GREAT RIVER ENERGY

LONG-RANGE TRANSMISSION PLAN

TRANSMISSION PLANNING DIVISION

OCTOBER, 2008

GREAT RIVER ENERGY

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

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Executive Summary

Great River Energy (GRE), consisting of its member distribution cooperatives, is the second largest electric utility in the state of Minnesota and, as such, has an important role in the planning of the electric transmission system with the goal to develop a coordinated, efficient, and economical transmission network for the purpose of providing reliable delivery of generation resources to the member system loads.

This Long-Range Plan (LRP) report summarizes the results of the analysis of the existing transmission system conducted by the GRE transmission services planning staff. It includes input and feedback from the GRE members systems and the interconnected utilities with which GRE has transmission agreements. The report does not include any analysis of bulk transmission (115 kV and above) that would be required for generation outlet facilities or to improve the bulk power transfer capability of the electric transmission network.

The proposed transmission plan included in this report is intended to be a road map for the development of the electric transmission network in the GRE service area for the next 25 years (2006-2031). Over this same period the GRE member coincident electric summer peak will grow from 2808 MW to 5941 MW. Likewise, the GRE member winter coincident peak will grow from 2458 MW to 5492 MW over the same 25 year period. The report includes suggested in-service dates and cost estimates, based on 2008 dollars, for projects over the 25 year period.

The LRP calls for construction of over $700 million of transmission projects. Transmission line activity will include nearly 1250 miles of new transmission lines or lines upgraded to a higher operating voltage, and nearly 625 miles of new right of way corridor. Substations projects will consist of nearly 100 transmission substation projects consisting of 32 new transmission stations. GRE member systems are also expected to add 55 new distribution substations throughout the LRP period.

The results of the LRP will be used to determine the near-term projects that will enter into the GRE Capital Spending Plan (CSP). Through the CSP process, projects will be re-evaluated on an annual basis to determine if deferral is possible and to assure that the project is still the optimal solution before being included in any capital budget. Due to the unknown growth potentials and other factors that may arise, GRE considers this document to be applicable for 5 years of service when a new LRP would be expected to be published.

1: Introduction

Purpose

This study is a guide for future needs in the GRE service territory that assures its customers a reliable, cost-effective, and energy efficient power source to the year 2031. Although different plans may eventually be developed, this guide gives a good foundation for formulating ideas for future plans in specific areas.

Scope

This report is limited to transmission facilities owned by GRE or foreign utility lines that serve the GRE member systems. Central station generation needs with their respective facilities and reactive control of the high voltage system are not considered as part of the study. These systems are assumed to be available when they are needed. Therefore, new facility additions consist of transmission lines, transmission and distribution substations, and sub-transmission capacitors or reactors.

Use

The Long-Range Transmission Plan is used as a source of information to parties interested in the development of the GRE transmission system. Interested parties include GRE management and staff, GRE's member systems, and neighboring utilities. The main use of this document is for financial applications and forecasting construction activities.

Planning engineers can also use this document as a guide to identify areas of need, a source of information of the existing system, and a planning tool to determine alternatives, particularly distributed generation and demand-side management, for an integrated resource plan.

This document is intended to be used only as a guide and not as a construction work plan. Due to the uncertainty of load growth in the future, the facilities may be changed, delayed, advanced, or canceled for another lower-cost alternative.

2: Forecast Information

The power flow models for the Long Range Plan (LRP) were developed using a combination of information from various sources: historical substation loads and interviews with individual member cooperatives. Historical and projected load data was also gathered from the other transmission network load customers. Load values and growths were taken from the 2007 series 2012-2017 models. These loads were applied to a detailed model and sent for revision to participating companies. Participating companies were Alliant Energy, Minnesota Power, Western Area Power Agency, Xcel, Missouri River Energy Services, Southern Minnesota Municipal Power Agency and local municipalities throughout Minnesota.

Individual member substation loads within the GRE transmission network peak at different times due to differences in weather, load types, and availability and use of load management systems. Individual bus load levels were projected from the individual cooperative member demands and then apportioned across the member's substations according to historical substation load shares. This results in a total system demand level that is higher then the GRE total system peak demand (due to loss of coincidence) but more adequately tests the capability of the transmission network to serve localized peak power demand. Since the LRP does not address transmission requirements for bulk power transfers or outlet for new generators, this is a valid test of the load serving transmission system.

In addition to historical data, interviews were conducted of each individual GRE member cooperative to determine whether load development with their individual service areas would grow at rates different than what might be projected from the trending historical data. New housing developments, new large power loads, and changes in service area boundaries will cause changes in load growth rates. Information from the interviews was used to adjust the load projections of the individual members.

In general, those members in the vicinity of the large metropolitan centers of St. Cloud and Minneapolis/St. Paul are experiencing larger growth rates due to the expansion of the suburban areas and the greater use by residential customers. Also, open land exist for industrial expansion within the suburban ring that results in potential large load additions such as data processing centers.

Recent cost of oil and gas has caused a significant growth in electrical heating. Winter loads in the north are increasing at a tremendous rate with continued growth expected until electric rates come in line with present propane costs.

Agri-businesses, specifically those in the bio-energy field, are also being added into the transmission grid at a high rate. These loads can add a large lump of load on the system in a fairly short amount of time.

Long Range Plan Total Member System Load Forecast

Season	Historical 2006 MW	Growth %/yr	2011 MW	Growth %/yr	2021 MW	Growth %/yr	2026 MW
Summer	2808	2.5	3180	3.3	4412	3.0	5941
Winter	2458	2.7	2810	3.5	3962	3.3	5492

3: Design Criteria

Design criteria, in accordance to good utility practice, was developed using sound engineering judgment to determine the need for future facilities. The criteria include:

- Acceptable voltage limits
- Thermal loading limits
- Required reliable service to consumers measured by past performance
- MW-mile projections as guide for adding loop service to radial lines or circuit breaker protection to looped systems
- Financial factors to determine the present worth of each alternative

This criterion is listed below.

Voltage Criteria

		Percent of Nominal			
		Normal Conditions		Emergency Conditions	
System	Facility	Max	Min	Max	Min
GRE	Load Serving Buses Remaining Buses	105% 105%	95% 95%	110% 110%	92% 90%
XEL	Metro Non Metro	105% 105%	95% 95%	110% 110%	92% 90%
MP OTP ITC	All buses	105%	95%	110%	90%

Power Factor

GRE requires that its member systems maintain a power factor of at least 98% to maintain transmission system voltage, although this limit may be adjusted to a higher performance standard, if needed. The reasoning is that correcting voltage issues is less expensive at the distribution level versus implementing bulk facility additions to deliver capacitive power to the distribution system. Improved efficiency is also achieved by improved voltages on the distribution system. If member systems are deficient, GRE has the capability of implementing a charge for not being compliant. For purposes of this study, GRE used the historical meter readings at peak times to establish power factor for the loads. Future loads were scaled at this same level for all models used. Planning engineers will adjust plans such that at least a 98% power factor is modeled at GRE load serving buses, and make note of loads that violate the criteria.

Overload Criteria

The following steady-state loadings shall not be exceeded:

Facility Ratings		Line		Station Equipment		Transformer	
System	**Condition**	**Loading**	**Duration**	**Loading**	**Duration**	**Loading**	**Duration**
GRE	Normal Emergency*	100% None	Continuous 30 Minutes	100% None	Continuous 30 Minutes	100% 125%	Continuous 30 Minutes
XEL MP OTP ITC	Normal Emergency	100% None	Continuous 30 Minutes	100% None	Continuous 30 Minutes	100% 125%	Continuous 30 Minutes

* GRE will conduct an engineering analysis, when needed, to determine whether a specific facility is capable of having an emergency rating or an extension in emergency duration.

Reliability

Although a variety of reliability indices are calculated and used for comparisons and decision making, a general reliability goal is an outage time of less than 1 hour per consumer per year and an outage frequency less than 6 per consumer per year.

This report will review all possible single contingencies ensuring that the stated criteria are met at both summer and winter seasonal peaks. Normally open lines will remain open when developing the long-range system so the need for circuit breaker stations can be analyzed unless open line segment is required to serve load on contingency.

GRE will use MW-mile projections as a tool to determine when loop service to a radial line is to be considered or when circuit breaker protection is needed for looped systems. The MW-mile criteria are discussed in detail in Appendix III.

Financial Factors

The financial factors used to determine the present worth of each alternative are:

Investment	Distribution	Line	Substation
Capital Recovery:	8.00%	8.00%	8.00%
Property Tax:	6.00%	6.00%	6.00%
O&M:	2.00%	2.00%	2.00%
G&A:	0.80%	0.80%	0.80%
Insurance:	0.10%	0.00%	0.10%
Charge Rate:	16.90%	16.80%	16.90%
Interest		7%	
Inflation		6%	
Cost of Power (Losses)		$291.05/kW/year	

4: Study Development

Use of PSS/E

In order to determine the facility needs in the Long Range Transmission Plan, the use of Power Technologies, Inc. (PTI) Power System Simulator for Engineers (PSS/E) was utilized. Due to the complexity of the power system, it would take time for an engineer to calculate the results of changes to the power grid; whereas, PSS/E can produce a reliable and quick solution. The results are easily observed in many forms of output, which relate important information to the engineer on system conditions such as voltage and line loading. One of the forms of output is automap drawings, which provide an understandable and detailed output of the power grid.

Through the use of this program, a model representation of the system's lines and substations are available. Each substation serves its contribution to the system load. Changes to the system occur in many forms; whereby, PSS/E solves for these changes and provides the results to the engineer. In the LRP, changes to the existing system include load growth and facility additions to meet this growth. Contingencies were performed on the system to determine the location and timing of the new facilities.

GRE Model Development

GRE model development consists of transmission line, substation load, generation, and transformer data. This data is needed to perform a steady-state analysis on the system. Generation plants, transformers, and transmission line facilities basically contain constant data, which is retrieved from past models. Additions are made to the models if new facilities are implemented.

Substation load data changes every day. The peak substation load is used for the LRP because it creates the most critical power flows or voltages during system intact or contingent cases. Load was forecasted for both winter and summer for the years of 2011, 2021, and 2031. These loads are then placed into the models as the substation loads.

Study Area

The GRE system was divided into 13 study areas for analysis. Each study area was based on the configuration and location of the bulk facilities in the electrical network. The study areas listed below show the systems included.

Study Area	System
A. Arrowhead Region	Arrowhead Electric Cooperative, Inc. (AECI) Cooperative Light & Power (CL&P)
B. Northern Lakes Region	Crow Wing Power (CWP) Lake Country Power (LCP) North Itasca Electric Cooperative, Inc. (NIEC)
C. GRE-MP 34.5 kV Region	Crow Wing Power (CWP) Itasca-Mantrap Cooperative Electric Association (IMCEA) Lake Country Power (LCP) Stearns Electric Association (SEA) Todd-Wadena Electric Cooperative (TWEC)
D. Central Minnesota Region	Crow Wing Power (CWP) East Central Energy (ECE) Lake Country Power (LCP) Mille Lacs Electric Cooperative (MLEC)
E. North Suburban Region	Connexus Energy (CE) East Central Energy (ECE)
F. GRE-OTP 41.6 kV Region	Agralite Electric Cooperative (AEC) Lake Region Electric Cooperative (LREC) Runestone Electric Association (REC)
G. Stearns Region	Agralite Electric Cooperative (AEC) Meeker Cooperative Light & Power Association (MCL&PA) Runestone Electric Association (REC) Steans Electric Association (SEA)
H. Southwestern Minnesota Region	Brown County Rural Electric Association (BCREA) Federated Rural Electric Association (FREA) Nobles Cooperative Electric (NCE) Redwood Electric Cooperative (REC) South Central Electric Association (SCEA)

Study Area	System
I. West Central Minnesota Region	Kandiyohi Power Cooperative (KPC) McLeod Cooperative Power Association (MCPA) Meeker Cooperative Light & Power Association (MCL&PA)
J. Southeastern Minnesota Region	Benco Electric Cooperative (BENCO) Goodhue County Cooperative Electric Association (Goodhue) Minnesota Valley Electric Cooperative (MVEC) Steele Waseca Cooperative Electric (SWCE)
K. Dakota-Minnesota Valley Region	Dakota Electric Association (DEA) Minnesota Valley Electric Cooperative (MVEC)
L. Hennepin and Wright County Region	Wright-Hennepin Cooperative Electric Association (WHCEA)
M. Bulk Transmission System (230kV and above)	Minnesota Facilities North Dakota Facilities

Recommended Plan Development

An analysis procedure was developed to determine the need for future facilities. The basic procedure includes the following three steps.

Determining that a problem exists

The first step in the analysis procedure is to determine whether or not a future facility is needed. A new facility may be needed if one or more of the following conditions exist:

- The thermal loading of the transmission lines and transformers are exceeded as defined in the design criteria;
- The voltage criteria is violated as defined in the design criteria;
- The electrical system is unreliable;
- The sectionalizing capability is not adequate;
- MW-mile criteria are surpassed.

Developing Alternatives

After the need for a facility is determined, the second step is to decide when a facility will be needed and what the facility will be.

To determine the year when the facility is needed, a straight-line approximation is used. The year that is determined assumes the forecasted load will be at a certain level at that particular time. Therefore the time of need is dependent on the forecasted load. Several different options are looked at for the type of facility addition. Any one or a combination of these options is used in the development of the alternatives. These options include:

- Build new bulk delivery points;
- Build transmission lines;
- Add transformer capacity;
- Transfer distribution load;
- Add capacitor bank;
- Add automatic sectionalizing equipment;
- Reconductor/rebuild existing transmission lines.

The proposed need for the distribution substations for each system is also included in addition to the recommended plan for each study area. The new distribution substations are proposed in the member system's long range plan and included in the recommended plan for their respective study areas.

Evaluating Each Alternative

The last step in the analysis is to evaluate each alternative and determine a recommended plan. After the timing and costs were determined, a present worth analysis is done on each alternative. When calculating the present worth of each alternative, the losses are included in the evaluation. Other factors besides the present worth analysis are involved when deciding on the best alternative for the recommended plan. These factors include:

- The capacity to serve the loads beyond the planning period;
- The ability of the recommended plan facility additions to serve a higher load growth rate than forecasted;
- The possible use of other power supplier's facilities;
- A joint facility alternative between GRE and other power suppliers.

5: Member Systems and Agreements

Planning Summaries

The Member Systems have the following records filed with GRE Planning:

Cooperative	LRP Report	Date	CWP Report	Date
Agralite Electric Cooperative	1991	6-15-92	2006-2008	10-25-06
Arrowhead Electric Cooperative	2003	10-23-03	2005-2008	11-17-04
BENCO Electric Cooperative	1998 (volumes I& II)	2-26-99	2007-2010	4-7-06
Brown County Rural Electric Association	1999	11-22-99	2005	3-15-05
Connexus Energy	1996	5-24-96	5 Year Plan	12-29-00
Cooperative Light & Power	1994	11-8-94	2007-2010	11-20-06
Crow Wing Power	2004	7-1-04	2005-2007	10-18-04
Dakota Electric Association	1991 (vol 1 & 2)	1-18-1991	1997-2001	9-12-96
East Central Energy	2003	12-10-03	2007-2010	10-24-06
Federated Rural Electric Association	1997	3-25-98	2005(4 Year Plan)	3-15-05
Goodhue County Cooperative Electric Association	1998	2-17-98	2003-2005	10-23-02
Itasca-Mantrap Cooperative Electric Association	2002	10-2002	2007-2008	January 07
Kandiyohi Power Cooperative	2002	3-19-02	2007-2008	11-2-06
Lake Country Power	2003	12-10-03	2006-2008	9-12-05
Lake Region Electric Cooperative	1997	12-27-96	2008-2009	11-16-07
McLeod Cooperative Power Association	1998	11-30-98	2003-2006	6-25-03
Meeker Cooperative Light & Power Association	June 2001	7-16-01	2008-2010	9-24-07
Mille Lacs Electric Cooperative	2007	11-28-07	2007-2008	10-4-06
Minnesota Valley Electric Cooperative	2008	6-20-08	2007-2008	4-13-06
Nobles Cooperative Electric			2008	1-9-08
North Itasca Electric Cooperative	1997	9-05-97	2008-2011	8-29-07
Redwood Electric Cooperative		7-8-87	2005-2008	4-26-05
Runestone Electric Association	1996	6-6-96	2008-2010	9-24-07
South Central Electric Association	2001	7-1-02	2001 (4 year plan)	5-14-01
Stearns Electric Association	1994	6-5-95	2002-2004	10-16-01
Steele-Waseca Cooperative Electric	2001-2010	4-8-02	2005-2008	10-21-04
Todd-Wadena Electric Cooperative	2004-2019	4-26-05	2007-2009	
Wright-Hennepin Cooperative Electric Association	2002-2011	1-29-02	2003-2005	9-25-02

Summary of Inter-Utility Agreements

Great River Energy's (GRE) service area overlaps parts of the service territories of the Northern States Power (NSP) operating company of Xcel Energy, Minnesota Power (MP), International Transmission Company Midwest (ITCM), Otter Tail Power (OTP), Southern Minnesota Municipal Power Agency (SMMPA), Hutchinson Municipal Utilities (HMU) and Willmar Municipal Utilities (WMU).

Because of the overlap, interconnections and joint use facilities are common giving the utilities an opportunity to reduce costs and the environmental impact of facilities.

Consequently, there is a great deal of inter-utility planning, coordination of facilities design, construction and operation and administration of inter-utility cost sharing arrangements.

GRE Member Agreements

GRE has 28 separate Member Transmission Service Agreements (TSA) that govern the provision of transmission service to the Members and their 627,000 customers in 54,000 square miles of Minnesota and Wisconsin. All TSA's became effective on January 1, 1999 and are in effect until 2035. The TSA uses a complete "rolled – in " rate that recovers all GRE transmission-related expenses for facilities owned by GRE, O&M and transmission arrangements with others. Deliveries to the member from any power supplier are covered by the TSA.

Existing Inter-utility Agreements

Network Integration Transmission Service (NITS)

In 2000 GRE entered into a NITS agreement with MP. NITS agreements are flexible arrangements that allow the Network Customer to integrate and economically dispatch its current and planned Network Resources to serve its Network Load located on the Transmission Provider's Control system in a manner comparable to that of the Transmission Provider. Each party's share of the total load in the network is used to determine its financial obligation while credit is received for the facilities each party owns.

Integrated Transmission Agreement (ITA)

An ITA is similar to a NITS agreement and provides for integrating resources and loads. ITA's are more restrictive in nature and include only the facilities that are jointly used within some specific boundary rather than all the facilities. GRE has ITA's with OTP, SMMPA and HUC.

Transmission Utilization Agreement (TUA)

ITCM has the only TUA with GRE. The original agreement called for GRE to pay ITCM (formerly Alliant Energy) for wheeling of power and energy to GRE's Points of Delivery (POD) within the ITCM control area and for ITCM to pay GRE a facility charge for "Mutually Utilized Facilities" built by GRE in the ITCM transmission system. Since December of 2006, these arrangements are handled through a Joint Pricing Zone Agreement. This TUA remains in effect for the interconnections within the ITCM control area. When a Master Interconnection Agreement is created between ITCM and GRE, the TUA contract will end.

Joint Pricing Zone Agreement (JPZ)

A JPZ agreement details the arrangements for imputing the network service charge and the allocation of point-to-point and network service revenue to parties within the JPZ. Parties to a JPZ jointly share the use of their transmission facilities within a common geographical area.

GRE has JPZ agreements for the Xcel and ITC Midwest control areas. SMMPA is a party to both JPZ agreements.

TOA

GRE's only Transmission Ownership Agreement (TOA) is with WMU. This agreement calls for the sharing of certain transmission capacity rights based on the ratio of facilities owned by each party. Facility additions were to be made by each party such that ownership was held at a 50-50 split.

Transitions of Present Agreements

Minnesota Power NITS:

Discussions are currently in process between GRE and MP on updating the existing NITS or to create a JPZ Agreement for the MP Control Area.

Otter Tail Power ITA:

This contract is grandfathered within MISO and remains in effect.

SMMPA/HUC ITA:

This contract is grandfathered within MISO and remains in effect. This ITA will change or be eliminated when a JPZ agreement is completed for the GRE control area, depending on how HUC is included within the JPZ Agreement since they are not a Transmission Owner within MISO.

Willmar:

The municipality of Willmar has facilities within the GRE control area and partially serves its load via an agreement with GRE. This contract is grandfathered within MISO and remains in effect.

A: Arrowhead Region

The Arrowhead Region is located northeast of Duluth and serves the area along the north shore of Lake Superior. The member systems that serve this territory are:

- Arrowhead Electric Cooperative, Inc. (AECI)
- Cooperative Light & Power (CL&P)

Arrowhead Electric is a local, member-owned electric cooperative established in 1953 to serve Cook County and a small portion of Lake County. The economy of this area is primarily driven by tourism. Other business related loads in the area are Hedstrom's Sawmill, Grand Portage Casino and the Lutsen Mountain Corporation ski hill.

Cooperative Light & Power (CL&P) provides energy and related services to consumers in Lake and St. Louis counties in northeastern Minnesota. Tourism, timber and taconite are the main industries in the service territory. The taconite industry is experiencing an increase in activity.

Existing System

This system is served from the Minnesota Power (MP)-GRE integrated transmission system and the MP 138 kV lines that terminate at the Taconite Harbor bulk transmission substation. Delivery to the GRE 69 kV system is through a 115/69 kV, 28 MVA transformer at Taconite Harbor that serves a single radial 69 kV transmission line that runs northeast following the shore line. This 69 kV line serves the AECI loads and the Grand Marais Municipal, who is a member of Southern Minnesota Municipal Power Agency (SMMPA). CL&P distribution substations are served from the 115 kV transmission line between Taconite Harbor and Duluth. CL&P's Island Lake substation is actually served from the 14 kV system emanating from MP Ridgeview 115 kV substation.

An emergency 12.5/69 kV transformer exists at Taconite Harbor, which can be manually switched in-service during outage conditions such as the loss of the 115-69 kV transformer. This emergency transformer is connected to the tertiary winding of the MP 138-115 kV transformer. The tertiary has a maximum rating of 12.9 MVA, whereby MP limits GRE to 12.5 MVA on the winding.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 70	Taconite Harbor 42WB1 (GC, GM, SG, TH)	Rank: 5

Transmission Lines Built before 1980

Line 70	Taconite Harbor 42WB1 69KV (SG)	34 Mi.-1956-58
Line 66	Finland Tap 115 kV (FT)	4 Mi.-1974

The reliability for this region is split between the two cooperatives. CL&P has excellent service that is better then the GRE average; whereas Arrowhead Electric is supplied by the Taconite Harbor 69 kV line which has had many periods of significant outages. The line age and maintenance information for this area does not include data for the Minnesota Power facilities.

Line 70 from Taconite Harbor is a 50 mile radial 69 kV line serving all five of the Arrowhead substations. This line has 34 miles of line built in the 1950s. Its reliability is worse than the GRE

average for each of the six reliability indices analyzed, with the worst overall ranking on both average consumer minutes out and average lost energy. The line also has the third worst average substation hours out ranking. The maintenance history shows a significant number of right-of-way maintenance and woodpecker pole-damage incidents for the SG line, putting it at number 30 on the list of lines with the most maintenance incidents. This line ranked #1 for the radial MW-mile exposure well exceeding the 100 MW-mile criteria for radial lines with a value of 766.1 MW-mile based on the 2011 winter load projection.

There are several projects completed or planned to improve the transmission reliability for the Taconite Harbor 42WB1 69 kV line. They are remote controls on the Maple Hill and Cascade tap switches, relay and breaker replacement at Taconite Harbor 42WB1, and distributed generation at the Colvill distribution substation site.

Existing Deficiencies

No existing deficiencies exist at this time on GRE facilities. The MP 42 Line is overloaded based on the Taconite Harbor generation plant schedule. This line overload is dependent on the plant output and is not related to load serving issues. MP will operate the plant such that the 42 Line will not overload.

Future Development

Load Forecast

The following forecast is the load served by the transmission system in the area. This load includes GRE, MP, and SMMPA load.

Arrowhead Region Load (in MW)

Season	2011	2021	2031
Summer	189.5	207.1	217.3
Winter	235.7	262.5	285.7

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- Colvill Generation Station with nine 2 MW diesels at an estimated cost of $10 million

Taconite Harbor-Grand Marais Area

The Taconite Harbor-Grand Marais system consists of the 115/69 kV transformer at Taconite Harbor. A 50 mile, radial 69 kV line extends up the north shore of Lake Superior to serve loads at Schroeder, Lutsen, Grand Marais Municipal, Maple Hill and Colvill. The following forecast is the load served in this area. This load includes GRE and SMMPA load.

Season	2011	2021	2031
Summer	16.4	20.2	23.7
Winter	31.6	42.7	57.5

Based on the previous LRP, the Arrowhead area load will reach the 2022 level by 2011 for the summer. Likewise, the winter load for 2020 is expected to occur in 2011.

Long-term Deficiencies

Overloads

Line Segment	Rating MVA	Estimated Year	Action	2011 MVA	2021 MVA
Taconite Harbor 28 MVA transformer	28	2008	Replace	30.9	42.2
Taconite Harbor 41.6 MVA transformer	41.6	2021	Move or Double-End	30.9	42.2

The transformer will be replaced with the rebuilt, 41.6 MVA Blackberry unit in 2008 which will extend the capability to 2021, when a second transformer will be needed or the transformer will be moved further north with a 69 kV to 115 kV conversion of the line.

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %	2031 %
Colvill	2010	94.88	89.17	
Colvill (LTC)	2013	96.19	90.7	
Colvill [1]	2015	96.83	91.69	
Colvill [2]	2026		97.23	92.7
Colvill [3]	2038		100.9	98.08

1: Taconite Harbor-Schroeder rebuilt to 477 ACSR
2: Schroeder-Lutsen rebuilt to 477 ACSR
3: Lutsen-Cascade rebuilt to 477 ACSR

These are system intact voltages as there are no contingencies that create a worse voltage for the area. The criteria are to have a 95% voltage during system intact conditions which will be the first voltage deficiency to occur. The Taconite Harbor transformer will have its LTC settings adjusted to elevate the voltage at Colvill.

Alternatives

With the radial aspect of this load and the growth that is projected on this system, another source to the area would enhance the system greatly. However, establishing a new line to this area will have a significant environmental impact. Some of the line options considered were to establish sources from the Ely area or even from Thunder Bay, Ontario. Both of these possibilities would require over 70 miles of line to be built, which would not be economical and can not offer the voltage support needed due to voltage drop across the lines. For new line construction it would seem that building from the existing Taconite Harbor substation would be the most feasible, however a different line corridor would need to be established. Due to environmental and cost issues for a new line corridor, GRE concluded that the best reliability improvement for the Arrowhead region was the installation of generation at Colvill in 2008. This generation will provide load service when permanent line outages are experienced. This generation is fairly expensive, so system intact issues will be resolved with transmission improvements.

The Taconite Harbor transformer is nearing its 28 MVA limit. This transformer will be changed out to a 41.6 MVA transformer, which is the repaired Blackberry unit that needs to be placed in-service for warranty purposes. Potentially, a second Taconite Harbor 115/69 kV transformer will be needed when the load reaches 41.6 MVA, if the repaired unit remains at Taconite Harbor. However, due to voltage drop concerns, it may be more feasible to rebuild the 69 kV system out

of Taconite Harbor to 115 kV and move the Taconite Harbor transformer further north to a location such as Cascade or Grand Marais Tap.

Portions of the SG line were built between 1956 and 1958 and are becoming age limited. It is expected that this line will need to be replaced at some time in the LRP study timeframe.

With the environmental issues, GRE's only option is to upgrade the existing corridor and use generation as back up to the transmission system on failure. With an initial 18 MW of generation added, the load will be covered for the majority of the year except during some winter peak hours. Many of these peak hours are during the off peak recharging periods; whereby GRE can suspend or implement the control of the loads during transmission outages to maintain a generation level below 18 MWs. When the load level starts to exceed the generation limit, a second generation site should be established in the Cascade substation area.

The transmission plan for this area is to replace the aging SG line with new 115 kV construction and moving the Taconite Harbor transformer to Cascade or Grand Marais tap. This will remove some of the load that flows through the 115/69 kV transformer and put a voltage controlling device near the Grand Marais load center which will help the Colvill substation voltage issues. The new line would be constructed with 477 ACSR and consist of up to 31.31 miles of new 115 kV construction.

This construction does not resolve the radial aspect of the line meaning that a contingency at Taconite Harbor will still black-out the load, however the Colvill generation is expected to cover this load in a fairly quick manner with its short startup time.

Since the transformer is projected to overload in 2021, the Lutsen-Cascade rebuild will be advanced to 2021 instead of the projected 2026 time frame. Depending on land availability, the transformer can be sited at Cascade, however it will be assumed that the source will be placed near Grand Marais Tap which would allow breaker protection to the tap to Grand Marais Municipal and tap to Colville-Maple Hill. This plan will be further reviewed when the transformer needs to be moved north. Option 1 will assume that a second parallel transformer will be added at Taconite Harbor. Option 2 will assume a transformer move to the Grand Marais Tap.

Option 1: Double-end Taconite Harbor

Estimated Year	Facility	Cost
2013	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 115 kV line operated at 69 kV (1.85 miles)	$627,150
2015	Rebuild Schroeder-Lutsen to 477 ACSR, 115 kV line operated at 69 kV (10.98 miles)	$3,908,670
2021	Add second Taconite Harbor 115/69 kV transformer	$1,769,910
2026	Rebuild Lutsen-Cascade to 477 ACSR, 115 kV line operated at 69 kV (12.85 miles)	$4,356,150

Option 2: Move Taconite Harbor to Grand Marais Tap

Estimated Year	Facility	Cost
2013	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 115 kV line operated at 69 kV (1.85 miles)	$627,150
2015	Rebuild Schroeder-Lutsen to 477 ACSR, 115 kV line operated at 69 kV (10.98 miles)	$3,908,670
2021	Rebuild Lutsen-Cascade to 477 ACSR, 115 kV line operated at 69 kV (12.85 miles)	$4,356,150
	Rebuild Cascade-Grand Marais Tap to 477 ACSR, 115 kV line operated at 69 kV (5.17 miles)	$1,752,630
	Grand Marais Tap 115/69 kV substation	$1,491,000
	Convert Schroeder, Lutsen, and Cascade to 115 kV	$1,650,000
	Taconite Harbor 115 kV line Termination	$410,000

Generation Options

Generation will have to be considered if the load consistently reaches above the 18 MW level. Any generation addition will probably be oil based generation making it difficult to justify being on unless it's under an emergency situation. Cascade would be a favorable location for added generation.

Present Worth

A cost analysis was performed on each option with line losses evaluated from the Taconite Harbor Plant to Colvill with Option 2 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2021 Winter	2031 Winter
1	-2.6	-4.6
1*	-2.0	-3.3
* Lutsen-Cascade Rebuilt		

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$22,925	$21,780	$35,044
2	$27,320	$29,543	-

The 115 kV conversion provided by Option 2 allows for a long-term solution. Option 2 could see a reduction of nearly $2 million in investment if the 115/69 kV substation was located closer to the Cascade substation. Option 2 also offers a significant loss savings value which may be an important benefit for environmental stewardship. GRE will have to further investigate this area as the load grows. Based on the value of line losses, the recommendation is to proceed with Option 2.

Viability with Growth

The 115 kV conversion will allow for considerable growth and with the three loads converted to 115 kV, the transformer will be able to continue to serve the local load. A larger transformer may eventually be needed as the loads at Grand Marais Municipal, Maple Hill and Colvill grow beyond its capability.

Taconite Harbor-Duluth Area

The Taconite Harbor-Duluth system consists of 115 kV lines that serve CL&P loads at Waldo and Finland plus a distribution connected load at Island Lake served out of MP's Ridgeview 115 kV substation. The following forecast is the load served in this area. This load includes GRE and MP load.

Season	2011	2021	2031
Summer	173.1	186.9	193.6
Winter	204.1	219.8	228.2

Long-term Deficiencies

The MP 42 Line is overloaded based on the Taconite Harbor generation plant schedule. This line overload is dependent on the plant output and is not related to load serving issues. MP will operate the plant such that the 42 Line will not overload.

Alternatives

GRE did a quick analysis looking at a 115 kV line to serve the Island Lake distribution substation to improve the service to this substation. This load is expected to reach 2.6 MW by 2031, making it difficult to spend a great amount of money for reliability purposes. If improved service is a necessity, distribution options should be reviewed first. Potentially a distribution connection may be able to be tied to the Lake Country distribution emanating from the new Bergan Lake 115 kV substation. This distribution may cost less than establishing a 115 kV source which will involve nearly 7.5 miles of 115 kV to be built off the MP Colbyville-Arrowhead 115 kV line. The estimated cost of the 115 kV line is $2.85 million for a 336 ACSR line including a 3-way 115 kV switch with no underbuild.

MP has also indicated that a 34.5 kV system will be evaluated for the Duluth area. Potentially the 14 kV system serving the Island Lake substation will also be converted to 34.5 kV. This new construction should improve the reliability to this system. If this construction proceeds, CL&P will need to establish a 34.5/12.5 kV substation at Island Lake or convert to a 34.5 kV distribution system.

Generation Options

No generation options are viable as the existing system has over generation.

Present Worth

Since no counter options were developed no present worth analysis was needed.

Viability with Growth

If the Island Lake load approaches levels that the distribution system improvements can not be cost justified compared to the 115 kV option, then GRE will institute the construction of the 115 kV line.

Recommended Plan

To insure continuity of service of the SG 69 kV radial line, it is recommended that continued line maintenance and right-of-way clearing be implemented. GRE will pursue Option 2 which involves major rebuilding to 115 kV, but operated at 69 kV, from the southern end of the system. The lines will need new conductor as the voltage drop on the existing conductor is significant. The Island Lake substation will also continue to be served from the distribution system until it is

deemed that the distribution system can not economically serve the load. The following are the proposed projects for the Arrowhead region:

Estimated Year	Responsible Company	Facility	Cost
2013	GRE	Rebuild Taconite Harbor-Schroeder to 477 ACSR, 115 kV line, operated at 69 kV (1.85 miles)	$627,150
2015	GRE	Rebuild Schroeder-Lutsen to 477 ACSR, 115 kV line operated at 69 kV (10.98 miles)	$3,908,670
2021	GRE	Rebuild Lutsen-Cascade to 477 ACSR, 115 kV line operated at 69 kV (12.85 miles)	$4,356,150
2021	GRE	Rebuild Cascade-Grand Marais Tap to 477 ACSR, 115 kV line operated at 69 kV (5.17 miles)	$1,752,630
2021	GRE	Grand Marais Tap 115/69 kV substation	$1,491,000
2021	AEC	Convert Schroeder, Lutsen, and Cascade to 115 kV	$1,050,000
2021	GRE	Schroeder, Lutsen, Cascade 115 kV 2-way switches (m.o.)	$600,000
2021	GRE	Taconite Harbor 115 kV line Termination	$410,000

It is advised that additional generation be investigated in the Cascade area as the load grows to levels where Colvill generation cannot support the radial load anymore.

B: Northern Lakes Region

The Northern Lakes Region is the area north of the Arrowhead and Riverton 230 kV substations that extends up through the Iron Range to the Canadian border. This area is composed of some of the largest loads in the state of Minnesota consisting of large manufacturing plants involving the timber industry and the iron ore industry. Also, this is a high recreational area with many lakes and parkland to attract tourism and weekend getaways.

The member systems that serve this territory are:

- Crow Wing Power (CWP)
- Lake Country Power (LCP)
- North Itasca Electric Cooperative, Inc (NIEC)

Located in the heart of Minnesota's lake country, Crow Wing Power serves over 36,000 members in Crow Wing, Cass and Morrison counties. Crow Wing serves members in an approximately 2,800 square mile area, which includes eastern and northwestern Morrison County, the greater portion of Crow Wing County, and the southern portion of Cass County.

Lake Country Power serves a large diverse area in Northeastern Minnesota covering nearly 10,000 square miles. The area served varies from bedroom communities to lakeshore properties to remote wilderness.

North Itasca Electric Cooperative provides energy and related services to consumers in Itasca, Koochiching and Beltrami counties.

The economy of region continues to grow rapidly. Although tourism remains a key component of the economy, the area has seen an increase in year round population as vacation homes get converted to retirement homes for year round living. The population increase has resulted in community growth in service related businesses. Large industrials such as mining are recovering and the timber industry continues to move along as the home construction cycles dictate need. The manufacturing loads have been cyclic in growth as the world economy can cause fluctuation in supply and demand.

Existing System

The Northern Lakes Region is served by the GRE 69 kV transmission system that extends from Riverton to the Canadian border. Also included within this area is the MP bulk 230 and 115 kV system that serves most of the northern Minnesota area transmission with GRE having many loads served from the 115 kV system. Other transmission in this region that concerns GRE include the MP 46 kV system in the Ely area and the 23 kV system in the Nashwauk area.

The MP 115 kV transmission system serves some very large industrial loads, but also due to location of the lines, serves some of GRE's rural load substations. This 115 kV system is supported by an extensive 230 kV system. The Boswell generation station provides a major source to the area with separate connections at both the 230 and 115 kV level. GRE loads that are within the 115 kV network include Iron, Lakeland, Keewatin, Cotton, Peary, Hill City, Cohasset, and Bergan Lake. GRE is adding the Mud Lake-Wilson Lake 115 kV line that will be in-service by the end of 2008. This will unload the Riverton 115/69 kV transformer.

The GRE 69 kV system consists of two separate systems. One system consists of a single 69 kV loop between the Shannon and Virginia 115 kV substations. The Potlatch breaker station

splits this system nearly in half. The second system consists of a larger looped 69 kV system with 115 kV sources at Blackberry, Deer River, Pequot Lakes and Riverton. The Badoura 34.5 kV system also supports this loop through the Blind Lake 69/34.5 kV substation. A long radial line out of the Deer River source serves the entire NIEC load. Many other radial lines exist that serve individual loads within this system.

The MP 46 kV system consists of 115/46 kV transformations at Virginia and Babbitt. This system consists of a looped 46 kV system with many miles of exposure. A breaker station is located at Winton, which also includes a small hydro generation plant.

The MP 23 kV system serves the Nashwauk and Crooked Lake substations which consists of a GRE radial 23 kV line tapping off of one of MP's feeders that serves the Nashwauk area. GRE has a regulator on this line to boost the voltage for these fairly sizeable 23 kV loads.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 71	Deer River 21NB4 69 kV (RB, RBX, TW, SQ)	Rank: 3
Line 78	Blackberry 20WB1 - Deer River 21NB2 69 kV (BB, DG, DH, LB, LH)	Rank: 15
Line 93	Virginia 27WB1 - Potlatch 17NB3 69 kV (LP, PK, VP)	Rank: 28
Line 85	Arrowhead 16L - Virginia 16L - Eveleth Tac 16L (16 line)	Rank: 36

Transmission Lines Built before 1980

Line 24	Blind Lake 58NB1/58NB2 – Birch Lake 69 kV (HW)	9 Mi.-1956; 4 Mi.-1967
Line 71	Deer River 21NB4 69 kV (RB, RBX, TW)	30 Mi.-1966; 12 Mi.-1969-73
Line 78	Blackberry 20WB1- Deer River 69 kV (BB, DG, LB)	2 Mi.-1950; 12 Mi.-1971-79
Line 93	Virginia 27WB1-Potlatch 17NB3 69 kV (LP, PK, VP)	21 Mi.-1962; 11 Mi.-1978
Line 28	Blind Lake 58NB2 - Deer River 69 kV (BE, BO, TL)	83 Mi.-1971-78
Line 81	Nashwauk Tap 22GB1 (NC, NW)	11 Mi.-1958; 1 Mi.-1977
Line 86	Shannon 26WB1-Potlatch 17NB1 69 kV (LG, PK, SM)	15 Mi.-1950; 32 Mi.-1962-78
Line 301	Blind Lake 58NB1 - Mission 69 kV (TL, CO, EC)	13 Mi.-1966; 13 Mi.-1974-78
Line 302	Mission 240NB2 -Pequot Lakes 69 kV (PP, PQ, ST)	24 Mi.-1977-79
Line 303	Mission 240NB1 - Riverton 69 kV (RV)	1 Mi.-1972

The overall reliability for this region is generally a little better than the GRE average, except for the North Itasca area served by the radial 69 kV line from Deer River. The line age table shows several segments of older line where replacement may need to be considered. The line age and maintenance information is not complete for some lines in this area since data is not included for Minnesota Power owned facilities.

Line 71 from Deer River is a 62 mile, radial 69 kV line, which serves all four of the North Itasca substations. Its reliability performance is worse than the GRE average for each of the six indices used. The line experienced high numbers of momentary events as well as poor performance from long outage durations. The line had maintenance work to improve reliability. The maintenance reports show the SQ, TW and RB lines each on the top 50 lines with the most maintenance incidents, with the RB line in the top 10. Most incidents for the SQ line were for right-of-way, while the TW and RB lines had mostly pole deterioration incidents. Distributed generation is being considered to improve reliability for sustained outages.

Line 78 from Blackberry to Deer River is a 48 mile, 69 kV line serving five substations. Its performance is worse than the GRE average on all six indices, but not extreme on any of them.

The maintenance reports do not show much maintenance on the line, but the LB section did have several insulator incidents. There are no recent or planned projects to improve reliability of this line.

Line 93 from Virginia to Potlatch is a 32 mile, 69 kV line serving two substations. This line is worse than the GRE average for five of the six reliability indices. Maintenance reports show high maintenance incidents for the PK and VP line sections with mostly pole deterioration incidents and ROW condition incidents (on the VP line). A fault location relay and lightning arresters were added on this line in 2005 to improve reliability.

Line 85 from Arrowhead to Virginia to Eveleth Taconite is a 63 mile, 115 kV line, serving three substations. This line is worse than the GRE average for four of the six reliability indices. The poor performance is mostly due to long outage duration in 2002. The majority of the line is owned by Minnesota Power, so maintenance and age information is not available. There are no recent or planned projects to improve reliability of this line.

Existing Deficiencies

The region has seen tremendous growth, especially in the lake areas. This growth has been in both summer and winter seasons, however winter load is growing at a much more significant rate as many homes are converting to electric heat options. The winter growth has been near 10% on an annual basis over the last 5 years. This growth has caused significant voltage issues on the system such that many areas are now voltage deficient. Past LRP load projections indicate that some areas have historically passed 2020 load projections. The voltage limitations are numerous with some new projects already developed to serve these loads. These projects will be reviewed in this plan to determine that the projects are still appropriate.

Future Development

Load Forecast

The following forecast is the load served by the sub transmission system in the area. More load occurs on the 115 kV system consisting of major industrial load and some GRE loads served directly from the 115 kV system. However this load has no known load serving issues unlike the sub transmission system involving the 69, 46, and 23 kV systems. The 115 kV load will not be considered for this area except the 115 kV load served on the 28L tap as the 69 kV system can potentially serve some of the 115 kV load. The following load forecast for the sub transmission system includes GRE and MP load.

Northern Lakes Region Load (in MW)

Season	2011	2021	2031
Summer	168.7	234.7	326.3
Winter	257.2	346.4	466.8

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- GRE is constructing the Mud Lake-Wilson Lake 115 kV line and Wilson Lake 115/69 kV substation with ISD of Fall 2008.
- LCP has proposed a Shoal Lake substation near the town of Nashwauk. This will require an approximately 9 mile line tapping the MP 28 Line between Clay Boswell and Nashwauk and is planned to follow a new 230 kV corridor that will serve the proposed MN Steel plant. This substation would remove the 23 kV Crooked Lake and Nashwauk substations. The expected ISD is 2009.
- LCP has proposed a Frazer Bay substation roughly 10 miles east of Cook with expected ISD of 2010. This substation will be served through a new Tower 115/69 kV source on a 15 mile, 69 kV radial line for the short-term.
- LCP has proposed a Pokegama substation that is expected in 2010 and will be served from the 115 kV system on the 92 Line between Grand Rapids and Hill City. An 8 mile, radial 115 kV line is proposed to be built with this substation, although actual length will be determined by land acquisition.
- LCP has proposed an Orr substation that is expected in 2012 and will be served from the 69 kV system from the Cook substation. A 13.0 mile radial 69 kV line is proposed to be built with this substation, although actual length will be determined by land acquisition.
- CWP has proposed a new Bass Lake Substation that is expected in 2014. This substation will tap the 69 kV ST line from Pequot Lakes to Breezy Point Tap and will require a short radial line off the proposed tap point to reach the substation.
- CWP has proposed a new Whitefish Substation that is expected in 2014. This substation will tap the 69 kV PQ line from Pequot Lakes to Stonybrook and will require a short radial line off the proposed tap point to connect the substation to the system.
- CWP has proposed a new Mission Lake 69 kV substation that is proposed to tap the Mission-Riverton 69 kV line. The expected ISD is 2019.
- CWP has proposed a Woman Lake substation that is expected around 2024. This substation will tap the BH line between Blind Lake and Wabedo. Currently 0.5 miles of line will be needed from the tap point to the substation.
- CWP has proposed a new Outing substation that is proposed to directly tap the Blind Lake to Thunder Lake (TL) 69 kV line. The expected ISD is 2024.

Nashwauk Area

The LCP Nashwauk and Crooked Lake load is 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 will be combined at the proposed new Shoal Lake 115 kV substation. This substation is largely dependent on the Minnesota Steel development, whereby the 115 kV line will share corridor with one of the 230 kV lines that is serving this large industrial plant. GRE will try to coordinate the 115 kV line such that the transmission development can be coordinated so that transmission investment will not be wasted. If the Minnesota Steel plant gets delayed, GRE will have to consider alternatives as the 23 kV system has limited life. Lake Country Power has indicated they have 24 kV regulators that can be used to replace the GRE regulator if it fails. GRE's plan is to continue to operate at 23 kV as long as possible. If by 2009, the steel plant is looking like it will not proceed, GRE will have to re-evaluate its options and possibly pursue the Lawrence Lake option. The following is the load projections that are served from this system which contains only GRE load:

Season	2011	2021	2031
Summer	3.8	5.2	7.2
Winter	7.7	10.7	14.8

Long-term Deficiencies

GRE is planning on consolidating and converting the Crooked Lake and Nashwauk loads to 115 kV and to turn the existing 23 kV system over to Lake Country Power for their use as distribution after the 115 kV conversion. In the meantime, it is planned that Lake Country Power will do some construction work on the GRE line to accommodate potential Minnesota Steel construction load that would eliminate the 7.2 MVA, #6 conductor, whereby the next limit would be the 9.7 MVA #2 conductor based on winter ratings. The voltage drop and loading on the 23 kV system is critical, and the hope is that Minnesota Steel will move forward soon so that unnecessary transmission investments will not have to be made.

Alternatives

GRE will try to coordinate any construction with the Minnesota Steel transmission additions. If the plant does not proceed, GRE will recommend the Lawrence Lake alternative. Shoal Lake is more attractive a location for Lake Country Power as the new substation will be located in the middle of Crooked Lake and Nashwauk substations. It is also advantageous to GRE as GRE will also be able to eliminate the 23 kV system by turning it over to Lake Country Power for their use.

Lawrence Lake offers a 115 kV solution to the Crooked Lake substation, however Lake Country Power may have issues serving the Nashwauk load due to voltage drop along feeders from Lawrence Lake. In this case, GRE may have to maintain the 23 kV system to Nashwauk of which GRE would rather prefer to abandon the 23 kV line.

Option 1: Shoal Lake 115 kV line

Estimated Year	Facility	Cost
2009	Minnesota Steel-GRE Nashwauk 5 mile, 336 ACSR, 115/230 kV line (assumed 115 kV cost addition to 230 kV line)	$1,550,000
2009	GRE Nashwauk-Shoal Lake 2.5 miles, 336 ACSR, 115 kV line	$895,000
2009	Minnesota Steel 3-way, 115 kV switch	$165,000

Option 2: Lawrence Lake 115 kV line

Estimated Year	Facility	Cost
2009	Greenway-Lawrence Lake 7.5 mile, 336 ACSR, 115 kV line	$2,685,000
2009	Greenway 3-way, 115 kV switch	$165,000

Generation Options

Generation does not seem to be an attractive option based on the limitations of the existing 23 kV system.

Present Worth

Since alternatives are on the same timeline, no present worth analysis was needed. The Shoal Lake alternative will be the least cost investment if GRE pays for the incremental costs of adding a 115 kV line to the 230 kV structure. This involved an additional $60,000/mile for structure changes from H frame to Steel Pole and $250,000 per mile for double circuit structure tower and second circuit conductor additions. Right of way cost is not expected to be increased as the corridor should be the same or less in size.

Viability with Growth

The 115 kV being developed in this area will allow for long-term growth.

Riverton-Deer River Area

The Riverton-Deer River area covers the load served between the 115/69 kV sources at Riverton, Pequot Lakes, and Deer River. There is another source at the 69/34.5 kV Birch Lake substation that gets its support from the Badoura 115/34.5 kV substation. A Birch Lake 115/69 kV source tied to the Badoura substation is planned for 2009 which will provide additional support to this area. The following is the load projections that are served from this system, which contains only GRE load.

Season	2011	2021	2031
Summer	70.7	111.9	177.4
Winter	84.7	122.3	179.1

The 2011 winter load is projected to surpass the 2003 Long Range Plan's 2026 winter load projection.

Crow Wing Power has identified multiple new substations needed to cover for load growth in the rapidly growing lakes region. To meet the distribution needs of its customers, Crow Wing has proposed the Bass Lake, Whitefish, Mission Lake, and Outing 69 kV substations and the Woman Lake substation which will be designed for 115 kV operation. The following are the transmission needs for these new substations:

Estimated Year	Facility	Cost
2014	Bass Lake 3 mile, 336 ACSR, 69 kV line tap	$1,325,000
2014	Whitefish 4 mile, 336 ACSR, 69 kV line tap	$1,720,000
2019	Mission Lake 69 kV tap	$140,000
2024	Woman Lake 0.5 mile, 336 ACSR, 115 kV tap	$424,000
2024	Outing 69 kV tap	$140,000

Long-term Deficiencies

Voltage support is driving the need for system improvements in the Riverton-Deer River area. Many of the transmission facilities in this region were built before 1980 and are fairly lossy due to relatively small conductor size. Additionally, there are long distances between the sources into the 69 kV system. It should also be noted that the 230 kV system voltages in and around the Brainerd area are becoming depressed with the growing area loads which significantly affects the voltage regulation on the underlying systems.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Riverton 115/69 kV transformer	56	2015	43.2	82.3

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Bena 69 kV	2012	93.1	83.9
Boy River 69 kV	2012	92.9	83.8
Ball Club 69 kV	2013	93.5	84.6
Emily 69 kV	2014	94.5	85.7
Ox Lake 69 kV	2014	94.1	87.0
Remer 69 kV	2015	95.2	87.2
Cross Lake City 69 kV	2015	94.9	86.2
Blind Lake 69 kV	2016	95.2	88.8
Thunder Lake 69 kV	2017	96.0	89.1
Deer River 69 kV	2018	97.3	87.1
Bass Lake 69 kV	2019	95.6	91.1
Pleasant Lake 69 kV	2019	95.8	90.7
Stonybrook 69 kV	2020	96.8	91.0
Merrifield 115 kV	2021	100.3	91.7
Wabedo 69 kV	2021	96.6	91.9

Alternatives

The voltage issues are driving the need for new facilities in the area. New development looks at adding new sources off the MP 230/115 kV system that parallels the GRE 69 kV system to the east. The MP 115 kV system from Grand Rapids-Riverton does not offer strong voltage support and is approaching line loading limits. Thus, a new 230 kV source that taps the MP Blackberry-Riverton 230 kV line would be desirable as this would provide the GRE system another strong voltage source. Several options involving 230 kV source development were considered for this area.

Option 1: Perry Lake-Blind Lake-Birch Lake 115/69 kV development

This option establishes a new 230/115/69 kV substation at Perry Lake with outlets to Mission (9 miles of 69 kV) and Birch Lake (52 miles of 115 kV) via rebuild of the Blind Lake-Birch Lake 69 kV line. Voltage conversions to 115 kV operation would take place at the Pleasant Lake, Wabedo, and Emily substations. A 115/69 kV transformation would be installed at Blind Lake providing a new 69 kV source into the middle of the area while a 115/34.5 kV Birch Lake transformer would replace the existing 69/34.5 kV unit. To alleviate low voltages caused by the loss of the Deer River-Ball Club outage, a Longville-Boy River 69 kV line and Salem Breaker station are proposed. Additionally, a capacitor bank at Longville would alleviate voltage deficiencies caused by loss of the Blind Lake source to Longville.

Option 1: Perry Lake-Blind Lake-Birch Lake 115/69 kV development

Estimated Year	Facility	Cost
2012	Perry Lake 112 MVA, 230/69 kV source	$6,873,371
2012	Perry Lake-Mission 9 mile, 477 ACSS, 69 kV outlet	$3,345,000
2014	Perry Lake-Emily 9 mile, 795 ACSS, 115 kV outlet (operate at 69 kV)	$4,427,000
2017	Perry Lake 300 MVA, 230/115 kV source	$4,183,000

Estimated Year	Facility	Cost
2017	Emily-Blind Lake 18 mile, 795 ACSS, 115 kV line	$9,441,500
2017	Blind Lake 84 MVA, 115/69 kV source	$2,569,384
2017	Convert Emily substation to 115 kV operation	$650,000
2022	Blind Lake-Birch Lake 69 kV to 115 kV (25.3 Miles) Rebuild	$11,246,700
2022	Convert Pleasant Lake and Wabedo substations to 115 kV operation	$1,300,000
2022	Birch Lake 50 MVA, 115/34.5 kV source	$1,020,159
2026	Longville-Boy River 17 mile, 336 ACSS, 69 kV line	$5,555,000
2026	Salem 69 kV breaker station	$1,260,000
2027	Longville 7.8 MVAr, 69 kV capacitor	$246,200

Option 2: New Macville and Pelican 230 kV sources

This option provides two new 230 kV sources into the area: one at Macville tapping the Blackberry-Riverton 230 kV line and one at Pelican tapping the Riverton-Badoura 230 kV line. A 230/69 kV transformer would be placed at Pelican and a double circuit 69 kV line would replace the existing Breezy Point-Breezy Point Tap 69 kV line creating a Pelican-Breezy Point-Pequot Lakes 69 kV line and a Pelican-Mission 69 kV line. Additional voltage support is provided to the system north of the Blind Lake sub via a Longville-Boy River 69 kV line and Longville capacitor bank. A Salem breaker station provides additional sectionalizing capability for this area while a rebuild of the 69 kV RBX line is needed to allow the Deer River-Ball Club line to realize its full thermal capacity.

Two sub-options exist for the Macville source. The first of these establishes a 230/69 kV transformer at Macville with a 69 kV outlet (constructed to 115 kV standards) to Blind Lake. This line eventually is switched to 115 kV operation and the Birch Lake-Blind Lake 69 kV line is upgraded to 115 kV. A 115/69 kV transformation is made at Blind Lake while a 115/34.5 kV Birch Lake transformer replaces the existing 69/34.5 kV unit.

The second sub-option is to establish a 230/115 kV transformer Macville and build a Macville-Blind Lake 115 kV line and 115/69 kV Blind Lake transformation. The Birch Lake-Blind Lake 69 kV line is replaced and upgraded to 115 kV and a 115/34.5 kV transformer is placed at Birch Lake.

Option 2A: Pelican 230/69 kV source and Macville 230/69 kV source

Estimated Year	Facility	Cost
2012	Macville 112 MVA, 230/69 kV source	$6,098,371
2012	Macville-Blind Lake 22 mile, 795 ACSS, 115 kV line (operate at 69 kV)	$10,881,000
2021	Macville 300 MVA, 230/115 kV transformer	$4,183,000
2021	Blind Lake 84 MVA, 115/69 kV transformer	$2,442,884
2021	Blind Lake-Birch Lake 69 kV to 115 kV (25.3 Miles) Rebuild	$11,246,700
2021	Convert Pleasant Lake and Wabedo substations to 115 kV operation	$1,300,000
2021	Birch Lake 50 MVA, 115/34.5 kV transformer	$1,020,159
2021	Pelican 112 MVA , 230/69 kV transformer and substation. (Use Macville 230/69 kV transformer)	$3,973,000

Estimated Year	Facility	Cost
2021	Pelican-Breezy Point-Breezy Point Tap 4.25 mile, 336 ACSS, 69 kV line	$2,108,125
2025	Longville-Boy River 17 miles, 336 ACSS, 69 kV line	$5,555,000
2025	Salem 69 kV breaker station	$1,260,000
2025	7.8 MVAR Longville 69 kV cap bank	$246,200
2027	Rebuild RBX line to 336 ACSS construction	$469,000

Option 2B: Pelican 230/69 kV source and Macville 230/115 kV source

Estimated Year	Facility	Cost
2012	Macville 300 MVA , 230/115 kV source	$7,816,000
2012	Macville-Blind Lake 22 mile, 795 ACSS, 115 kV line	$10,881,000
2012	Blind Lake 84 MVA, 115/69 kV source	$2,442,884
2023	Blind Lake-Birch Lake 69 kV to 115 kV (25.3 Miles) Rebuild	$11,246,700
2023	Convert Pleasant Lake and Wabedo substations to 115 kV operation	$1,300,000
2023	Birch Lake 50 MVA, 115/34.5 kV transformer	$1,020,159
2023	Pelican 112 MVA, 230/69 kV source	$6,574,371
2023	Pelican-Breezy Point-Breezy Point Tap 4.25 mile, 336 ACSS, 69 kV line	$1,913,125
2025	Longville-Boy River 17 mile, 336 ACSS, 69 kV line	$5,555,000
2025	Salem 69 kV breaker station	$1,260,000
2025	Longville 7.8 MVAr, 69 kV cap bank	$246,200
2027	Rebuild RBX line to 336 ACSS construction	$469,000

Generation Options

Generation in the Cross Lake area will provide a source at the largest load center in the area. Another possibility would be the Blind Lake substation, as a source here would boost the voltage in the area. Environmentally it may be difficult to establish a generator in these areas.

Present Worth

A cost analysis was performed on each option with line losses evaluated with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2A	0.00	3.20	-11.6
2B	0.00	4.70	-11.6

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$112,330	$109,558	-
2A	$114,633	$109,065	$107,644
2B	$112,333	$104,306	$100,891

Option 2B is the least cost plan while offering significant loss savings over Option 1.

Viability with Growth

This area is projected to see a great amount of growth and providing the additional sources to the 69 kV system offers increased system robustness while reducing the required transmission investment.

Deer River-Blackberry Area

This area consists of the load served between Deer River and Blackberry 115/69 kV substations. The 62 mile, 69 kV line that serves the NIEC load is also included in this area. The radial Deer River-Boswell 115 kV line which includes some 115 kV loads (including the GRE Cohasset load) will also be examined for the capability of the 69 kV system in supporting the 115 kV load. The following are the load projections that are to be served from this system over the LRP timeframe (including MP load between Boswell and Deer River).

Season	2011	2021	2031
Summer	45.9	57.4	67.2
Winter	68.6	86.5	104.2

The 2011 winter load is projected to surpass the 2003 Long Range Plan's 2026 winter load projection.

Lake Country Power has identified a new substation need to cover for load growth south of Lake Pokegama. The line to serve Pokegama is estimated to be about 8 miles in length and will tap into the MP Grand Rapids-Hill City 115 kV line. The conductor is presently proposed to be 336 ACSR with an in-service date of 2010.

Estimated Year	Facility	Cost
2010	Pokegama 8.0 miles, 336 ACSR, 115 kV line tap of 11 Line	$3,709,000

Long-term Deficiencies

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Blackberry 115/69 kV transformer	46.7	2012	57.8	78.7
Deer River 115/69 kV transformer	56	2014	64.0	83.9
Deer River-Jessie Lake 69 kV	13.3	2015	11.3	16.3
Blackberry-Warba Switch 69 kV	71.7	2019	59.2	75.9
Jessie Lake-Wirt Tap 69 kV	9.7	2021	10.5	7.1

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Bigfork 69 kV	2010	91.0	79.8
Wirt 69 kV	2010	91.7	80.5
Evenson 69 kV	2010	91.2	80.1
Jessie Lake 69 kV	2014	94.4	84.6
Goodland 69 kV	2014	92.8	89.6
Blackberry Dist. 69 kV	2016	93.3	90.7
Lakehead Blackberry 69 kV	2016	93.2	90.6
Gunn 69 kV	2018	93.7	91.3
Arbo 69 kV	2020	97.6	90.6

Alternatives

Alternatives look at reducing the radial nature of the NIEC area. One option provides a new source at Bigfork via a new Effie 230/69 kV substation tapping the Running-Shannon 230 kV line. The other looks at adding generation to the NIEC system and providing looped 115 kV service to the Deer River substation.

