SECTION 3- THE PROJECT

3.1 Project Description

The Utilities propose constructing a 230 kV line from the Wilton 230 kV Substation located just west of Bemidji, Minnesota, to the Boswell 230 kV Substation in Cohasset, Minnesota, northwest of Grand Rapids, Minnesota. Locating the Bemidji-Grand Rapids Line in the Utilities' preferred corridor results in the Project being about 68 miles in length.

The corridor begins at the Wilton Substation northwest of Bemidji and runs southeast through Beltrami County, across the northeast corner of Hubbard County, and into Cass County. The corridor then runs generally due east across Cass County past the City of Cass Lake and through Bena Township to a point between Zemple Township and the City of Deer River, in eastern Cass County. The corridor then turns southeast and crosses into Itasca County until it reaches the Boswell Substation in Cohasset, northwest of Grand Rapids.

While final engineering and design has not been completed, the Project's construction would likely utilize two-pole H-frame structures for a majority of the route. These are the typical structures used for a 230 kV line located on wooded, rugged topography. They are also suited for areas requiring longer spans to avoid or minimize the placement of structures in wetlands or waterways. Each H-frame structure would range in height from 70 to 90 feet, and be placed 600 to 1,000 feet apart. See H-frame structure illustrations in Appendix C.

Where conditions warrant it, single-pole structures may be used. Single pole structures are typically used in areas where the available right-of-way is limited, such as where the right-of-way runs along roads in developed areas. The height of single-pole structures in constrained areas ranges from 80 to 100 feet, with the span between structures from 400 to 800 feet. See single-pole structure illustrations in Appendix C.

It is anticipated that the project will utilize 954 ACSR conductors (non-bundled), with a capacity of approximately 470 MVA (Mega Volt Ampere). The conductor size may need to be modified once the ultimate route is selected and additional electrical optimization studies are completed.

The typical right-of-way for a 230 kV line is approximately 125 feet wide. Ultimately the right-of-way width will depend upon conductor blowout and the recommended clearances between the conductor and other structures along the route. The width of the right-of-way may be reduced in certain high density, developed areas with the use of single pole construction. The width of the-right-of way may also be reduced where the new line follows an existing linear corridor, such as another utility line or roadway. On the other hand, a wider right-of-way may be required for longer spans of the line or special design requirements dictated by topography. The Applicants will seek permanent easements providing the right to construct, operate, and maintain the transmission line along the full width and length of its right-of-way, as necessary.

There are opportunities within the proposed corridor for the Project to be located in existing rights-of-way and, where feasible, "double circuit" the Project with existing 115 kV or 69 kV lines. That means the structures for the proposed 230 kV line would be designed to also carry the lower voltage line already located in the right-of-way. Double circuiting, however, raises

transmission reliability concerns. For example, a single weather-related event could result in the outage of two circuits rather than just one. Double circuiting can also impact the constructability and costs of the Project. The feasibility of double circuiting portions of the Project will be addressed in detail in the Route Permit application for the Bemidji-Grand Rapids Line.

3.2 Associated Facilities

Certain upgrading of the Wilton Substation near Bemidji and the Boswell Substation near Grand Rapids will be required. The upgrades are discussed below.

- Wilton Substation- The Project would not require physical expansion of the existing Wilton 230 kV Substation. Two new 230 kV breakers and a line termination structure would be added as a result of the Project, along with modifications to the existing 230 kV buses and relay panels. The Project will also require completion of a new ring bus section, as well as five new 230 kV switches with foundations, steel structures, and control panels.

- Boswell Substation- The Project requires the expansion of the Boswell 230 kV Substation by approximately 1.3 acres. This would be accomplished by extending the existing fence line approximately 120 feet to the east. No land procurement is required because the entire extension of the substation will be on Minnesota Power owned property. In addition to modifications to the existing 230 kV buses and relay panels, a new 230 kV breaker and a half bay would be added to the substation. This would involve installing two new 230 kV circuit breakers and 230 kV dead-end structures, a new 230 kV bus, five new 230 kV switches, and associated foundations, steel structures, and control panels.

Subject to the results of on-going system planning studies, a new 230 kV substation to serve Cass Lake may also be constructed. If so, its location would depend on the ultimate route selected for the Project as discussed in Section 6.2 below. This issue will be addressed in more detail in the Route Permit Application.

3.3 Estimated Cost

Depending on the terrain crossed, the cost of construction for this 230 kV line is estimated to be in the range of $675,000 to $915,000 per mile in 2007 dollars (excluding right-of-way acquisition, permitting, and other ancillary costs). The cost of 230 kV substation upgrades is estimated to be approximately $1 to $1.5 million per substation.

The length of the proposed Bemidji-Grand Rapids 230 kV Line along the Utilities' preferred corridor is approximately 68 miles, and based on the projected number of miles of the line that would be constructed on wooded and wetland terrain, the estimated cost for line construction is about $58 million. Another $2.5 million is estimated to upgrade the Wilton Substation near Bemidji and the Boswell Substation near Grand Rapids, for a total estimated construction cost for the Project of $60.5 million.

For accounting purposes, the Utilities use different estimates of the service life of a transmission line. Xcel Energy, for instance, uses a 40-year life for a transmission line, Minnesota Power uses 45- year life, Otter Tail Power uses a 55-year life, and Minnkota Power uses a 45-year life for the structures and a 55-year life for the conductor. As a practical matter, however, a high voltage transmission line is rarely completely retired, but rather refurbished as necessary to continue to operate effectively.

3.4 Effect on Rates

The Commission's rules require an applicant to provide the annual revenue requirements to recover the costs of a proposed project. This requirement presumes that a single utility proposes to construct, own, and operate the project, and therefore the utility provides an estimate of the impact on ratepayers by calculating the annual revenue requirements for the project against a forecast of sales as though the cost of the project will be borne primarily by retail customers.

However, the model for determining the impacts on ratepayers has changed due to implementation of Midwest ISO ("MISO") Attachment FF to the Transmission Energy Market Tariff ("TEMT") (FERC Docket No. ER06-18), which now allocates and recovers costs associated with new transmission projects and system upgrades within the MISO system on a regional basis, using provisions developed by the Regional Expansion Criteria and Benefits ("RECB") Task Force. Where a project has been determined to be a Baseline Reliability Project below 345 kV but above 100 kV, its total cost is recovered through a "subregional" allocation based on an analysis of the line outage distribution factor ("LODF") impacts of the project. The LODF analysis is used to determine which utilities' benefit from the line.

Under the RECB criteria identified in Attachment FF, the Bemidji-Grand Rapids Line has been designated a Baseline Reliability Project, and therefore the costs of the Project are subject to recovery through Attachment FF and Schedule 26 to MISO's TEMT. The Utilities' Project Development Agreement contemplates that 68.5% of the Bemidji-Grand Rapids Line will be owned by the four Utilities who are members of MISO (Otter Tail Power, Minnesota Power, Xcel Energy, and Great River Energy), and therefore MISO will collect 68.5% of the revenue requirements for the Project through Attachment FF and Schedule 26. Minnkota Power, which is not a transmission-owning member of MISO, is to own the other 31.5% of the line.

The revenue necessary to pay for Minnkota's 31.5% share of the Project's costs will be collected from its ratepayers through an adjustment in rates. The revenue necessary to pay for the other Utilities' 68.5% of the Project's costs will come from each transmission owner in the MISO system. Thus Otter Tail Power, Minnesota Power, Xcel Energy, and Great River Energy will each be charged a portion of the Project's revenue requirements under Attachment FF and Schedule 26 of the TEMT based on their respective LODF calculation for the line. The four Utilities will ultimately recover these charges from their respective ratepayers. Additional MISO transmission owners who are not owners of the line but share in the LODF calculation will also be assessed a portion of the line's costs through Attachment FF and Schedule 26. Therefore the 68.5% of the Project costs incurred by the Utilities would not be recovered through the traditional method of any one or all of them funding the project, but rather recovered through MISO charges paid by all MISO transmission owners that benefit from the line.

The following subsections estimate project revenue requirements and the charges to each owner's network load through Attachment FF and Schedule 26 of the TEMT. Because MISO's cost recovery mechanism is relatively new and untested, the analysis below is subject to revision based on new information from MISO on how this cost recovery mechanism performs.

3.4.1 Estimated Project Ownership Shares and Revenue Requirements

Table 3.4-1 below shows the estimated ownership shares for the Bemidji-Grand Rapids Line contained in the Utilities' Project Development Agreement. It also shows the estimated annual levelized revenue requirement associated with each owner's share based on the Project construction cost estimate in Section 3.3 above and each of the Utilities' specific fixed charge rate for developing revenue requirements. The revenue requirements for each owner were derived from its individual MISO Attachment O worksheet and includes an equity component equal to the FERC-approved MISO return on equity.

Table 3.4-1 Estimated Project Revenue Requirements by Ownership Share

Transmission Owner	Ownership Estimate	Estimated Annual Revenue Requirement (millions)
Great River Energy	13.0 %	$1.3
Minnesota Power	9.3 %	$1.1
Otter Tail Power	20.0 %	$2.4
Minnkota Power	31.5 %	$3.6
Xcel Energy	26.2 %	$2.5

3.4.2 Allocation of Project Cost under MISO's TEMT

As discussed earlier, the Utilities anticipate 68.5% of the cost of the Bemidji-Grand Rapids Line will be recovered under the TEMT, and those costs will be allocated across MISO pricing zones pursuant to Attachment FF cost allocation for Baseline Reliability Projects. The pricing zones are generally congruent with the boundaries of each transmission owner's Control Area, now called Balancing Authority Area. Because of co-mingled service areas and the joint development of the transmission system by utilities in this area of the Midwest, however, many transmission owners have facilities and load in more than one pricing zone. For example, Great River Energy has facilities and loads in the Xcel Energy, Minnesota Power, Otter Tail Power, and Alliant West pricing zones as well as in its own zone. The unit charges will vary by pricing zone. Table 3.4-2 below shows the estimated allocation of the Project's annual revenue requirements to MISO pricing zones.

