment production and ethanol and soybean processing plants.

In addition to the commercial users of electric energy in the Southwest Planning Zone, the development of wind generation has had significant impact on the area, including the transmission network. The first 25 MW of wind generation was installed around 1994. Today, more than 360 MWs are installed and thousands of MWs of wind generation requests are pending in the MISO interconnection queue. The expansion of wind generation is expected to continue for the foreseeable future and to continue to strain the transmission system in this zone.

The transmission system in the Southwest Zone consists mainly of the following: A 345 kV transmission line from Lakefield Junction (location of a 480 MW gas-fired generation plant) to Mankato provides for major hub with the 161 kV lines providing transmission to loads in this zone. 115 kV lines from Sioux Falls to Pipestone to Granite Falls; from White, South Dakota to near Ivanhoe, Minnesota; and from Flandreau, South Dakota to Holland, Minnesota, provide the other transmission service to loads in the area, particularly the large municipal utility load at Marshall. The 115 kV lines also provide transmission service for the wind generation being developed along the Buffalo Ridge.

The transmission system in this Zone will soon be enhanced (2006-2007) by the addition of 345 kV and 115 kV transmission lines to provide additional outlet for the wind generation in the Southwest Planning Zone approved in the Commission's Certificate of Need Order, Docket No. E002/CN-010158 (March 2003). These lines will provide opportunities for new transmission substations to improve the load serving capability of the underlying subtransmission system. However, several lines are not expected to be in service until 2007.

Much of the load in the Southwest Planning Zone is served by 69 kV subtransmission lines, which have sources from 115/69 kV or 161/69 kV substations. The 69 kV transmission network is becoming inadequate for supporting the growing load in the area. Some of the solutions to the 69 kV transmission inadequacies will involve the construction of new 115 kV and 161 kV transmission lines and substations; therefore, discussions about the inadequacy of the existing system (Section II below) include an analysis of the existing 69 kV subtransmission system.

II. Utility Contacts and Regional Transmission Organization Participation

The utilities which own transmission facilities of voltages greater than 100 kV within the Southwest Planning Zone include East River Electric Power Cooperative, Interstate Power and Light Company, L&O Power Cooperative, Marshall Municipal Utilities, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy. Contact information for these utilities can be found in Appendix IX.

The Midwest Independent Transmission System Operator (MISO) is a Federal Energy Regulatory Commission (FERC) recognized Regional Transmission Organization (RTO). MISO provides non-discriminatory, open access to electricity and serves as the regional hub for the flow of electric energy in a 15-state area, including Minnesota. More information on MISO and its role can be found in the first section of this Report. In order to insure continued reliability of the regional transmission system and continued access to competitive electric energy, MISO has developed a regional transmission expansion plan. A copy of this plan, the *MISO Transmission Expansion Plan – 2003 MTEP-03* can be found on the MISO web site, at www.midwestiso.org/plan_inter/expansion.shtml. Although not all of the transmissions owners in the Southwest Planning Zone are members of MISO, this expansion plan has included data form all the owners. The *2003 Minnesota Biennial Transmission Projects Report* here includes updates to the MTEP-03 that are in the process of getting incorporated in the MISO update to the MISO Transmission Expansion Plan.

All of the utilities in the Southwest Planning Zone participate in the MAPP, a regional transmission reliability group. MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the *Regional Load and Capability Report* produced by MAPP can be found on the MAPP web site at www.mapp.org. More information on MAPP and its role can be found in the first section of this Report.

The *2003 Minnesota Biennial Transmission Projects Report* includes updates to the *MAPP 2002 Regional Plan* and are in the process of getting incorporated in the 2003 update to the *MAPP Regional Plan*. A copy of the *MAPP 2002 Regional Plan* can be obtained from MAPP (*see* Appendix I for contact information).

III. Transmission System Inadequacies and Alternative Solutions

This section provides information on the inadequacies that have been identified in the Southwest Planning Zone transmission system over the next ten years. It also provides information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental and social issues associated with each alternative.

The transmission system in this zone is studied regularly by the transmission owners in this zone. The most recent study for this area is the *Southwest Minnesota Load Serving Study*. This study, still in progress, is expected to be completed by the end of this year (2003). Because of the large geographic area of the Southwest Planning Zone, it has been more efficient, from a practical analysis standpoint, to divide the zone into smaller study areas. The following discussion presents the results of these studies by subzonal areas:

JACKSON AREA

A. Inadequacies

This area is served by a 69 kV transmission system with sources at Fox Lake and Heron Lake. Approximately 13 MW of load are connected to the system midway between the sources. Some of the existing transmission lines have very low thermal ratings (11 MVA for the Heron Lake to Miloma tap 69 kV line). The design of these lines is under review to determine whether increased ratings are possible.

The long distances from the 69 kV sources result in voltage violations during system intact (Jackson at 90.2% in 2001 summer). With a contingency on one of the 69 kV sources lines (Dunnel to Fox Lake tap 69 kV), the voltages at Jackson fall to 85.1%, also in 2001 summer. Thermal overloads of several lines occur during contingencies due to their low ratings.

B. Alternative Solutions

Four alternatives were developed for the Jackson area. All of the alternatives bring new transmission sources into the area to provide additional voltage support during system intact and contingency conditions. Because of the severity of the voltage problems in this area, particularly the fact that the system intact voltages are already below the contingency criteria, two new sources are required for the Jackson area. All of the alternatives below introduce two new sources.

1. Jackson Area Alternative #1 (A1): New Fox Lake-Lakefield Junction 161 kV line

This alternative consists of the following transmission components:

- 20 miles of 161 kV line from Fox Lake to Jackson to Lakefield Junction (coordinated with Xcel Energy's plans for expanding the wind transmission outlet in southwestern Minnesota);
- 6 miles of 69 kV line from Jackson to Lakefield; and
- new 161/69 kV substation at Jackson.

This option utilizes the Xcel Energy plan to expand the transmission network in southwestern Minnesota to accommodate the large amount of wind generation being developed along the Buffalo Ridge. The Xcel Energy plan includes the addition of a second, 161 kV circuit from Fox Lake to Lakefield Junction. If the new line is routed south of the existing Fox Lake to Lakefield Junction 161 kV circuit (along interstate highway I-90) it would be in the proximity of the Jackson area, and cost savings could be realized by tapping the new circuit with a new 161/69 kV substation at Jackson. This would be one of the two new sources required into the Jackson area.

The second new transmission source would be established by constructing the six miles of 69 kV line from Jackson to Lakefield Junction. This utilizes the existing 161/69 kV substation at Lakefield Junction. This new 69 kV transmission line could be constructed as a second circuit on a double circuit 161-69 kV line from Lakefield Junction. This would minimize the amount of new right-of-way required. The circuit breaker configuration at the Jackson 161/69 kV substation would have to be arranged so that both new sources are not lost simultaneously.

2. Jackson Area Alternative #2(A2): Fox-Lake-Lakefield Junction 161 kV line

This alternative consists of the following transmission components**:**

- 5 miles of 161 kV line from Jackson to Jackson tap;
- 6 miles of 69 kV line from Jackson to Lakefield Junction; and
- new 161/69 kV substation at Jackson.

This option also introduces two new transmission sources into the Jackson area but uses the existing Fox Lake-Lakefield Junction 161 kV transmission line. It also includes construction of a new 69 kV line from Jackson to Lakefield Junction as the second transmission source.

3. Jackson Area Alternative #3 (A3): Tap new Fox Lake-Lakefield Junction 161 kV line with two transformers at Jackson

This alternative A3 consists of the addition of the following transmission components:

- 20 miles of 161 kV line from Fox Lake to Jackson to Lakefield (coordinated with Xcel Energy's plans for expanding the wind transmission outlet in southwestern Minnesota); and
- New substation at Jackson with two 161/69 kV transformers.

This option also takes advantage of the proposed Xcel Energy 161 kV line from Fox Lake to Lakefield Junction, but installs two 161/69 kV transformers at Jackson instead of constructing the 69 kV circuit from Jackson to Lakefield Junction. The two transformers would have to be separated on both the high side (161 kV) and the low side (69 kV) by circuit breakers in order to prevent losing the two 161 kV sources simultaneously.

4. Jackson Area Alternative #4 (A4): Tap the existing Fox Lake—Lakefield Junction 161 kV line

This option would tap the existing Fox Lake-Lakefield Junction 161 kV line and bring a 161 kV loop (two separate routes, not a double circuit) into a new 161 kV/69 kV substation near Jackson. It would consist of the following transmission components:

- 10 miles of 161 kV line (2 independent circuit routes);
- Two 161/69 kV transformers at Jackson; and
- 69 kV components to complete a loop around the Jackson loads.

C. Economic, Environmental and Social Issues Associated with Each Alternative

Economic Summary of Alternatives #s 1-4

Description of Alternative	Base Cost
Alternative 1 (tap new Fox Lake-Lakefield Jct. 161 kV second circuit, 69 kV from Lakefield Jct.)	$ 11,950,000
Alternative 2 (tap existing Fox Lake-Lakefield Jct. 161 kV line, 69 kV from Lakefield Jct.)	$ 4,765,000
Alternative 3 (tap new Fox Lake-Lakefield Jct. 161 kV second circuit with two transformers at Jackson)	$ 12, 279,000
Alternative 4 (tap existing Fox Lake-Lakefield 161 kV, two transformers and two 161 kV lines to Jackson	$ 6,579,000

The last column of the above table recognizes that the cost associated with the constructing the second. Fox Lake-Lakefield Jct. 161 kV circuit can be attributed to the need for expanding the transmission in southwestern Minnesota to provide outlet for the wind generation. Thus the incremental cost is reduced.

The costs for these alternatives may be compared in two ways: one comparison to determine a choice between a second 161/69 kV transformer at Jackson versus a 69 kV line from Lakefield Junction; and a second comparison to show what cost savings are realized if the new Xcel Energy 161 kV line is routed along the southern route (i.e. I-90 corridor).

To determine the choice of a second transformer versus a 69 kV line from Lakefield Junction, the costs of Alternative 1 would be compared to Alternative 3 (take advantage of the new Xcel Energy line-southern route) *or* the costs of Alternative 2 would be compared to Alternative 4 (use existing line). In both comparisons the cost of installing a second 161/69 kV transformer at Jackson is higher than building a 69 kV line from Jackson to Lakefield Junction. Therefore, the 69 kV line option, Alternative 1 or 2, is the preferred alternative in this comparison.

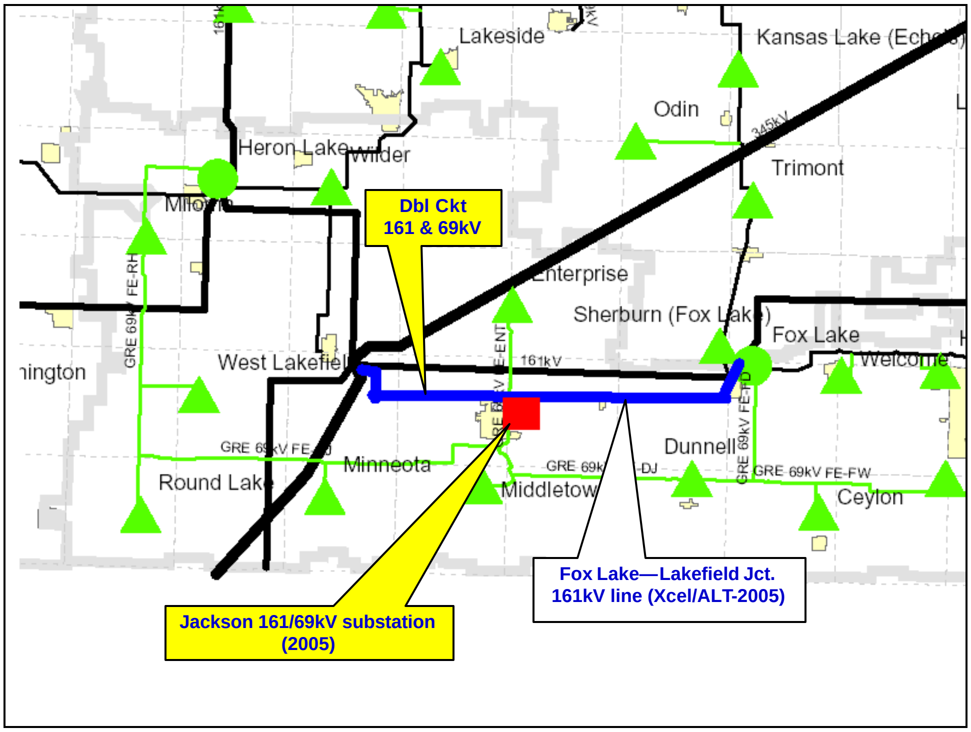
To determine the benefits of a southern route for the new Xcel Energy 161 kV line from Fox Lake to Lakefield Junction, the cost for Alternative 1 would be compared to the cost for Alternative 2 *or* the cost or Alternative 3 would be compared to the cost for Alternative 4. Again, in both comparisons the availability of a southern 161 kV line would be less costly than using the existing 161 kV line. For example, choosing Alternative 1 ($ 3,750,000) over Alternative 2 ($ 4,765,000) would save approximately $ 1,000,000.

D. Recommendation

The four alternatives are very similar in scope. Each relies on the new Jackson 161/69 kV substation as the main component to provide one of the new sources. Based on the cost comparison in the table, the construction of a new 69 kV circuit from the Lakefield Junction substation is part of the lowest cost options (Alternative 1 or Alternative 2), in comparison to installing two 161/69 kV transformers at Jackson (Alternative 3 or Alternative 4). It is therefore also a fundamental element to the recommended plan. The only unknown is whether or not it is possible to take advantage of synergies with the proposed Xcel Energy wind outlet plan by the routing of the Fox Lake to Lakefield Junction 161 kV line.

The recommendation is to construct a new 161/69 kV substation at Jackson and a new 69 kV line from Jackson to Lakefield Junction. The ultimate route of the 161 kV line from Fox Lake to Lakefield Junction will be determined in the EQB routing process.