Option 1: Effie 230/69 kV source

A new source at Effie would provide looped service to the NIEC loads and provide support to the Deer River area, especially on loss of the MP 115 kV system out of Boswell. The loads at Blackberry and Gunn are placed on the MP 11 Line to relieve Blackberry transformer loading and to alleviate voltage concerns on loss of the Blackberry 115/69 kV transformer.

Option 1: Effie 230/69 kV source.

Estimated Year	Facility	Cost
2011	Effie 60 MVA, 230/69 kV source	$5,690,600
2011	Effie-Bigfork 18.5 miles, 336 ACSR, 69 kV line and switches at Big Fork, Wirt, and Jessie Lake	$6,162,500
2011	Deer River-Jessie Lake 69 kV - Temperature Upgrade	$1,321,600
2011	Jessie Lake-Wirt Tap 69 kV - Temperature Upgrade	$717,600
2011	Wirt Tap-Big Fork 69 kV - Temperature Upgrade	$572,800
2017	Gunn and Blackberry to 115 kV – Relocate	$2,167,000
2022	Wirt Tap 7.2 MVAr 69 kV cap bank	$243,800

Option 2: NIEC generation and Deer River area transmission system improvements

This option adds in generation at Bigfork and Evensen to avoid transmission development to loop the NIEC loads. Generation is added based on projected load growth to serve the NIEC system if disconnected from the Deer River source. 115/69 kV transformers at Blackberry (replacement) and Deer River (second unit) would alleviate transformer loading issues seen at those locations. A 115-69 kV double circuit from Arbo Tap to Deer River (tapping the MP 28 Line) would loop in the Deer River substation and provide support to Deer River upon loss of the 115 kV tie out of Boswell.

Option 2: NIEC Generation

Estimated Year	Facility	Cost
2009	12 MW of generation on NIEC loop	$6,000,000
2010	Jessie Lake-Wirt Tap 69 kV rebuild to 336 ACSS	$2,107,950
2011	6 MW of generation on NIEC loop	$3,000,000
2012	Blackberry 140 MVA, 115/69 kV transformer replacement	$1,939,385
2013	Deer River-Jessie Lake 69 kV – Temperature Upgrade	$1,321,600
2014	Blackberry Distribution 4.8 MVAr 69 kV cap bank	$243,800
2014	Second Deer River 56 MVA, 115/69 kV transformer	$1,592,077
2015	Deer River-Arbo Tap 795-336 ACSS, 115-69 kV double circuit rebuild	$5,985,850
2021	6 MW of generation on NIEC loop	$3,000,000
2031	6 MW of generation on NIEC loop	$3,000,000

Present Worth

A present worth analysis was performed with Option 1 being used as a benchmark for loss savings. Loss savings for Option 2 are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	-0.6	-1.1	-1.4

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$24,091	$37,185	-
2	$51,665	$61,225	$55,916

Option 1 is the least cost plan and requires the least amount of investment.

Viability with Growth

Option 1 provides the NIEC radial system with looped service and better transmission reliability while offering support to the Deer River area. The Effie source can be sized to accommodate long-term load growth whereas generation investment would require continual investment as load growth occurs. Depending on system growth, a second, future 115 kV source into the Deer River substation would reduce the effects of losing the Boswell tie.

Shannon-Virginia Area

This area consists of the 69 kV line between Shannon and Virginia 115/69 kV substations. A large industrial load, Ainsworth, is served off of this system at the Potlatch breaker station, which basically splits this 69 kV system.

The following is the load forecasted for this system.

Season	2011	2021	2031
Summer	24.3	30.9	40.1
Winter	53.4	71.6	97.9

The 2011 winter load is projected to surpass the 2003 Long Range Plan's 2026 winter load projection.

A new substation for Lake Country Power, Frazer Bay, will be installed in the Lake Vermillion area which will be initially served from a new Tower 115/69 kV substation as the Shannon-Virginia loop can not handle this new load. This line is estimated to be about 15 miles in length and will terminate at the new Tower 115/69 kV substation. The conductor is presently proposed to be 477 ACSR and construction will be for a 69 kV line with an in-service date of 2010.

Lake Country Power has also identified a new substation need in Orr to cover for load growth in the Crane Lake area. This line is estimated to be about 13 miles in length and will terminate at the Cook substation. The conductor is presently proposed to be 336 ACSR and construction will be for a 69 kV line with an in-service date of 2012.

Estimated Year	Facility	Cost
2010	Tower-Frazer Bay 15 mile, 477 ACSR, 69 kV line	$7,515,000
2010	Tower 115/69 kV, 70 MVA substation	$2,183,875
2012	Cook-Orr 13 mile, 336 ACSR, 69 kV line	$5,275,000

Long-Term Deficiencies

The voltages need to be improved immediately due to a 50% growth in load over the last 5 years. This can be done by placing capacitors at the distribution substations or by installing a large parallel capacitor bank at Potlatch breaker station. However due to the load growth, near 10% on a winter annual basis, capacitors would only be for the short-term and would not be a good investment. Also the load will approach the emergency capability of the transformers at Shannon and Virginia around 2020. A third source is needed for the area. The critical outages are loss either of the three sources of Shannon, Virginia, or Tower.

Voltage Deficiencies

Substation	Estimated Year	2011 %
Side Lake	Existing	77.9
Meadowbrook	Existing	79.0
Cook	Existing	79.6
Potlatch	Existing	77.9
Sand Lake	Existing	75.8
Pike River	Existing	78.2
Tower	Existing	85.6
Frazer Bay	Existing	85.0
Orr	2012*	78.8

*Deficient when built

GRE realized this significant growth was occurring and immediately began the process for developing the Tower 115 kV source jointly with MP to facilitate a 69 kV line to the proposed new Frazer Bay substation. Following this construction, the Frazer Bay line would be extended into to Cook to establish a third source into the Shannon-Virginia loop.

Alternatives

Option 1: Frazer Bay-Cook 69 kV line

The plan would be to connect the Tower source through Frazer Bay into Cook. The alternative would be a 69 kV source from the MinnTac 230/115 kV substation into Potlatch. A 10.8 MVAr capacitor will be needed in 2023 to support the Pike River load on loss of the Virginia source.

Estimated Year	Facility	Cost
2011	Cook Breaker Station	$1,891,000
2011	Frazer Bay-Cook 12 miles, 477 ACSR, 69 kV line	$5,402,000
2023	Cook 10.8 MVAr capacitor	$258,200

Option 2: MinnTac 115/69 kV source

This option would establish a 115/69 kV source at the MinnTac 230/115 kV substation, extend a 9.0 mile, 69 kV line to the Sand Lake 69 kV substation from Minn Tac, and build an 18 mile line along railroad corridor from the Pike River-Sand Lake 69 kV line to Cook substation.

Estimated Year	Facility	Cost
2011	MinnTac, 70 MVA, 115/69 kV source	$2,278,375
2011	MinnTac-Sand Lake 9.0 miles, 477 ACSR, 69 kV line	$2,925,000
2011	Railroad Tap-Cook 18 miles, 477 ACSR, 69 kV line	$5,850,000
2011	Railroad Tap 3-way, 69 kV Switch	$100,000
2011	Cook 69 kV Breaker Station	$1,891,00

Since the time line is the same it is easy to determine that Option 1 will be the least cost plan and involves the least amount of investment. Since Tower is already establishing a 69 kV line into the area, the extra 12 miles from Frazer Bay to Cook is not that much more when compared to the MinnTac infrastructure that would be developed. Option 1 also allows Frazer Bay to be looped unlike Option 2 thus an improved reliability is being created. The other concern is that Option 2 is going through a mining area which may pose some corridor issues.

Future Considerations

The voltage in the area will continue to be a concern, if the load continues to grow as projected. More capacitance may need to be added to the system to account for the voltage drop on the long 69 kV lines. The other alternative is looking at rebuilding the aging infrastructure. The Side Lake–Meadowbrook line will be 70 years old by 2020. This line and other lines could be rebuilt to 115 kV standards while being operated at 69 kV. Eventually, the option would then involve moving the Shannon or Virginia transformer closer to Cook, if not at Cook. The benefit is that the LTC transformer will be in the load center alleviating any voltage concerns. The other alternatives would be adding a fourth source such as the MinnTac option or another 69 kV line from Tower to Pike River. GRE will need to revisit the area and determine if the load is continuing to grow and if line rebuilding to 115 kV provides an economical solution compared to providing a fourth source. At this time, due to age, portions of the SM and PK lines will be considered to be rebuilt to 115 kV standards and operated at 69 kV until enough of the infrastructure has been replaced to move the Virginia or Shannon transformer to a more northerly point such as Cook. The following is the estimated schedule for replacing the line segments:

Estimated Year	Facility	Cost
2020	Side Lake-Meadowbrook 15.1 mile, 477 ACSR, 115 kV Line	$4,152,500
2032	Virginia to Cook (PK) 34.17 mile, 477 ACSR, 115 kV line	$9,396,750

Generation Options

The Potlatch plant site would be a great site for a generation plant as it will remove the major load from this 69 kV system and provide a voltage source when Virginia or Shannon is out of service. A generation plant in this area could lead to a long-term solution.

Present Worth

No present worth was performed based on Option 1 being clearly the least cost plan.

Viability with Growth

Option 1 is establishing the needed third source. The voltage may continue to be a problem requiring additional voltage support. One issue is the Side Lake-Meadowbrook line which will be 70 years old by 2020. Replacing this line with a larger conductor and capability of future 115 kV operation will decrease the voltage drop.

Virginia-Babbitt Area

This area consists of the load served between the Virginia and Babbitt 115/46 kV sources. Basically, it's an extensive looped 46 kV system with an internal loop in the Ely area emanating from the Winton hydro generation site. One of the hydro units will be considered on-line for this area. The following is the load projections for this system, which consists of GRE and MP load:

Season	2011	2021	2031
Summer	24.0	29.3	34.4
Winter	42.8	55.3	70.8

The 2011 winter load is projected to surpass the 2003 Long Range Plan's 2026 winter load projection.

With the Embarrass-Tower 115 kV addition projected in 2009, the area is expected to operate fairly well through 2031. MP will need to upgrade a few of their facilities to accommodate the load growth including the 115/46 kV transformers at Virginia and Babbitt. The Tower source may also need an additional transformer if load continues to grow. GRE is not expected to make any investments is this area.

Generation Options
Generation in the Ely area will offer a source to the area without any new transmission being installed. Another generation site would be at the Vermillion substation, specifically at the casino served from this substation.

Present Worth
No Present Worth analysis was needed for this area.

Viability with Growth
The Tower Project is projected to serve this area very well over the next couple of decades.

Recommended Plan
The following are the recommended facilities to be installed in the Northern Lakes Region.

Estimated Year	Responsible Company	Facility	Cost
2009	GRE	MN Steel-Shoal Lake 7.5 mile, 336 ACSR, 115 kV line and 3-way 115 kV switch	$2,850,000
2009	LCP	Shoal Lake 115 kV Distribution Substation	$1,090,000
2010	GRE	Tower 115/69 kV, 70 MVA substation	$2,183,875
2010	GRE	Tower-Frazer Bay 15 mile, 477 ACSR, 69 kV line	$7,515,000
2010	LCP	Frazer Bay 69 kV Distribution Substation	$940,000
2010	GRE	92 Line Tap-Pokegama, 8.0 mile, 336 ACSR, 115 kV line	$3,709,000
2010	LCP	Pokegama 115 kV Distribution Substation	$1,090,000
2011	GRE	Effie 60 MVA, 230/69 kV source	$5,690,600
2011	GRE	Effie-Bigfork 18.5 mile, 336 ACSR, 69 kV line and switches at Big Fork, Wirt and Jessie Lake	$6,162,500
2011	GRE	Deer River-Jessie Lake 69 kV – Temperature Upgrade	$1,321,600
2011	GRE	Jessie Lake-Wirt Tap 69 kV – Temperature Upgrade	$717,600
2011	GRE	Wirt Tap-Big Fork 69 kV – Temperature Upgrade	$572,800
2011	GRE	Cook Breaker Station	$1,891,000
2011	GRE	Frazer Bay-Cook 12 mile, 477 ACSR, 69 kV line	$5,402,000
2012	GRE	Cook-Orr 13 mile, 336 ACSR, 69 kV line	$5,275,000
2012	LCP	Orr 69 kV Distribution Substation	$940,000

2012	GRE	Macville 300 MVA, 230/115 kV source	$7,816,000
2012	GRE	Macville-Blind Lake 22 mile, 795 ACSS, 115 kV line	$10,881,000
2012	GRE	Blind Lake 115/69 kV, 84 MVA source	$2,442,884
2014	GRE	Bass Lake 3 mile, 336 ACSR, 69 kV line tap	$1,325,000
2014	CWP	Bass Lake 69 kV Distribution Substation	$940,000
2014	GRE	Whitefish 4 mile, 336 ACSR, 69 kV line tap	$1,720,000
2014	CWP	Whitefish 69 kV Distribution Substation	$940,000
2017	GRE	Move Gunn and Blackberry to 115 kV	$2,167,000
2019	GRE	Mission Lake 69 kV tap	$140,000
2019	CWP	Mission Lake 69 kV Distribution Substation	$940,000
2020	GRE	Side Lake-Meadowbrook 15.1 mile, 477 ACSR, 115 kV Line	$4,152,500
2022	GRE	Wirt Tap 7.2 MVAR 69 kV cap bank	$243,800
2023	GRE	Blind Lake-Birch Lake Rebuild 69 kV to 115 kV (25.3 miles)	$11,246,700
2023	GRE	Pleasant Lake and Wabedo substation conversions to 115 kV operation	$1,300,000
2023	GRE	Birch Lake 50 MVA, 115/34.5 kV transformer	$1,020,159
2023	GRE	Pelican 112 MVA, 230/69 kV source	$6,754,371
2023	GRE	Pelican-Breezy Point-Breezy Point Tap 4.25 mile, 336 ACSS, 69 kV line	$1,913,125
2023	GRE	Cook 10.8 MVAr capacitor	$258,200
2024	GRE	Woman Lake 0.5 mile, 336 ACSR, 115 kV tap	$424,000
2024	CWP	Woman Lake 115 kV Distribution Substation	$1,090,000
2024	GRE	Outing 69 kV tap	$140,000
2024	CWP	Outing 69 kV Distribution Substation	$940,000
2025	GRE	Longville-Boy River 17 mile, 336 ACSS, 69 kV line	$5,555,000
2025	GRE	Salem 69 kV breaker station	$1,260,000
2025	GRE	Longville 7.8 MVAr, 69 kV cap bank	$246,000
2027	GRE	RBX line rebuild to 336 ACSS construction	$469,000
2032	GRE	Virginia to Cook (PK) 34.17 mile, 477 ACSR, 115 kV line	$9,396,750

C: GRE-MP 34.5 kV Region

The GRE-MP 34.5 kV region covers the area that is served in majority by the GRE and MP 34.5 kV integrated transmission system with some substations taking service at 115 kV. Generally the region is centrally located west of the Brainerd area with tourism and agriculture being the main industries in the area. Some of the major towns served from this area on the northern side from west to east are Park Rapids, Walker, and Pequot Lakes. The central towns are Wadena to the far west and the major eastern loads of Baxter and Brainerd. On the southern side of the region, from west to east, are the towns of Long Prairie and Little Falls. Many smaller towns fill in the spaces between these regional communities. The member systems which serve this area are:

- Crow Wing Power (CWP)
- Itasca-Mantrap Cooperative Electric Association (IMCEA)
- Lake Country Power (LCP)
- Stearns Electric Association (SEA)
- Todd-Wadena Electric Cooperative (TWEC)

Located in the heart of Minnesota's lake country, Crow Wing Power serves over 36,000 members in Crow Wing, Cass, and Morrison counties. Crow Wing serves members in an approximately 2,800 square mile area, which includes eastern and northwestern Morrison County, the greater portion of Crow Wing County, and the southern portion of Cass County.

The Itasca-Mantrap service area includes approximately two-thirds of Hubbard County, one-half of Becker county, and small parts of Cass, Wadena, and Clearwater counties.

Lake Country Power serves a large diverse area in Northeastern Minnesota covering nearly 10,000 square miles. The area served varies from bedroom communities to lakeshore properties to remote wilderness. The Onigum substation is the only LCP load in this region.

Stearns Electric Association is located in central Minnesota, serving consumers in all of Stearns county, and portions of Todd, Morrison, Douglas, Pope, and Kandiyohi counties. The northern portion of Stearns is served by this region.

Todd-Wadena Electric Cooperative serves member consumers in a majority of the rural areas of Todd and Wadena counties along with portions of Becker, Cass, Douglas, Hubbard, Otter Tail, and Morrison counties.

This region has a diversified economy consisting largely of agriculture and related agri-businesses. Other economic activity includes logging, tourism, and various service-related businesses. Population growth is occurring in the region due to the region’s rural character and the many lakes that are spread across the region.

Existing System

The load in this region is primarily served by the 34.5 kV sub-transmission system. The 34.5 kV system is supported by a 115 kV system in the area, with a bulk 230 kV system serving the 115 kV system. The 230 kV system parallels the 115 kV system, except the Riverton-Benton County line. The other 230 kV lines are from Riverton to Badoura to Hubbard and Riverton to Wing River. These 230 kV points deliver power into the 115 kV system. The MP 250 kV DC line also passes through the area.

Fourteen 115 kV bulk delivery points to the 34.5 kV system are located at Brainerd, Baxter, Dog Lake, Little Falls, Blanchard, Long Prairie, Verndale, Hubbard, Akeley, Swanville, Eagle Valley, Long Lake, Platte River, and Pequot Lakes. Several 115 kV lines tie these substations together providing the main support to the area. A 69/34.5 kV transformation at Birch Lake provides an additional tie into the 34.5 kV system. Furthermore, the Badoura-Pequot Lakes-Birch Lake 115 kV project will provide further 115 kV support through a 115/69 kV transformer at Birch Lake and a new 115/34.5 kV source at the Pine River substation.

The 34.5 kV system contains several loops between the 115 kV sources from which the majority of the region's load is served. Some loads are served on radial lines from these 34.5 kV loops including some radials that extend over 15 miles from the main 34.5 kV loop. In many of these loops, 34.5 kV voltage regulators and capacitors are present to maintain adequate voltages on the system when one end of the loop fails.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 25	Little Falls 526FM 34.5 kV (PL)	Rank: 11
Line 224	Blanchard 502F 34.5 kV	Rank: 17
Line 244	Verndale 510FM 34.5 kV	Rank: 20
Line 289	Long Lake 545F (OT, RT) 34.5 kV	Rank: 24
Line 243	Long Prairie 501FM (TW-HAT, TW-IOT) 34.5 kV	Rank: 38
Line 29	Dog Lake 1T 34.5 kV (TW-WAT)	Rank: 46

Transmission Lines Built before 1980

Line 25	Little Falls 526FM 34.5 kV (PL)	8 Mi.-1958
Line 76	Badoura 507FM-Birch Lake 516F 34.5 kV (HO)	5 Mi.-1960
Line 224	Blanchard 508F 34.5 kV (ST-FN, ST-SU, ST-NTP)	12 Mi.-1969-71
Line 244	Verndale 510FM 34.5 kV (TW-LRT)	4 Mi.-1962
Line 289	Long Lake 545F 34.5 kV (OT, RT)	15 Mi.-1976
Line 29	Dog Lake 1T 34.5 kV (TW-WAT)	8 Mi.-1974
Line 231	Blanchard 524F 34.5 kV (ST-US, ST-SU)	13 Mi.-1971-75
Line 245	Hubbard 515F 34.5 kV (TW-MET)	6 Mi.-1971

The reliability of this region is generally a little worse than the GRE average. The line age information does not provide the full view of its reliability impact because it only covers part of the system. Much of the 34.5 kV system is owned and operated by Minnesota Power; GRE does not have line age and maintenance information for the MP facilities.

Line 25 from Little Falls is a 32 mile 34.5 kV line serving two substations. Its reliability performance is among the 50 worst lines for each of the six indices used. The majority of the line is owned by Minnesota Power, so most of the maintenance and age information is not available. Minnesota Power rebuilt nearly 10 miles of line from MP Little Falls to the Lastrup tap in 2006 with arresters. Also, the tap switch at Crow Wing's Little Falls substation has been replaced.

Line 224 from Blanchard is a 40 mile, 34.5 kV line serving two substations. This line is operated by Minnesota Power. Its reliability performance is among the 50 worst lines for each of the six indices used, with its worst performance from high numbers of momentary and sustained

outages. The majority of the line is owned by Minnesota Power, so most of the maintenance and age information is not available. MP rebuilt about six miles of this line and GRE added arresters on the GRE owned portions of the line in 2006. Also, a grounding survey is planned to determine grounding additions if indicated.

Line 244 from Verndale is a 19 mile, 34.5 kV line serving two substations. Its reliability performance is worse than the GRE average on all six indices. The majority of the line is owned by Minnesota Power, so most of the maintenance and age information is not available. Remote control has been added at the Sebeka tap switches to aid in outage restoration.

Line 289 from Long Lake is a 33 mile, mostly radial 34.5 kV line serving three substations. Its reliability performance is worse than the GRE average on all six indices; with it worst performance due to long term outages. The maintenance reports do not show much maintenance on this line. The recent addition of the Long Lake 115-34.5kV substation should improve overall reliability, but not for issues related to the radial supply. The RDO substation has been converted to 115kV supply and the planned Long Lake-Badoura 115kV line will provide it with two-way 115kV supply.

Line 243 from Long Prairie is a 28 mile, 34.5 kV line serving two substations. Its reliability performance was worse than the GRE average on five of the six indices. The majority of the line is owned by Minnesota Power, so most of the maintenance and age information is not available. The 2005 addition of the Eagle Valley 115-34.5kV substation has allowed the line to be reconfigured to reduce exposure. Also, remote control is being added to the Hartford tap switches to aid in outage restoration.

Line 29 from Dog Lake is a 20 mile, 34.5 kV line serving two substations. Its reliability performance was worse than the GRE average on four of the six indices. Part of this line is owned by Minnesota Power, so most of the maintenance and age information is not available. There are no recent or planned projects to improve reliability of this line.

Future Development

Load Forecast

The following forecast is the load served by the transmission system in the region. This load includes GRE, MP, and municipal load.

GRE-MP 34.5 kV Region Load (in MW)			
Season	2011	2021	2031
Summer	338.8	430.8	560.2
Winter	363.0	473.4	613.6

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- GRE and MP are planning a new 115 kV transmission line and substation that will connect CWP's Southdale substation to MP's 24 Line (Baxter-Dog Lake Tap) via a breaker station at Scearcyville. The scheduled ISD for this project is 2009.

- IM is planning a new Shingobee distribution substation with an ISD of 2009. GRE is building approximately 2.8 miles of 115 kV line from the Akeley-Badoura 115 kV line to connect the new substation to the system.
- GRE and MP are constructing the Badoura project consisting of 63 miles of new 115 kV transmission connecting the Pequot Lakes, Badoura, Birch Lake, and Long Lake substations. New transformations will be placed at Birch Lake (115/69 kV) and at a new substation at Pine River (115/34.5 kV). As a result of this project, CWP is upgrading their Pine River substation and IM is converting its Tripp Lake substation from 34.5 kV to 115 kV. The scheduled ISD for the project is 2010.
- GRE and MP are planning a new 115 kV transmission connecting the GRE Menahga 34.5 kV substation with MP's Hubbard-MN Pipeline 34.5 kV line. The scheduled ISD for the project is 2010.
- IM is planning a new Potato Lake substation in 2010. GRE is planning to connect the substation with approximately 6 miles of transmission line that taps the Mantrap Tap-Mantrap 34.5 kV line.
- CWP is proposing to add a new 115 kV distribution substation at Hardy Lake in 2012. This substation will directly tap the Southdale-Scearcyville 115 kV line.
- CWP is planning a new Shamineau Lake substation in 2014. GRE will connect this substation via a new 5 mile line that taps the MP Motley-GRE Motley 34.5 kV line.
- CWP is has identified a need for a new Barrows substation that will tap the Nokay-Southdale 115 kV line. The projected ISD for this addition is 2014.
- IM has identified the need for a new Shell Lake substation to be energized in 2015. In order to connect this substation to the bulk system, GRE plans to construct approximately 4.5 miles of transmission line from the Osage-Pine Point 34.5 kV line to the new substation.
- CWP is planning to add a new 115 kV distribution substation at Portage Lake in 2019. This substation will connect to the Tripp Lake-Birch Lake 115 kV line via a 4.0 mile 115 kV line.
- CWP is proposing to add a Gilbert Lake substation that taps the Riverton-Baxter 115 kV line. The expected ISD is 2024.
- CWP has identified a need for a new Ripley distribution substation that will directly tap the Dewing-Little Falls 115 kV line. The expected ISD for this project is 2029.
- CWP has indicated that a new Royalton substation is needed in 2029. This substation will directly tap the Little Falls-Langola Tap 115 kV line.

230-115 kV Bulk Delivery

Analysis of the 34.5 kV region has shown that the regional bulk system voltages are beginning to depress as system loading is increasing. Of concern are the 230 kV system voltages in and around the Riverton area. While not violating criteria, the high voltage system voltage issues directly lead to voltage issues on the lower voltage systems. A more detailed analysis of bulk system issues will have to be done as this is outside the scope of this study. Some of the System Intact voltages are listed in the below table.

Facility	2011 SUPK %	2021 SUPK %
Riverton 230 kV	102.2	97.2
Mud Lake 230 kV	101.8	96.8
Wing River 230 kV	101.5	95.7
Badoura 230 kV	102.9	97.3

Facility	2011 SUPK %	2021 SUPK %
Hubbard 230 kV	103.1	97.2
Little Falls 115 kV	102.5	96.7
Blanchard 115 kV	102.5	97.0
Platte River 115 kV	101.8	96.1
Swanville 115 kV	103.0	97.3

A new bulk source into the Little Falls area would help to boost the 115 kV voltages and improve regional 34.5 kV load serving capability. This source could come from the proposed Pierz 230/115 kV source in the ***Central Minnesota Region-Mille Lacs Area***. Other potential sources would involve 230 or 115 kV transmission from the St. Cloud and/or the Brainerd areas. Additions of 230 kV capacitor could help with the 230 kV system voltages. It is expected that the CAPX Fargo-Monticello 345 kV line would greatly help out with voltages in the area as through-flow to the St. Cloud and Twin Cities metro areas would be reduced.

A few bulk system thermal overloads were also observed. The Riverton-Brainerd and Mud Lake-Brainerd 115 kV lines overload for loss of the Mud Lake and Riverton 230/115 kV transformers, respectively.

Thermal Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Riverton-Brainerd 115 kV line	90	2018	76.1	110.8
Mud Lake-Brainerd 115 kV line	120	2020	102.5	134.8

It is assumed that the cheapest option would be to rebuild these facilities to a higher capacity conductor. A new 230/115 kV transformation at Scearcyville may also provide loading relief to these facilities. However, further study is required to validate this option. Assuming a rebuild to 636 ACSR, the following are the recommended bulk facility installations. The lines will likely be rebuilt by MP as they are the owners of these facilities.

Estimated Year	Facility	Cost
2018	Riverton-Brainerd, 13.13 Mile, 636 ACSR, 115 kV line rebuild	$4,267,250
2020	Mud Lake-Brainerd, 4.41 Mile, 636 ACSR, 115 kV line rebuild	$1,433,290

Verndale-Dog Lake-Baxter-Brainerd Area

The Verndale-Dog Lake-Baxter-Brainerd system consists of the 34.5 kV system that ties these 115/34.5 kV sources together. The following are the 34.5 kV outlets for this area:

- 503 Line from Verndale
- 503 Line from Dog Lake
- 534 Line from Baxter
- 504 Line from Brainerd

This area also has two hydroelectric stations at Pillager and Sylvan. From Sylvan, the normally open 502 Line goes to the ***Little Falls-Platte River-Blanchard Area***.

Other lines exist in the Verndale and Brainerd area that tie to the system, but are not of concern to the capability of serving GRE substations of Staples, Ward, and Motley. The GRE 115 kV loads in the area include Aldrich (Verndale), Thomastown, Southdale, Baxter, Nokay, and Dewing. The following forecast is the load served in this area. This load includes GRE, MP, and Staples Municipal load.

Season	2011	2021	2031
Summer	124.5	166.7	226.6
Winter	117.3	151.5	195.9

The distribution substation interconnections that are scheduled over the LRP time period are depicted in the following table. In total, four distribution substation interconnections are planned for the Shamineau Lake, Hardy Lake, Gilbert Lake, and Barrows substation projects.

Estimated Year	Facility	Cost
2012	Hardy Lake 115 kV 3-way switch	$205,000
2014	Shamineau Lake- MP 524 Line, 5.0 Mile, 477 ACSR, 115 kV line and 3-way switch (operated at 34.5 kV)	$2,700,000
2014	Nokay-Southdale Line Tap to Barrows 1.0 mile, 336 ACSR 115 kV line and 3-way switch	$894,000
2024	Gilbert Lake 115 kV 3-way switch	$205,000

Area Deficiencies

Deficiencies seen in this area reside in the western portion of this system around Dog Lake and Verndale. The completion of the Scearcyville-Southdale 115 kV line in the eastern portion of the region will loop in the Southdale substation and create a 115 kV ring around the Brainerd/Baxter area, thus securing the transmission system through the LRP time frame. The overload of the Brainerd and Verndale 115/34.5 kV transformers can be alleviated by switching loads to the other transformers in the system if necessary. Most of the 34.5 kV voltage deficiencies seen are caused by loss of the Dog Lake 115/34.5 kV transformer.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA	Contingency
Brainerd 115/34.5 kV transformer #1	30	2010	38.2	42.9	Brainerd 115/34.5 kV transformer #2
Brainerd 115/34.5 kV transformer #2	30	2010	38.3	43.0	Brainerd 115/34.5 kV transformer #1
Verndale 115/34.5 kV transformer #1	20	<2011	34.0	41.8	Verndale 115/34.5 kV transformer #2
Verndale 115/34.5 kV transformer #2	20	<2011	36.9	45.3	Verndale 115/34.5 kV transformer #1

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %	Contingency
Shamineau Lake 34.5 kV	2017	95.6	89.3	Dog Lake 115/34.5 kV transformer
Ward 34.5 kV	2018	99.4	88.0	Dog Lake 115/34.5 kV transformer
GRE Motley 34.5 kV	2019	96.9	90.3	Dog Lake 115/34.5 kV transformer
GRE Staples 34.5 kV	2019	97.3	90.0	Verndale-Wing River 115 kV
MP Staples 34.5 kV	2020	96.7	89.3	Verndale-Wing River 115 kV

Alternatives

Alternatives look at providing a new source into the 34.5 kV system and converting more load from 34.5 kV to 115 kV.

Option 1: Motley 115 kV conversion and Shamineau Lake-Ward development

The conversion of the GRE Motley load to 115 kV would offload the 34.5 kV system to provide better voltage regulation upon outage of the Dog Lake 115/34.5 kV transformer. Adding a line between Shamineau Lake and Ward would allow for Ward to be served from the Dog Lake source upon loss of the Dog Lake Tap-Ward Tap 34.5 kV line or the Verndale-Aldrich 34.5 kV line. This line would be constructed to 115 kV standards and operated at 34.5 kV.

Estimated Year	Facility	Cost
2017	Motley- MP 24 Line, 4.3 Mile, 477 ACSR 115 kV line	$1,747,400
2017	GRE Motley conversion to 115 kV operation	$350,000
2018	Shamineau Lake-Ward, 6.75 Mile, 477 ACSR 115 kV line (operated at 34.5 kV)	$2,814,000

Option 2: Shamineau Lake 115/34.5 kV source

This option would establish a 115/34.5 kV source at Shamineau Lake and provide 34.5 kV outlets to the MP 534 Line, Ward, and North Parker substations. This would provide another source into the middle of the area plus provide support to the Blanchard area.

Estimated Year	Facility	Cost
2016	Shamineau Lake-North Parker, 13.6 Mile, 477 ACSR 115 kV line (operated at 34.5 kV)	$5,384,800
2019	Shamineau Lake 115/34.5 kV source	$6,201,400
2022	Shamineau Lake-Ward, 6.75 Mile, 477 ACSR 115 kV line (operated at 34.5 kV)	$3,149,000

Generation Options

Generation would be attractive on the low-side of the Verndale to unload the transformers. However, to offset transmission projects it would be more feasible away from the main delivery points to delay future lines or voltage support improvements. The capacity and radial nature of the 34.5 kV lines make it very difficult to justify generation placement in this area.

Present Worth

A cost analysis was performed on each option with loss savings assumed to be benchmarked against Option 1. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	-0.5	-0.9

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$9,644	$9,903	-
2	$30,417	$29,822	$27,927

Option 1 offers the least amount of investment. However, Option 1 provides marginal voltage support throughout the LRP time period. The Ward and Shamineau Lake substations will need additional transmission facilities that will allow for adequate voltage support for System Intact conditions in 2032. The Option 2 facilities offer much improved system performance over the Option 1 facilities and provide benefits not only to this area but the ***Long Prairie-Swanville-Blanchard Area*** as well via the Shamineau Lake-North Parker 115 kV line. Therefore, Option 2 is being preferred as the recommended plan.

Viability with Growth

GRE will have to watch the load growth closely in this region. The Shamineau Lake 115/34.5 kV source will provide for additional flexibility in serving the area loads as they grow as they could be potential candidates for 115 kV conversion. A 115 kV line to Shamineau Lake would also lend itself to be a potential start to a 115 kV loop to Long Prairie and/or Blanchard. However, if load growth does not occur at the expected rates, GRE will have to revisit the transmission plan for the area to see if an alternate option makes better sense to pursue.

Verndale-Hubbard Area

The Verndale-Hubbard area consists of the 34.5 kV system that ties the 115/34.5 kV sources between Verndale and Hubbard. The 34.5 kV MP 515 Line ties the Verndale and Hubbard substations together and serves the GRE substations of Twin Lakes, Menahga, Orton, Sebeka, and Leaf River. Other lines exist in the Verndale and Hubbard area that tie to the system, but are not of concern to the capability of serving these GRE substations. This load includes GRE and MP load.

Season	2011	2021	2031
Summer	16.9	21.0	26.4
Winter	21.9	27.5	35.1

GRE's Pipeline-Menahga 34.5 kV project will help to serve this system upon loss of either end of the loop. This project is currently budgeted with an expected ISD of 2010, will be constructed to 115 kV specifications, and is assumed as being in-service for the simulations.

Estimated Year	Facility	Cost
2010	Pipeline-Menahga, 8.5 Mile, 477 ACSR 115 kV line (operated at 34.5 kV)	$1,644,563

Area Deficiencies

Area deficiencies are voltage-related in nature and stem from the loss of ties to either the Hubbard or Verndale sources.

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Leaf River 34.5 kV	2014	93.1	86.2
GRE Sebeka 34.5 kV	2017	95.8	88.9
Blue Grass 34.5 kV	2018	94.6	88.0
Sebeka Regulator 34.5 kV	2020	95.4	89.2
Orton 34.5 kV	2020	97.3	91.0
Twin Lakes 34.5 kV	2020	97.1	91.0
MP Sebeka 34.5 kV	2021	95.7	89.8

Alternatives

Alternatives look to providing additional sources and ties to the 34.5 kV system.

Option 1: Leaf River-Compton 115 kV line

Addition of a Leaf River-Compton 115 kV line operated at 34.5 kV would tie the Leaf River substation back to the Verndale substation upon loss of the Leaf River-Verndale 34.5 kV line.

Estimated Year	Facility	Cost
2021	Leaf River-Compton, 9.0 Mile, 477 ACSR 115 kV line (operated at 34.5 kV)	$3,642,000

Option 2: Hubbard-Wing River 115 kV development

This option looks at establishing a 115 kV path between the Hubbard and Wing River 115 kV substations and placing a new 115/34.5 kV substation at Orton Tap. Distribution substation conversions at Menahga, Leaf River, Compton, and Hewitt are required with this option.

Estimated Year	Facility	Cost
2021	Hubbard-Wing River 115 kV development	$26,316,010

Generation Options

As discussed in the ***Verndale-Dog Lake-Baxter-Brainerd Area***, generation would be attractive on the low-side of the Verndale substation to unload the transformers. However, to offset transmission projects it would be more feasible away from the main delivery points to delay future lines or voltage support improvements. Depending on load growth, distributed generation may offer a great opportunity in this area as small generation units may have long-term impacts on the transmission grid.

Present Worth

A cost analysis was performed on each option with line losses evaluated with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Winter	2021 Winter	2031 Winter
2	0.0	-0.6	-2.6

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$8,728	$7,093	-
2	$63,068	$51,315	$47,150

Based on the present worth values, it is evident that Option #1 is the preferred plan.

Viability with Growth

Option 1 provides adequate support to the system based on the present LRP load projections and would provide a base for deploying the Option 2 plan if needed. GRE will have to monitor load growth to see if Option 2 might become necessary. It may feasible to simply build the Orton Tap 115/34.5 kV source and Hubbard-Menahga-Orton Tap 115 kV line and convert Menahga to

115 kV operation. Wind projects may also push the development of the Option 2 facilities as the area around Verndale has the potential to see many wind interconnections.

Verndale-Eagle Valley-Long Prairie Area

The Verndale-Eagle Valley-Long Prairie system consists of the 34.5 kV system that ties the 115/34.5 kV sources between Verndale, Eagle Valley, and Long Prairie. Two 34.5 kV outlets, the 519 and 533 Lines, exist at Verndale, one outlet exists at Long Prairie (501 Line), and two outlets emanate from Eagle Valley (513 and 517 Lines). Other lines exist in the Long Prairie and Verndale area that tie to the system, but are not of concern to the capability of serving GRE substations at Hartford, Iona, Eagle Bend, Hewitt, and Compton. The following forecast is the load served in this area. This load includes GRE, MP, and Wadena Municipal load.

Season	2011	2021	2031
Summer	37.4	43.6	49.4
Winter	39.9	46.7	53.0

Area Deficiencies

The Eagle Valley 115/34.5 kV source greatly aids in holding the voltage at the Hewitt, Compton, and Wadena 34.5 kV substations upon loss of the Verndale source. However, the Compton voltage falls below criteria in 2022 and the Wadena voltage in 2023. Also of interest is the loading on the Verndale 115/34.5 kV transformers. The third 20 MVA, 115/34.5 kV transformer failed in 2006 and is has put additional strain on the remaining transformers. The most severe loading is seen when one Verndale 115/34.5 kV transformer is lost. Switching the system to have load sourced from other transformers will likely alleviate these overloads. The addition of the Shamineau Lake 115/34.5 kV source as identified in the ***Brainerd-Baxter-Dog Lake-Verndale Area*** would also offer transformer loading relief.

Overloads

Facility	Rating MVA	2011 MVA	2021 MVA	Contingency
Verndale 115/34.5 kV transformer #1	20	34.0	41.7	Verndale 115/34.5 kV transformer #2
		22.2	28.2	Dog Lake 115/34.5 kV transformer
Verndale 115/34.5 kV transformer #2	20	36.9	45.3	Verndale 115/34.5 kV transformer #1
		21.8	27.7	Dog Lake 115/34.5 kV transformer

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Compton 34.5 kV	2022	97.2	92.3
Wadena 34.5 kV	2023	96.0	91.0

The GRE criterion is to have a 92% voltage at GRE buses, whereas MP buses have a criterion of 90% during contingency conditions.

Alternatives

The deficiencies in the area stem from the loss of the Verndale-Wadena 34.5 kV line as this puts the largest load in the area on a long radial line far from any source. Therefore, alternatives focus on 115 kV load conversion and providing additional ties into the Wadena area.

The following are options that were considered:

Option 1: Compton-Leaf River 115 kV line and Hewitt 115 kV conversion

This option examines adding a Compton-Leaf River 115 kV line that is initially operated at 34.5 kV. This would provide another tie to the Compton/Wadena area from the Verndale sub and help mitigate the Verndale-Wadena 34.5 kV outage. Conversion of the Hewitt substation to 115 kV via a Wing River-Hewitt 115 kV line would further offload the 34.5 kV system to maintain the Wadena voltage during contingency situations. Finally, a 21.6 MVAR cap bank would be placed at the Verndale 115 kV bus to provide voltage support upon loss of the tie to Wing River.

Estimated Year	Facility	Cost
2022	Hewitt 115 kV conversion	$350,000
2022	Wing River-Hewitt, 4.5 Mile, 477 ACSR, 115 kV line	$2,156,000
2022	Compton-Leaf River, 9.0 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$3,642,000
2026	Verndale 115 kV 21.6 MVAR capacitor bank	$281,200

Option 2: Wing River-Hubbard 115 kV development

This option looks at establishing a 115 kV path between the Hubbard and Wing River 115 kV substations and establishes a new 115/34.5 kV substation at Orton Tap in the ***Hubbard-Verndale Area***. Distribution substation conversions at Menahga, Leaf River, Compton, and Hewitt are required with this option.

Estimated Year	Facility	Cost
2022	Wing River-Hubbard 115 kV development	$26,316,010

Present Worth

A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Winter	2021 Winter	2031 Winter
2	0.0	0.0	-2.6

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$16,520	$12,605	-
2	$66,852	$50,835	$46,822

Option 1 offers the least cost plan and requires the least investment.

Viability with Growth

Load growth will have to be carefully monitored in this area. The Leaf River-Compton 115 kV line offers only limited support to the Wadena substation. Conversion of the Wadena load to 115 kV operations or establishing a 115/34.5 kV source at Wadena would provide more reliable service to this substation and would help with the Verndale transformer loading issues. Also, the area surrounding Wadena has the potential to have many larger wind farm interconnections that

could not be handled by the 34.5 kV system. In the event that that these wind projects develop, GRE would likely have to revert to the Option 2 facilities to handle the interconnections.

Long Prairie-Swanville-Blanchard Area

The Long Prairie-Swanville-Blanchard system consists of the 34.5 kV system that ties the 115/34.5 kV sources between Long Prairie, Swanville, and Blanchard. Three 34.5 kV outlets, 521, 524 and 508 Line, exist at Blanchard and one 34.5 kV outlet, the 527 Line, sources from Long Prairie. The Swanville source connects the 508 and 524 Lines. The 521 Line serves the MN Pipeline load individually as its start up causes voltage dips on the system. MP has isolated this load to its own 115/34.5 kV transformer at Blanchard. Other lines exist in the Long Prairie and Blanchard area that tie to the system, but are not of concern to the capability of serving GRE substations at Sobieski, Pine Lake, Pillsbury, Flensburg, and North Parker. The following forecast is the load served in this area and includes both GRE and MP load.

Season	2011	2021	2031
Summer	39.7	47.3	57.1
Winter	34.6	40.7	48.7

Area Deficiencies

No line overloads were identified within this area. Voltage deficiencies stem from loss of the Swanville source which requires significant reconfiguration of the system.

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
North Parker 34.5 kV	2016	97.0	86.1
GRE Flensburg 34.5 kV	2019	99.1	89.2
North Parker Jct. 34.5 kV	2019	97.9	87.3
Flensburg Switch 34.5 kV	2021	99.1	89.4

Alternatives

The immediate issue in this area is the voltage performance of the 34.5 kV system. The North Parker substation is on a radial line distant from all three area sources. Alternatives look to provide voltage support via new sources closer to the North Parker area.

Option 1: Pike Creek 115/34.5 kV source

This option provides a new source at the junction of the 34.5 kV 508 and 521 Lines by rebuilding the Blanchard to 508-521 Tie 34.5 kV line to 115 kV. This also places a stronger source closer to the MN Pipeline load which would likely help in reducing voltage dips upon starting of the compressor station.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facility	Cost
2016	Blanchard-Pike Creek, 9.15 Mile, 477 ACSR 115 kV rebuild	$2,516,250
2016	Pike Creek 30 MVA, 115/34.5 kV source	$3,814,400

Option 2: Shamineau Lake-North Parker development

This option establishes a 34.5 kV connection between Shamineau Lake and North Parker to provide support to the North Parker substation (constructed to 115 kV standards). Eventually, a Shamineau Lake 115/34.5 kV source is required for support of both the Shamineau Lake and North Parker areas.

Estimated Year	Facility	Cost
2016	Shamineau Lake-North Parker, 13.6 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$5,219,800
2019	Shamineau Lake 30 MVA, 115/34.5 kV source	$6,201,400

Generation Options

Generation would be attractive at North Parker to provide voltage support and defer transmission investment. However, the Shamineau Lake-North Parker transmission development would be beneficial to both the Dog Lake and the Swanville-Blanchard areas, thus making generation investment difficult to justify.

Present Worth

A cost analysis was performed on each option with line losses evaluated with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	-0.6	-0.8

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$11,337	$12,969	-
2	$22,870	$23,484	$21,365

Option 1 is the least cost plan. However, as discussed in the ***Brainerd-Baxter-Dog Lake-Verndale Area***, the Shamineau Lake 115/34.5 kV source provides benefits to both areas. Therefore, Option 2 will be the recommended plan for the area.

Viability with Growth

Option 2 allows for future conversion of the North Parker and other area substations to 115 kV operation. The Blanchard and Little Falls 115 kV voltages are fairly weak as the sources into the 115 kV system are distant from these substations, thus the voltage support provided by the Pike Creek source to the 34.5 kV system is dictated by the 115 kV system voltage levels. Also, the Shamineau Lake 115 kV line also would provide the basis for a 115 kV loop to Blanchard or Long Prairie.

Blanchard-Platte River-Little Falls Area

The Blanchard-Platte River-Little Falls system consists of the 34.5 kV system that ties the 115/34.5 kV sources between Blanchard, Platte River, and Little Falls. One 34.5 kV outlet, the 511 Line, exists at Blanchard and another outlet, the 526 Line, emanates from Little Falls. The two outlets meet with the 5261 FDR line, which ties the system together as a looped system. The Platte River substation is in the middle of the radial line that serves Rice and provides

emergency support upon loss of the Blanchard source. Other lines exist in the Little Falls and Blanchard area that tie to the system, but are not of concern to the capability of serving GRE substations of Little Falls and Lastrup. The following forecast is the load served in this area. This load includes GRE and MP substations.

Season	2011	2021	2031
Summer	28.7	35.3	35.7
Winter	24.6	31.1	32.5

Two distribution interconnection projects are planned for the area for the Ripley and Royalton substations. GRE interconnection costs are listed in the following table.

Estimated Year	Facility	Cost
2029	Royalton 115 kV 3-way switch	$205,000
2029	Ripley 115 kV 3-way switch	$205,000

Long-term Deficiencies

The transmission system in this area is already deficient for both line overloads and voltage violations. They are as follows:

Overloads

Facility	Rating MVA	Outage	2011 MVA
Royalton 34.5 kV regulator	10	Little Falls Bulk-GRE Little Falls 34.5 kV	19.2
Royalton Regulator-Rice Tap 34.5 kV	18	Little Falls Bulk-GRE Little Falls 34.5 kV	19.2
Rice Tap-Little Rock 34.5 kV	18	Little Falls Bulk-GRE Little Falls 34.5 kV	18.8
Little Rock-526-511 Tie Sw. 34.5 kV	18	Little Falls Bulk-GRE Little Falls 34.5 kV	17

Voltage Deficiencies

Substation	2011 %	2021 %	Outage	Estimated Year
Pierz Regulator 34.5 kV	92.1	75.8	Little Falls Bulk-GRE Little Falls 34.5 kV	2013
Rich Prairie 34.5 kV	92.6	77.3	Little Falls Bulk-GRE Little Falls 34.5 kV	2013
Buckman 34.5 kV	93.7	79.5	Little Falls Bulk-GRE Little Falls 34.5 kV	2014
Lastrup 34.5 kV	97.6	88.7	System Intact	2014
Lastrup 34.5 kV	101.2	101.5	Little Falls Bulk-GRE Little Falls 34.5 kV	2016
Pierz Regulator 34.5 kV	99.0	91.2	System Intact	2016
Pierz 34.5 kV	99.0	91.1	System Intact	2016
GRE Little Falls 34.5 kV	102.8	83.5	Little Falls Bulk-GRE Little Falls 34.5 kV	2017
Lastrup 34.5 kV	97.2	88.2	Rice Tap-61k Distribution 34.5 kV	2017
Little Rock 34.5 kV	97.2	86.0	Little Falls Bulk-GRE Little Falls 34.5 kV	2018
Pierz 34.5 kV	102.4	83.7	Little Falls Bulk-GRE Little Falls 34.5 kV	2018
GRE Little Falls 34.5 kV	100.4	93.1	System Intact	2019
Little Falls 34.5 kV	101.1	94.6	System Intact	2021

The GRE criteria are to have a 95% System Intact voltage and a 92% contingent voltage at GRE buses, whereas MP buses have a criterion of 90% during contingency conditions. Also of note are the bulk system voltages at Little Falls and Blanchard in the out-year scenarios. While not below the 95% criterion for system intact violations, the 115 kV voltage is becoming

depressed which is leading to depressed voltages on the 34.5 kV system and causing the Royalton and Pierz regulator stations to saturate their LTC's.

Alternatives

The immediate issue in this area is relieving the flow on the 34.5 kV system upon loss of the Little Falls source. Also, it already takes two regulators to maintain voltage when the tie out of the Little Falls is lost. Taking these items into consideration, only one alternative was tested:

Option 1: 115 kV conversion

This option examines converting the GRE Little Falls and Lastrup substations to 115 kV operation by connecting them to the Little Falls 115 kV bulk substation. This would remove the two largest loads on this loop and greatly extend the life of the 34.5 kV system.

Estimated Year	Facility	Cost
2012	Little Falls-GRE Little Falls, 3.0 Mile, 795 ACSS 115 kV line	$2,099,000
2012	GRE Little Falls 115 kV conversion	$350,000
2018	GRE Little Falls-Lastrup, 12.0 Mile, 795 ACSS, 115 kV line	$6,646,000
2018	Lastrup conversion to 115 kV operation	$350,000

The 2012 timeline for the Little Falls conversion is based on the voltage. Conversion should take place as soon as funding can be procured for the project.

Generation Options

Generation would be attractive in the Buckman area, thus, providing a voltage source in the middle of the system. This generation however 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.

Present Worth

Present worth analysis was not performed as there are no counter options provided for proposed plan.

Viability with Growth

Conversion of the GRE loads to 115 kV will greatly extend the life of the 34.5 kV system and provide 34.5 kV loading relief to the regulating stations. Establishing a 115 kV path to Little Falls from Lastrup will also provide a future tie to the Pierz 230/115 kV source (as discussed in the ***Central Minnesota Region-Mille Lacs Area***) to help with bulk system voltage support around the Little Falls area. GRE and MP will have to monitor the load growth in the Little Falls region to see if the Pierz source is needed sooner than the 2022 time frame as estimated by the Mille Lacs area needs. Depending on the timing, establishing a 115/34.5 kV source from this substation would place a source in the middle of the loop thus potentially delaying the conversion of the Lastrup substation until the Mille Lacs development is needed.

Akeley-Pequot Lakes Area

The Akeley-Pequot Lakes system consists of the 34.5 kV system that ties the 115/34.5 kV sources between Akeley and Pequot Lakes. A 69/34.5 kV transformation exists at the Birch Lake substation that provides additional support to the area. A future 115/34.5 kV transformation will be placed at Pine River upon completion of the Badoura project along with a Badoura-Pine River-Pequot Lakes 115 kV line and a Badoura-Birch Lake 115 kV line. These

facilities are scheduled for completion in 2010 and are assumed as part of the base models. The 34.5 kV system consists of:

- The 507 Line which ties the Birch Lake and Pequot Lakes 34.5 kV substations together and serves the GRE substations of Pine River and Tripp Lake. Both of these substations will be converted to 115 kV operation as part of the Badoura project.
- The 543 and 509 Lines which serve GRE load of Onigum.

The GRE Merrifield load is served from the Riverton-Pequot Lakes 115 kV line. This line not only serves the MP Pequot Lakes 115,34.5 kV substation, but also GRE's 115/69 kV substation. The load served in this region includes GRE and MP load with the following forecast:

Season	2011	2021	2031
Summer	30.4	38.1	45.4
Winter	38.9	52	63.7

Crow Wing Power is also planning to add a new Portage Lake substation in 2019. GRE will have to install approximately 4 miles of 115 kV line and a 3-way switch on the Tripp Lake-Birch Lake 115 kV line for the interconnection.

Estimated Year	Facility	Cost
2019	Portage Lake 4.0 Mile, 336 ACSR, 115 kV line and 3-way switch	$2,197,000

Area Deficiencies

Deficiencies stem from the loss of the Birch Lake 34.5 kV tie to Hackensack or the 69/34.5 kV source at Birch Lake. This requires that the large loads of Onigum and Walker be fully supplied from Akeley. The system between Badoura and Pequot Lakes is secure throughout the LRP timeframe upon completion of the Badoura project.

Overloads

Line Segment	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Badoura Tap-Akeley 34.5 kV	22	2013	20.8	26.9
Akeley-Walker 34.5 kV	22	2016	25.3	19.5
Badoura Tap-Akeley Bulk 34.5 kV	17	2021	14.6	17.2

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Onigum 34.5 kV	2009	89.9	79.7
Hackensack 34.5 kV	2015	93.1	84.8
Ten Mile Lake 34.5 kV	2015	93.2	84.9
Walker 34.5 kV	2019	95.5	88.4

Alternatives

Alternatives will focus on converting the Onigum load to 115 kV as this is the largest load on the 34.5 kV system between Akeley and Birch Lake. Onigum is the only Lake Country Power substation on the 34.5 kV system so conversion of this load would allow it to be backfed from LCP's other substations.

Option 1: Birch Lake-Onigum 115 kV line

This option establishes a Birch Lake-Onigum 115 kV line and Onigum 115 kV voltage conversion.

Estimated Year	Facility	Cost
2009	Birch Lake-Onigum, 9.85 Mile, 477 ACSR, 115 kV line	$4,861,550
2009	Onigum conversion to 115 kV	$350,000

Option 2: Shingobee-Onigum 115 kV line

This option establishes a Shingobee-Onigum 115 kV line and Onigum 115 kV voltage conversion. It is assumed that the Akeley-Shingobee Tap 115 kV line would be rebuilt to double circuit back to the Akeley substation so that the radial line could be on a dedicated breaker.

Estimated Year	Facility	Cost
2009	Shingobee-Onigum, 12.2 Mile, 477 ACSR, 115 kV line	$6,176,100
2009	Shingobee Tap-Akeley, 0.75 Mile, 477 ACSR, 115 kV double circuit line	$796,250
2009	Onigum conversion to 115 kV	$350,000

Generation Options

Generation would be attractive at the Onigum substation as this is the largest load on the Akeley-Birch Lake system and could provide voltage support to the area. However, due to its proximity to many lakes, distributed generation may be environmentally difficult to site.

Present Worth

A cost analysis was performed on each option with line losses evaluated for MP and GRE control areas with Option 1 being the benchmark for loss savings. The loss savings in MW for Option 2 are as follows:

Option	2011 Winter	2021 Winter	2031 Winter
2	0.1	0.1	-0.2

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$6,207	$11,372	--
2	$8,721	$15,973	$16,188

Option 1 is the least cost plan and requires the least amount of investment.

Viability with Growth

Option 1 is shorter in distance and would utilize existing right of way along its entire route. As load grows in the Walker area, the Option 2 line could be constructed to loop in the Onigum and Birch Lake substations and provide another 115 kV connection to the Akeley area. The MP Walker load could then be easily converted to 115 kV to extend the life of the area 34.5 kV system.

Hubbard-Long Lake-Akeley Area

The Hubbard-Long Lake-Akeley system consists of the 34.5 kV system that ties the 115/34.5 kV sources of Akeley and Hubbard. The 115/34.5 kV Long Lake substation provides a source in the middle of the system. Two 115 kV lines tie the Badoura substation to the region; one terminating at Hubbard and one terminating at Long Lake as part of the Badoura project. Furthermore, a 115 kV line ties the Hubbard and Long Lake substations together. Three GRE distribution substations take service at 115 kV: RDO, Palmer Lake, and Long Lake. The 34.5 kV system consists of the following outlets:

- Akeley 544 Line which serves GRE load of Nevis.
- Long Lake 540 Line which serves the GRE load of Mantrap.
- Long Lake 540 and 541 Lines which serve the Park Rapids area.
- Long Lake 545 Line which serves GRE loads of Osage and Pine Point.
- Hubbard 523 Line which serves the MP Hubbard substation.

The load in the area has been increasing at a rate much greater than was anticipated during the previous long range plan. Based on current load projections, the 2011 loads will exceed the 2003 LRP 2026 load forecast. Additionally, the projected 2031 winter peak load will more than double the 2026 WIPK load forecast from the previous LRP. The load served in this region includes GRE and MP load with the following forecast:

Season	2011	2021	2031
Summer	61.2	78.8	119.6
Winter	85.8	123.9	184.7

There are two new substation interconnections planned for the area over the LRP time frame for the Potato Lake and Shell Lake substations. The Potato Lake substation is proposed to be interconnected to the Mantrap-Mantrap Tap 34.5 kV line via a 7.0 Mile, 477 ACSR, 115 kV line while the Shell Lake substation is proposed to be connected to the Osage-Pine Point 34.5 kV line via a 5.0 Mile, 336 ACSR, 115 kV line. GRE interconnection costs are as follows:

Estimated Year	Facility	Cost
2010	Potato Lake 7.0 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$2,901,000
2015	Shell Lake 5.0 Mile, 336 ACSR, 115 kV line (operated at 34.5 kV)	$2,380,000

Area Deficiencies

Due to the significant load growth projected to occur in the region, the 34.5 kV system will rapidly grow inadequate to serve the GRE substations in the area. This is demonstrated by the inability to achieve model solution with the 2031 WIPK loads applied. The remaining 115/34.5 kV transformer at Badoura is assumed to be placed at Akeley upon completion of the Badoura project and has been included in the modeling. Violations seen were purely voltage-related; there were no thermal overloads observed with the analysis.

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %	Contingency
Potato Lake 34.5 kV	2013	96.1	66.8	Park Rapids Tap-Mantrap Tap 34.5 kV
Mantrap 34.5 kV	2013	96.8	68.6	Park Rapids Tap-Mantrap Tap 34.5 kV
GRE Osage 34.5 kV	2014	98.4	85.4	System Intact
Pine Point 34.5 kV	2014	98.5	83.8	System Intact
Dorset 34.5 kV	2015	98.7	76.8	Park Rapids Tap-Mantrap Tap 34.5 kV
GRE Nevis 34.5 kV	2016	100.1	83.9	Park Rapids Tap-Mantrap Tap 34.5 kV
MP Nevis 34.5 kV	2017	100.1	83.4	Park Rapids Tap-Mantrap Tap 34.5 kV

Alternatives

Options look at converting the majority of the area GRE load to higher voltage levels due to the large loads being located far from the 34.5 kV sources. All options include a new termination at the Hubbard substation. Due to lack of space at the Hubbard substation, the 115/34.5 kV Hubbard transformers would have to be relocated to other locations. A likely location for a new 115/34.5 kV source would be at the GRE Menahga substation. This would place a 115/34.5 kV source about midway between the Long Lake and Verndale sources. The TWEC Menahga distribution substation would be converted to 115 kV operation.

Option 1: Long Lake-Mantrap Tap 115 kV line and 115 kV conversion.

This option explores rebuilding the Long Lake-Mantrap Tap 34.5 kV line to 115 kV specs with 34.5 kV underbuild. This will place the Mantrap and Potato Lake loads on a dedicated breaker out of Long Lake and separate these loads from the Long Lake-Akeley loop. Eventually, these loads would have to be converted to 115 kV operation. To resolve the voltage issues seen at Pine Point and Osage, a voltage regulator would be placed approximately half way between the Osage 34.5 kV Tap Switches and the Osage 34.5 kV substation. Furthermore, a 115 kV loop would be constructed out of Hubbard to pick up the MN Pipeline, Osage, Shell Lake, and Pine Point substations once the voltage regulator can no longer hold the 34.5 kV voltage to an acceptable level. A 17 Mile, 115 kV line and a breaker station at Carsonville would connect the Osage/Pine Point area with the Potato Lake substation.