Table 3.4-2 Estimated Allocation of Project's Annual Revenue Requirements to MISO Pricing Zones

MISO Pricing Zones	Bemidji-Grand Rapids Line ($ thousands)
Alliant West	$ 30
Ameren	$ 5
American Transmission Co.	$ 300
Great River Energy	$ 100
Montana-Dakota Utilities	$ 1
Minnesota Power	$ 1,900
Northern States Power	$ 2,400
Otter Tail Power	$ 2,600

Note that the analysis above is only for the currently estimated 68.5% portion of the Project that is part of the MISO transmission system. It is anticipated that the other 31.5% of the Project will be paid for by Minnkota Power, which is not a member of the MISO transmission system.

3.5 Project Schedule

The Project is needed to be in service by the end of 2011. The regulatory review and construction schedule for the Project, shown in Table 3.5 below, was developed to meet that deadline.

Table 3.5 Regulatory Review/Construction Timetable

Action	Action Initiated By:	Action Completed By:
Certificate of Need filing	Mar. 2008	May 2009
Route Permit filing	Apr. 2008	May 2009
Joint state/federal environmental review	Apr. 2008	May 2009
Project contractor selection	May 2008	May 2009
Transmission line design	After survey	June 2009
Procurement process	May 2009	Nov. 2009
Right-of-way acquisition	June 2009	Nov. 2009
Construction of line	Nov. 2009	Dec. 2011

Action	Action Initiated By:	Action Completed By:
Substation upgrades	Jan. 2011	Dec. 2011
Line in service	--	Dec. 2011

3.6 Property Acquisition

3.6.1 Transmission Line Right-of-Way

There are various rights-of-way within the Utilities' preferred corridor along which the Bemidji-Grand Rapids Line could be routed. These include power line, railroad, pipeline, and highway rights-of-way. The Project's route within the corridor could also include segments on private and public land.

The Applicants will work with private landowners to negotiate the terms of an easement that are acceptable to both parties. In the event the parties cannot come to agreement on easement terms, the Applicants would consider exercising their eminent domain authority.

3.6.2 Substation Property

Currently the Applicants do not believe that any additional land is needed for the 230 kV upgrades at the Wilton and Boswell Substations. In the event that route selection and transmission line design considerations indicate that additional land will be necessary, the Applicants will contact the appropriate landowners to negotiate for the acquisition of the additional property. In the event that a new substation to serve Cass Lake is needed, additional land would be required. The Utilities will seek to obtain the property through a voluntary purchase, and if an agreement can not be reached, would consider exercising their rights of eminent domain.

3.7 Construction Practices

3.7.1 Transmission Line

Standard construction and mitigation practices developed from experience with past projects as well as industry-specific best management practices ("BMPs") will be employed. BMPs address right-of-way clearance, erecting transmission line structures, and stringing transmission lines. BMPs for the Project will be based on the specific construction design, prohibitions, maintenance guidelines, inspection procedures, and other activities involved in constructing the line. In some cases these activities, such as schedules, are modified to incorporate a BMP for construction that will assist in minimizing impacts on sensitive environments. For instance in areas where construction occurs close to waterways, BMPs are employed to help prevent soil erosion, and ensure that equipment fuel and lubricants do not enter the waterway.

3.7.2 Substations

The substation upgrades involve adding new equipment, modifying existing equipment, or replacing existing equipment with new equipment. All construction work occurs within the

existing substation property unless expansion of the site and/or establishing a new Cass Lake Substation site, is necessary.

The substations will be upgraded in compliance with the applicable requirements of RUS, National Electrical Safety Code, Occupational Safety and Health Act, and state and local regulations. Contractors will be committed to safe working practices. The final design of the substation upgrades will take the local conditions of the substation sites into consideration, and where warranted will include safety provisions beyond the minimum requirements established in the various applicable safety codes. The substation upgrades will be designed to allow future maintenance to be done with the minimum impact on substation operation and the necessary clearance from energized equipment to ensure safety.

3.8 Restoration Practices

3.8.1 Transmission Line

Post-construction reclamation activities include removing and disposing of debris, removing all temporary structures (including staging and laydown areas), employing appropriate erosion control measures, reseeding areas disturbed by construction activities with vegetation similar to that which was removed within certain height restrictions to prevent interference with the line using a seed mixture certified as free of noxious or invasive weeds, and restoring the areas to their original condition to the extent possible. In cases where soil compaction has occurred, the construction crew or a restoration contractor uses various methods to alleviate the compaction, or as negotiated with landowners.

Once restoration procedures are completed, the Utilities contact affected landowners to determine if the clean-up measures have been to their satisfaction and if any other damage may have occurred. If damage has occurred to crops, fences, or other property, the Utilities will compensate the landowner.

3.8.2 Substations

Upon the completion of construction activities, the Utilities restore the remainder of the site. Post-construction reclamation activities will include removing and disposing of debris, removing all temporary structures (including staging areas), and employing appropriate erosion control measures. If areas outside the substation's fence line are disturbed by construction activities, they will be reseeded with vegetation similar to that which was removed, within certain height restrictions to prevent interference with the substation and the transmission lines entering the substation.

3.9 Operation and Maintenance Practices

3.9.1 Transmission Line

Access to the right-of-way of a completed transmission line is required periodically to perform inspections, conduct maintenance, and repair damage. Regular maintenance and inspections will be performed during the life of the facility to ensure its continued integrity. Generally, a 230 kV

line is inspected annually for problems by foot, ATV, truck, snowmobile, or by air. Inspections are limited to the right-of-way and to those areas where obstruction or terrain may require off-right-of-way access. If problems are found during inspection, repairs are performed and the landowners compensated for any losses incurred.

The right-of-way is managed to remove vegetation that interferes with the operation of the line. Vegetation maintenance for 230 kV lines is typically on a two to five year cycle. Right-of-way clearing practices include a combination of mechanical and hand clearing, along with herbicide application where allowed, to remove or control vegetation growth. The structures for the line will be new, so very little maintenance will be required for several years.

3.9.2 Substations

Over the life of the substations, inspections will be performed regularly to maintain equipment and make necessary repairs. Routine maintenance will be conducted as required to remove undesired vegetation that may interfere with the safe and reliable operation of the substations.

3.10 Work Force Required

The work force required for construction of the Project's facilities is estimated to be 75 people. This includes tree trimming crews, transmission line construction workers, substation upgrade construction workers, safety supervisors, environmental support, and other on- and off-site support staff. The Utilities will work with governments in the Project area to meet any specific local employment obligations. There will also be a need for additional contracted professional services related to line and substation design.

It is not expected that additional permanent jobs will be directly created by construction of the Project. The construction activities will provide, however, a seasonal influx of additional dollars into the communities during the construction phase, with construction materials purchased from local vendors where feasible.

3.11 Electric and Magnetic Fields

Electric and magnetic fields ("EMF") are present around any electrical device, and can occur indoors and outdoors. Electric fields are the result of voltage or electrical charges, and the intensity of the electric field is related to the operating voltage of the line or the device. Magnetic fields are the result of the flow of the electrical current along transmission lines, distribution (feeder) lines, substation transformers, house wiring, and household electrical appliances. The intensity of a magnetic field is related to the amount of current flowing through the conductors (wire).

Considerable research has been conducted throughout the past three decades to determine whether exposure to power-frequency (60 hertz) electric and magnetic fields causes biological responses and health effects. Epidemiological and toxicological studies have shown only a weak association (*i.e.*, no statistically significant associations) between EMF exposure and health risks.

In 1999, the National Institute of Environmental Health Sciences (NIEHS) issued its final report on "Health Effects from Exposure to Power-Line Frequency Electric and Magnetic Fields" in response to the Energy Policy Act of 1992. NIEHS concluded that the scientific evidence linking EMF exposures with health risks is weak and that this finding does not warrant aggressive regulatory concern. However, because of the weak scientific evidence that supports some association between EMF and health effects, and the common exposure to electricity in the United States, passive regulatory action such as providing public education on reducing exposures is warranted.

Minnesota, California, and Wisconsin have all recently conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group on EMF Issues ("Working Group") to evaluate the research and develop policy recommendations to protect the public health from any potential problems resulting from high voltage transmission line EMF effects. The Minnesota Department of Health published the Working Group's findings in a White Paper on Electric and Magnetic (EMF) Policy and Mitigation Options (MDH, Sept. 2002) ("EMF White Paper"). The Working Group summarized its findings as follows:

> Research on the health effects of EMF has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to EMF and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between EMF and health effects; however many of them also concluded that there is insufficient evidence to prove that EMF exposure is safe.

EMF White Paper at 1.

The Minnesota Environmental Quality Board ("EQB") has addressed the matter of EMF with respect to new transmission lines in a number of separate dockets over the past few years. *See* Docket Nos. 03-64-TR-XCEL (161 kV Lakefield line); 03-73-TR-Xcel (345 kV Buffalo Ridge line); 04-84-TR-XCEL (115 kV Buffalo Ridge to White line); and 04-81-TR-Air Lake-Empire (115 kV line in Dakota County). The Environmental Assessments and finding prepared by the EQB for each of these transmission lines are pertinent to this issue. Documents from those matters are available on the Commission webpage: energyfacilities.puc.state.mn.us.

In its assessment of the 345 kV Buffalo Ridge line, the EQB made the following findings with regard to EMF:

> 118. No significant impacts on human health and safety are anticipated from the Project. There is at present insufficient evidence to demonstrate a cause and effect relationship between

> EMF exposure and any adverse health effects. The EQB has not established limits on magnetic field exposure and there are no federal or Minnesota health-based exposure standards for magnetic fields. There is uncertainty, however, concerning long-term health impacts and the Minnesota Department of Health and the EQB all recommend a "prudent avoidance" policy in which exposure is minimized.
>
> 119. In previous routing proceedings, the EQB has imposed a permit condition on high voltage transmission line permits limiting electric field exposure to 8 kilovolts per meter (kV/m) at one meter above ground. This permit condition was designed to prevent serious hazard from shocks when touching large objects such as semi trailers or large farm equipment under extra HVTLs of 500 kV or greater. Predicted electric field densities are less than half of the 8 kV/m permit condition for both the 345 kV line and the 115 kV line.