Fox Lake – Lakefield Junction



ST. JAMES AREA

A. Inadequacies

This area is characterized by a relatively large municipal utility load located a long distance (electrically) from the 69 kV transmission sources. By 2006, even with the system intact, the voltage at St. James falls below criteria (92.8%) unless the local generation is on-line (96.2%). With the local generation on-line and the contingent outage of the Fox Lake-Sherburne 69 kV line, the voltage at St. James drops to 91.6%. Without the local generation, the voltage would drop to 86%. Numerous other outages involving the other sources (Heron Lake, Rutland or Wilmarth) also result in low voltage at the St. James busses.

Line overloads are also projected to occur beginning by 2006 on the first leg of the lines from the 69 kV sources. In 2006, with the outage of the Fox Lake-Sherburne 69 kV line, the Truman-Rutland 69 kV line loads to 107% of rating.

B. Alternatives

Based on the results showing low voltage problems due to the distance to the sources, the alternatives developed for the St. James area need to introduce a new source in 2006 and preferably a source that could include the options for connecting some of the larger loads directly to 115 kV transmission. The nearby 345 kV transmission line from Lakefield Junction to Mankato provides an obvious new source for this area. Both of the alternatives developed include a new connection to this 345 kV line: one at the existing Lakefield Junction Generating Station (LGS) and one at a new 345 kV station in Fieldon Township, Watonwan County.

Two long-range alternative visions have been developed for this area.

1. St. James Area Alternative #1: New 115 kV source at Lakefield Generating Station ("LGS") in 2006

The long-range vision for this alternative consists of the following transmission components:

- new 345/115 kV transformer connected to the existing 345 kV bus at LGS (one new 345 kV breaker in the ring bus);
- 9 miles of 115 kV double circuit line to Butterfield;
- 50 miles of 115 kV line from Butterfield to Madelia to Fort Ridgely;
- 10 miles of 115 kV line from Butterfield to Mountain Lake;
- 115/69 kV transformer connection into the existing Madelia 69 kV switching station;
- 115/69 kV transformer connection into the existing Mountain Lake 69 kV switching station; and
- convert the GRE St. James, GRE Searles and the St. James municipal utility loads to 115 kV (4 substations).

This alternative introduces a new 115 kV source into the area and converts the larger loads to 115 kV. It also includes converting some of the smaller loads along the existing 69 kV transmission route to 115 kV operation.

This option takes advantage of the pre-existing LGS 345 kV substation property and equipment. By converting the larger load in this area (St. James municipal utility), the 69 kV system is unloaded. The addition of new 115/69 kV sources at Madelia and Mountain Lake is also needed to reduce the length of transmission line miles from the existing 69 kV sources.

2. St. James Area Alternative #2: New 345/115 kV substation in Fieldon Township in 2006

This alternative consists of the following transmission components:

- new 345/115 kV substation in Fieldon township, Watonwan County that taps the LGS-Wilmarth (Mankato) 345 kV line'
- 30 miles of 115 kV line from Fieldon to Fort Ridgely;
- 24 miles of 115 kV line from Fieldon to Mountain Lake;
- 115/69 kV transformer addition at the existing Madelia 69 kV switching station;
- 115/69 kV transformer addition at the existing Mountain Lake 69 kV switching station; and

- convert 4 substations (Searles and St. James (3)) to 115 kV.

This option also converts the large load in the area (St. James Municipal Utility to 115 kV and alleviates the voltage drop on the 69 kV system. The introduction of the new 69 kV source at Madelia also improves the voltage profile for the remaining 69 kV loads.

C. Economic, Environmental and Social Issues Associated with Each Alternative

The costs of the alternatives are as follows:

Alternative B1 (new 345/115 kV at LGS)	$ 25,818,575
Alternative B2 (new 345/115 kV at Fieldon)	$ 23,356,000

Other factors that need to be considered include:

- The environmental impacts of using an existing site (the 345 kV station already located near the Lakefield generating station) are much less than establishing a new 345/115 kV substation site on an undeveloped site.
- The costs of Alternatives 1 and 2 are relatively equal, but the uncertainties involved with permitting a new 345 kV site could significantly increase the estimated costs for Alternative 2.
- Alternative 2 provides some additional transmission outlet capability for LGS by connecting local load directly to the generation. Although not included in the above analysis, the inherent benefit of fewer output restrictions of LGS due to the present transmission limitations could be estimated as the utilities work toward a final recommendation.

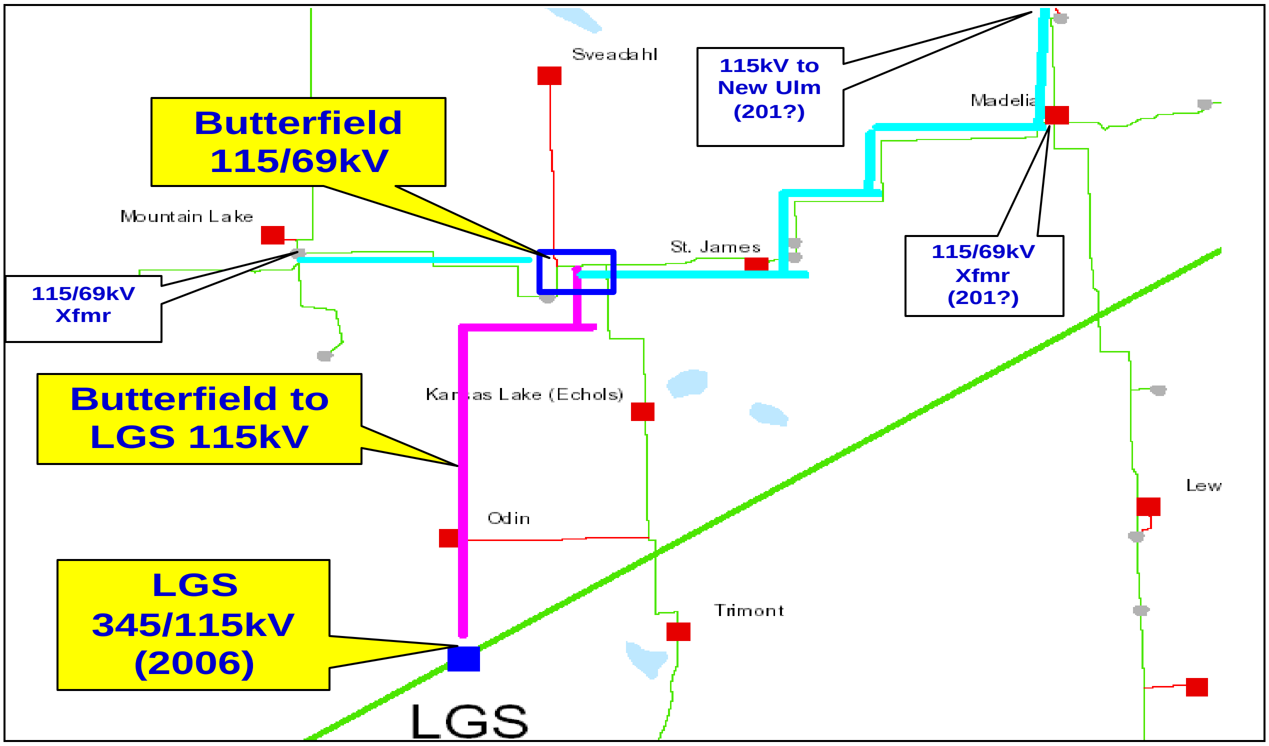
D. Recommendation

Alternative 1 is recommended based on the following:

- relatively equal costs compared to Alternative 2;
- use of an existing 345 kV substation rather than establishing a new site; and
- provides some additional outlet for the LGS by connecting local load directly to the generation.

The expected initial (first-step) development includes a new 69 kV switching station and capacitor bank near Butterfield followed by a new 115 kV line from LGS to the new switching station and a 115/69 kV transformation in the 2005-2007 timeframe. Final decisions on this first step are awaiting completion of the study and are expected later this year. Other steps in the long-range plan, such as continuation of the 115 kV line from Butterfield to New Ulm or other alternatives, would be reviewed and developed as load growth warranted. It is generally expected, however, that further expansion of the transmission system in this area is necessary.

St. James Area Transmission Projects



MARSHALL AREA

Marshall Municipal Utilities "MMU" owns and operates a 115 kV loop around the City of Marshall for load serving.

A. Inadequacies

Regional studies have identified that additional capacity will be required to serve MMU's future load. Xcel Energy has performed a high level study which identified the need for improvements in the area to serve future load growth. Timing for the transmission improvements was not determined in the study. MMU will be performing a study to determine the required improvements in the area for load growth.

B. Alternative Solutions

Any alternatives to new transmission will be determined and analyzed during the study.

C. Economic, Environmental and Social Issues Association with Each Alternative

The economic, environmental and social impacts will be determined when the required facilities are determined.

D. Recommendation

MMU will be performing a study to determine the required improvements in the area for future load growth.

WIND GENERATION OUTLET

generation development on the Buffalo Ridge area in Minnesota has become one of the primary drivers for future transmission needs in southwestern Minnesota. The Buffalo Ridge extends from southwest North Dakota, through northeast South Dakota, southwest Minnesota and into northwest Iowa. The Buffalo Ridge is considered to have the best resource for wind generation in the region. Independent Power Producers ("IPP"), both large and small, have been very active in attempting to develop new wind farms and expand the wind generation industry in the upper Midwest. Total wind generation has increased 25 MW in 1994 to 360 MW today.

The first section of this Report includes a map that identifies the location of new generation requests in the MISO generation interconnection queue. The large number of requests in northeast South Dakota, southwest Minnesota, and northwest Iowa represents approximately 5,000 MW of proposed generation additions in the area. Most of this is wind power. While much of this is speculative, it nonetheless shows the strong interest in continued wind generation development.

Most of the early wind generation development has occurred in Minnesota on the Xcel Energy system. The transmission in this area is roughly defined by the communities of Granite Falls on the north to Pipestone on the south. The area is currently served by a 115 kV line south from Minnesota Valley to Pipestone; from White, South Dakota to near Ivanhoe, Minnesota; and from Flandreau, South Dakota to Holland, Minnesota, with a parallel 69 kV system.

As this part of the state is primarily sparsely populated, rural farmland, most of any wind generation needs to be exported from this area to load centers in the more populated regions, mainly the Twin Cities. The Xcel Energy renewable energy purchase obligations imposed by the legislature and Commission, and smaller commitments by many of the other utilities far outstrip capability of the existing transmission system.

Recent studies in this area include:

- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW) Volume 1 and 2* (November 13, 2001);
- *Southwest Minnesota/Southeast South Dakota Electric Transmission study, Volume 1 and 2* (November 13, 2001);
- *Preliminary results of an interconnection study for 36-130 MW of wind generation near Chanarambie, Minnesota*, (January 11, 2001); and
- *Xcel Energy Certificate of Need Application, Docket No. E002 (CN-01-1958).*

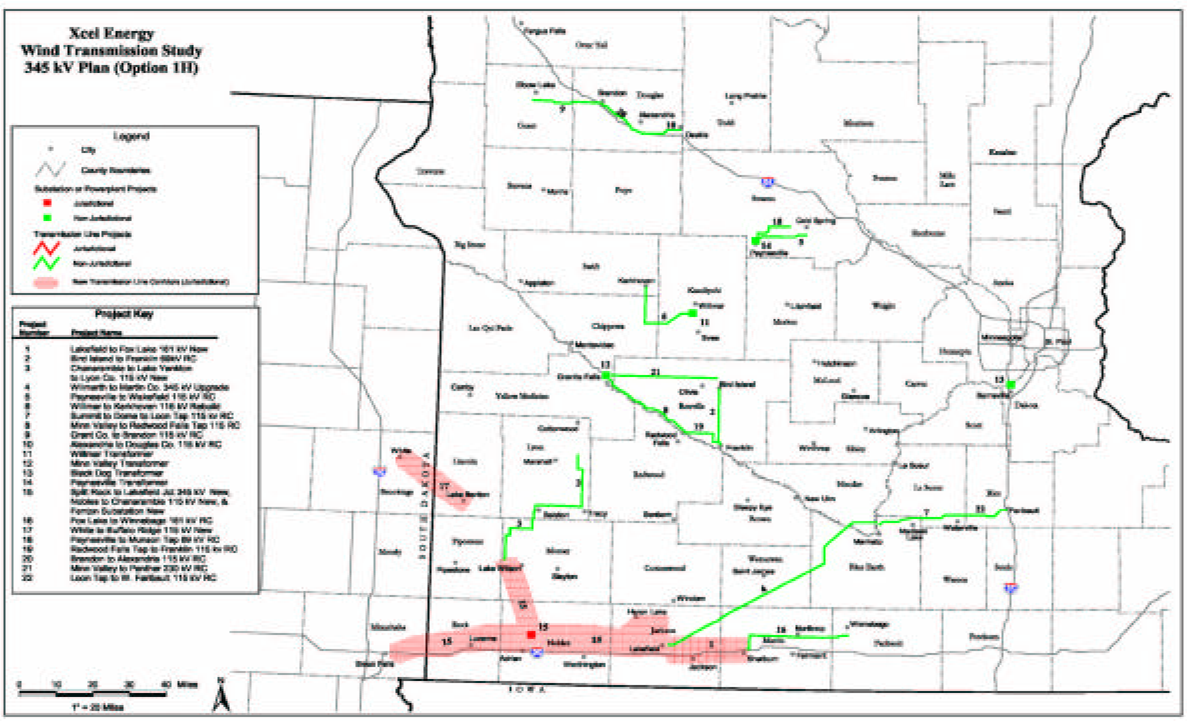
A. Inadequacies

There is presently insufficient transmission capacity to provide firm transmission service for more than 264 MW of wind generation from the Buffalo Ridge area. The existing transmission system and several system improvements options were evaluated to determine appropriate transmission additions to accommodate up to 825 MW of power output from the wind generation on the Buffalo Ridge.

B. Alternatives

Four alternatives were extensively analyzed as part of Xcel Energy's Certificate of Need filing in Docket No. E002 (CN-01-1958). On March 11, 2003, the MPUC approved the development of the alternative known as *"Option 1H"* and awarded the necessary certificate of need for four transmission lines. Further information on the certificate of need filing may be obtained on the Xcel Energy web site, at www.xcelenergy.com

Southwest Zone Wind Transmission



The proposed transmission developments to incorporate 425 MW of wind generation include the following principle components:

- 26 miles of new 115 kV line from Chanarambie to Lake Yankton;
- 27 miles of new second 115 kV line from Lake Yankton to a new Lyon County substation near Marshall;

- A +/- 60 MVAR static var compensator (SVC) along with two 20 MVAR, 115 kV capacitor banks at Lake Yankton;
- 27.2 miles Minnesota Valley-Redwood Falls 115 kV reconductor; and
- Upgrade Wilmarth-Martin County 345 kV line to 100C design temperature.