Estimated Year	Facility	Cost
2013	Long Lake-Mantrap Tap, 1.75 Mile, 477 ACSR, 115 kV line (operate at 34.5 kV)	$1,233,890
2014	Osage 25 MVA, 34.5 kV Voltage Regulator Station	$100,000
2017	Potato Lake and Mantrap 115 kV conversions	$1,000,000
2017	Mantrap Tap-Potato Lake Tap-Mantrap, 4.75 Mile, 477 ACSR 115 kV line	$1,444,640
2019	Hubbard-Carsonville-Potato Lake, 47.33 Mile, 477 ACSR, 115 kV loop	$20,839,950

Option 2: Potato Lake Tap 115/34.5 kV source

This option places a new 115/34.5 kV source at the Potato Lake Tap switches and would be initially fed via a new 4.25 Mile, 477 ACSR, Long Lake-Potato Lake Tap 115 kV line with 34.5 kV underbuild. Similarly to Option 1, the Potato Lake and Mantrap substations would be converted to 115 kV operation and the Hubbard-Carsonville-Potato Lake loop would be constructed after the installation of the Osage 34.5 kV regulator.

Estimated Year	Facility	Cost
2013	Potato Lake Tap 50 MVA, 115/34.5 kV source	$5,519,909
2014	Osage 25 MVA, 34.5 kV Voltage Regulator Station	$100,000
2019	Hubbard-Carsonville-Pine Point, 30.33 Mile, 477 ACSR, 115 kV loop	$12,147,950
2021	Potato Lake-Carsonville, 17 Mile, 477 ACSR, 115 kV line	$9,397,000
2021	Potato Lake Tap-Mantrap, 2.25 Mile, 477 ACSR, 115 kV line	$618,750
2021	Potato Lake and Mantrap 115 kV conversions	$1,000,000

Option 3: Itasca-Mantrap 115 kV development

This option initially converts the Mantrap and Potato Lake loads to 115 kV, adds the Osage 34.5 kV regulator station, and eventually constructs the Hubbard-Carsonville-Potato Lake 115 kV loop.

Estimated Year	Facility	Cost
2013	Potato Lake and Mantrap 115 kV conversions	$3,427,500
2014	Osage 25 MVA, 34.5 kV Voltage Regulator Station	$100,000
2019	Hubbard-Carsonville-Potato Lake, 47.33 Mile, 477 ACSR, 115 kV loop	$20,839,950

Option 4: Itasca-Mantrap 69 kV development

This option examines placing 115/69 kV sources at Long Lake and Hubbard and converting the majority of the Itasca-Mantrap loads to 69 kV operation. Potato Lake and Mantrap would be converted initially while the Hubbard-Carsonville-Potato Lake portions would be added when the Osage 34.5 kV regulator station fails to support Osage, Pine Point, and Shell Lake.

Estimated Year	Facility	Cost
2013	Long Lake 70 MVA, 115/69 kV source	$2,174,028
2013	Potato Lake and Mantrap 69 kV conversions	$2,760,000
2014	Osage 25 MVA, 34.5 kV Voltage Regulator Station	$100,000
2019	Hubbard 70 MVA, 115/69 kV source	$2,174,028
2019	Hubbard-Carsonville-Potato Lake, 47.33 Mile, 477 ACSR, 69 kV loop	$17,326,850

Generation Options

Generation would be attractive at the Osage or Pine Point substations. The amount of load served on the radial OT Line is requiring the majority of the transmission alternatives proposed above. Due to the cost of the proposed additions, any generation addition that causes delay may be cost justified.

Present Worth

A cost analysis was performed on each option with line losses evaluated against Option 1 for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Winter	2021 Winter	2031 Winter
2	0.0	0.0	0.0
3	0.0	0.0	0.0
4	0.0	0.5	6.8

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$51,105	$49,288	-
2	$60,770	$58,070	$58,874
3	$49,017	$48,323	$47,638
4	$49,172	$49,635	$58,560

Option 3 is the least cost plan and requires the least amount of investment.

Viability with Growth

Option 3 will provide the best flexibility to serve the load in the area. It will also offer most of the Itasca-Mantrap loads with 115 kV service and extend the life of the 34.5 kV system without major 34.5 kV system additions.

Recommended Plan

The following are suggested projects for the GRE-MP 34.5 kV region.

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Estimated Year	Responsible Company	Facility	Cost
2009	GRE	Birch Lake-Onigum, 9.85 Mile, 477 ACSR, 115 kV line	$4,861,550
2009	GRE	Onigum conversion to 115 kV	$350,000
2010	CWP	Pine River 115 kV distribution substation upgrade	$350,000
2010	IM	Tripp Lake 115 kV distribution substation upgrade	$350,000
2010	GRE	Pipeline-Menahga, 8.5 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$1,644,563
2010	GRE	Potato Lake 7.0 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$2,901,000
2010	IM	Potato Lake 34.5 kV distribution substation	$940,000
2012	GRE	Little Falls-GRE Little Falls, 3.0 Mile, 795 ACSS, 115 kV line	$2,099,000
2012	CWP	GRE Little Falls 115 kV conversion	$350,000
2012	GRE	Hardy Lake 115 kV 3-way switch	$205,000
2012	CWP	Hardy Lake 115 kV distribution substation	$1,090,000
2013	GRE	Potato Lake and Mantrap 115 kV conversions	$3,427,500
2014	GRE	Osage 25 MVA, 34.5 kV Voltage Regulator Station	$100,000
2014	GRE	Shamineau Lake - MP 524 Line, 5.0 Mile, 477 ACSR, 115 kV line and 3-way switch (operated at 34.5 kV)	$2,700,000
2014	CWP	Shamineau Lake 34.5 kV distribution substation	$940,000
2014	GRE	Nokay-Southdale Line Tap to Barrows 1.0 Mile, 336 ACSR, 115 kV line and 3-way switch	$563,000
2014	CWP	Barrows 115 kV distribution substation	$1,090,000
2015	GRE	Shell Lake 5.0 Mile, 336 ACSR, 115 kV line (operated at 34.5 kV)	$2,380,000
2015	IM	Shell Lake 34.5 kV distribution substation	$940,000
2016	GRE	Shamineau Lake-North Parker, 13.6 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$5,384,000
2018	GRE	GRE Little Falls-Lastrup, 12.0 Mile, 795 ACSS, 115 kV line	$6,646,000
2018	CWP	Lastrup conversion to 115 kV operation	$350,000
2018	MP	Riverton-Brainerd, 13.13 Mile, 636 ACSR, 115 kV line rebuild	$4,267,250
2019	GRE	Shamineau Lake 115/34.5 kV source	$6,201,400

GRE Long-Range Transmission Plan

Estimated Year	Responsible Company	Facility	Cost
2019	GRE	Hubbard-Carsonville-Potato Lake, 47.33 Mile, 477 ACSR, 115 kV loop	$20,839,950
2019	GRE	Portage Lake 4.0 Mile, 336 ACSR, 115 kV line and 3-way switch	$2,197,000
2019	CWP	Portage Lake 115 kV distribution substation	$1,090,000
2020	MP	Mud Lake-Brainerd, 4.41 Mile, 636 ACSR, 115 kV line rebuild	$1,433,290
2021	GRE	Leaf River-Compton, 9.0 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$3,642,000
2022	GRE	Shamineau Lake-Ward, 6.75 Mile, 477 ACSR, 115 kV line (operated at 34.5 kV)	$3,149,000
2022	TWEC	Hewitt 115 kV conversion	$350,000
2022	GRE	Wing River-Hewitt, 4.5 Mile, 477 ACSR, 115 kV line	$2,156,000
2024	GRE	Gilbert Lake 115 kV 3-way switch	$205,000
2024	CWP	Gilbert Lake 115 kV distribution substation	$1,090,000
2026	MP	Verndale 115 kV 21.6 MVAR capacitor bank	$281,200
2029	GRE	Royalton 115 kV 3-way switch	$205,000
2029	GRE	Ripley 115 kV 3-way switch	$205,000
2029	CWP	Royalton 115 kV distribution substation	$1,090,000
2029	CWP	Ripley 115 kV distribution substation	$1,090,000

D: Central Minnesota Region

The Central Minnesota Region is generally located in a box southwest of Duluth and northeast of Milaca. The member systems that serve this territory are:

- Crow Wing Power (CWP)
- East Central Energy (ECE)
- Lake Country Power (LCP)
- Mille Lacs Electric Cooperative (MLEC)

Located in the heart of Minnesota's lake country, Crow Wing Power serves over 36,000 members in Crow Wing, Cass and Morrison counties. Crow Wing serves members in an approximately 2,800 square mile area, which includes eastern and northwestern Morrison County, the greater portion of Crow Wing County, and the southern portion of Cass County. The south-eastern portion of Crow Wing Power is in the central region.

East Central Energy (ECE) serves over 54,000 homes, farms, and businesses in east central Minnesota and northwestern Wisconsin. It serves the counties of Benton, Morrison, Mille Lacs, Sherburne, Isanti, Chisago, Washington, Kanabec, Pine, Aitkin, and Carlton in Minnesota and Douglas and Burnett in Wisconsin.

Lake Country Power (LCP) serves a large diverse area in Northeastern Minnesota covering nearly 10,000 square miles. The area served varies from bedroom communities to lakeshore properties to remote wilderness. The south-eastern portion of Lake Country Power is within the central region.

Mille Lacs Energy Cooperative (MLEC) includes a major portion of Aitkin County and parts of Crow Wing and Mille Lacs Counties. Rural residences, commercial properties and industrial businesses in this area enjoy many of the same conveniences as those in urban areas, due in large part to the electricity provided by MLEC. All of the Mille Lacs Energy service territory is in the central region.

The region's economy continues to grow rapidly. The economy of the region is principally based on recreational activities, agriculture, two casinos, and light industry. Lake cabin conversions to year round homes have driven the economy in the area resulting in some service oriented growth within the region.

Existing System

This region is served from the MP-GRE integrated transmission system and the GRE 69 kV system. Delivery to the GRE 69 kV system is through 115/69 kV transformations at Stinson, Four Corners, Cromwell, and Riverton and a 161/69 kV transformation at Frog Creek. Two 230/69 kV sources also serve the area at Milaca and Bear Creek with residual support coming from the Rush City 230/69 kV source through Pine City. The 69 kV system provides the delivery to the bulk of the distribution substations in this area.

MP's transmission system delivers directly to some of GRE's substations at the 115, 46, and 23 kV voltage levels. MP support to the load serving lines includes the Thomson and Mahtowa 115/46 kV and Mahtowa's 115/23 kV transformations. MP also provides strong 230/115 kV sources at Riverton and Arrowhead which provides the support to the Riverton-Cromwell-Thomson 115 kV line that splits the region into a northern and southern half.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 44	Fond du Lac 24KB1 46 kV (DF)	Rank: 41

Transmission Lines Built before 1980

Line 44	Fond du Lac 24KB1 46 kV (DF)	10 Mi.-1966-77
Line 21	Riverton 25NB1- Vineland 69 kV (DO, RW, RWT)	9 Mi.-1965; 18 Mi.-1972
Line 39	Isle 56NB1/56NB2 69 kV (DO, OI, DL)	13 Mi.-1965; 21 Mi.-1972-74
Line 43	Frog Creek 48NB3 69 kV (BW)	20 Mi.-1976
Line 47	Mahtowa 430F 23 kV (MM)	4 Mi.-1968
Line 68	Milaca 5BN2-Isle -Vineland 57NB1 69 kV (MI, JX, PO)	33 Mi.-1970-75
Line 69	Cromwell 18NB2-Gowan 118NB1 69 kV (CV, RL)	38 Mi.-1959; 18 Mi.-1965
Line 83	Four Corners 40NB1-Gowan 69 kV (GL, GS, GST)	10 Mi.-1978
Line 262	Ogilvie 3NB1–Isle 56NB2 69 kV (RO)	24 Mi.-1970
Line 277	Bear Crk 210NB4-Cromwell-Sandstone (PD, KC, KS)	14 Mi.-1952; 34 Mi.-1959-79
Line 278	Bear Crk 210NB3-Pine City-Hinckley 69 kV (PA, PD)	4 Mi.-1962

Although there is some old transmission line in this region, its reliability has been better than the GRE average. The good reliability should continue with planned additional improvements in the area. The maintenance reports show the BW line from Dairyland to Wascott (Line 43 – Frog Creek) among lines with the highest maintenance due to high numbers of pole condition incidents.

Line 44 from Fond du Lac was a 25 mile radial 46 kV line serving three substations. The three substations were converted to 69 kV in 2005 and supplied from Stinson. In early 2007, the Fond du Lac 46/69kV was completed to provide a back-feed source for the three substations.

The Mud Lake–Wilson Lake 115 kV line and Wilson Lake 115/69 kV source will provide a new breaker station northwest of Mille Lacs Lake. This will further reduce line exposure in the area.

The Kettle River-Cromwell and Wilson Lake-Spirit Lake 69 kV lines were rebuilt in 2007.

Future Development

Load Forecast

The following forecast is the load served by the transmission system in the area. This load includes GRE and MP load.

Central MN Region Load (in MW)

Season	2011	2021	2031
Summer	165.2	240.7	385.8
Winter	205.0	305.9	399.3

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- The Mud Lake-Wilson Lake 115 kV project is scheduled for completion in 2008.
- ECE has proposed a North Milaca substation that is planned to be served off the Milaca-Rum River 69 kV line. The expected ISD is 2012.
- LCP has proposed a Big Sandy substation that is planned to be served off a 69 kV radial line that taps the 69 kV RL line from Round Lake to Palisade. The expected ISD is 2015.
- MLEC has proposed a Riverside Point substation that is planned to be served off a 3.0 mile, 115 kV radial line that taps the MP Riverton-Aitkin 115 kV line. The expected ISD is 2015.
- MLEC has proposed a Wealthwood substation that is planned to be served off the 69 kV system near Spirit Lake Switch. The expected ISD is 2016.

Head of the Lakes Area

The Head of the Lakes area is served from the Stinson 115/69 kV and Frog Creek 161/69 kV sources. The loads served from these substations are on long radial lines. Frog Creek also has a dedicated breaker to serve the Dahlberg system. There is a 69/46 kV transformer at Fond du Lac that serves as an emergency tie into the Stinson area. A 7 MVA, 161/69 kV at Frog Creek is kept as a spare as this is a fairly unique transformation. This transformer sits at the site for replacement for failure of main transformer. The use of this transformer is dedicated only to GRE load served from this bus. Allowing for 125% loading, this transformer will meet the load through 2021 projected in the LRP. Dahlberg also has made a commitment to potentially have their generation pick up some of the HLEC Load out of Frog Creek. The following is the load projections in MW that are served from this system, which contains only GRE load:

Season	2011	2021	2031
Summer	10.5	13.1	16.6
Winter	15.9	22.5	31.9

Long-term Deficiencies

No long-term deficiencies are noticed with the projected LRP loads.

Alternatives

With the radial aspect of this load and the growth that is projected on this system, another source to the area would enhance the system greatly. However establishing a new line to this area will have a significant environmental impact and would also involve many miles of line. Due to the distance in line construction, maintaining voltages may be difficult.

The emergency transformer will be functional for the Frog Creek source through 2021 based on LRP projected loading. However, additional emergency transformation capacity will be needed in the 2021-2031 time frame. GRE will monitor the load growth on the Frog Creek radial system to ensure that sufficient emergency transformation is maintained.

The emergency transformer at Fond du Lac is capable of serving the Stinson area load through 2021 but is unable to hold acceptable voltages in 2031 upon failure of the Stinson 115/69 kV transformer. Both the Fond du Lac 69/46 kV and Thomson 115/46 kV transformers overload for this outage as well. GRE is investigating the purchase of an emergency 115/69 kV transformer that would be dedicated to transformer failures. This would eliminate the long-term aspect of

potential failures. Line failures are assumed to be able to be repaired in a much timelier manner compared to complete failure of a transformer.

Since there are no deficiencies reported for this area, no projects will be submitted, as the necessity is not there.

Generation Options

Generation is an attractive alternative for this radial transmission system. It will also be able to provide for a second source into the area. Based on the load projections, GRE will be looking at about a 10 MW turbine on the Frog Creek radial and a 25 MW turbine on the Stinson radial. Ideally, generation should be sized such that it will be capable of serving future load, voltage support, and in an island condition. Costing of generation is beyond the scope of this study, therefore no estimates are included.

Present Worth

Since no counter options were developed no present worth analysis was needed.

Viability with Growth

If the load grows at a faster rate than projected, GRE may need to place some capacitors at the end of the radial lines to account for voltage drop. Otherwise, no capacity issues are expected at this time.

Bear Creek Area

The Bear Creek area covers the load served on:

- The Cromwell-Bear Creek-Pine City 69 kV line
- The Mahtowa-Sandstone-Thomson 46 kV line

Moose Lake Municipal has three generators that are available for picking up some of the load and providing some voltage support. The main support to the area is through the Bear Creek substation. MP has indicated that they are looking at potential normally open switches on their 46 kV system, however for this study GRE will still consider the system as being closed through. GRE will continue to operate the 69 kV system with all lines closed through.

The following is the load projections that are served from this system which contain both GRE and MP load:

Season	2011	2021	2031
Summer	59.3	78.1	128.8
Winter	74.6	107.3	136.6

Long-term Deficiencies

The critical outage in this area is the Kettle River to Cromwell 69 kV outage, which causes voltage deficiencies at the Sturgeon Lake 69 kV bus in 2011. Another contingency of concern is the Bear Creek 230/69 kV transformer outage as this transformer provides the main system support for this area.

Alternatives

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

Option 1: 230/69 kV source to serve Moose Lake and Sturgeon Lake area

With a new source to serve Moose Lake and Sturgeon Lake, the loss of the Kettle River to Cromwell 69 kV line would not be as severe as this would provide another source to serve the area. However, this source does not adequately resolve the 69 kV voltage problems seen for the loss of the Bear Creek transformer. The addition of a 15 MVAr capacitor bank at the Bear Creek 69 kV bus would hold the voltage to acceptable levels. Rebuilding the Kettle River-Denham-Harry Maser 69 kV line would alleviate overloads on this section of line as well as help with area voltages as this line is constructed with small conductor.

The effect of replacing the existing 60 MVA Bear Creek 230/69 kV transformer with a 70 MVA unit is examined as part of the analysis as a 70 MVA unit is a better fit for the Bear Creek site and would allow for the 60 MVA unit to be used for the Effie 230/69 kV project (see Study Area B – ***Northern Lakes Region*** for more info).

Option 1A: Assume 230/69 kV source with existing 60 MVA Bear Creek transformer

Estimated Year	Facilities	Cost
2009	Sandstone Tap to Sandstone MP, 0.93 Mile, 69 kV temperature upgrade	$74,400
2011	Moose Lake Area 140 MVA 230/69 kV source	$5,790,600
2011	Moose Lake Bulk-Sturgeon Lake, 4 mile, 336 ACSS 69 kV line	$1,360,000
2018	Bear Creek 15 MVAR 69 kV cap bank	$275,000
2024	Denham to Kettle River, 15.16 Mile, 336 ACSS 69 kV rebuild	$5,306,000
2027	Harry Maser to Denham, 8.3 Mile, 336 ACSS 69 kV rebuild	$2,905,000

Option 1B: Assume 230/69 kV source with replacement 70 MVA Bear Creek transformer

Estimated Year	Facilities	Cost
2009	Sandstone Tap to Sandstone MP, 0.93 Mile, 69 kV temperature upgrade	$74,400
2011	Bear Creek - Replace existing 60 MVA transformer with 70 MVA unit	$2,101,246
2011	Moose Lake Area 140 MVA 230/69 kV source	$5,790,600
2011	Moose Lake Bulk-Moose Lake Muni, 4 miles, 336 ACSS 69 kV line	$1,360,000
2018	Bear Creek 15 MVAR 69 kV cap bank	$275,000
2024	Denham to Kettle River, 15.16 Mile, 336 ACSS 69 kV rebuild	$5,306,000
2027	Harry Maser to Denham, 8.3 Mile, 336 ACSS 69 kV rebuild	$2,905,000

Both Options 1A and 1B show similar results over the LRP timeframe, but a 70 MVA transformer at Bear Creek will extend the period of time before further Bear Creek area upgrades need to be made.

Option 2: Sturgeon Lake to Sandstone 69 kV line with a 2nd Bear Creek Transformer

The addition of a 25 mile 69 kV line from Sturgeon Lake to Sandstone would provide another tie from Bear Creek into the Moose Lake area and would help to provide support upon loss of the Cromwell source. The 69 kV line feeding the Sandstone substation would be reconfigured by removing its three-way switch connection on one of the Bear Creek 69 kV outlets and connecting it directly to the Bear Creek 69 kV bus. A second Bear Creek 230/69 kV transformer would help to alleviate overloading on the existing unit and ensure adequate system support throughout the LRP time frame.

Option 2: Sturgeon Lake-Sandstone 69 kV line

Estimated Year	Facilities	Cost
2009	Sandstone Tap to Sandstone MP, 0.93 Mile, 69 kV temperature upgrade	$74,400
2011	Sandstone to Sandstone Switch, 3.99 Mile, 69 kV temperature upgrade	$319,200
2011	Sandstone Switch-Bear Creek 69 kV line and breaker termination	$746,500
2011	Sturgeon Lake-Sandstone, 25 mile, 336 ACSS, 69 kV line	$8,010,000
2024	Second Bear Creek 60 MVA 230/69 kV transformer	$2,638,600

Generation Options

Additional generation at Moose Lake Municipal or a new plant at Sturgeon Lake will enhance the radial aspect of the system that serves these substations, although any additional generation would be limited to the capacity of the radial transmission line. Based on the transmission issues in this area, other generation options do not seem to defer any transmission investment.

Present Worth

A cost analysis was performed on each option with line losses evaluated for the Bear Creek area with Option 2 being the benchmark for loss savings. The loss savings in MW for Option 1 are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
1A	-0.8	-1.8	-1.8
1B	-0.8	-1.8	-1.8

With the loss allocations, the present worth is summarized as follows (in 1000's)

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1A	$35,232	$32,398	$24,437
1B	$38,044	$37,142	$29,181
2	$19,765	$25,455	NA

Option 2 involves the least amount of investment, although the present worth value with loss savings for Option 1A is slightly less than Option 2. Option 2 is the preferred option at this time.

Viability with Growth

Option 2 provides the system with redundancy at the major source for the area. Placing a second transformer at Bear Creek will also provide support farther south to Pine City and Rush City than a new source at Moose Lake would. The Sandstone-Sturgeon Lake 69 kV line would also allow for more flexibility in serving new distribution substations as development occurs along the I-35 corridor.

Mille Lacs Area

The Mille Lacs area consists of the load served between Riverton and Milaca with most of this load being located on a 69 kV loop that surrounds Mille Lacs Lake. The soon-to-be-completed Mud Lake-Wilson Lake 115/69 kV project will provide another 69 kV source into the middle of the region. The loads around the lake have continued to grow and are expected to grow especially on the west side of the lake including the major load of the Mille Lacs Casino, which is served from the Vineland substation. The following is the load projections that are expected for this system, which contains only GRE load:

Season	2011	2021	2031
Summer	59.1	98.7	172.9
Winter	59.6	96.8	128.7

Load growth is causing the need for several new distribution substation additions being planned by MLEC and ECE over the LRP time frame. GRE's interconnection costs are depicted in the following table.

Estimated Year	Facility	Cost
2012	North Milaca 2-way, 69 kV switch	$140,000
2015	Riverside Point 3.0 mile, 336 ACSR, 115 kV line	$1,549,000
2016	Wealthwood Substation 3-way 69 kV switch	$140,000

Area Deficiencies

The system deficiencies in the area are mainly voltage related issues that stem from loss of Wilson Lake 115/69 kV source and the Milaca-Onamia 69 kV line.

Line Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Riverton 115/69 kV transformer	56	2015	42.6	77.6
Riverton-Oak Lawn Tap 69 kV line	45.5	2016	30	61.6
Spirit Lake-Spirit Lake Switch 69 kV line	9.7	2016	7.4	11.6

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Pine Center 69 kV	2017	97.8	86.7
Vineland 69 kV	2017	98.1	87.3
Onamia 69 kV	2019	96.8	90.1
Glen 69 kV	2020	99.2	91.2
Spirit Lake 69 kV	2020	99.0	90.8
Isle 69 kV	2021	97.6	91.6
Opstead 69 kV	2021	99.3	91.8

The Riverton 115/69 kV transformer loading is temporarily relieved by the Macville-Blind Lake 115 kV project (identified in the ***Northern Lakes Area*** – Study Area B). This defers the need for Riverton transformer loading relief until 2022.

Alternatives

Alternatives look at establishing a second source into the Mille Lacs loop as loads on the west side of Mille Lacs Lake continue fast-paced growth over the LRP time period.

Option 1: Pierz-Harding-Wilson Lake 115 kV development

This option would establish a new 230/115 kV source on the Mud Lake-Benton County 230 kV line. A 35 mile 115 kV line from this substation would connect in the Wilson Lake substation and provide a loop for a new Harding 115/69 kV substation on the southwest side of Mille Lacs Lake. The Vineland-Rum River Tap 69 kV line would be tapped and a new 10 mile 69 kV double circuit line would tie the Mille Lacs loop to the Harding substation. The Lastrup and Wilson Lake distribution substations also would be converted to 115 kV operation and a third 69 kV source would be brought into Onamia via a new line from the Rum River 69 kV tap switches.

Option 1: Pierz-Harding-Wilson Lake 115 kV development

Estimated Year	Facility	Cost
2016	Spirit Lake-Spirit Lake Tap 1.81 mile 69 kV temperature upgrade	$144,800
2016	Riverton-Oak Lawn Tap 7.24 mile, 266 ACSS, 69 kV reconductor	$579,200
2017	Pine Center 9.0 MVAr, 69 kV Cap Bank	$251,000
2022	Pierz 300 MVA, 230/115 kV source	$8,755,000
2022	Pierz-Lastrup-Harding 9 mile, 795 ACSS, 115 kV line	$3,762,000
2022	Harding-Wilson Lake 14 mile, 795 ACSS, 115 kV line	$5,852,000
2022	Pine Center-Wilson Lake 11.72 mile, 795-336 ACSS, 115-69 kV double circuit line	$5,848,280
2022	Lastrup convert distribution sub to 115 kV operation	$515,000
2022	Harding 140 MVA, 115/69 kV source	$4,404,835
2022	Harding-PO Line double circuit 10 miles, 336 ACSS, 69 kV line	$4,357,500
2023	Onamia 69 kV line sectionalizing	$494,000
2027	Wilson Lake - convert distribution sub to 115 kV operation	$705,000

Option 2: Milaca-Onamia 115 kV development

This option looks at providing another 69 kV source on the south side of Mille Lacs Lake by creating a 230/115 kV source at Milaca and building a 20 mile Milaca-Onamia 115 kV line. A 115/69 kV transformation would be placed at Onamia and the Rum River 69 kV tap switches would be eliminated as the lines would be reconfigured to bring the Vineland-Rum River Tap 69 kV line into the Onamia substation. A Wilson Lake-McGregor 115 kV line would also be built to support both the Wilson Lake substation and the Cromwell area (see the ***Gowan-Cromwell Area*** in this report section). The Spirit Lake distribution substation would eventually be placed on the 115 kV system to improve 69 kV system voltages.

Option 2A: Milaca-Onamia 115 kV development.

Estimated Year	Facility	Cost
2012	Wilson Lake-McGregor 45 mile, 795 ACSS, 115 kV line	$22,368,150
2016	Spirit Lake-Spirit Lake Tap 1.81 mile 69 kV temperature upgrade	$144,800
2017	Pine Center 9.0 MVAr, 69 kV cap bank	$251,000
2022	Milaca 300 MVA, 230/115 kV source	$5,591,000
2022	Milaca-Onamia 20 mile, 795 ACSS, 115 kV line	$9,065,000
2022	Onamia 140 MVA, 115/69 kV source	$4,894,835
2023	Riverton-Oak Lawn Tap 69 kV reconductor	$579,200
2027	Spirit Lake - convert distribution sub to 115 kV operation	$1,312,750

Option 2B addresses the possibility that the Wilson Lake-McGregor 115 kV line may be installed for the needs of the ***Gowan-Cromwell Area***.

Option 2B: Milaca-Onamia 115 kV development – Assume Wilson Lake-McGregor 115 kV line is in-service.

Estimated Year	Facility	Cost
2016	Spirit Lake-Spirit Lake Tap 1.81 mile 69 kV temperature upgrade	$144,800
2017	Pine Center 9.0 MVAr, 69 kV cap bank	$251,000
2022	Milaca 300 MVA, 230/115 kV source	$5,591,000
2022	Milaca-Onamia 20 mile, 795 ACSS, 115 kV line	$9,065,000
2022	Onamia 140 MVA, 115/69 kV source	$4,894,835
2023	Riverton-Oak Lawn Tap 69 kV reconductor	$579,200
2027	Spirit Lake – convert distribution sub to 115 kV operation	$1,312,750

Generation Options

Projected loads for the Mille Lacs area make placing generation here uneconomical, thus generation options were not considered.

Present Worth

A cost analysis was performed on each option with line losses evaluated with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0	-0.6	2.3

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$90,588	$70,493	-
2A	$88,154	$92,697	$98,366
2B	$56,424	$43,028	$48,697

Based on the present worth values, either Option 1 or Option 2B seem to be the best options for the area. Given the fact that the Wilson Lake-McGregor 115 kV line is not the preferred option for the ***Gowan-Cromwell Area***, Option 1 is the least cost plan for this area.

Viability with Growth

Option 1 provides another strong tie to the Wilson Lake substation and adds another source to the 69 kV system near the major area loads. A source at Pierz also can be tied into the Little Falls area to strengthen the regional 115 and 34.5 kV systems and to convert some of the GRE 34.5 kV distribution loads to 115 kV (see Report Section C – ***GRE-MP 34.5 kV Region*** for more details). Furthermore, the Onamia 115/69 kV source would likely have to be looped in at some point in the future for voltage support upon loss of the Milaca-Onamia 115 kV line. This line would be long in length as no 115 kV sources are currently established in the area.

Gowan-Cromwell Area

The Gowan-Cromwell Area consists of the load served between the Cromwell and Four Corners 115/69 kV sources and between the Thomson and Riverton 115 kV substations. The 69 kV system consists of two long radials extending from the Cromwell-Four Corners loop including a 29.0 mile line ending at Palisade and 17.6 mile line ending at Cedar Valley. The Palisade radial serves a fairly large amount of load resulting in the fourth highest radial mile exposure. The following is the load that is expected to be served from this system, which contains only GRE load:

Season	2011	2021	2031
Summer	36.3	50.8	67.5
Winter	54.9	79.3	102.1

The following table depicts the new load connections that will be provided for this area:

Estimated Year	Facility	Cost
2015	Big Sandy 3.0 miles, 336 ACSR, 69 kV line	$1,880,000

Area Deficiencies

This area suffers from both low voltage problems and thermal overloading issues as the transmission lines are rather old and constructed of small conductor. The Cromwell area 115 kV system also experiences low voltages upon loss of the Thomson 115 kV source. MP has also indicated a need to rebuild the Riverton-Thomson 115 kV line so another 115 kV line into the system would be required before this can occur.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Four Corners 115/69 kV transformer	28	2010	35.6	63.0
Cromwell-Cromwell Distribution 69 kV	36.9	2010	38.6	59.4
Four Corners-Solway 69 kV	35.9	2010	38.5	65.2
Cromwell-Wright 69 kV	9.7	2011	9.7	14.5
Cromwell Distribution-Gowan 69 kV	26.8	2014	20.0	42.7
Wright-Round Lake 69 kV	9.7	2018	6.4	10.8
Cromwell 115/69 kV transformer	56	2020	23.3	79.1

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Round Lake 69 kV	2009	85.7	54.0
Wright 69 kV	2010	88.1	60.2
Palisade 69 kV	2010	85.3	52.8
Cromwell Distribution 69 kV	2011	90.2	65.5
Grand Lake 69 kV	2011	91.5	77.9
Solway 69 kV	2011	91.3	77.5
Cromwell 69 kV	2011	89.4	41.4
Branden Road 69 kV	2012	92.3	80.5
Cedar Valley 69 kV	2013	94.8	78.7
Gowan 69 kV	2014	95.6	80.3
Lakehead Gowan 69 kV	2014	95.8	81
Peterson 24 kV	2017	94.4	90.0
McGregor 115 kV	2019	95.2	91.2

The Gowan area is in need of a new source as this area has capacitors at almost every substation in the area. As recommended by the previous LRP, a new Floodwood 115/69 kV substation will be established in 2010 and provide a third source into the Gowan area system.

Estimated Year	Facility	Cost
2010	Floodwood 28 MVA 115/69 kV source	$2,465,000
2010	Floodwood 69 kV outlets	$488,000

With the addition of the Floodwood 115/69 kV source and the area LTCs adjusted to give a 1.045 pu low side voltage, the area deficiencies are as follows.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Floodwood-Gowan 69 kV	8.7	2010	16.3	20.2
Cromwell Distribution-Wright 69 kV	9.7	2012	9.3	13.3
Gowan SS-Cromwell Distribution 69 kV	24.3	2015	19.7	30.9
Wright-Round Lake 69 kV	9.7	2018	7.6	11.2

Voltage Deficiencies (LTC Adjusted)

Substation	Estimated Year	2011 %	2021 %
Palisade 69 kV	2012	92.8	81.0
Round Lake 69 kV	2012	93.0	82.6
Wright 69 kV	2015	95.2	86.9
Cromwell Distribution 69 kV	2019	97.0	90.4

Alternatives

Alternatives look at rebuilding the area transmission lines to higher capacity construction and providing another 115 kV source into the Thomson-Riverton 115 kV system via a Floodwood-Cromwell 115 kV line or a Wilson Lake-McGregor 115 kV line. The Floodwood-Cromwell line would tie back to the 230/115 kV sources at Arrowhead and Blackberry while the Wilson Lake-McGregor line would tie back to the 230/115 kV source at Mud Lake.

Option 1: Floodwood-Cromwell 115/69 kV double circuit line

This option would replace the existing Floodwood-Cromwell 69 kV path with a new 29 mile 115-69 kV double circuit line. A rebuild of the Cromwell Distribution-Wright-Round Lake 69 kV line would be done to eliminate thermal loading issues seen on this section of line and to improve voltage drop issues.

Option 1: Floodwood-Cromwell 115/69 kV double circuit.

Estimated Year	Facility	Cost
2012	Floodwood-Gowan SS-Cromwell 29 mile, 795-336 ACSS, 115-69 kV double circuit rebuild	$16,071,000
2012	Floodwood 115 kV Breaker and Deadend	$500,000
2012	Cromwell 115 kV Breaker and Deadend	$500,000
2012	Gowan SS Breaker Addition for Floodwood 69 kV	$215,000
2012	Cromwell Dist.-Wright 7.31 mile, 336 ACSS, 69 kV line rebuild	$1,717,850
2018	Wright-Round Lake 69 kV 10.96 mile, 336 ACSS, 69 kV line rebuild	$2,575,600

Option 2: Floodwood-Cromwell 69 kV rebuild and Wilson Lake-McGregor 115 kV line.

This option connects the Wilson Lake and McGregor 115 kV lines with a 45 mile, 115 kV line, a portion of which would be double circuited with the Wilson Lake-Spirit Lake Tap-Glen 69 kV line. The Floodwood-Gowan-Cromwell Distribution 69 kV line is rebuilt to address thermal loading and voltage issues upon loss of the Cromwell source. The Cromwell Distribution-Palisade 69 kV area issues are resolved through a resag of the Cromwell Distribution-Wright-Round Lake 69 kV line and through a new 115/69 kV source at McGregor. A new McGregor-Round Lake 69 kV line would connect this source to the Palisade area. Furthermore, a 28.8 MVAr capacitor bank at McGregor will help alleviate voltage issues seen on the 115 kV system.

Option 2: Floodwood-Cromwell 69 kV rebuild and Wilson Lake-McGregor 115 kV line.

Estimated Year	Facility	Cost
2010	Floodwood-Gowan SS 9.48 mile, 336 ACSS, 69 kV rebuild	$2,554,550
2012	Gowan-Cromwell Dist. 13.8 mile, 336 ACSS, 69 kV rebuild	$3,478,200
2012	Wilson Lake-McGregor 45 mile, 795 ACSS, 115 kV line	$22,368,150
2012	Cromwell Dist.-Wright 7.31 mile 69 kV temperature upgrade	$731,000
2012	Wright-Round Lake 10.96 mile 69 kV temperature upgrade	$1,096,000
2023	McGregor 140 MVA, 115/69 kV source	$3,619,500
2026	McGregor 28.8 MVAr, 115 kV capacitor bank	$295,600

Generation Options

The Gowan Switching station would be a location for potential generation plant in that it will put a voltage source in the middle of the system thus allowing for support when either end of the system is loss. Even with this benefit, transmission investment would be very competitive making generation difficult to justify.

Present Worth

A cost analysis was performed on each option with line losses evaluated with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	0.1	-1.5

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$35,868	$53,049	-
2	$58,833	$78,794	$77,258

Option 1 is the least cost plan and requires the least amount of investment.

Viability with Growth

Option 2 has limited availability for growth past the 2031 summer peak. The area 115 kV summer peak voltages rapidly deteriorate beyond 2031 and a solution would have to be found by 2036. Given the limitations in providing new sources to the area, the likely solution would be the Floodwood-Cromwell 115 kV line. Furthermore, the Floodwood substation has a 230 kV line in the vicinity that can be tapped for a new source into the 115 kV system which should provide good voltage support if needed. Option 1 will also loop in MP's Floodwood load, which is rather large due to a pumping station and is currently served off of a long radial line. Option 1 uses existing corridor for new transmission investment while Option 2 will require significant new corridor acquisition. As the load grows on the Cromwell Distribution-Palisade 69 kV line, a new Kimberly or McGregor 115/69 kV source may still be a viable option to provide looped service to this long radial line.

Further Considerations

Accounting for the fact that the Wilson Lake-McGregor 115 kV line is considered for a solution for both the ***Mille Lacs Area*** and the ***Gowan-Cromwell Area***, a cost analysis was performed for a combination of both area solutions. Combining the Pierz-Harding-Wilson Lake 115 kV development with the Floodwood-Cromwell 115-69 kV development and the Milaca-Onamia 115 kV development with the Wilson Lake-McGregor 115 kV development, the present worth analysis is as follows.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
Pierz-Wilson Lake+ Floodwood-Cromwell	$126,456	$123,542	-
Milaca-Onamia+ Wilson Lake-McGregor	$115,257	$121,822	$125,955

With loss savings taken into consideration, the Pierz-Wilson Lake+Floodwood-Cromwell 115 kV development is the least cost option. This option also has the added benefit of supporting the Little Falls 115 kV system through the Pierz source.

Recommended Plan

The following are the recommended facilities to be installed in the Central MN Region.

Estimated Year	Responsible Company	Facility	Cost
2009	GRE	Sandstone Tap to Sandstone MP, 0.93 Mile, 69 kV temperature upgrade	$74,400
2010	GRE	Floodwood 28 MVA 115/69 kV source	$2,465,000
2010	GRE	Floodwood 69 kV outlets	$488,000
2011	GRE	Sandstone to Sandstone Switch, 3.99 Mile, 69 kV Temperature Upgrade	$319,200
2011	GRE	Sandstone Switch-Bear Creek 69 kV line and breaker termination	$746,500
2011	GRE	Sturgeon Lake-Sandstone Line 25 mile, 336 ACSS, 69 kV line	$8,010,000
2012	GRE	North Milaca 2-way 69 kV switch	$140,000
2012	ECE	North Milaca 69 kV Distribution Substation	$350,000
2012	GRE	Floodwood-Gowan SS-Cromwell 29 mile, 795-336 ACSS, 115-69 kV double circuit rebuild	$16,071,000
2012	GRE	Floodwood 115 kV Breaker and Deadend	$500,000
2012	GRE	Cromwell 115 kV Breaker and Deadend	$500,000
2012	GRE	Gowan SS Breaker Addition for Floodwood 69 kV	$215,000
2012	GRE	Cromwell Dist.-Wright 7.31 mile, 336 ACSS, 69 kV line rebuild	$1,717,850
2015	GRE	Riverside Point 3.0 mile, 336 ACSR, 115 kV line	$1,549,000
2015	MLEC	Riverside Point 115 kV Distribution Substation	$350,000
2015	GRE	Big Sandy 3.0 mile, 336 ACSR, 69 kV line	$1,880,000
2015	LCP	Big Sandy 69 kV Distribution Substation	$350,000
2016	GRE	Wealthwood Substation 3-way 69 kV switch	$140,000
2016	MLEC	Wealthwood 69 kV Distribution Substation	$350,000
2016	GRE	Spirit Lake-Spirit Lake Tap 1.81 mile 69 kV temperature upgrade	$144,800
2016	GRE	Riverton-Oak Lawn Tap 7.24 mile, 266 ACSS, 69 kV reconductor	$579,200
2017	GRE	Pine Center 9.0 MVAr, 69 kV Cap Bank	$251,000
2018	GRE	Wright-Round Lake 69 kV 10.96 mile, 336 ACSS, 69 kV line rebuild	$2,575,600
2022	GRE	Pierz 300 MVA, 230/115 kV source	$8,755,000
2022	GRE	Pierz-Lastrup-Harding 9 mile, 795 ACSS, 115 kV line	$3,762,000
2022	GRE	Harding-Wilson Lake 14 mile, 795 ACSS, 115 kV line	$5,852,000
2022	GRE	Pine Center-Wilson Lake 11.72 mile, 795-336 ACSS, 115-69 kV double circuit line	$5,848,280
2022	GRE	Lastrup distribution sub conversion to 115 kV operation	$515,000
2022	GRE	Harding 70 MVA, 115/69 kV source	$4,404,835
2022	GRE	Harding-PO Line double circuit 10 mile, 336 ACSS, 69 kV line	$4,357,500
2023	GRE	Onamia 69 kV line sectionalizing	$494,000
2024	GRE	Second Bear Creek 70 MVA 230/69 kV transformer	$2,638,600
2027	GRE	Wilson Lake distribution sub conversion to 115 kV operation	$705,000

E: North Suburban Region

The North Suburban region is located in the northern Twin Cities suburbs. It is bounded by Saint Cloud to the west, Pine City to the north, the Wisconsin border to the east, and Mississippi River to the south. The member systems that serve this territory are:

- Connexus Energy (CE)
- East Central Energy (ECE)

Connexus Energy serves approximately 114,000 customers in the North Twin Cities Metropolitan area, making it Great River Energy's largest member distribution cooperative. The co-op, which has approximately 260 employees, was established in 1937. Connexus Energy serves portions of Anoka, Chisago, Hennepin, Isanti, Ramsey, Sherburne, and Washington Counties.

East Central Energy (ECE) serves over 54,000 homes, farms and businesses in east central Minnesota and northwestern Wisconsin. It serves portions of the counties of Benton, Morrison, Mille Lacs, Sherburne, Isanti, Chisago, Washington, Kanabec, Pine, Aitkin, and Carlton in Minnesota and Douglas and Burnett in Wisconsin.

The region's southern area is primarily a suburban economy, influenced by the growth of the Twin Cities metropolitan area. The northern area economy is largely agriculture with some light industrial activity. The northern area has seen in influx of residential growth as cities and small town continue to expand with residential growth.

Existing System

The load in the region is served by the 69 kV network except for two 115 kV substations at Vadnais Heights and Crooked Lake. A semi-loop of 230 kV lines surrounds the circumference of the 69 kV grid. The 230 kV bulk power sources which serve the 69 kV network are located at Milaca, Benton County, Elk River, Bunker Lake, Blaine, and Rush City. Two 115 kV bulk sources at Parkwood and Liberty also serve the 69 kV networks. The Parkwood substation is double ended and served by a 115 kV loop from Coon Creek while the Liberty substation is located near the Sherco generating plant in Becker.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 33	Benton Co. 41NB13 - Milaca 5NB3 (BP, JC, JX, MP, WG, WGT)	Rank: 4
Line 6	Blaine 23NB5 - Rush City 9NB2 (HU, MA, NU, RH, RHX, RX)	Rank: 13
Line 38	Cambridge 2NB3 - Princeton 8NB2 (DT, OP)	Rank: 35
Line 3	Elk River 14NB3 - Princeton 8NB1 69KV (CO-ELX, EB,EL, ELT)	Rank: 42
Line 31	Milaca 5NB1 - Princeton 8NB1/8NB2 (BCX, BM, OL)	Rank: 43
Line 10	Becker 50NB2 - Elk River 14NB9 69KV (EW,EWT)	Rank: 47
Line 15	Arden Hills 4P92 - St. Croix Falls 4A37	Rank: 50

Transmission Lines Built before 1980

Line 33	Benton Co. 41NB13- Milaca (JC, JX, MP, MPT, WG)	19 Mi.-1948; 27 Mi.-1967-70
Line 6	Blaine 23NB5-Rush City 69KV (HU, NU, RH, RHX, RX)	2 Mi.-1950; 41 Mi.-1972-76
Line 38	Cambridge 2NB3-Princeton 8NB2 69KV (DT, OP)	1 Mi.-1970
Line 3	Elk River 14NB3– Princeton 69KV (EB, EL, ELT)	20 Mi.-1950
Line 31	Milaca 5NB1- Princeton 69KV (BCX, BM, OL)	2 Mi.-1949; 9 Mi.-1975
Line 10	Becker 50NB2- Elk River 14NB3 69KV (EW, EWT)	21 Mi.-1966-67
Line 1	Elk Rvr 14NB1- Soderville - Bunker L (EPX, ES, PSX)	15 Mi.-1950; 3 Mi.-1969-74
Line 2	Bunker Lake 30NB10/11 - Elk River 6NB4 (EP, EPX)	10 Mi.-1969-70; 5 Mi.-1974
Line 7	Blaine 23NB2 - Soderville 7NB3 69KV (SP)	11 Mi.-1950
Line 8	Becker 50NB1- Benton Co. 69KV (BG, CB, EW)	4 Mi.-1966; 9 Mi.-1978
Line 9	Parkwood 12NB2 69KV (CR)	8 Mi.-1965
Line 11	Bunker Lake 30NB11/14- Parkwood 12NB5 (PEX)	3 Mi.-1969
Line 12	Parkwood 12NB1 - Soderville 69KV (PRX, PS, PSX)	12 Mi.-1970-71
Line 13	Parkwood 12NB6 – Cedar Island 69KV (PCX, SL)	8 Mi.-1954; 1 Mi.-1969
Line 36	Pine City 4NB1- Rush City 69KV (CP, CPT, PX, TR)	15 Mi.-1950; 4 Mi.-1972
Line 37	Grasston 15NB2-Milaca-Ogilvie 69KV (MT, PG)	36 Mi.-1957; 2 Mi.-1966
Line 264	Pine City 4NB3 – Grasston 15NB1/2 69KV (PG)	9 Mi.-1957
Line 280	Blaine 23NB3 - Parkwood 12NB3 69KV (SL, CO-SLX)	9 Mi.-1954; 12 Mi.-1965
Line 281	Blaine 23NB4 69KV (CO-SLX, SP, CH)	1 Mi.-1950; 12 Mi.-1965
Line 314	Soderville 7NB2- Athens 204NB3/4 69KV (SC, CO-EBT)	12 Mi.-1950
Line 315	Cambridge 2NB1- Athens 204NB2/4 69KV (SC, IT, SCT)	3 Mi.-1964

The overall reliability for this region is better than the GRE average. Some of the lines show up on the list of the worst composite reliability because of the high number of consumers/high load supplied by the substations in this area. However, there is a significant amount of older transmission line in this area; some of which may need to be replaced due to age within the timeframe of this Long-Range Plan. The PG line from Pine City to Milaca has a high number of maintenance incidents, mainly related to pole condition or insulators; and the SP line from Soderville to Blaine also had a significant number of pole condition incidents. Other maintenance information is covered with the following line-specific reliability discussions.

Line 33 from Benton County to Milaca is a 59 mile 69 kV line serving five substations. Its reliability performance places it solidly among the worst 50 lines for each of the six indices used; with number 2 rankings for both consumer minutes out and lost energy sales. The maintenance reports do not show much maintenance on this line, although the JC section had a few maintenance incidents related to insulators and trees. The JC line was built in 1948. It is also planned to add remote control at the Mayhew tap switches to improve outage restoration for this line.

Line 6 from Blaine to Rush City is a 54 mile 69 KV line serving seven substations (counting two double-ended substations separately). Its performance is worse than the GRE average on all six indices used, including the worst ranking for consumer-momentaries. The maintenance reports show a high number of incidents on the RH section, mostly pole and woodpecker damage incidents. The new Linwood 230-69 kV substation is planned near Forest Lake for completion in 2008. This line will reduce the exposure of this line to improve the reliability.

Line 38 from Cambridge to Princeton is a 24 mile 69 KV line serving one substation. Its performance is worse than the GRE average on five of the six indices used. This line was rebuilt in 2006.

Line 3 from Elk River to Princeton is a 37 mile 69 kV line serving three substations. The reliability performance for the line is worse than the GRE average on five of the six indices used. The maintenance reports show a relatively high number of incidents on the EL line, mostly pole-rot and woodpecker damage incidents. Most of this line was built in 1950. The line was rebuilt from Elk River to the E.R. Municipal North sub, but more may need to be rebuilt.

Line 31 from Milaca to Princeton is an 11 mile 69 kV line serving one substation. The reliability performance for the line is worse than the GRE average on five of the six indices used. The maintenance reports show a relatively high number of incidents related to pole conditions on the OL line, which was built in 1949. Also the BM line had a number of insulator incidents. There are no recent or planned projects to improve reliability of this line.

Line 10 from Liberty to Elk River is a 21 mile 69 kV line serving three substations. The reliability performance for the line is worse than the GRE average on four of the six indices used. The maintenance reports do not show any significant maintenance activity. A new 69kV Waco breaker station was constructed in 2007 just west of Elk River reducing line exposure on the Liberty-Elk River line.

Line 15 from Arden Hills to St. Croix Falls is a 52 mile 69 kV line serving two substations. The reliability performance for the line is worse than the GRE average on four of the six indices used. Most of this line is owned by Xcel Energy, so the maintenance and age information is not available. There are no recent or planned projects to improve reliability of this line.

Future Development

Load Forecast

The following forecast is the load served by the transmission system in the region. This load includes GRE, Minnesota Municipal Power Agency (MMPA), Elk River Municipal Utilities, and Southern Minnesota Municipal Power Agency (SMMPA) loads.

North Suburban Region Load (in MW)			
Season	2011	2021	2031
Summer	910.1	1299.4	1521.6
Winter	652.5	920.7	1068.9

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- GRE is upgrading its ES line between Elk River S14 and Soderville 69 kV and its EP line between Elk River S6 and RDF Tap 69 kV in 2009 due to the Elk River peaking plant interconnection.
- CE has proposed an Elmcrest substation that will directly tap the Hugo-Forest Lake 69 kV line. The expected ISD is 2009.
- CE has proposed a Round Lake substation that is expected around 2010. This substation will directly tap the Bunker Lake-Ramsey 69 kV line.
- CE has proposed a Rum River substation that is expected around 2010. This substation will directly tap the Athens-St. Francis Tap 69 kV line or be within the Athens substation.

- EC has proposed an Athens substation that is expected around 2012. This substation will be near the Athens breaker substation.
- EC has proposed a Knife Lake substation that is expected around 2014. This substation will be connected by an approximately 8 mile 69 kV line emanating from the Mora switching station.
- EC has proposed a Henriette substation that is expected around 2015. This substation will directly tap the Mora - Grasston 69 kV line.
- CE has proposed a Cornfield substation that is expected around 2015. This substation will be connected to the West End 69 kV substation through an approximately 8 mile long 69 kV line.
- EC has proposed a Brunswick substation that is expected around 2016. This substation will be connected via approximately 10 miles of 69 kV line connecting to the SMMPA Mora Municipal 69 kV substation.
- EC has indicated the need for a Cambridge East substation around 2016. GRE will build 1.75 miles of 69 kV transmission to connect the substation to the Cambridge-Rush City 69 kV line.
- EC has proposed a Pease substation that is expected around 2016. This substation will directly tap the Milaca - Long Siding 69 kV line.
- CE has proposed a Carlos Avery substation that will directly tap the Blaine-Soderville 69 kV line. The anticipated ISD is 2027.

Rush City - Linwood - Blaine Area

This area is served by three 230/69 kV sources at Rush City, Linwood, and Blaine. The total mileage for the transmission lines in this area is 64 miles serving 6 GRE distribution substations. The following is the forecasted load to be served in this area which includes both GRE and SMMPA loads.

Season	2011	2021	2031
Summer	98.1	155.0	193.5
Winter	65.4	102.9	127.0

In order to interconnect the proposed Connexus Energy Elmcrest distribution substation, GRE will install a three-way switch on the Hugo-Forest Lake 69 kV line. GRE's costs for the project are listed in the following table.

Estimated Year	Facilities	Cost
2009	Elmcrest 69 kV 3-way switch	$140,000

Area Deficiencies

The 2008 addition of the Linwood 230/69 kV source provides good voltage support to the area and as such, few voltage problems are seen over the LRP timeframe. Voltage issues in the area are likely the result of weak 230 kV voltages as the LTCs on all three area transformers saturate by the projected 2021 summer peak. Load growth is also taxing the area transformers as overloads are seen on all three area transformers.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Rush City 230/69 kV transformer	84	2014	94.9	144.5
Blaine-Hugo 69 kV	58.8	2017	44.1	71.3
Blaine 230/69 kV transformer	112	2018	103.5	156.4
Linwood-North Branch 69 kV	58.8	2020	43.7	61.7
Linwood 230/69 kV transformer	112	2020	97.4	149.9

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
White Bear Township 69 kV	2020	97.5	91.2
Blaine 230 kV	2018	93.8	87.9
Linwood 230 kV	2019	94.5	88.7

Alternatives

Two alternate options were developed as solutions to the long-range problems that occur in this area. Both focus on additional transformation capacity between the 230 kV and 69 kV systems. The options are as follows:

Option 1: 69 kV Reconductoring

This option involves reconductoring the Blaine-Hugo-Elmcrest 69 kV line and the Linwood-North Branch 69 kV line. The transformer issues are resolved by replacing the Rush City transformer with a 140 MVA unit (as examined in the ***Milaca-Rush City-Linwood-Elk River Area***) and adding a second 230/69 kV transformer at Blaine. Additionally, a 39.6 MVAR capacitor bank is placed at the Blaine 69 kV substation to help with area voltage regulation. The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2017	Blaine-Hugo 6.64 mile, 266 ACSS, 69 kV reconductor	$531,200
2018	Blaine 39.6 MVAR 69 kV capacitor bank	$373,400
2018	Blaine 112 MVA 230/69 kV transformer #2	$3,573,598
2019	Linwood-North Branch 12.19 mile, 266 ACSS, 69 kV reconductor	$1,019,750
2021	Hugo-Elmcrest 2.33 mile, 266 ACSS, 69 kV reconductor	$186,400

Option 2: 69 kV Rebuild

This option involves rebuilding the Blaine-Hugo-Elmcrest 69 kV line and the Linwood-North Branch 69 kV line to 477 ACSS construction. Similar to Option 1, the Rush City transformer would be replaced with a 140 MVA unit and a second 230/69 kV transformer would be placed at Blaine. The 39.6 MVAR capacitor bank would be installed at Blaine 69 kV for voltage support.

The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2017	Blaine-Hugo 6.64 mile, 477 ACSS, 69 kV rebuild	$1,626,800
2018	Blaine 39.6 MVA 69 kV capacitor bank	$373,400
2018	Blaine 112 MVA 230/69 kV transformer #2	$3,573,598
2019	Linwood-North Branch 12.19 mile, 477 ACSS, 69 kV rebuild	$3,031,100
2021	Hugo-Elmcrest 2.33 mile, 477 ACSS, 69 kV rebuild	$570,850

Generation Options
Generation options are not considered in this area.

Present Worth
A cost analysis was performed on each option with line losses evaluated for the Rush City - Linwood - Blaine area with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0	-1.2	-3.2

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$11,572	$11,561	-
2	$18,863	$18,593	$12,232

Option 1 is the least cost plan and it involves the least amount of investment.

Viability with Growth
Option 1 offers a long-term solution for this area in term of load serving capability and reliability. Option 2 should be pursued if it is determined that the area 69 kV lines need to be replaced based on age or loss savings considerations.

Parkwood - Blaine Area
This area is served by the 230/69 kV source at Blaine and the 115/69 kV source at Parkwood. The total mileage of 69 kV transmission is 24 miles and serves 6 GRE distribution substations. The area load forecast is depicted in the following table.

Season	2011	2021	2031
Summer	112.7	144.3	170.8
Winter	77.3	98.9	117.0

Area Deficiencies

Significant load growth is taxing both the 115 kV and 69 kV systems. The loss of Crooked Lake to Champlin Tap 115 kV causes the Coon Creek to Parkwood 115 kV line to overload in 2012 while the loss of either transformer at Parkwood causes the other transformer to overload in 2015. There are also many overloads that occur on various portions the 69 kV system between 2011 and 2021 for loss of a 69 kV tie out of Parkwood.

Alternatives

Four alternate options were developed as solutions to the long-range problems that occur in this area. Please note that each alternative involves a double circuit Coon Creek-Woodcrest-Parkwood 115-69 kV line and that each alternative requires a new source in the area. The options are as follows:

Option 1: New Coon Creek 115/69 kV source and Coon Creek-Hwy 65 SS 69 kV double circuit

This option involves the 115-69 kV double circuit from Coon Creek to Parkwood in 2012 and the addition of a new 115/69 kV source and outlet at Coon Creek installed in 2015. The outlet consists of rebuilding the Coon Creek-Hwy. 65 SS 69 kV line to double circuit 115 kV construction effectively creating a Coon Creek-Northtown-Spring Lake Park-Parkwood 69 kV circuit and a Coon Creek-Airport-Lexington-Blaine 69 kV circuit. Building a double circuit line will help reduce 69 kV system loading through this corridor and provide better sectionalizing and load serving capability while offering the option of future 115 kV conversion.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2012	Coon Creek to Parkwood 3.5 mile, 795-477 ACSS, 115-69 kV double circuit line	$4,765,250
2015	Coon Creek 210 MVA, 115/69 kV source	$4,905,777
2015	Coon Creek-Hwy. 65 SS 3.25 mile, 795 ACSS, 69 kV double circuit rebuild	$3,331,125

Option 2: New Coon Creek 115/69 kV source & Johnsville to Blaine 69 kV line

This option involves the 115-69 kV Coon Creek-Parkwood double circuit and the addition of a new 115/69 kV source at Coon Creek in 2015. The addition of a Johnsville to Blaine 69 kV line would help to greatly reduce loading on the Parkwood-Spring Lake Park and Parkwood-Soderville 69 kV lines while a number of area line reconductors give increased capability of the existing system.

The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2012	Coon Creek to Parkwood 3.5 mile, 795-477 ACSS, 115-69 kV double circuit line	$4,765,250
2015	Coon Creek 210 MVA, 115/69 kV source	$4,905,777
2018	Johnsville to Blaine 4.29 mile, 477 ACSS, 69 kV line	$2,775,313
2021	Spring Lake Park to Hwy 65 SS 1.84 mile, 266 ACSS, 69 kV Reconductor	$147,200
2028	Hwy 65 SS to Lexington 3.21 mile, 477 ACSS, 69 kV rebuild	$770,400
2028	Crooked Lake to Parkwood 3.36 mile, 795 ACSS, 115 kV Reconductor	$436,800
2030	Airport-Northtown-Coon Creek 3.25 mile, 795 ACSS, 69 kV rebuild	$1,017,600

Option 3: 3rd Parkwood transformer & Johnsville to Hwy 65 SS 69 kV line

This option also includes the 115-69 kV double circuit from Coon Creek to Parkwood along with a third 140 MVA Parkwood 115/69 kV transformer. Construction of a Johnsville-Hwy. 65 SS 69 kV line along with a Hwy. 65 69 kV breaker station would provide further support to the Airport substation and relieve contingency loading on the Parkwood-Spring Lake Park 69 kV circuit.

The following is the estimated timeline for Option 3 installations:

Estimated Year	Facilities	Cost
2012	Coon Creek to Parkwood 3.5 mile, 795-477 ACSS, 115-69 kV double circuit line	$4,765,250
2015	Parkwood 140 MVA 115/69 kV transformer #3	$2,293,835
2018	Hwy 65 SS 69 kV breaker station	$3,207,800
2018	Johnsville to Hwy 65 SS 2.25 mile, 795 ACSS, 69 kV line	$2,158,000
2021	Spring Lake Park to Hwy 65 SS 1.84 mile, 266 ACSS, 69 kV Reconductor	$147,200
2028	Crooked Lake to Parkwood 3.36 mile, 795 ACSS, 115 kV Reconductor	$436,800

Option 4: 3rd Parkwood transformer & Hwy 65 breaker station

This option involves the 115-69 kV double circuit from Coon Creek to Parkwood and the addition of a 3rd Parkwood transformer at 140 MVA. The addition of a 69 kV breaker station at the Hwy 65 switches would allow the Airport to Hwy 65 Switch 69 kV line to be closed, providing support to the Airport substation.