In the Matter of the Route Permit Application by Xcel Energy for the Split Rock to Lakefield Junction 345-kV High Voltage transmission Line, the Nobles County to Chanarambie 115-kV High Voltage Transmission Line, and Nobles County Substation in Rock, Nobles, Jackson, and Murray Counties, Minnesota, MEQB Docket No. 03-73-TR-Xcel, Findings of Fact, Conclusions, and Order Issuing Route Permit for Construction of Two High Voltage Transmission Lines, One Substation, and Associated Facilities at 31 (June 2005).

3.11.1 Electric Fields

Voltage on a transmission conductor, or wire, produces an electric field in the area surrounding the conductor. The electric field associated with high voltage transmission lines extends from the energized conductors to other nearby objects, such as the ground, towers, vegetation, buildings, and vehicles. The electric field from a transmission line weakens with increasing distance from the line.

The intensity of electric fields is measured in kiloVolts per meter ("kV/m"). Transmission line electric fields are typically measured near the ground, usually one meter above the ground. As noted in the subsection above, the EQB has determined that electric fields for HVTLs are limited to 8 kV/m.

Graphs showing the expected electric field at one meter above the ground for the structure types currently being considered for the Project are provided in Appendix C. As shown in the graphs, the maximum electric field is well below the 8 kV/m limit the EQB has imposed as a condition on other HVTL permits.

(a) Induced Voltage

When an electric field reaches a nearby conductive object, such as a vehicle or a metal fence, it induces voltage in the object. The magnitude of this voltage is dependent on many factors,

including the object's capacitance, shape, size, orientation, and location, object to ground resistance, and weather conditions. If the object is insulated or semi-insulated from the ground and a person touches it, a small current would pass through the person's body to the ground. This might be accompanied by a spark discharge and mild shock, similar to what can occur when a person walks across a carpet and touches an object or person.

The main concern with induced voltage of an object is not the level of the induced voltage, but the current that flows through a person to the ground should the person touch the object. To ensure the safety of persons in the proximity of HVTLs, the National Electrical Safety Code ("NESC") requires that any discharge be less than 5 milliAmperes ("mA"). The Applicants used computer modeling to estimate the spark discharge from a typical school bus (40' long by 8.5' wide by 10.75' high) stopped at mid-span under a 230 kV line. The modeling showed that the spark discharge current would be slightly less than 1 mA. This is less than the 5 mA NESC limit, and unlikely to register as an annoyance. The Applicants would also ensure that any fixed conductive object in close proximity or parallel to the Project, such as a fence or other permanent conductive fixture, would be grounded so any discharge would be less than the 5 mA NESC limit.

(b) Pacemakers

High intensity electric fields can have adverse impacts on the operation of pacemaker and implantable cardioverter defibrillators ("ICD"). Interference with implanted cardiac devices can occur if the electric field intensity is high enough to induce sufficient body currents to cause interaction. Magnetic fields from transmission lines do not reach levels where they would have adverse impacts on the operation of pacemakers or ICD's.

Modern "bipolar" cardiac devices are much less susceptible to interactions with electric fields. Medtronic and Guidant, manufacturers of pacemakers and ICDs, have indicated that electric fields below 6 kV/meter are unlikely to cause interactions affecting operation of most of their devices. The older "unipolar" designs of cardiac devices are more susceptible to interference from electric fields. Research from the early 1990s indicates that the earliest evidence of interference was in electric fields ranging from 1.2 to 1.7 kV/meter.

The graphs in Appendix C show that the electric fields for all structure alternatives are well below levels at which modern bipolar devices are susceptible to interaction with the fields. For older style unipolar designs, the electric fields do exceed levels that research from the 1990s has indicated may produce interference.

However, recent research conducted in 2005 concluded that the risk of interference inhibition of unipolar cardiac pacemakers from high voltage power lines in everyday life is small. In 2007, Minnesota Power and Xcel Energy conducted studies with Medtronic, Inc. under 115 kV, 230 kV, 345 kV, and 500 kV transmission lines to confirm these 2005 findings. The analysis was based on real life public exposure levels under actual transmission lines in Minnesota and found no adverse interaction with pacemakers or ICDs. The analysis concluded that although interaction may be possible in unique situations, device interaction as a result of typical public exposure would be rare. 2007 Minnesota Power Systems Conference Proceedings (University of

Minnesota), *Electromagnetic Compatibility of Active Implantable Medical Devices (AIMD) and Their Interaction with High Voltage Power Lines*, at 23·11

In the unlikely event a pacemaker is impacted, the effect is typically a temporary asynchronous pacing (commonly referred to as reversion mode or fixed rate pacing). The pacemaker would return to its normal operation when the person moves away from the source of the interference.

3.11.2 Magnetic Fields

As noted above, current passing through any conductor, including a transmission wire, produces a magnetic field in the area around the wire. The magnetic field associated with HVTLs surrounds the conductor and decreases rapidly with increasing distance from the conductor. The magnetic field is typically expressed in milliGauss (mG). The magnetic fields of some home appliances are greater than that from transmission lines. Table 3.11 shows the magnetic fields of some common household appliances.

Table 3.11 Magnetic Fields of Common Electric Appliances
(mG)

Appliance	Distance from Source		
	6 inches	1 foot	2 feet
Hair Drier	300	1	--
Electric Shaver	100	20	--
Can Opener	600	150	20
Electric Stove	30	8	2
Television	NA	7	2
Portable Heater	100	20	4
Vacuum Cleaner	300	60	10
Copy Machine	90	20	7
Computer	14	5	2

Source: *EMF In Your Environment* (EPA 1992).

There are no federal or Minnesota exposure standards for magnetic fields. The EQB and the Commission have recognized that Florida and New York, which have 150 and 200 mG exposure limits at the edge of the right-of-way, respectively, are the only two states with magnetic field exposure standards in the country. The general standard among the other states is prudent avoidance.

The profile of the magnetic field associated with the Project depends on the final line structure(s) and conductor configuration(s) chosen. Thus a magnetic field profile for each combination of structure and conductor currently being considered for the Project is provided by the graphs in Appendix C. The graphs show the potential magnetic field should the current flow on the line reach a conductor's thermal limit. Since the expected normal peak current flow of the Project will be approximately 60% of the conductor's thermal limit, the actual magnetic field of the Project once placed in service will be significantly less than shown in the graphs. In addition,

the actual current flow on the line will vary throughout the day in relation to the electrical demand, and therefore the magnetic field will be less than the expected normal peak current flow for most hours of the day. In short, the graphs depict the maximum magnetic field possible when current flow is at the conductor's capacity limit; the expected normal operation of the Project, whether during on-peak or off-peak hours, results in a considerably smaller magnetic field.

3.12 Stray Voltage

"Stray voltage" is a condition that can occur on the electric service entrances to structures from distribution lines – not transmission lines. More precisely, stray voltage is a voltage that exists between the neutral wire of the service entrance and grounded objects in buildings such as barns and milking parlors.

Transmission lines do not, by themselves, create stray voltage because they do not connect to businesses or residences. Transmission lines, can, however, induce stray voltage on a distribution circuit that is parallel and immediately under the transmission line. Appropriate measures will be taken to prevent stray voltage problems when the proposed Project parallels or crosses distribution lines.

3.13 Ozone and Nitrogen Oxide Emissions

Ozone and oxides of nitrogen can be produced by corona, which consists of an ionic or electrical discharge from the surface of a transmission line conductor. Corona occurs when the electric field intensity or surface gradient on the conductor exceeds the breakdown strength of the surrounding air, and usually the conductor surface gradient for a 230 kV transmission line is below the air breakdown level. Some imperfection, such as loose conductor support hardware or water droplets, is necessary for corona to occur. When it occurs, corona is within a few centimeters or less of the area immediately surrounding the conductor.

Ozone also forms naturally in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants such as hydrocarbons from auto emissions. Ozone is a very reactive form of oxygen and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, ozone is relatively short-lived. The natural production rate of ozone is directly proportional to temperature and sunlight and inversely proportional to humidity. Therefore humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the production of ozone.

The US Environmental Protection Agency ("EPA") has promulgated a 0.08 parts per million ("ppm") per 8-hour period ozone emissions standard. The 8-hour period is based on the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area.

Computer modeling for a typical 230 kV line using H-frame structures calculated a maximum concentration of 0.0012 ppm per 8-hour period near the conductor, and a concentration of 0.0002 ppm per 8-hour period at one meter above ground during foul weather or worst case conditions. Both of these ozone levels are well below EPA standards.

The computer modeling of the above ozone concentration levels assumed high humidity or rainy conditions with no reduction in the amount of ozone due to oxidation or air movement. The levels therefore overestimate the amount of ozone at ground level and during fair weather conditions. Ozone concentration at ground level is generally expected to be near zero. Studies designed to monitor the production and concentration of ozone under transmission lines justify this expectation by generally failing to detect any ground level increase in ozone due to the presence of a transmission line.

3.14 Radio/Television Interference

Besides producing ozone and nitrogen oxides, corona discharges can result in radio frequency ("RF") noise. While the likelihood of an occurrence of corona increases as the operating voltage of a line increases, its potential to interfere with radio and television signals is not the magnitude of the transmission line-induced RF noise, but the level of that noise in comparison to the strength of the broadcast signals. Very few interference problems have resulted from existing 230 kV transmission lines because the strength of the broadcast signal within a broadcaster's primary coverage area is great enough to maintain a RF signal to noise ratio that prevents interference.

3.14.1 Mitigating Radio Interference

If interference from transmission line corona does occur for an AM radio station that had good reception before the line was built, satisfactory reception can be obtained by appropriate modification of (or addition to) the receiving antenna system. Interference with FM broadcast reception is generally not a problem for two reasons. First, corona-generated RF noise decreases in magnitude with increasing frequency and is quite small in the FM broadcast band (88-108 MegaHertz ("MHz"). Second, the excellent interference rejection properties inherent in FM broadcast systems make them virtually immune to amplitude type disturbances.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel transmission line structure) may experience interference because of the signal blocking effects of the structure. Moving either mobile unit by less than 50 feet so that the metallic structure is no longer immediately between the two units should restore communications. RF noise is not an issue for cellular phones because it is almost non-existent in the frequency range for cellular type phones, and the technology used by cell phones is superior to that used in two-way mobile radio units.