The above additions to the system are scheduled to be in service by the end of 2004. There are several smaller related upgrade projects associated with Option 1H.

To achieve 825 MW of wind generation outlet, the plan's major components include:

- A new 345 kV line from Lakefield, Minnesota to Sioux Falls, South Dakota;
- A new 115 kV line from the existing Chanarambie wind generation collection substation north to a new Lyon County substation near Marshall, Minnesota;
- A new 115 kV line from the existing Chanarambie wind generation collection substation south to the new 345 kV line;
- A new 161 kV line from Lakefield Junction substation to the Fox Lake substation in Minnesota;
- A new 115 kV line from the Buffalo Ridge wind generation collection substation west to a Western Area Power Administration (WAPA) substation near White, SD;
- Two new wind generation collection substations (known as Fenton and Yankee) on the new 115 kV lines along the Buffalo Ridge north and south of the existing collection substations; and
- Reconductor the Redwood Falls-Franklin 115 kV line (13 miles).

Certain of these projects require construction on neighboring systems, such as IPL.

Relief of the "Fort Calhoun South" constrained interface on the Omaha Public Power District System near Omaha, NE is also a principal feature of the recommended plan. More analysis still needs to be done to address this issue.

D. <u>Economic, Environmental and Social Issues Associated with Each Alternative</u>

In evaluating the economics of the wind outlet alternatives, the cost of the base plan, other required upgrades, mitigating the Ft. Calhoun South constrained interface and the financial impact of losses for each alternative were taken into account. The details of the financial analysis can be found in the Xcel Energy Certificate of Need filing and PUC Order.

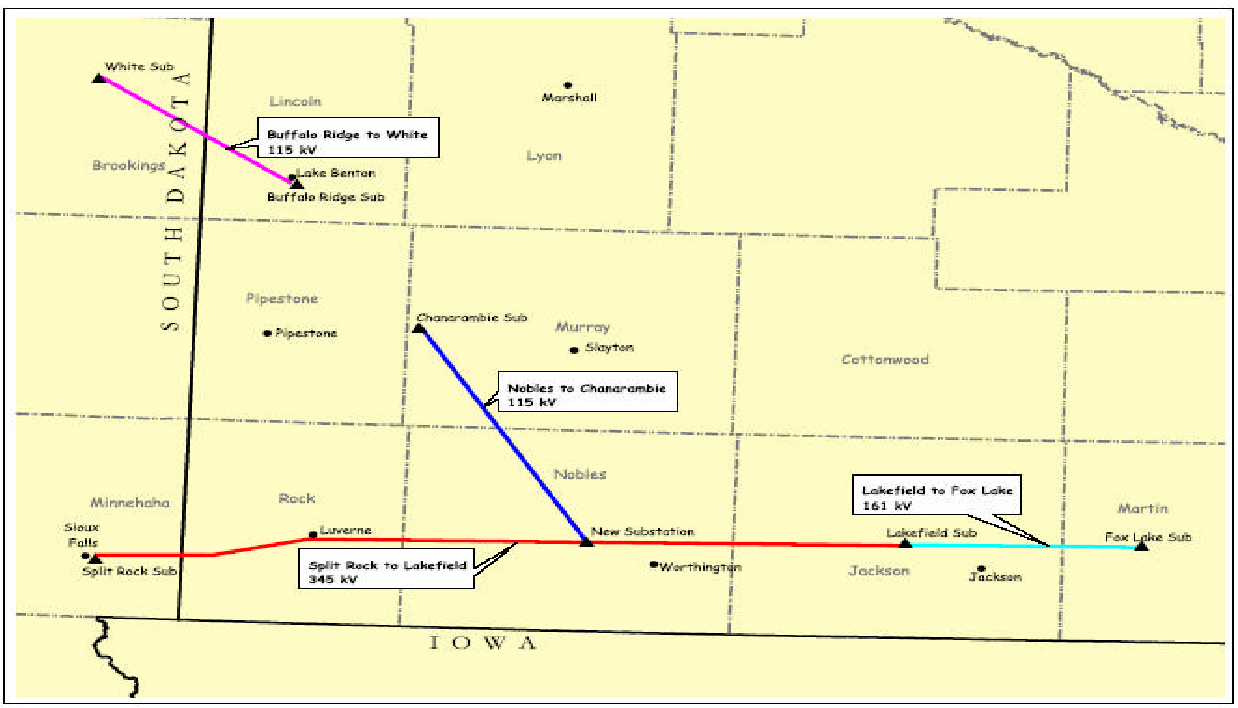
E. <u>Recommendation</u>

Based on the study efforts, it is readily apparent that the impacts of the need for wind generation outlet are not just localized to the Southwest Zone where the generation is being developed. The addition of wind generation has regional impacts, including transmission upgrades throughout the southern half of Minnesota. It also requires projects that cross state lines into South Dakota. In addition, the study work and the development plans identified the Fort Calhoun South constrained interface limit that will need to be addressed prior to reliably incorporating this level (825 MW) of wind generation. Finally, the wind generation outlet is not a single utility issue, since multiple utilities transmission systems are impacted.

Moreover, there already are sufficient requests for the interconnection of wind generation projects that even the 825 MW level transmission capacity (expected to be in place in 2007) is being exceeded. The transmission and generation system is also not static. There is now also significant new wind generation development in northern Iowa. Interest is also extending into eastern South Dakota. Just as the Minnesota wind generation developments impact other utilities and states, developments in neighboring states impact the transmission capability in Minnesota. As more wind generation is developed in and around the Buffalo Ridge, the impacts are expected to get geographically broader.

One major strategic issue that policy makers and stakeholders should start addressing in the near future is the long-term vision of the Minnesota wind generation industry. With the good wind resources available in parts of the state, does Minnesota want to develop this industry to be an export product for the state? This will require a transmission delivery network expansion designed to reach such external markets.

Transmission Projects for Wind Generation Outlet



IV. Studies of Issues in the Southwest Zone

- *Southwest Minnesota Load Serving Study* (in progress, expected to be completed by the end of 2003);

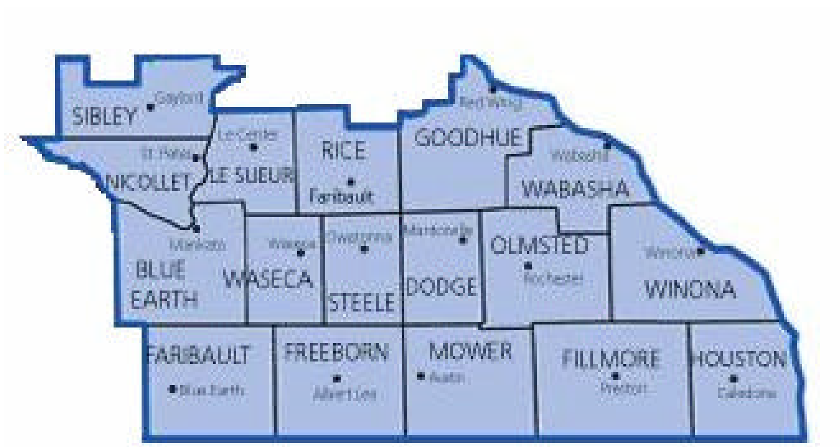
- Plan 1H, In the matter of the application of Northern States Power Company d/b/a Excel Energy for certificate of need for four large high voltage transmission line projects in southwestern Minnesota, Docket No. E002/CN-01-1958;
- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW) Volume 1 and 2* (November 13, 2001);
- *Southwest Minnesota/Southeast South Dakota Electric Transmission study, Volume 1 and 2* (November 13, 2001);
- *Preliminary results of an interconnection study for 36-130 MW of wind generation near Chanarambie, Minnesota* (January 11, 2001); and
- *Xcel Energy Certificate of Need Application, Docket No. E002/CN-01-1958, Option 1H.*

Southeast Transmission Planning Zone

I. Introduction

The Southeast Planning Zone represents Blue Earth, Dodge, Faribault, Fillmore, Freeborn, Goodhue, Houston, LeSueur, Mower, Nicollet, Olmsted, Rice, Sibley, Steele, Wabasha, Waseca, and Winona Counties. The zone is bordered by the State of Iowa to the south, the Mississippi River to the east, the Twin Cities Planning Zone and West Central Planning Zone to the north, and the Southwest Planning Zone to the west.

Southeast Transmission Planning Zone



A land use map is located in Appendix IX. With the exception of the city of Rochester, the Southeast Planning Zone is primarily agricultural land with communities having populations of less than 10,000. The primary locations of concentrated industrial and residential development are along Interstates 90 and 35 and State Highways 14 and 52. Using a city population of 10,000 or more as a baseline, the zone contains the following population centers: Albert Lea, Austin, Faribault, Mankato, North Mankato, Northfield, Owatonna, Red Wing, Rochester, and Winona.

The Southeast Planning Zone is predominantly agricultural in nature with primary electrical users being residential and agri-business related. Manufacturing, health care, and some industrial customers are located in the larger communities within the zone.

The transmission system in the Southeast Planning Zone consists of 345 kV, 161 kV, 115 kV and 69 kV lines that serve lower voltage distribution systems. The 345 kV system is used to import power to the Southeast Planning Zone for lower voltage load service from generation stations outside of the area. The 345 kV system also allows the seasonal and economic exchange of power from Minnesota to the east and south from large generation stations that are located within and outside of the zone. The 161 kV and 115 kV systems are used to carry power from the 345 kV system and from local generation sites to the major load centers within the zone.

From the regional load centers and smaller local generation sites, 69 kV lines are used for load service to the outlying areas of the Southeast Planning Zone.

A map showing the 100 kV and above transmission facilities located in Minnesota is located in Appendix VII. This map also identifies the Southeast Planning Zone and the other State Transmission Planning Zones.

II. Utility Contacts and Regional Transmission Organization Participation

The utilities which own transmission facilities within the Southeast Planning Zone include Great River Energy ("GRE"), Dairyland Power Cooperative ("DPC"), Interstate Power and Light Company ("IPL"), Rochester Public Utilities ("RPU"), Southern Minnesota Municipal Power Agency ("SMMPA"), and Xcel Energy. Contact information for these utilities can be found in Appendix I.

All the utilities in the Southeast Planning Zone participate in the MAPP, a NERC regional transmission reliability group. MAPP coordinates regional transmission reliability studies and transmission planning studies. A copy of the Regional Load and Capability Report produced by MAPP can be found on the MAPP web site, at www.mapp.org. More information on MAPP can be found in the first section of this Report.

The *2003 Minnesota Biennial Transmission Projects Report* includes updates to the *MAPP 2002 Regional Plan* and are in the process of getting incorporated in the 2003 update to the MAPP Regional Plan. A copy of the *MAPP 2002 Regional Plan* can be obtained directly from MAPP (see Appendix I for contact information).

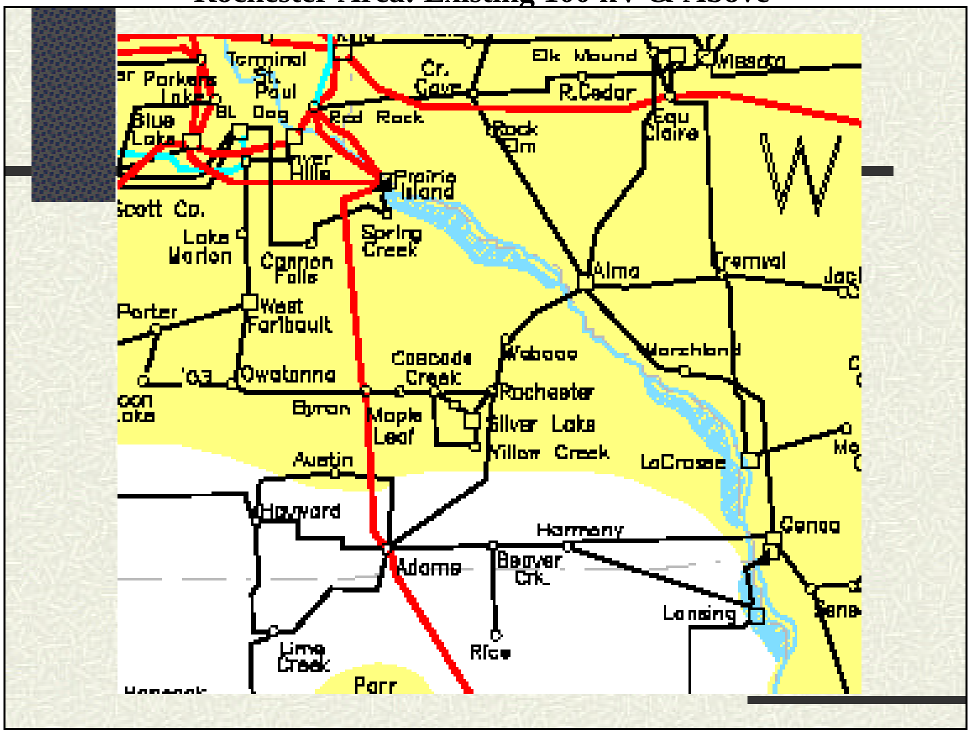
The Midwest Independent System Operator ("MISO") is the most appropriate Regional Transmission Organization ("RTO") for this zone and although not all of the transmission owners in the Southeast Planning Zone are members of MISO, the MISO expansion plan has included data from all the owners. A copy of this plan, the Midwest ISO Transmission Expansion Plan–2003 ("MTEP-03") can be found on the MISO web site, at www.midwestiso.org/plan_inter/expansion.shtml. More information on MISO can be found in the first section of this Report. This report includes updates to the MTEP-03 that are in the process of getting incorporated in the MISO update to the MISO Transmission Expansion Plan.

III. Transmission System Inadequacies and Alternative Solutions

This section provides information on the inadequacies that have been identified in the Southeast Planning Zone's transmission system over the next ten years. It also provides information on alternative means of addressing each inadequacy, studies that are planned to determine the best method to correct each inadequacy, and economic, environmental and social issues associated with each alternative.