The following is the estimated timeline for Option 4 installations:

Estimated Year	Facilities	Cost
2012	Coon Creek to Parkwood 3.5 mile, 795-477 ACSS, 115-69 kV double circuit line	$4,765,250
2015	Parkwood 140 MVA 115/69 kV transformer #3	$2,293,835
2018	Hwy 65 SS 69 kV breaker station	$2,787,800
2024	Spring Lake Park to Hwy 65 SS 1.84 mile, 266 ACSS, 69 kV Reconductor	$147,200
2026	Airport-Northtown-Coon Creek 3.25 mile, 795 ACSS, 69 kV rebuild	$1,378,000
2028	Crooked Lake to Parkwood 3.36 mile, 795 ACSS, 115 kV Reconductor	$436,800

Generation Options

Generation options are not considered in this area.

Present Worth

A cost analysis was performed on each option with Option 4 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	0.2	-2.7
3	0.0	1.7	6.1
4	0.0	2.3	6.9

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$20,676	$27,301	-
2	$27,078	$30,436	$29,018
3	$23,359	$27,858	$41,092
4	$22,658	$25,074	$40,253

Option 1 is the least cost plan when loss savings are considered and involves the least amount of investment.

Viability with Growth

Option 1 offers the best solution for long-term load growth because the 69 kV double circuit can be converted to 115 kV if there is a future need and provides improved sectionalizing capability. However, the other options are capable to serve this area through this LRP. A Hwy 65 breaker station would be difficult to build as the existing switching station is situated in a high-density commercial development and several businesses would likely have to be condemned.

Elk River - Ramsey - Bunker Lake Area

This area is served by the two 230/69 kV sources at Elk River and Bunker Lake. The total mileage of 69 kV transmission is 21 miles serving six GRE distribution substations. The following is the forecasted load to be served in this area over the LRP timeframe. This load includes GRE and Anoka Municipal Utilities load.

Season	2011	2021	2031
Summer	85.3	125.0	146.0
Winter	62.2	90.1	104.8

Connexus Energy is planning for a Round Lake distribution substation that will directly tap the Bunker Lake-Ramsey 69 kV line. GRE's interconnection costs for this project are depicted in the table below. The scheduled ISD for the substation is 2010.

Estimated Year	Facilities	Cost
2010	Round Lake 69 kV 3-way switch	$140,000

Area Deficiencies

The loss of either the Elk River or the Bunker Lake sources cause both overload and voltage problems in the area.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Bunker Lake-Ramsey 69 kV	75.8	2009	86.4	134.1
Daytonport 69 kV - RDF Tap	75.8	2010	84.8	135.2
Daytonport-Enterprise Tap 69 kV	75.8	2011	76.4	122.8
Ramsey-Enterprise Tap 69 kV	75.8	2019	56.9	82.0

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Enterprise Park 69 kV	2017	96.0	89.3
Ramsey 69 kV	2017	96.7	88.1
Energy Park 69 kV	2017	96.2	88.2
Daytonport 69 kV	2018	96.4	89.9
RDF 69 kV	2018	96.2	89.7
Enterprise Tap 69 kV	2020	96.7	88.9

Alternatives

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

Option 1: 115/69 kV source at Enterprise Park

This option involves establishing a 115/69 kV source at Enterprise Park by constructing a 3.5 mile, 795 ACSS, 115 kV line between the Enterprise Park and Crooked Lake substations. This

would place a third source into the system midway between Bunker Lake and Elk River and would relieve transformer flow at both locations. Additionally, this option would provide looped service to the existing radial Enterprise Park 69 kV substation.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2009	Enterprise Park 140 MVA 115/69 kV source.	$6,880,043
2024	Enterprise Park to Energy Park 1.46 mile, 397 ACSS, 69 kV reconductor	$116,800

Option 2: 69 kV system improvement before 115/69 kV source at Enterprise Park

This option involves strengthening the 69 kV lines in the area by either reconductoring or rebuilding to alleviate the short-term overloads and then introducing the Enterprise Park source when voltage problems occur in 2018. This would also provide looped service to the existing radial Enterprise Park substation.

The following is the estimated timeline for Option 2 installations:

Option 2a: Assuming 69 kV system rebuild before 115/69 kV source at Enterprise Park

Estimated Year	Facilities	Cost
2009	Daytonport to RDF Tap 4.14 mile, 795 ACSS, 115 kV rebuild (operated at 69 kV)	$1,345,500
2009	Bunker Lake to Round Lake 2.43 mile, 477 ACSS, 69 kV rebuild	$595,350
2011	Round Lake to Ramsey 4.6 mile, 477 ACSS, 69 kV rebuild	$1,127,000
2011	Daytonport to Enterprise Tap 3 mile, 795 ACSS, 115 kV rebuild (operated at 69 kV)	$975,000
2018	Enterprise Park 140 MVA 115/69 kV source	$6,880,043
2024	Enterprise Park to Energy Park 1.46 mile, 397 ACSS, 69 kV reconductor	$116,800

Option 2b: Assuming 69 kV system reconductor before 115/69 kV source at Enterprise Park

Estimated Year	Facilities	Cost
2009	Daytonport to RDF Tap 4.14 mile, 795 ACSS, 115 kV rebuild (operated at 69 kV)	$1,345,500
2009	Bunker Lake to Round Lake 2.43 mile, 397 ACSS, 69 kV reconductor	$194,400
2011	Round Lake to Ramsey 4.6 mile, 397 ACSS, 69 kV reconductor	$368,000
2011	Daytonport to Enterprise Tap 3 mile, 397 ACSS, 69 kV reconductor	$240,000
2018	Enterprise Park 140 MVA 115/69 kV source	$6,880,043
2024	Enterprise Park to Energy Park 1.46 mile, 397 ACSS, 69 kV reconductor	$116,800

Generation Options
Generation options are not considered in this area.

Present Worth
A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for Option 2 are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2a	0.7	-0.1	-0.1
2b	1.3	0	0

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$8,528	$15,976	-
2a	$19,302	$23,510	$25,602
2b	$16,825	$19,261	$23,338

Option 1 is the least cost plan and it involves the least amount of investment. This will be GRE's preferred alternative.

Viability with Growth
Option 1 and Option 2 offer similar long-term solutions for this area. This region parallels the rapidly growing Highway 10 corridor. Building an Enterprise Park source in the near-term will assure that adequate space is available at the Enterprise Park substation location to accommodate expansion for the 115 kV feed. It will also allow for greater flexibility for modifying the system as load grows. Along with a future Orrock 345/115 kV source, establishing a new 115 kV connection at Enterprise Park will offer a starting point for upgrading the existing 69 kV system to 115 kV. GRE is actively pursuing locations for a 345/115 kV substation in the Elk River area.

Soderville Area
This area is served by three 230/69 kV sources at Elk River, Bunker Lake, and Blaine and the 115/69 kV source at Parkwood. The Linwood 230/69 kV source provides additional support to the area through the Athens Switching Station. The total mileage for the transmission lines in this area is 58.9 miles serving 9 GRE distribution substations. The following forecast is the load served in this area.

Season	2011	2021	2031
Summer	181.6	249.6	288.8
Winter	124.4	171.1	197.9

Connexus Energy is planning for a new Carlos Avery distribution substation in 2027. GRE will directly connect this substation to the Blaine-Soderville 69 kV line with a three-way switch. The interconnection costs are as follows.

Estimated Year	Facilities	Cost
2027	Carlos Avery 69 kV 3-way switch	$140,000

Area Deficiencies

The majority of the deficiencies seen in the area are facility overloads caused by loss of a 69 kV tie to the Elk River and Parkwood sources. The loss of the Bunker Lake 230/69 kV transformer is also a problematic contingency resulting in overloaded facilities.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Parkwood-Johnsville 69 kV	58.4	2008	69.6	105.7
Bunker Lake-Andover Tap 69 kV	58.4	2009	69.0	106.2
Parkwood-Village Ten 69 kV	75.8	2010	86.1	141.9
Soderville-East Bethel 69 kV	58.8	2012	56.0	84.2
Soderville-Ham Lake 69 kV	58.4	2013	55.4	77.1
Bunker Lake Distribution-Village Ten 69 kV	75.8	2016	60.6	95.6
Johnsville-Ham Lake 69 kV	58.4	2018	40.2	66.3
Coopers Corner-East Bethel 69 kV	58.8	2020	42.9	61.1

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
East Bethel 69 kV	2018	96.2	89.6
Coopers Corner 69 kV	2020	97.7	91.4

GRE has budgeted for a 212° F temperature upgrade of several of the area transmission facilities by the 2009 summer peak. The following table shows the updated timelines for overloads based on these upgrades.

Overloads Based on 212° F Temperature Rating

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Parkwood-Johnsville 69 kV	75.8	2013	69.6	105.7
Bunker Lake-Andover Tap 69 kV	75.8	2013	69.0	106.2
Soderville-Ham Lake 69 kV	75.8	2021	55.4	77.1
Johnsville-Ham Lake 69 kV	75.8	2025	40.2	66.3

Alternatives

Only one option was developed to correct the long-term deficiencies seen. It focuses on reconductoring and rebuilding the area transmission lines. The Soderville-East Bethel and Blaine-Soderville 69 kV lines are considered for a rebuild based on conductor size and age. The remaining overloaded facilities are either all or partially double circuited with the 230 kV system and were considered only for a reconductor due to cost concerns and effort in replacing 230 kV structures for a rebuild.

Option 1: 69 kV Reconductoring

This option focuses on reconductoring the overloaded transmission facilities with ACSS conductor.

Estimated Year	Facilities	Cost
2010	Parkwood-Village Ten 0.9 mile, 397 ACSS, 69 kV reconductor	$72,000
2013	Parkwood-Johnsville 5.2 mile, 397 ACSS, 69 kV reconductor	$416,000
2013	Bunker Lake-Andover Tap 1.9 mile, 397 ACSS, 69 kV reconductor (PEX portion only)	$152,000
2014	Soderville-East Bethel 2.5 mile, 795-477 ACSS, 115-69 kV rebuild	$1,075,000
2019	Soderville-Ham Lake 0.38 mile, 397 ACSS, 69 kV reconductor	$30,400
2024	Blaine-Soderville 10.96 mile, 795-477 ACSS, 115-69 kV rebuild	$3,836,000

Generation Options

Generation options are not considered in this area.

Present Worth

Since no alternative was developed, present worth analysis was not performed.

Viability with Growth

The proposed option offers a long-term solution for this area in term of load serving capability and reliability. If field surveys of the Soderville-Ham Lake 69 kV line (single circuit portion) show that the line is severely deteriorated, this would also be a strong candidate for a rebuild.

Elk River - Liberty Area

This area is served by the 230/69 kV source at Elk River and the 115/69 kV source at Liberty. The newly constructed 69 kV Waco breaker station provides separation of the system between the two sources and ties in a second line from the Elk River substation. The total mileage for the 69 kV transmission lines is 25.3 miles. There are 3 GRE distribution substations served from the 69 kV system. The following forecast is the load served in this area and includes GRE and Elk River Municipal load.

Season	2011	2021	2031
Summer	68.1	99.4	110.9
Winter	48.8	72.9	80.8

Area Deficiencies

Currently, the loss of the Monticello-Elk River 230 kV line or either area source causes the 69 kV system to overload. Also, the Liberty 115/69 kV transformer becomes system intact overloaded due to growing loads along the Hwy. 10 corridor.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Thompson Lake-Remmele Tap 69 kV	45.5	2006	60.2	86.1
Waco-Rice Lake Switch 69 kV	58.8	2010	63.6	89.8
Remmele Tap-Big Lake 69 kV	45.5	2012	44.2	62.2
Liberty 115/69 kV transformer	140	2013	131.2	189.3
Big Lake-Waco 69 kV	45.5	2013	41.7	64.6
Elk River S14-Elk River West 69 kV	92.7	2013	91.9	140.0
Elk River West-Waco 69 kV	58.8	2015	53.1	69.6
Elk River 230/69 kV transformer #2	187	2020	159.7	241.6
Elk River 230/69 kV transformer #1	187	2021	159.7	239.5

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Elk River 230 kV	2020	95.4	89.3

The majority of the 69 kV lines in this area have a 170° F temperature rating. GRE is currently budgeting to increase the temperature rating to 212° F by the 2009 summer peak. This would change the estimated years for the overloads as follows.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Thompson Lake-Remmele Tap 69 kV	58.8	2011	60.2	86.1
Remmele Tap-Big Lake 69 kV	58.8	2019	44.2	62.2
Big Lake-Waco 69 kV	58.8	2019	41.7	64.6

Alternatives

Two alternate options were developed as solutions to the long range problems that occur in this area. The options look at establishing new sources into the area. Any line rebuilds that occur in the area will be rebuilt to double circuit 115-69 kV construction with only the 69 kV portion having conductor placed on the structures. The 115 kV conductor would be strung if and when 115 kV development would occur in the area.

Option 1: Foley 230/69 kV source

This option involves establishing a new 230/69 kV source at Foley with a double circuit 69 kV outlet to the Mayhew Tap 69 kV switches. Near-term solutions involve a mix of line reconductors and rebuilds as necessary. A second Liberty 115/69 kV transformer is added to alleviate the Liberty transformer loading problems seen while a 78.6 MVAR capacitor bank is placed at the Elk River 69 kV bus to unsaturate the Elk River 230/69 kV transformer load tap changers and to boost the voltages near the Elk River substation. The estimated timeline for the Option 1 facilities is depicted in the following table.

Estimated Year	Facilities	Cost
2010	Waco-Rice Lake Switch 5.37 mile, 266 ACSS, 69 kV reconductor	$429,600
2011	Thompson Lake-Remmele Tap 6.42 mile, 266 ACSS, 69 kV reconductor	$513,600
2013	Liberty 140 MVA 115/69 kV transformer #2	$3,394,835
2015	Waco-Elk River West 2.79 mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$1,476,300
2017	Foley 140 MVA 230/69 kV source	$6,429,422
2017	Foley-Mayhew Switch 3.99 mile, 336 ACSS, 69 kV double circuit rebuild	$1,336,650
2018	Elk River 78.6 MVAR 69 kV capacitor bank	$529,400

Option 2: Orrock 345/115 kV source and 115 kV outlet

This option focuses on establishing a 115 kV path along the Hwy. 10 corridor via a new Orrock 345/115 kV source and conversion of the area 69 kV lines to double circuit 115-69 kV lines. The Elk River West substation is converted to 115 kV operation to relieve the Elk River and Liberty transformer loadings. Like Option 1, various line reconductors and rebuilds are needed to solve thermal loading issues and a second Liberty 115/69 kV transformer is needed to alleviate the overload of the existing unit. The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2010	Waco-Rice Lake Switch 5.37 Mile, 266 ACSS, 69 kV reconductor	$429,600
2011	Thompson Lake-Remmele Tap 6.42 Mile, 266 ACSS, 69 kV reconductor	$513,600
2013	Liberty 140 MVA 115/69 kV transformer #2	$3,394,835
2015	Waco-Elk River West 2.79 Mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$1,476,300
2017	Orrock 336 MVA 345/115 kV source	$10,141,325
2017	Orrock-Waco-Remmele Tap 7.41 Mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$8,000,100
2017	Liberty-Big Lake 10.21 Mile, 795 ACSS, 115 kV conductoring	$992,700
2017	Waco-Elk River West 2.79 Mile, 795 ACSS, 115 kV conductoring	$362,700
2017	Elk River West 115 kV conversion	$815,000
2018	Elk River 78.6 MVAR 69 kV capacitor bank	$529,400

Generation Options

Generation options are not considered in this area.

Present Worth

A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0	-3.9	-6.1

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$24,636	$29,417	-
2	$48,453	$54,969	$38,500

Option 1 is the least cost plan. However, it offers limited ability to provide support to and alleviate the loading along the Hwy. 10 corridor. It also has inferior loss savings when compared to Option 2. Therefore, Option 2 will be the preferred option.

Viability with Growth

Option 2 would offer the system with a better opportunity for long-term load growth and extension of the 69 kV system as the distribution substations could be converted to 115 kV operation. Option 1 would offer the system with only limited opportunity for accommodating further load growth.

Milaca - Liberty - Benton County Area

This area is served by 2 230/69 kV sources from Milaca and Benton County and the 115/69 kV source at Liberty. A normally open 69 kV switch at Duelm splits the system in two. The total mileage for the 69 kV transmission lines is 85.1 miles serving 8 GRE distribution substations. The following forecast is the load served in this area.

Season	2011	2021	2031
Summer	55.3	89.0	116.6
Winter	41.2	65.0	84.5

Connexus Energy intends on constructing a new Cornfield distribution substation in 2015. GRE plans to connect this substation via a new eight mile, 477 ACSS, 69 kV line terminating at the existing West End 69 kV distribution substation. The cost for the distribution sub interconnection is as follows.

Estimated Year	Facilities	Cost
2015	West End-Cornfield 8.0 Mile, 477 ACSS, 69 kV line	$6,260,000

Area Deficiencies

Currently, the loss of the Milaca 230/69 kV transformer causes the Milaca-Gilman 69 kV line and the Pipeline #2 Tap-Popple Creek Switch 69 kV line to overload. Furthermore, the Benton County 230/69 kV transformer overloads upon loss of the 69 kV tie to the Liberty substation.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Pipeline #2 Tap-Popple Creek Sw. 69 kV	45.4	2019	37.0	48.1
Milaca-Gilman 69 kV	31.4	2021	23.7	31.9
Benton County 230/69 kV transformer	84	2021	74.6	106.3

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Benton County 230 kV	2020	97.4	89.3

Alternatives

Two alternate options were developed as solutions to the long range problems that occur in this area. The options are similar to those developed in the ***Elk River-Liberty Area***, but differ in that a rebuild of the Milaca-Gilman-Mayhew Switch 69 kV line presented as a solution for this area.

Option 1: Foley 230/69 kV source

This option involves establishing a new 230/69 kV source at Foley with a double circuit 69 kV outlet to the Mayhew Tap switches. A rebuild of the Milaca-Gilman-Mayhew Switch 69 kV line will help alleviate overloads on this section of line caused by an outage of the Milaca 230/69 kV transformer. The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2017	Foley 140 MVA 230/69 kV source	$6,429,422
2017	Foley-Mayhew Switch 3.99 mile, 336 ACSS, 69 kV double circuit rebuild	$1,336,650
2017	Milaca-Gilman 20.61 mile, 336 ACSS, 69 kV rebuild	$4,843,350
2019	Gilman-Mayhew Switch 6.68 mile, 336 ACSS, 69 kV rebuild	$1,569,800

Option 2: Orrock 345/115 kV source and 115 kV outlet

This option focuses on establishing a 115 kV path along the Hwy. 10 corridor via a new Orrock 345/115 kV source and conversion of the area 69 kV lines to double circuit 115-69 kV lines. The Elk River West substation is converted to 115 kV operation to relieve the Elk River and Liberty transformer loadings. A reconductor of the single circuit portion of the Liberty-Becker 69 kV line would need to be done to alleviate the overload of this facility while the Milaca-Gilman 69 kV line would have to be rebuilt. The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2017	Liberty-Becker 0.8 mile, 397 ACSS, 69 kV reconductor	$64,000
2017	Orrock 336 MVA 345/115 kV source	$10,141,325
2017	Waco-Elk River West 2.46 mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$1,476,300
2017	Orrock-Waco-Remmele Tap 7.41 mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$8,000,100
2017	Liberty-Big Lake 10.21 mile, 795 ACSS, 115 kV conductoring	$992,700
2017	Waco-Elk River West 2.79 mile, 795 ACSS, 115 kV conductoring	$362,700
2017	Elk River West 115 kV conversion	$815,000
2019	Milaca-Gilman 20.61 mile, 336 ACSS, 69 kV rebuild	$4,843,350

Generation Options

Generation options are not considered in this area.

Present Worth

A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	-4.5	-12.3

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$27,285	$28,931	-
2	$53,089	$54,528	$28,892

Option 2 is the least cost plan when loss savings are considered.

Viability with Growth

Both options do offer similar long-term solutions for this area. However, Option 2 offers more support for future load growth in the both the ***Elk River-Liberty Area*** and this area. The Benton County 230/69 kV transformer loading should be monitored to see what effect 115 kV load conversions have on this facility. Also, should the load grow sufficiently in the area, a 69 kV breaker station at the future Foley 230/69 kV source would provide more flexibility in switching the system and allow for the normally open Duelm 69 kV switches to be closed.

Milaca - Rush City - Linwood - Elk River Area

This area is served by 4 230/69 kV sources from Rush City, Linwood, Elk River, and Milaca. The Cambridge Generating Station also resides in the middle of the system. There are 14 GRE distribution substations in the area served from a total of 158.4 miles of 69 kV transmission. The following forecast is the load served in this area and includes both GRE and SMMPA load.

Season	2011	2021	2031
Summer	233.9	341.1	369.0
Winter	168.2	241.3	259.6

There are several distribution projects scheduled for the area that have no impact on determining alternatives for the problems seen. The timelines and estimated costs for these projects are listed in the following table.

Estimated Year	Facilities	Cost
2010	Rum River 69 kV 3-way switch	$140,000
2012	Athens 69 kV 3-way switch	$140,000
2016	EC-CP Line Tap-Cambridge East 1.75 mile, 477 ACSS, 69 kV line	$1,590,750
2016	Pease 69 kV 3-way switch	$140,000

Area Deficiencies

This is another area of significant load growth in the North Suburban region resulting in stress of the 69 kV system. Each of the four sources into the area experience overloading on a contingency basis between 2011 and 2021. Loss of the area 69 kV ties to Elk River source reduces voltage levels throughout much of the area, most notably in the Zimmerman and St. Francis areas. Loss of the 69 kV tie to the Milaca source also is causing low voltage issues in the Zimmerman and Princeton areas. Furthermore, outage of the either end of the Cambridge-Isanti-Athens 69 kV line causes deficient voltage levels in the Isanti and Cambridge areas.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Milaca-Milaca Distribution 69 kV	58.8	2008	76.6	119.3
Princeton Municipal Tap-Princeton SS 69 kV	58.8	2011	58.5	98.2
Long Siding-Milaca Distribution 69 kV	58.8	2011	60.9	95.3
Rush City 230/69 kV transformer	84	2013	94.9	144.5
Long Siding-Princeton SS 69 kV	58.8	2014	51.5	79.5
Baldwin-Zimmerman 69 kV	58.8	2015	50.7	71.0
Milaca 230/69 kV transformer	112	2019	109.4	149.8
Princeton Municipal Tap-Baldwin 69 kV	58.8	2019	38.8	65.9
Elk River 230/69 kV transformer #1	187	2020	162.7	247.0
Elk River 230/69 kV transformer #2	187	2020	162.7	247.0
Linwood 230/69 kV transformer	112	2020	97.4	149.9
Princeton Municipal Tap-Princeton Industrial 69 kV	32	2021	19.5	32.3

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Zimmerman 69 kV	2011	91.7	73.3
Baldwin 69 kV	2012	93.3	75.9
Princeton Municipal South 69kV	2012	93.3	75.9
Pipeline 69 kV	2012	92.6	85.5
St. Francis 69 kV	2012	92.6	85.5
Princeton Industrial 69 kV	2012	93.6	76.4
Crown 69 kV	2013	92.9	85.7
Princeton Tap 69 kV	2014	94.3	77.6
Long Siding 69 kV	2016	98.1	84.8
Milaca Distribution 69 kV	2016	96.4	87.3
Princeton Municipal North 69 kV	2016	97.7	84.2
Isanti 69 kV	2016	98.0	84.4
St. Francis Tap 69 kV	2016	93.4	86.3
Princeton SS 69 kV	2017	97.6	83.7
Isanti Tap 69 kV	2017	98.5	85.7
Dalbo 69 kV	2017	98.6	87.2
Cambridge Industrial 69 kV	2018	98.9	87.7
Dalbo Tap 69 kV	2019	98.7	87.4
Cambridge 69 kV	2019	99.4	89.3
Cambridge Industrial Tap 69 kV	2020	99.0	88.0
Milaca 69 kV	2021	101.9	91.6

Alternatives

Two alternate options were developed as solutions to the long-range problems that occur in this area. There are several projects common to both alternatives. It was determined that moving the Milaca 69 kV load from the Milaca to Long Siding 69 kV line to a dedicated breaker at the Milaca substation would be the best solution to resolve the Milaca to Milaca Distribution 69 kV line overloading. The overloading problem seen on the 69 kV line from Milaca to Princeton, as well as the age of that line, provided justification for rebuilding that line in both alternatives. A new line from the proposed Cambridge East distribution substation to a new tap point south of the Cambridge Industrial 69 kV substation is suggested to alleviate the voltage problems in the Isanti area. While this line is suggested in both alternatives, it is needed two years earlier in the Crown to Zimmerman line solution than in the Dalbo to St. Francis line solution. Lastly, a new 230/69 kV source at Dalbo connected by two 230 kV lines from Rush City and Milaca are common to both alternatives. This new source and these lines will alleviate many voltage problems in the area. One key difference between the two alternatives is the year in which the Dalbo project is needed.

Option 1: New Crown to Zimmerman 69 kV line

In addition to the aforementioned upgrades, this option involves building a new, 10.94 mile, 69 kV line from Zimmerman to Crown. This will help hold the voltage at the Zimmerman and Pipeline 69 kV buses to an acceptable level when the tie to the Elk River 69 kV substation is lost.

Estimated Year	Facilities	Cost
2008	Milaca 69 kV deadend and breaker for the Milaca distribution substation	$420,000
2011	Long Siding-Milaca 9.51 mile, 477 ACSS, 69 kV line rebuild	$2,329,950
2012	Crown to Zimmerman 10.94 mile, 477 ACSS, 69 kV line	$6,461,180
2014	Rush City 140 MVA 230/69 kV transformer upgrade	$2,911,422
2015	Zimmerman Tap-Baldwin 5.07 mile, 477 ACSS, 69 kV line rebuild	$248,430
2017	Cambridge East to South Cambridge Industrial 3.5 mile, 477 ACSS, 69 kV line	$2,656,500
2018	Dalbo 140 MVA 230/69 kV source	$12,034,816
2018	Dalbo-Milaca 24.5 mile, 954 ACSS, 230 kV line	$16,838,500
2018	Dalbo-Rush City 31.35 mile, 954 ACSS, 230 kV line	$28,251,500
2020	Long Siding-Princeton 1.57 mile, 477 ACSS, 69 kV line rebuild	$384,650

Option 2: New Dalbo to St. Francis 69 kV line and Zimmerman Capacitor Bank

This option involves building a new, 14 mile, 69 kV line from Dalbo to St. Francis. A 19.2 MVAR capacitor bank is also needed at Zimmerman to boost the voltage at this site. This option also requires the Princeton SS-Princeton Municipal Tap 69 kV line to be rebuilt which is not needed in the other alternative.

Estimated Year	Facilities	Cost
2008	Milaca 69 kV deadend and breaker for the Milaca distribution substation	$420,000
2011	Long Siding-Milaca 9.51 mile, 477 ACSS, 69 kV line rebuild	$2,329,950
2012	Zimmerman 19.2 MVAR 69 kV cap bank	$291,800
2012	Dalbo-St. Francis 14.0 mile, 477 ACSS, 69 kV double circuit line	$6,485,000
2012	Princeton-Princeton Municipal Tap 5.12 mile, 477 ACSS, line rebuild	$1,254,400
2014	Rush City 140 MVA 230/69 kV transformer upgrade	$2,911,422
2018	Long Siding-Princeton 1.57 mile, 477 ACSS, 69 kV line rebuild	$384,650
2019	Cambridge East to South Cambridge Industrial 3.5 mile, 477 ACSS, 69 kV line	$2,656,500
2020	Dalbo 140 MVA 230/69 kV source	$12,034,816
2020	Dalbo-Milaca 24.5 mile, 954 ACSS, 230 kV line	$16,838,500
2020	Dalbo-Rush City 31.35 mile, 954 ACSS, 230 kV line	$28,251,500

Generation Options
Generation options are not considered in this area.

Present Worth
A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	-1.90	-3.60

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	126,447	143,955	-
2	142,630	144,072	131,269

Option 2 is the least cost plan with loss savings considered although it involves a larger amount of investment.

Viability with Growth
Both options do offer similar long-term solutions for this area. Option 2 will allow for a third 69 kV outlet from the Dalbo 230/69 kV source to provide support to the St. Francis, Zimmerman, and Athens areas. Eventually, a 69 kV outlet could be extended to the Mora Municipal 69 kV substation to provide support to the ***Rush City-Pine City-Ogilvie-Milaca Area***.

Rush City - Pine City - Ogilvie - Milaca Area
This area is served by two 230/69 kV sources at Rush City and Milaca. The distant Bear Creek 230/69 kV source provides additional support to the area. The total mileage for the transmission lines in this area is 61.5 miles serving 5 GRE distribution substations. The following forecast is the load served in this area.

Season	2011	2021	2031
Summer	71.2	90.5	119.3
Winter	62.0	74.7	92.7

Several new distribution substation additions are planned for this region over the LRP time frame. GRE's interconnection costs are listed in the table below.

Estimated Year	Facilities	Cost
2014	Mora SS-Knife Lake 8.0 mile, 336 ACSS, 69 kV line	$5,116,000
2015	Henriette 69 kV 3-way switch	$140,000
2016	Mora Municipal-Brunswick 10.0 mile, 477 ACSS, 69 kV line	$6,620,000

Area Deficiencies

The transmission lines in the area are mostly 1950's vintage facilities constructed with small conductor. As a result, many line overloads and voltage issues are seen, most notably for the Mora-Grasston 69 kV outage or the Bear Creek-Hinckley Tap 69 kV outage.

Overloads

Facility	Rating MVA	Estimated Year	2011 MVA	2021 MVA
Rush City-Adrian Robinson 69 kV	45.5	2012	44.8	60.7
Adrian Robinson-Rush City Distribution 69 kV	45.5	2015	40.1	53.9
Milaca-Ogilvie 69 kV	36.2	2017	31.4	39.4
Grasston-Mora 69 kV	36.2	2017	31.4	39.5
Pine City-Grasston 69 kV	36.2	2021	22.1	37.2

Voltage Deficiencies

Substation	Estimated Year	2011 %	2021 %
Mora Municipal 69 kV	2012	92.3	87.4
Mora SS 69 kV	2013	92.7	97.9

Alternatives

Options focus on reconductoring and rebuilding the area transmission lines as applicable.

Option 1: 69 kV Reconductoring

This option reconductors the Rush City-Adrian Robinson-Rush City Distribution-Rock Lake 69 kV line and rebuilds the Pine City-Grasston 69 kV and Milaca-Ogilvie 69 kV lines. A 69 kV breaker station and 12.6 MVAR capacitor bank are established at Mora switching station to boost voltage upon loss of the Grasston-Mora 69 kV line.

Estimated Year	Facilities	Cost
2012	Mora SS 12.6 MVAR 69 kV capacitor bank and breaker station	$2,124,400
2012	Rush City-Adrian Robinson-Rush City Distribution 3.56 mile, 266 ACSS, 69 kV reconductor	$519,800
2017	Milaca-Ogilvie 12.69 mile, 336 ACSS, 69 kV rebuild	$3,026,700
2018	Pine City-Grasston 9.57 mile, 336 ACSS, 69 kV rebuild	$2,225,450
2018	CP Line Tap Switches-Rock Lake 9.23 mile, 266 ACSS, 69 kV	$738,400

Option 2: 69 kV Rebuild

This option rebuilds the Rush City-Adrian Robinson-Rush City Distribution-Rock Lake 69 kV line, the Pine City-Grasston 69 kV, and Milaca-Ogilvie 69 kV lines. A 69 kV breaker station and 12.6 MVAR capacitor bank are established at Mora switching station to boost voltage upon loss of the Grasston-Mora 69 kV line.

Estimated Year	Facilities	Cost
2012	Mora SS 12.6 MVAR 69 kV capacitor bank and breaker station	$2,124,400
2012	Rush City-Adrian Robinson-Rush City Distribution 3.56 mile, 477 ACSS, 69 kV rebuild	$1,469,450
2017	Milaca-Ogilvie 12.69 mile, 336 ACSS, 69 kV rebuild	$3,026,700
2018	Pine City-Grasston 9.57 mile, 336 ACSS, 69 kV rebuild	$2,225,450
2021	CP Line Tap Switches-Rock Lake 9.23 mile, 477 ACSS, 69 kV rebuild	$2,361,350

Generation Options

Generation options are not considered in this area.

Present Worth

A cost analysis was performed on each option with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer	2031 Summer
2	0.0	-0.11	-0.2

With the loss allocations, the present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$15,460	$17,857	-
2	$20,981	$23,246	$21,960

Option 1 is the least cost plan and it involves the least amount of investment.

Viability with Growth

Option 1 offers a long-term solution for this area in term of load serving capability and reliability. Option 2 should be pursued if it is determined that the area 69 kV lines need to be replaced based on age considerations. It should be noted that the Mora-Brunswick 69 kV line proposed to interconnect the Brunswick substation can be extended to the Dalbo 230/69 kV source once installed to provide additional support to the area. Furthermore, the Mora-Knife Lake 69 kV line would serve as a starting point for rebuilding the Ogilvie-Isle 69 kV line, providing further support to the Mora area.

May Substation

The May substation is being served from a radial, 5.87 mile, 69 kV line. The radial line taps the Xcel Energy Arden Hills - Saint Croix Falls 69 kV line at May Tap. The following forecast is the load served at this substation.

Season	2011	2021	2031
Summer	4.4	5.5	6.7
Winter	3.0	3.8	4.6

Area Deficiencies

With the 2009 completion of the Xcel/DPC Chisago Project, the May substation experiences no voltage violations through the LRP time frame. There is the possibility however that Xcel may upgrade the Arden Hills-Lawrence Creek 69 kV line to 115 kV operation within the LRP time period based on line age and performance.

Alternatives

Two alternate options were developed to connect the May substation to the transmission system if the Arden Hills-Lawrence Creek 69 kV line should be upgraded to 115 kV operation.

Option 1: May Tap - Hugo 69 kV line

This option involves building a 69 kV line from May Tap to Hugo. The new line will tie the May substation with the 69 kV system in the Hugo area.

The following is the cost estimate for Option 1 installations:

Facilities	Cost
May Tap - Hugo 4.1 mile, 477 ACSS, 69 kV line	$1,385,625

Option 2: 115 kV load conversion

This option involves converting load at May substation and the May Tap - May 69 kV line to 115 kV operation.

The following is the cost estimate for Option 2 installations:

Facilities	Cost
May substation conversion to 115 kV	$350,000
May Tap-May 5.87 mile, 336 ACSR, 115 kV line	$1,725,750
May Tap 115 kV 3-way switch	$165,000

Generation Options

Generation options are not considered in this area.

Present Worth

Present worth analysis was not performed as it is unknown if and when the Arden Hills-Lawrence Creek 69 kV line would be upgraded. A cost analysis would be performed at that time to determine the least-cost plan. Neither plan developed above is included in the recommended plan for the North Suburban Region.

Recommended Plan

The following are the proposed projects for the North Suburban region:

Estimated Year	Responsible Company	Facility	Cost
2008	GRE	Milaca 69 kV deadend and breaker for the Milaca distribution substation	$420,000
2009	GRE	Elmcrest 69 kV 3-way switch	$140,000
2009	CE	Elmcrest 69 kV distribution substation	$940,000
2009	GRE	Enterprise Park 115/69 kV source.	$6,880,043
2010	GRE	Round Lake 69 kV 3-way switch	$140,000
2010	CE	Round Lake 69 kV distribution substation	$940,000
2010	GRE	Parkwood-Village Ten 0.9 mile, 397 ACSS, 69 kV reconductor	$72,000
2010	GRE	Waco-Rice Lake Switch 5.37 mile, 266 ACSS, 69 kV reconductor	$429,600
2010	GRE	Rum River 69 kV 3-way switch	$140,000
2010	CE	Rum River 69 kV distribution substation	$940,000
2011	GRE	Thompson Lake-Remmele Tap 6.42 mile, 266 ACSS, 69 kV reconductor	$513,600
2011	GRE	Long Siding-Milaca 9.51 mile, 477 ACSS, 69 kV line rebuild	$2,329,950
2012	GRE	Coon Creek to Parkwood 3.5 mile, 795-477 ACSS, 115-69 kV double circuit line	$4,765,250
2012	GRE	Athens 69 kV 3-way switch	$140,000
2012	ECE	Athens 69 kV distribution substation	$940,000
2012	GRE	Zimmerman 19.2 MVAR 69 kV cap bank	$291,800
2012	GRE	Dalbo-St. Francis 14.0 mile, 477 ACSS, 69 kV double circuit line	$6,485,000
2012	GRE	Princeton-Princeton Municipal Tap 5.12 mile, 477 ACSS, 69 kV line rebuild	$1,254,400
2012	GRE	Mora SS 12.6 MVAR 69 kV capacitor bank and breaker station	$2,124,400
2012	GRE	Rush City-Adrian Robinson-Rush City Distribution 3.56 mile, 266 ACSS, 69 kV reconductor	$519,800
2013	GRE	Parkwood-Johnsville 5.2 mile, 397 ACSS, 69 kV reconductor	$416,000
2013	GRE	Bunker Lake-Andover Tap 1.9 mile, 397 ACSS, 69 kV reconductor (PEX portion only)	$152,000
2013	GRE	Liberty 140 MVA, 115/69 kV transformer #2	$3,394,835
2014	GRE	Soderville-East Bethel 2.5 mile, 795-477 ACSS, 115-69 kV rebuild	$1,075,000
2014	GRE	Rush City 140 MVA 230/69 kV transformer upgrade	$2,911,422
2014	GRE	Mora SS-Knife Lake 8.0 mile, 336 ACSS, 69 kV line	$5,116,000
2014	ECE	Knife Lake 69 kV distribution substation	$940,000
2015	GRE	Coon Creek 210 MVA, 115/69 kV source	$4,905,777
2015	GRE	Coon Creek-Hwy. 65 3.25 mile, 795 ACSS, Switch 69 kV double circuit rebuild	$3,331,125

GRE Long-Range Transmission Plan

Estimated Year	Responsible Company	Facility	Cost
2015	GRE	Waco-Elk River West 2.79 mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$1,476,300
2015	GRE	West End-Cornfield 8.0 mile, 477 ACSS, 69 kV line	$6,260,000
2015	CE	Cornfield 69 kV distribution substation	$940,000
2015	GRE	Henriette 69 kV 3-way switch	$140,000
2015	ECE	Henriette 69 kV distribution substation	$940,000
2016	GRE	EC-CP Line Tap-Cambridge East 1.75 mile, 477 ACSS, 69 kV line	$1,590,750
2016	ECE	Cambridge East 69 kV distribution substation	$940,000
2016	GRE	Pease 69 kV 3-way switch	$140,000
2016	ECE	Pease 69 kV distribution substation	$940,000
2016	GRE	Mora Municipal-Brunswick 10.0 Mile, 477 ACSS, 69 kV line	$6,620,000
2016	ECE	Brunswick 69 kV distribution substation	$940,000
2017	GRE	Blaine-Hugo 6.64 mile, 266 ACSS, 69 kV reconductor	$531,000
2017	GRE	Orrock 336 MVA 345/115 kV source	$10,141,325
2017	GRE	Orrock-Waco-Remmele Tap 7.41 mile, 795-477 ACSS, 115-69 kV double circuit rebuild	$8,000,100
2017	GRE	Liberty-Big Lake 10.21 mile, 795 ACSS, 115 kV conductoring	$992,700
2017	GRE	Waco-Elk River West 2.79 mile, 795 ACSS, 115 kV conductoring	$4,362,700
2017	ERMU/GRE	Elk River West 115 kV conversion	$815,000
2017	GRE	Liberty-Becker 0.8 mile, 397 ACSS, 69 kV reconductor	$64,000
2017	GRE	Milaca-Ogilvie 12.69 mile, 336 ACSS, 69 kV rebuild	$3,026,700
2018	GRE	Blaine 39.6 MVAR 69 kV capacitor bank	$373,400
2018	GRE	Blaine 112 MVA 230/69 kV transformer #2	$3,573,598
2018	GRE	Elk River 78.6 MVAR 69 kV capacitor bank	$529,400
2018	GRE	Long Siding-Princeton 1.57 mile, 477 ACSS, 69 kV line rebuild	$384,650
2018	GRE	Pine City-Grasston 9.57 mile, 336 ACSS, 69 kV rebuild	$2,225,450
2018	GRE	CP Line Tap Switches-Rock Lake 9.23 mile, 266 ACSS, 69 kV reconductor	$738,400
2019	GRE	Linwood-North Branch 12.19 mile, 266 ACSS, 69 kV reconductor	$1,019,750
2019	GRE	Soderville-Ham Lake 0.38 mile, 397 ACSS, 69 kV reconductor	$30,400
2019	GRE	Milaca-Gilman 20.61 mile, 336 ACSS, 69 kV rebuild	$4,843,350
2019	GRE	Cambridge East to South Cambridge Industrial 3.5 mile, 477 ACSS, 69 kV line	$2,656,500
2020	GRE	230/69 kV 140 MVA, Dalbo source	$12,034,816
2020	GRE	Dalbo-Milaca 24.5 mile, 954 ACSS, 230 kV line	$16,838,500
2020	GRE	Dalbo-Rush City 31.35 mile, 954 ACSS, 230 kV line	$28,251,500
2021	GRE	Hugo-Elmcrest 2.33 mile, 266 ACSS, 69 kV reconductor	$186,400
2024	GRE	Enterprise Park to Energy Park 1.46 mile, 397 ACSS, 69 kV reconductor	$116,800
2024	GRE	Blaine-Soderville 10.96 mile, 795-477 ACSS, 115-69 kV rebuild	$3,836,000
2027	GRE	Carlos Avery 69 kV 3-way switch	$140,000
2027	CE	Carlos Avery 69 kV distribution substation	$940,000

F: GRE-OTP 41.6 kV Region

The GRE-OTP 41.6 kV region is located in the northwest quadrant of the state of Minnesota. This region covers the entire GRE 41.6 kV loads. The member systems that serve this territory are:

- Agralite Electric Cooperative (AEC)
- Lake Region Electric Cooperative (LREC)
- Runestone Electric Association (REA)

The economy of this region is driven by commercial and residential developments, agricultural including irrigation activities, seasonal based industries and multiple light industries. There are number of dairy farms in the region, and new digesters are being built in the region. The region has also seen spot loads, such as ethanol plants, in the past. Such spot loads including ethanol producing plants are expected to come to the region in the foreseeable future. Irrigation activities at some areas in the region are considerable during summer peak conditions.

Agralite Electric Cooperative, based in Benson, MN, serves consumers in Swift, Big Stone, Stevens and Pope Counties in west-central Minnesota. The economy of this area is primarily driven by commercial and irrigation activities. AEC foresees new digesters and ethanol producing plants in its service territory while the existing ethanol producing plant is expanding

Lake Region Electric Cooperative (LREC), based in Pelican Rapids, MN, provides electric services primarily to Otter Tail County and in portions of Wikin, Bekcer, Clay, Grant, Douglas, Todd and Wadena counties The economy of the area is driven by agricultural, tourist (seasonal based industry) and some commercial developments.

Runestone Electric Association (REA) is headquartered in Alexandria, MN, and its service territory includes Douglas, Grant, Otter Tail, Pope, Stevens and Todd counties. The economy of the area is driven by agriculture and light industries. Residential and commercial developments around the town of Alexandria and the surrounding Lakes area contribute to the load growth in the REA's service territory. Irrigation activities account to a significant amount of load during summer peak conditions.

Existing System

This region is served by the GRE-Otter Tail Power (OTP)-Missouri River Energy Services (MRES) high voltage integrated system. The transmission systems in this region include 230 kV, 115 kV and 41.6 kV lines with the 41.6 kV system serving almost all of the loads in the region. The 115 kV system serves a small portion of the total load in the region. Delivery to the 41.6 kV system is through the Wahpeton and Henning 230/41.6 kV sources and with 115/41.6 kV transformations at Hoot Lake, Audubon, Pelican Rapids, Tamarac, Rush Lake, Miltona, Brandon, Elbow Lake , Alexandria, Walden, Morris, Graceville, Benson, Appleton, Marsh Lake, Ortonville and Kerkhoven. Deliver to the 115 kV system is though the 230/115 kV transformations at Fergus Falls, Inman, Morris, Big Stone, Granite Falls, Minn Valley and Audubon.

In general the Maple River to Budoura 230 kV line crosses the region in the north, the Wing River to Wahpeton 230 kV line crosses the region around the center from east to west, and the Wing River to Granite Falls 230 kV line crosses the region from north to south. There are also two 115 kV loops in the region: Morris – Benson –Minnvalley-Granite Falls – Canby – Graceville

– Morris 115 kV loop and Alexandria – Inman – Frazee – Tamarac- Pelican – Hoot Lake – Elbow Lake – Brandon – Alexandria 115 kV loop

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 154	Hoot Lake 145 41.6KV (LR-MAT)	Rank: 2
Line 213	Walden 415 41.6KV (RU-WC)	Rank: 6
Line 159	Frazee 235 41.6KV (LR-FEX, LR-DOT, LR-DET)	Rank: 7
Line 163	Henning 625 41.6KV (LR-SLT)	Rank: 16
Line 158	Hoot Lake 135 41.6KV (LR-RTT)	Rank: 25
Line 172	Wahpeton 225 41.6KV (LR-ROT)	Rank: 27
Line 209	Alexandria 345 41.6KV (RU-AH, RU-HM)	Rank: 31
Line 208	Brandon 325 41.6KV (RU-SAT, RU-BRT)	Rank: 32
Line 168	Hoot Lake 165 41.6KV	Rank: 39

Transmission Lines Built before 1980

Line 154	Hoot Lake 145 41.6KV (LR-MAT, LR-UNT)	14 Mi.-1975-77
Line 213	Walden 415 41.6KV (RU-WC, RU-HCT)	11 Mi.-1970-73
Line 159	Frazee 235 41.6KV (LR-DET, LR-EP)	11 Mi.-1960-64
Line 163	Henning 625 41.6KV (LR-SLT)	9 Mi.-1974
Line 158	Hoot Lake 135 41.6KV (LR-RTT)	3 Mi.-1978
Line 172	Wahpeton 225 41.6KV (LR-ROT)	4 Mi.-1955
Line 209	Alexandria 345 41.6KV (RU-AH, RU-HM)	17 Mi.-1965; 3 Mi.-1969-73
Line 208	Brandon 325 41.6KV (RU-SAT, RU-BRT)	1 Mi.-1956
Line 95	Marsh Lake 475 41.6KV (AG-AA, AG-AF, AG-MA)	23 Mi.-1969-70
Line 97	Morris 3232 41.6KV (AG-AM)	3 Mi.-1962
Line 99	Morris 1662 – Benson 1555 115KV (AG-MB)	34 Mi.-1970
Line 100	Benson 785 41.6KV (AG-CAT)	5 Mi.-1958
Line 102	Morris 1762–Ortonvil-Gracevil 115KV (AG-MJ, AG-JG)	21 Mi.-1970
Line 106	Benson 735 41.6KV (AG-BS, AG-GW, AG-SG)	15 Mi.-1950; 15 Mi.-1965-76
Line 108	Benson 1515/1525-Wilmar-Maynard 115KV (AG-RK)	10 Mi.-1964
Line 111	Appleton 845 41.6KV (AG-SLT)	2 Mi.-1977
Line 156	Frazee 255 41.6KV (LR-EP, LR-FE, LR-BUT)	14 Mi.-1964; 5 Mi.-1975
Line 157	Audubon 1425-Hoot Lk-Frazee 115KV (LR-CF, LR-PC)	16 Mi.-1954; 15 Mi.-1969
Line 165	Audubon 555 41.6KV (LR-LET)	10 Mi.-1968
Line 167	Frazee 1325/1345 – Inman 115KV (LR-HR)	12 Mi.-1975
Line 170	Miltona 187KB3/187KB4 41.6KV (RU-MP, LR-PPT)	2 Mi.-1952; 8 Mi.-1965
Line 173	Tamarac 445 41.6KV (LR-TAT)	7 Mi.-1964
Line 211	Miltona 187KB1/187KB2 41.6KV (RU-HM, LR-BET)	1 Mi.-1965; 7 Mi.-1973
Line 212	Miltona 187KB1/187KB4 41.6KV (RU-GL)	3 Mi.-1971
Line 251	Brandon 355 41.6KV (RU-GL)	2 Mi.-1971

The reliability for this region is generally not as good as the GRE average due to higher numbers of momentary and long-term outage events on a per substation average. Nearly all of this area is supplied from the 41.6 kV system, much of which is owned and operated by OtterTail Power Company. The line age table shows several segments of older line where replacement may need to be considered. The line age and maintenance information for this area is not complete since data for the OTP owned portion is not included. GRE is continuing to work with OTP to improve reliability on the transmission system serving this area.

Line 154 from Hoot Lake is a 35 mile 41.6 kV line serving three substations. The line has an open switch connection to a 41.6 kV line from Henning. Its reliability performance places it among the worst lines for each of the six indices used (in the worst 10 for five of the indices). The maintenance reports do not show any significant maintenance activity, but the majority of the line is owned by OTP. Remote control switches are planned at Kristie Jct. to improve outage restoration.

Line 213 from Walden is a 60 mile 41.6 kV line serving three substations. The line has open switch connections to 41.6 kV lines from Morris and Elbow Lake. Its reliability performance places it among the worst lines for each of the six indices used, including being second worst for the number of momentary outages. The maintenance reports show a few pole condition incidents, but the majority of the line is owned by OTP. A ground fault neutralizer was added at Walden in 2004 and relay setting changes have been made to improve performance.

Line 159 from Frazee is a 36 mile 41.6 kV line serving four substations. The line has an open switch connection to a 41.6 kV line from Rush Lake. Its reliability performance places it among the worst lines for each of the six indices used. The maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. There are no recent or planned projects to improve reliability of this line.

Line 163 from Henning is a 25 mile 41.6 kV line serving two substations. The line has an open switch connection to a 41.6 kV line from Hoot Lake. Its reliability performance places it among the worst lines for each of the six indices used. The maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. There are no recent or planned projects to improve reliability of this line.

Line 158 from Hoot Lake is a 38 mile 41.6 kV line serving three substations. The line has an open switch connection to a 41.6 kV line from Pelican Rapids. Its performance is worse than the GRE average on all six of the indices used, with high numbers of momentary outages having the biggest impact. The maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. A ground fault neutralizer was added at Hoot Lake in 2003 reducing the number of momentary outages, but the reliability is still below average.

Line 172 from Wahpeton is a 49 mile 41.6 kV line serving one substation. The line has open switch connections to 41.6 kV lines on the North Dakota system. Its performance is worse than the GRE average on four of the six of the indices used, with long outage duration having the biggest impact. Much of the outage time was due to a single ice storm. The maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. The new OTP Mapleton substation will reduce the transmission line length exposure for this line.

Line 209 from Alexandria is a 20 mile 41.6 kV line serving three substations. The line has an open switch connection to a 41.6 kV line from Miltona. Its performance is worse than the GRE average on all six of the indices used, with high numbers of momentary outages having the biggest impact. The maintenance reports show a few incidents of cross-arm and insulator damage for this line, which was built in the 1960s. There are no recent or planned projects to improve reliability of this line.

Line 208 from Brandon is a 23 mile 41.6 kV line serving three substations. The line has an open switch connection to a 41.6 kV line from Elbow Lake. Its performance is worse than the GRE average on all six indices used, mainly due to the number of momentary outage events. The

maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. A ground fault neutralizer was installed at Brandon in 2006 to reduce the number of momentary outages.

Line 168 from Hoot Lake is a 27 mile 41.6 kV line serving two substations. The line has open switch connections to 41.6 kV lines from Wahpeton and Elbow Lake. Its performance is worse than the GRE average on five of the six indices used, mainly due to the number of momentary and long-term outage events. The maintenance reports do not show any significant activity, but the majority of the line is owned by OTP. There are no recent or planned projects to improve reliability of this line.

Existing Deficiencies

Studies in this region show several low voltage and line overload violations at system intact and during contingency conditions. Multiple substations along the Hoot Lake to Henning 41.6 kV system experience low voltage problems for the loss of Hoot Lake 115/41.6 kV transformers or Henning 230/41.6 kV transformer. The loss of Frazee 115/41.6 kV transformer causes low voltage problems at multiple substations along the Frazee to Perham 41.6 kV system. The Hoot Lake 115/41.6 kV, 29.9 MVA, transformer, Hoot Lake to Aurdal 41.6 kV 17 MVA line, Pelican Rapids 115/41.6 kV, 10 MVA, and 12.5 MVA, transformers and Tamarac 115/41.6 kV, 12.5 MVA, transformers are overloaded during contingency or system intact conditions in the near term. These and other identified transmission problems along with their recommended solutions are discussed in the following sections.

Future Development

Load Forecast

The following table forecast the total load served by the transmission system in the region. This load forecast includes GRE, OTP and MRES loads.

Season	2011	2021	2031
Summer	461.6	560.4	703.9
Winter	453.4	548.2	673.9

Planned Additions

The following substations are planned by the cooperatives and will come online during the LRP time period. Loads to be served from the planned new substations have been forecasted and incorporated in the LRP studies. These substations are planned either to unload existing distribution substations, or serve new loads coming to the cooperative's service territory.

- REA has proposed to add the Lake Mina distribution substation in 2008. This substation will tap the OTP Brandon - Alexandria 115 kV line.
- AEC has proposed to double end the Vector Hanson distribution substation in 2008. This sub will unload the existing Victor Hanson sub and pick up new loads in the area.
- REA has proposed a Solem distribution substation in the 2015 timeframe. This substation will tap the OTP Hoffman to Kensington 41.6 kV line.

Frazee - Perham - Rush Lake Area

Loads in this area are served by two 115/41.6 kV substations from Frazee and Rush Lake with normally opens located at Dent tap and North Perham Junction. There are 8 GRE distribution substations and 3 OTP distribution substations in the area. There is a total of 91.24 miles of 41.6 kV transmission lines in the area. The following forecast is the load served in the area which includes both GRE and OTP loads.

Season	2011	2021	2031
Summer	42.1	52.0	67.3
Winter	42.6	52.4	66.9

Long-term Deficiencies

The long-term system intact voltage profile of the area is good. Contingency analyses however show several voltage violations in the area. The loss of the Frazee 115/41.6 kV transformer cause low voltage problems at Frazee, Dora, Evergreen and Burlington in the 2008 timeframe. This outage also overloads the Rush Lake to Otto 41.6 kV, 28.8 MVA, line in the 2008 timeframe. This line is capable for 43.2 MVA flow, but it is limited to a maximum flow of 28.8 MVA by a CT (current transformer) and 34.6 MVA by a RLL (Relay Load Limit).

Alternatives

Three options have been considered to address the short-term and long-term needs of the area. All options for this area recommend installing a 3 MVAr capacitor bank at Perham in the 2009 timeframe and adjusting the CT and RLL at Rush Lake so that the Rush Lake to Otto line is capable to handle a higher flow.

Estimated Year	Facility	Cost
2008	CT and RLL at Rush Lake Adjustment	NA
2009	Perham - Install 3 MVAr capacitor bank	$227,000

Option 1: Install a second 115/41.6 kV, 43 MVA transformer at Frazee

This option involves installing a 3 MVAr capacitor bank at Perham in the 2009 timeframe and a 1.8 MVAr capacitor bank at Dent in the 2011 timeframe. These capacitor banks will keep the voltage in the area within the acceptable limits up to the 2012 timeframe. In the 2012 timeframe, this option recommends a second 115/41.6 kV, 43 MVA transformer at Frazee. This transformer eliminates the low voltage and line overload problems in the area for the loss of existing Frazee 115/41.6 kV, 43 MVA transformer. This area will yet experience low voltage problems in the 2015 timeframe for the loss of Frazee to Perham 41.6 kV line. This option recommends rebuilding the high impedance radial 9.8 mile Dent tap to Dent 41.6 kV line with 477 ACSS conductor in the 2015 timeframe. The Dent tap to Dent 41.6 kV line currently has a 2/0A conductor, which contributes to a higher loss and a steep voltage drop across it. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2009	Perham 3 MVAr Cap Bank Installation	$227,000
2011	Dent 1.8 MVAr cap Bank Installation	$222,200
2012	Frazee - Install a second 115/41.6 kV, 43 MVA transformer	$1,973,000
2015	Dent - Rebuild tap to Dent 10 mile line with 477 ACSS	$2,450,000

Option 2: North Perham Jct 115/41.6 kV Source

This option recommends capacitor bank installations at Perham and Dent in the 2009 and 2011 timeframes respectively. A 3 MVAr capacitor bank at Perham and 1.8 MVAr capacitor bank at Dent will provide voltage support in the area up to the 2012 timeframe for the loss of Frazee 115/41.6 kV transformer. In order to address the voltage and transmission line overload in the area for a long-term, this option recommends a 115/41.6 kV, 70MVA source at North Perham Jct. This sub will tentatively be located north of the city of Perham and will tap11 miles from Frazee along the Frazee – Rush Lake 115 kV line. The following is the estimated timeline and cost of installation for option 2.

Estimated Year	Facility	Cost
2009	Perham 3 MVAr Cap Bank	$227,000
2011	Dent 1.8 MVAr cap Bank	$222,200
2012	North Perham Jct 115/41.6 kV, 70 MVA source	$4,335,000

Option 3: 115 kV load conversion

This option recommends installing a 3 MVAr capacitor bank at Perham in the 2009 timeframe, and converting GRE's Frazee, OTP's Frazee and GRE's Perham 41.6 kV subs to 115 kV in the 2009, 2013 and 2020 timeframes respectively. It also recommends a new 115/41.6 kV, 70 MVA source at North Perham Jct in the 2021 timeframe to address the low voltage and line overload concerns in the area. The following is the estimated timeline and cost of installation this option.

Estimated Year	Facility	Cost
2009	3 MVAr Capacitor bank at Perham	$227,000
2009	Convert GRE's Frazee sub to 115kV	$515,000
2013	Convert OTP Frazee sub to 115kV	$515,000
2020	Convert GRE Perham sub to 115kV	$883,000
2021	North Perham Jct 115/41.6 kV, 70 MVA source	$4,235,028

Generation Options

Generation options are not considered in this area

Present Worth

Present worth analysis was performed in all of the three options. Line losses for the area was evaluated with Option 1 being the benchmark for loss saving. The MW loss saving for each option is as follow:

Option	2011 Summer	2021 Summer
2	-	0.1
3	-	-0.1

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$6,680,000	$10,764,000	NA
2	$5,978,000	$10,421,000	$10,631,000
3	$12,499,000	$13,368,000	$13,987,000

Option 2 is the least cost plan which involves the minimum cumulative investment

Viability with Growth

All considered options address the long-term transmission needs of the area. The North Perham Jct source in option 2 divides loads in the area almost equally to the Rush Lake, Frazee and North Perham Jct 115/41.6 kV sources. As a result, it relieves loading on the lines and transformers in the area. In addition to being the least expensive plan, option 2 is better positioned to serve new loads coming to the area for a longer term than either option 1 or option 3. Therefore, option 2 is the recommended plan to address the long-term needs of the area.

Henning - Hoot Lake Area

This area is primarily served by a 230/41.6 kV source from Henning and 115/41.6 kV source from Hoot Lake. There are 5 GRE and 6 OTP distribution substations in the area. The area constitutes 55 miles of 41.6 kV transmission lines with a normally open at Battle Lake tap. The following forecast is the total load served in the area.

Season	2011	2021	2031
Summer	35.7	41.5	49.2
Winter	28.7	35.3	42.0

Long-term Deficiencies

This area experienced low voltage problems in the past, and capacitor banks were installed at multiple substations along the 41.6 kV system for voltage support. Due to severe low voltage problems and high voltage rise issues in the area, some of the installed capacitors were made to come online in steps of two. The existing capacitor banks will support the voltage in the area up the 2010 timeframe. Contingency analyses show that the area will experience low voltage problems in the 2011 timeframe for the loss of Henning 230/41.6 kV transformer, Henning to Vining 4.8 mile 41.6 kV line or Henning to Henning tap 2 mile 41.6 kV line. These outages also cause the Hoot Lake 115/41.6 kV, 29.9 MVA transformer to overload in the 2010 timeframe, and the Hoot Lake to Aurdal 5.9 mile 41.6 kV line to overload in the 2009 timeframe.