3.14.2 Mitigating Television Interference

Corona-generated RF noise and transmission line structure placement could cause interference with TV broadcast signals. The transition to digital TV broadcasts will be complete by the time the Project is constructed. Digital reception is in most cases considerably more tolerant of noise and somewhat less resistant to multipath reflections (*i.e.*, reflections from structures) than analog broadcasts. The picture on a digital television does not gradually degrade as with analog broadcasts, but rather becomes pixilated (turns into squares) at what is called the "avalanche point" and usually "freezes." This pixilation and freezing occurs at approximately the same interference level that an analog broadcast picture would become completely unviewable. So

although digital reception is more tolerant of RF noise, if the noise level is great enough it will impact digital television reception.

Due to the higher frequencies of television broadcast signals (54 MHz and above), a 230 kV transmission line seldom causes reception problems within a station's primary coverage area. In the rare situation where the construction of the Project cause interference within a television station's primary coverage area, the Applicants will work with the affected viewers to correct the problem. Usually any reception problem can be corrected with the addition of an outside antenna.

Loose and/or damaged transmission line hardware may also cause television or radio interference. If interference is caused by or from the operation of the Project, the Applicants will inspect and repair any loose or damaged hardware in the transmission line or take other necessary action to restore reception to the present level.

The Applicants are not aware of any complaints related to radio or television interference resulting from the operation of the existing 230 kV transmission lines located near the Project area, and do not expect that such interference will be an issue along the Project's line route.

3.15 Audible Noise

There are two possible sources of audible noise from the Project. They are the transmission line conductors and the transmission line's substations. Noise levels are measured on a logarithmic scale in units of decibels. Because human hearing is not equally sensitive to all frequencies of sound, it is customary to apply a weighting factor so the overall measured sound pressure level relates as closely as possible to the ear's perception of the sound. The A-weighting network is typically used, and the measured sound level is expressed in units of decibels A-weighted ("dB(A)"). In general terms, a noise level change of 3-dB(A) is imperceptible to human hearing, while a 5-dB(A) change in noise level is clearly noticeable and a 10-dB(A) change in noise level is perceived as a doubling of noise loudness. Table 3.15-1 provides the estimated noise levels for some common noise sources, expressed in dB(A).

Table 3.15-1 Common Noise Levels

Sound Level dB(A)	Noise Source
140	Jet Engine (at 25 meters)
130	Jet Aircraft (at 100 meters)
120	Rock and Roll Concert
110	Pneumatic Chipper
100	Jointer/Planer
90	Chainsaw
80	Heavy Truck Traffic
70	Business Office
60	Conversational Speech
50	Library
40	Bedroom
30	Secluded Woods
20	Whisper

Source: A Guide to Noise Control in Minnesota (MPCA 1999)

Pursuant to Minn. R. 7030.0030, noise contributors must comply with the Noise Area Classifications ("NAC") criteria of Minn. R. 7030.0040, developed by the MPCA. These criteria establish the range of noise levels that may be emitted in an area based on the land use activities in that area. For example, NAC (1) includes the most noise-sensitive land use activities, such as households, hospitals, churches, and campgrounds. NAC (2) includes less noise sensitive land use activities, such as bus passenger terminals, and NAC (3) includes the least sensitive land use activities, such as highways.

A-weighted statistical sound levels ("L Level Descriptors") establish the permissible noise levels for specific periods of time for a particular NAC. "L_{10}" is the noise level that may not be exceeded more than 10 percent of the time in the NAC, for example, six minutes in an hour. "L_{50}" is the noise level that may not be exceeded more than 50 percent of the time, such as 30 minutes in an hour. Table 3.15-2 below shows the range of permissible noise levels established by the MPCA.

Table 3.15-2 Acceptable Noise Levels by Noise Area Classification and Time of Day
(dB(A))

Noise Area Classification	Day (7 a.m.- 10 p.m.)		Night (10 pm.- 7 a.m.)	
	L_{50}	L_{10}	L_{50}	L_{10}
1	60	65	50	55
2	65	70	65	70
3	75	80	75	80

Source: Minn. R. 7030.0040

The utility industry generally reports expected audible noise emissions at the lower L Level Descriptor of L_5 rather than at L_{10}. L_5 is the noise level exceeded five percent of the time, or for three minutes in an hour.

3.15.1 Conductor Noise

Audible noise from conductors is due to corona formation (minor breakdown of air insulating a conductor), and the level of the noise is affected by conductor radius, surface condition, line geometry, weather conditions, and operating voltage. Noise from a transmission line reaches its maximum during heavy rain, however, the general background noise of heavy rain is greater than the noise from the transmission line. As a result, people do not normally notice audible noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines will produce an audible crackling noise at approximately household background levels from the small amount of electricity ionizing the moist air near the wires. During dry weather, audible noise from transmission lines is barely perceptible.

The Project is expected to be essentially inaudible at the edge of the right-of-way during fair weather conditions. Anticipated noise levels for the proposed 230 kV line in fair weather conditions and at the L_5 and L_{50} levels for wet conditions are shown in graphs in Appendix C. These graphs are based on transmission line noise level algorithms developed by the Bonneville Power Administration. The graphs show that the maximum L_5 noise level directly under the line in wet conditions is less than 50 dBA. This is below the most restrictive permissible noise level for NAC (1), shown in Table 3.14-2 above. The expected noise levels at the edge of the right-of-way during typical fair weather conditions would be less than 20 dBA, which is the level of a whisper as shown in Table 3.14-1 above. That level of noise is generally inaudible the majority of the time.

The BPA has developed its own general guideline for audible noise emissions based on public responses to noise from alternating current (AC) transmission lines. According to the BPA, numerous complaints can be expected if the line noise exceeds approximately 58.5 dB(A), and few complaints should be expected if audible noise is limited to 52.5 dB(A). The calculated values for the Project are well below these levels at the edge of the right of way in the rain, which is the condition that results in the most audible noise, and audible noise will be barely perceptible during fair weather within the right-of-way. The Applicants are not aware of any complaints related to audible noise resulting from the operation of the existing 230 kV transmission lines located outside the Project area, and do not expect that audible noise will be an issue along the Project's line route.

3.15.2 Substation Noise

The main source of audible noise at a substation is the transformers. Transformers produce noise whenever they are energized, with the level of the noise depending on transformer size, operating conditions (cooling fans on or off, *etc.*), voltage level, and weather conditions. Generally, noise levels during operation and maintenance of substations are minimal.

The proposed additions at the Wilton and Boswell substations consist of 230 kV line exits, circuit breakers, and associated facilities. The Project does not include the addition of transformers at the substations, so the noise levels of these substations will not change.

SECTION 4 - NEED FOR THE PROJECT

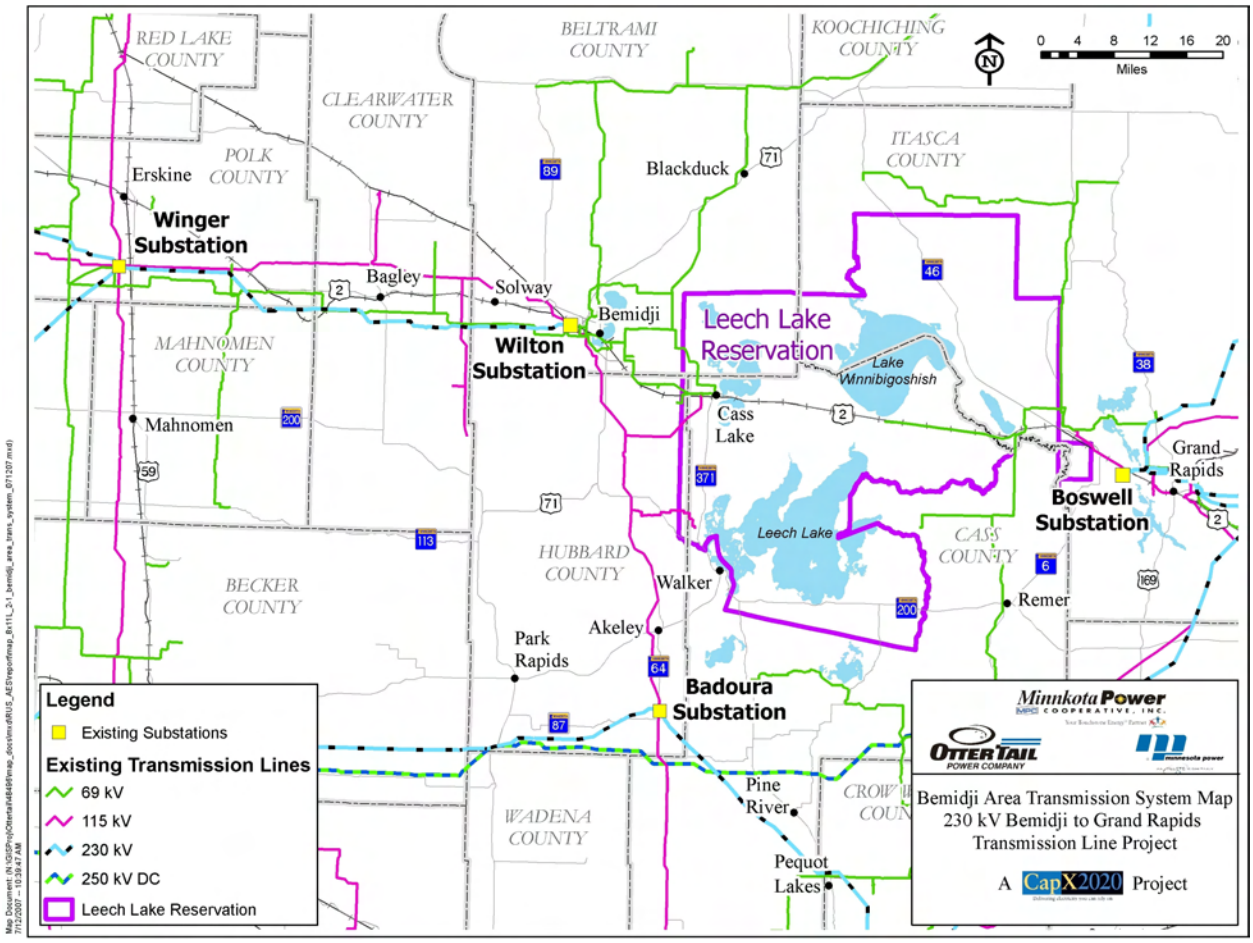
4.1 Overview of Need

Based on analyses of the Minnesota and larger regional transmission system, the Bemidji-Grand Rapids Line will address three critical issues: (i) it will improve the voltage stability of the transmission system in the Bemidji area to meet current and future load demands; (ii) it will help increase the reliability of the entire Red River Valley transmission system to meet long-term demand for electrical power; and (iii) it will facilitate development of new generation, including potential wind generation, in the Red River Valley and eastern North Dakota.