ROCHESTER AREA

Rochester Area: Existing 100 kV & Above



A. Inadequacies

1. Byron-Maple Leaf 161 kV Line

With the Byron-Maple Leaf 161 kV line out of service, voltage and other considerations on the DPC system limit the input from the east into the Rochester area to about 160 MW. RPU and DPC load in the Rochester area is currently approximately 290 MW during summer peak conditions. The Rochester area load growth is projected to require more than 160 MW of import in 2008 with the Byron-Maple Leaf 161 kV line out of service and all local area generation in service. A formal operating guide is on file with MAPP/MISO regarding this condition.

2. Rating on the Byron-Maple Leaf 161 kV Line

The rating on the Byron-Maple Leaf 161 kV line is a limiting factor in setting the transfer limit on the north-south portion (Prairie Island to Byron 345 kV line) of the Minnesota-Wisconsin Stability Interface ("MWSI") and thus is a contributor to the calculation of available transfer capability ("ATC") for Minnesota to Wisconsin transfers. The limit is imposed so that, during high export levels, a first contingency fault on the Byron-Pleasant Valley-Adams 345 kV line will not overload the Byron-Maple Leaf 161 kV line.

3. Load Serving Along the Red Wing-Alma 69 kV Line

Outages along the Red Wing-Alma 69 kV line can result in low voltage and thermal overloads along the line.

4. Serving Regional Base Load

This past summer the utilities in southeast Minnesota had difficulty obtaining transmission services under the MISO OATT (Open Access Transmission Tariff) to deliver firm generation purchases from outside the area to serve regional base load. Higher priced natural gas peaking units were run to supplement the loss of the purchased energy. Likewise, utilities in southeast Minnesota were at times unable to sell excess generation to utilities outside the area due to the same transmission limitations. Congestion of this type is expected to escalate in both magnitude and frequency.

B. Alternative Solutions

None of the alternative transmission projects listed below are seeking certification as part of this Report. RPU estimates that it will request a certificate of need in 2004 for a new transmission line to mitigate the identified inadequacies.

1. Rochester Area Alternative #1: New Transmission Tie

Inadequacies 1 and 2 can be eliminated with the addition of a new transmission tie into the Rochester Area. The following is a projected list of new transmission ties that are currently under evaluation:

- a 345 kV line from Byron to Pleasant Valley that loops around and taps on the eastern border of Rochester;
- a 345 kV line from Byron to DPC Rochester, with a 161 kV line from DPC Rochester to Pleasant Valley;
- a 345 kV line from Prairie Island to Adams that taps on the eastern border of Rochester;
- a 161 kV line from Prairie Island to Quarry Hill, with a 161kV line from Byron to Northern Hills;
- a 161 kV line from Prairie Island to Frontenac to Alma, with a 161 kV line from Frontenac to Quarry Hill, and a 161 kV line from Byron to Northern Hills; and
- a 161 kV line from Pleasant Valley to Quarry Hill, with a 161 kV line from Byron to Northern Hills.

Each of the proposed transmission line solutions will be evaluated based on the results of system impact studies using powerflow programs, economic analysis of the estimated construction costs, and regulatory and permitting feasibilities. Further, each solution will be evaluated based on social and environmental impacts for the area of Southeast Minnesota affected.

2. Rochester Area Alternative #2: Additional Generation

Inadequacies 1 and 3 above could be mitigated by increasing local generation within the Rochester Area by expansion of RPU's Silver Lake Plant, large installments of distributed generation, or large local wind installations. Extensive system impact studies using powerflow programs, economic analysis of the estimated construction costs, and regulatory and permitting feasibility analysis would be required for any significant local generation addition.

3. Rochester Area Alternative #3: Phase-Shifting Transformer

The inadequacy of the rating on the Byron-Maple Leaf 161 kV line could potentially be mitigated by installing a phase-shifting transformer on the Byron side of this line. System impact studies using powerflow programs would be required to generate the operational procedures for the phase shifting transformer and to verify that the addition of a phase-shifting transformer would not cause degradation to another portion of the bulk transmission system. Economic analysis of the estimated installation and operational costs would also be required. Additional powerflow programs dynamic analysis would be required to study the stability of the bulk transmission system in the local area if the phase-shifting transformer was out of service. The installation of a phase-shifting transformer would, at best, forestall installation of one of the other alternatives listed as the load in the area continues to grow. It does not replace the need for new transmission capacity into the area or generation in the area.

C. Economic, Environmental and Social Issues Associated with Each Alternative

Local generation is the most expensive alternative to construct and operate. Distributed generation and coal facilities are required to meet MPCA, EPA, and MEQB emission regulations and may face local opposition. For localized wind generation, the immediate Rochester Area has a low sustained wind coefficient, making wind generation a low efficiency source and difficult to cost justify. In addition, wind generation output is not always available.

Transmission is a moderate cost alternative. In considering the possible new transmission lines in Alternative 1, it appears there are limited existing corridors available for routes in this area due to the hilly and wooded terrain. Corridor-sharing opportunities may be available along some the major roads, some of which are known for their scenic qualities. There are state parks and large expanses of state forest in this area and the potential for visual impact concerns along the Mississippi River valley. The possible environmental impact of some of the proposed transmission line solutions includes acquiring right-of-way through state parks or along the Mississippi River valley. Any new transmission addition may impact landowners and tribal communities close to or on the transmission line corridor right-of-way.

Impacts of 345 kV transmission alternatives are usually considered to be greater than 161 kV alternatives. However, some of the above 161 kV solutions would need to include additional generation in order to provide the power supply equivalent to the 345 kV solutions. The impacts of the 345 kV solutions must be compared to the impacts of both the transmission and generation projects that will be required in equivalent 161 kV solutions.

Adding a phase-shifting transformer is the lowest cost alternative. An economic ramification of a phase-shifting transformer is the possible need to upgrade facilities on the bulk transmission system that are overloaded under first contingency due to the operational characteristics of the transformer. The environmental impact of this alternative will be the expansion of an existing 161 kV substation and the upgrades of the existing local transmission lines that become overloaded from the operation of the unit during a contingency. There may be public opposition to substation expansion and the upgrades of the existing local transmission system.

D. Recommendation

After evaluating the issues and potential solutions listed above, a transmission solution is recommended. Further studies are underway on the six transmission alternatives listed above. These analyses will be provided in the 2005 Biennial Report, or in certificate of need filings before 2005.

When the area transmission constraints are considered in relation to other regional issues, including the MWSI issue discussed in the Twin Cities Planning Zone, a more regional solution may have the greatest benefit. However, the Rochester Area load-serving deficiencies require that a solution be completed in the 2007/2008 time frame.

SOUTHWEST MINNESOTA WIND GENERATION OUTLET

A. Inadequacies

Wind generation developments on the Buffalo Ridge area in southwestern have become one of the main drivers for future transmission needs in much of the southern half of Minnesota. The primary discussion of the transmission inadequacies and requirements due to wind power development and the related need for wind generation outlet are discussed in the Southwest Planning Zone section of this report. However, several transmission upgrades in the Southeast Planning Zone are required in order to meet the needs of the wind generation outlet.

Several recent studies address the inadequacies in the Southeast Planning Zone.

- *Plan 1H, In the matter of the application of Northern States Power Company D/B/A Xcel Energy for certificate of need for four large high voltage transmission line projects in southwestern Minnesota* (Docket No. E002/CN-01-1958);
- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW) Volume 1 and 2* (November 13, 2001); and

- *Preliminary results of an interconnection study for 36-130MW of wind generation near Chanarambie, Minnesota* (January 11, 2001).

In addition, a study is planned of the next stage transmission wind generation outlet from the southwest Minnesota region. Details of the study scope have not yet been developed.

B. Alternative Solutions

Discussion of the basic wind development alternatives is found in the wind generation part of the Southwest Planning Zone section of this report. However, the following specific projects are anticipated:

- reconductor the Summit (near Mankato) – West Faribault 115 kV line (35.5 miles); and
- rebuild the Fox Lake – Winnebago 161 kV (34 miles).

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The projects proposed to address wind generation outlet in this zone all use existing lines to improve the system. The rebuild and reconductor projects will minimize impact on the environment by limiting the line work to existing transmission lines routes.

D. Recommendation

The following projects are recommended in the Southeast Planning Zone related to the transmission needs associated with increased wind generation in the Southwest Planning Zone:

- reconductor the Summit (near Mankato) – West Faribault 115 kV line (35.5 miles); and
- rebuild the Fox Lake – Winnebago 161 kV (34 miles).

City of Mankato

The city of Mankato is supplied by the Wilmarth 345-115- 69 kV substation on the north side of the city and a 69 kV transmission line loop around the city. Two separate transmission issues have been identified.

A. Inadequacies

In the *GRE Long Range Transmission Study*, outage of the Wilmarth-Eastwood-Pohl Road tap 69 kV line results in an overload of the Rutland-Truman 69 kV line and low voltages in the Decoria area.

The other issue identified in the *GRE Long Range Transmission Study* is overloading of the two remaining 115-69 kV transformers at Wilmarth with an outage to any one of the three transformers.

B. Alternative Solutions

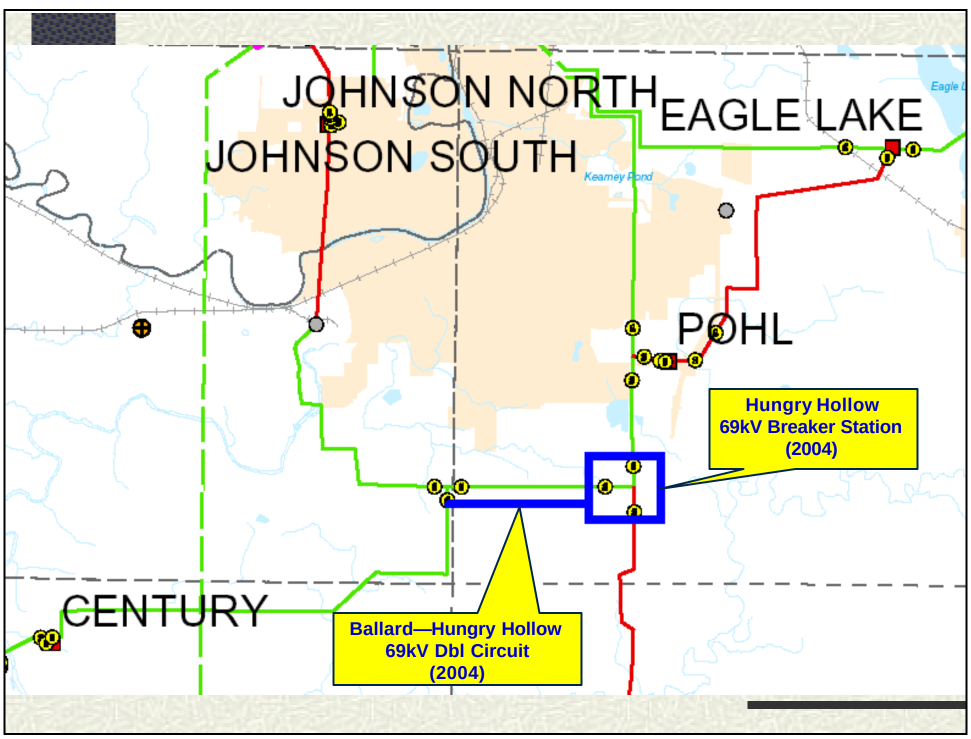
There are two options for the Wilmarth – Eastwood Pohl Road Tap 69 kV outage.

1. City of Mankato Alternative #1: Build Hungry Hollow 69 kV breaker station

This alternative adds a breaker station at Pohl Road tap (now called Hungry Hollow) and a new source from Sibley Park by rebuilding the 69 kV line the from the new breaker station to the Ballard Corner tap to Sibley Park as a double circuit. The map below shows the location of this alternative. This would allow the normally open tap to be closed. This has the added benefit of reducing the amount of line that would be affected at one time during an outage.

The double circuit would likely be built for 115 kV construction, reflecting a vision of someday converting the Mankato 69 kV loop to 115 kV. However, this would occur far beyond the present planning horizon.

Alternative 1: Hungry Hollow 69 kV breaker station



2. City of Mankato Alternative #2: Add a new 69 kV circuit from Wilmarth

This option would rebuild the Wilmarth-Sibley Park 69 kV line as a double circuit, 69 kV line and would operate the Ballard Corner-Pohl Road tap line normally open. Consideration would be given to constructing the new line at 115 kV since the long-term vision for the Mankato 69 kV loop is to upgrade to 115 kV. There are two alternatives for the Wilmarth 115/69 kV transformer overload:

a. Convert the load to 115 kV

This option reduces the loading on the 115/69 kV transformers by reconnecting the Wilmarth distribution load to 115 kV and expanding the Summit substation. The Eastwood substation is also converted to 115 kV to get significant load off the 69 kV system. The 115 kV system is extended to Eastwood by converting one Wilmarth-Eastwood line to 115 kV operation, adding a 115 kV breaker at Wilmarth (the line is already constructed for 115 kV), building a 115 kV breaker station at Eastwood and routing the Loon Tap-Summit 115 kV line through the Eastwood substation.

b. Upgrade the Wilmarth 115-69 kV transformers

This option defers the conversion of load to 115 kV by replacing the three 115/69 kV transformers with 112 MVA units. This will require a rebuild of much of the 69 kV Wilmarth substation due to higher fault currents. This alternative is expected to be adequate until about 2009 when the transformer loading again becomes an issue.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

The alternatives that would address the Wilmarth-Eastwood-Pohl Road Tap 69 kV outage are located in the southern urban area of Mankato, where the terrain is hilly. Alternative 1 passes through the expanding urban area and would require the rebuild of an existing line that should minimize impacts. It would require the siting of the new Hungry Hollow breaker station. Alternative 2 would not require this new breaker station, but would require the 69 kV line to be rebuilt as a double circuit 69 kV line, which would require taller structures. Additional right-of-way may be required. There is also concern that Alternative 2 may not be physically feasible near Sibley Park substation due to the surrounding park and rail line.