Alternatives

Two options were developed to address the near-term and long-term transmission needs of the area. Capacitor bank installation for voltage support was not considered as an option because this area continues to experience low voltage problems despite the number of available capacitor banks installed in the area. Moreover, the area has already reached the maximum allowable capacitor bank size to be operated in single step. Additional capacitor banks in the area must be operated in steps of two or more, which increase installation cost.

Option 1: New Silver Lake 230/41.6 kV Source

This option involves rebuilding portion of the Hoot Lake to Aurdal, 5.9 mile, 41.6 kV line in the 2009 timeframe and establishing a new 115/41.6 kV, 33.6 MVA, source at Silver Lake in the 2010 timeframe. The Hoot Lake to Aurdal 41.6 kV line consists of 0.5 mile of 3/0A and 5.4 miles of 266 ACSR conductors. This option recommends rebuilding the 3/0A portion of the line with 266 ACSR conductor. The new Silver Lake source will boost the voltage in the area and unload the 41.6 kV transmission lines including the Hoot Lake and Henning transformers. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2009	Hoot Lake Rebuild – Aurdal 0.5 mile 3/0A line with 266 ACSR	$122,500
2010	Silver Lake 230/41.6 kV, 33.6 MVA source	$3,804,000

Option 2: Hoot Lake – Inman 115 kV line

This option involves building 40 mile of new 115 kV transmission line from Hoot Lake to Inman in the 2010 timeframe and converting multiple 41.6 kV distribution substations to 115 kV. Relatively large loads in the area are found on relatively long radial lines at either sides of the Hoot Lake to Henning 41.6 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2009	Hoot Lake Rebuild – Aurdal 0.5 mile 3/0A line with 266 ACSR	$122,500
2010	Hoot Lake - Inman ~40 mile 115 kV line with 795 ACSS	$17,720,000
2010	Battle Lake 115 kV conversion	$700,000
2010	Underwood 115 kV conversion	$1,208,120

In addition to the above distribution substation conversions, this option recommends conversion of one substation per two or three year to the new 115 kV line.

Generation Option

Generation option are not considered in this area

Present Worth

Present worth analysis was performed in all the three options. Line losses for the area was evaluated with Option 1 being the benchmark for loss saving. The MW loss saving for each option is as follow:

Option	2011 Summer	2021 Summer
2	0.5	-0.2

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$2,979,000	$5,868,000	NA
2	$23,423,000	$45,949,000	$46,112,000

Option 1 is the least cost plan which involves the minimum cumulative investment. In addition to being the most expensive option, option 2 is not a likely option to be in-service in the estimated timeframe. Option 2 also recommends continuing converting the 41.6 kV subs along the Hoot Lake to Henning 41.6 kV system to 115 kV. This makes the option even more expensive as relatively large loads in the area are located on relatively lengthy radial lines.

Viability with Growth

Both considered options are capable to address the near-term and long-term transmission needs of the area. Option 2 provides a longer life time to the 41.6 kV system and more flexibility to serve existing and new loads in the area. Option 1 also strengthens the 41.6 kV system to

serve the growing loads in the area for a long-term at a minimum cumulative investment. Therefore, option 1 is the recommended plan for this area.

Rush Lake – Henning Area

This area is served from a 115/41.6 kV source from Rush Lake and 230/41.6 kV source from Henning. There are 6 distribution substations in the area of which GRE , MRES, and WAPA own 1 distribution substation each and OTP owns 3 distribution substations in the area. The total mileage of the 41.6 kV transmission lines in this area is 27. The following forecast is the total load served in the area.

Season	2011	2021	2031
Summer	13	15.8	19.2
Winter	13.1	14.2	16.54

Long-term Deficiencies

The area has good voltage and transmission line loading profile at system intact. For the loss of Rush Lake to New York Mills 41.6 kV line in the 2010 timeframe, New York mills will experience low voltage problem. For the same outage, the Henning to Henning Muni tap short 41.6 kV line is overloaded in the 2012 timeframe. This line could be limited by a CT at Henning; the CT needs to be adjusted so that the line could handle higher flow.

Alternatives:

Two alternatives were developed to address the long-term transmission deficiencies of the area. The following are the options:

Option 1: NY Mills 115 kV upgrade and 3.6 MVAr Cap bank at NY Mills

This option involves installing a 3.6 MVAr capacitor bank at GRE's NY Mills sub in the 2010 timeframe and converting OTP's New York Mills sub to 115 kV in the 2022 timeframe. The capacitor bank provides voltage support to the area up the 2022 timeframe. Conversion of OTP's NY Mills sub to 115 kV in the 2022 timeframe keeps the voltage in the area within the criteria for a long-term. This will require constructing 2 miles of 115 kV line from the NY Mills sub to the tap point on the Rush Lake to Henning 115 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2010	NY Mills - Install a 3.6 MVAr Cap Bank	$229,400
2022	NY Mills - Convert OTP's load to 115 kV	$958,000

Option 2: Rebuild Henning to NY Mills with 477ACSR conductor

This option involves installing a 3.6 MVAr capacitor bank at New York Mills in the 2010 timeframe and rebuilding 8.2 mile of 3/0A and 8.2 mile of 1/0A conductors with 477 ACSR conductor in the 2022 timeframe. The 3.6 MVAr capacitor bank will provide voltage support to the area up to the 2022 timeframe. The high impedance 3/0A and 1/0A conductors are sources of steep voltage drop in the area. Rebuilding this line will improve the voltage of the area for a long-term. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2010	NY Mills - Install a 3.6 MVAr Cap Bank	$229,400
2022	Henning – New York Mills- Rebuild 14.4 mile line with 477 ACSR	$4,018,000

Generation Options:
Generation options was not considered for this area

Present Worth
Present worth analysis was performed on each alternative with option 1 being the benchmark for loss saving. The two options were found to have the same line loss.

Option	Cumulative Investment	Present Worth
1	$2,424,000	$2,423,000
2	$8,428,000	$9,342,000

Option 1 is the least cost plan which involves the least cost cumulative investment.

Viability with Growth
Both option 1 and option 2 are capable of addressing the long-term needs of the area. There is however a significant difference in the present values of option 1 and option 2. Depending on the age and maintenance record of the 1/0A and 3/0A conductors on the Henning to New York Mills 41.6 kV line, option 2 could be a preferred project for this area. This long rage plan, however, recommends option 1 to address long-term needs of the area. A rebuild of the 1/0A and 3/0A conductor by OTP prior to the 2022 timeframe will delay the New York Mills load conversion beyond the LRP life time.

Tamarac -Pelican Rapids Area
The Tamarac - Pelican Rapids area is served by two 115/41.6 kV substations from Tamarac and Pelican Rapids. The Tamarac 115/41.6 kV sub has two 12.5 MVA transformers. Similarly Pelican Rapids is a double transformer 115/41.6 kV sub with one of the transformers rated at 12.5 MVA and the second transformer rated at 10 MVA. The area serves 2 GRE distribution substations, 2 OTP distribution substations, 1 MRES distribution substation and 1 WAPA distribution substation. The total mileage of the transmission lines in the area is 17.7 miles. The following is the forecasted load in the area.

Season	2011	2021	2031
Summer	28.3	33.6	37.2
Winter	30	35.9	38.9

Long-term Deficiencies
This area has acceptable voltage profile during contingencies up to the 2022 timeframe. In the 2022 timeframe, the Burnsville area will experience low voltage problems for the loss of the Tamarac 115/41.6 kV transformers. Contingency analyses in the area show that the Pelican Rapids transformers are overloaded in 2008 for the loss of Tamarac 115/41.6 kV source. Also the Tamarac 115/41.6 kV transformers are overloaded for the loss of Pelican Rapids transformers in the 2023 timeframe.

Alternatives:
Two alternatives were developed to address the near-term and long-term transmission deficiencies of the area. As the Pelican Rapids transformers are exceeded their emergency loading limits in 2008, it is imperative to replace these transformers with a higher capacity transformer. The area has a good voltage profile at least for the next 10 years. New

transformers in the area need to have LTC to help boost the voltage in the 2022 timeframe. The following are the options:

Option 1: Replace Pelican Rapids 115/41.6 transformers

This option involves replacing the existing Pelican Rapids 10 MVA and 12.5 MVA 115/41.6 kV transformers with a 25 MVA transformer each in the 2008 timeframe. The existing transformers at Pelican Rapids are overloaded at system intact in the 2013 timeframe and during contingency in 2008 timeframe. The new Pelican Rapids transformers are recommended to have LTC for voltage support in the 2022 timeframe.

Estimated Year	Facility	Cost
2008	Replace Pelican Rapids transformers with 25 MVA LTC transformers	$2,300,000

Option 2: 115 Load Conversions

This option involves converting loads from the 41.6 kV system to the nearest 115 kV transmission system to relieve loading on the transformers. The Pelican Rapids Turkey plant is one of the largest loads in the area, and converting it to 115 kV unloads the Pelican Rapids transformers and strengthens the voltage in the area. This option also recommends converting the Erhard 41.6 kV load to 115 kV in the 2014 timeframe. This will further relieve the loading on the Pelican Rapids transformers. Converting Erhard requires building about 1.5 miles of 115 kV line. The following is the estimated timeline and cost of installation for option 2.

Estimated Year	Facility	Cost
2008	Convert Pelican Rapids Turkey plant Load to 115 kV	$881,000
2014	Convert Erhard load to 115 kV	$702,000

Generation Options:

Generation options was not considered for this area

Present Worth

Present worth analysis was made on each alternative with option 1 being the benchmark for loss saving. The MW loss saving for each option is as follow:

Option	2011 Summer	2021 Summer
2	0.1	-0.3

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

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Option	Cumulative Investment	Present Worth	Present Worth Loss Savings
1	$2,300,000	$5,316,000	NA
2	$2,723,000	$5,088,000	$5,260,000

Option 1 is the least cost plan which involves the least cost cumulative investment.

Viability with Growth

Both options are capable of addressing the long-term transmission needs of the area. If option 2 is considered as a solution, future load conversions are required to continue unloading the Pelican Rapids transformers as loads grow in the area. This makes option 2 even more expensive. Therefore, option 1 is the recommended option that will address the long-term transmission needs of the area.

Pelican Rapids - Hoot Lake Area

The Pelican Rapids – Hoot Lake 41.6 kV system is served by two 115/41.6 kV sources from Pelican Rapids and Hoot Lake. There are 4 GRE and 5 OTP distribution substations in the area. This area consist a total of 45 miles of 41.6 kV transmission lines. Loads in the area are forecasted as follows:

Season	2011	2021	2031
Summer	14.8	17.8	20.9
Winter	17.7	21.3	25.2

Long-term Deficiencies

In the 2017 timeframe, the loss of Pelican Rapids to Pelican tap 41.6 kV line or the loss of Hoot Lake to Diversion 2.7 mile 41.6 kV line causes low voltage problems in the area. The Hoot Lake to Diversion 41.6 kV line overloads in the 2022 timeframe for the loss of Pelican Rapids to Pelican tap 41.6 kV line. The Hoot Lake to Diversion 2.7 mile line is limited by a CT at Hoot Lake. The CT needs to be adjusted so that the line can handle higher flow.

Estimated Year	Facility	Cost
2011	Hoot Lake sub - Adjust CT	NA

Alternatives:

Two alternatives were developed to address the long-term transmission needs of the area. Capacitor bank installations and substation conversations to the 115 kV system were considered in the following options.

Option 1: Capacitor bank installation

This option involves installing capacitor banks at multiple substations in the 2017 and 2022 timeframes. Installation of a 3 MVAr capacitor bank at Elizabeth in the 2017 timeframe will address the low voltage problems in the area for the loss of Pelican Rapids to Pelican tap 41.6 kV line or Hoot Lake to Divers 41.6 kV line up to the 2022 timeframe. This option also recommends a 3 MVAr capacitor bank at Erhard in the 2022 timeframe for voltage support beyond the 2022 timeframe. The following is the estimated timeline and cost of installation for option 1.

Estimated Year	Facility	Cost
2011	Hoot Lake sub - Adjust CT	NA
2017	Elizabeth - 3 MVAr capacitor bank	$227,000
2022	Erhard - 3 MVAr capacitor bank	$227,000

Option 2: 115 kV Load Conversion

This option involves converting the Erhard 41.6 kV distribution substation to 115 kV in the 2017 timeframe and installing a 3 MVAr capacitor bank at Elizabeth in the 2022 timeframe. Erhard is one of the largest loads in the area. This option recommends converting the Erhard sub to 115 kV to strengthen the 41.6 kV voltages and relive line loading on the 41.6 kV system including the Hoot Lake – Diversion 41.6 kV line. The substation conversion requires constructing nearly 1.5 miles of 115 kV line to the Erhard sub tapping the Pelican Rapids – Fergus Falls 115 kV line. Installation of a 3 MVAr capacitor bank at Elizabeth in the 2022 timeframe provides voltage support and keeps the voltage within the criteria throughout the LRP lifetime. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2011	Hoot Lake sub - Adjust CT	NA
2017	Erhard sub conversion to 115 kV	$902,000
2022	Elizabeth - 3 MVAr Capacitor Bank	$227,000

Generation Option

Generation option was not considered for this area.

Present Worth

Present worth calculations were made on each alternative with option 1 being the benchmark for loss saving. The MW loss saving for each option is as follow:

Option	2011 Summer	2021 Summer
2	-	-0.1

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$897,000	$929,000	NA
2	$3,566,000	$4,274,000	$4,217,000

Option 1 is the least expensive plan to address the deficiencies in the area.

Viability with Growth

Both options are capable to serve the existing and growing loads in the area through the LRP lifetime. Option 2 is capable to reduce the loading on the Pelican Rapids 115/41.6 kV transformers and Hoot Lake – Diversion 41.6 kV line. It, however, is over three times as expensive as option 1. The Hoot Lake to Diversion 41.6 kV line will be relieved when the CT at Hoot Lake is adjusted. The Pelican Rapids transformer overload is addressed in the Tamarac – Pelican Rapids area study in this report. Therefore, option 1 is the least expensive option to address the needs of the area.

Note: The timelines of capacitor bank installations need to be revisited if the Cap X Fargo to Monticello 345 kV project is in-service prior to the 2017 timeframe.

Benson - Kerkhoven Area

The Benson - Kerkhoven area is served by two 115/41.6 kV sources from Benson and Kerkoven and one 10 MW generator at Benson Muni. The area serves 4 GRE, 3 OTP, 1 MRES and 1 WAPA distribution substations. There is a total of 33 miles of 41.6 kV transmission lines in the area. The following is the forecasted load in the area.

Season	2011	2021	2031
Summer	16.0	19.5	24.1
Winter	16.7	13.2	19.83

Long Term Deficiencies

The study for this area includes to parts. The first part looks at the area with the Benson Muni 10 MW unit running throughout the LRP lifetime. In this case, the area was found to experience low voltage problems in the 2014 timeframe for the loss of Benson to Benson Muni 0.5 mile 41.6 kV line or loss of Kerkhoven 115/41.6 kV transformer. Transmission lines in the area are found to be within the required loading limit in the long-term. The second part of the study takes the Benson Muni 10 MW generator offline. In this case, the area was found to experience voltage collapse for the loss of Benson to Benson Muni 41.6 kV line or loss of Kerkhoven 115/41.6 transformer.

Alternatives

Alternatives to address long-term transmission needs of the area are divided into two based on the state of the 10 MW generator at Benson. Two alternatives were developed in the case where the Benson 10 MW generator is online, and one alternative was developed to address the near-term and long-term transmission deficiencies when the area is served with the Benson Muni generator taken offline in 2008.

Case 1: Benson 10 MW generator online

Option 1: Substation Conversion to 115 kV

This option involves substation conversion from the 41.6 kV to 115 kV transmission system and capacitor bank installation for voltage support in the area. The Benson Muni loads accounts close to 60% of the total load served in the area. This option recommends converting the Benson Muni distribution subs to 115 kV in the 2014 timeframe. These substations are located nearby the Benson to Kerkhoven 115 kV line and could be converted with a minimal transmission cost. This option also recommends installing a 2.4 MVAr capacitor bank at Kildare in the 2024 timeframe to provide voltage support to the area throughout the LRP lifetime. The following is the estimated timeline and cost of installation for option 1.

Estimated Year	Facility	Cost
2014	Convert Benson Muni subs to 115 kV	$1,398,000
2024	Install a 2.4 MVAr capacitor bank at Kildare	$224,600

Option 2: A second Benson to Benson Muni 41.6 kV line

This option involves constructing a second Benson – Benson Muni 0.5 mile 41.6 kV line, installing a second Benson 115/41.6 kV, 29 MVA, transformer, converting the Cashel distribution sub to 115 kV and installing a 2.4 MVAr capacitor bank at Kildare. Installing a second Benson 115/41.6 kV transformer and double circuiting the Benson to Benson Muni 41.6 kV line in the 2014 timeframe eliminates the voltage problem for the loss of Benson 115/41.6 kV

Ckt#1 transformer or Benson to Benson Muni Ckt#1 41.6 kV line. This option also recommends converting the Cashel distribution sub to 115 kV in the 2019. This requires constructing a 1 mile 115 kV line to Cashel distribution sub from a tap point on the Benson to Kerkhoven 115 kV line. A 2.4 MVAr capacitor bank is required at Kildare in the 2024 timeframe to provide voltage support to the area throughout the LRP lifetime. The following is the estimated timeline and cost of installation for option 2.

Estimated Year	Facility	Cost
2014	Benson - Install a second 115/41.6 kV, 29 MVA transformer	$1,162,000
2014	Benson to Benson Muni- Build a second 0.5 mile 41.6 kV line	$620,000
2019	Cashel convert sub to 115 kV	$644,000
2024	Kildare - Install a 2.4 MVAr capacitor bank	$224,600

Case 2: Benson 10 MW generator offline

The area was studied with the Benson Muni 10 MW generator taken offline. In this case, the system intact voltage and line loading profile of the area was found to be good. During contingencies, however, the area was found to experience voltage collapse concern in 2008 for the loss of Benson to Benson Muni 41.6 kV line. Only one alternative was considered to address the transmission needs of the area assuming that the 10 MW generator is taken offline.

Option 1: 115 kV load Conversion

This option involves converting the Benson Muni 41.6 kV substations to 115 kV in 2008. The timeline to take the generator offline and to convert the Benson loads should be the same to avoid severe voltage problem in the area during contingency. Benson Muni loads accounts close to 60% of the total load served in the area. The distributions subs are located nearby the 115 kV system, and the conversion could be done at a minimum transmission investment. This option also recommends converting the Cashel 41.6 kV substation to 115 kV in the 2019 timeframe and installing a 2.4 MVAr capacitor bank at Kildare in the 2024 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2008	Benson Muni - Convert loads to 115 kV	$1,030,000
2019	Cashel – Convert sub to 115 kV	$644,000
2024	Kildare - Install a 2.4 MVAr capacitor bank	$224,600

Generation Options

The Benson Muni 10 MW generator is available in the area, so generation options are not considered. It is important to keep this generator online until all the Benson Mini loads have been converted to 115 kV.

Present Worth

Present worth analysis was performed on each option. Option 1 was taken as the benchmark for loss saving analysis. The MW loss saving is shown in the following table.

Option	2011 Summer	2021 Summer
2	0.0	0.1

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$2,552,000	$3,502,000	NA
2	$4,319,000	$5,619,000	$5,605,000

Option 1 is the least cost plan that involves the minimum cumulative investment.

Viability with Growth
Both options address the long-term transmission needs of the area. Option 1 is more cost effective than option 2. Option one also gives the 41.6 kV system a longer life while providing options to turn off the Benson generation in an exchange with installation of capacitor banks in the area.

Benson – Appleton Area

This area is served by two 115/41.6 kV sources from Appleton and Benson. There is a total of 24.6 miles of 41.6 kV transmission lines in the area. There are 2 GRE distribution substations and 4 OTP distribution substations in the area. The following forecast is the load served in the area.

Season	2011	2021	2031
Summer	15.1	19.4	25.0
Winter	8.6	10	11.54

Long – term Deficiencies

This area has a good voltage and transmission line loading profile at system intact. In the 2024 timeframe, the area will experience low voltage problems for the Appleton to Shible Lake 41.6 kV line outage. The existing transmission lines are capable of serving the area for a long-term.

Alternatives

Only one alternative is considered to address the long-term needs of the area. The following is the option:

Option 1: Danvers 2.4 MVAr Capacitor Bank

This option involves installing a 2.4 MVAr capacitor bank at Danvers in the 2024 timeframe. This capacitor bank will address the reactive support needs of the area throughout the LRP lifetime. The following is the timeline and cost of installation for option 1.

Estimated Year	Facility	Cost
2024	Danvers 2.4 MVAr capacitor bank	$224,600

Viability with Growth

Option 1 is capable of addressing the long-term voltage support needs of the area. The existing transmission lines are capable to serve loads in the area for a long-term.

Brandon – Miltona – Parker Prairie Area

This area is served by two 115/41.6 kV sources from Miltona and Brandon. These sources serve the Miltona Brandon 41.6 kV loop in the area including the radial GRE and OTP Parkers Prairie distribution substations. There is a total 72.26 miles of 41.6 kV transmission lines in the area. There are 4 GRE and 4 OTP distribution substations in the area. Loads served in this area are forecasted as follows:

Season	2011	2021	2031
Summer	23.9	28.2	35.4
Winter	19.1	24.6	31.2

Long Term Deficiencies

The area experiences low voltage problems in the 2009 timeframe for the loss of the Miltona 115/41.6 kV source. This outage also overload the Brandon 115/41.6 kV, 33.6 MVA, transformer in the 2017 timeframe and the Brandon to Garfield, 7.6 mile, 41.6 kV line in the 2019 timeframe. The large portion of the transmission lines in the area are constructed with 1/0, 2/0 and 4/0 conductors. These conductors are highly resistive, constitute higher line losses and result in steep voltage drop across the lines. During the Miltona 115/41.6 kV source outage, loads in the area are served from the Brandon 115/41.6 kV source along the radial 41.6 kV lines. In this case, large loads, such as Parkers Prairie, are located at the radial end of the transmission lines. This results in a large voltage drop along the 41.6 kV high impedance lines and cause low voltage problems in the area.

Alternatives

Two options have been developed to address the long-term transmission needs of the area. The following are the options:

Option 1: Substation Conversion to 115 kV, Line Rebuilding and Capacitor Bank Installation

This option calls for converting Parkers Prairie 41.6 kV substations to 115 kV , rebuilding the Brandon to Garfield 1/0 and 3/0A, 7.6 mile, 41.6 kV line and installing capacitor banks in the area. The Parkers Prairie loads constitute about 32% of the total loads in the area. For the loss of the Miltona 115/41.6 kV source, Parkers Prairie experiences low voltage problem. This option recommends converting OTP's Parkers Prairie and GRE's Parkers Prairie substations to 115 kV in the 2009 and 2013 timeframes respectively. OTP's Parkers Prairie sub is located right under the Miltona to Elmo 115 kV line, and conversion of this load to 115 kV involves minimum transmission cost. Conversion of GRE's Parkers Prairie sub requires constructing 2 miles of 115 kV line from the tap position on Miltona to Elmo 115 kV line to GRE's Parkers Prairie substations.

This option also recommends rebuilding the Brandon to Garfield 7.6 mile line with a 477 ACSS conductor in the 2020 timeframe. This line currently consists of 1/0 and 3/0 conductors, which result in a steep voltage drop across the line. Rebuilding the line boosts the voltage in the Garfield and Leaf Valley areas. Lastly, this option recommends two 3 MVAr capacitor banks at Garfield and Leaf Valley in the 2022 and 2027 timeframes respectively. These capacitor banks will provide voltage support to the area throughout the LRP lifetime.

The following is the timeline and estimated installation cost for option 1:

Estimated Year	Facility	Cost
2009	Parkers Prairie - Convert OTP's sub to 115 kV	$515,000
2013	Parkers Prairie - Convert GRE's sub to 115 kV	$1,050,000
2020	Brandon to Garfield Rebuild 7.6 mile 41.6 kV line with 477 ACSS conductor	$1,470,000
2022	Garfield - Install 3 MVAr Capacitor Bank	$227,000
2027	Leaf Valley - Install 3 MVAr Capacitor Bank	$227,000

Note that the above projects could be delayed for two years with the installation of a 2.4 MVAr capacitor bank at Parker Prairie.

Option 2: A second Miltona Transformer and 41.6 kV Line Rebuild

This option involves installing a second 115/41.6 kV, 30 MVA, transformer at Miltona, and constructing a second Miltona to Miltona tap 2 mile 115 kV line. The critical contingencies in the area are the loss of the Miltona 115/41.6 kV transformer and the Miltona to Miltona tap 1.2 mile 115 kV line. Installing a second transformer at Miltona will eliminate problems due to the first transformer outage. Similarly, construction of new 115 kV, 2 mile, line from Miltona to Miltona tap will eliminate the voltage problems for the loss of the existing 1.2 mile 115 kV line. This line needs to be built on a different right of way to avoid common structure outage. This option also recommends rebuilding the Brandon to Parker Prairie 27.3 mile line with 477 ACSS conductor. This line currently has 2/0 and 3/0 conductors, which constitute higher losses and cause significant voltage drop . The project start date could be delayed by two years with the installation of a 2.4 MVAr capacitor bank at Parkers Prairie in 2009. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2009	Install 2.4 MVAr capacitor bank at Parker Prairie	$223,000
2011	Rebuild Parkers Prairie –Brandon 27.3 mile with 477 ACSS	$6,615,000
2011	Construct 2 mile 115 kV line from Miltona tap - Miltona	$736,000
2011	Add a second Miltona 115/41.6 kV, 30 MVA transformer at Miltona	$929,000

Generation Option

Generation option was not considered for this area.

Present Worth

A present worth analysis was performed in each option with option 2 being the benchmark for loss saving. The following table shows the MW loss saving.

Option	2011 Summer	2022 Summer
1	0.0	0.11

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$6,109,000	$7,487,000	NA
2	$10,098,000	$19,466,000	$21,234,000

Option 1 is the least cost plan which involves the least cumulative investment

Viability with Growth

Both options are capable to address the long–term transmission needs of the area. Large loads such as Parkers Prairie and Leaf Valley are served on a radial high impedance line when losing the Miltona 115/41.6 kV transformer or Miltona to Miltona tap 115 kV line. This results in low voltage problems in the Parkers Prairie area. Converting the Parkers Prairie subs to 115 kV avoids low voltage problems in the area. It also relieves the Brandon transformer and the entire 41.6 kV lines in the area. Therefore, option 1 is the recommended and least expensive plan for this area.

Alexandria - Miltona Area

This area is served by two 115/41.6 kV sources from Alexandria and Miltona. There are 4 GRE distribution substations and 2 OTP distribution substations in the area. There is a total of 21 miles of 41.6 kV transmission lines in the area. Loads in the area are forecasted as follows:

Season	2011	2021	2031
Summer	21.2	29.6	32.8
Winter	20.5	28.1	30.7

Long-term Deficiencies

The 41.6 kV system in the area from Lake Mary Tap to Parkers Prairie tap, 26.67 mile, has a 4/0 conductor rated at 7.1 MVA. This line is overloaded in both system intact and contingency conditions. The line currently is being surveyed and will undergo temperature upgrade in 2008. For the loss of the Alexandria 115/41.6 kV transformer, the Miltona 115/41.6 kV transformer overloads in the 2010 timeframe. This area also experience low voltage problems in the 2013 timeframe for the loss of Lake Mary Tap to Hudson 41.6 kV line.

Alternatives:

This area is highly impacted by the CapX Fargo to Monticello 345 kV project as the project strengthens the 115 kV system in Alexandria area. When the Cap X project is in-service in the 2015 timeframe, the area will have a good voltage profile at system intact or contingency conditions. Only one option was developed to address the transmission deficiencies of this area. The following is the option.

Option 1: Substation Conversion to 115 kV

This option involves converting the Hudson and Le Home Dieu 41.6 kV subs to 115 kV in the 2010 and 2013 timeframes respectively. Converting the Hudson load to 115 in the 2010 timeframe relives the Miltona transformer overload up to the 2013 timeframe. The Le Homme Dieu load conversion will further relive the Miltona transformer overload up to the 2017 timeframe. The Hudson sub will tap the Alexandria to Douglas County 115 kV line, and the Le

Homme Dieu sub will tap the Alexandria to Miltona 115 kV line. The Brandon to Miltona to Parkers Prairie area study recommends the conversion of the Parkers Prairie loads to 115 kV in the 2013 timeframe. This conversion along with the Hudson and Le Homme Dieu substations conversion relieves the Miltona transformer loading up to the 2028 timeframe. Further load conversion in the area or a second transformer at Miltona may be necessary to serve loads within the criteria beyond the 2028 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2008	Alexandria-Parkers Prairie, 26.7mile, 41.6 kV line temperature upgrade	$2,140,000
2010	Hudson sub 115 kV Conversion	$714,000
2013	Le Homme Dieu sub 115 kV Conversion	$714,000

Generation Option
Generation option was not considered for this area.

Viability with Growth
This option is capable to address the long-term transmission needs of the area. The Cap X Fargo to Monticello 345 kV project anticipated to be in-service in the 2015 timeframe will have a 345/115 kV bulk substation in the Alexandria area. This substation improves the 115 kV system voltage in the area, which subsequently improves the 41.6 kV voltage profile.

Graceville - Ortonville Area
This area is served by two 115/41.6 kV sources from Graceville and Ortonville. There is a total of 24 miles of 41.6 kV transmission lines in this area. There are 1 GRE distribution substation and 3 OTP distribution substations in the area. Loads in this area are forecasted as follows.

Season	2011	2021	2031
Summer	10.9	12.5	14.3
Winter	9.6	11.1	13.2

Long-term Deficiencies
The area has a good system intact voltage profile for a long-term. In the 2016 timeframe, the Ortonville 115/41.6 kV transformer will reach 100% loading limit at system intact. For the loss of the Ortonville 115/41.6 kV transformer or Ortonville to Ortonville Muni 41.6 kV line, the area experiences low voltage problems at multiple substations. For these outages, the voltage at Clinton distribution sub will drop down to 0.92 per unit in the 2010 timeframe. The Ortonville 22 MVA transformer will overload in the 2013 timeframe for the loss of Graceville 115/41.6 kV transformer.

Alternatives
Two options have been developed to address the long-term transmission needs of the area. In all the options, adjusting the taps of Graceville transformer is recommended to boost the 41.6 kV voltages in the area. The following are the options:

Estimated Year	Facility	Cost
2010	Graceville 115/41.6 kV transformer taps adjustment	NA

Option1: Capacitor Bank and a second Ortonville transformer Installation

This option involves installing capacitor banks at Clinton and Othonville Muni subs for voltage support, and adding a second transformer at Ortonville for eliminating existing transformer overload. A 2.4 MVAr capacitor bank at Clinton in the 2010 timeframe maintains the voltage within the required limits up to the 2016 timeframe. A 2.4 MVAr capacitor bank at Ortonville Muni in the 2016 timeframe provides voltage support to the area for a long-term. This option also recommends a second Ortonville 115/41.6 kV, 22 MVA, transformer in the 2013 timeframe. The second transformer eliminates the existing transformer overload and avoids voltage problems due to the loss of the existing Ortonville transformer. This option requires constructing a second Ortonville to Ortonville Muni 0.4 mile line on a new corridor in the 2021 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2010	Clinton - Install 2.4 MVAr Cap bank	$224,600
2013	Ortonville - Second 115/41.6 kV, 22 MVA, transformer	$1,558,294
2016	Ortonville Muni - Install 2.4 MVAr Cap bank	$224,600
2021	Ortonville to Ortonville Muni - Build 0.4 mile line	$550,000

Option 2: Ortonville – Ortonville Muni 0.4 mile line

This option involves building a 41.6 kV, 0.4 mile line from Ortonville to Ortonville Muni on a different corridor from the existing Ortonville to Ortonville Muni line to avoid common structure outage. This eliminates the low voltage problems in the area for the loss of the existing 0.4 mile Ortonville to Ortonville Muni line outage. This option also recommends a second Ortonville 115/41.6 kV, 22 MVA, transformer in the 2013 timeframe. This will eliminate the existing transformer overload at system intact or during contingencies in the area. In addition, the second transformer will eliminate the low voltage problems for the existing transformer outage.

Estimated Year	Facility	Cost
2013	Ortonville to Ortonville Muni - Build 0.4 mile line	$550,000
2013	Ortonville - second 115/41.6 kV, 22 MVA, transformer	$1,558,294

Present Worth

Present worth analysis was performed on each option with option 1 being the benchmark for loss savings. The following table shows the MW loss saving.

Option	2011 Summer	2021 Summer
2	-0.1	0.0

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$3,867,000	$5,543,000	NA
2	$2,821,000	$4,670,000	$4,612,000

Option 2 is the least expensive plan which involves the least cumulative investment.

Viability with Growth

Both options are capable to address the long-term transmission needs of the area. Option 2 is the recommended and the least expensive option to address the needs of the area for a long-term.

Walden - Elbow Lake Area

This area is served by two 115/41.6 kV sources from Walden and Elbow Lake. There are 4 GRE distribution substations and 7 OTP distribution substations in the area. There is a total of 77.5 miles of 41.6 kV transmission lines in the area. Loads in this area are forecasted as follow:

Season	2011	2021	2031
Summer	19.4	25.5	30.73
Winter	23	28.8	33.67

Long-term Deficiencies

The fact that the 115 kV system in the area is weak result in a weak 41.6 kV system, which experiences low voltage problems at system intact and contingency conditions. The loss of Elbow Lake 115/41.6 kV transformer or Elbow Lake to Barrette 41.6 kV line causes low voltage problems at Rossville in the 2010 timeframe and in the Hoffman and Holmes City areas in the 2011 timeframe. These outages also cause the Walden to Cyrus 41.6 kV line and Walden 115/41.6 kV transformer to overload in the 2013 and 2018 timeframes respectively. The loss of the Morris to Morris tap 6 mile 115 kV line cause low voltage on the 115 kV system as well as on the 41.6 kV system around the Holmes City and Framnas area in the 2012 timeframe.

Alternatives:

Four options were developed to address the long-term transmission needs of the area. The CapX Fargo to Monticello 345 kV project that will have a bulk substation at Alexandria will strengthen the 115 kV system in the area beyond the 2015 timeframe. None of the options will be long lasting otherwise. The following are the options:

Note that the tap position for the Elbow Lake 115/41.6 kV transformer should be adjusted to boost the voltage on the 41.6 kV system. Similarly, the Walden 115/41.6 kV transformer tap should be adjusted for voltage support on the 41.6 kV system. The following are common to all options:

Estimated Year	Facility	Cost
2009	Cyrus - Motor Operated switch	$135,000
2009	Elbow Lake 115/41.6 kV transformer tap adjustment	NA
2009	Walden 115/41.6 kV transformer tap - adjustment	NA

In all of the alternatives, a motor operated switch at Cyrus is recommended in the 2012 timeframe. This switch will help divide loads in the area to be served from two sources rather than one source when losing the Elbow Lake transformer, Elbow Lake transformer, Elbow Lake – Barrette 41.6 kV line or Walden to Cyrus jct 41.6 kV line. The high side tap settings of the Walden transformer should be lowered a step to 0.95 per unit, and the Walden transformer should also be lowered a step from the current position, 1.025 per unit to 1.0 per unit. The transformer taps needs are recommended to be adjusted in the 2009 timeframe. Moreover, CT (current transformer) and RLL (Relay Load Limit) at Walden and Elbow Lake need to be adjusted so that the Walden to Cyrus jct and the Elbow Lake to Barrett 41.6 kV lines could accommodate higher flow.

Option 1: Capacitor Bank Addition

This option involves installing capacitor banks at multiple substations in the 2012 timeframe. This option recommends installing a 2.4 MVAr and 1.2 MVAr capacitor banks, respectively, at Hoffman Junction and Holmes City in the 2012 timeframe and a 2.4 MVAr capacitor bank at Framnas in the 2017 timeframe for voltage support in the area. The Framnas and Holmes City capacitor banks will maintain the voltage within the criteria up to the 2015 timeframe. The recommended plan to strengthen the 115 kV system from Morris to Minnvalley (See Morris – Minnvalley Area in the West Central Study) needs to in service by the 2015 timeframe for these cap banks to support voltage for longer term. The CapX Fargo to Monticello 345 kV project, which is expected to be in-service in the 2015 timeframe, will strengthen the voltage along the 115 kV system in the area. This intern strengthens the voltage along the 41.6 kV systems in the Walden – Elbow Lake area. These projects designed to improve voltage along the 115 kV transmission systems, which feed the Elbow Lake – Walden 41.6 kV system, are crucial and need to in-service in the 2015 timeframe for this alternative to last throughout the LRP lifetime.

Estimated Year	Facility	Cost
2012	Framnas - 2.4 MVAr Capacitor Bank	$224,600
2012	Holmes City - 1.2 MVAr Capacitor Bank	$219,800
2017	Framnas - 2.4 MVAr Capacitor Bank	$224,600

Option 2: New 115/69 kV source at Roseville

This option calls for establishing a new 115/41.6 kV source at Roseville and reconfiguring the normally opens in the area in the 2012 timeframe. This sub will tap the Grant County to Morris 115 kV line 7 mile on the West side of Roseville. When the new source is in-service, the Roseville to Cyrus junction 41.6 kV line will be operated as normally closed, the Roseville to Hoffman junction 41.6 kV line will be operated as normally open, and the Framnas to Cyrus 41.6 kV line will be operated as normally open. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2012	Roseville 115/41.6 kV source	$6,277,771

Option 3: New 115/69 kV source at Holmes City

This option involves establishing a new 115/69 kV sub at Holmes City in the 2012 timeframe. This requires constructing about 17 miles of 115 kV line from Alexandria switching station to

Holmes city in the 2012 timeframe. The following is the estimated time line and cost of installation for this option.

Estimated Year	Facility	Cost
2012	Holmes City - 115/41.6 kV Source	$3,451,771
2012	Alex Switching to Holmes- 7 mile, 115 kV line	$6,256,000

Option 4: New 115/69 kV source at Alexandria and New 69 kV line from Alexandria to Lawry though the Holmes City

This option involves building a 69 kV line from Alexandria switching station to Xcel's Lowry substation in the 2012 timeframe. This line will be designed to pick up GRE's Holmes City load and White Bear Lake loads. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2012	Holmes City convert to Load to 69 kV	$400,000
2012	White Bear Lake conversion to 69 kV	$400,000
2012	Alexandria - 115/69 kV Source	$3,451,771
2012	Alex Switching to Lawry - 28 mile 69 kV line	$10,304,000

Present Worth:

Present worth analysis was performed in each alternatives with option 1 being the benchmark for loss saving. The following is the MW loss saving for each alternative.

Option	2015 Summer	2021 Summer
2	0.01	-0.1
3	0.01	0.7
4	0.4	0.9

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$894,000	$1,438,000	NA
2	$7,926,000	$13,929,000	$13,764,000
3	$12,256,000	$21,455,000	$21,961,000
4	$20,750,000	$36,327,000	$37,270,000

Option 1 is the least cost alternative that involves minimum investment.

Viability with Growth

Option 2, option 3 and option 4 are capable to address the long-term transmission needs of the area. Option 1, the least cost plan, and is contingent with CapX's Fargo to Monticello 345 kV project being in-service in the 2015 timeframe, and the recommended plan for the Morris to

Minnvalley Area being implemented by the 2015 timeframe. It is not a viable option otherwise. The need for a new 115/41.6 kV source in the area needs to be studied in the 2030 timeframe or in the next long range plan. Option 1 is the recommended plan for the area .

Elbow Lake- Morris

The Elbow Lake Morris area is served from the Elbow Lake and Morris 115/41.6 kV substations. There is one GRE distribution substation, 6 OTP distribution substation and 2 MRES distribution substations in the area. There is a total of 49.2 miles of 41.6 kV transmission system in the area. The following table is the load served in the area.

Season	2011	2021	2031
Summer	10.2	12.6	15.78
Winter	12.7	15.8	19.41

Long-Term Deficiencies

The area has good system intact voltage and transmission line loading profile. Contingency analysis in the area showed low voltage problem in the area. For the loss of the Morris to Donnelly 4 mile 69 kV line, the voltage at the Donnelly sub drops to 0.93 per unit in 2011 and 0.78 per unit in the 2021 timeframes.

Alternatives:

One alternative was developed to address the long-term needs of the area.

Option 1: Convert Donnelley Sub to 115 kV

This option includes converting Agralite's Donnelley 41.6 kV distribution substation to 115 kV. This requires constructing a 1 mile 115 kV line from future Donnelley tap on the Morris Pelican Rapids 115 kV line to Donnelley in the 2011 timeframe. This sub conversion keeps the voltage in the area within the limits up to the 2021 timeframe. Capacitor bank installation or continuation of the load conversion to 115 kV is required to keep the voltage within the criteria beyond the 2021 timeframe. The following is the estimated timeline and cost of installation for this option.

Year	Facility	Cost
2011	Donnelley sub conversion to 115 kV	$1,225,000

Generation Options

Generation options are not considered in this area

Viability with Growth

This option addresses the needs of the area up the 2021 timeframe. A capacitor bank at Wendell and Herman will be required for voltage support to the 41.6 kV system beyond the 2021 timeframe. The Donnelly sub will however be served from the 115 kV system without low voltage concerns.

Fergus Falls Area

The Fergus falls area is primarily served from the Fergus Falls 230/115 kV source and from the Audubon 230/115 kV source during the Hoot Lake – Edgetown tap 1.1 mile 115 kV line outage. The Fergus Falls ethanol plant load and OTP's Edgetown load are the largest loads in the area being served on a 4.5 mile radial 115 kV line from Hoot Lake. The following is the load forecast of the area.

Season	2011	2021	2031
Summer	30.1	35.6	42.3
Winter	29.5	33.7	38.6

Long-term Deficiencies

Lake Region electric cooperative established the second Fergus Falls substation to serve the new ethanol producing plant which is up and running as of 2008. This sub along with OTP's Edgetown sub is served on a 4.5 mile radial 115 kV line. The Fergus Falls and Edge town loads are the largest in the area and are projected to be 30 MW in the 2011 timeframe. These subs are served from the Audubon 230/115 kV source on a 51 mile 115 kV line when losing the Edge town tap – Hoot Lake 115 kV line. This resulted in low voltage at Fergus Falls. In order to mitigate the low voltage problem in the Fergus Falls area in the near-term, a 20 MVAr capacitor bank at Tamarac was planned to be in-service in the 2009 timeframe. This capacitor bank will help the voltage in the area up the 2012 timeframe. In order to address the voltage problems in the area for a long-term the following alternatives were considered.

Alternatives

Only one alternative was developed to address the long-term transmission needs of the area. Capacitor bank installation as long-term solution to the Fergus Falls area was not considered as the existing substations in the Fergus Falls area have space and voltage rise limitations. The following is the alternative.

Option 1: Fergus Falls – Fergus Falls Tap 1 mile double circuit line.

This option involves constructing a 1 mile double circuit 115 kV line from the Fergus Falls 230/ 115 kV sub to a tap point 1.5 miles north of Edgetown tap along the Edgetown to Tamarac 115 kV line. This line will sectionalize the 115 kV line and significantly reduce the voltage drop across the long radial Edgetown tap to Audubon 115 kV line during the critical Edgetown – Hoot Lake 115 kV line outage. In addition, this project creates a mini 115 kV loop with the Fergus Falls – Hoot Lake – Edgetown tap 115 kV line near the Fergus falls area. The 115 kV loop provides alternative paths to serve the Edgetown and Fergus Falls loads from the Fergus Falls 230/115 kV source during contingencies. This project puts the Fergus Falls area within 7 miles from the nearest Fergus Falls 230/115 kV source during the loss of the Hoot Lake – Edgetown 1.1 mile 115 kV line. The following is the estimated timeline and cost of installation for this option.

Year	Facility	Cost
2012	Fergus Falls – Fergus Falls tap 1-mile Double ckt 115 kV line	$1,679,000

Generation Option

Generation option was not considered for this area.

Viability with Growth

This option is capable to address the transmission needs of the area for a long-term. The project sectionalizes the area, creates a mini 115 kV loop and eliminates the 51 mile exposure of the Fergus Falls area from the Audubon source when losing the Hoot Lake – Edgetown tap 115 kV line. When the project is in-service, the Fergus Falls area will be within 7 miles from the nearest source during the Hoot Lake – Edgetown tap 115 kV line outage.

Recommended Plan

The following are the proposed projects for the GRE-OTP 41.6 kV region:

Estimated Year	Responsible Company	Facility	Cost
2008	Agralite	Victor Hanson distribution sub - Double end AEC's	NA
2008	GRE	Rush Lake - Adjust CT and RLL	NA
2008	OTP	Pelican Rapids - Replace transformers with 25 MVA LTC transformers	$2.300,000
2008	GRE	Alexandria to Parkers Prairie 26.7mile 41.6 kV line temp upgrade	$2,140,000
2008	Agralite	REA Lake Mina distribution sub	NA
2009	GRE/OTP	Perham - Install 3 MVAr capacitor bank	$227,000
2009	OTP	Hoot Lake – Aurdal Rebuild 0.5 mile 3/0A line with 266 ACSR	$122,500
2009	OTP	Parkers Prairie - Convert OTP's sub to 115 kV	$515,000
2009	GRE	Elbow Lake 115/41.6 kV transformer tap adjustment	NA
2009	GRE	Walden 115/41.6 kV transformer tap adjustment	NA
2010	GRE	Silver Lake 230/41.6 kV, 33.6 MVA source	$3,804,000
2010	GRE	NY Mills - Install a 3.6 MVAr Cap Bank	$229,400
2010	GRE	Hudson sub 115 kV Conversion	$364,000
2010	Runstone	Hudson sub 115 kV Conversion	$350,000
2010	GRE	Graceville 115/41.6 kV transformer taps adjustment	NA
2011	GRE	Donnelley Sub convert to 115 kV	$625,000
2011	Agralite	Donnelley Sub convert to 115 kV	$600,000
2011	GRE	Dent 1.8 MVAr cap Bank	$222,200
2011	OTP	Hoot Lake sub Adjust CT	NA
2012	GRE/OTP	Framnas - 2.4 MVAr Capacitor Bank	$224,600
2012	GRE/OTP	Holmes City - 1.2 MVAr Capacitor Bank	$219,800
2012	GRE/OTP	Cyrus - Motor Operated switch	$135,000
2012	GRE/OTP	North Perham Jct 115/41.6 kV, 70 MVA source	$4,335,028
2012	GRE/OTP	Fergus Falls – Fergus Falls tap 1-mile Double ckt 115 kV line	$1,679,000
2013	GRE	Parkers Prairie - - Convert GRE's sub to 115 kV	$700,000
2013	Runstone	Parkers Prairie - Convert GRE's sub to 115 kV	$350,000
2013	GRE	Le Homme Dieu sub 115 kV Conversion	$364,000
2013	Runstone	Le Homme Dieu sub 115 kV Conversion	$350,000
2013	GRE/OTP	Ortonville to Ortonville Muni - Build 0.4 mile line	$550,000
2013	GRE/OTP	Second Ortonville 115/41.6 kV 22 MVA transformer	$1,558,294
2014	GRE	Benson Muni – convert subs to 115 kV	$1,398,000
2015	Runstone	REA Solem Distribution sub	NA
2017	GRE/OTP	Hoffman Jct - 2.4 MVAr Capacitor Bank	$224,600
2020	OTP	Brandon to Garfield Rebuild 7.6 mile 41.6 kV line with 477 ACSS conductor	$1,470,000
2022	OTP	NY Mills - Convert OTP's load to 115 kV	$958,000
2022	GRE/OTP	Garfield - Install 3 MVAr Capacitor Bank	$227,000
2024	GRE	Kildare - Install a 2.4 MVAr capacitor bank	$224,600
2024	OTP	Danvers 2.4 MVAr capacitor bank	$224,600
2027	GRE/OTP	Leaf Valley Install 3 MVAr Capacitor Bank	$227,000

G: Stearns Region

The Stearns region is located west of St. Cloud roughly bounded by lines from West St. Cloud to Wakefield, Wakefield to Paynesville, Paynesville to Benson, Benson to Douglas County, Douglas County to Albany and Albany to West St. Cloud. The member systems that serve this territory are:

- Agralite Electric Cooperative (AEC)
- Meeker Cooperative Light & Power Association (MCL&PA)
- Runestone Electric Association (REC)
- Stearns Electric Association (SEA) except the GRE/MP 34.5 kV system

Agralite Electric Cooperative, based in Benson, MN, serves consumers in Swift, Big Stone, Stevens and Pope Counties in west-central Minnesota. The economy of this area is primarily driven by commercial and irrigation activities. AEC foresees new digesters and ethanol producing plants in its service territory while existing ethanol producing plant is expanding

Meeker Cooperative Light and Power is headquartered in Litchfield, MN, and its service territory includes a large portion of the rural Meeker County and portions of Kandiyohi, McLeod, Renville, Stearns and Wright Counties. The economy of the area is driven by agricultural activities and commercial and residential developments around the city of Litchfield and Lake shore areas. MCL & PA foresees large spot loads, such as ethanol producing plant at Eden Valley, new supper Wal-Mart in Litchfield and new state park in its service territory.

Runestone Electric Association (REA) is headquartered in Alexandria, MN, and its service territory includes Douglas, Grant, Otter Tail, Pope, Stevens and Todd counties. The economy of this area is driven by agriculture and light industries. Residential and commercial developments around the town of Alexandria and the surrounding Lakes Area contribute to the load growth in the REA's service territory. Irrigation activities account a significant amount of load during summer peak conditions.

Stearns Electric Association (SEA) is headquartered in Melrose, MN, and its service territory includes all of Stearns County and portions of Todd, Morrison, Douglas, Pope and Kandiyohi counties. The economy of SEA is driven by agricultural activities in the Western portion, residential, retail and small businesses in eastern potion of the service territory. Large industrial loads, such as paper mill, bus manufacturing and granite quarrying are located in the area. St. Cloud State, St. Johns and St. Benedicts universities are found in the vicinity of St. Cloud and are factors which contribute to SEA's economy. SEA has seen new light industrial loads in the past, such as pumping station. New industrial loads are expected to come to the area in the near future.

Existing System

This region consists of 115, 69 and 34.5 kV integrated transmission systems for load serving. Delivery to the 115 kV system is through Sherco 345/115 kV transformation, Benton County and Paynesville 230/115 kV transformations. The 69 kV subtransmisison system is served from Douglas County, Benson, Paynesville, Wakefield and West St. Cloud 115/69 kV sources. This region consists of 34.5 kV subtransmission systems served from Paynesville, Wakefield, Sauk River and St. Cloud 115/34.5 kV sources.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 184	Wakefield 4N114 - Maple Lake 1NB3 69KV (ST-FIT, ST-LUT)	Rank: 8
Line 222	Albany 4N86/4N90 – W. St. Cld 4N51 (ST-BR, ST-WL, ST-WW)	Rank: 26
Line 109	Glenwood 4N29 - Paynesville 4N58 69KV (AG-WL, ST-BAT)	Rank: 29
Line 225	Black Oak 4N19/4N20 - Douglas County 4N25 69KV (ST-KAT)	Rank: 33
Line 221	Albany 4N86/4N87 - Paynesville 4N32 - Wakefield 4N113 69KV (ST-AF, ST-RF, ST-ROT)	Rank: 34

Transmission Lines Built before 1980

Line 184	Wakefield 4N114 - Maple Lk 69KV (ST-FIT, ST-LUT)	9 Mi.-1969; 1Mi.-1978
Line 222	Albany 4N86/87–W. St. Cloud 69KV (ST-BR, ST-WL)	7 Mi.-1965; 8 Mi.-1969-74
Line 109	Glenwood 4N29 – Paynesville 69KV (AG-WL, ST-BAT)	6 Mi.-1967; 8 Mi.-1977
Line 225	Black Oak 4N19/20- Douglas Co. 69KV (ST-KAT)	4 Mi.-1976
Line 221	Albany 4N86/90-Paynsvl-Wakefld 69KV (ST-RF, ST-ROT)	11 Mi.-1973-78
Line 220	Albany 4N87/90– Black Oak 69KV (ST-MIT, ST-ALT)	6 Mi.-1967-71
Line 223	Black Oak 4N18/20- Paynesville 69KV (ST-ELT, ST-ZIT)	5 Mi.-1960; 1 Mi.-1978

The reliability for this region is generally about the same as the GRE average. Much of this area is served from the Xcel Energy 69 kV system. The line age and maintenance information for this area is not complete since data for the Xcel Energy owned portion is not included.

Line 184 from Wakefield to Maple Lake is a 51 mile 69 kV line serving four substations. Its reliability performance places it among the worst lines for each of the six indices used, with long term outages having the biggest impact. The maintenance reports do not show any significant activity, but the majority of the line is owned by XE. Xcel Energy has rebuilt the section of line from Wakefield to Watkins Tap in 2005, and fault locating relays are being installed at Wakefield to improve performance and restoration for this line.

Line 222 from Albany to West St. Cloud is a 38 mile 69 kV line serving four substations. Its performance is worse than the GRE average on all six of the indices used, with the biggest factors being long outage durations and the high number of consumers affected. The maintenance reports do not show any significant activity, but part of this line is owned by XE. RTU additions were completed in 2005 at Albany and West St. Cloud, which will improve outage response times.

Line 109 from Glenwood to Paynesville is a 62 mile 69 kV line serving three substations. Its performance is worse than the GRE average on all six of the indices used, with the biggest factors being the number of momentary and long term outages. The maintenance reports do not show any significant activity, but part of this line is owned by XE. There are no recent or planned projects to improve reliability of this line.

Line 225 from Black Oak to Douglas County is a 26 mile 69 kV line serving three substations. Its performance is worse than the GRE average on all six of the indices used. The maintenance reports do not show any significant activity, but the majority of this line is owned by XE. There are no recent or planned projects to improve reliability of this line.

Line 221 from Albany to Paynesville is a 47 mile 69 kV line serving four substations. Its performance is worse than the GRE average on all six of the indices used. The maintenance reports do not show any significant activity, but part of this line is owned by XE. The Farming to Big Fish Tap to Farming Tap line sections is scheduled to be rebuilt in 2007.

Existing Deficiencies

Studies in this region identified several low voltage and transmission line overload problems in the area. The West St. Cloud transformer overloaded for the loss of the Big Fish to Farming tap 115 kV line. The 69 kV line from West St. Cloud to Albany overloaded for various contingencies in the area. Analyses in the Stearns region has also identified severe low voltage problems along the Douglas County to West St. Cloud 69 kV system and Douglas County to Benson to Paynesville 69 kV system for contingencies in the area.

Future Development

Load Forecast

The following forecast is the load served by the transmission system in the region. This load includes both projected GRE and XE load.

Stearns Region Load (in MW)			
Season	**2011**	**2021**	**2031**
Summer	632.4	777.3	1035.7
Winter	475.8	568.8	730.6

Planned Additions

The following are projects that are expected to be in-service in the LRP time period. The necessity of these projects could be to unload transmission lines or transformers, serve new spot loads or pick up growing loads in the area.

- SEA has proposed a Sartell distribution substation in the 2010 timeframe. This substation will be located about 2.5 miles east of the existing Fisher Hill distribution substation. This substation is expected to tap the future 115 kV West St. Cloud to St. Ridges 115 kV line that Xcel energy is currently studying to build.
- SEA is also planning to add the Beaver Lake 115 kV distribution substation in the 2015 timeframe. This substation is expected to tap Xcel's Wakefield to St. Cloud 115 kV line.
- Grove Lake Switching station is proposed in the area in the 2009 timeframe. It will be located nearby Bangor tap where the 69 kV lines from Douglas County, Benson and Paynesville meet.
- A second Douglas County 115/69 kV, 47 MVA transformer is proposed to be in-service in the 2011 timeframe.
- Xcel Energy plans to replace Paynesville 115/69 kV, 47 MVA transformers with 70 MVA transformers each.
- Xcel Energy plans to add a second 115/34.5, 28 MVA transformer at Paynesville
- Rebuilding the Richmond to Big Fish tap to Farming 6 mile, 69 kV line is underway. This line will have 795 ACSS conductor for future 115 kV conversion capabilities.
- The Cap X Fargo to Monticello 345 kV project will have two bulk 345/115 kV substations, one in St. Cloud area and the other one in the Alexandria area. The bulk substation in the St. Cloud area is expected to be in-service in the 2011 timeframe. The substation in the Alexandria area is expected to be in-service in the 2015 timeframe.

Benson - Douglas County - Paynesville Area

This area is served by three 115/69 kV sources from Douglas County, Benson and Paynesville. The total mileage of the transmission system in this area is 109 miles. There are 8 GRE distribution substations and 7 Xcel Energy distribution substations in the area. Loads in this area are forecasted as follows:

Season	2011	2021	2031
Summer	51.9	64.6	73.8
Winter	37	45.9	48.4

Long-term Deficiencies

The voltage in the area was improved with the recent 41.6 kV to 69 kV upgrade from Benson to Williams and with a 7.2 MVAr capacitor bank installation at Ommen. The Grove Lake switching station, which is planned to be in-service in the 2009 timeframe, improves reliability in the area while improving the voltage profile on the 69 kV system during contingency. The long range plan study in this area identified low voltage problems in the 2008 timeframe for the loss Douglas County to Westport 69 kV line or Westport to Villard 69kV line. The 69 kV transmission lines loading are within the planning criteria up to the 2015 timeframe. The Grove Lake to Glenwood 69 kV line is loaded over 100% for the loss of Douglas County to Westport 69 kV line in the 2015 timeframe. This line exceeds Xcel Energy's allowable emergency overload (110%) in the 2019 timeframe.

Alternatives:

Two options have been developed to address the long term transmission needs of the area. The followings are the options:

Option 1: 69 kV Rebuild and Lowry 115/69 kV source

This option involves rebuilding the high impedance, 2/0A conductor, 69 kV lines with a 477 ACSS conductor and establishing a new 115/69 kV, 70 MVA source at Lowry. This option recommends rebuilding the Lowry to Grove Lake 13.5 miles of 69 kV line with 477 ACCS in the 2011 timeframe. This will eliminate the steep voltage dope across the line due to the high impedance conductor. The Paynesville to Belgrade 69 kV 16 mile, 69 kV line has a mixed 2/0, 3/6 and 4/0 A conductors, which result in a significant voltage drop. This option recommends rebuilding this line with a 477 ACSS conductor in the 2015 timeframe. The Westport to Douglas County 10 mile line is also a source of low voltage problem due to its high impedance 2/0 conductor. This option recommends rebuilding this line with 477 ACSS conductor in the 2015 timeframe. The line rebuilds in this option will keep the voltage within the required voltage limits at system intact or during contingency up to the 2024 timeframe. In the 2024, a new 115/69 kV, 70 MVA source is needed at Lowry to provide voltage support to the area for a long-term. This will require 13 miles of new 115 kV line from Alexandria breaker station to Lowry on a new 115 kV line corridor. The following is the estimated timeline and cost of installation for this project.

Estimated Year	Facility	Cost
2011	Lowry to Grove Lake Switching Station 13 mi rebuild with 477 ACSS	$3,900,000
2015	Paynesville to Belgrade 16 mi of 69 kV line rebuild with 477 ACSS	$4,800,000
2015	Douglas Co. – Westport 10 mi, 69 kV line rebuild with 477 ACSS	$3,000,000
2024	Alexandria to Lowry Construct 13 mi 115 kV line rebuild with 795 ACSS	$6,854,000
2024	Lowry - Establish a new 115/69 kV, 70 MVA source	$3,635,000

Option 2: Lowry 115/69 kV, 70 MVA source

This option establishes a new 115/69 kV, 70 MVA source at Lowry. This requires building 13 miles of 115 kV line from the Alexandria breaker station to Lowry on a new 115 kV corridor. This option also recommends converting Xcel Energy's Lowry distribution substation to 115 kV so as to relive the 69 kV system. The 115 kV system in the Alexandria area will be strengthened when the Cap X Fargo to Monticello 345 kV project is complete.

Estimated Year	Facility	Cost
2011	Alexandria to Lowry Construct 13 mi 115 kV line with 795 ACSS	$6,854,000
2011	Lowry - Establish a new 115/69 kV, 70 MVA source	$3,635,000
2011	Lowry Convert substation to 115 kV	$2,000,000

Generation Option:

Generation option was not considered for this area.