4.2 Overview of Bemidji Area Transmission System

Bemidji area electric demand is currently supplied primarily from remote generation with some assistance from a local 40 MW generating facility at Solway, located approximately 15 miles west of Bemidji. The transmission network into the Bemidji area consists of three circuits: the Winger-Wilton 230 kV line, the Winger-Bagley-Solway- Wilton 115 kV line, and the Badoura-Akeley-Bemidji-Wilton 115 kV line (which includes a tap to Cass Lake). See Figure 4.2 below.

Figure 4.2 Bemidji Area Transmission System



Otter Tail Power and Minnkota Power have recently made facility upgrades within the Bemidji area. Minnkota Power added a second 230/115 kV transformer at the Wilton Substation in 2005 to provide a redundant 230/115 kV delivery from the Winger–Wilton 230 kV line to loads in the Bemidji area. In 2001 and 2002, Minnkota Power and Otter Tail Power installed a second 23 MVAR capacitor bank at the Wilton Substation, and one 23 MVAR capacitor bank at the Bemidji Substation. However, the reactive support offered by these capacitor banks is now fully consumed by the existing transmission system.

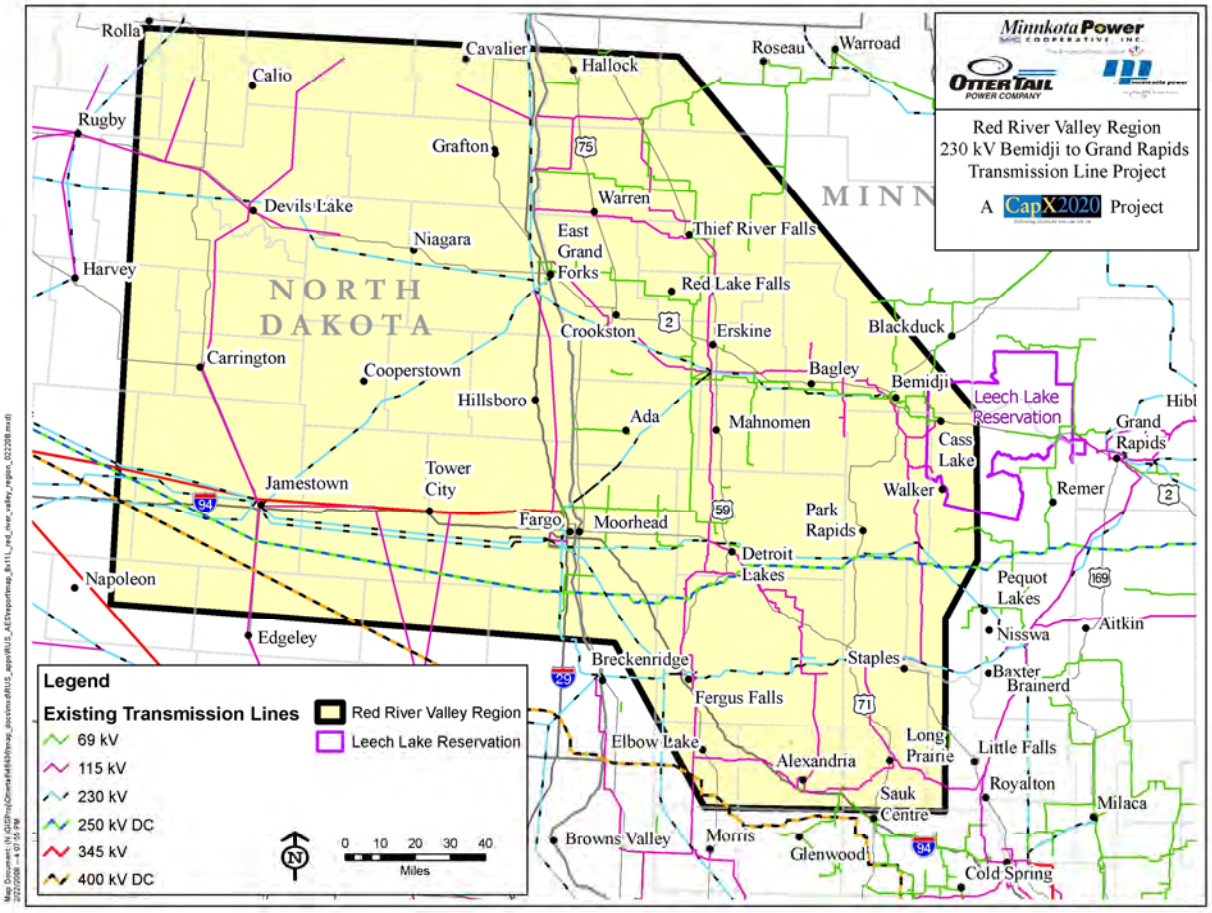
Historically, load-serving capability in the Bemidji area has been constrained primarily by post-contingent voltage inadequacies (rather than line or transformer loadings) for both local and remote transmission contingencies. The most severe local contingency within the Bemidji area is outage of the Winger-Wilton 230 kV line, the only 230 kV source into the Bemidji area. The most severe remote contingency is outage of the Dorsey-Roseau County-Forbes 500 kV line (Dorsey-Forbes Line) connecting the Minnesota transmission system to that of Manitoba Province, Canada. These inadequacies are most apparent during winter peak loading conditions.

Based on recent studies, thermal problems are expected in the near future on the 115 kV facilities in the Bemidji area. The limiting contingencies are the loss of the 230 kV source from Winger, the Wilton-Bemidji 115 kV line, or the 40 MW Solway generation source.

4.3 Overview of Red River Valley Transmission System

The bulk electric transmission system in the Red River Valley primarily consists of a 230 kV network, with a single 345 kV connection between the Red River Valley and western North Dakota. Nearly all of the power supply to the Red River Valley is from remote generation sources. Power typically flows through the Red River Valley region from west-to-east and north-to-south. However, long-term power purchase and capacity exchange agreements between Manitoba Hydro and US power suppliers require that adequate transmission capability be maintained to enable both northward and southward power transfers at all times of the year. When Manitoba Hydro imports power from the United States there is a heavy south-to-north flow through the Red River Valley. When this occurs during the winter season, it aggravates the load-serving inadequacies in the Red River Valley as well as the Bemidji area. The Red River Valley transmission system is shown in Figure 4.3 below.

Figure 4.3 Red River Valley Transmission System



As is the case in the Bemidji area, load-serving capability in the Red River Valley has been constrained primarily by post-contingent voltage concerns for both local and remote transmission contingencies. The most severe contingency of local lines connecting the Red River Valley to the generation from the west and north is outage of the Center-Jamestown-Buffalo-Maple River 345 kV line, which is the highest capacity transmission tie between the Red River Valley area and the baseload generation sources to the west. As discussed above in subsection 4.2, the most severe remote contingency for the Red River Valley is outage of the Dorsey-Forbes Line. Outage of this 500 kV circuit during northward flow conditions causes significant power to flow through the Red River Valley's transmission system. This "throughflow" results in high reactive power losses, contributing to the risk of voltage collapse.

4.4 Regional Transmission System Studies and Analyses

The purpose and need for the Bemidji-Grand Rapids Line has been the subject of extensive studies over the last five years. A brief history of the studies is provided below.

4.4.1 2002 Red River Valley/West Central Minnesota Transmission Improvement Planning Study (2002 TIPS)

In the summer of 2000, the McHenry – Ramsey 230 kV line, which establishes a 230 kV tie from western North Dakota to Grand Forks, had about 10 miles of structures knocked down by severe storms. A coordinated emergency mobilization of the regional utilities' construction crews enabled the line to be temporarily restored to service in December of that year to prepare for peak winter loads throughout the region. This sustained outage raised operating concerns, and the Northern Mid-Continent Area Power Pool ("MAPP") Operating Review Working Group alerted regional utilities of the potential risk of voltage collapse in the Red River Valley if certain critical combinations of conditions were present.

Recognizing the severity of this outage, local transmission planners in the region came together through the efforts of the Red River Valley Subregional Planning Group to study a long-term solution for the region. The Red River Valley/West Central Minnesota Transmission Improvement Planning Study, completed in 2002 ("2002 TIPS"), was initiated to identify possible transmission options to address the long-term voltage collapse concern within the region. The analysis confirmed that the system was vulnerable to voltage collapse and that improved compensation of reactive loads on the system would improve the situation, but not eliminate it. The 2002 TIPS analysis concluded that new transmission or generation was necessary to remedy the voltage security problems and also maintain reliable service to the region's growing load.

The 2002 TIPS report also included an extensive analysis of the existing transmission system. Based on identified system shortcomings, the report recommended a number of projects to address the Bemidji area's voltage security issues in the short term, including improvement of the distribution system loads' power factor, the addition of 115 kV shunt capacitor banks, and the addition of 230/115 kV transformer capacity. Most of these short-term solutions are underway or have been completed. The reactive support provided by the added capacitor banks is now fully consumed by the existing transmission system. Thus, future load growth requires additional reactive power supplies beyond those already existing in the area, and new transmission or local area generation.

The 2002 TIPS report considered 30 transmission options, which included lines with voltages over and under 230 kV between a variety of alternative terminals and substations. The study effort analyzed the abilities of eleven of the 30 options to provide a long-term solution to the voltage collapse concerns in the Red River Valley, including the Bemidji area. The following major conclusions of the report relate to the Bemidji-Grand Rapids line (referred to as the Boswell-Wilton line in the report):

- The 230 kV Boswell – Wilton Line improves the reliability of the Bemidji area which is vulnerable to voltage problems, given an outage of the radial 230 kV line presently serving the area or opening of the 115 kV loop that serves the area.