The two alternatives that address the Wilmarth transformer issue both require substation work at the major substation in the area. Alternative 1 also requires an upgrade at the Eastwood substation located near Mankato. Siting concerns related to expanding the substations may be encountered. Alternative 1 also requires the siting of a new section of 115 kV transmission line to the Eastwood substation. Routing options available for the new line section include existing roads and a 69 kV transmission line. Alternative 2 defers the need to build a new line and upgrade the Eastwood substation.

D. Recommendation

The Hungry Hollow breaker station is the recommended alternative to address the Wilmarth-Eastwood Pohl Road Tap 69 kV outage. The two alternatives are economically similar, but the new substation is viewed as more flexible for the future. There are also concerns with the feasibility of the double circuit to Sibley Park in Alternative 2.

The study is not yet complete in evaluating the two alternatives for relieving the Wilmarth transformer overload. No recommendation has been established. This study is expected to be completed within the year.

FARIBAULT AREA

A new 300 MW generating plant has been proposed by an independent power producer, Faribault Energy Park, LLC, just north of the City of Faribault near the existing 115 kV line from the Twin Cities to Faribault. The new generator is scheduled to be operational in 2004.

A. Inadequacies

A 300 MW generator would interconnect to the 115kV line from Lake Marion to West Faribault. This new generation creates or aggravates the loading inadequacies of the following transmission facilities:

- The two existing 115/69kV transformers at West Faribault;
- Lake Marion–West Faribault 115kV transmission line; and
- Circle Tap–Northfield 69kV transmission line.

B. Alternative Solutions

There are two options under investigation for providing the transmission outlet requirements for the new plant:

1. Faribault Area Alternative #1: Interconnect generation

Interconnect the generation with an in-and-out to a new 3-breaker substation off the 115kV line from Lake Marion to West Faribault. This also requires the rebuild of the entire 23 mile long Lake Marion–West Faribault 115 kV line.

2. Faribault Area Alternative #2: Interconnect generation; construct 161 kV line

Interconnect the generation with an in-and-out transmission line to a new 4-breaker substation off the 115kV line from Lake Marion to West Faribault. Also, new 161 kV line will be constructed from the new substation to the South Faribault substation. In addition to providing the generator a third transmission source, this alternative also alleviates the necessary reconductor/rebuild of the entire 23-mile 115 kV line from Lake Marion–West Faribault.

C. Economic, Environmental, and Social Issues Associated with Each Alternative

Limited routing analysis has been done. Alternative 1 requires a new breaker substation near the new generation plant and the rebuild of an existing 115 kV line that would have minimal new environmental impacts. Alternative 2 has the potential to route the new 161 kV line along an existing 115 kV or 69 kV corridor to the South Faribault substations. Both routes go through the city of Faribault, and the 69 kV line currently goes through the downtown area along a recreational trail. Routing concerns may be raised in siting the lines in a more developed area, with the possible requirement to expand the right-of-way in an area with limited space for expansion. The Cannon River would be crossed by either option.

D. Recommendation

The study evaluating the two alternatives is not yet complete. This study is expected to be completed within the next few months.

IV. Other Zone-Specific Issues

The Southeast Planning Zone has been identified as having additional wind generation potential. As these wind generation sites are identified, transmission studies will take place to determine their impact on the existing transmission system. MISO interconnection feasibility, system impact, and interconnection facilities studies will determine if there is a need for transmission line enhancements before additional wind generation is added to the transmission grid at any given point.

VI. Studies of Issues in the Southeast Planning Zone

- *Plan 1H, In the matter of the application of Northern States Power Company D/B/A Xcel Energy for certificate of need for four large high voltage transmission line projects in southwestern Minnesota* (Docket No. E002/CN-01-1958);
- *Southwest Minnesota/Southeast South Dakota Electric Transmission Study Phase 1: Transmission outlet Analysis for Southwest Minnesota (Buffalo Ridge Area) Generation Additions (0-400 MW beyond initial 425 MW) Volume 1 and 2* (November 13, 2001);
- Preliminary results of an interconnection study for 36-130MW of wind generation near Chanarambie, Minnesota (January 11, 2001); and
- *GRE Long Range Transmission Study*.

Appendix I: UTILITY CONTACT INFORMATION

Questions about this report or the status of transmission projects in this state can be directed to the following persons:

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Southern Minnesota Municipal Power Agency:

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SMMPA
500 First Avenue SW
Rochester, MN 55902-3303
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Fax: (507) 292-6414
rj.hettwer@smmpa.org
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Willmar Municipal Utilities:

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General Manager
Willmar Municipal Utilities
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Xcel Energy:

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Manager, Regulatory Administration
Xcel Energy
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Minneapolis Minnesota 55104
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james.r.alders@xcelenergy.com
Web: www.xcelenergy.com

MAPP:

Mid-Continent Area Power Pool
MAPP Center
1125 Energy Park Drive
St. Paul, MN 55108-5001
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Fax : (651) 632-8572
communications@mapp.org
www.mapp.org

Appendix II: SUMMARY OF OUTREACH EFFORTS

Minnesota's transmission-owning utilities followed an extensive public participation process, proscribed by state law[1] and newly adopted state transmission planning rules,[2] in order to inform the public of possible transmission projects and to gain public input and suggestions for transmission planning.

Fifteen utilities[3] cooperatively held a transmission planning public meeting in each of Minnesota's six transmission planning zones.[4] In the West Central and Southwest Zones afternoon and evening meetings were held; the other zones held just evening meetings.

Prior to each a meeting, a request for local government participation and designation of a liaison to communicate with the utilities on transmission issues, along with a notice of the meeting, was mailed to each county and tribal government in the zone, to the League of Minnesota Cities, to the Association of Minnesota Counties, and to the Minnesota Environmental Quality Board, the Minnesota Department of Commerce, the Minnesota Department of Agriculture, the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency, the United States Fish and Wildlife Service, and the United States Park Service.

Also prior to each meeting, a meeting notice was mailed to the Minnesota Public Utilities Commission Service List, to the 2003 Transmission Planning Mailing List,[5] and to a number of other entities, such as regional development councils, utility regulatory agencies in neighboring states, Minnesota's Congressional Delegation, Minnesota legislators for the zone, and, in some cases, individual city council and county board members. The meeting notice was e-mailed to interested citizen organizations that utilities were aware of.

Notification of each meeting was also given by a display ad placed in one or more newspapers of general circulation in the county seat and other cities in each county within the appropriate zone.

The utilities also developed a web site, www.minnelectrans.com, for the purposes of publishing notice of the transmission planning public meetings, soliciting public input in the transmission planning process, and providing background information on transmission issues. A notice of each meeting was posted on this web site, accompanied by a summary of issues specific to that zone. Following the meeting, a summary of the meeting, including a synopsis of

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1 Minnesota Statutes §216B.2425.

2 Minnesota Rules Chapter 7848, effective June 23, 2003.

3 Dairyland Power Cooperative, East River Electric Power Cooperative, Great River Energy, Hutchinson Utilities Commission, Interstate Power and Light Company, L&O Power Cooperative, Marshall Municipal Utilities, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities Commission, Southern Minnesota Municipal Power Agency, Willmar Municipal Utilities, and Northrn States Power Company d/ba/ Xcel Energy.

4 July 10, 2003 in Northwest Zone; August 20, 2003 in Northeast Zone; July 8, 2003 in West Central Zone; August 19, 2003 in Twin Cities Zone; June 10, 2003 in Southwest Zone; July 22, 2003 in Southeast Zone.

5 All who register – through the utilities' web site www.minnelectrans.com, e-mail, or by phone – for the transmission planning mailing list and all who sign an attendance register at any of the transmission planning public meetings.

public input received at the meeting and the utilities' response to specific public input, was posted. The PowerPoint presentations given at each meeting may be viewed on the web site as well. The 2003 Biennial Minnesota Transmission Projects Report will also be posted on www.minnelectrans.com. The web site includes an on-line form to submit comments or questions, and to request inclusion on the utilities' transmission planning mailing list.

Appendix III: SUMMARIES OF ZONAL PUBLIC MEETINGS

SUMMARY OF NORTHWEST ZONE TRANSMISSION PLANNING PUBLIC MEETING

The Northwest Zone electric transmission planning public meeting was held on July 10, 2003 at 7:00 p.m. at the Northland Inn, 2200 University Avenue, Crookston, MN 56716. Representatives from Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Moorhead Public Service Utilities, Otter Tail Power Company, and Xcel Energy were in attendance. Approximately 12 members of the public attended the meeting.

The meeting began with remarks by Ken Wolf, Reliability Administrator, Minnesota Department of Commerce Office of Energy Reliability, outlining the statutory and regulatory background of the transmission planning process. A utility representative then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Otter Tail Power Company, and Xcel Energy followed with presentations on transmission system inadequacies, alternative ways to address identified inadequacies, and current or future transmission projects and studies in the zone.

The final presentation of the meeting was an overview of the TIPS Study (Transmission Improvement Planning Study for the Red River Valley and West Central Minnesota).

A copy of the meeting presentations, including descriptions of specific transmission problems/inadequacies in the zone, alternative solutions, and current or planned projects, is available on www.minnelectrans.com by using the "Northwest Zone" link and downloading either of the following files: WZonePresentation.pps or NWZone Presentation.pdf .

Questions and comments from the audience were welcomed during all presentations and during a general discussion period at the end of the meeting. Comment cards for written questions/comments were also made available to the attendees.

Audience questions during the meeting concerned trends in system losses; cost of building new transmission lines; time period for a transmission project; the nature of "low voltage"; the nature of reactors; questions about the transmission line to the RDO potato processing plant; whether Minnesota's transmission lines extend into Canada; the proposed routes of possible transmission improvement alternatives in the TIPS Wires Study; general environmental concerns of transmission lines; the physical nature of possible 345 kV lines and towers; when the Certificate of Need process will occur for the 345 kV lines being discussed in the Red River Valley/Western Minnesota Transmission Improvement Planning Study; whether possible additional generation will be constant; and whether expanded wind generation could eventually replace coal and natural gas generating plants.

The following is a summary of public comments/suggestions received at or following the meeting and how that public input is expected to influence the utilities' decision-making process:

- *Public Comment*: Great River Energy and Otter Tail Power should consider creating more of a loop in Otter Tail County by building a 41.6 kV line. *Utility Response:* Great River Energy responded at the meeting that it did consider this option, but the presence of many lakes in the area made it a very expensive choice. In addition, generally connecting a loop on a 41.6 kV line does not have the same impact on the transmission system as upgrading the voltage.
- *Public Comment:* The phase-out of the power plant at Thief River Falls should be considered. *Utility Response:* The utilities responded at the meeting that the Thief River Falls plant is just used as a reserve.
- *Public Comment:* Recommendation of expansion of Otter Tail Power Company's TailWinds program. *Utility Response:* Otter Tail Power Co. has noted this comment and will bear it in mind for future decisions concerning the TailWinds program.
- *Public Comment:* Encouragement of alternate sources of power, for example, wind and solar energy, whenever possible. *Utility Response:* Public encouragement of alternate generation sources, in particular wind energy, has been a recurrent theme in comments from those who attended this year's transmission planning public meetings. This has been duly noted by the utilities, but it must be borne in mind that the process at hand – the series of public meetings and the subsequent compilation of the 2003 Biennial Minnesota Transmission Projects Report – concerns "transmission", not "generation sources". Transmission-owning utilities are required by the Federal Energy Regulatory Commission (FERC Order No. 888) to provide access to the transmission system to all electricity generators on the same wholesale basis as is offered to the public utilities. Thus, alternate generation sources are guaranteed that they will have access to the transmission system.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

SUMMARY OF NORTHEAST ZONE TRANSMISSION PLANNING PUBLIC MEETING

The Northeast Zone electric transmission planning public meeting was held on August 20, 2003 at 7:00 p.m. at Central Lakes College, 501 W. College Drive, Brainerd, Minnesota 56401. Approximately six members of the public attended the meeting.

The meeting began with remarks by Ken Wolf, Reliability Administrator, Minnesota Department of Commerce Office of Energy Reliability, outlining the statutory and regulatory background of the transmission planning process. A utility representative then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Minnesota Power and Great River Energy followed with presentations on current and projected transmission system inadequacies in the zone, alternative ways to address identified inadequacies, and current or future transmission projects and studies in the zone.

Minnesota Power presented information on:

- the Mantrap-Walker-Hackensack Area
- Pequot Lakes Area load serving issues
- Tower-Ely-Babbitt voltage issues
- Wrenshall-Mahtowa voltage issues
- the Pillsbury-Bertram-Upsala-Swanville Area; and
- Eagle Valley and Grand Rapids projects

Great River Energy presented information on:

- the Central Lakes Area
- the Milaca-Princeton-Cambridge Area
- the Nashwauk Area
- the Fond du Lac Area
- the Mille Lacs Area
- the Pierz-Genola Area
- Taconite Harbor to Grand Marais
- the Floodwood Area; and
- projected new distribution substations

The final presentation of the meeting was an overview of the TIPS Study (Transmission Improvement Planning Study for the Red River Valley and West Central Minnesota).

A copy of the meeting presentations, including descriptions of specific transmission problems/inadequacies in the zone, alternative solutions, and current or planned projects, is available on www.minnelectrans.com by using the "Northeast Zone" link and downloading the following files:

- General Presentation: Acrobat PDF file
- Transmission Issues: Acrobat PDF file
- Transmission Improvement Planning Study: Acrobat PDF file

Questions and comments from the audience were encouraged during all presentations and during a general discussion period at the end of the meeting. Comment sheets for written questions/comments were also available.

One question during the meeting concerned whether transmission lines are built before or after new generators are operational. There were several questions regarding the TIPS study.