Present Worth

Present worth analysis was performed on each option with option 2 being the benchmark for loss saving. The loss savings in MW for each option are as follow:

Option	2011	2021
1	0.6	0.2

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$43,019,000	$46,033,000	$46,019,000
2	$36,329,000	$52,884,000	NA

In order to reflect a fairly complete comparison between the two options, the cost of rebuilding the old 2/0 conductors in the area have been added to option 2 in the present worth calculation. The Douglas County to Westport 10 mile line, Grove Lake to Lowry tap 13 mile line and Paynesville to Belgrade 16 mile 69 kV lines have 2/0 conductor and are old. These lines have been a poor source of reliability in the area as they reach the end of their life time.

Option 1 has the minimum present worth value. The difference in the cumulative investment between option 1 and option 2 is due to the time of investment for rebuilding the aged conductor in option 2. The timeframe to rebuild the line is not firm in option 2. As a result, the cost of rebuilding the old lines in the area is equally distributed between 2011 and 2024. The cumulative investment of option 2 could potentially come close to the cumulative investment of

option 1 when the time to rebuild the aged conductors is fixed. Therefore, option 1 is the recommended plan for this area.

Viability with Growth

The two options are of capable serving loads in the area for a long-term. Option 1 consists of rebuild aged 69 kV transmission lines which should be done regardless of which option is chosen as a recommended plan for the area. Moreover, option 2 requires filing CON and acquiring 13 miles of right of way. It may be unlikely to have option 2 in-service within the required timeframe. Option 1 is the recommended option for this area.

Wakefield –Paynesville—Maple Lake Area

This area constitutes about 18 miles of 34.5kV and 29.3 miles of 69kV transmission lines. The area is served primarily from the Wakefield 115/69 kV and Paynesville 115/34.5 kV sources. Liberty and Dickinson 115/69 kV sources provide service to the area during contingency. There are 4 GRE distribution substations and 6 Xcel Energy distribution substations in the area. Loads in the area are forecasted as follows:

Season	2011	2021	2031
Summer	71	88.6	111.2
Winter	53.2	76.5	105.7

Long-term Deficiencies

System intact voltage profile of the area is within the required limits for a long-term. For the loss of Wakefield to Fairhaven tap 69 kV line, however; multiple substations along the Wakefield to Fairhaven 69 kV line experience low voltage problems starting the 2013 timeframe. The Wakefield to Fairhaven tap 69 kV line will overload in the 2017 timeframe for the loss of Annandale to Maple Lake 69 kV line. The Annandale to Maple Lake 69 kV line overloads in the 2011 timeframe for the loss of Wakefield to Fairhaven 69 kV line. The Paynesville 115/34.5 kV transformer serving the radial 34.5 kV loads is overloaded at system intact in 2008. The Paynesville load is growing fast during winter. It is project to be 14 MW in 2021 and 25 MW in the 2031 timeframe.

Alternatives

Three options were developed to address the long-term transmission deficiencies of the area.

The following are the options:

Option 1: New Watkins 115/69 kV, 70 MVA Source

This option involves establishing a new 115/69 kV source at Watkins in the 2013 timeframe and installing a second Paynesville 115/34.5 kV, 28 MVA transformer in the 2008 timeframe. The new source at Watkins will eliminate the low voltage problem and the line overload problems in the area. The second Paynesville 115/34.5 kV, 28 MVA transformer unloads the existing Paynesville transformer at system intact. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2008	Paynesville – A Second 115/34.5 kV, 28 MVA transformer	$1,666,400
2013	New Watkins 115/69 kV, 70 MVA source	$4,784,028

Option 2: Paynesville to Watkins 69 kV upgrade

This option involves upgrading the Paynesville to Watkins 34.5 kV system to 69 kV leaving Xcel Energy Paynesville load to continue being served from the Paynesville 115/34.5 kV. This still requires installing a second Paynesville 115/34.5 kV, 28 MVA transformer at Paynesville and building 17 miles of new 69 kV line on a new corridor. This line will be constructed with 477 ACSS conductor. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2008	A Second Paynesville 115/34.5 kV transformer	$1,666,400
2013	Paynesville to Watkins 69 kV upgrade	$6,180,000

Option 3: Rebuild Maple Lake to Watkins 69 kV line

This option involves rebuilding the Maple Lake to Watkins high impedance mostly 3/6Cu conductor with 477 ACSS conductor. This option also recommends installing a second 115/34.5, 28 MVA transformer at Paynesville and adjusting the CT (Current Transformer) at Wakefield for the Wakefield to Luxemburg 69 kV line to accommodate more power flow. The Maple Lake to Watkins 69 kV line is 22 miles and has a mix of 2/0Cu and 3/6Cu conductors, which are sources of weak voltage along the Wakefield to Maple Lake 69 kV system during contingencies. Rebuilding this line improves the voltage in the area significantly. Moreover, the Maple Lake to Watkins 22 mile line is old and rebuilding it with a new conductor renews the age of the line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2008	Paynesville – A Second 115/34.5 kV transformer	$1,666,400
2013	Maple Lake to Watkins - Rebuild 22 mile 69 kV line with 477 ACSS conductor	$5,390,000

Generation Options

Generation options are not considered in this area.

Present Worth

Present worth analysis was performed on each option with line losses evaluated for the area with Option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011	2013	2021
2	-0.2	-0.28	-0.6
3	-0.4	-0.4	-0.4

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$7,336,000	$11,737,000	NA
2	$8,270,000	$13,221,000	$13,144,000
3	$8,147,000	$12,992,000	$13,033,000

Note that the present worth values of option 1 and option 3 include the cost of replacing the 5 MVA 69/34.5 kV transformer at Watkins with a 25 MVA transformer. This transformer was used at Watkins to serve GRE's Paynesville sub during contingency. The present worth analysis show option 1 being the least expansive plan. Option 2 and option 3 have equal present worth values.

Viability with Growth

All options are capable of addressing the long-tem needs of the 69 kV transmission system in the area. GRE's Paynesville load is one of the fastest growing loads in the area. It is a winter peaking load and is projected to be 14 MW in the 2021 timeframe and 25 MW in the 2031 timeframe. Moreover, there has been a rumor for a new ethanol plant load in the Eden Valley area. The 34.5 kV subtransmission system will not be capable to serve the growing Paynesville load and future new industrial loads in the area for a long-term. This fact makes option 1 and option 3 the least preferred options. Therefore, option 2 is the recommended plan for this area.

Douglas County – Paynesville - Wakefield-West St. Cloud Area

This area is served by four 115/69 kV sources from Douglas County, Wakefield, Paynesville and West St. Cloud. There is 156 miles of 69 kV transmission lines in the area. There are 16 GRE distribution substations, 2 MRES distribution substations, 1 WAPA distribution substation and 11 Xcel Energy distribution substations in the area. Loads in the area are forecasted as follows:

Season	2011	2021	2031
Summer	144.4	192.9	234.8
Winter	142.2	186.3	222.0

Long-term Deficiencies

The area is within the acceptable voltage limits at system intact. The West St. Cloud 115/69 kV, 46.7 MVA transformer is overloaded at system intact in the 2011 timeframe. The West St. Cloud 115/69 kV, 46.7 MVA transformer outage, Richmond to Big Fish tap 69 kV line outage and the Douglas County to Osakis 69 kV line outage are critical in the area. The loss of West St. Cloud 115/69 kV transformer causes low voltage problems at multiple substations in the area in the 2009 timeframe. Substations between Albany to West St. Cloud 69 kV line experience low voltage problems due to the West St. Cloud transformer outage. The loss of the Big Fish to Farming 69 kV line overloads the West St. Cloud transformer in the 2008 timeframe. This outage also causes the West St. Cloud to Brockway tap 69 kV line to overload starting the 2008 timeframe. The Douglas County to Osakis, Paynesville to Roscoe tap and Paynesville to Zion tap 69 kV line outages cause low voltage problems and line overload problems in the area. The Wakefield 115/69 kV, 70 MVA, transformer outage overloads the Paynesville to Richmond 69 kV line in the 2016 timeframe.

Alternatives

Four alternatives were developed to address the long-term transmission deficiencies of the area. Note that the near-term solution to the area is the same to all the alternatives. The options are as follows:

Short-term solution:

The short term solution involves replacing the West St. Cloud 46.7 MVA transformer with an 84 MVA transformer, installing a 9 MVAr capacitor bank at West Union, rebuilding the West St. Cloud to Brockway 69 kV 8.3 mile line with 477 ACSS conductor and converting the LeSauk, Westwood and St. Stephen 69 kV distribution substations to 115 kV. The LeSauk, Westwood and St. Stephen substation conversions to 115 kV eliminate the low voltage problems in the area for the loss of the West St. Cloud 115/69 kV transformer. The 84 MVA transformer at West St. Cloud is sufficient to accommodate flows to the 69 kV system for the loss of the Richmond to Big Fish tap 69 kV line. The West St. Cloud to Brockway 69 kV line has mostly a 4/0 conductor and is overloaded for the Richmond to Big Fish 69 kV line outage. Rebuilding it with 477 ACSS conductor eliminates the line overload and improves the voltage in the area. The 9 MVAr capacitor bank recommended at West Union in the 2011 timeframe address the low voltage problems in the West Union and Osakis area for the loss of Douglas County to Osakis 69 kV line. The following is the estimated timeline and cost of installation for this project.

Estimated Year	Facility	Cost
2009	Convert 69 kV load to 115 kV	$835,000
2009	West St. Cloud to St. Joseph - Rebuild 2.5 mi line with 477ACSS	$525,000
2010	St. Joseph to Brockway - Rebuild tap 5.8 mi line	$1,218,000
2010	West Union - Add 9 MVAr Capacitor bank	$251,000
2011	West St. Cloud – Replace 46.7 MVA transformer with 84 MVA	$100,000
2011	Westwood – Convert 69 kV load to 115 kV	$835,000
2015	St. Stephen – Convert the 69 kV load to 115 kV	$1,100,000

The long term solutions below are recommended with the presumption that the CapX Fargo to Monticello 345 kV project being in-service in the 2015 timeframe.

Option 1: Build Alexandria to West St Cloud 115 kV line

This option has two portions. The first option of this project involves establishing a new 115/69 kV, 70 MVA, source at Albany and converting the Sauk Centre GPKV to 115 kV in the 2016 timeframe. These require building 50 miles of 115 kV line from Alexandra to Albany on new 115 kV corridor. The 115 kV line from Alexandria to Albany will be constructed with a 795 ACSS conductor. A 10 MVAr capacitor bank is recommended at Sauk Centre in the 2016 timeframe for voltage support in the area until the second portion this option is completed. The second portion involves constructing 20 miles of 115 kV line from Albany to West St. Cloud on a new 115 kV corridor in the 2021 timeframe. This line will also be constructed with 795 ACSS conductor. The following is the estimated timeline and cost of installation for option 1.

Estimated Year	Facility	Cost
2016	Alexandria to Albany - Build 50 mile 115 kV line	$21,750,000
2016	Albany – Establish a 115/69 kV, 70 MVA, source	$3,753,000
2016	Sauk Centre load conversion to 115 kV	$1,440,000
2016	Sauk Centre - Install a 10 MVAr capacitor bank	$258,000
2021	Albany to West St. Cloud - Build 20 mile 115 kV line	$8,860,000

New 115 kV line constructions including upgrades to 115 kV are done with 795 ACSS conductor in this option.

Option 2: Build Rockville to Alexandria 115 kV line

This option has two stages with the first stage involving building 7 miles of new 115 kV line from Rockville to Big Fish with 795 ACSS conductor on a new 115 kV corridor, upgrading 11.3 miles of 69 kV line from Big Fish tap to Albany to 115 kV, establishing a new 115/69 kV, 70 MVA source at Albany, building 11 miles of 115 kV line for 69 kV operation from Albany to Melrose and converting substations along the Big Fish to Albany 69 kV line to 115 kV. This option requires a breaker station at Rockville and rebuilding the Douglas County to Sauk Centre 15.2 mile, 2/0A conductor, 69 kV line with 477 ACSS conductor. The fist stage of this option is recommended to be in-service in the 2016 timeframe. The second stage involves constructing 39 miles of 115 kV line from Melrose to Alexandria with 795 ACSS conductor on a new 115 kV right of way, upgrading the Albany to Melrose 69 kV line to 115 kV and converting the Melrose 69 kV substation to 115 kV. The second stage of this option is recommended to be in-service in the 2021 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2016	Rebuild Douglas Co to Sauk Centre 15 mi 69 kV line(477 ACSS cond)	$3,192,000
2016	Build Rockville to Big Fish 7 mi 115 kV line	$2,926,000
2016	Rockville Breaker Station	$2,379,000
2016	Farming tap to Albany 8.9 mi 115 kV line upgrade	$3,150,600
2016	Albany 115/69 kV, 70 MVA source	$3,753,000
2016	Build Albany to Melrose 11 mi 115 kV line operated at 69 kV	$4,948,000
2016	Farming Load Conversion to 115 from 69 kV	$815,000
2016	Big Fish Load conversion to 115 from 69 kV	$815,000
2021	Build Alexandria to Albany 39 mi 115 kV line	$16,802,000
2021	Albany to Melrose 69 kV 11 mi 115 kV upgrade	NA
2021	Melrose load conversion to 115 from 69 KV	$2090,000

New 115 kV line constructions including upgrades to 115 kV are done with 795 ACSS conductor in this option.

Option 3: New Alexandria to Rockville 115 kV line

The first stage of this option involves constructing 50 miles of 115 kV line from Alexandria to Albany with 795 ACSS conductor on a new 115 kV corridor, establishing a new 115/69 kV, 70 MVA source at Albany, converting the Sauk Centre 69 kV substation to 115kV and installing a 10 MVAr capacitor bank at Sauk Centre. This stage of the project is recommended to be in-service in the 2016 timeframe. The second stage of this option recommends upgrading the Albany to Big Fish 8.9 mile, 69 kV line to 115kV, constructing 7 miles of new 115 kV line from Big Fish to Rockville and establishing a breaker station at Rockville. The second stage is expected to be in-service in the 2021 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2016	Alexandria to Albany - Build 50 mile 115 kV line	$21,750,000
2016	Albany 115/69 kV, 70 MVA, source	$3,753,000
2016	Sauk Centre 69 kV substation conversion to 115 kV	$1,440,000
2016	Sauk Centre - 10 MVAr 115 kV capacitor bank	$258,000
2021	Rockville 115 kV breaker station	$2,379,000
2021	Rockville to Big - Build Fish 7 mile 115 kV line	$2,926,000
2021	Farming tap to Albany 8.9 mile 115 kV line upgrade	$3,150,600
2021	Farming load conversion to 115 from 69 kV	$815,000
2021	Big Fish 69 kV load conversion to 115 kV	$815,000

New 115 kV line constructions including upgrades to 115 kV are done with 795 ACSS conductor in this option.

Option 4: New St. Stephen to Alexandria 115 kV line

The first stage of this option involves constructing 50 miles of 115 kV line from Alexandria to Albany with 795 ACSS conductor on a new 115 kV corridor, establishing a 115/69 kV, 70 MVA source at Albany, converting the Sauk Centre substation to 115 kV and installing a 10 MVAr capacitor bank at Sauk Centre. This stage is expected to be in-service in the 2016 timeframe. The second stage of this option involves establishing a 115 kV breaker station at St. Stephen, constructing 16 miles of 115 kV line with 795 ACSS conductor from St. Stephen breaker station to Albany, upgrading the Albany breaker station to Albany 4.5 mile radial 69 kV line to 115 kV and converting the Brockway 69 kV substation to 115 kV. This sage is expected to be in-service in the 2021 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2016	Alexandria to Albany, 50 mile, 115 kV line with 795 ACSS	$21,750,000
2016	Sauk Centre 69 kV substation conversion to 115 kV	$1,440,000
2016	Sauk Centre - 10 MVAr capacitor bank	$258,000
2016	Albany 115/69 kV, 70 MVA source	$3,753,000
2021	St. Stephen 115 kV breaker station	$3,172,000
2021	St. Stephen to Albany tap 115 kV line, 795 ACSS	$6,272,000
2021	Albany breaker station to Albany 4.5 mi, 115 kV upgrade	$1,593,000
2021	Minncan 69 kV load conversion to 115 kV	$815,000
2021	Albany 69 kV load conversion to 115 kV	$815,000
2021	Brockway load conversion to 115 kV	$815,000

New 115 kV line constructions including upgrades to 115 kV are done with 795 ACSS conductor in this option.

Generation Options
Generation options are not considered in this area.

Present Worth
A present worth analysis was performed on each option with line losses evaluated for area with option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follows:

Option	2011 Summer	2021 Summer
2	-	-0.3
3	-	-0.8
4	-	-0.6

With the loss allocations, the present worth is summarized as follows:

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$62,252,000	$75,426,000	NA
2	$73,940,000	$83,001,000	$83,855,000
3	$64,866,000	$77,906,000	$77,610,000
4	$72,110,000	$84,660,000	$83,571,000

Option 1 is the least cost plan and it involves the least cumulative investment.

Viability with Growth
All the four options equally address the long-term transmission needs of the area. Option 1 is the least cost and recommended plan for this area.

Recommended Plan

The following are the proposed projects for the Stearns region:

Estimated Year	Responsible Company	Facility	Cost
2008	GRE	Richmond to Big Fish – Rebuild line with 795 ACSS conductor	$1,368,000
2008	XEL	Paynesville – A Second 115/34.5 Kv, 28 MVA transformer	$1,666,400
2009	XEL	Grove Lake Switching Station	$1,917,000
2009	GRE	LeSauk 115 kV, 3way Switch	$185,000
2009	STEARNS	LeSauk – convert 69 kV load to 115 kV	650,000
2009	XEL	West St. Cloud to St. Joseph - Rebuild with 477ACSS	$525,000
2010	GRE	New Sartell Distribution Substation	$1,001,000
2010	STEARNS	New Sartell Distribution Substation	$1,090,000
2010	GRE	West Union - Add 9 MVAr Capacitor bank	$251,000
2010	GRE	Westwood – 115 kV, 3way switch	$185,000
2010	STEARNS	Westwood – 115 kV, 3way switch	$650,000
2010	XEL	St. Joseph to Brockway – Rebuild tap 5.8 mile line with 477 ACSS	$1,218,000
2011	XEL	Douglas County – A Second 115/69 kV, 47 MVA transformer	$1,917,000
2011	XEL	Paynesville - Replace 115/69 kV, 47 MVA transformers with 70 MVA each	$2,800,000
2011	XEL	Lowry to Grove Lake - Rebuild Switching Station with 477 ACSS	$3,900,000
2011	GRE	West St. Cloud – Replace 115/69 kV, 47 MVA with 84 MVA Xfmer	$100,000
2013	GRE	Paynesville to Watkins 69 kV upgrade	$6,080,000
2015	XEL	Paynesville to Belgrade – Rebuild 16 mile of 69 kV line with 477 ACSS	$4,800,000
2015	XEL	Douglas Co. – Westport Rebuild 10 mile, 69 kV line with 477 ACSS	$3,000,000
2015	GRE	St. Stephen 115 kV, 3way switch	$465,000
2015	STEARNS	St. Stephen 115 kV, 3way switch	$650,000
2015	GRE	New Beaver Lake Distribution Substation	$944,000
2015	STEARNS	New Beaver Lake Distribution Substation	$1,090,000
2016	GRE/XEL MRES	Alexandria to Albany, build 50 mile, 115 kV line	$18,500,000
2016	GRE/XEL /MRES	Albany – Establish115/69 kV, 70 MVA sub	$3,607,000
2016	MRES	Sauk Centre 69 kV load conversion to 115 kV	$1,440,000
2016	MRES	Sauk Centre - Install a 10 MVAr capacitor bank	$258,000
2021	GRE/XEL/ MRES	Albany to West St. Cloud, build 20 mile, 115 kV line	$7,200,000
2024	XEL	Alexandria to Lowry - construct 13 mile 115 kV line with 795 ACSS	$6,854,000
2024	XEL	Lowry - Establish a new 115/69 kV, 70 MVA source	$3,635,000

H: Southwestern Minnesota Region

This study region 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 Pipestone on the west. The following GRE member cooperatives are located in this region:

- Brown County Rural Electric Association (BCREA)
- Federated Rural Electric Association (FREA)
- Nobles Cooperative Electric (NCE)
- Redwood Electric Cooperative (REC)
- South Central Electric Association (SCEA)

Brown County Rural Electrical Association (BCREA) is headquartered in Sleepy Eye, Minnesota, and serves members in the south central portion of the state. BCREA is an electric distribution cooperative providing power to rural customers primarily in Brown, Nicollet and Sibley counties.

Federated Rural Electric Association (FREA) is headquartered in Jackson, Minnesota, and serves member consumers in the southwest portion of state. FREA is an electric distribution cooperative providing power to rural customers primarily in Jackson and Martin counties and in portions of Cottonwood, Nobles, Faribault, and Watonwan counties and the northern border of Iowa. The communities of Alpha, Ceylon, Dunnell and Round Lake purchase wholesale power from Federated and the residents of Petersburg, Welcome and Wilder are retail consumers.

Nobles Cooperative Electric (Nobles) serves member members in the southwest portion of Minnesota. Nobles is an electric distribution cooperative providing power to rural members primarily in Nobles and Murray Counties and in portions of Cottonwood, Jackson, Lincoln, Lyon, Pipestone, Redwood and Rock counties. Nobles also serves a small portion of members in Iowa.

South Central Electric Association (SCEA) serves the counties of Cottonwood and Watonwan in southwestern Minnesota with minor extensions into the surrounding counties of Martin, Blue Earth, Brown, Jackson, Murray, and Redwood.

The electric load in this region is also served by Alliant Utilities and XCEL Energy (XE), as well as several municipal electric systems.

Commerce in the region is highly agricultural and includes large cash-crop farms. Many small and large commercial industries, which support the agriculture businesses, are also present. In the last five years several ethanol plants have been constructed.

This region also has a high potential for wind generation with approximately 800 MW of wind generation already connected. Additional wind generation and the associated electric transmission required to provide outlet for the power will impact the plans for this region of study. Where possible, load serving and wind outlet transmission needs will be combined to provide an efficient and economic joint plan.

The economy of the area is dependent on the rural members, with corn and beans as the major land crops, and hog production and dairy farming prevalent throughout the area. Other industries served are, for the most part, farm-oriented industries such as feed mills and grain

elevators. The potential for large industries unrelated to farming is limited due to the relatively small amount of unemployed skilled labor force.

There is a gradual change occurring that may affect future energy usage. Some smaller farms (80 – 160 acres) are being taken over by larger operations due to economics of scale, retirement, or marginal operation. In a slow economy, land values fall and marginal operations become a losing proposition. The take-over of smaller farm by larger farms is likely to become more frequent during these times. The larger farms are much more energy intensive. What before was handled by manual operation is now propelled by electricity. Crops that used to be brought to town for drying and storage in grain elevators, are now dried and stored on the farm. The net result is an increase in electrical usage when the two farms are viewed as a single unit.

Existing System

Load in this region is primarily served by 69 kV transmission lines and substations. Several load serving substations are also served by 115 kV and 24 kV transmission lines. The sources to the 69 kV transmission are located along the 161 kV perimeter of the study region and result in long 69 kV circuits with many miles of exposure between circuit breakers.

The lines and substations in this region are constructed and operated under either a GRE-XE or Alliant-GRE integrated connection agreements.

Transmission substations serving the 69 kV and 24 kV transmission systems are located as follows:

161/69 kV transformers		
Elk	1-33 MVA	w/LTC
Elk	1-30 MVA	w/LTC
Fox Lake	1-75 MVA	w/LTC
Fox Lake	1-75 MVA	w/LTC[1]
Heron Lake	2-26 MVA	w/LTC
Lakefield	1-75 MVA	w/LTC
Magnolia	1-30 MVA	w/LTC
Rutland	1-75 MVA	w/LTC
Rutland	1-84 MVA	w/LTC[2]
Winnebago	1-75 MVA	w/LTC
115/69 kV transformers		
Franklin	2-47 MVA	w/LTC
Fort Ridgely	1-70 MVA	w/LTC
Lyon County	1-70 MVA	w/LTC
Wilmarth	3-70 MVA	w/LTC
69/24 kV transformers		
Fulda	1-5.25 MVA	w/o LTC
Magnolia	1-7.5 MVA	w/o LTC

[1] Scheduled to be in-service in the fall of 2007
[2] Scheduled to be in-service in the spring of 2008

Reliability and Transmission Age Issues

This region covers the southwestern region of the GRE system: Brown County Rural Electric Association, Federated Rural Electric Association, Nobles Cooperative Electric, Redwood Electric Cooperative, and South Central Electric Association.

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 135	Fox Lake 735 69KV (FE-DJ, FE-FD, FE-FW, FE-WB)	Rank: 9
Line 201	Pipestone 4X742 - Tracy 700 69KV (NO-CHT, NO-RC)	Rank: 19
Line 136	Heron Lake 830 69KV (FE-DJ, FE-ENT, FE-RH, FE-RJ)	Rank: 22
Line 138	Madelia 760 - Rutland 711 69KV (FE-TRT)	Rank: 23
Line 199	Fulda 826 23KV (NO-BL)	Rank: 44
Line 203	Magnolia 816 23KV	Rank: 48
Line 218	Heron Lake 833 - Lamberton 855 69KV (SC-JET)	Rank: 49

Transmission Lines Built before 1980

Line 135	Fox Lake 735 69KV (FE-DJ, FE-FD, FE-FW, FE-WB)	21 Mi.-1956-60; 34 Mi.-1971-74
Line 201	Pipestone 4X742 - Tracy 69KV (NO-CHT)	7 Mi.-1960
Line 136	Heron Lake 830 69KV (FE-ENT, FE-RH, FE-RJ)	46 Mi.-1960-69; 12 Mi.-1978
Line 138	Madelia 760 - Rutland 701 69KV (FE-TRT)	2 Mi.-1966
Line 218	Heron Lake 833 – Lamberton 69KV (SC-JET)	5 Mi.-1974
Line 112	Dotson Corner 862 - Madelia 69KV (BR-DL, -LS, -SE)	27 Mi.-1960-70
Line 113	Dotson 860 - Lamberton 69KV (RE-WS, -SB -JOT)	17 Mi.-1953-55; 6 Mi.-1976
Line 115	Fort Ridgely 4S51 - Franklin 69KV (BR-SL, BR-SE)	3 Mi.-1951; 8 Mi.-1960
Line 117	Fort Ridgely 4S49 – Winthrop 69KV (BR-SCT)	4 Mi.-1973
Line 137	Fairmont 701 - Fox Lake 734 69KV (FE-WET)	2 Mi.-1966
Line 200	Elk 845 69KV (NO-WF)	9 Mi.-1973
Line 205	Elk 847 69KV (NO-WO, NO-WR, NO-WT)	7 Mi.-1962
Line 207	Franklin 4N108 69KV (RE-FR, RE-SR, RE-WA)	27 Mi.-1955; 6 Mi.-1961
Line 216	Mountain Lake 893 – Windom 896 69KV (SC-BLT)	2 Mi.-1979
Line 266	Magnolia 819 - Sibley 69KV (NO-ADT, NO-RUT)	5 Mi.-1961; 5 Mi.-1973
Line 275	Lyon Co. 4N151- Minnesota Valley 472 69KV (RE-MIT)	7 Mi.-1978
Line 276	Lyon Co. 4N153 - Tracy 713 69KV (RE-WGT)	6 Mi.-1979
Line 297	Fox Lake 736 -Watonwan 69KV (SC-SHT, SC-ODT)	6 Mi.-1955-61

The overall reliability for this region is comparable to the GRE average, but it varies across the area. The southern part is generally impacted more by ice storms resulting in lower levels of reliability, while the northern part has better than average reliability. Parts of this region are served from the Xcel Energy and Alliant 69 kV systems. The line age table shows several segments of older line where replacement may need to be considered. Also, in addition to maintenance information covered with the following line-specific reliability discussions, the BR-HS and BR-LS line segments (Line 112) had high numbers of incidents related to pole condition. The line age and maintenance information for several of the lines in this area is not complete since data is not included for the lines owned by the other utilities.

Line 135 from Fox Lake is a 57 mile long, 69 kV line serving six substations. The line has open switch connections to 69 kV lines from Heron Lake and Blue Earth. Its reliability performance places it among the worst lines for each of the six indices used, due to high numbers of outages and the large number of substations on the line. The maintenance reports show a relatively high

number of incidents related to pole conditions and shield hardware, mostly on the FE-FD and FE-WB sections. The FE-FD line was built in 1956. Airflow spoilers were added to the Middletown tap line and a fault locating relay was added to the Fox Lake breaker in 2006 to prevent galloping and improve restoration respectively.

Line 201 from Pipestone to Tracy is an 85 mile 69 kV line serving five substations. Its reliability performance places it among the worst lines for five of the six indices used, due to high numbers of outages and the large number of substations on the line. The majority of the line is owned by XE, so much of the age and maintenance data is not included. The GRE maintenance reports show a relatively high number of incidents related to pole conditions and shield hardware on the NO-CHT section (the NO-CHT line was built in 1960). The NO-CHT line from Chandler switching station to the Chandler tap will be rebuilt as part of a wind generation outlet.

Line 136 from Heron Lake is a 59 mile long, 69 kV line serving five substations. The line has an open switch connection to a 69 kV line from Fox Lake. Its performance is worse than the GRE average on all six indices used, with high numbers of momentary outages having the biggest impact. The maintenance reports show a relatively high number of incidents related to shield and pole hardware, mostly on the FE-RH and FE-ENT sections. Airflow spoilers were added to portions of the FE-RJ line in 2006 to prevent galloping.

Line 138 from Madelia to Rutland is a 30 mile long, 69 kV line serving three substations. Its performance is worse than the GRE average on all six indices used, due to a high number of momentary and long term outages. The maintenance reports do not show any significant activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve the reliability of this line.

Line 199 from Fulda is a 20 mile long, 23 kV line serving one substation. The line has an open switch connection to the 23 kV line from Magnolia. Its performance is worse than the GRE average on five of the six indices used, due to a high number of momentary outages and long outage durations. The maintenance reports do not show any significant activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve the reliability of this line.

Line 203 from Magnolia is a 14 mile long, 23 kV line serving one substation. The line has an open switch connection to the 23 kV line from Fulda. Its performance is worse than the GRE average on four of the six indices used, with long outage durations having the biggest impact. The maintenance reports do not show any significant activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve the reliability of this line.

Line 218 from Heron Lake to Lamberton is a 35 mile long, 69 kV line serving six substations. Its performance is worse than the GRE average on four of the six indices used, due to a high number of momentary and long term outages. There are no recent or current projects to improve the reliability of this line. The maintenance reports do not show any significant activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve the reliability of this line.

Existing System Deficiencies

There have been very few additions to the transmission system in southwestern Minnesota in recent years. Loads have continued to slowly grow and the introduction of new large loads, such as ethanol plants, has severely stressed the system. Low voltages and some line overloads are

possible in several areas on the existing system with the existing load levels. Most of the undervoltages and overloads will occur during system contingencies, however the addition of the large ethanol plant loads has required that temporary mitigation be implemented. This mitigation usually requires that the new load be tripped if an undervoltage condition occurs. Several projects are presently underway to eliminate the need for load tripping. These projects will not be in-service for two to three years and the system may not be able to serve these loads during system peaks should a critical contingency occur.

In the Lamberton to Dotson areas a new 69 kV transmission circuit from the new Lyon County 115/69 kV substation is expected to be put into service in late 2009. The projects are described in the Dotson area discussion portion of this section of the report. The Highwater Ethanol load is at risk of being tripped on undervoltage in the interim.

Future Development

Load Forecast

Loads served in this region are those of Alliant-West, GRE, MRES, SMMPA, Xcel Energy and several municipal systems. Due to the nature of the joint 69 kV transmission network it is difficult to determine exact regional boundaries in order to calculate totals of the non-GRE loads. The following load forecast was used for the GRE loads in this region. The summer/fall season has higher loads than the winter season therefore summer loads were used during system analysis.

Coop-Member	2011		2021		2031		20-year growth rate (%) S / W	
	Summer	Winter	Summer	Winter	Summer	Winter		
Brown	22.0	25.5	29.5	32.8	37.5	42.2	2.7	2.6
Federated	63.0	57.1	75.5	66.8	84.0	79.0	1.5	1.6
Nobles	42.0	30.9	60.0	32.6	72.0	34.2	3.1	.5
Redwood	21.5	14.4	28.0	13.4	35.0	13.3	2.0	0.0
South Central	54.5	36.6	80.5	47.3	109.5	60.8	3.5 [3]	2.6

Planned Additions

Two major types of development are occurring in the southwestern Minnesota region; wind generation and ethanol processing plants. The primary impact is from the wind generation on the Buffalo Ridge. This region of the United States has been identified as having very high potential for the capture of wind energy. XE and other utilities are developing these resources at a fast pace. This has results in severe loading conditions on the existing 115 kV transmission system in this region.

XE has a mandate from the State of Minnesota to add sufficient transmission to handle the expanding wind generation. A recent filing by XE recommends the addition of 345 kV transmission lines in this region with connections to existing 345 kV transmission at Sioux Falls, South Dakota and Lakefield, Minnesota. 34.5 kV and 115 kV collector transmission circuits will also be built.

[3] Includes three new ethanol plant loads

These new transmission facilities have, with one exception, little impact or benefit on the load serving capability of the 69 kV transmission system. The one exception is an opportunity to connect a 161 kV distribution substation at Jackson on the new 161 kV circuit from Fox Lake to Lakefield Jct. The City of Jackson municipal load will be connected to this new distribution substation in 2008 and removed from the 69 kV transmission line from Heron Lake. This will reduce the loading on the 69 kV system eliminating minor overloads and major voltage criteria violations.

The other development is the continued expansion of ethanol processing plants. The existing plants are expanding their production capacities, which have resulted in increased load. New plants are also being constructed. In most cases these loads are being added to the transmission system that is relatively weak. Those increased loads have been reflected in the load in the power flow models used in the analysis.

Several new load serving substations have been indicated in the forecast period by the other utilities in the region and are under construction. This projects are expected to be in-service by the time this report is completed.

- Buffalo Lake (Federated)—new ethanol plant near Fairmont
- VeraSun (Federated)—new ethanol plant near Welcome
- Highwater Ethanol (Redwood)—new ethanol plant near Lamberton

In addition, several new substations have been planned by the GRE member systems in order to serve possible ethanol plants. The location and timing of the ethanol loads is very speculative and will change depending on land, water, and corn availability from year to year. For example, the prospective substations listed below are essentially “on-hold” due to high corn prices. Based on the nebulous locations and timing for these loads, no funding will be reserved for these substations at this time.

- Cobden Ethanol (Brown)—prospective new ethanol plant
- Butterfield--St. James area—prospective new ethanol plant
- Lakeside second transformer-Bingham Lake—ethanol expansion

Long-term deficiencies

During the development of alternatives, this region was divided into different areas of study. Solutions to the long-term deficiencies in the different areas are somewhat independent of each other. Although solutions that correct the low voltage slightly benefit the region as a whole, no one set of projects can benefit the entire southwestern Minnesota region.

The following sections discuss the descriptions of the existing system by the different study areas and the evaluations of the alternatives that were studied.

Dotson Area

This area is served by the centrally located, Dotson 69 kV switching station and three normally closed (looped), 69 kV transmission circuits to 161/69 kV substations to the south. The 69 kV circuits are quite long and the slow but continuous load growth has resulted in low voltages during normal system conditions and during single contingencies.

The following table shows the loads for Dotson area along with the estimated 20-year growth rate.

Dotson Area Loads

Season	2011	2021	2031	Growth Rate (%)
Summer	31.6	40.0	45.5	1.8
Winter	27.1	32.2	36	1.4

In the 2003 GRE long range plan, low voltages were seen as early as 2001 in the areas between Dotson and South Storden. Since the 2003 plan, the following additions to the transmission system have been constructed or committed:

- 69 kV circuit breakers at the Storden switching station (Alliant-2007)
- Lyon County 115/69 kV substation and 69 kV circuit breaker for the Milroy—Sheridan circuit (XE-2006)
- Milroy—Sheridan 69 kV and reconductor of the existing Sheridan tap 69 kV line (GRE-2008)
- Waterbury 69 kV breaker station (Alliant-2009)

The above improvements have improved the voltage profile, but additional ethanol plant loads continue to stress the 69 kV system. The prospective ethanol plants near Cobden and St. James as well as possible expansion of the existing plants at Northstar and Lakeside will result in the need for additional system improvements. Possible system improvements are discussed below.

Alternatives Reviewed for the Dotson Area

Several options were proposed to correct the voltage deficiencies that still exist in the Dotson area. A description of the alternatives and the effectiveness of each are discussed below. The priority and recommendation to construct the projects will be highly dependent on the development of the larger loads, e.g. ethanol plants. This new, large loads are expected to overshadow the needs for the relatively slow traditional consumer load growth. Should the new, large loads not develop, one or more projects will still be beneficial for the area, although with delayed in-service dates.

Generation options

No generation options were considered for this area during development of this report. Although generation additions could be considered the generation would have a high load factor since load in this area is both summer and fall peaking. It would likely be less economical to run local generation as compared to any recommended options due to the high fuel cost associated with smaller dispersed generation.

Heron Lake—Storden—Dotson—West New Ulm 161 kV line

As part of the MISO generation interconnection process, a large (130 MW) wind generation project has been proposed near Storden. It was determined that the existing 69 kV transmission system was inadequate for this request due to the resulting 69 kV overloads. MISO studies proposed a 161 kV transmission line between Heron Lake, Storden, Dotson, and West New Ulm with new 161/69 kV transformers at Storden and Dotson. At West New Ulm, new 161/115 kV and 115/69 kV transformers were proposed for transmission interconnection and load serving,

respectively. GRE's portion of this project included constructing the 161/69 kV substation at Dotson and the 161 kV transmission line from Dotson to West New Ulm.

After the development of the above plan, the developer of the wind project has postponed construction of the generation project which has, in turn, resulted in the postponement of the new 161 kV line and substation projects. Coincidentally, ethanol expansion has also slowed somewhat. This delay has allowed a review of the plan for the Dotson area which has resulted in a slight modification to better accommodate future load and wind interconnections. The 161 kV line from Heron Lake/Storden will terminate into a 161 kV bus at the Dotson 161/115/69 kV substation. A 115 kV transmission line will continue from Dotson to West New Ulm to provide the interconnection to the 115 kV system in the Fort Ridgely area.

The Heron Lake—Dotson 161 kV transmission line, the Dotson-West New Ulm 115 kV line, and the new substations at Dotson, Storden, and West New Ulm would be beneficial to the load serving needs in the Dotson area. However, the delay of these projects will require further analysis to determine whether this project would be the most economical alternative for the area if the wind generation at Storden fails to develop. Numerous larger system needs, including possible bulk transmission additions for wind development in areas just west of the Dotson, might result in other alternatives being recommended.

Lakefield Generating Station 345/115 kV Substation

Prior to the larger generation request near Storden, the transmission utilities had considered constructing a 345/115 kV substation at the 345 kV tap for the Lakefield Generating Station to introduce a new transmission source on the southern part of the Dotson area. This alternative might be reconsidered as the location of the wind generation requests change as new loads develop, especially in the Butterfield St. James area. This alternative will be further described in the discussion for the St. James area.

Cost Analysis

Recommended Plan for the Dotson Area

At this time there are two alternatives for the Dotson area that have been supported by transmission studies:

- Heron Lake—Storden—Dotson 161 kV line
- Dotson – West New Ulm 115 kV line
- Milroy—Sheridan 69 kV line and 69 kV circuit from Lyon County substation
- Dotson 161/115/69 kV substation

The recommended alternative for the Dotson Sub-Area are the Milroy—Sheridan 69 kV line and 69 kV circuit from the Lyon County substation:

- new 69 kV line from Sheridan to Milroy (8 miles)
- new 69 kV switching station (Waterbury) at the site of the Johnsonville tap
- reconductor the Milroy tap (6 miles)
- reconductor the Sheridan tap (3.5 miles)

These projects are all needed immediately since the voltage problems would have developed during the 2001 summer peak loading conditions had the contingencies occurred. The GRE projects should be included in the GRE Financial Plan and be completed as soon as the agreements are in place between the developer and GRE.

Estimated Year	Company	Facilities	Cost
2012	ITC-Midwest	Heron Lake—Storden—Dotson 161 kV line, 47 miles	$31,600,000
2012	ITC-Midwest	Storden 161/69 kV substation	$4,800,000
2012	GRE	Dotson 161/115/69 kV Substation	$10,100,000
2012	GRE	Dotson—West New Ulm 115 kV line, 33 miles, 795 ACSS	$23,100,000
		TOTAL	$69,600,000

Jackson Area

This area is served by a 69 kV transmission system with sources at Fox Lake and Heron Lake. Approximately 13 MW of load (City of Jackson municipal load) is connected to the system midway between the sources. Some of the existing transmission lines had very low thermal ratings (11 MVA for the Heron Lake—Miloma tap 69 kV line). The design of these lines was reviewed and minor design changes were made to increase the ratings to 45 MVA.

The following table shows the amounts and growth rates of the loads in the Jackson area.

Jackson Area Loads

Season	2011	2021	2031	Growth Rate (%)
Summer	26.5	33.0	39.0	2.0
Winter	23.6	29.5	37.0	2.3

The long distances from the 69 kV sources results in the voltage violations during system intact (Jackson @ 90.2% in 2001 summer). With a contingency of one of the 69 kV sources lines (Dunnel—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.

In the 2003 GRE LRP, three alternatives were developed for the Jackson area. The recommendation in that report was to take advantage of the new 161 kV line being constructed by Xcel Energy as part of the 825 MW wind development projects. A new 161/69 kV transmission substation would be constructed on that line in the Jackson area. Subsequent discussions with the City of Jackson resulted in the City constructing a new distribution substation to serve their load directly from the 161 kV transmission, thus reducing the immediate need for developing the 161/69 kV substation by reducing the loading on the 69 kV system.

With the removal of the City of Jackson load from the 69 kV system and the upgrade of the thermal capacity of the existing 69 kV lines, the transmission system in the Jackson area will be adequate until 2021. This assumes that the general load growth trends continue and that no large spot loads, e.g. ethanol plants, develop in the area served by this system.

Contingency analysis results of the 2021 summer peak model indicate that voltage problems and overloads will develop during the contingency of either 69 kV source as follows:

- Miloma @ 0.904 p.u. for the outage of the Heron Lake—Miloma 69 kV line
- Dunnel @ 0.893 p.u. for the outage of the Dunnel—Fox Lake Tap 69 kV line
- Fox Lake—Fox Lake tap 69 kV line at 100.2% loading

Alternatives Reviewed

Two alternatives were developed for the Jackson area to correct voltage and loading deficiencies that will begin to develop around 2021.

Construct a 10 mile long, 69 kV line between Enterprise and Lakefield Junction

Components for this alternative consist of the following items:

Description	Estimated Cost
10 miles of 69 kV line, 477 ACSR	$ 3,250,000
3-way, 69 kV switch at Enterprise sub	$60,000
69 kV breaker and equipment at Lakefield Junction	$440,000
Total cost estimate	$ 3,750,000

Add a 69 kV capacitor bank at the Minneota tap and rebuild overloaded lines

Components for this alternative consist of the following items:

Description	Estimated Cost
5.4 MVAR, 69 kV cap bank	$ 21,600
Capacitor bank switching	$252,000
Rebuild Fox Lake—Fox Lake tap69 kV line (6 miles)	$2,112,500
Total cost estimate	$ 2,386,100

Cost Analysis

Based on the above cost estimates it is apparent that adding a 5.4 MVAr capacitor bank at the Minneota and rebuilding the overloaded lines is the least cost alternative. The cost estimate for the Fox Lake—Fox Lake tap 69 kV line includes the cost of a complete rebuild of the line. If the rating of the line can be increased to the thermal rating of the conductor (45 MVA) this cost can be (significantly) reduced to the resag costs.

Recommendation

The addition of the capacitor bank at the Minneota tap and the rebuilding of the overloaded Fox Lake—Fox Lake tap 69 kV line is the recommended plan. The in-service date for the new capacitor bank would be approximately 2015-2017. The Fox Lake—Fox Lake 69 kV line is 100.2% loaded in the 2021 summer peak model and the resag/rebuild of that line could be delayed until then. For purposes of cash flow estimates the following dates are provided:

Estimated Year	Company	Facilities	Cost
2015	GRE	Minneota Tap, 5.4 MVar Cap Bank, 69 kV	$
2021	GRE	Fox Lake—Fox Lake tap 69 kV line rebuild, 477 ACSS, 6 miles	$2,112,500

St. James Area

This area is characterized by a relative large (20 MW) municipal load located a long distance (electrically) from the transmission sources. A large ethanol load (Ethanol2000 at the Lakeside substation) is located on the transmission system at a location that, during contingencies, will also be a long electrical distance from the sources at Fox Lake and Rutland. The potential for additional ethanol plants also exists in this area.

The following tables show the amounts and growth rates of the loads along the 69 kV lines in the St. James area.

Madelia – Watonwan 69 kV line loads

Season	2011	2021	2031	Growth Rate (%)
Summer	17.3	20.6	21.6	1.1
Winter	14.3	16.9	17.7	1.1

Watonwan – Wilder Jct 69 kV line loads

Season	2011	2021	2031	Growth Rate (%)
Summer	65.7	80.5	94.0	1.8
Winter	44.0	49.8	54.1	1.0

Fox Lake – Watonwan 69 kV line loads

Season	2011	2021	2031	Growth Rate (%)
Summer	15.3	19.3	23.3	2.1
Winter	12.4	16.0	19.3	2.2

Analysis of the 2011 summer peak model indicates that the voltages at several busses in this area will be below criteria for numerous contingencies. The Lakeside ethanol plant and will be below 90% and Bingham Lake and Battle Lake will be below 92% for the contingency of the Lakeside—Windom Tap 69 kV line. This assumes that the prospective ethanol plant expansion at the Lakeside will continue and result in a total site load of approximately 20 MW. It should be noted that this line outage also causes undervoltages in the Dotson area.

In 2011 summer peak conditions, several minor line overloads will occur during contingencies. Switching procedures can reduce this overloads to below the line ratings.

The 2021 summer peak analysis indicates that additional undervoltages and line overloads will result for several contingencies. This model includes one additional ethanol plant in the Butterfield-Lakeside area (total of 3 plants).

- Outage of the Lakeside—Windom Tap 69 kV line results in undervoltages from the St. James to Lakeside busses as well as busses in the Dotson area

- Outage of the Fox Lake—Sherburn 69 kV line results in undervoltages in the entire St. James area from Lakeside eastward to Sherburn and Trimont.
- Overload of Fox Lake—Sherburn 69 kV line (110%) occurs for the outage of the Lakeside—Windom Tap 69 kV line. The Sherburn(GRE)—Sherburn 69 kV line overloads (107%) for this same outage

Alternatives Reviewed

Based on the results showing low voltage problems due to the distance to the source busses, the long-term, visionary alternatives developed for the St. James area are to introduce a new source and preferably the options to convert some of the larger loads to 115 kV connections. In the short term an additional capacitor bank at the Mountain Lake switching station will provide voltage support until a decision can be made on the longer term plan. If additional ethanol plants develop a more permanent solution will be needed before adequate service can be provided to the new loads. The following alternative is suggested. No other alternatives were evaluated.

Lakefield Generating Station 345/115 kV Substation

The 345 kV transmission line from Lakefield Junction to Mankato provides an obvious new source for this area. One of the alternatives developed includes a new connection to this 345 kV line near the Lakefield Generating Station (LGS). This alternative consists of the following 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 line to Butterfield (Watonwan)
- 115/69 kV transformer connection into the existing Watonwan 69 kV switching station

This option introduces a new 115 kV source into the area and takes advantage of the pre-existing LGS 345 kV substation property and equipment. The addition of the new 115/69 kV source at Watonwan reduces the length of transmission line miles from the existing 69 kV sources.

Cost Analysis

The costs of the option are as follows:

Estimated Year	Company	Project Description	Estimated cost
2021	ITC-Midwest	Mountain Lake 5.4 MVar capacitor (#2)	$ 236,000
2025	GRE-Xcel	LGS 345/115 kV substation, 336 MVA	$7,298,300
2025	GRE-Xcel	Butterfield—LGS 115 kV line, 795 ACSS, 9 miles, w/CON	$4,742,000
2025	GRE-Xcel	Watonwan 115/69 kV substation, 112 MVA w/LTC (add to existing breaker station)	$3,283,600
		TOTAL	$ 11,289,900

Fulda—Magnolia Area

The Bloom and Lismore substations are owned by Nobles coop and are presently served from a 24 kV line between Fulda and Magnolia. This line is owned by Alliant Energy. Reliability of this line has been degrading over the years. Voltage at the Lismore substation 24 kV bus is projected to be well below criteria by the 2011 summer peak load conditions. For many years, Nobles' management has indicated a desire to improve the service to the Bloom and Lismore substations.

The following table shows the amounts and growth rates of the loads in the Fulda—Magnolia Area:

Fulda—Magnolia Area Loads

Season	2011	2021	2031	Growth Rate (%)
Summer	10.2	13.1	15.1	1.0
Winter	7.8	8.7	8.8	0.6

In the early 1990's, a plan to convert the 24 kV Fulda—Magnolia line to 69 kV was developed. Slow load growth pushed the project in-service date back several years. In the late 1990s, Alliant started a project to begin converting the line, however a permitting dispute between Alliant and Nobles County (Minnesota) halted the project. The status of that project since then has become unclear.

In late 2007, GRE asked Alliant Energy for an update on the status of the Fulda-Magnolia 24 kV to 69 kV conversion project. In January 2008 a response came back from Alliant indicating that they were not going to convert the line to 69 kV, but were going to rebuild it at 24 kV and install a bi-directional voltage regulator to resolve the voltage issues. Alliant Energy is now solely a distribution company and no longer has the option of building transmission to solve the problems on the 24 kV system.

Also mentioned in the Alliant response was the need to resolve the non-standard transformer winding at the Bloom substation. The transformer is rated 22/13.2 kV which prevents Alliant from operating the Fulda source bus at nominal voltage in order to avoid overvoltages on the low-side bus at Bloom.

Alternatives to consider

- Do nothing: GRE and Nobles could do nothing and wait for Alliant to rebuild the 24 kV system to T-2, 4/0 conductor and add the bi-directional voltage regulator. This will require no changes at the Lismore substation but will require that the Bloom 22/13.2 kV transformer be replaced with a transformer of the proper voltage ratio. Alliant estimates that this solution would last about 10 years, however GRE believes Alliant has underestimated the load growth potential on the Lismore and Bloom substations. Cost to GRE for this option would be negligible; Nobles would have to replace the substation transformer at Bloom at a cost of about $200,000. The cost to Alliant for the 24 kV rebuild is not known at this time. Ultimately, one of the following solutions would also have to be implemented in 10 years.

- GRE rebuild the line to 69 kV: GRE could choose to take over responsibility upgrading the transmission to 69 kV. With the addition of 69 kV breakers at Magnolia and Fulda and the construction of approximately 35 miles of 69 kV line for a total cost of about $14 million.

- Tap nearby 69 kV sources: This would require only constructing a portion of the 69 kV loop project and leave the Bloom and Lismore substation on 69 kV radials from Magnolia and Fulda, respectively. Each tap is assumed to be about 10 miles in length. 69 kV breakers would be required at Magnolia and Fulda. Approximate cost is $8.1 million. If Lismore alone were converted to 69 kV, the approximate cost would be $6.5 million.

- Tap the new Fenton—Nobles 115 kV #2 line: This option is only appropriate for the Lismore substation. It would involve adding a 3-way, 115 kV switch in the Fenton—Nobles 115 kV line[4] and constructing about 3 miles of new 115 kV line from the tap to the Lismore substation. Total cost is approximately $1.27 million. Nobles coop would have costs of about $500,000 to upgrade the substation to 115 kV. A similar option might be available for the Bloom substation although the cost would be higher due to a longer 115 kV tap line (about 4 miles). Total cost for Bloom would be about $1.7 million. Total for both subs about $3 million for GRE and $1 million for Nobles. Total combined cost is approximate $4 million.

Summary of Alternatives

Description	GRE Cost	Alliant Cost	Nobles Cost	Total Cost
Rebuild 24 kV	$0	?	$200,000	$200,000+
GRE build 69 kV	$14,000,000	?	$800,000	$22,000,000
Tap “local” 69 kV	$8,100,000	?	$800,000	$16,100,000
Tap 115 kV lines	$3,000,000	?	$1,000,000	$4,000,000

Conclusion-Recommendation

Based on the summary table above the 115 kV solution is recommended. Although rebuilding the 24 KV system is lower cost, it is only a short-term solution and one of the other solutions would also be required within 10 years. The 115 kV plan has lower long-term costs and provides a longer term, load serving solution. Some cost savings can also be realized if the 3-

[4] GRE has asked Xcel Energy for this connection request to start the evaluation of the proposed interconnection.

way switch in the 115 kV tap on the Fenton—Nobles 115 kV circuit #2 line, for the Lismore substation, can be installed during construction of this new line. Construction is expected to start late-summer of 2008.

Estimated Year	Company	Project Description	Estimated Cost
2009	GRE	Lismore 115 kV tap, 477 ACSR, 3 miles, 3-way switch	$1,269,000
2015	GRE	Bloom 115 kV tap, 477 ACSR, 3 miles, 3-way switch	$1,269,000

Summary of Projects for the Southwestern Minnesota Region

The following table summaries the GRE projects recommended for construction in the Southwestern Minnesota region of the GRE Long Range Plan. It does not include the associated projects that will be constructed by the adjacent utilities. Also, it does not include provisions for new ethanol plant development due to the uncertainty of their size and locations.

Estimated Year	Company	Project Description	Estimated Cost
2009	GRE	Lismore 115 kV tap, 477 ACSR, 3 miles, 3-way switch	$1,269,000
2012	ITC-Midwest	Heron Lake—Storden—Dotson 161 kV line, 47 miles	$31,600,000
2012	ITC-Midwest	Storden 161/69 kV substation	$4,800,000
2012	GRE	Dotson 161/115/69 kV Substation	$10,100,000
2012	GRE	Dotson—West New Ulm 115 kV line, 33 miles, 795 ACSS,	$23,100,000
2015	GRE	Minneota Tap, 5.4 MVar Cap Bank, 69 kV	$273,600
2015	GRE	Bloom 115 kV tap, 477 ACSR, 3 miles, 3-way switch	$1,269,000
2021	GRE	Fox Lake—Fox Lake tap 69 kV line rebuild, 477 ACSS, 6 miles	$2,112,500
2021	ITC-Midwest	Mountain Lake 5.4 MVar capacitor (#2)	$236,000
2025	GRE-Xcel	LGS 345/115 kV substation, 336 MVA	$7,298,300
2025	GRE-Xcel	Butterfield—LGS 115 kV line, 795 ACSS, 9 miles, w/CON	$4,742,000
2025	GRE-Xcel	Watonwan 115/69 kV substation, 112 MVA w/LTC (add to existing breaker station)	$3,283,600

I: West Central Minnesota Region

This study region is located in western central Minnesota and is, in general, the area west of the Twin Cities Metro area to Granite Falls. The following GRE member cooperatives are located in this region:

- Kandiyohi Power Cooperative (KPC)
- McLeod Cooperative Power Association (MPCA)
- Meeker Cooperative Light & Power Association (MCL&PA)

In addition to the GRE member cooperatives, the electric load in this region is also served by members of Southern Minnesota Municipal Power Agency (SMMPA) and XCEL Energy (XEL) as well as several municipal electric systems including Glencoe, Hutchinson and Willmar. The municipal systems are the largest spot loads on the system.

Commerce in the region is highly agricultural and includes large cash-crop farms. Many small and large commercial industries, which support the agriculture businesses, are also present. The cities of Glencoe, Hutchinson, Litchfield and Willmar provide commercial hubs. Agricultural processing plants (beets, soybean oil, and ethanol) are also large loads on the electric system in this region.

Kandiyohi Power Cooperative serves a majority of Kandiyohi County and portions of Swift, Chippewa and Stearns Counties in the heart of west central Minnesota. There has been a slow increase in the economy the last year due to a couple of “big box stores” coming into the area as well as the increased popularity of the lakes areas. There are some manufacturing and processing plants in the area that have helped maintain the local economy.

McLeod Cooperative Power Association (McLeod) serves all of McLeod County, portions of Renville, Sibley, and Carver Counties, as well as fringe areas of Meeker and Wright Counties in Minnesota. Boundaries of the service area are fixed and unlikely to change in the future, with the exception of the areas surrounding Glencoe and Hutchinson, which may be annexed by those cities and the existing facilities and customers in those areas purchased by those cities. Xcel Energy also serves within the area, serving several towns and some rural accounts. The cities of Arlington, Glencoe, Hutchinson, and Winthrop have municipal power systems, and serve all accounts within their corporate boundaries as well as a few rural accounts adjacent to their municipal boundaries. The eastern boundaries of McLeod’s service area are approximately 25 to 30 miles from the metropolitan area of Minneapolis-St. Paul. The rest of the cooperative’s boundaries are joint with several other rural electric cooperatives adjacent to McLeod.

Meeker Cooperative Light and Power Association is headquartered in Litchfield, Minnesota. Meeker provides electricity and other services to residents, businesses and industries in six central Minnesota counties, including Meeker, Kandiyohi, McLeod, Renville, Stearns and Wright**.** The economy of is mainly driven by residential development and some commercial activities. Meeker foresees new ethanol producing plant at Eden Valley, new super Wal-Mart in Litchfield and new state park in the service territory.

Existing Transmission System

The lines and substations in this region are constructed and operated under either a GRE-XEL or Hutchinson-SMMPA-GRE integrated connection agreements.

Load in this region is primarily served by 69 kV transmission lines and substations. Direct 115 kV to distribution substations are located Hutchinson and on the west side of St. Cloud. Additional 115 kV distribution substations are expected in the near future as the load grows in this region.

The 230 kV transmission lines from Granite Falls and the 115 kV lines from Granite Falls, St. Cloud and Twin Cities metro area support the 69 and 115 kV transmission through the following transmission substations:

Transmission substations serving the 69 kV transmission systems are located as follows:

230/115 kV transformers		
McLeod	1-112 MVA	w/o LTC
Minn-Valley	2-50 MVA	w/LTC
230/69 kV transformers		
Panther	1-70 MVA	w/LTC
Willmar	1-84 MVA	w/LTC
115/69 kV transformers		
Big Swan	1-47 MVA	w/LTC
Carver County	1-47 MVA	w/LTC
Crow River	1-112 MVA	w/LTC
Franklin	2-47 MVA	w/LTC
Minn-Valley	1-47 MVA	w/o LTC
Minn-Valley	1-42 MVA	w/o LTC
St. Bonifacius	1-70 MVA	w/LTC
Willmar	1-84 MVA	w/LTC

This area covers Kandiyohi Power Cooperative, McLeod Cooperative Power Association, and Meeker Cooperative Light and Power Association.

Reliability and Transmission Age Issues

This area covers Kandiyohi Power Cooperative, McLeod Cooperative Power Association, and Meeker Cooperative Light and Power Association.

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 176 Hutchinson C3NB9 - Winthrop 4S54 69KV (MC-GB, MC-HB, MC-WB, MC-WW) Rank: 10

Line 181 Big Swan 4N2 - Panther 4N66/4N71 - Litchfield C7NB7 69KV (ME-CMT, -MET) Rank: 12

Transmission Lines Built before 1980

Line 176 Hutchinson C3NB9–Winthrop 69KV (MC-GB,-WB,-WW) 9 Mi.-1946; 30 Mi.-1959-67

Line 181 Big Swan 4N2-Panther-Litchfld 69KV (ME-CMT, -MET) 15 Mi.-1968-78

Line 59	Willmar 13NB5 69KV (HE, SH)	35 Mi.-1948-50
Line 60	Willmar 13NB1 – WMUC 6P4 69KV (HE, WS)	7 Mi.-1948-58; 10 Mi.-1970
Line 61	Willmar 13NB3-Hutch-Litchfield 69KV (DS, HN, SH, LT)	40 Mi.-1950; 21 Mi.-1955
Line 62	Willmar 13NB2 - Granite Falls 69KV (BR, BRT)	39 Mi.-1958; 5 Mi.-1970
Line 178	Carver Co. 4M51 69KV (MC-HIT,-GB,)	11 Mi.-1965-66
Line 179	St. Bonifacius 4M24 69KV (MC-LN, MC-HOT)	4 Mi.-1965
Line 269	Hutchinson C3NB2–Victor 69KV (DS, MC)	16 Mi.-1950; 9 Mi.-1967-79
Line 271	Big Swan 4N3 - Victor 69KV (ME-DAT, MC-SHT)	1 Mi.-1952; 2 Mi.-1971
Line 284	Bird Island 4N337/426- Panther 69KV (MC-BRT)	6 Mi.-1973
	Wakefield 5N27 – Big Swan 5N20 115KV (ME-BW)	28 Mi.-1969

The overall reliability for this region is generally similar to the GRE average. Parts of the area are served from the Xcel Energy 69 kV system. The line age table shows several segments of older line where replacement may need to be considered. The BR line from Willmar to Granite Falls and SH and HE from Svea to Hawick to Sunburg (Line 59) have high number of maintenance incidents, mainly related to pole condition. Other maintenance information is discussed with following line-specific reliability discussions. The line age and maintenance information for several of the lines in this area are not complete since data for the Xcel Energy owned portion is not included.