- The 230 kV Boswell – Wilton Line represents the least cost transmission improvement option providing remarkable voltage performance during prior outage conditions on nearby 345 kV and 500 kV systems.

- Both the 230 kV Boswell – Wilton Line and 345 kV Maple River - Alexandria - Benton County Line are geographically diverse compared to other transmission improvement options considered that originate from North Dakota, the primary generation source for the Region.

- Both the 230 kV Boswell – Wilton Line and 345 kV Maple River - Alexandria - Benton County Line support anticipated future load growth in the Bemidji area and areas northwest of Minneapolis.

4.4.2 2003 Minnesota Biennial Transmission Projects Report

In 2003, fifteen utilities that own or operate high voltage transmission lines in the state of Minnesota prepared the second Minnesota Biennial Transmission Projects Report ("2003 Biennial Report") for the Commission. The Biennial Report was prepared pursuant to Minn. Stat. § 216B.2425, which requires utilities owning or operating electric transmission facilities in the State to report on the status of the transmission system, including present and foreseeable inadequacies and proposed solutions.

The conclusions of the 2002 TIPS study were carried forward in the 2003 Biennial Report, confirming the State's utilities' support of the study conclusions regarding needed upgrades of the Red River Valley's transmission system. The 2003 Biennial Report included preliminary study results of eight new transmission options, which indicated that the combination of a 230 kV line from Bemidji to Grand Rapids and a 345 kV line from Fargo, North Dakota to Monticello, Minnesota would provide the most robust, economic, and efficient transmission solution to address the concerns regarding the Bemidji and Red River Valley areas' voltage stability and load-serving capability.

4.4.3 2005 CapX2020 Vision Study

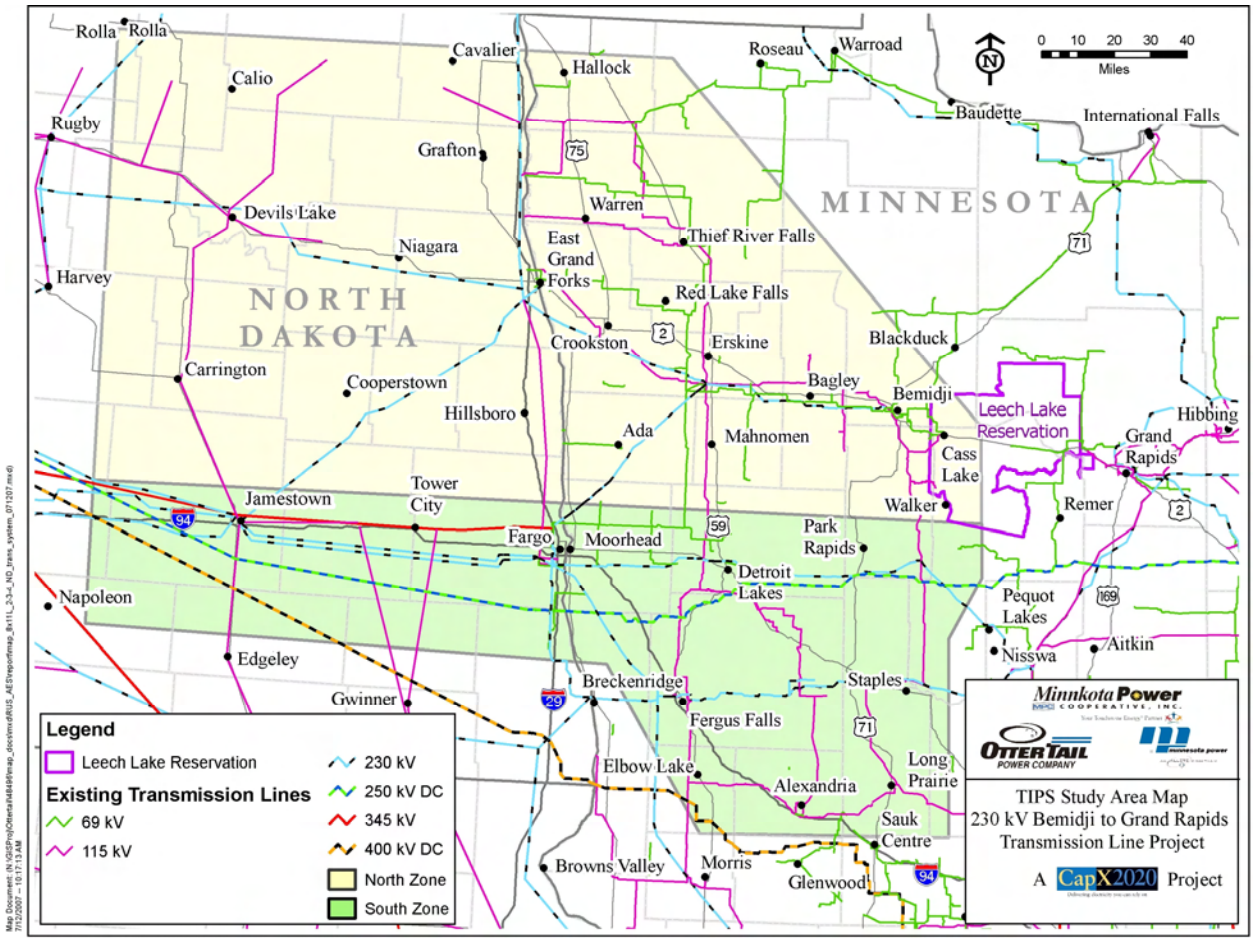
Minnesota's largest transmission-owning utilities (including Xcel Energy, Otter Tail Power, Minnesota Power, and Great River Energy) launched the CapX2020 initiative in 2004. This initiative focused on prioritizing the transmission infrastructure investments needed in Minnesota to meet the growing demand for electricity in the region, and to ensure timely and efficient regulatory review and approval of those investments. The result was the CapX2020 Vision Study. This study and other information about this initiative can be found at www.capx2020.com.

Consistent with the 2003 Biennial Report, the CapX2020 Vision Study concluded that a number of new high-voltage transmission lines will be required to accommodate the Red River Valley and surrounding region's increasing demand for electricity, and the additional generation capacity required to meet that demand. The CapX2020 study work found that the Bemidji-Grand Rapids Line, along with a Twin Cities-Fargo 345 kV line, were preferred transmission options for this region because they were effective in: 1) addressing the voltage stability and load serving needs of Bemidji and other principal load centers within the Red River Valley, and 2) improving the load-serving capability of the transmission system in Minnesota and the surrounding region to meet the load growth anticipated by 2020.

4.4.4 2006 Red River Valley/Northwest Minnesota Load-Serving Transmission Study (2006 TIPS Update)

The Utilities, along with Missouri River Energy Services, updated the 2002 TIPS analysis in 2006 ("2006 TIPS Update"). The 2006 TIPS Update was undertaken to refine the analysis from the 2002 TIPS report to verify that the best transmission options to address specific voltage stability issues and load serving deficiencies within the Red River Valley hadn't changed since the original 2002 TIPS analysis. In the update, the Red River Valley was divided into three areas: the northern portion of the Red River Valley region in which Bemidji is located ("North Zone"); the southern portion of the Red River Valley region ("South Zone"); and the entire Red River Valley region ("Combined Zone"). See Figure 4.4 below.

Figure 4.4 TIPS Study Area



Consistent with previous studies, the 2006 TIPS Update confirmed that the most robust, economic, and efficient upgrades to improve the load-serving capability of the Red River Valley area and local load centers within it are the Bemidji-Grand Rapids Line (North Zone); and a 345 kV line between Fargo, North Dakota and Monticello, Minnesota (South Zone). In reaching this conclusion, the 2006 TIPS Update considered other options including increasing the reactive power supply in the area and other transmission line alternatives.

4.4.5 Bemidji, Minnesota Area Electric Transmission System Study (2007 Bemidji Transmission Study)

The Utilities completed a study in January 2007 that focused on the electric infrastructure improvements required to meet the Bemidji area's existing and upcoming load-serving obligations prior to the proposed in-service date for the Bemidji-Grand Rapids Line. As previously discussed in Section 4.2, the Bemidji area is served by three transmission lines and has limited local generation. The study confirmed the need for another power delivery or supply facility for this load center by 2012, and identified measures necessary to provide reliable service until that time.

4.4.6 MISO Transmission Expansion Plan (MTEP 2006)

In December 2006, MISO issued its Transmission Expansion Plan ("MTEP 2006"), which identified violations within the MISO footprint of system performance criteria. In the West Area of the MISO system, which includes all of Minnesota, the Bemidji-Grand Rapids Line was identified as a Baseline Reliability Project to alleviate several of these criteria violations. MISO provided the following statement of justification for this determination:

> Serious voltage issues may occur in the Red River Valley area for hundreds of category C contingencies in the area. These low voltage violations are mainly observed in Maple River/Fargo/Moorhead, Prairie, Badoura/Hubbard, Wing River/Verndale, Riverton, Alexandria, Winger, Ramsey, Wilton/Bemidji, Buffalo, Jamestown, Drayton, Audubon, Hankinson, and Wahpeton, which are widely spread throughout the Red River Valley area. The Red River Valley area is geographically large with limited local generation. Outage of more than one source to the area is problematic and load shedding is often the only way to restore system performance to acceptable levels.
>
> * * *
>
> The Boswell-Wilton 230 kV line is the most effective transmission alternative to satisfy both [the] need[ ] [for] another transmission source for the Minnesota North Zone as a whole. It involves considerably fewer miles of new line construction than other alternatives.

MTEP 2006 at 128 (emendation added).

4.5 Summary of Need in Bemidji Area and Red River Valley

The 2006 TIPS Update analyzed the current incremental load serving capability of the system in the North Zone under contingency conditions. While the North Zone currently can support almost 500 MW of incremental load during system intact conditions, that is of little practical value because a system's load-serving capability is assessed based on the incremental load it can handle in the event of one or more contingencies. The analysis in the TIPS Update showed that the North Zone system currently has a 112 to 150 MW incremental load-serving capability above the zone's current peak winter load of 850 MW depending on which one of several single contingencies occur. However, the system currently has incremental load-serving capability of 0 MW in a double-contingency situation.