The following is a summary of public suggestions received at the meeting (no comments concerning the Northeast Zone have been received to-date since the meeting) and how that public input is expected to influence the utilities' decision-making process:

Public Comment: The preliminary study results from the WIRES portion of the TIPS study identify a number of specific proposed transmission improvement alternatives. Are the 230 kV Boswell-Wilton and 345 KV Benton County-Alexandria-Maple River lines alternatives to each other, and if so, would it make sense to build the Boswell-Wilton line first, since it is short, then to build the St. Cloud area line later? *Utility Response:* It does make sense to build the fairly short Boswell-Wilton line first. The Benton County-Alexandria-Maple River line in general might be able to wait a few years, with the exception of an inadequacy in the St. Cloud area, which may be able to be addressed by a short line.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

SUMMARY OF WEST CENTRAL ZONE TRANSMISSION PLANNING PUBLIC MEETING

The West Central Zone transmission planning public meeting was held on July 8, 2003 at 2:00 p.m. and 7:00 p.m. at the Willmar Municipal Utilities auditorium, 700 Litchfield Ave. SW, Willmar, Minnesota. Representatives from East River Electric Power Cooperative, Glencoe Great River Energy, Melrose Public Utilities, Missouri River Energy, Otter Tail Power Co., Willmar Municipal Utilities, and Xcel Energy were in attendance. Eight members of the public attended the meetings.

The meeting began with remarks by Ken Wolf and Bob Cupit, with the Office of Energy Reliability, Minnesota Department of Commerce, giving the statutory and regulatory background of the transmission planning process. A utility representative
then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Xcel Energy, Great River Energy, Missouri River Energy Services, and Otter Tail Power Company then gave presentations on system deficiencies, alternative ways to address identified deficiencies, and current or future transmission projects and studies in the zone.

Xcel Energy presented information on:

- an update of wind generation outlet transmission projects
- the Hutchinson-Glencoe-Waconia Area
- the US10/I94 Corridor Monticello to St. Cloud; and
- the City of St. Cloud

:

- the Elk River-Becker Area;

- the Benton County-Milaca Area
- the Willmar-Paynesville Area
- the Willmar-Granite Falls Area
- the Panther Area
- the Alexandria-St. Cloud Area; and
- the Benson Area

Missouri River Energy Services presented information on:

- the Grant-Alexandria Reconductor Project

Otter Tail Power company presented information on:

- the Appleton-Canby Rebuild

The final presentation of the meeting was an overview of the TIPS Study (Transmission Improvement Planning Study for the Red River Valley and West Central Minnesota).

A copy of the meeting presentations is available on www.minnelectrans.com by using the "West Central Zone" link and downloading the following files:

- GenPresentationwc.pdf (General Presentation)
- WC Zone Presentation.pdf (Issues/Proposals)
- RRVTIPS.pdf (Major System Study)

Questions and comments from the audience were welcomed during all presentations and during a general discussion period at the end of the meeting. Comment cards for written questions/comments were also made available to the attendees. No written comments were submitted at the meeting.

Although there were a number of audience questions about the transmission planning process and possible future transmission projects in the zone, none involved suggestions or comments aimed at altering the identification of inadequacies, list and evaluation of alternatives, and planned projects presented by the utilities. Subsequent to the public meeting, staff from the City of Buffalo asked that consideration of moving a 69 kV line in the city be included in future study work.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

SUMMARY OF TWIN CITIES ZONE TRANSMISSION PLANNING PUBLIC MEETING

The Twin Cities Zone electric transmission planning public meeting was held on August 19, 2003 at 7:00 p.m. in the 3M Auditorium at the University of St. Thomas, 2115 Summit Avenue, St. Paul, MN. Approximately 20 members of the public attended the meeting.

The meeting began with remarks by Ken Wolf, Reliability Administrator, Minnesota Department of Commerce Office of Energy Reliability, outlining the statutory and regulatory background of the transmission planning process. A utility representative then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Xcel Energy and Great River Energy followed with presentations on current and projected transmission system inadequacies in the zone, alternative ways to address identified inadequacies, and current or future transmission projects and studies in the zone.

Xcel Energy presented information on:
- the Aldrich to St. Louis Park 115 kV line
- the Eden Prairie-Minnetonka Area
- the Carver County-Waconia Area
- the Chisago to Apple River Project
- the High Bridge to Rogers Lake 115 kV line; and
- the Twin Cities 345/115kV transformer capacity

Great River Energy presented information on:
- the Plymouth-Maple Grove area
- the Rush City-Forest Lake area
- the Elk River-Ramsey-Bunker Lake area
- Dakota County Generation; and
- The Air Lake-Farmington area

The regional issue of the Minnesota-Wisconsin Stability Interface was also discussed.

A copy of the meeting presentations, including descriptions of specific transmission problems/inadequacies in the zone, alternative solutions, and current or planned projects, is available on www.minnelectrans.com by using the "Twin Cities Zone" link and downloading one of the following files:
- General Presentation: Acrobat PDF file or MS PowerPoint
- Presentation specific to the Twin Cities zone issues: Acrobat PDF file

Questions and comments from the audience were encouraged during all presentations and during a general discussion period at the end of the meeting. A comment sheet for written questions/comments was also made available to the attendees.

A number of audience questions during the meeting concerned distributed generation: how is it defined; does it take pressure off the transmission system; and questions about the cost-effectiveness of distributed generation. Several questions dealt with who bears the cost of additional transmission lines and whether MAPP can refuse transmission service to a generator if the system cannot accept the additional generation without adding transmission capacity.

Other questions included: does energy conservation in a target area affect transmission planning; are the computer models the utilities use for planning public information; were the state's transmission lines originally overbuilt; will the Minnesota Wisconsin Stability Interface (MWSI) require a 345 kV line; will the possible Duluth-Marathon 345 kV line affect the MWSI; what are the major issues in deciding whether to use underground lines; what criteria are used to identify a "problem area"; who would control the use of metro area small coal-fired plants that are being converted to gas if Xcel sells those plants; and what impact will TRANSLink have on transmission planning.

There were a number of audience questions about the transmission planning process and possible future transmission projects in the zone, but only the following involved suggestions or comments aimed at altering the identification of inadequacies, list and evaluation of alternatives, and planned projects presented by the utilities (no comments concerning the Twin City Zone have been received to-date since the meeting).

- *Public Comment:* Notice of future transmission planning public meetings should be included with utility customer billings. *Utility Response:* This will definitely be considered for the next series of similar meetings.
- *Public Comment:* The utilities should plan a transmission system that can accommodate, foster, and promote a system of many <2 MW non-traditional generation facilities in place of building transmission. *Utility Response:* The utilities have duly noted this public comment in support of smaller generation facilities.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

SUMMARY OF SOUTHWEST ZONE TRANSMISSION PLANNING PUBLIC MEETING

The Southwest Zone electric transmission planning public meeting was held on June 10, 2003 at 2:00 p.m. and 7:00 p.m. at the American Legion Hall in Pipestone, Minnesota. Approximately 38 members of the public attended the afternoon session, and 11 the evening session. Utility presentations were identical at both sessions.

The meeting began with remarks by Ken Wolf, Reliability Administrator, Minnesota Department of Commerce Office of Energy Reliability, outlining the statutory and regulatory background of the transmission planning process. A utility representative then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Great River Energy, Otter Tail Power Company, and Xcel Energy followed with presentations on current and projected transmission system inadequacies in the zone, alternative ways to address identified inadequacies, and current or future transmission projects and studies in the zone.

Great River Energy presented information on:

- the St. James Area
- the Jackson Area
- the Dotson-Springfield Area; and
- the Fulda-Lismore-Magnolia Area

Otter Tail Power Company presented information on:

- the Appleton-Canby 41.6 kV to 115 kV Line Rebuild

Xcel Energy presented information on:

- Marshall load serving; and
- wind generation outlet capacity

A copy of the meeting presentations, including descriptions of specific transmission problems/inadequacies in the zone, alternative solutions, and current or planned projects, is available on www.minnelectrans.com by using the "Southwest Zone" link and downloading one of the following files:

- SWZonePresentationpds
- SWZonePresentation.pdf

Questions and comments from the audience were encouraged during all presentations and during a general discussion period at the end of the meeting. A comment sheet for written questions/comments was also made available to the attendees.

There were a number of audience questions concerning the proposed rebuilding of part of the transmission line in the Fulda-Lismore-Magnolia area; Xcel Energy's wind purchase obligations; whether transmission service for future wind generation in Southwest Minnesota would involve interconnection with WAPA (Western Area Power Administration); and how local land owners and investors can participate in the transmission planning process and negotiate with Xcel Energy for transmission service. Inquiries were also made about the impact of TRANSLink on transmission service and outlet capacity in Southwest Minnesota.

The following is a summary of public comments/suggestions received at the meeting (no comments concerning the Southwest Zone have been received to-date since the meeting) and how that public input is expected to influence the utilities' decision-making process:

- *Public Comment:* The property owners (of transmission right-of-way) do not appear to be involved in the transmission planning process. *Utility Response:* One of the purposes of the zonal transmission public planning meetings is to alert the public to the transmission planning process. SRG (Subregional Planning Groups of the Mid-Continent Area Power Pool {MAPP}) meetings are also open to the public. Individuals can be included on the information list to find out the dates and places of SRG meetings, and are welcome to attend.
- *Public Comment:* Property owners have questions on issues involving right-of-way (ROW) for electric transmission lines. *Utility Response:* Utility representatives are available during and after this meeting to discuss any specific ROW questions. If there

are other questions regarding compensation or valuation of easements, those may be issues for other forums, e.g., the State Legislature. ROW is always an important issue with transmission lines.

- *Public Comment:* Western Area Power Administration (WAPA) tariffs for transmission service are rumored to be "prohibitive". *Utility Response:* If transmission service is requested across the WAPA transmission system, WAPA, like other transmission systems, has a rate, or tariff, for that service. WAPA's rate is considered high compared to other systems, and there are reasons for that.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

SUMMARY OF SOUTHEAST ZONE TRANSMISSION PLANNING PUBLIC MEETING

The Southeast Zone transmission planning public meeting was held on July 22, 2003 at 7:00 p.m. at the Rochester Public Utilities community room, 4000 East River Road NE, Rochester, Minnesota. Representatives from Great River Energy, Interstate Power and Light Company, Rochester Public Utilities, Dairyland Power Cooperative, Southern Minnesota Municipal Power Agency and Xcel Energy were in attendance. More than 28 members of the public attended the meeting including representatives from the Minnesota Environmental Quality Board, Minnesota Department of Natural Resources, the Minnesota House of Representatives, the Minnesota Municipal Utilities Association and the Rochester Public Utilities Board of Directors.

The meeting began with remarks by Ken Wolf, Reliability Administrator with the Minnesota Department of Commerce, giving the statutory and regulatory background of the transmission planning process. Bob Cupit, Planning Director with the Minnesota Department of Commerce and David Jacobson from the Public Utilities Commission staff were also in attendance. A utility representative then gave a presentation explaining the transmission planning process, the fundamentals of electricity transmission, the general need for transmission system improvements in Minnesota, and how the utilities determine whether there will be a future transmission system deficiency.

Representatives from Xcel Energy, Great River Energy, Dairyland Power Cooperative, and Rochester Public Utilities then gave presentations on transmission studies presently underway to identify deficiencies in the transmission system, alternative ways to address identified deficiencies, and current or future transmission projects and studies in the zone.

A copy of the meeting presentations is available on www.minnelectrans.com by using the "Southeast Zone" link and downloading either of the following files: SEZonePresentation.pdf or SEZonePresentation.pps

Questions and comments from the audience were welcomed during all presentations and during a general discussion period at the end of the meeting. Comment cards for written questions/comments were also made available to the attendees. Two individuals submitted written comments at the meeting. One of these comments expressed an interest in connecting wind generators to the transmission grid. The other contained questions regarding the involvement of local governments in the transmission planning process and the use of alternatives in the planning process.

Although there were a number of audience questions about the transmission planning process and possible future transmission projects in the zone, none involved suggestions or comments aimed at altering the identification of inadequacies. No public comments or suggestions concerning the Southeast Zone have been received to-date since the July 22nd meeting.

- *Public Comment:* Several individuals inquired about how the planning process could accommodate future wind generators and the process by which an individual would connect a generator to the transmission grid. *Utility Response:* The utility studies do take into account new generation, of all types, that are in the MISO (Midwest Independent System Operator) queue. Typical installations of small-scale wind generators would not automatically require construction or reconstruction of transmission facilities although an interconnection study is required to verify that reliability of the system will not be adversely affected. A study of the transmission system would be done for large-scale wind projects when the location of the project is known and an interconnect request has been made. A transmission project may be the result of the study.
- *Public Comment:* Demand and capacity reserve margins are already more than adequate. A member of the public in attendance at the Southeast Zone meeting submitted to the utilities written information regarding the demand and capacity reserve margins in the various NERC (North American Reliability Council) regions. *Utility Response:* A copy of the submitted information referred to above may be obtained by use of the on-line form under the "Contact Us" link on www.minnelectrans.com

Rochester Public Utilities presented information from a transmission study presently underway to improve the reliability of the transmission system serving the Rochester area. Transmission options under study were discussed with the audience. At this time there are six transmission options being explored which include various combinations of 161kV and 345kV lines.

The utilities presenting projects at the meeting are in the process of completing transmission studies however none will be requesting certification for any of the projects in the 2003 Biennial Transmission Projects Report. The substance of input received from the public will be included in the Biennial Transmission Projects Report.

Additional comments or questions may be submitted by using the "Contact Us" link on www.minnelectrans.com.

Appendix XI: ADDITIONAL RESOURCES

Further information on issues affecting transmission may be found at the following web sites:

- American Public Power Association: http://www.appanet.org
- Edison Electric Institute: http://www.eei.org
- Electricity Consumers Resource Counsel: http://www.elcon.org
- Electric Power Research Institute: http://www.epri.com
- Electric Power Supply Association: http://www.epsa.com
- Federal Energy Regulatory Commission: http://www.ferc.gov
- Minnesota Department of Commerce: http://www.commerce.state.mn.us
- Minnesota Public Utilities Commission: http://www.puc.state.mn.us
- National Association of Regulatory Utility Commissioners: http://www.naruc.org
- National Rural Electric Cooperative Association: http://www.nreca.org
- North American Electric Reliability Council: http://www.nerc.com
- Wind on the Wires: http://windonthewires.org

Appendix V: SUMMARY OF LOCAL AND TRIBAL GOVERNMENT INPUT IN THE 2003 BIENNIAL TRANSMISSION PLANNING PROCESS

Based on the attendance registers from the six transmission planning public meetings, 12 local or tribal government officials or their representatives attended the meetings. It is possible that other local and tribal government representatives attended, but either did not sign the attendance register, or did not indicate their affiliation on the attendance register.