Line 176 from Hutchinson to Winthrop is a 42 mile 69 kV line serving three substations. Its reliability performance places it among the worst lines for each of the six indices used, due to a high number of momentary outages and long outage duration. Most of the outage duration was related to an outage occurring when the alternate source was out for maintenance. The maintenance reports show a high number of incidents related to pole conditions, bad pole grounds, conductor ties, and insulator problems. Most incidents were on the MC-WW line, which was build in 1946. Remote control was added to the switches at Bell tap to improve restoration time.

Line 181 from Big Swan to Panther is a 78 mile 69 kV line serving seven substations. Its reliability performance places it among the worst lines for each of the six indices used. The high number of substations on this line has had the biggest effect on its reliability ranking. The majority of the line is owned by XEL, so much of the age and maintenance data is not included. The GRE maintenance reports do show several incidents related to pole conditions on the ME-CMT section. There are no recent or current projects to improve reliability for this line.

Existing and Long-Term System Deficiencies

The west central Minnesota transmission system covers a large geographic area. Historical studies have been done by subdividing the area into smaller independent study areas that generally have independent deficiencies and solutions. Alternatives to address both the existing and long-term system deficiencies will be discussed in the following sub-areas:

- Glencoe
- Hutchinson
- Panther
- Willmar

Future Development

Load Forecast

The following load forecast for GRE member systems was used in the models in the west central Minnesota region. The total GRE member load in this area is projected to grow at a rate of 3% to 4% over the next 25 years.

GRE Member Load in the West Central Minnesota System

Coop-Member	2011		2021		2031		20-year growth rate (%) S / W	
	Summer	Winter	Summer	Winter	Summer	Winter		
Kandiyohi	34.0	37.8	51.0	56.7	66.0	85.0	3.4	4.1
McLeod	55.0	41.9	80.5	61.7	100.0	90.9	3.0	3.9
Meeker	39.5	53.8	56.0	88.7	81.3	139.4	3.7	4.9
TOTAL	128.5	133.5	187.5	207.1	247.3	315.3	3.3	4.4

Glencoe Area

Planned additions

At present, no new distribution substations are planned for the Glencoe area. This area is experiencing rapid load growth and new substations, not yet identified, could develop along with the addition of new housing developments in this area.

Glencoe recently constructed a 115 kV transmission line from the McLeod 230/115 kV substation, just south of Hutchinson, to the City of Glencoe. A new 115 kV to distribution substation was also completed as part of this project. Continued development of the 115 kV source for Glencoe will include extending the 115 kV transmission to West Waconia. This project is under development and expected to be completed in 2012. The McLeod, High Island 69 kV substation will be affected by this project and be converted to 115 kV. The existing Glencoe—High Island 69 kV line will also be upgraded to 115 kV in 2012.

Existing System Deficiencies

In addition to being studied by GRE as part of the long range plan effort, this area was recently studied by XEL Energy (Outer Metro 115 kV Transmission Development Study and Addendums, 2007) to determine the adequacy of the transmission system to serve the load in and around the City of Glencoe. The following table (Table 3.1) is an excerpt from the study and shows the overloads and low voltages that were identified in the analysis.

Table 3.1

Year	Contingency	Monitored Element	Rating	Current MVA	% Flow
2011	Loss of Glencoe – McLeod 115 kV line	Carver Co – Young America	47	55.3	118
2011	Loss of Glencoe – McLeod 115 kV line	Young America – Glencoe tap	37	49.75	134
2011	Loss of Glencoe – McLeod 115 kV line	Glencoe tap – Plato	37	38.74	103
2011	System Intact	Carver Co 115 / 69 kV transformer	70	77.53	111
2011	Loss of Carver Co 115/69 kV transformer	St. Boni TX	70	77.11	110
2011	Loss of Carver Co 115/69 kV transformer	St. Boni – Waconia 69 kV line	48	77.51	111

Year	Contingency	Bus	Voltage
2011	Loss of Glencoe – McLeod 115 kV line	City of Glencoe	0.877
2011	Loss of Glencoe – McLeod 115 kV line	Plato	0.910
2011	Loss of Glencoe – McLeod 115 kV line	McLeod	0.896
2011	Loss of Carver Co 115/69 kV transformer	Plato	0.878
2011	Loss of Carver Co 115/69 kV transformer	McLeod 69 kV	0.881

Another factor considered was the decreasing reliability of the existing 69 kV system due to the age of the conductors.

Proposed Alternatives

Since the XEL study is very current, GRE did not review any alternatives in addition to those proposed in the Glencoe Area Study. The study reviewed alternatives as follows:

- New 115 kV line from Glencoe to West Waconia
- New 115 kV line from Glencoe to Carver County
- New 115/69 kV substation at Glencoe
- Convert High Island and Plato to 115 kV distribution

Based on the analysis cost and benefits of the alternatives, the study recommended the option to build a 115 kV line from Glencoe to West Waconia. This option has the best long term capabilities because it is expected that the West Waconia 115 kV system will be expanded and strengthened with the CapX2020 projects. This option introduces a new source into the Glencoe area to provide the voltage support needed for both base case conditions and during system contingencies.

The other recommendation in the study is to convert some of the area distribution loads, including High Island and Plato, to 115 kV to avoid the significant costs associated with reestablishing a 115/69 kV source in the area.

The 115 kV option mentioned above does impact the McLeod High Island substation. It is possible to maintain 69 kV service to the substation, however developing a 115/69 kV source at

Glencoe is a significantly higher cost than converting the Glencoe—High Island 69 kV line and High Island substation to 115 kV. An additional factor in the choice to convert to 115 kV is that the load in the Glencoe area can be expected to grow much faster than historical trends due to the near completion of a new US Highway 212 project. This expanded highway corridor will increase the potential for new business, commercial, housing and industrial development. Constructing 115 kV transmission in the area will provide for a more robust system to serve this anticipated load.

Cost Analysis

The cost analysis for this area is included in XEL's Glencoe area study and addendum. GRE will be responsible for the costs associated with the rebuilding the existing 69 kV line from Glencoe (Biscay Jct.) to the High Island substation to 115 kV. The estimated costs for the line reconstruction and converting the distribution substation are in the following table. Also included is the future extension of the Glencoe—High Island 115 kV line to Arlington.

Year in-service	Company	Project	Estimate Cost
2012	GRE	Glencoe-High Island 115 kV line, 8 miles, 795 ACSS	$3,500,900
2012	McLeod	Convert High Island sub to 115 kV	$600,000
2020	GRE	Arlington—High Island 115 kV line, 10 miles, 795 ACSS	$4,180,000

Panther Area

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

New Substations

Great River Energy member cooperatives have indicated no new distribution substations in this area. XEL has also indicated no plans for new distribution substations in this area.

Planned additions

XEL has 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. No new transmission lines are planned, however a new 69 kV breaker station is planned 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 Olivia load.

Existing System Deficiencies

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 summer peak conditions.

- 2011: Hector bus voltage at 93.6% for the outage of the Bird Island—Hector 69 kV line
- 2021: Hector bus voltage at 87.3% for the outage of the Bird Island—Hector 69 kV line
- 2021: Panther 230/69 kV transformer loading at 103% during system intact
- 2021: Panther 230/69 kV transformer loading at 123% for the outage of the Birch—Franklin 69 kV line (could be reduced by switching)
- 2021: Melville Tap—Panther 69 kV line at 103 %

Proposed Alternatives

In the previous long range plan the alternative developed for this area was the addition of a second 230/69 kV transformer at Panther. This, along with the capability to switch some load during the Birch—Franklin 69 kV line outage, would solve the transformer overload issue for the a few years. New load developments in the Atwater, Grove City, and Spicer areas resulted in the recommendation to add a new Spicer 230/69 kV source with a 69 kV double-circuit transmission line into the Atwater-Grove City area (see discussion in Willmar area below). This new source unloads the Panther transformer to 89% system intact and 103% for the outage of the Birch—Franklin 69 kV line.

Another factor for the Panther area is discussion to upgrade the existing 230 kV line from the Minnesota Valley substation (near Granite Falls) to the Blue Lake substation in the southwest metro Twin Cities area. It is possible that the voltage on this line could be upgraded to 345 kV without keeping 230 kV available. In this event the Panther 230/69 kV substation would have to be significantly modified.

The only alternative considered for the Hector low-voltage concern is the addition of a 115 kV line from the McLeod substation to Brownton and a 115/69 kV source at Brownton. With the addition of this source the Hector 69 kV voltage is 95.2% for the outage of the Bird Island—Hector 69 kV line. Based on interpolation between the 2011 summer peak results and the 2021 summer peak results this critical year for the Hector voltage to drop below criteria is 2013.

It is anticipated that GRE will be responsible for the Brownton—McLeod 115 kV line and Brownton 115/69 kV substation projects.

Year in-service	Company	Project	Estimate Cost
2013	GRE	Brownton to the McLeod substation - Construct 10 miles of 115 kV line from	$4,500,000
2013	GRE	Brownton - Construct a 115/69 kV substation	$4,600,000

Arlington—Winthrop Area

The transmission in this area consists of a 69 kV line between Arlington and Winthrop. Sources for the load in this area are the Franklin 115/69 kV substation and the Carver County 115/69 kV substation. A relatively large ethanol, located on the east side of Winthrop, and two loads near Gaylord are served by this 69 kV circuit. No new substations are proposed along this line.

System Deficiencies

The outage of the Heartland—Winthrop 69 kV line results in a voltage concern at the Heartland ethanol load. During 2011 summer peak conditions the voltage drops to 92.6% for this outage and during the 2021 summer peak conditions is projected to drop to 87.7% without any system improvements. The critical year (year which the voltage drops to less than 92%) is approximately 2013.

The outage of the Gaylord—Heartland also results in low voltage at Gaylord (88.3% in 2021 summer peak).

Overloads on this line are of concern for outages of the parallel 345 kV paths between southwestern Minnesota and the Twin Cities metro area, particularly the Helena—Wilmarth 345 kV line. This outage results in high through-flow on the 69 kV system. It is assumed in this study that those overloads will be mitigated by additional EHV paths between those areas.

No overloads are caused by 69 kV outages in the Arlington—Wilmarth area

Proposed Alternatives

Three alternatives were evaluated for this area.

- Alternative One: additional transmission followed by capacitor banks
  - 2013: construct a second 69 kV line from Winthrop to Heartland
  - 2018: construct a 2x10.9 MVAr capacitor bank at Arlington
- Alternative Two: Arlington capacitor bank then Heartland capacitor bank
  - 2013: construct a 2x10.9 MVAr capacitor bank at Arlington
  - 2021: construct a 9.6 MVAr capacitor bank at Heartland
- Alternative Three: Heartland capacitor bank then Arlington capacitor bank
  - 2013: construct a 9.6 MVAr capacitor bank at Heartland
  - 2018: construct a 2x10.9 MVAr capacitor bank at Arlington

Cost Analysis

Alternative	Year-Cost	Total Cost	Present Worth[1]
One	2013: $ 1,530,000 2018: $ 517,200	$ 2,047,200	$ 4,403,000
Two	2013: $ 517,200 2021: $ 253,400	$ 770,600	$ 1,628,000
Three	2013: $ 253,400 2018: $ 517,200	$ 770,600	$ 1,614,000

Alternative One has a much higher cost, both on a total cost basis and a present worth basis, than Alternatives Two and Three. Alternatives Two and Three are very close with regard to present worth costs. Alternative Two has a higher upfront cost in 2013 ($517,000) than does Alternative Three ($253,400).

[1] See appendices for factors used in the present worth calculations

Recommendation

The recommendation is to pursue Alternative Three due to its lower initial cost. Adding the lower cost bank at Heartland first pushes back the investment in the larger capacitor bank at Arlington by 4 years. Additionally, this would allow time for the development of stronger sources in the Arlington area which may preclude the need for a capacitor bank at that location.

Year in-service	Company	Project	Estimate Cost ($2007)
2013	GRE	Heartland 9.6 MVAr Cap Bank	$ 255,000
2017	XCEL	Arlington 2X10.9 MVAr Cap Bank	$ 517,000

Big Swan – Willmar – Panther Area

This area is served by 115/69 kV sources from Hutchinson, Willmar and Big Swan and by a 230/69 kV source from Panther. There are 7 GRE distribution substations, 2 Xcel Energy distribution substations, 1 WAPA distribution substation and 1 Litchfield municipal distribution substations in the area. There is 88.4 miles of 69 kV transmission lines in the area. The following is the load forecast for the area.

Season	2011	2021	2031
Summer	70	92.9	103.1
Winter	55.7	84.6	109.5

Planned Additions

Kandiyohi Power Cooperative has indicated the need for a new substation in the area just east of Lake Lillian in northeastern Lake Lillian township. This substation is needed for general increases in loads in the southern portion of the Kandiyohi system. The estimated in-service date is in 2012. Approximately two miles of 69 kV line will be needed from a tap point on the Xcel Lake Lillian—Panther 69 kV line.

A 14 MVAr capacitor bank is planned to be in-service at Litchfield Muni in the 2009 timeframe. This capacitor bank will substantially help boost the voltage in the area.

Existing System Deficiencies

The area has a good voltage profile and transmission line loading profile at system intact. For the loss of Panther to Melville or Melville to Lake Lillian 69 kV line, however, the area experiences severe low voltage problems along the Panther to Big Swan 69 kV system starting the 2009 timeframe. For Panther to Melville 69 kV line outage, the Big Swan transformer overloads in 2009, and the Litchfield to Litchfield muni 69 kV line overloads in 2017. The Big Swan 115/69 kV transformer overloads to 125% in the 2016 timeframe for the loss of Melville tap to Lake Lillian 69 kV line.

Alternatives:

Two alternatives were developed to address the long-term deficiencies of the area. The following are the options:

Option 1: New Spicer 230/69 kV , 140 MVA sub

This option involves establishing a new 230/69 kV, 140 MVA, substation tapping the Paynesville to Willmar 230 kV line and constructing 10 mile double circuit 69 kV lines from Spicer to Grove City. One of these 69 kV transmission lines connecting near Grove City will be built to 115 kV standards for 69 kV operations. The second 69 kV line will connect to Atwater introducing a new source to Atwater and the areas south of Atwater. This option also recommends moving the Melville 69 kV sub to a breaker at Panther in the 2009 timeframe, constructing a new 9.8 mile 115 kV line operated at 69 kV from Litchfield Muni to Big Swan in 2018 and undergoing temperature upgrade on the Litchfield muni to Litchfield tap 2 mile 69 kV line in the 2016 timeframe. Litchfield Muni is the largest load in the area and will need to be converted to 115 kV in the future to relieve the 69 kV system. A 48 MVAr capacitor bank is recommended at Big Swan in the 2022 timeframe to strengthen the weak Wakefield to Big Swan 115 kV system in the area. The following is the estimated time line and cost of installation for this option

Estimated Year	Facility	Cost
2009	Melville – move to a breaker at Panther	$670,000
2012	Spicer 230/69 kV, 140 MVA sub	$7,016,000
2012	Spicer to Atwater – Build 10 mile double ckt line	$5,630,000
2016	Litchfield – Litchfield Muni temperature upgrade	$160,000
2018	Big Swan to Litchfield – Build 9.8 mile, 115 kV line	$4,891,400
2022	Big Swan 48 MVAr Capacitor bank	$334,000

Option 2: Build Paynesville to Grove City 115 kV line

This option involves building a new 19 mile of 69 kV transmission line from Paynesville to Grove City and establishing a breaker station at Grove City in the 2012 timeframe. This line will be built to 115 kV standards but operated initially at 69kV. This option also recommends constructing 9.8 mile of 115 kV line for 69 kV operation from Big Swan to Litchfield in the 2018 timeframe. Similar to option 1, this option also recommends undergoing temperature upgrade on the Litchfield tap to Litchfield Muni 69 kV, 2 mile, line in the 2016 timeframe and installing a 48 MVAr capacitor bank at Big Swan in the 2022 timeframe for voltage support. The Melville sub will be moved to a breaker position at Panther. The Melville sub move help improve the near term voltage problems for the loss of Panther to Melville 69 kV line. The Litchfield Muni load is the largest load in the area and will be converted to 115 kV in the 2030 timeframe. The following is the estimated timeline and cost of installation for this option.

Year	Facility	Cost
2012	Melville – move to a breaker at Panther	$670,000
2012	Paynesville to Grove City - Build 19 mile 69 kV line	$9,262,000
2012	Grove City Breaker Station	$2,379,000
2016	Litchfield – Litchfield Muni temperature upgrade	$160,000
2018	Big Swan to Litchfield – Build 9.8 mile line	$4,891,400
2022	Big Swan – Install 48 MVAr Capacitor Bank	$334,000

Present Worth

Present worth analysis was performed on each option with option 1 being the benchmark for loss savings. The loss savings in MW for each option are as follow:

Option	2012	2021
2	1.72	3.7

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$15,965,000	$27,400,000	NA
2	$14,696,000	$25,170,000	$25,622,000

Option 2 is the least expensive plan

Viability with Growth
Both options are capable to address the long-term needs of the area. Option 1 introduces a new source to the area and relieves the Panther 230/69 kV transformer overload. Option 1 moreover brings solutions to the voltage problems in the Willmar area. A double circuit 69 kV 2 mile line will be constructed from the new Spicer sub to Green Lake to serve the Willmar area. If option 2 is considered as an option for this area, Panther may need a second 230/69 kV transformer in the near term and a new 69 kV line will be required from Paynesville to Hawick to serve the Willmar area, which is an expensive option. Therefore, option 1 is the recommended plan for this area.

Willmar Area:
The 69 kV system in the Willmar area is served from 230/69 kV and 115/69 kV sources from Willmar and three Willmar Municipal generators. There are 11 GRE distribution substations and 1 WAPA distribution substation in the area. There is a total of 28.7 miles of 69 kV transmission line in the area. The following is the load forecast.

Season	2011	2021	2031
Summer	96.5	124.0	145.3
Winter	83.6	111.2	136.0

Long-term Deficiencies
The area has good voltage and transmission line loading profiles at system intact. For the loss of Willmar to Kandiyohi 69 kV line, multiple substations along the 69 kV loop experience low voltage problems starting the 2012 timeframe. For the same contingency, the Sunburg to Prairie Woods tap, the Prairie Woods to Hawick, and the Willmar tap to Sunburg 69 kV lines are overloaded in the 2013, 2014 and 2021 timeframes respectively.

Alternatives:
Two alternatives were considered to address the long-term transmission needs of the area. The options are as follows:

Option 1: Spicer to Green Lake double circuit line
This option involves building a 2 mile double circuit 69 kV line from Spicer to Green Lake in the 2012 timeframe. The double circuit to Green Lake sectionalizes the 69 kV system while introducing the Spicer 230/69 kV source to the Willmar area. This option eliminates the low voltage and transmission line loading problems in the area for the loss of the Willmar to

Kandiyohi 69 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2012	Spicer to Green Lake – Construct 2 mile double Circuit 69 kV line	$1,670,500

Option 2: Build Paynesville to Hawick 69 kV line
This option involves building a 9.5 mile 69 kV line from Paynesville to Hawick in the 2012 timeframe and establishing a 69 kV breaker station at Hawick. This line introduces the Paynesville 230/69 kV source to the Willmar area. This option eliminates the voltage problems and transmission line loading problems in the area for a long-term. The following is the estimated timeline and cost of installation.

Estimated Year	Facility	Cost
2012	Paynesville to Hawick – Build a 69 kV line	$3,507,500
2012	Hawick 69 kV breaker station	$1,917,000

Present Worth
Present worth analysis was performed on each option with option 1 being the benchmark for loss saving. The loss savings in MW for each option are as follow:

Option	2012	2021
2	0.34	0.7

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$2,108,000	$3,606,000	NA
2	$6,848,000	$11,739,000	$11,835,000

Option 1 is the least cost plan which involves the minimum cumulative investment

Viability with Growth
Both options are capable of addressing the long-tem transmission needs of the area. Option 1 is the least cost plan, which involves the minimum cumulative investment to address the long-term needs of the area. Therefore, option 1 is the recommended option for this area.

Minnesota Valley to Morris 115 kV system

The Minnesota Valley to Morris 115 kV transmission system fed from two 230/115 kV source at Minnesota Valley and Morris is the backbone for the 69 kV and 41.6 kV sub transmission systems in the area. This line serves the Benson – Paynesville – Douglas County area and Willmar area with 115/69 kV sources at Benson and Willmar respectively. It also serves the Kerkhoven to Benson 41.6 kV system and Walden to Elbow Lake 41.6 kV systems with 115/41.6 kV sources at Kerkhoven, Benson and Walden. There are 2 GRE 115 kV distribution

substations, Benson and Hancock subs, and 1 OTP 115 kV distribution substation, Morris sub, along the Minnesota Valley to Morris 115 kV line. The total mileage of this line is 113.

Existing System Deficiencies

System intact voltage in the area is within the criteria in the near-term. In the 2020 timeframe, the transmission system experiences system intact voltage violations in the Kerkhoven area. The loading on the transmission lines is also within the criteria for a long-term at system intact. The Minnesota Valley to Morris 115 kV system is weak to serve 69kV and 41.6 kV sub transmission system during contingency conditions. The critical contingencies are the Morris to Morris tap 115 kV line outage and the Granite Falls to Willmar 230 kV line outage. For the loss of Granite Falls to Willmar 230 kV system, the Minnesota Valley to Maynard 26 mile line overloads above 110% in the 2013 timeframe. For the same outage, the 115 kV system in the Kerkhoven area experiences low voltage problem in the 2014 timeframe. The Morris to Morris tap outage also cause low voltage problems along the Morris to Minnesota Valley 115 kV system which surpasses to the 41.6 kV and 69 kV systems served from the Morris to Minnesota Valley 115 kV system. The Morris to Morris tap outage also overloads the Minnesota Valley to Kerkhoven 115 kV line.

Alternatives

Three alternatives were developed to address the long-term transmission needs of the area. The following are the alternatives:

Option 1: Rebuild Minnesota Valley to Kerkhoven 115 kV line

This option involves rebuilding the existing Minnesota Valley to Kerkhoven 37 mile 115 kV system to address the low voltage and line overload problems of the area. The Minnesota Valley to Kerkhoven 115 kV line is a relatively old line with high impedance 4/0 and 2/0 cu conductors. This line constitutes the major portion of the loss and a large percentage voltage drop on the 115 kV system. Moreover, it experiences overload problem in the 2013 timeframe, when it exceeds the allowable emergency loading limit of 110%. This option recommends rebuilding this line with 795 ACSS conductor to avoid the line overload, reduce loss and boost the voltage in the area. This option also recommends installing a second 115/69 kV 112 MVA transformer at Willmar in the 2024 timeframe. The existing Willmar transformer overloaded in the 2024 timeframe for the loss of the Granite Falls to Willmar 230 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2013	Minnesota Valley - Maynard Rebuild 37 mile line with 795 ACSS	$10,701,000
2024	Willmar - Add a Second 115/69 kV, 112 MVA transformer	$1,702,600

Option 2: Mandt to Woods 230 kV line

This option involves building new 18 miles 230 kV line from Mandt area tapping the Granite Falls to Morris 230 kV line to Woods area where a new 230/115 kV source will be established. The new 230/115 kV source in the Woods area will tap 6.5 miles south of Kerkhoven on the Kerkhoven to Kerkhoven tap 115 kV line. This option also recommends rebuilding the Kerkhoven tap to the new Woods tap 3.5 mile 115 kV line with 795 ACSS in the 2013 timeframe. Rebuilding the Kerkhoven to Woods tap 3.5 mile 115kV line and establishing the new Woods 230/115 kV source removes the low voltage problems and overload problems on the Minnesota Valley to Woods tap 115 kV line in the area. This option also lays the foundation to continue building a 230 kV line to Willmar in the 2024 timeframe to create a 230 kV loop service. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2013	Mandt to Woods tap - Build 32 miles of 230 kV line	$11,227,000
2013	Woods - Establish a 230/115 kV ,180 MVA source	$8,577,000
2013	Kerkhoven tap to Woods - Rebuild Tap 3.5 mile line, 115 kV line	$1,015,000
2024	Woods Tap to Willmar – Build 13.5 mile, 230 kV line	$9,089,000

Option 3: Olivia to Willmar 230 kV line and New Benson 230/115 kV sub

This option involves establishing a new 230/115 kV , 180 MVA source at Benson and building 19 miles of 230 kV transmission line from Olivia to Willmar in the 2013 timeframe. The new 230 kV line along with the Granite Falls to Willmar 230 kV line creates a loop service at Willmar. This eliminates the voltage problem in the area for the loss of the Granite Falls to Willmar 230 kV line. The new Benson 230/115 kV source helps maintain the voltage on the 115 kV system within the criteria for the loss Morris to Morris tap 115 kV line, which is one of the critical outage in the area. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2013	Olivia to Willmar - Build 19 miles of 230 kV line	$12,356,000
2013	Benson - Establish a 230/115 kV ,180 MVA source	$9,622,000

Generation Options

Generation options are not considered in this area

Present Worth

Present worth analysis was performed in all of the three options. Line losses for the area was evaluated with Option 1 being the benchmark for loss saving. The MW loss saving for each option is as follow:

Option	2011 Summer	2021Summer
2	-0.8	-2
3	0.6	0.8

The present worth, cumulative investment and present worth with loss savings are summarized in the following table.

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$18,646,000	$27,083,000	NA
2	$50,950,000	$64,021,000	$59,254,000
3	$29,412,000	$48,955,000	$51,322,000

Viability with Growth

All the three options address the long-term needs of the area. As the present worth calculation shows, option 1 is by far the least expensive plan. Option 1 is a 115 kV project which rebuilds an old and high impedance 115 kV transmission lines. Option 2 and option 3 includes 230 kV projects which should be restudied or coordinated with other studies to strengthen the radial 230

kV line from Granite Falls to Paynesville. Option 1 is the least expensive and preferred option to address the transmission needs of the area.

Summary Table of Projects in the West Central Region

Estimated Year	Responsible Company	Facility	Cost
2009	GRE	Melville – move sub to a breaker at Panther	$670,000
2012	GRE	Lake Lillian transmission-construct 2 miles of 69 kV, 3-way switch for new Kandiyohi distribution substation in the Lake Lillian area	$1,075,000
2012	GRE	Spicer to Green Lake – Construct 2 mile double Circuit 69 kV line	$1,670,500
2012	Kandiyohi	Lake Lillian area substation	
2012	GRE	Spicer 230/69 kV, 140 MVA sub	$7,016,000
2012	GRE	Spicer to Atwater - Build 10 mile 69 kV double circuit line	$5,630,000
2012	McLeod	High Island convert sub to 115 kV	$600,000
2012	GRE	Glencoe-High Island 115 kV line, 8 miles, 795 ACSS	$3,500,900
2013	GRE	Brownton - Construct a 115/69 kV substation	$4,600,000
2013	GRE	Heartland 9.6 MVAr Cap Bank	$255,000
2013	GRE	Brownton to the McLeod substation - Construct 10 miles of 115 kV line from	$4,500,000
2013	XCEL	Minnesota Valley - Maynard Rebuild 37 mile 115 kV line with 795 ACSS	$10,701,000
2016	GRE	Litchfield – Litchfield Muni 2 mile 69 kV line temperature upgrade	$160,000
2017	XCEL	Arlington 2X10.9 MVAr Cap Bank	$517,000
2018	GRE	Big Swan to Litchfield Build 9.8 mile, 115 kV line	$4,891,400
2020	GRE	Arlington—High Island 115 kV line, 10 miles, 795 ACSS	$4,180,000
2022	GRE	Big Swan 48 MVAr Capacitor bank	$ 334,000
2024	GRE	Willmar - Add a Second 115/69 kV transformer	$1,702,600

J: Southeastern Minnesota Region

The Southeast Minnesota region encompasses the entire southeastern part of the GRE system with the exception of Dakota and Scott Counties, which are covered as a separate study region. Member system service territory in this area includes:

- BENCO Electric Cooperative, (BENCO)
- Goodhue County Cooperative Electric Association (Goodhue)
- Minnesota Valley Electric Cooperative (MVEC)
- Steele Waseca Cooperative Electric (SWCE)

The load consists of mostly farm and agricultural services, but BENCO also has some higher density residential and commercial & industrial load in North Mankato and around Mankato. Geographically, the region covers the area south and east of a line from Red Wing to Northfield to New Prague to Arlington to west of Mankato and east of Fairmont. It is bounded on the south and east by the Iowa border and a line from Albert Lea to Rochester to Lake City. Other utilities supplying load in this area include XCEL Energy (XEL), Alliant Energy, and Southern Minnesota Municipal Power Agency (SMMPA). Some of the connecting transmission is owned and operated by Dairyland Power Cooperative (DPC). Appendix VI-J contains the detail data for this region.

BENCO

BENCO Electric Cooperative's service area is located in south central Minnesota in prime farm country. The Minnesota River Valley cuts through the northern portion of the service area. The major city is Mankato, located in the north central portion of the service area. Around the Mankato area are emerging suburbs with several housing developments and mobile home parks.

The economy of the BENCO Electric Cooperative service area is primarily dependent upon agriculture. Most of the BENCO Electric Cooperative service is prime farmland producing predominantly soybeans and corn, with some wheat, oats, hay and vegetables. The economy of Mankato and North Mankato continues to grow when surrounding areas have little or no economic growth. Housing starts are at record levels with mortgage interest rates at very low levels.

Goodhue

The Cooperative's electric distribution service territory is located in the southeastern part of Minnesota, serving the rural areas in a large part of Goodhue County and small portions of Wabasha, Olmsted, Dodge, Dakota and Rice Counties. Growth is expected because of the location and convenient access to the Cooperative's area. A major four-lane highway between the Twin Cities and the City of Rochester angles through the center of the Cooperative, in addition to other highways and paved county roads throughout the area. The Cannon Falls area in the northwest part of the Cooperative is only about 35 miles southeast of Minneapolis and St. Paul, Rochester is about 15 miles south of the cooperative's service territory and the City of Red Wing is located just northeast of the area. The growth has been controlled by zoning regulations for the purpose of protecting farmland from development.

Goodhue County has started to allow some rural housing developments. As a result, the Cooperative is providing water and wastewater system operation and maintenance for some of these developments.

Xcel Energy serves the larger towns and villages as well as a small amount of rural area within the Cooperative's general service area. The electrical distribution service territory boundaries have been established by the Minnesota Public Utilities Commission (MPUC). No significant service territory changes are expected during the period of this Long Range Load Forecast Plan.

The economy in the Goodhue County Cooperative area is primarily agriculture based. Corn and soybeans are the major crops, along with a significant number of dairy farms. Alfalfa and small grains are also grown to some extent. The terrain in the service area varies from relatively flat in some portions to gently rolling in other parts and to extremely hilly and wooded in other areas. In addition rural residential housing is increasing due to employment in the Rochester and Twin Cities areas.

The economy of Goodhue County Cooperative Electrical Association's service area has seen an increase in population attribute to the following factors:

- Demographics – There is a trend of population growth due to the increasing numbers of people choosing to live in the area and work in the Twin Cities and Rochester areas;
- Improved Infrastructure – Continued improvement in basic services such as schools, hospitals, roads, and telecommunication has made the area a great place to live;
- Quality of Life Concerns – The rural/small town atmosphere of the area attracts real estate developers and home buyers.

Minnesota Valley

Minnesota Valley Electric Cooperative (MVEC) service area includes a major portion of Scott, LeSueur, Sibley, and Carver Counties, and smaller portions of Blue Earth, Dakota, Rice, Hennepin, and Waseca Counties.

The economy of Minnesota Valley Electric Cooperative's service area is principally based on agriculture and light industry. The area has seen an increase in population attributed to the close proximity to the Minneapolis/St. Paul metro area, which strongly influences residential growth. Consumer growth is especially prevalent in the northern portion of MVEC's service territory.

Steele Waseca

Steele Waseca Cooperative Electric (SWCE) serves parts of Blue Earth, Dodge, Faribault, Freeborn, Goodhue, LeSueur, Rice, Steele, and Waseca counties.

The economy of Steele-Waseca Co-op Electric's service area has seen an increase in population attributed to a trend of new housing developments in the Lonsdale area and continued improvement in basic services such as schools, hospitals, roads, and telecommunications. Agricultural related activity continues to be significant.

Existing System

The region is served from the XEL - GRE integrated transmission system and the Alliant Energy system. The majority of the delivery point substations are served from the 69 kV system. As larger loads develop, such as the ethanol plant at Al-Corn, more load will be connected to the 115 kV and 161 kV transmission lines. The major sources to the region from the 345 kV system are at Adams,

Byron, Prairie Island, West Lakefield and Wilmarth. The 69 kV system has sources from the 115 kV system at Cannon Falls, Carver County, Loon Lake, West Faribault and Wilmarth; and from the 161 kV system at Byron, Hayward, Owatonna, Spring Creek and Winnebago. The 69 kV system also connects to the Dakota and Scott County study region at Northfield and New Prague, and the Southwestern Minnesota study region at Madelia.

Since the last GRE long range plan, The XEL loads at Wilmarth and Eastwood have been transferred from the 69 kV system to the 115 kV system and the Al-Corn substation has been added to the 161 kV. Additional, new 115 kV circuits from Wilmarth to Eastwood and from Eastwood to West Faribault have been added to help alleviate the Wilmarth 115/69 kV transformer overloading that will be mentioned below (existing deficiencies).

Reliability and Transmission Age Issues

This area covers BENCO Electric Cooperative, Goodhue County Cooperative Electric Association, and Steele Waseca Cooperative Electric.

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 142	Wilmarth 4S43/4S45 - Madelia 761 (BE-MD, BE-SC, BE-DM, SW-DM,	Rank: 1
Line 144	Wilmarth 4S40,4S42 - Cleveland 4S100 - Waterville 193 (BE-CJ, BE-JA,	Rank: 14
Line 192	Cleveland 4S99/4S100 69KV (MV-CLX, MV-ST)	Rank: 18
Line 235	W. Owatonna 4S73 69KV (SW-RB, SW-PRT)	Rank: 21
Line 239	Albert Lea Westside 629 (SW-MB)	Rank: 30
Line 121	Cannon Fls 105 – Sp. Crk 4H7/4H8 - W. Hastings 4P78 (DA-HA, DA-HM,	Rank: 40
Line 145	Winnebago Local 746 69KV (BE-WCT, BE-SCT, BE-GCT)	Rank: 45
Line 150	Spring Creek 4H6/4H9 - Zumbrota 4H15 (GO-SG, GO-WG, GO-WZ)	Rank: 50

Transmission Lines Built before 1980

Line 142	Wilmarth 4S43/45- Madelia 69KV (BE-SC, BE-DM, SW-MD)	15 Mi.-1951-58; 33 Mi.-1964-68
Line 144	Wilmarth 4S40/42– Cleveland – Waterville 69KV (BE-JA)	4 Mi.-1969
Line 192	Cleveland 4S99/4S100 69KV (MV-ST)	4 Mi.-1962
Line 235	W. Owatonna 4S73 69KV (SW-RB)	9 Mi.-1953
Line 239	Albert Lea Westside 629 69KV (SW-MB)	11 Mi.-1950
Line 121	Cannon Falls 105-Sp.Crk-W. Hastings 69KV (GO-GS, -VAT)	11 Mi.-1969-77
Line 145	Winnebago Local 746 69KV (BE-SCT, -WCT, -GCT)	14 Mi.-1975-78
Line 150	Spring Creek 4H6/9– Zumbrota 69KV (GO-SG, -WG, -WZ)	28 Mi.-1968-74
Line 140	Bricelyn 720 – Winnco 34NB42 69KV (BE-BRT)	1 Mi.-1958
Line 143	Walters 628 - Winnebago Jct. 69KV (BE-WIT)	1 Mi.-1975
Line 148	Arlington 4S199 -Traverse 69KV (MV-JET, BE-NST)	8 Mi.-1966-69
Line 149	Wilmarth 4S46/48–Traverse 69KV (BE-JO)	1 Mi.-1974
Line 151	Faribault 4S62 - Zumbrota 69KV (GO-CGT, SW-WC)	8 Mi.-1963-67
Line 153	Zumbrota 4H13 69KV (GO-LET)	1 Mi.-1964
Line 236	Faribault 4S61-Northfield–W. Faribault 69KV (SW-FC)	10 Mi.-1959; 5 Mi.-1973
Line 237	Waseca 647 – W. Owatonna 4S76 69KV (SW-OM)	6 Mi.-1952

The reliability for this region varies across the area. Overall the reliability is similar to the GRE average, but this area also has the worst ranked reliability line. Part of this area is served from the Xcel Energy and Alliant 69 kV systems. The line age table shows several segments of older line where replacement may need to be considered. The line age and maintenance information for

several of the lines in this area are not complete since data for the lines owned by the other utilities is not included.

Line 142 from Wilmarth to Madelia is a 101 mile 69 kV line serving seven substations. The line also has open switch connections to the Alliant Energy system from Albert Lea Westside and Walters-Winnebago Jct. Its performance is among the worse lines on all six of the indices used, with the worst performance on three of the indices. The three are substation momentary outages, substation long term outages, and substation hours out. Part of the reason for the poor performance is the long line exposure and the high number of substations supplied. The GRE maintenance reports show some significant activity with a large number of bad pole grounds on the BE-DM line section, a few pole condition incidents on the BE-MD and BE-SC lines, and a few other various incidents. Maintenance records are not complete since part of the line is owned by Xcel Energy. Present plans call for the construction of a new 115 kV loop around the southern Mankato area and new 115/69 kV sources at two new substation locations: South Bend and Stoney Creek. This new sources will break up the line exposure into smaller segments to reduce the numbers of substations outages during a single incident.

Line 144 from Wilmarth to Cleveland and Waterville is a 46 mile 69 kV line serving four substations. Its performance is among the worse lines on all six of the indices used, mainly due to a high number of outages and long outage durations. The maintenance reports do not show much activity, but part of this line is owned by Xcel Energy. Fault locating relays were added at Cleveland in 2005 to improve outage response time and the Eagle Lake tap switch was replaced in 2006.

Line 192 from Cleveland is a 32 mile 69 kV line serving three substations. The line has open switch connections to Le Sueur and the Montgomery 69 kV substation. Its performance is among the worse lines on all six of the indices used, mainly due to a high number of outages and long outage durations. The maintenance reports do not show much activity, but most of this line is owned by Alliant Energy. Fault locating relays were added at Cleveland in 2005 to improve outage response time

Line 235 from West Owatonna is a 48 mile 69 kV line serving three substations. The line has open switch connections from the Austin and Hayward substations. Its performance is worse than the GRE average on all six of the indices used, mainly due to a high number of long term outage events. The GRE maintenance reports show a few incidents with a variety of causes on the SW-RB section, but part of the line is owned by other utilities resulting in incomplete maintenance data. There are no recent or current projects to improve reliability for this line.

Line 239 from Albert Lea Westside is a 35 mile 69 kV line serving two substations. This line has open switch connections to the Waseca Jct.-Loon Lake line and the Wilmarth-Madelia line. Its performance is worse than the GRE average on all six of the indices used. The maintenance reports do not show much activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve reliability for this line.

Line 121 from Cannon Falls to Spring Creek and West Hastings is a 41 mile 69 kV line serving five substations. Its reliability performance is worse than the GRE average on four of the six of the indices used, due to a high number of momentary events and the high number of substations served by this line. The maintenance reports show a number of incidents related to insulators on the DA-HM line, but not many other issues. About half of the line is owned by Xcel Energy. The Miesville tap to Byllesby Jct. (DA-MI) line was rebuilt in 2006 and the Spring Creek relay and RTU replacement project will be completed in 2007. These projects will help improve reliability for this line.

Line 145 from Winnebago is a 37 mile 69 kV line serving three substations. The line has an open switch connection to the Wilmarth-Madelia 69 kV line at Garden City. Its performance is worse than the GRE average on five of the six indices used, mainly due to higher momentary outage events and higher outage durations. The maintenance reports do not show much activity, but most of this line is owned by Alliant Energy. There are no recent or current projects to improve reliability for this line.

Line 150 from Spring Creek to Zumbrota is a 38 mile 69 kV line serving two substations. Its performance is worse than the GRE average on four of the six indices used, mainly due to higher outage durations. The maintenance reports do not show much activity; only a small part of this line is owned by Xcel Energy. Spring Creek relay and RTU replacement projects will be completed in 2007 to help improve reliability for this line.

Mankato 69 kV and 115 kV Area

This area covers the load served by the Wilmarth 115 kV and 69 kV systems in the area around Mankato. The loading of the 69 kV loop includes the 69 kV loop around the city as well as the 69 kV lines that tap this loop and serve the areas down to Minnesota Lake and Madelia. Separate discussions of the analysis of these other areas will be discussed in the Mankato—Madelia and Mankato—Minnesota Lake sections later in this report.

Existing and long-term deficiencies

There are two primary deficiencies in the Mankato area. The first is the heavy loading on the three, 70 MVA 115/69 kV transformers at the Wilmarth substation. Within the last five years, the Xcel Energy load at Eastwood has been transferred to the 115 kV source to alleviate the possible transformer overloads. However the area load continues to grow and a more permanent solution is needed.

The second deficiency is the reliability of the 69 kV circuit from Wilmarth to Madelia/Minnesota Lake. This poor performance of this has resulted in its ranking as the worst performing circuit on the GRE system. This deficiency was addressed in the last long range plan. In 2003, GRE attempted to construct a new 69 kV breaker station on the southeast side of the Mankato 69 kV loop (known then as Hungry Hollow), but the local permitting could not be obtained due to township ordinances prohibiting electrical substations. Therefore this issue still exists.

In the long term a third deficiency will become apparent. This is the overload of the conductor on the 69 kV loop as the load in the city continues to grow.

Planned additions

In order to address the concerns mentioned above, a joint GRE-Xcel Energy study was conducted since the last GRE long range plan. A longer term, more permanent solution was recommended which establishes a new 115 kV loop to replace the 69 kV loop. New 115/69 kV delivery points will be established on the southeast (Stoney Creek) and southwest (South Bend) corners of the city to feed the 69 kV lines to Minnesota Lake and Madelia as wells as an Xcel Energy substation (Sibley Park) which will remain on the 69 kV system. The expected completion of this project is summer, 2010. Depending on the load growth over the next couple of years, this should be in time to prevent overloading of the 115/69 kV transformers.

Mankato-Madelia 69 kV Area

This area includes a 69 kV transmission line between the new South Bend substation, described in the "Mankato 69 and 115 kV Area" above, and the Madelia breaker station. The loads along this line include municipal and cooperative substations. Sources to the 69 kV system are located at Fox Lake, Rutland and South Bend.[1]

Existing System Deficiencies

A large, ethanol load was added to this 69 kV line at the Northstar substation in 2006. This addition has resulted in concerns about low voltages along this circuit for the contingent loss of the South Bend source, which is the nearest source. Capacitors were added to the substation that serves the ethanol plant and this has resolved the near-term deficiencies. If expansion of the ethanol production at Northstar occurs, with a corresponding increase in load, additional transmission will be necessary.

Long Term Deficiencies

Concerns about voltage spikes during capacitor switching have highlighted the need for a more permanent solution. Based on power flow analysis additional transmission will be required sometime in the 2015 time frame. Further discussion of this area can is found in the Southwestern section of this report.

Mankato—Minnesota Lake 69 kV Area

This area consists of a 69 kV line from Stoney Creek[2] to Minnesota Lake and Danville. The normal source for this is the Stoney Creek 115/69 kV substation. During outages of this source, line switching allows the loads to be served from the 69 kV source at Albert Lea.

Existing System Deficiencies

There are no existing deficiencies in this area.

Long-term Deficiencies

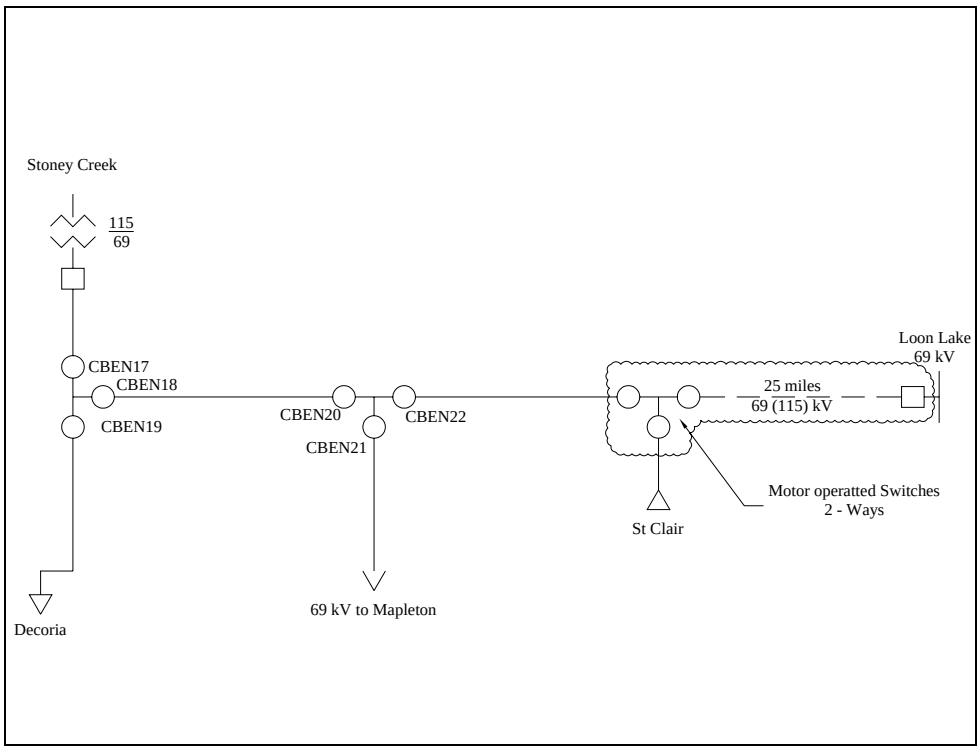
Based on load projects for the area deficiencies will occur in the 2015 time frame during contingency loss of the 69 kV source at Stoney Creek. The back-up source is located a relatively long distance away at Albert Lea and the voltages at Decoria and St. Clair can no longer be adequately supported.

The long term solution proposed is a new 69 kV line (built at 115 kV) between the Loon Lake substation near Waseca and the St. Clair substation southeast of Mankato. The project consists of the following components:

- 25 miles of 69 kV line, 477 ACSR, built to 115 kV standards, initially operated at 69 kV
- 69 kV breaker addition at the Loon Lake substation
- 3-way, motor operated switch at the St. Clair substation

[1] The South Bend source is under development and is expected to be in service in 2010.
[2] The Stoney Creek source is under development and is expected to be in service in 2010.

The total estimate cost for this project is approximately $10,000,000. This project is needed by the summer of 2016. A diagram of the proposed project is shown below.



Proposed Loon Lake—St. Clair 69 kV project

Wilmarth-Carver County 69 kV Area

The Wilmarth-Carver County 69 kV area covers the transmission system from Wilmarth (Mankato) to Arlington and Carver County, and also to Cleveland and Montgomery. This area includes the cities of St. Peter, LeSueur, and LeCenter. The primary sources for this area are the Wilmarth and Carver County 115/69 kV substations, but there are connections to other 69 kV areas at Arlington and Cleveland, and an open tie at Montgomery. The Cleveland tie connects back to Wilmarth-West Faribault 69 kV line.

Analysis for this area was recently (2008) compiled in a joint Alliant (ITCo), GRE and Xcel Energy study, conducted by Xcel Energy, entitled "*North Mankato Load Serving Study".* The discussion shown below includes information from this study.

Long-term Deficiencies

This area will experience overloading of the those sections of Traverse—Wilmarth 69 kV transmission line that have 2/0 copper conductor. Low voltages will also occur at peak load levels in the St. Thomas area for outages of the Wilmarth-Eastwood-Eagle Lake line or the Eagle Lake-Jamestown Tap line.

An outage of the Wilmarth-Johnson Tap-Penelope Tap 69 kV line will overload the Eagle Lake-Jamestown Tap line at present loads, overloads Jamestown Tap-Cleveland starting about 2010, and results in low voltage at LeSueur starting in 2012.

A Traverse-St. Peter 69 kV line outage will result in low voltage from St. Peter to Montgomery at present load levels, and overload the Eagle Lake-Jamestown Tap and Jamestown Tap-Cleveland lines. Traverse-Traverse line outages result in low voltages at LeSueur in the existing system, followed by low voltages on other substations north of Traverse in subsequent years. The outage of the LeSueur Tap-LeSueur 69 kV line will result in low voltage from LeSueur to Montgomery at present load levels. This outage will overload the Cleveland-LeCenter line starting in 2010 and the LeCenter Tap-St. Thomas Tap starting in 2012.

Another long-range loading problem will occur on the Johnson Tap-Johnson line. The load forecast for this study has the Johnson load exceeding the rating of the line by 2020.

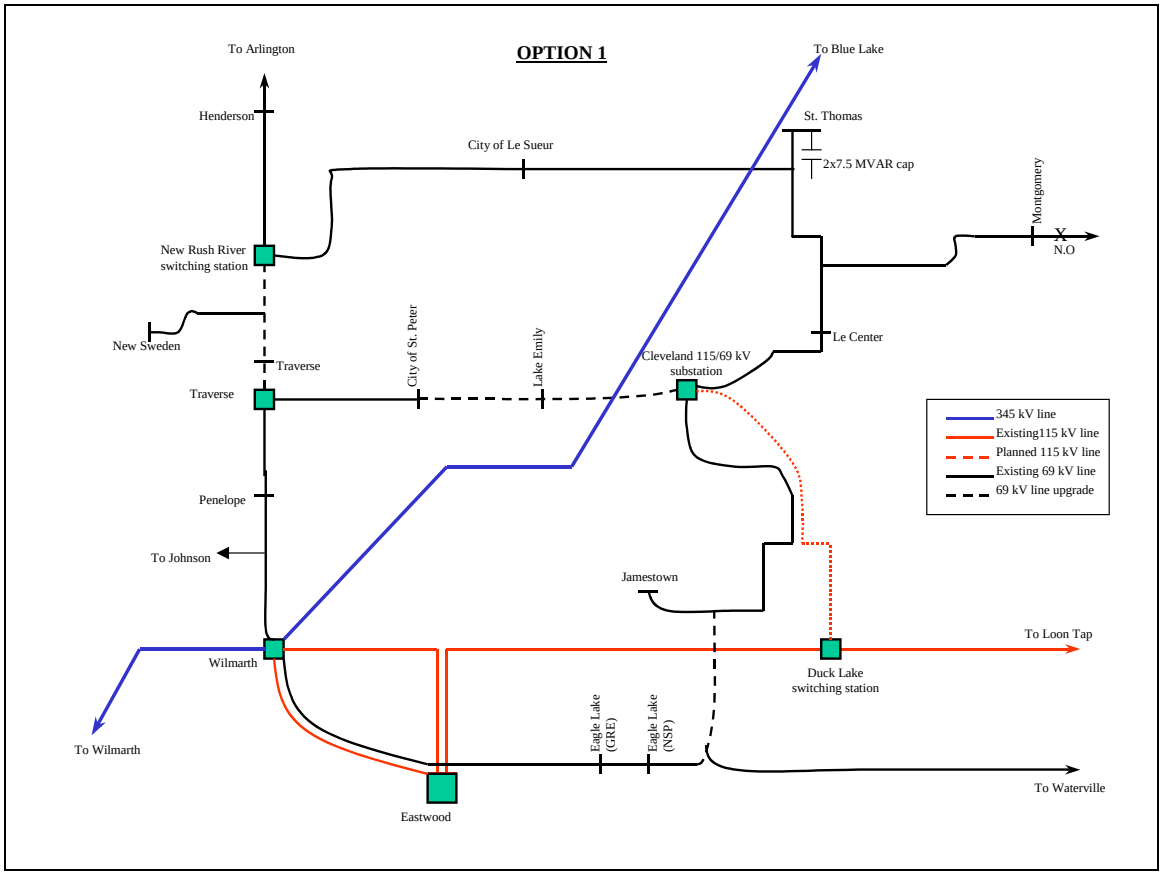
Alternatives

Due to the topology on the transmission system in this area, it is found that a new 115 kV source in the region northeast of Wilmarth is the most optimal solution to meet the transmission needs in this region. A new source will help alleviate the load on the other two sources to the region out of Wilmarth.

Two options have been developed to resolve the deficiencies in this area.

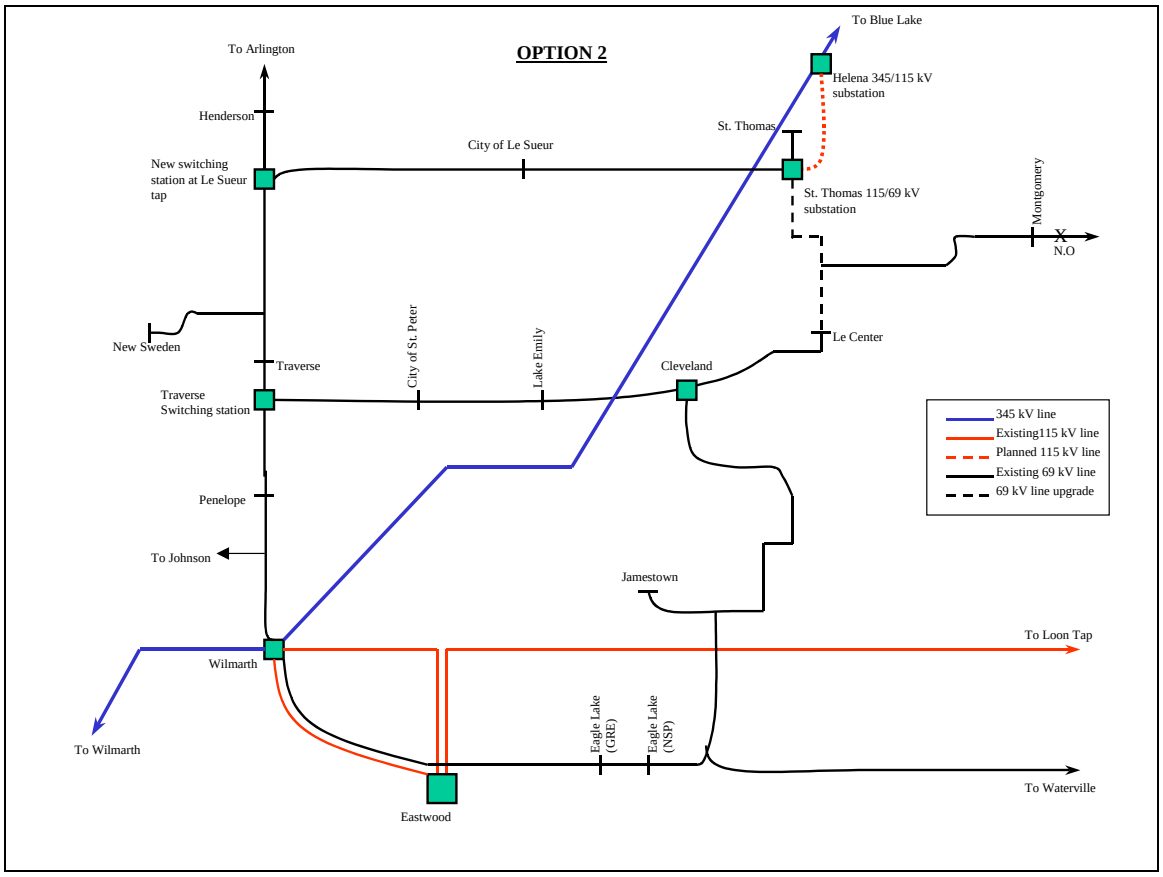
Option 1

Option 1 proposes to build a new switching station (Duck Lake) on the 115 kV line between Eastwood and Loon tap, build a new 115 kV line from Duck Lake – Cleveland and build a new 115/69 kV substation at Cleveland. Along with the above additions, a number of 69 kV system upgrades and additions are required to avoid any new violations on the underlying system. The total cost for Option 1 is $28,100,000. The figure below illustrates the new transmission lines required by this option.



Option 2

This option proposes to build a new 115 kV line from the future, proposed Helena 345 kV substation[3] to St. Thomas. This will involved installing a new 345/115 kV transformer at Helena, build new 115 kV line from Helena to St. Thomas and a new 115/69 kV substation at St. Thomas. Similar to Option 1 this plan also requires a number of 69 kV system upgrades in order to avoid overloading the underlying system. The total cost for Option 2 is approximately $21,950,000. The figure below illustrates the new transmission lines required by this option.



The cost estimates and the project elements for the two options from the North Mankato Load Serving Study are included in the following excerpt.

[3] The Helena substation projects is part of the CapX2020 development.

Estimated Cost of facilities (from *North Mankato Load Serving Study)*

The cost of facilities associated with options 1 and 2 are listed in Tables 1 and 2. The estimates are typical planning level estimates used for comparing multiple options.

Table 5.1

Facility	Year	Cost
New 115 kV line from Cleveland – Duck Lake (12.5 miles)	2011	$5,000,000
New 115 kV breaker station at Duck Lake	2011	$4,000,000
New 115/69 kV substation at Cleveland	2011	$7,500,000
Capacitor Banks at St. Thomas	2011	$2,000,000
Upgrade Cleveland – Lake Emily – St. Peter line to 477 ACSR 6 miles	2011	$1,800,000
Traverse – New Sweden – Rush River 69 kV line to 477 ACSR 7.1 miles	2011	$2,130,000
Reterminate the Le Sueur – Le Sueur tap line into Rush River 2 miles	2011	$600,000
New 69 kV switching station at Rush River	2011	$3,000,000
Increase capacity of Eagle Lake tap – Jamestown tap line.	2011	1,300,000
Rebuild Cleveland – LeCenter 69 kV line to 336 or 477 ACSR	2011	$2,070,000
Total		$29,400,000

Table 5.2

Facility	Year	Cost
New 345/115 kV transformer at Helena (assuming Helena sub already exists)	2011	$6,000,000
New 115/69 kV transformer at St. Thomas	2011	$7,500,000
New 115 kV line from Helena to St. Thomas (6 miles)	2011	$2,400,00
Upgrade St. Thomas – LeCenter 69 kV line to 477 ACSR (11 miles)	2014	$2,750,000
New Breaker station at Le Sueur tap	2011	$3,000,000
SPS to trip the 345/115 kV TR at Helena	2011	$300,000
Increase capacity of Eagle Lake tap – Jamestown tap line.	2011	$1,300,000
Total		$23,250,000

Other Alternatives Considered

Lake Marion – St. Thomas 115 kV line: This option builds a new 115 kV line from Lake Marion to St. Thomas and a new 115/69 kV substation and 30 MVAR capacitor at St. Thomas. Analysis indicated that this option does not provide long term benefits. Lake Marion is not a strong source and the voltages drop steeply due to the weak source and length of the new line. This option was not studied any further.

Distributed generation: Based on the analysis it was found that the system intact voltages could drop to below 95% by 2017. Since the generators cannot be turned on when the voltages drop below 95%, the distributed generation has to run during on and off peak conditions making it a must run unit. For this reason, this option was not studied further.

Recommendation

The recommended plan is option 2 which recommends building a new 115 kV line from the proposed Helena 345 kV substation to St. Thomas. This plan is less expensive than option 1 and provides a strong source to the region with minimum upgrades on the 69 kV system. A special protection scheme (SPS) that trips the 345/115 kV transformer during the loss of Helena – Blue Lake or Helena – Wilmarth 345 kV line avoid overloading the underlying system. The need for this SPS will be re-evaluated after the 345 kV lines from Franklin to Helena to Lake Marion are inservice.