Focusing on the Bemidji area of the North Zone, the 2007 Bemidji Transmission Study analyzed the peak demand for the Bemidji area over the next 10-15 years, projecting that the peak load by the winter of 2011/2012 would be approximately 280 MW. That projected peak load is 60 MW greater than the projected 220 MW maximum load-serving capability of the system by the winter of 2011/2012 under single-contingency circumstances without the 40 MW Solway generation unit, which typically runs for only a limited number of hours per year.

In preparing this Application, another forecast of the winter peak demand for the next 15 years in the Bemidji area and North Zone was prepared, using the latest vintage data available. The results of that forecasting are presented in Section 4.7 below.

4.6 Winter Peak Demand and Annual Electrical Consumption

To assess need, the Commission's rules require that demand and consumption data be provided on a system-wide and seasonal basis by customer class. System-wide data is not helpful to assess need for the Project, however, because the need is primarily based on reliability concerns in the Bemidji area as a result of low voltages that occur under system contingency conditions, as well as on the Project's ability to meet anticipated load growth in the North Zone. The need is also dependent on the growth in winter peak demand in those areas, not on demand at any other time of year or by any particular customer class, so summer and customer class data is not helpful in assessing need either. For these reasons, the Applicants requested exemptions from these data requirements, which the Commission granted. See Data Exemption Order in Appendix B.

4.7 Winter Peak Demand and Consumption Forecasts

Pursuant to the Commission's Data Exemption Order, the Applicants provide below: 1) historical and forecasted winter peak demand and annual consumption for the Bemidji load center and for the North Zone of the Red River Valley; and 2) historical and forecasted annual consumption for the Minnesota portion of the North Zone.

4.7.1 Forecast Methodology

The forecasting was based on five years of historical load center data for the North Zone. The individual steps of the forecasting methodology are summarized below.

Consumption Forecasting

- Each utility with load in the Minnesota portion of the North Zone supplied data to be used to determine annual Minnesota consumption in the North Zone. Revenue meter data was used at the locations where it was available, with Energy Management System ("EMS") data used for the remaining locations. This data was collected over the last five year period to determine historic annual consumption for Minnesota load centers in the North Zone.

- Each load-serving utility developed a growth factor for their loads which was then applied to project the growth in consumption at each load center over the next 15 years.

- For load centers with customers served by multiple utilities, each load serving utility applied its growth factor to its customer's consumption to project the growth in consumption attributed to its customers. Each load serving utility's projected consumption was then summed to determine growth in consumption by all customers served from that load center.

North Zone Winter Peak Demand Forecasting

- EMS data was collected over the last five-year period to determine annual Non-Coincident Winter Peak Demand for each load center in the North Zone.

- For EMS data collection points where customers are served by multiple utilities, the 2006 Series MRO 2007 Winter Peak power flow model was used to determine the amount of Winter Peak Demand attributable to each utility.

- Each load-serving utility developed a growth factor for their loads which was then applied to project the growth in Winter Peak Demand in each load center attributed to its customers in the North Zone over the next 15 years. These individual peak demand projections were then summed to determine the projected Non-Coincident Peak Demand at each load center in the North Zone

- The North Zone Non-Coincident 2003/2004 Winter Peak Demand was divided by the 2003/2004 historic North Zone Coincident Winter Peak Demand as established in the 2006 TIPS Update to determine a "Coincident Factor."

- The Coincident Factor was then applied to each North Zone load center's Non-Coincident Peak Demand to convert the historic and projected Non-Coincident Winter Peak Demand to a Coincident Winter Peak Demand for all load centers in the North Zone. The Bemidji Load Center was handled in this same manner for determination of the North Zone Coincident Winter Peak Demand.

Bemidji Area Winter Peak Demand Forecasting

Since the ability of the transmission system to meet the Bemidji Area Winter Peak Demand is becoming a critical concern (see Sections 4.1, 4.2, 4.4 and 4.5) Coincident Winter Peak Demand for loads in the Bemidji Area was also determined. The forecast methodology used to determine the Bemidji Area Winter Peak Demand is summarized below

- EMS data was collected over the last five-year period to determine annual Non-Coincident Winter Peak Demand for each load-serving substation in the Bemidji Area.

- For substations where customers are served by multiple utilities, the 2006 Series MRO 2007 Winter Peak power flow model was used to determine the amount of Winter Peak Demand attributable to each utility.

- Each load-serving utility developed a growth factor for their loads which was then applied to project the growth in Winter Peak Demand at each load serving substation in the Bemidji area over the next 15 years. These individual Peak Demand projections were then summed to determine the projected Non-Coincident Peak Demand at each substation in the Bemidji Area.

- EMS data was used to determine the 2006/2007 Bemidji Area Historic Coincident Peak Demand. This data indicated that the 2006/2007 Winter Peak Demand was 219.02 MW which occurred on February 3, 2007.

  The Bemidji Area Coincident Winter Peak Demand on February 3, 2007 was divided by the Bemidji Area actual 2006/2007 Non-Coincident Winter Peak Demand to determine a "Bemidji Area Coincident Factor."

- The Bemidji Area Coincident Factor was then applied to each Bemidji Area substation's Non-Coincident Winter Peak Demand to convert the historic and projected Non-Coincident Winter Peak Demand to a Coincident Winter Peak Demand for all Bemidji area load serving substations. These substations' Coincident Peak Demands were then summed to determine the Bemidji Load Center's Coincident Peak Demand.

4.7.2 Peak Winter Demand Forecast

A snapshot of the historical and forecasted coincident winter peak demand for the North Zone is shown in Table 4.7-1 below. A 20-year annual historical and forecasted coincident winter peak demand analysis by load center is also provided in Appendix D.

Table 4.7-1 North Zone Coincident Winter Peak Forecast

Load Center	North Zone Coincident Winter Peak Demand (MW)					
	2003/04	2007/08	2010/11	2011/12	2017/18	2022/23
Bemidji	200.55	242.33	276.47	287.59	321.57	349.23
Crookston/Thief River Falls	197.10	236.56	274.06	281.90	319.33	337.36
Lakota/Leeds	29.62	31.30	32.66	33.04	35.38	37.76
Devils lake	38.34	40.11	42.24	42.62	45.37	47.55
Winger/ Mahnomen	38.47	45.49	48.48	49.37	55.01	60.06
Grand Forks	213.98	261.80	273.87	277.52	301.11	321.63
Langdon/Hensel	74.79	76.97	81.95	83.27	92.33	100.39
Finley/Carrington	57.06	63.59	67.06	67.92	74.23	79.94
Total*	849.91	998.15	1096.79	1123.22	1244.33	1333.92

*Total MWs may differ from sum of load center MWs due to rounding

Consistent with previous forecasts (see Section 4.5), the Utilities most current forecast shows that by the winter of 2011/2012, demand in the Bemidji area during the North Zone winter peak will be approximately 288 MW. That is 68 MW greater than the projected 220 MW maximum load-serving capability of the local transmission system in 2011 under single-contingency circumstances without the Solway generation unit running.

Whenever the coincident seasonal peak for a specific area is calculated within the context of a much larger region, however, there is a risk that the local area peak will be understated because it

does not peak at the same time as the region at large. To ensure the risks facing the local transmission system in the Bemidji area are accurately represented, additional analysis was done to determine the coincident winter peak for the Bemidji area alone. Table 4.7-2 below shows the results of this analysis.

Table 4.7-2 Bemidji Area Coincident Winter Peak Forecast

Load Center	Bemidji Area Coincident Winter Peak Demand (MW)					
	2003/04	2007/08	2010/11	2011/12	2017/18	2022/23
Bemidji	207.63	250.34	285.07	296.36	331.49	360.26

The anticipated growth of demand in the Bemidji load center when considered in isolation results in its projected winter peak increasing from the approximately 288 MW shown in Table 4.7-1 to the approximately 296 MW shown in the table above. As discussed in detail in subsection 5.2.2 below, the installation of additional capacitor banks at the Wilton or Cass Lake Substations and the forced operation of the 40 MW Solway generator pre-contingency can address the bulk of this 76 MW shortfall in the system's operating capability until the Project is installed by the winter of 2011/2012. Even so, these system enhancements likely will not be able to handle all of the capability shortfall in the event of a single contingency, so there is the real risk that under-voltage load shedding will be necessary to maintain the system's stability.

4.7.3 Energy Consumption Forecast

A snapshot of historical and forecasted energy consumption for the Minnesota portion of the North Zone is shown in Table 4.7-3 below. Historical and forecasted annual energy consumption for a 20-year period for the Minnesota portion of the North Zone is included in Appendix D.

Table 4.7-3 Consumption in the Minnesota Portion of the North Zone

Load Center	Minnesota Consumption in North Zone (kWh Millions)					
	2003	2008	2011	2012	2018	2022/23
Bemidji	1,187	1,408	1,505	1,532	1,687	1,832
Crookston/Thief River Falls	903	1,116	1,187	1,204	1,299	1,389
Winger/ Mahnomen	226	252	269	274	304	332
East Grand Forks	142	175	176	177	180	183
Langdon/Hensel	39	43	46	47	55	61
Total*	2,496	2,995	3,183	3,233	3,525	3,797

*Total kWhs may differ from sum of load center kWhs due to rounding

4.7.4 Renewable Energy Standard Forecasts

In compliance with the Commission's Data Exemption Order, the Utilities have included the following information in Appendix E: 1) the Utilities' existing supply units that qualify under the Legislature's recently enacted Renewable Energy Standards ("RES"); 2) the Utilities capacity and energy requirements through 2020 to meet the new RES based on assumed capacity factors of 30, 35, and 40 percent; and 3) the Utilities' estimates of the requirements through 2020 to meet the new RES considering the impacts of forecast demand and sales, assuming 1 and 1.5 percent conservation of gross annual Minnesota retail energy sales and RES-qualified generation with 30, 35, and 40 percent capacity factors.