Those attending the meetings were:

Northwest Zone:	Pennington County Commissioner, District 2 Polk County Commissioner Director, Minnesota Association of Townships Representative from White Earth Reservation Tribal Council
Northeast Zone:	Cass County Commissioner Isanti County Commissioner, District 3
West Central Zone:	Representative from Kandiyohi County
Twin Cities Zone:	Representative from Dakota County Assistant to Ramsey County Commissioner Minneapolis City Councilperson, Ward 6
Southwest Zone:	Commissioner, Southwest Regional Development Commission Physical Development Director, SW Regional Development Cmn.

Comments of these local and tribal government officials and representatives are included in the *"Summary of Public Input"* in Appendix IV.

In addition, five counties and one regional development commission have, as of the printing of this report, designated a person to be a liaison with the utilities on transmission issues.

STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

LeRoy Koppendrayer	Chair
Marshall Johnson	Commissioner
Phyllis Reha	Commissioner
Gregory Scott	Commissioner
Kenneth Nickolai	Commissioner

In the Matter of Transmission Projects Report and Development of Certified List of Transmission Line Projects - 2003

AFFIDAVIT OF COMPLIANCE WITH STATE REQUIREMENTS FOR TRANSMISSION PLANNING MEETINGS

Docket No. _______________

Todd J. Guerrero, being duly sworn, states as follows:

1. Affiant is a partner with the law firm of Lindquist & Vennum PLLP, 80 South Eighth Street, 4200 IDS Center, Minneapolis, Minnesota 55402 and is licensed to practice law in this state.

2. Minnesota Rules, Chapter 7848 requires that utilities that own or operate electric transmission lines in Minnesota hold transmission planning meetings to provide the public and local and tribal governments with the opportunity to be involved in the transmission planning process and the consideration of possible alternatives. The rules specify, among other things, the frequency and general location of these meetings, "outreach efforts" to inform government officials, tribal government officials and the public of these meetings, and certain follow-up requirements. The rules allow the utilities to hold joint transmission planning meetings. Accordingly, the following fifteen electric utilities participated in jointly sponsoring public transmission planning meetings.

- Dairyland Power Cooperative
- East River Electric Power Cooperative

- Great River Energy
- Hutchinson Utilities Commission
- Interstate Power and Light Company
- L&O Power Cooperative
- Marshall Municipal Utilities
- Minnesota Power
- Minnkota Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Willmar Municipal Utilities
- Northern States Power Company d/b/a Xcel Energy

2. The following lists the date and location of the meetings, the dates on when certain mailings and notices required under Minn. Rules part 7848.1000 were provided, and the follow-up requirements under Minn. Rules part 7848.1100.

	Northwest Zone	**Northeast Zone**	**West Central Zone**
Meeting Date & Location	July 10, 2003 Crookston, MN	August 20, 2003 Brainerd, MN	July 8, 2003 Willmar, MN
Mailing Date: Request for Transmission Liaisons (7848.0900, Subp. 1)	June 19, 2003	August 1, 2003	June 16, 2003
Date Display Ads Published	Week of June 16, 2003	August 3-9, 2003	Week of June 22, 2003
Mailing Date: Meeting Notice	June 16-17, 2003	August 1, 2003	June 16-17, 2003
Mailing Date, Meeting Synopses	October 8, 2003	October 8, 2003	October 8, 2003

	Twin Cities Zone	**Southwest Zone**	**Southeast Zone**
Meeting Date and Location	August 19, 2003 St. Paul, MN	June 10, 2003 Pipestone, MN	July 22, 2003 Rochester, MN
Mailing Date, Request for Transmission Liaisons (7848.0900, Subp. 1)	August 4, 2003	May 21, 2003	July 1, 2003
Date Display Ads Published	Week of August 4, 2003	Week of May 26, 2003	Week of July 6, 2003
Mailing Date, Meeting	August 7, 2003	May 21, 2003	July 1, 2003

Notice			
Mailing Date, Meeting Synopses	October 8, 2003	October 8, 2003	October 8, 2003

3. In addition, as required by the rules, the utilities established a joint transmission planning web site (www.minnelectrans.com), on which the following was, and is, published:

- A utility contact person for each zone;
- An on-line registration for the utilities' transmission planning mailing list;
- An on-line form for submitting comments on transmission planning;
- A notice of each transmission planning meeting;
- A summary of each transmission planning meeting, including a synopsis of public input received, and how that input has influenced the utilities' decision-making process;
- A summary of Minnesota's transmission planning process; and
- A link to each individual utility's web site.

4. That to the best of his knowledge and belief, affiant believes that the utilities met all requirements for the public meeting process as set forth in Chapter 7848.

Todd J. Guerrero

Todd J. Guerrero

Subscribed and sworn to before
me this 29th day of October, 2003.

Susan M Ainsworth

Notary Public

SUSAN M. AINSWORTH
NOTARY PUBLIC-MINNESOTA
HENNEPIN COUNTY
My Commission Expires Jan. 31, 2005

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Appendix X: OTHER REGIONAL TRANSMISSION STUDIES

In addition to the studies specifically noted in main sections of the 2003 Minnesota Biennial Transmission Projects Report, several other studies are underway that are likely to affect regional transmission decisions in the near future. A brief summary of these studies is provided below:

- **Western Area Power Administration's Montana-Dakotas Regional Transmission Study**

Results of a study to determine the "costs and feasibility of transmission expansion methods and technologies" in the Western Area Power Administration's (WAPA) Upper Great Plains Region are now available on WAPA's web site at http://www.wapa.gov/ugp/study/default.htm. WAPA is a federal power marketing agency of the U.S. Department of Energy.

The Montana-Dakotas Regional Transmission Study, authorized by Congress and commissioned by WAPA, specifically targets transmission system reinforcements and upgrades needed to support an additional 1,000 megawatts of new wind and lignite coal energy generation in North Dakota, South Dakota and Montana.

The study concludes that significant transmission system upgrades are needed to meet transmission reliability criteria before the proposed generation sites are constructed.

- **Lignite Energy Council – Vision 21 Program**

The Lignite Vision 21 Program is sponsored by a variety of government agencies, elected leadership, and the lignite industry. The goal of the Lignite Vision 21 Program is to study the feasibility of an additional coal-fired electrical generating plant to be located in North Dakota. The North Dakota Industrial Commission has committed to invest substantial resources for research of the project. Generation technologies under review include conventional pulverized coal technologies (subcritical, supercritical and ultra supercritical), fluidized bed, and integrated coal gasification combined cycle operations. Vision 21 is also undertaking a comprehensive review of the power flow of the MAPP region for the purposes of identifying any transmission additions and/or improvements necessary to absorb the increases in power generated by a new baseload plant. The first phase of this study has identified a proposed export route that will service the additional generation and enhance reliability. Site-specific analysis, system operation, line loss and stability study and recommendations are ongoing. More information on the Lignite Vision 21 Program can be found at its website at http://www.lignitevision21.com/index.htm.

- **Central North Dakota–Manitoba 230 kV Interconnection Study**

This study identified the transmission requirements for load serving capability in Central North Dakota and for increasing transfer capability between the United States and Manitoba. The study was completed in 2000 and received MAPP Design Review Subcommittee Approval in December of 2000. The bulk of the facilities recommended are located in North Dakota and Manitoba, including approximately 100 miles of 230 kV facilities in North Dakota already permitted by the North Dakota Public Service Commission. However, the study also identified excess line loading problems on the Wilton–Bemidji 115 kV line that will need reconductoring.

- **MISO Baseline Reliability Study**

MISO is at present conducting a Transmission Expansion Plan Reliability Study to provide an independent assessment of the currently planned system upgrades for the years 2003 through 2009. The study will compare the results of the assessment with established NERC, regional, and local planning standards.

Appendix XI: ADDITIONAL RESOURCES

Further information on issues affecting transmission may be found at the following web sites:

- American Public Power Association: http://www.appanet.org
- Edison Electric Institute: http://www.eei.org
- Electricity Consumers Resource Counsel: http://www.elcon.org
- Electric Power Research Institute: http://www.epri.com
- Electric Power Supply Association: http://www.epsa.com
- Federal Energy Regulatory Commission: http://www.ferc.gov
- Minnesota Department of Commerce: http://www.commerce.state.mn.us
- Minnesota Public Utilities Commission: http://www.puc.state.mn.us
- National Association of Regulatory Utility Commissioners: http://www.naruc.org
- National Rural Electric Cooperative Association: http://www.nreca.org
- North American Electric Reliability Council: http://www.nerc.com
- Wind on the Wires: http://windonthewires.org

Appendix XII: MINNESOTA ELECTRIC TRANSMISSION PLANNING GLOSSARY OF TERMS AND ACRONYMS

AC: Alternating current.

ACSR: Aluminum conductor steel reinforced.

ACSS: Aluminum conductor steel supported.

ATC: Available Transfer Capacity, or Available Transmission Capacity.

Amp: Unit used for measurement of electric current flow.

Apparent Power: Proportional to the mathematical product of voltage times current in any circuit. Designated kilovolt-amperes (kVA) comprised of both real and reactive power. Power used to do work plus power stored during part of a cycle by inductance and capacitance and then returned to the power source.

Available Transfer Capacity : A measure of the transfer capability remaining in the physical transmission for further commercial activity over and above already committed uses.

Available Transmission Capacity : *See* "Available Transfer Capacity"

Availability: A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service.

Baseload: The minimum amount of electric power delivered or required over a given period at a constant rate.

Btu: British thermal unit. The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit under stated conditions of pressure and temperature (equal to 252 calories, 778 foot-pounds, 1,005 joules and 0.293 watt-hours.). It is the U.S. customary unit of measuring the quality of heat, such as the heat content of fuel.

Bus: An electrical conductor that serves as a common connection for two or more electrical circuits.

Capacity: The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA), of generation, transmission, or other electric equipment.

Conductor: A material that allows an electric current to pass through it. Also, the wire that carries electricity in an electric distribution or transmission system.

Contingency: Outage of a transmission line, generator, or other piece of equipment that affects the flow of power or the transmission network.

Control Area: An electric system bounded by transmission lines that are equipped with metering and telemetry equipment to track and report power flows with adjacent control areas. A control center for each control area controls the operation of generation within its portion of the transmission grid schedules interchanges with other control areas, and helps to stabilize the frequency of alternating current in the interconnection. Control centers are currently operated by individual utilities, power pools, ISOs or RTOs.

Cooperative Electric Associations: Democratic organizations controlled by their members, who actively participate in setting policies and making decisions. The elected representatives are accountable to the membership. Cooperative Electric Associations are not regulated by the PUC except in certain defined areas related to service standards and practices. With the exception of Dakota Electric Association, which elected to be subject to rate regulation, the rates of cooperative electric associations are not regulated by the PUC.

Current: The flow of electricity through a conductor. Current is usually measured in amps.

DC: Direct current.

DOC: The Minnesota Department of Commerce.

DOE: U.S. Department of Energy.

DSM: Demand Side Management.

Demand: The measure of power needed by equipment to operate, usually shown as a KW rating.

Demand Charge: A fee based on the peak amount of electricity used during the billing cycle.

Demand Side Management (DSM): Programs to influence the amount or timing of customers' energy use.

Distribution: The delivery of electricity to the retail customer's home or business through low voltage distribution lines.

Distribution Utility: The regulated owner/operator of the distribution system that serves retail customers.

EMF: Electromagnetic fields.

EPA: U.S. Environmental Protection Agency.

EQB: The Minnesota Environmental Quality Board.

Electric Energy: The generation or use of electric power by a device over a period of time, expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

Electric System Losses: Total electric energy losses in the electric system. Losses are primarily due to electric resistance within electrical conductors or wires and transformers.

Electricity: The energy made available by the flow of electric current through a conductor.

Electromagnetic Field (EMF): Electric and magnetic fields often occur together, hence the term "electromagnetic field". EMFs are found throughout nature and can be grouped by wavelength or frequency. The counterparts have the following definitions:

- Electric field: Created by voltage. Anytime something electric is plugged in it has an electric field, even if it is not in use. An electric field, in some instances, can be felt when the hair on your neck stands up during a lightning storm, for example. An electric field can be blocked by trees, walls, or buildings.
- Magnetic field: Created by current. Anything that carries electricity (such as power lines) and anything that uses electricity (such as home appliances in use) has a magnetic field. A magnetic field cannot be felt, and it passes through most objects.

Eminent Domain: The process by which rights to land needed for public interest facilities are acquired regardless of objection by the landowner. Eminent domain is generally applied by or through the power of the relevant siting authority that found the facilities to be in the public interest.

Energy: The capacity for doing work; may be natural or manufactured. Electrical energy is usually measured in kilowatt-hours.

Energy Policy Act: This 1992 federal legislation provides for the deregulation of wholesale power markets, i.e., utilities and other marketers purchasing and selling electricity from one another (as opposed to selling to the end-use customer).

FERC: Federal Energy Regulatory Commission.

Federal Energy Regulatory Commission (FERC): Regulates the price, terms and conditions of power sold in interstate commerce and regulates the price, terms and conditions of all transmission services. FERC is the federal counterpart to state utility regulatory commissions.

Flow-Gates: The ability to transfer power from numerous source points to points of delivery depends on the relative impact that the resulting power flow has upon its components and key defined interfaces, known within MAPP as flowgates. A flow-gate is one or more elements that act as a proxy for an operating security limit. An operating security limit can be determined by transient or voltage stability, unacceptable voltage levels or thermal restrictions, whichever is most limiting. Flowgates have been identified for known system "bottlenecks", which limit transfer of power.

GWH: Gigawatt-hour.

Gigawatt-Hour (GWH): The unit of energy equal to that expended in one hour at a rate of one billion watts. One GWH equals 1,000 megawatt-hours.

Grid: A system of interconnected power lines and generators that is managed so that power from generators is dispatched as needed to meet the requirements of the customers connected to the grid at various points.

Gridco: Gridco is sometimes used to identify an independent company responsible for the operation of the grid.

HVTL: High-voltage transmission line.

High-Voltage Transmission Line (HVTL): (a) Any transmission line with capacity of 200 kV or more, or (b) Any transmission line with capacity of 100 kV or more with more than 10 miles of its length in Minnesota or that crosses a state line.

IPP: Independent Power Producer.

ISO: Independent System Operator.

ITC: Independent Transmission Company

Import/Export: Ability of the transmission system to bring power into or out of an area in order to serve load.

Independent Power Producer (IPP): An organization that is not a utility and that operates a power plant that produces electric energy and then sells it to a utility.

Independent System Operator (ISO): A neutral and independent organization with no financial interest in generating facilities. An ISO administers the operation and use of the transmission system. ISOs exercise final authority over the dispatch of electricity from generators to customers to preserve reliability and facilitate efficiency, ensure non-discriminatory access, administer transmission tariffs, ensure the availability of ancillary services, and provide information about the status of the transmission system and available transmission capacity. An ISO may make some transmission investment decisions.

Interconnected System: A system consisting of two or more individual electric systems that have connecting tie lines and whose operations are synchronized.

Interconnection: When the word "Interconnection" is capitalized, it means any one of the five major electric system networks in North America: Eastern, Western, ERCOT (Texas), Quebec, and Alaska. When not capitalized, "interconnection" means the facilities that connect two systems or control areas. Additionally, an "interconnection" refers to the facilities that connect a nonutility generator to a control area or system.

Investor-Owned Utility: Common term for a privately owned (shareholder-owned) gas or electric utility regulated by the Minnesota Public Utilities Commission as to the services they provide and the rates they may charge to their customers. (Referred to as "public utilities" in Minnesota statutes).

KV: Kilovolt.

Kilovolt (kV): Equal to 1,000 volts.

KW: Kilowatt.

KWH: Kilowatt-hour.

Kilowatt (KW): A measure of demand for power. The rate at which electricity is used during a defined period (usually metered over 15-minute intervals).

Kilowatt-hour (KWH): A measure of the amount of electricity that is used. Customers are charged a rate per KWH of electricity used.

LTC: Load Tap Changer.

Load: All the devices that consume electricity on a specific electric system at any given moment.

Load Tap Changer (LTC): Power transformers may have load tap changers, which enable the transformer tap position to be changed while the transformer is carrying load. Changing the transformer tap is typically used to boost the voltage of the load serving side of the transformer.

Losses: Power (kilowatts) and energy (kilowatt-hours) lost during the operation of an electric system. Losses occur principally when energy is transformed into wasted heat in conductors and other apparatus.

MAPP: Mid-Continent Area Power Pool.

MBWG: MAPP's Modeling Building Working Group. Maintains what is essentially a power flow, base case transmission model library. The library includes a series of power system models that simulate the behavior of the bulk electric system over a ten-year period. The models are designed to represent accurately all major generation, load, and transmission facilities in MAPP.

MISO: Midwest Independent Transmission System Operator, Inc.

MVA: Megavolt-ampere.

MVAR: Megavar.

MW: Megawatt.

MWH: Megawatt-hour.

MWSI: Minnesota-Wisconsin Stability Interface.

MAPP Regional Plan: Also called the "Regional Plan". A regional transmission plan developed by MAPP's TPSC (Transmission Planning Sub-committee) for all transmission facilities 115 kV and higher in the MAPP regional.

Megavolt-Ampere (MVA): 1 million volt-amperes.

Megavar (MVAR): 1 million reactive volt-amperes. Reactive power is that part of "apparent power" that does not do work.

Megawatt (MW): 1,000 kilowatts or 1 million watts.

Megawatt-Hour (MWH): The unit of energy equal to that expended in one hour at a rate of one million watts. One MWH equals 3,414,000 Btus.

Mid-Continent Area Power Pool (MAPP): A NERC subregional organization that includes Minnesota; a voluntary association of electric utilities and other electric industry participants. MAPP's offices and control center are in St. Paul. Responsible for the safety and reliability of the bulk electric system, including system-wide planning functions; responsible for facilitating open access of the transmission system; provides a power and energy market where MAPP members and non-members may buy and sell electricity at wholesale. MAPP's approximate 107 members include investor-owned utilities, electric cooperatives, municipal utilities and public power districts, a federal power marketing agency, private power marketers, regulatory agencies, and independent power producers.

Midwest Independent Transmission System Operator, Inc. (MISO): A FERC-recognized Regional Transmission Organization (RTO).

Minnesota Energy Security and Reliability Act: Minnesota Statutes Chapter 216B. Comprehensive energy legislation that addresses a wide range of energy issues, including energy planning, conservation and infrastructure. Minn. Stat. §216B.245 requires the state's electric utilities to file a state "transmission projects report" by November 1 of each odd-numbered year.

Minnesota-Wisconsin Stability Interface (MWSI): The interface defined as the sum of powerflow on the Eau Claire-Arpin 345 kV line and the Prairie Island-Byron 345 kV line.

Municipal Utilities: Managed by their city councils or other governmental agencies, which are responsible to voters who are also the customers. Not regulated by the PUC, except on complaint about services or discriminatory prices, but do report certain types of information to the PUC and DOC.

NERC: North American Electric Reliability Council.

NESC: National Electric Safety Code.

National Electric Safety Code (NESC): Governs the design, construction and operation of electric utility transmission facilities to ensure public and employee safety.

Network: A system of interconnected lines and equipment.

North American Electric Reliability Council (NERC): A not-for-profit corporation that is the coordinating arm of the ten-member regional reliability councils. The principal mission of NERC is to promote the reliability and adequacy of electric supply. Establishes standards to ensure adequate reliability of the electric grid system. (*See also* Reliability Councils).

OASIS: MISO's Open Access Same-Time Information System.

Off Peak: Those hours or other periods defined by contract or other agreements or guides as periods of lower electrical demand.

On Peak: Those hours or other periods defined by contract or other agreements or guides as periods of higher electrical demand.

Open Access Same-Time Information System (OASIS): A function of MISO. Gives transmission users the same access to transmission information that the wholesale merchant function of a utility enjoys. A utility's wholesale merchant function is limited to receiving from a utility's transmission function only such transmission information that is posted on an OASIS, and is thereby publicly available on a simultaneous basis to third-party transmission customers.

Operating Reserve: Extra generating capacity needed to meet unanticipated demand or to generate electricity when generating units break down.

Order No. 888: ERC Order that requires all transmission owners to (1) offer comparable open-access transmission service for wholesale transactions under a tariff of general applicability on file at FERC and (2) take transmission service for their own wholesale sales under the same tariff.

Order No. 889: ERC Order that requires public utilities to functionally separate their transmission and reliability functions from their wholesale power marketing functions and to develop and maintain an Open Access Same-Time Information System (OASIS) to give transmission users the same access to transmission information that the wholesale merchant function of a utility enjoys.

Order No. 2000: FERC Order issued in 1999, encouraging transmission-owning utilities to voluntarily join large regional transmission organizations.

Order No. 2003: FERC Order published in August, 2003, adopting final rules governing the interconnection of large generators (20 MW and above) to the transmission systems of all public utilities.

Overload: Power flowing through the wires/equipment is more than they can carry without damage.

PPSA: Power Plant Siting Act.

Power Plant Siting Act (PPSA): Minnesota legislation enacted in 1973 governing location of large electric power facilities in Minnesota.

PUC: The Minnesota Public Utility Commission. The state agency with regulatory jurisdiction over certain Minnesota utilities.

Parallel Path Flows: When electricity flows from a power plant over the transmission system, it obeys the laws of physics and flows over the paths of least resistance. Though there may be direct connection between a power plant and a particular load area, some of the power will flow over other network lines.

Peak Load or Peak Demand: The electric load that corresponds to a maximum level of electric demand within a specified time period, usually a year.

Power: The capability to do work. The time rate of generating, transferring or using electric energy, usually expressed in watts.

Power Flows: Electricity moving through lines or other transmission equipment.

Power Pool: Two or more interconnected electric systems planned and operated to supply power for their combined demand requirements.

Public Utility: By Minnesota Statute, an investor-owned utility regulated by the PUC. "Public Utility" excludes municipal utilities cooperatives, and power marketing authorities.

REIS: Regional Energy Information System.

RRC: Regional Reliability Council.

RTC: MAPP's Regional Transmission Council. The Transmission Planning Sub-committee (TPSC), which reviews sub-regional plans, is a sub-committee of the RTC.

RTO: Regional transmission organization.

Reactive Power (VAR): The portion of "Apparent Power" that does not perform work. Measured in kilovars,or megavars, it must be supplied to most types of electric equipment, such as motors and transmission lines.

Redispatch: The need for certain generators to operate during certain periods in order to avoid interrupting power purchases for which the buyer has reserved firm transmission service.

Regional Energy Information System (REIS): The Minnesota Department of Commerce's computerized state energy data collection and information system, required under Minnesota Statutes. It includes energy data the DOC collects directly from energy suppliers as well as data collected by other state departments such as the Minnesota Department of Revenue, Petroleum Taxation Division. It also includes energy data specific to Minnesota collected by the U.S. Department of Energy, the U.S. Department of Commerce, Bureau of Census, and the U.S. Department of Transportation.

Regional Reliability Council (RRC): Organized after the 1965 Northeast blackout to coordinate reliability practices and avoid or minimize future outages. Voluntary organizations of transmission-owning utilities and in some cases power cooperatives, power marketers, and nonutility generators. Membership rules vary from region to region. They are coordinated through NERC. There are ten major regional councils plus the Alaska Systems Coordinating Council.

Regional Transmission Organization (RTO): An organization comprised mostly of electric utilities that own, operate, or control facilities for the transmission of electric energy in interstate commerce over large geographic regions. RTOs are designed to operate the grid and its wholesale power market over a broad region and with independence from commercial interests, to facilitate independent system operations, to stimulate development of large wholesale energy market areas, and to ensure the reliable operation of the transmission grid system. An RTO would coordinate with other RTOs. An RTO would also have a role in planning and investing in the grid, although how it would conduct these activities remains unresolved.

Reliability: Electric system reliability has two components – adequacy and security. Adequacy is the ability of the electric system to supply the aggregate electric demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system facilities. Reliability also refers to the security and availability of natural gas and petroleum supply, transportation and delivery.

Reserve Margin: Capacity over and above anticipated peak loads, maintained for the purpose of providing operational flexibility and for preserving system reliability. Reserve margins cover for planned and unplanned outages of generation and/or transmission facilities.

SPG: Subregional Planning Group.

Sag: *See* "Voltage Sag"

Sectionalize: To reconfigure the transmission system after a contingency by the opening of switches or circuit breakers.

Subregional Planning Group (SPG): The five SPGs in MAPP provide a forum to coordinate the individual member plans and facilitate the coordination of plans among SPGs and neighboring non-member utility systems. Each SPG develops a coordinated 10-year subregional transmission plan for all transmission facilities in the subregion at a capacity of 115 kV or greater.

Substation: A facility where transmission lines connect to each other and where protective equipment is located. Also where transformers are located to "step" the voltage up or down in order to put power into or take power out of the transmission network.

Subtransmission: The electric power lines and associated facilities which are used to link the transmission system and distribution system together. Subtransmission lines operate below 100 kV; common subtransmission voltages are 69 kV, 46 kV, 41.6 kV, 34.5 kV, and 23 kV.

System Intact: When all components of the transmission system are operating in their normal fashion. Not a contingency condition.

TPSC: MAPP's Transmission Planning Sub-Committee.

Transco: Transmitting Utility.

TRANSlink: TRANSlink Transmission Co., LLC

Thermal Rating: The amount of power, measured in MVA, that electrical equipment can carry. The thermal rating is determined by the ability of the equipment to safely dissipate heat generated by internal resistance.

Transformer: Device that changes voltage levels.

TRANSlink Transmission Co., LLC. (TRANSlink): On April 25, 2002, FERC approved the transfer of functional control of the Interstate Power and Light Company (IPL) and Xcel Energy systems to TRANSLink, a proposed independent transmission company member of MISO. IPL, Xcel Energy, Dairyland Power Cooperative, Great River Energy, Southern Minnesota Municipal Power Agency, and Rochester Public Utilities are presently working toward indirect MISO membership through participation in the TRANSLink ITC. On June 25, 2004, the Minnesota PUC deferred action on the IPL and Xcel Energy requests to participate in TRANSLink, pending submission of additional information.

Transmission Planning Sub-Committee (TPSC): A MAPP sub-committee that reviews and coordinates subregional plans.

Transmission system: The high voltage power lines that transmit electric energy from generation plants to local load and among utilities to ensure a high degree of reliability.

Transmitting Utility (Transco): A regulated entity that owns, and may construct and maintain, wires used to transmit wholesale power. It may or may not handle the power dispatch and coordination functions. It is regulated to provide nondiscriminatory connections, comparable service and cost recovery.

Utility: A corporation, person, agency, authority, or other legal entity that owns or operates facilities for the generation, transmission, distribution, or sale of electric energy or natural gas primarily for use by the public and is defined as a utility under the statutes and rules by which it is regulated. A utility is a regulated entity that exhibits the characteristics of a natural monopoly. For the purposes of the electric industry, "utility" generally refers to a regulated, vertically integrated monopoly electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system that serves retail customers.

VAR: Reactive Power. (Volt –ampere reactive)

Voltage: The "pressure" that causes electric current to flow. Voltage is a measure of the potential for current flow and may exist between objects without a flow of current.

Voltage Dips: *See* "Voltage Sag"

Voltage Reduction: Any intentional reduction of system voltage by 3 percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Voltage Sag: Under-voltage conditions of 1/60th of a second to 1/10th of a second duration. Caused by improper grounding, undersized wiring or sudden start-ups of large electrical loads. Also called voltage dips.

Voltage Support: To make upgrades to the transmission system that result in improved voltage levels.

Voltage Violation: When a substation bus voltage does not meet applicable operating and planning criteria. The voltage is either too high or too low.

Watt: The unit of measure for electric power, or rate of doing work. The rate of energy transfer equivalent to one ampere flowing under pressure of one volt.

Wheeling: The use of a utility's transmission lines by other power producers. Wheeling occurs when there is a buyer, a seller, and one or more utilities in between that transmit – or wheel – the electricity. Wheeling requires a contractual agreement or tariff to allow the use of the transmission systems of one party to transmit electricity from the buyer to the seller.

Wholesale Competition: Power producers competing to sell their power to a variety of distribution companies.

Wholesale Power Market: The purchase and sale of electricity from generators to resellers (who sell to retail customers and/or other resellers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.