4.8 Increased System Capacity

The Commission's rules require that seasonal firm and participation sales, as well as purchases and associated load and generation capacity data, be provided to assess need against system capacity. See Minn. R. 7849.0280. This data is relevant to demonstrating need for a generator, however, not a transmission line, and so the Commission granted the Applicants' request for an

exemption from this requirement in favor of providing a description of how the addition of the Project will increase the capacity of the existing transmission network to meet forecasted demand in the Bemidji area and North Zone. See Data Exemption Order in Appendix B.

Two analyses were conducted to determine the incremental load-serving capability for the North Zone by adding the Bemidji-Grand Rapids Line: (i) a voltage stability (P-V) analysis to examine voltage adequacy as load increases; and (ii) a thermal limit analysis to determine at what point line or transformer overloads (thermal constraints) are experienced as load increases. P-V and thermal limits were analyzed for pre-contingency conditions (*i.e.*, system intact), and after each of the following critical contingencies occurred: a) outage of the Dorsey-Forbes 500 kV line; b) outage of the Wilton-Winger 230 kV line; and (c) coincident outages of the Wilton-Winger 230 kV line and Badoura-Laporte 115 kV line. These were identified as the most limiting contingencies in the transmission studies described in Section 4.4.

4.8.1 Increased Voltage Stability Limits

As shown in Table 4.8-1 below, the addition of the Bemidji-Grand Rapids Line adds 150 MW of incremental load serving capability in the event of an outage of the Dorsey-Forbes Line, and an incremental 550 MW in the event of a Wilton-Winger Line outage. Should there be a double contingency involving the Wilton-Winger and Badoura-LaPorte Lines, the existing system faces collapse while the addition of the Bemidji-Grand Rapids Line provides a minimum of 560 MW of incremental load serving capability to deal with the event.

Table 4.8-1 Voltage Stability Limits for North Zone With Project
(Incremental Load-Serving Capability Based on 2003/2004 Winter Peak Load of 850 MW)

Condition	Voltage Stability Load Limit (MW)		
	Existing System	Existing System plus Bemidji-Grand Rapids Line	Increase in Load Serving Capability
System Intact	525	805	280
Dorsey-Forbes outage	300	450	150
Wilton-Winger outage	230	780	550
Wilton-Winger & Badoura-LaPorte outage	No solution*	560	560+

* Infeasible condition due to voltage collapse.

4.8.2 Increased Thermal Limits

Table 4.8-2 below shows how the Bemidji-Grand Rapids Line also increases load-serving capability in the North Zone in terms of post-contingent line loading (thermal) limits.

Table 4.8-2 Thermal Limits for North Zone With Project
(Incremental Load-Serving Capability Based on 2003/2004 Winter Peak Load of 850 MW)

Condition	Thermal Load Limit (MW)		
	Existing System	Existing System plus Bemidji-Grand Rapids Line	Increase in Load Serving Capability
System Intact	350	500	150
Dorsey-Forbes outage	0	275	275
Wilton-Winger outage	100	500	400
Wilton-Winger & Badoura-LaPorte outage	No solution*	500	500+

* Infeasible condition due to voltage collapse

Again, in the event of a double-contingency involving the loss of the Wilton-Winger and Badoura-LaPorte Lines, the transmission system faces collapse absent the addition of the Bemidji-Grand Rapids Line. The addition of the Project also provides a 275 MW buffer before the system reaches its thermal limit if the Dorsey-Forbes Line goes out. Without the Project, that same outage would bring the existing system to its thermal limit.

4.8.3 Increased NDEX Interface Capability

The Bemidji area is "inside" the North Dakota Export ("NDEX") boundary. The NDEX interface is a known transmission constraint in the northern MAPP region, and is monitored to limit power export from the state of North Dakota, primarily to the Twin Cities metropolitan area. The interface runs to the north, east, and south of North Dakota. Its northern boundary is the North Dakota/Manitoba Province border; its eastern boundary extends from Roseau, Minnesota south past Bemidji and Alexandria to the Granite Falls, Minnesota area; and the interface's southern boundary runs west from Granite Falls through northern South Dakota to Montana. The NDEX boundary does not include the transmission facilities from North Dakota west to Montana, nor those between North Dakota and Saskatchewan to the northwest.

Since the NDEX boundary is a power transfer-limited interface, adding new transmission near its boundaries increases NDEX transfer capability. Based on analysis from the 2006 TIPS Update, the addition of the Bemidji-Grand Rapids Line improves the power system dynamic performance sufficiently to yield approximately 100-150 MW of incremental capability on the NDEX interface.

4.8.4 Enhanced Ability to Add Generation

The increase in the NDEX boundary limit is very significant in light of the new higher renewable energy objectives established by the Legislature in the 2007 Session: a minimum of 25% percent of all retail energy consumed within the state must be from renewables by 2025. Minn. Stat. § 216B.1691, subd. 2a (the 25% renewable energy by 2025 standard must be met by all the Utilities except Xcel Energy, which must meet a 30% renewable energy by 2020 standard). With a 100-150 MW increase in the NDEX boundary limit, new generation including wind energy generation can be developed in the Red River Valley and eastern North Dakota.

4.9 Increased System Efficiency

Losses are a measure of the energy flowing across the system that is lost through the elements of the transmission system. When electrical power is sent over a transmission line, some of it is lost through its conversion into heat from the resistance in the conductor. The amount of the loss is related to the square of the current flowing through the line. Higher voltages need less current to provide the same amount of power. The higher the voltage, the lower the current, and therefore less energy is lost to transfer the same amount of power. Since current across a transmission line can vary over time, losses are seldom constant from hour to hour, or from month to month. Transformers have a different type of energy loss, which is related to the physical construction of the transformer. Transformer energy losses are primarily due to the electrical characteristics of the iron core and copper windings within a transformer.

When determining the amount of generation necessary to serve their respective loads and power pool reserve requirements, utilities must take into account the amount of energy that will be lost in the course of transmission and distribution before it can actually be consumed. There are two aspects to losses: capacity and energy. The capacity aspect represents the total generation needed to cover losses. Decreasing losses on the system results in real savings, as it defers the need to add more generation to the system. The energy aspect of losses represents the energy consumed by the resistive elements of the transmission system. Decreasing losses reduces the fuel consumed by generators to cover losses while meeting load.

In determining the amount of losses associated with the addition of a particular transmission line, it is not reasonable to consider only the line associated with the Project. This is because the addition of the line will reduce current flow on other elements of the transmission system, which in turn affects line losses across a broad geographic area. This represents an improvement in efficiency of the transmission system. To get a true understanding of the potential efficiency improvement associated with the addition of a transmission line, it is necessary to look at the losses of the larger transmission system that result with and without the proposed line. The

reduction in winter peak demand losses as a result of the Bemidji-Grand Rapids Line are shown in Table 4.9-1 below.

Table 4.9-1 Project Demand Loss Reductions
Eastern Interconnection

Condition	Peak Winter Demand Losses (MW)
Existing System	11,988.1
System with Bemidji-Grand Rapids Line	11,964.2
Reduction in Demand Losses	23.9

The amount of the reduction in winter peak demand losses is used to estimate the energy losses associated with the Project. Basing the energy losses on the winter peak demand is appropriate because energy consumption in the Bemidji area is greatest during the winter season and engineering formulas used to estimate annual energy losses are based on the peak loss values. Upon calculating the loss factor for the area transmission system, it was applied to the winter peak demand loss reduction and multiplied by the number of hours per year to obtain the annual energy loss savings in MWh. This was then converted to a dollar value by applying an assumed average annual energy cost of $50 per MWh for replacement energy from existing regional generation resources. As shown in Table 4.9-2 below, the annual energy loss savings resulting from the Bemidji-Grand Rapids Line is estimated to be over $4 million per year.

Table 4.9-2 Project Annual Energy Loss Savings
(at $50/MWh)

Project	Winter Peak Loss Reduction (MW)	Loss Factor (%)	Equivalent Hourly Loss Savings (MW)	Annual Loss Savings (MWh)	Annual Loss Savings @ $50/MWh ($ thousands)
Bemidji-Grand Rapids Line	23.9	41.5	9.92	86,886	$4,344

4.10 Effect of Energy Conservation and Demand Side Management Programs

Current forecasts project the winter peak load in the Bemidji area will be 76 MW greater than the 220 MW maximum load-serving capability of the existing transmission system in 2011/2012 under single-contingency circumstances. Thus in lieu of the Utilities' proposed Project, an estimated 76 MW more of generation strategically located and running in the Bemidji area would

be necessary to alleviate the current transmission system's load serving deficiencies. And additional generation beyond that 76 MW would then be needed to keep up with estimated load growth in the area beyond 2011/2012. See Section 5.3 below for a full discussion of the generation alternatives to the proposed Project.

Based on this local generation requirement, future conservation and demand side management ("DSM") programs can only be considered feasible alternatives to the Project if they would reduce the peak demand in the area by 76 MW by 2011/2012, as well as eliminate future load growth within the Bemidji area going forward from then. However, it is not feasible for DSM and conservation measures to achieve that level of reduction and do so within the specific geographic area that is necessary. Reducing demand by 76 MW represents approximately 26% of the projected coincident winter peak for the Bemidji area in 2011/2012. The state-mandated load reduction goal for a utility's entire system is 1.5%. Minn. Stat. § 216B.241, subd. 1c(b). It is not realistic to expect that DSM and conservation programs can yield 17 times that goal in the Bemidji area alone.

4.11 Effect of Promotional Practices

The growth in demand in the Bemidji area and North Zone is the result of the growth in the number of customers and in the amount of energy that customers in the aggregate are consuming. The Utilities have not engaged in any direct promotional practices to encourage the use of more power. The Utilities' demand-side management and conservation programs are discussed in subsection 5.2.1 and Appendix F.

4.12 Delay of Project

As noted in subsection 4.4.6 above, MISO has observed that an outage of more than one source to the Red River Valley area is "problematic and load shedding is often the only way to restore system performance to acceptable levels." MTEP 2006 at 128. While running local generation in the Bemidji area and adding capacitors at the Wilton and Cass Lake Substations increases the load-serving capability of the transmission system in the Bemidji area, by the time winter peak demand is projected to be 296 MW in 2011/2012, a single contingency will likely trigger the need for under voltage load shedding to maintain system stability. Delay beyond this point simply increases that risk and is not a viable alternative.