Another long-term vision[4] for this region is to convert the 69 kV line from Scott County to Gifford Lake to Merriam to Jordan to Helena to 115 kV. Some sections of this existing line are already built to 115 kV specifications. The proposed Helena – St. Thomas 115 kV line can be extended to the new switching station at Rush River by converting the St. Thomas – Le Sueur – Rush River 69 kV line to 115 kV and then extending it either to Fort Ridgely or High Island.

West Faribault—Wilmarth 69 kV Area

The 69 kV line between West Faribault and Wilmarth (Mankato) serves load at Elysian, Morristown, Walcott, Warsaw and Waterville. The sources to this circuit are the 115/69 kV substations at Wilmarth and West Faribault. With the proposed addition of other sources north of this area (see section on the Wilmarth—Carver County 69 kV system) this analysis concentrated on the outage of either end of the 69 kV line between the Jamestown tap and West Faribault.

System Deficiencies

Low voltages will occur at Walcott for the loss of the Walcott—West Faribault 69 kV line beginning in approximately 2015, however this undervoltage may occur sooner if the transmission improvements in the Helena-St. Thomas area are not completed (see Wilmarth—Carver County section above). No line overloads are expected for outages of either source except for the Eagle Lake—Jamestown 69 kV line.

Alternatives

Three options were developed for this area in the previous GRE long range plan (2003). A cursory review indicates that these options are still valid for this area. The costs have been updated to more current cost estimates.

The first option adds a new 115/69 kV source in the middle of the area at Waterville. This source would replace the 69 kV source from West Owatonna (Loon Lake) that was removed when the Loon Lake-Waterville line was converted to 115 kV. Option 2 extends the life of the existing 69 kV system by moving the Waterville and Elysian loads to the 115 kV system. Option 3 relies on rebuilding overloaded 69 kV lines, adding capacitors, and adding a Morristown 69 kV breaker station to connect to the Alliant Waseca Jct.-Montgomery line.

[4] The long-range vision is based on the assumption that there will be load growth between Carver and Mankato due to metro area expansion. The area has to be restudied as the deficiencies are identified in the future.

Rebuilding the Eagle Lake-Jamestown Tap 69 kV line with a large size conductor is included in all three of the alternatives. Other options to resolve the overloading of this line are much more expensive. Rebuilding the line is a low cost option to defer high cost line and substation additions.

The following are options that were considered:

Option 1: Build Waterville 115/69 kV Source

To provide the additional capacity and voltage support needed in the area, Option 1 adds a 115/69 kV source at Waterville. If the new substation connects to the 69 kV system at a different location, such as Elysian or Morristown, some of the 69 kV lines would need to rebuild to higher capacity.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2009	Eagle Lake-Jamestown – Rebuild Tap 69 kV Line	$1,269,000
2014	Waterville - add 115/69 kV Substation	$3,361,000

Option 2: Move Waterville and Elysian Load to 115 kV

This option reduces the loading on the 69 kV system by moving the Waterville and Elysian loads to the 115 kV system. The Elysian substation is located close to the existing 115 kV line and would only require a short tap, in additions to rebuilding the substation high side and replacing the transformer. Waterville is the largest load on this line. It will require approximately one-half mile of 115 kV and more extensive substation changes to convert three transformers to 115 kV and also maintain the 69 kV system continuity.

The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2009	Eagle Lake-Jamestown – Rebuild Tap 69 kV Line	$1,269,000
2014	Waterville and Elysian - Convert to 115 kV	$3,420,000

Option 3: Upgrade 69 kV System

Option 3 upgrades the 69 kV facilities to maintain system performance. It includes rebuilding overloaded lines, adding a capacitor to provide voltage support, and adding a breaker station to tie to the Alliant Waseca Jct.-Montgomery 69 kV line. The timing of the switching station is linked to low voltages for loss of the West Faribault source and overloading of the Warsaw-Morristown line for loss of the Wilmarth source. The Warsaw capacitor addition provides a five year deferral until 2018 and the switching station addition avoids the need to rebuild the Warsaw-Morristown line.

The following is the estimated timeline for Option 3 installations:

Estimated Year	Facilities	Cost
2009	Eagle Lake-Jamestown – Rebuild Tap 69 kV Line	$1,269,000
2014	Warsaw – Add 5.4 MVAr Capacitor	$236,600
2018	Jamestown Tap - West Faribault rebuild 69 kV Line	$15,678,000
2018	Morristown - Build 69 kV Switching Station	$2,032,000

Generation Options
Generation is a option for this area if connected to the 69 kV system and operated whenever loads are high enough to cause contingency problems, however the cost of generation installation would be much higher than the transmission options and therefore is not evaluated any further.

Viability with Growth
Each of the plans above have similar viability to supply additional growth, depending on where the growth occurs. Options 1 and 2 are stronger than Option 3 for growth at Waterville. Option 1 provides the best contingency support for this area and is the least cost plan. It is recommended that GRE and Xcel Energy follow the plan in Option 1, but encourage the consideration of 115 kV sources if distribution substations are added or upgraded.

Faribault-Northfield 69 kV Area
The Faribault-Northfield 69 kV area includes the cities of Faribault and Northfield and the 69 kV system serving the cities and surrounding loads. The sources to this area are the West Faribault and Cannon Falls 115/69 kV substations and the Dakota County area 69 kV system from Farmington. There is also a normally open 69 kV tie to New Prague.

Long-term Deficiencies
Several projects have recently been completed in this area to upgrade the West Faribault source to the 69 kV system related to a planned generation addition connecting to the West Faribault 115 kV system. This has included the replacement of the 2x25 MVA and 50 MVA 115/69 kV transformers with two 112 MVA units. Several of the 69 kV circuits from the West Faribault substation have also been upgraded to 795 ACSR conductor to eliminate overloading.

Subsequent to the West Faribault generation, a 350 MW generator was added at a new Colville substation north of Cannon Falls. This addition required upgrading the 115/69 kV transformers at Cannon Falls to two 112 MVA units which eliminated any overloads of the transformers for outages in the Northfield—West Faribault area.

A remaining critical outage in this area is the loss of the Fair Park-Circle Lake Tap 69 kV line. This outage results in low voltage at Circle Lake starting in 2019, however it is expected that the addition of the new Helena 345/115/69 kV substation (see Wilmarth—Carver County 69 kV Area section above) in 2015 will improve the voltage in New Prague, which is the source for Circle Lake during the contingency.

With the addition of the transmission projects associated with the addition of the generation at West Faribault and Cannon Falls (Colville) no significant deficiencies are found until 2021. Line overloads might be possible if the load or generation pattern changes from that included in the power flow models, however no alternatives were developed for this area in this plan.

Byron Zumbrota 69 kV Area

The Goodhue-Byron 69 kV area covers the Goodhue Cooperative area and the 69 kV lines connecting to Byron. Sources to the 69 kV system are from the Cannon Falls and West Faribault 115/69 kV substations and the Spring Creek and Byron 161/69 kV substations. The largest loads are the cities of Dodge Center, Kasson, and Byron on the south edge of the area, Zumbrota and Pine Island along the east-central part of the area, and Cannon Falls on the north side of the area. The city of Red Wing is located at the northeast corner of this area, but has not been included in

the study. The 69 kV system is characterized by long lines with no higher voltage transmission in the area, except the Prairie Island-Byron 345 kV line.

Long-term Deficiencies

The deficiency in this area occurs during an outage of the Byron 161/69 kV transformer. This outage results in low voltages at the Byron (0.873 pu) and Kasson (0.878 pu) 69 kV buses. It should be noted here that the wind generation at Dodge Center (Garwind) was modeled as zero output to represent low wind conditions at summer peak.

A multi-state switching procedure could be used to restore the voltage to the Byron and Kasson buses. This would involve closing in from Dodge Center to Claremont Junction, opening Dodge Center to Kasson and closing Kasson to Pine Island. The use of switching procedures is a viable option because the load will be outages during the contingency and system operators will have time to plan for the restoration of the load.

Alternatives that could be evaluated further and avoid the multi-stage switching procedures are:

- Second 161/69 kV transformer at Byron
- 161/69 kV transformer at Dodge Center

Alternatives

No alternatives were evaluated for this area since the load could be restored with switching procedures.

Owatonna-New Prague 69 kV Area

This area consists of the Alliant Energy 69 kV line from West Owatonna to Montgomery and New Prague and the GRE line to Claremont. The West Owatonna 161/69 kV substation is the main source for this line, along with the Loon Lake 115/69 kV source at Waseca and a connection to the Scott County 69 kV system at New Prague. There is also an open connection at Montgomery to the Wilmarth-Carver County 69 kV area and an open connection from the Claremont substation to the Dodge Center-Kenyon 69 kV line. The largest loads are at Montgomery and New Prague.

Long-term Deficiencies

The analysis for this area was completed with the assumptions that the Montgomery gas turbine would not be operated for normal peak load times, but the New Prague diesel generation would be on-line.

The first deficiency is low voltage (0.910 pu) at New Prague in 2021 for the outage of the Jordan—New Prague 69 kV line outage. A second deficiency is the overload, also in 2021 of the Montgomery—New Prague 69 kV line to 122%. This line is rated 36 MVA.

Alternatives

This area was included in the *North Mankato Load Serving Study*[5] conducted by Xcel Energy in 2008. Several alternatives were evaluated in this study including:

[5] This study is presently in draft form however the recommended projects in the study are not expected to change.

- Option 1: A new 115 kV line from a tap point on the Eastwood—West Faribault line and a new 115/69 kV source at Cleveland.
- Option 2: A new 345/115/69 kV substation in the Helena area and a tap on the Blue Earth—Wilmarth 345 kV line.

Distributed generation was also discussed in the study report. However, due to the low voltages and numerous contingencies that had to be covered by distributed generation, it was not studied further.

The study recommended proceeding with Option 2 (the new 345/115/69 kV substation at Helena) based on the lower cost and the anticipated construction, by 2017, of a new 345 kV breaker station as part of the CapX2020 project. GRE's portion of Option 2 is expected to include the following costs:

- 2011: Rebuild (increase the capacity of) the Eagle Lake tap—Jamestown 69 kV line -- $1,300,000
- 2014: A portion (est. 3.5 miles) of the 11 mile rebuild of the St. Thomas—LeCenter tap 69 kV line -- $1,450,000

Transmission diagrams and additional cost information are included in the Wilmarth-Carver County 69 kV discussion above.

Viability with Growth

Addition of a new 345/115/69 kV source in the Helena will provide strong transmission support into an area that is expected to see significant load growth in the near future. This option provides capabilities to convert some existing 69 kV transmission lines and loads to 115 kV as increased area development continues.

Owatonna and South 69 kV Area

This area includes the Alliant 69 kV system south of Owatonna down to Albert Lea including the GRE loads of Bixby, Pratt, and River Point. The source to this area is the 69 kV bus at Owatonna. The 69 kV has a normally open connection south of River Point to the Hayward 116/69 kV substation and a normally open connection to Blooming Prairie from Bixby. Blooming Prairie is on the Dairyland 69 kV system supplied from the Austin 161/69 kV substation.

Long-term Deficiencies

No deficiencies were found in the 69 kV system between Owatonna and Albert Lea.

Alternatives

No alternative were developed for this area.

Faribault—Owatonna—Alcorn—Byron 161 kV System

This area covers that 161 kV transmission line between West Faribault and Bryon. This line serves as the source for the large 161/69 kV substation at Owatonna and the 161 kV Steele Waseca Al-Corn substation. Sources to this line are the Byron 345/161 kV substation and the South Faribault 115/161 kV substation.

Long Term Deficiencies

The long term deficiency for this area is the outage of the Al-Corn—Byron 161 kV line. This outage results in a 0.900 per unit voltage at the Al-Corn distribution substation in 2021. No overloads were indicated during this outage.

Alternatives

Only one alternative was considered as a solution to the long-term, low-voltage deficiency. The recommendation is to install a switched capacitor at the Al-Corn substation. The capacitor bank should consist of 2 stages, 15 MVAR each, on the 161 kV bus. Based on power flow analysis the voltage rise for each step during the contingency outage of the Al-Corn—Byron 161 kV line is approximately 2.5%. The in-service date recommended for this capacitor bank is approximately 2018.

Other considerations

Recent studies[6] by Xcel Energy have recommended additional transmission in the Byron, Loon Lake, and Owatonna areas to increase wind generation outlet capability. There would be some benefit to the Owatonna area if the chosen project establish a new 161 or 115 kV source into Owatonna. This could eliminate the need for, or reduce the size of, the capacitor bank recommended for the Al-Corn substation.

The RIGO studies are still ongoing and the results not yet finalized. No quantitative impact related to the this long range plan for the Owatonna area can be done at this time.

Waseca-Albert Lea 69 kV Area

The Waseca-Albert Lea 69 kV area covers the 69 kV system from the Loon Lake 115/69 kV substation to the Albert Lea area, which is supplied by the Hayward 161/69 kV substation. The line between these two sources is operated normally open to the north of St. Olaf Lake. The St. Olaf Lake-Matawan line also has a normally open connection to the Pohl Road Tap to Minnesota Lake line, which is supplied from Wilmarth. The largest loads in this area are at Waseca and Albert Lea, but Albert Lea area load is not included in the following table.

Long-term Deficiencies

There are no deficiencies in the GRE part of the area. No further analysis was done.

Viability with Growth

This area can handle additional growth with the existing system. Enhancements are needed in the local Albert Lea area, and the Waseca area will also require upgrades for growth beyond this study, but the rural 69 kV line between these source areas will remain adequate. It is recommended that GRE monitor the system enhancements to the sources in this area to maintain reliable service and adequate voltages.

[6] RIGO (Regional Incremental Generation Outlet) study

Winnebago 69 kV Area

The Winnebago 69 kV area includes the Winnebago-Garden City line and the south part of the BENCO cooperative's area. The main source to this area is the Winnebago 161/69 kV substation. The Winnebago-Garden City line has a normally open connection to the Wilmarth-Madelia 69 kV line, while the lines south and east from Winnebago have another normally open connection to the Wilmarth source at Minnesota Lake and connections to the Albert Lea area 69 kV system at Walters and the Alliant 69 kV system in Iowa. The largest loads in this area are the cities of Winnebago and Blue Earth, but Blue Earth has a second source from a separate 161/69 kV transformer. The following forecast is the load served in this area.

Long-term Deficiencies

There are no deficiencies in this area. As such, no further analysis was done.

Viability with Growth

The existing facilities in this area can supply additional growth beyond the forecast for this study. It is recommended that GRE continue to watch load growth in this area and re-evaluate if additional growth occurs.

Recommended Plan

The analysis for this region included certain generation assumptions that can have significant effects on the adequacy of the power system. Effects on the 69 kV areas of the system are discussed in the individual analysis areas. However, the 115 and 161 kV system from Lake Marion-Wilmarth-Byron was not analyzed in detail with respect to alternate generation schedules. The base case models include Owatonna generation as on-line and 250 MW of new generation at West Faribault by 2006.

The following are the proposed projects for the Southeast Minnesota region:

Estimated Year	Responsible Company	Facility	Cost
2009	GRE	Eagle Lake-Jamestown – Rebuild Tap 69 kV Line	$1,269,000
2011	CAPX	Helena - New 345/115 kV transformer (assuming Helena sub already exists)	$6,000,000
2011	XEL	St. Thomas - New 115/69 kV transformer	$7,500,000
2011	XEL	Helena to St. Thomas - New 115 kV line (6 miles)	$2,400,00
2011	SMMPA	Le Sueur tap - New Breaker station	$3,000,000
2011	CAPX	Helena - SPS to trip the 345/115 kV TR	$300,000
2014	XEL	Waterville – Add 115/69 kV Substation	$3,361,000
2014	GRE/ITC	St. Thomas – LeCenter - Upgrade 69 kV line to 477 ACSR (11 miles)	$2,750,000
2016	GRE	Loon Lake-St. Clair 115 kV line	$9,335,000

K: Dakota and Scott County Region

Dakota and Scott Counties are located on the south side of the Twin Cities metropolitan area. Member systems serving this territory are:

- Dakota Electric Association (DEA)
- Minnesota Valley Electric Cooperative (MVEC)

The load consists of mixed commercial and industrial, urban/suburban residential, rural residential, and farms. This region includes some of the highest growth areas in Minnesota. The northeastern part has the highest load density, but its growth is slowing down as it is mostly developed. The highest growth areas during the long-range plan timeframe will be in the outer suburbs of the Twin Cities and areas surrounding the smaller cities. Most of the southern and western parts of this region will remain agricultural, with some rural housing developments. Geographically, the region is bounded by the Twin Cities to the north, the Mississippi River to the east, and by a line from Red Wing to Northfield to New Prague to Belle Plaine to Waconia on the south and west. Other electric utilities serving load in this area include XEL Energy (XEL) and Shakopee, Chaska, and New Prague municipal utilities. Appendix VI-K contains the detail data for this region.

Dakota Electric Association (DEA) is headquartered in Farmington, Minnesota and provides power to customers in Dakota County and portions of Goodhue, Rice, and Scott counties. The economy of this area is generally linked to the overall economy of the Minneapolis and St. Paul metropolitan area. Along with residential development, the suburban area covering the northern portion of the DEA system has a large commercial and industrial component. This load is diversified, including retail and service businesses, computer technology, light manufacturing and distribution. The southern and eastern parts of DEA are agricultural, including a significant component of irrigated farmland in the eastern area.

Minnesota Valley Electric Cooperative (MVEC) service area includes a major portion of Scott, LeSueur, Sibley, and Carver Counties, and smaller portions of Blue Earth, Dakota, Rice, Hennepin, and Waseca Counties.

The economy of Minnesota Valley Electric Cooperative's service area is principally based on agriculture and light industry. The area has seen an increase in population attributed to the close proximity to the Minneapolis/St. Paul metro area, which strongly influences residential growth. Consumer growth is especially prevalent in the northern portion of MVEC's service territory.

Existing System

The system is served from the XEL-GRE integrated transmission system. Delivery point substations are served from the 115 kV and 69 kV systems in this area. The major sources to the area include the Prairie Island, Inver Hills, Blue Lake, Eden Prairie, and Dickinson 345 kV substations. The 115 kV system has additional sources from generation or other transmission ties at Black Dog, Faribault, and Cannon Falls. The 69 kV system has sources from the 115 kV system at West Hastings, Spring Creek, Cannon Falls, Inver Grove, Pilot Knob, Lake Marion, Burnsville, Glendale, Scott County, and Carver County. The 69 kV system also has ties to the Southeast Minnesota study region at Northfield and New Prague.

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

Line 194	Glendale 4M9-Lake Marion 4S60 69 kV (MV-CR, MV-PN)	Rank: 37
Line 121	Cannon Fls 105–Sp. Crk-W. Hastings 4P78 (DA-HA, DA-HM)	Rank: 40

Transmission Lines Built before 1980

Line 194	Glendale 4M9-Lake Marion 69 kV (MV-CR, -PN, -SL)	24 Mi.-1965-77
Line 121	Cannon Falls 105-Sp.Crk-W. Hastings 69 kV (DA-HA)	11 Mi.-1969-77
Line 123	Burnsville 4M73/88–Glendale 69 kV (MV-GO)	3 Mi.-1965
Line 127	Pilot Knob 4P45, TR3 69 kV (DA-LL)	1 Mi.-1974
Line 187	Carver Co 4M52–Scott Co.–N. Prague 69 kV (MV-AB,-CA)	15 Mi.-1967-69
Line 196	Glendale 4M10/TR2 69 kV (MV-GP)	1 Mi.-1965
Line 253	Carver Co 4M47 69 kV (MV-AU)	3 Mi.-1970
	Pilot Knob 4P30-Farmington 69 kV (DA-RE, -DE, -PKX)	8 Mi.-1970-73
	Carver Co. 5M100–St. Boni-Dickinson 115 kV (MV-CC)	24 Mi.-1970

The overall reliability for this region is significantly better than the GRE average. Part of this area is served from Xcel Energy 115 and 69 kV transmission facilities. The line age and maintenance information for several of the lines in this area are not complete since data for lines owned by other utilities is not included.

Line 194 from Glendale to Lake Marion is a 33 mile, 69 kV line serving four substations. Its reliability performance is worse than the GRE average on four of the six indices used, mainly due to the high number of consumers/load supplied by this line. The maintenance reports do show a significant number of incidents on the MV-PN section, mostly related to pole conditions. There are no recent or current projects to improve reliability for this line.

Line 121 from Cannon Falls to Spring Creek and West Hastings is a 41 mile, 69 kV line serving five substations. Its reliability performance is worse than the GRE average on four of the six indices used due to a high number of momentary events and the high number of substations served by this line. The maintenance reports show a number of incidents related to insulators on the DA-HM line, but not many other issues. About half of the line is owned by XEL. The Meisville tap to Byllesby Junction (DA-MI) line was rebuilt in 2006 and the Spring Creek relay and RTU replacement project will be completed in 2007. These projects will help improve reliability for this line.

Existing Deficiencies

The analysis of this region did not identify any direct transmission deficiencies at existing load levels. However, the summer peak models have included generation being on-line at either Montgomery or New Prague on the 69 kV system. At existing summer peak loads without generation, low voltages would be experienced in the New Prague area for an outage of the Jordan to New Prague 69 kV line. It appears that the generation could be started post contingency as part of load restoration, but as loads grow this will cause additional operational problems.

Another existing system issue is the need for the second 115 kV transmission source to be developed to supply the Yankee Doodle distribution substation. Yankee Doodle was converted from a single transformer 69 kV substation to a two-unit 115 kV substation in 2006. This substation supplies a major commercial load area and can not be adequately back-fed from the

distribution system. The substation is supplied with a radial transmission line from the XEL Lone Oak substation.

Future Development

Load Forecast

The load in this study region is reasonably consistent with the forecast used in the 2002 GRE Long-Range Transmission Plan. While several facilities from that plan have been completed, distribution system, generation, and bulk transmission plans have changed providing additional alternatives for the continued load-serving transmission expansion. This study uses the following load forecast to analyze the transmission system in the region. The load includes GRE, XEL, and Municipal utility load.

Dakota & Scott County Region Load (in MW)			
Season	2011	2021	2031
Summer	1369	1732	2163
Winter	1033	1373	1802

Planned Additions

The following are projects that are expected over the LRP time period that are not significant in defining alternatives for future load serving capability. This list may also include generation or transmission projects that are already budgeted for construction, but have yet to be energized.

- MVEC has the Sand Creek substation being built in 2008. The substation involves a tap line of about 2.5 miles from the Jordan-New Prague 69 kV line.
- DEA plans double-ending the existing River Hills substation with the second unit addition in 2008.
- MVEC has proposed a St. Lawrence substation that is expected in 2009. This substation will tap the Jordan-Belle Plaine 69 kV line.
- DEA has proposed a Ritter Park substation in western Lakeville for 2009. This substation is expected to tap the Xcel Energy 115 kV transmission line between the Dakota Heights and Kenrick substations.
- DEA has proposed the conversion/rebuild of the Eagan substation to 115 kV in conjunction with transmission plans for the addition of a 115 kV line from Pilot Knob to Yankee Doodle. The planned transmission line will provide two-way 115 kV transmission for the Yankee Doodle substation.
- DEA has proposed a Nininger substation for 2010. This substation is expected to tap the Rosemount-West Hastings 115 kV line.
- DEA has proposed a Ravenna substation for 2011. This substation will tap the Prairie Island-Spring Creek 161 kV line near the Prairie Island substation.
- DEA has proposed a Rich Valley substation that is expected in 2012. This substation is expected to tap the Inver Grove-Pine Bend 69 kV line.
- DEA also has identified several existing substations where plans require the addition of a second transformer and switchgear unit. A Burnscott substation unit addition is proposed for 2010, with Dodd Park, Lakeville, Lemay Lake, and Lake Marion proposed in longer-range plans. The Lake Marion options are dependent on configuration and space issues in conjunction with CapX 2020 transmission options. The distribution system alternative is a new substation supplied from the 115 kV transmission system in the area of the city of Elko New Market.

- Other long-range needs in the DEA plans are for a new substation in the Randolph area to tap the Cannon Falls-Empire 115 kV line and a future substation in the Eureka township/Airlake Airport area.

The study of this region is significantly affected by the facilities planned for the bulk transmission system in the CapX 2020 plans. This plan assumes completion of the proposed Brookings to Hampton Corner 345 kV transmission line with 345 kV breaker stations at Helena and Hampton Corner and a 345/115 kV substation in the Lake Marion substation area.

Dakota County 115 kV Area

The Dakota County 115 kV system consists of the 115 kV lines within the area from the Black Dog to Inver Hills to Cannon Falls to Lake Marion. Much of the load in this geographic area is served directly from the 115 kV system, but the 115 kV system also supplies 69 kV load areas with 115/69 kV substations at Inver Grove, Pilot Knob, Burnsville, and Lake Marion. Options to site future base load generation in this area have not been included in this analysis as the generation, if developed, could also interconnect directly to the 345 kV system. The following forecast is the load served directly from this 115 kV system. It includes GRE and XEL load.

Season	2011	2021	2031
Summer	516	651	801
Winter	358	470	615

Long-term Deficiencies

Analysis of this area indicates that the system is adequate for the planned load through the 2021 time-frame. In the long-range, lines will overload and low voltages will occur during contingency situations due to the large amount of load supplied from the limited number of sources into the system. As indicated earlier, the addition of a new 345/115 kV source near the Lake Marion substation is assumed to meet bulk transmission needs with the CapX 2020 facilities. That addition resolves the long-range voltage issues and most line overloads for this area, but results in overloads on the Lake Marion-Burnsville 115 kV line.

At long-range load levels with the existing system, the worst case outages are the loss of the Black Dog-Riverwood 115 kV line or the Inver Hills-Koch 115 kV line. Without the CapX 2020 addition, the Black Dog-Riverwood outage results in low voltages on the 115 kV system and overloading on the lines from Koch to Johnny Cake and Johnny Cake to Fischer. The Inver Hills-Koch outage results in overloading of Inver Hills to Inver Grove, Inver Grove to Pilot Knob, and Koch to Rosemount.

With the CapX 2020 addition of a 345/115 kV source near the Lake Marion substation, the 115 kV line from Lake Marion to Burnsville overloads for system intact conditions and outages of either the Lake Marion-Air Lake 115 kV or Johnny Cake-Fischer 115 kV lines. Also, the Inver Grove to Pilot Knob 115 kV line will still overload for the outage of Inver Hills-Koch.

Alternatives

Since the planned CapX 2020 addition of a 345/115 kV source near the Lake Marion substation solves most of the deficiencies for this area, and since the overloaded lines are lower rated ACSR conductor lines, only one option is included for this area. The option is to upgrade the overloaded lines with larger sized ACSS conductors.

Option 1: Upgrade Overloaded Lines

The 5.7 mile Inver Grove-Pilot Knob 115 kV line needs to be reconductored using ACSS to provide the required capacity rating. The need and timing of this project is for an outage of the Inver Hills-Koch 115 kV line. This results in additional power from the Inver Hills source flowing toward Black Dog to supply loads from the Dakota County 115 kV system.

The Lake Marion-Burnsville 115 kV line needs 11.8 miles to be upgraded with higher capacity conductor in conjunction with the CapX 2020 addition of the 345/115 kV source to the Lake Marion substation. A strong source at Lake Marion results in increased power flows into the Dakota County 115 kV system overloading the 477ACSR conductor of the existing line.

Since both of the lines are owned by Xcel Energy, it is expected that they will complete these projects. No costs are expected to be assigned to GRE.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2014	Burnsville-Lake Marion 11.8 Mile, 115 kV reconductor to 795ACSS	$1,534,000
2025	Inver Grove-Pilot Knob 5.7 Mile, 115 kV reconductor to 795ACSS	$741,000

Generation Options

As discussed earlier, there are options for future base load generation to be connected to the 115 kV system in the Rosemount area. Additional transmission may be required in conjunction with generation development. There is already existing generation at Inver Hills and Black Dog in this study area and at Faribault and Cannon Falls (under construction) to the south. Costing of generation and analysis of generation outlet facilities is beyond the scope of this study, therefore none are included.

Present Worth

Since only one option is developed for this area, loss analysis and present worth comparisons are not required. The present worth table is provided with the cost information.

The present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$4,422	$4,748	NA

Viability with Growth

This plan has the ability to supply growth beyond the forecast levels. However, the load capacity of this area is significantly impacted by generation schedules and regional power transactions. Generation outlet studies and bulk transmission planning efforts should consider the local load serving needs during their analysis.

Scott-Carver 115 kV Area

The Scott-Carver 115 kV system consists of the 115 kV lines from Black Dog and Blue Lake substations to the Scott County substation, and from the Scott County substation to the Carver County substation and Bluff Creek substation. Much of the load in this area is served directly from the 115 kV system, but the 115 kV system also supplies 69 kV load areas with 115/69 kV substations at Glendale, Scott County, and Carver County. The following forecast is the load served directly from the 115 kV system in this area. It includes GRE, XEL, and municipal utility load.

Season	2011	2021	2031
Summer	276	350	444
Winter	213	277	376

Long-term Deficiencies

The 115 kV system is relatively strong between Black Dog, Blue Lake, and Scott County, but the lines from Black Dog will overload in the future if the Blue Lake-Hyland Lake 115 kV line is open. The Blue Lake-Hyland Lake-Dean Lake-Scott County 115 kV line is the only line connecting Blue Lake to the Scott-Carver 115 kV system. When this line is open, additional power is routed from Blue Lake to Black Dog and then on the lines from Black Dog to supply the Scott County 115 kV loads. The Blue Lake-Hyland Lake line outage will also overload the Scott County-Dean Lake line at the long-range load level due to the loads forecasted at Hyland Lake and Dean Lake.

Plans in adjacent areas will help strengthen the system, particularly to the Carver County and West Waconia substations. One aspect of those plans are to develop a new 115 kV transmission line from Glencoe to West Waconia to resolve voltage and capacity problems on the 115 kV system and address underlying 69 kV system issues. Other plans address 69 kV problems with the Carver County-Chaska-Scott County line, the Westgate-Excelsior-Scott County line, and loading on the Scott County 115/69 kV transformers. While details of the plans are still being analyzed by Xcel Energy, development and conversions resulting in a West Waconia to Scott County 115 kV line and a second Westgate to Scott County 115 kV line are assumed in this long-range study. Other long-range issues for Eden Prairie-Westgate may have some affect on this area, but it is beyond our scope.

Alternatives

There are two basic alternatives to resolve the long-range problems of this area. They are to upgrade the overloaded lines or provide new sources to solve the outage problem. Since the costs to upgrade the overloaded lines are low compared to adding new lines or new line terminations, only one option has been fully developed for this area.

Several alternative projects were considered to solve the problems for the Blue Lake-Hyland Lake 115 kV line outage, but each is considered too expensive for the load-serving needs of this area. However, there may be benefits related to the high-voltage transmission system needs of the southern Twin Cities area that may justify larger scale investments. Those needs are beyond the scope of this study. The alternative projects include establishing a 345/115 kV source at the Scott County substation, building a second 115 kV line from Blue Lake to the Scott County substation, or establish a different 345/115 kV source with a 115 kV line to the Scott County substation. West Waconia or the proposed Helena 345 kV substations are each possible locations for a future 345/115 kV source.

An alternative to resolve overloading on the Scott County-Dean Lake 115 kV line is to split the Blue Lake-Hyland Lake-Dean Lake-Scott County line into two lines with new terminations at Blue Lake (Blue Lake-Hyland Lake-Blue Lake and Blue Lake-Dean Lake-Scott County). It's possible that the Hyland Lake and Dean Lake loads could be split to different lines as part of an alternative to build a second line from Blue Lake to Scott County as well. A third alternative, which is also beyond the scope of this study, is to cap the load supplied by the substations to the rating of the transmission line requiring excess load to be supplied by other distribution substation options.

Option 1: Upgrade Overloaded Lines

The first line to overload is the 7.3 mile Black Dog-Glendale 115 kV line. The line will be upgraded using 795 ACSS conductor. Its timing is dependent on system development in adjacent areas, particularly the Dakota County 115 kV system and the Lake Marion-Glendale 69 kV system, but is estimated for about 2020.

The 4.4 mile Black Dog-Savage 115 kV line will need to be upgraded to 795 ACSS in about 2025 and the 4.9 mile Scott County-Dean Lake 115 kV line in about 2028. While the timing for each of these upgrades is based on load, the Scott County-Dean Lake line need is directly tied to the load being served on the line since the critical outage is the outage of the Blue Lake end of this line.

Since each of the lines is owned by Xcel Energy, it is expected that they will complete these projects. No costs are expected to be assigned to GRE.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2020	Black Dog-Glendale 7.3 Mile, 115 kV reconductor to 795 ACSS	$949,000
2025	Black Dog-Savage 4.4 Mile, 115 kV reconductor to 795 ACSS	$572,000
2028	Scott Co.-Dean Lake 4.9 Mile, 115 kV reconductor to 795 ACSS	$637,000

Generation Options

Generation is a possible solution for supply problems in this area. The existing system does have generation at Blue Lake and Minnesota River (Chaska) on the 115 kV system, with plans to add 49 MW of additional generation at Minnesota River. The generation at Minnesota River does help strengthen the supply to the Scott County substation, and to Bluff Creek and the Eden Prairie area. However, it may require additional run time of the generation and does not eliminate the need to upgrade the transmission facilities with future load growth. Costing of generation is beyond the scope of this study, therefore no other generation projects are included.

Present Worth

Loss analysis was not done for this area since no alternative options were developed. The present worth for this area is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$5,822	$4,212	NA

Viability with Growth

This option will remain viable with additional growth by upgrading more of the facilities as they become overloaded. New high voltage sources will be required for significant load beyond the load levels in this study.

Cannon Falls Area

The Cannon Falls area includes the 115 kV, 161 kV, and 69 kV facilities connected with the Cannon Falls substations and the Cannon Falls generation substation (Colville). The issues of this area are related to generation outlet for the Cannon Falls 350MW combustion turbine generation plant. There is no GRE load within this immediate area.

Long-term Deficiencies

The critical outages with the planned transmission system for the Cannon Falls generation outlet are the loss of the Colville-Empire 115 kV line, loss of the higher rated of the two Colville-Cannon Falls 115 kV lines, or loss of one of the two Cannon Falls 115/69 kV transformers.

The Colville-Empire line is the main outlet tie to the Dakota County 115 kV area and the Twin Cities load. The loss of this line shifts more power to the other lines and to the 69 kV system. Xcel Energy upgrades to the Cannon Falls-Northfield and Cannon Falls-Byllesby-Miesville Tap 69 kV lines provide adequate capacity on those facilities, but this GRE study also shows overloading of the Cannon Falls-Cannon Falls City-South Cannon 69 kV lines. This is an XEL-owned line.

For an outage of the higher rated Colville-Cannon Falls 115 kV circuit, our models show the second line overloading in about 2012. XEL plans are expected to resolve this issue.

XEL is changing its transformer loading criteria in 2012 affecting the Cannon Falls 115/69 kV transformers. With more restrictive loading criteria, the second transformer will be overloaded for an outage of the other transformer.

Alternatives

XEL has developed a plan to add a 115/69 kV transformer at the Colville substation to supply the 69 kV line to Byllesby, which ties to the Spring Creek and West Hastings substations. This addition will reduce the loading on the Cannon Falls 115-69 kV transformers and the Colville-Cannon Falls 115 kV lines. The contingency loading of these facilities will be within limits with the addition.

Contingency loading on the Cannon Falls-Cannon Falls City-South Cannon 69 kV line will require upgrading of this line by Xcel Energy if it exceeds their loading criteria. The line has exceeded the loading criteria used in this GRE study, but not the criteria used by XEL.

Other alternatives considered for this area have included the addition of a 115 kV line to West Hastings (probably as part of a 69kV conversion), new 115 kV construction in conjunction with CapX 2020 projects, or adding a 115 kV source at Prairie Island with double-circuit part way to Spring Creek and operation of the Colville-Spring Creek 161 kV line at 115 kV. The Prairie Island 115 kV alternative would provide better options for shifting load from the 69 kV system to the higher voltage source and eliminate the need for the 115/161 kV transformer at Colville. Each of these alternatives is too expensive compared to the planned option and the needs of the area do not justify the higher cost.

As the facility additions and upgrades for this area are XEL projects, and GRE load is not directly involved with the changes, no financial analysis is in included in this study and the projects will not be listed with the recommended plan.

Viability with Growth

The facilities will remain viable for the generation outlet of the present generation capacity, but significant changes in regional transfers could affect contingency loading on some lines. Load growth on the connected 69 kV lines will result in increased power flows on the 115/69 kV transformers and the lines. The planned system will accommodate additional growth.

Hastings 69 kV Area

The Hastings 69 kV area includes the 69 kV line from West Hastings to Cannon Falls and Spring Creek. A 69 kV line from West Hastings to XEL Hastings to the Wisconsin 69 kV system is also connected to this area (at the West Hastings substation). The following forecast is the load served in this area. This load includes GRE and XEL load, but not the XEL Hastings load.

Season	2011	2021	2031
Summer	48	61	81
Winter	39	52	70

Long-term Deficiencies

This area will experience overloads on the Cannon Falls-Byllesby-Miesville Tap line segments for an outage of the Cannon Falls Generation-Empire 115 kV line when the generation comes on-line. This overload is based on the 4/0 ACSR, 48, MVA rating for the 69 kV line. The switches at Byllesby have been identified as a limiting factor in 2012 when the Colville 115/69 kV transformer is installed. In the longer range, the Spring Creek-Burnside line will overload starting in about 2020 for a Cannon Falls-Byllesby outage and low voltage would occur at Burnside starting in 2022 if Spring Creek-Burnside is open.

The Hastings-Spring Creek-Cannon Falls 69 kV line also has been identified as having poor reliability based on analysis of reliability indices. The Miesville Tap-Miesville line, which was one of the older sections of this line, was rebuilt in 2006 to improve reliability and to increase its capacity. However, the switches at the Miesville Tap are still a limiting factor during an outage of the West Hastings 115/69 kV transformer starting in about 2015.

Xcel Energy has built a new 115 kV distribution substation at West Hastings, and DEA has new substations proposed for Nininger on the 115 kV between West Hastings and Rosemount. Also a Ravenna distribution substation is proposed on the 161 kV line near Prairie Island. Each of these additions will reduce the amount of load supplied from the 69 kV system maintaining the viability of the 69 kV system for the long range.

Alternatives

The option to resolve the overloads for this area is to rebuild or reconductor the affected lines with higher capacity conductor. Rebuilding the Cannon Falls-Byllesby-Miesville Tap line will also improve the low contingency voltage issue at Burnside to acceptable levels for the forecasted long-range loads. The underrated switches at Byllesby and the Miesville taps will be replaced when necessary.

Other alternatives that were considered include converting the 69 kV line from Cannon Falls to West Hastings to 115 kV. This would require double-circuiting the line from Cannon Falls to the

Miesville taps to maintain the 69 kV line from Cannon Falls to Spring Creek. Another alternative is adding a 161/69 kV substation at the Miesville Tap. These alternatives were not analyzed in detail because of their high cost compared to the proposed option and that the system needs for the forecasted long-range load levels does not require the amount of increased capacity they would supply.

The switches at Byllesby and the Miesville taps need to be replaced with 1200 amp switches in 2012 and 2015 respectively. The switch replacements will be GRE projects.

Option 1: Upgrade Overloaded Facilities

This option rebuilds and upgrades facilities as required to continue to supply the load in the area from the 69 kV system. The 6.3 mile Cannon Falls-Byllesby-Miesville Tap 69 kV line needs to be rebuilt to 477 ACSS in 2008 to accommodate power flows due to the Cannon Falls generation plant addition for an outage of the Generation-Empire 115 kV line. In about 2020, the 0.1 mile Spring Creek-Burnside 69 kV line will need to be upgraded to 477 ACSS for a Cannon Falls-Byllesby line outage.

Since each of the lines is owned by Xcel Energy, it is expected that they will complete these projects.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2008	Cannon Falls-Byllesby-Miesville Tap 6.3 Mile, 69 kV rebuild to 477 ACSS	$1,323,000
2020	Spring Creek-Burnside 0.1 Mile, 69 kV reconductor to 477 ACSS	$25,000

Generation Options

Additional generation could be a viable alternative to future system upgrades if located on the 69 kV system. There is an existing 8 MW diesel peaking generation plant connected to the low voltage side of the DEA Hastings substation, but it is not regularly operated at peak load and was not used in the analysis. To be considered adequate in place of transmission facilities, generation needs to be on line at peak load times to provide contingency voltage support and have sufficient capacity to alleviate line and transformer overloads. Costing of generation is beyond the scope of this study, therefore generation is not utilized in the plans.

Present Worth

Loss analysis was not done for this area since no alternative options were developed. The present worth for this area is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$1,456	$3,109	NA

Viability with Growth

The 69 kV system for this area can remain viable with additional load growth, but facility upgrades will become necessary. It can be extended by utilizing the 115 kV system to supply the load growth when possible.

Pilot Knob-Inver Grove 69 kV Area

The Pilot Knob-Inver Grove 69 kV area includes the 69 kV system supplied by the Pilot Knob and Inver Grove 115/69 kV substations. In addition to the lines between these two sources, the 69 kV system has a line closed through to Farmington and a normally open tie to Burnsville. Also, the recent conversion of the Yankee Doodle substation to 115 kV and the planned transmission changes related to that project are included. The following forecast is the load served in this area. This load includes GRE and XEL load.

Season	2011	2021	2031
Summer	141	163	196
Winter	111	135	172

Long-term Deficiencies

A present need for this area is the completion of a second 115 kV source to the double-ended Yankee Doodle 115 kV substation, which was converted from 69 kV in 2006. This conversion resolved many of the long range issues of the 69 kV system by reducing the load supplied from it. However, the plan for the second 115 kV source will add to the radial exposure for the Lemay Lake substation, putting it on a 1.7 mile, radial 69 kV line.

The 69 kV line from Kegan Lake to Lebanon Hills will overload for system intact loading starting in 2015 and Lebanon Hills would experience low system intact and contingency voltage in about 2025. The critical contingency for the Lebanon Hills voltage is an outage of the Inver Hills-Inver Grove 115 kV line.

The Inver Grove 115/69 kV transformer loading will exceed the contingency loading criteria starting in 2024 for an outage of one of the two transformers.

Alternatives

The plan to complete a 115 kV transmission source from Pilot Knob to Yankee Doodle has been selected to provide the second source to the Yankee Doodle substation based on analysis and a report completed by Xcel Energy dated September 2007. Other alternatives evaluated in that study were to provide the second source to Yankee Doodle with a line from the Inver Grove substation or from a new 115 kV substation between Pilot Knob and Inver Grove on their connecting 115 kV line. The selected plan was the most economical of the alternatives.

The 115 kV addition involves conversion of the existing 69 kV line south from Yankee Doodle past the Eagan substation to the crossing of the existing Inver Grove-Pilot Knob 115 kV line. The 115 kV line reaches the Pilot Knob substation by double-circuiting with the Inver Grove-Pilot Knob 115 kV line and adding a breaker and termination at Pilot Knob. DEA plans to upgrade the Eagan substation to 115 kV in conjunction with the transmission upgrade. A new 0.5 mile 69 kV line is needed to connect the line going to Lemay Lake to the Wescott line to maintain two-way feeds between Pilot Knob and Inver Grove for the 69 kV substations.

Alternatives have been considered to reduce the radial transmission exposure for the Lemay Lake substation, which increases with the Yankee Doodle transmission plan. To provide a 69 kV loop, a new 1.2 mile 69 kV line would be needed from the existing line continuing north along Pilot Knob Road to the Lemay Lake substation. A 115 kV alternative is to build about 2 miles of 115 kV line from Cedarvale to Lemay Lake and convert the existing 69 kV line from Lemay Lake to Yankee Doodle to 115 kV. However, neither of these alternatives is included in the plan because of right-of-way difficulties, lack of space for 115 kV breakers, and the subjective need.

The only alternative considered for the Kegan Lake-Lebanon Hills line overload and low voltage is to rebuild the 1.3 mile limiting section of this line. This XEL-owned line section is old with very light conductor. Upgrading this will eliminate the overload and improve the voltage to acceptable levels.

The contingency overload on the Inver Grove 115/69 kV transformers can be resolved by changing the normally open location on the 69 kV line between Pilot Knob and Inver Grove. This plan shifts the DEA Wescott Park loads to the Pilot Knob source changing the open point to the east-side switch at Wescott Park.

Option 1: Pilot Knob-Yankee Doodle 115 kV Plan

This option implements the plan to provide the 115 kV transmission loop to Yankee Doodle from the Pilot Knob substation based on the analysis and recommendation of the Xcel Energy study. The project details are described above and listed in the following table. This option also rebuilds part of the Kegan Lake-Lebanon Hills 69 kV line and changes the normally open switch location at the Wescott Park substation to shift its load to the Pilot Knob 69 kV source.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2009	Pilot Knob-Yankee Doodle 115 kV Line	$1,680,000
2009	Pilot Knob 115 kV Breaker and Termination	$500,000
2009	Eagan 115 kV Buswork and Switches	$820,000
2009	Lemay Tap 2-Wescott Tap 0.5 Mile, 477 ACSR, 115 kV line (operate at 69kV)	$450,000
2009	Lemay Tap 2 69 kV 3-way Switch	$100,000
2015	Kegan Lake-Lebanon Hills 1.6 Mile 69 kV rebuild to 477 ACSR	$336,000

Generation Options

Utility scale generation connected to the 69 kV system in this area is not considered feasible. This study includes an assumption of major generation in this vicinity, but it would interconnect to the 115 kV system and not help loading issues on the 69 kV system. There is significant peak alert diesel generation in this area on the DEA distribution system, but it was not incorporated into these options. Costing of generation is beyond the scope of this study, therefore none are included.

Present Worth

Loss analysis was not done for this area since no alternative options were developed. The present worth for this area is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$4,524	$8,721	NA

Viability with Growth

This plan has the ability to supply significant additional growth, but it is dependent on where the additional load is added. Certain facilities on the 69 kV system will begin to overload or require additional voltage support if loads exceed the forecasted levels.

Burnsville-Glendale 69 kV Area

The Burnsville-Glendale 69 kV area includes the 69 kV system between these two 115/69 kV substations consisting of Glendale-Burnscott, Burnsville-Colonial Hills, and Burnsville-Orchard Lake and the connections between these three lines. The Burnsville-River Hills line is also considered to be included. This area connects with the Glendale-Lake Marion 69 kV area at Glendale and has a normally open tie between Burnsville and Pilot Knob on the line supplying the River Hills load. The following forecast is the load served in this area. The load in this area is all GRE load.

Season	2011	2021	2031
Summer	112	121	133
Winter	77	95	115

Long-term Deficiencies

The deficiencies of this area result from the load growing beyond the capacity of the existing facilities. There are through flow issues for some 115 kV system outages, but they will be resolved by planned additions in other areas.

The long term deficiencies are:

- overload of Glendale-Burnscott starting in 2011 when Burnsville-Colonial Hills is out,
- overload of the Colonial Hills switch starting in 2015 for through flows when the Black Dog-Glendale 115 kV line or the Lake Marion-Lake Marion Tap 69 kV line is out,
- overload of the Colonial Hills switch starting in 2020 when Burnsville-Orchard Lake or Glendale-Burnscott is out,
- overloading of the Glendale 115/69 kV transformers starting in 2014 for a Burnsville-Colonial Hills outage, 2015 for the loss of one of the two units, and 2018 for a Black Dog-Riverwood 115 kV or Lake Marion-Lake Marion Tap 69 kV line outage.

The Burnsville-Colonial Hills-Colonial Hills Tap line and the Burnsville-Orchard Lake-Colonial Hills Tap line were upgraded in 2005-2006 to 477 ACSS with a 109 MVA capacity. However, 600 amp line switches still limit the lines to 72MVA. These switches will be replaced when their ratings are exceeded.

The Glendale transformer loading will be addressed in the Glendale-Lake Marion 69 kV area analysis. The alternatives to replacing these two transformers with higher-rated units are part of the facilities needed for the long-range issues of that area.

Alternatives

Two alternate options have been developed for this area. Option 1 adds motor operators to the switches at Orchard Lake so the open switch at Orchard Lake can be closed to relieve contingency overloading. As contingency loads get higher, it may be necessary to operate this 69 kV system as a three-terminal line. Option 2 upgrades the Glendale-Burnscott line with 477 ACSS conductor so it can supply the higher contingency loads. Both options require the Colonial Hills switch on the Burnsville line be replaced with a higher-rated switch.

Closing the open switch at Orchard Lake to utilize the Burnsville-Orchard Lake source during contingencies, or operating the 69 kV system from Burnsville to Glendale as a three-terminal line, solves the Glendale-Burnscott overload for an outage of the Burnsville-Colonial Hills line. It also helps with loading on the Glendale 115/69kV transformers by providing a stronger supply from the Burnsville 69 kV substation.

The Colonial Hills switch on the Burnsville line side needs to be replaced with a 1200 amp switch in 2015.

Option 1: Close-Through 69 kV at Orchard Lake

This option involves adding motor operators on the Orchard Lake switches in 2011 and changing the relaying to operate the Burnsville-Glendale 69 kV system as a three-terminal line when required.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2011	Orchard Lake Switch Motor Operator addition	$50,000

Option 2: Upgrade Glendale-Burnscott 69 kV Line

This option upgrades the Glendale-Burnscott 69 kV line in 2011 by reconductoring the 2.5 mile line to 477 ACSS to provide the capacity needed during a Burnsville-Colonial Hills line outage. The estimate for this project has been increased 50% due to the work in a high traffic area. This project could be deferred until 2015 by implementing an operating procedure to use the Orchard Lake tie to restore service to the Colonial Hills substation for a Burnsville-Colonial Hills line outage.

The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2011	Glendale-Burnscott Reconductor 69 kV line	$300,000

Generation Options

Generation is not considered to be feasible in this area, which is a suburban residential/mixed commercial area. However, there is a significant amount of customer owned, peak alert generation on the distribution system in this area. Utilization of the generation could defer system upgrades. Costing of generation is beyond the scope of this study, therefore it is not included.

Present Worth

A cost analysis was completed for each of the options. The loss difference between the two options is not significant so losses were not included.

The present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$63	$108	NA
2	$379	$648	NA

Viability with Growth

Both options are similar in their ability to handle additional growth. Most of this area has been developed, so significant additional growth does not seem likely. Re-development with higher density load is not expected either. Since Option 1 is the least cost plan, it is recommended that GRE follow the plan in Option 1.

Glendale-Lake Marion 69 kV Area

The Glendale-Lake Marion 69 kV area includes the 69 kV system that is supplied from the Glendale and Lake Marion 115/69 kV substations, except for the Glendale-Burnsville 69 kV line and the Lake Marion-Farmington 69 kV line. The line from Lake Marion to Farmington and its ties to Pilot Knob and to Castle Rock-Northfield have not been included in a detailed study area. These lines do not experience any long-range supply problems as long as the Lake Marion area improvements are completed. The following forecast is the load served in this area. This load includes GRE and XEL load.

Season	2011	2021	2031
Summer	84	134	198
Winter	73	119	182

Long-term Deficiencies

This area is forecasted with high growth resulting in significant deficiencies with the present lines and equipment. Each of the 115/69 kV transformers and nearly all of the 69 kV lines in this area would be overloaded during contingencies at long-range load levels. Several facilities would overload for system intact loads as well. The transmission serving this area also has been identified as having poor reliability based on analysis of reliability indices mainly due to the high number of consumers and the large load impacted by the outages.

The following table summarizes the facilities, the cause of the criteria violation, and the estimated year the planning criteria are exceeded.

Facility	Contingency/Cause	Estimated Year
Credit River Tap-Cleary Lake 69 kV Line	Lake Marion Tap-Elko Out	2010
Cleary Lake-Credit River 69 kV Line	Lake Marion Tap-Elko Out	2013
Glendale 115/69 kV Transformers	Burnsville-Col. Hills Out	2014
Glendale 115/69 kV Transformers	2nd Transformer Out	2015
Glendale 115/69 kV Transformers	Lake Marion-LM Tap Out	2018
Glendale 115/69 kV Transformers	Black Dog-Riverwood Out	2018
Lake Marion 115/69 kV Transformer	System Intact	2015
Lake Marion 115/69 kV Transformer	Glendale-PL Jct.-CR Tap Out	2015
Lake Marion-Lake Marion Tap 69 kV Line	Glendale-PL Jct.-CR Tap Out	2016
Lake Marion Tap-Elko 69 kV Line	Credit River Tap-Cleary Lake Out	2016
Prior Lake Jct.-Credit River Tap 69 kV Line	Lake Marion-LM Tap Out	2016
Credit River-Spring Lake 69 kV Line	Lake Marion Tap-Elko Out	2018
Elko-New Market 69 kV Line	Credit River Tap-Cleary Lake Out	2026

The overloads would cause low voltage problems too, but the loading violations occur first.

Alternatives

Two basic alternate options have been developed to resolve the deficiencies in this area. Both options plan for development of 115 kV facilities and conversion of load to the 115 kV system, but one defers the load conversions. Option 1 utilizes load conversion to 115 kV and the addition of a 115/69 kV source at New Market to minimize the need for 69 kV facility upgrades. Option 2 includes the replacement of the Glendale 115/69 kV transformers to defer the need for load conversion to 115 kV. Both options require the Lake Marion 115/69 kV transformer to be replaced with a larger unit in conjunction with the Lake Marion 345/115 kV source. The strong Lake Marion source results in higher flows on the Lake Marion-Farmington 69 kV line causing system intact loading problems for the existing transformer. However, the stronger Lake Marion source also delays the loading problem for the Glendale transformers. Each option has flexibility to accommodate distribution system issues regarding the conversion of load to the 115 kV sources once the 115 kV facilities are developed.

The biggest issue related to the system development is the schedule and configuration of the planned CapX 2020 addition of a Lake Marion 345/115 kV substation. This area needs the Lake Marion area source for a new 115 kV line from Lake Marion to Helena to enable load to be shifted to the 115 kV system. The Scott-Carver 69 kV area plan includes a 115 kV line from Carver County to Helena, which will connect with the Lake Marion-Helena line to complete a transmission loop and to provide a 115 kV source for New Prague.

Overloads on the Credit River Tap-Cleary Lake-Credit River lines will require upgrading of the overloaded facilities in both options as well. The overloads occur before 115 kV options are feasible and the higher ratings are required to supply the long-range load within each of the alternatives.

The loading on the Glendale transformers is fixed for the Burnsville-Colonial Hills line outage by the Glendale-Burnsville area plan to close the Orchard Lake switch making the system into a three-terminal line. In 2015, loading on the Glendale transformers needs to be addressed. This need is delayed until 2018 with the stronger source at Lake Marion with the CapX 2020 projects. One option is to replace both transformers with larger units. Alternatively, the loading on the 69 kV system can be reduced by converting distribution load to 115 kV. The most direct and largest benefit is by converting the Prior Lake substation to 115 kV. That alternative may require a new substation site as the existing location does not have space for high-side upgrades. Converting load on the south part of the system and adding a New Market 115/69 kV source can also reduce the loading on Glendale. The loading issue for the Black Dog-Riverwood 115 kV line outage will be resolved by the CapX 2020 addition of a 345/115 kV source at Lake Marion. But changes at Lake Marion can not resolve all of the loading problems since the loss of the 69 kV line from Lake Marion is one of the critical outages.

Other overloads during Lake Marion-Lake Marion Tap outages or Lake Marion Tap-Elko outages are also resolved by converting Elko and New Market load to 115 kV or the addition of a New Market 115/69 kV source. With Elko conversion to 115 kV and a New Market 115/69 kV addition, the Lake Marion Tap-Elko-New Market line can be rebuilt as a single circuit 115 kV line. The Lake Marion-Lake Marion Tap section will need to be double circuit to maintain the 69 kV source. If the New Market 115/69 kV source is not added, double circuit 115 kV with one circuit operating at 69 kV will be needed all the way from Lake Marion to New Market. Alternatively, the new 115 kV line can use a new route leaving the existing 69 kV in place, but then converting loads to 115 kV may be more difficult.

Alternatives to upgrading the Lake Marion 115/69 kV transformer were considered, but they are not justified for the system problems identified in this study or do not resolve the deficiencies adequately. For example, utilizing 115/69 kV capacity at New Market instead of Lake Marion requires an upgraded New Market-Lake Marion 69 kV line be kept in the plan. Opening the Lake Marion-Farmington 69 kV line (or converting it to 115 kV operation) to reduce the loading at Lake Marion would require a 115/69 kV addition at Vermillion River to maintain adequate contingency sources to Farmington and Northfield.

Converting the 69 kV load at Lake Marion to 115 kV is not able to resolve the loading on the Lake Marion 115/69 kV transformer either. However, the larger Lake Marion transformer does provide the flexibility to continue supplying load from the Lake Marion 69 kV bus allowing additional options for coordinating distribution system plans with the CapX 2020 transmission plans.

Option 1: Convert Loads to 115 kV

This option minimizes investments on the 69 kV system by converting load to 115 kV. In 2010 and 2013, successive segments of the Credit River Tap-Cleary Lake-Credit River 69 kV line need to be upgraded. The plan is to rebuild this line to 115 kV, 477 ACSS construction with continued operation at 69 kV. In 2014, in conjunction with the CapX 2020 installation of a 345/115 kV source at Lake Marion, the Lake Marion 115/69 kV transformer will be upgraded to 140MVA.

Load conversion to 115 kV will start in 2016 with the addition of a 115 kV line from Lake Marion to Helena. This option uses the route of the existing Lake Marion Tap-Elko-New Market 69 kV line for a single circuit 115 kV line requiring Elko to be converted to 115 kV and adds a New Market 115/69 kV, 70 MVA substation to supply the other 69 kV loads. The Prior Lake load is converted to 115 kV in 2018 requiring a new substation site and New Market load is converted to 115 kV in 2016 by adding a distribution substation at the New Market 115/69 kV substation site.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2010	Credit River Tap-Cleary Lake 1.3 mile rebuild to 477 ACSS 115 kV (operate at 69kV)	$440,700
2013	Cleary Lake-Credit River 1 mile rebuild to 477 ACSS 115kV (operate at 69 kV)	$322,050
2014	Lake Marion 115/69 kV transformer replace with 140 MVA	$1,939,900
2016	Lake Marion-Lk Marion Tap 2.43 mile rebuild to 115 kV double circuit	$1,297,600
2016	Lk Marion Tap-Elko-New Market 5.6 mile rebuild to 795ACSS 115 kV	$2,178,400
2016	New Market-Helena 15 Mmle new 795 ACSS 115 kV line	$6,320,000
2016	New Market 115/69 kV, 70 MVA new substation	$3,395,000
2016	Elko (MVEC) substation conversion to 115 kV	$350,000
2018	Prior Lake load (MVEC) conversion to 115 kV (new site)	$2,000,000
2026	New Market load (MVEC) conversion to 115 kV (new location)	$650,000

Option 2: Upgrade Glendale 115-69kV Transformers

This option adds facilities to facilitate supplying the loads from the 69 kV system as long as feasible. In 2010 and 2013, successive segments of the Credit River Tap-Cleary Lake-Credit River 69 kV line need to be upgraded. The plan is to rebuild this line to 115 kV, 477 ACSS construction with continued operation at 69 kV. In 2014, in conjunction with the CapX 2020

installation of a 345/115 kV source at Lake Marion, the Lake Marion 115/69 kV transformer will be upgraded to 140 MVA. These additions are the same in both options.

This option also builds the 115 kV line from Lake Marion to Helena in 2016 as needed with the Scott-Carver 69 kV Area plans. However, this option builds the line as a double circuit 115 kV line from Lake Marion to Lake Marion Tap to Elko to New Market with one circuit operated at 69 kV to serve the existing substations at 69 kV.

The two 115/69 kV transformers at Glendale are replaced in 2018 with this option, effectively allowing Prior Lake load to remain on the 69 kV source. Elko and New Market still need to be converted to 115 kV in 2018 and 2026 respectively due to overloading of the Credit River-Spring Lake 69 kV line for the Lake Marion Tap-Elko contingency. Conversion of the New Market load will require a new substation site.

The following is the estimated timeline for Option 2 installations:

Estimated Year	Facilities	Cost
2010	Credit River Tap-Cleary Lake 1.3 mile rebuild to 477 ACSS 115 kV (operate at 69kV)	$440,700
2013	Cleary Lake-Credit River 1 Mile rebuild to 477 ACSS 115kV (operate at 69 kV)	$322,050
2014	Lake Marion 115/69 kV transformer replace with 140 MVA	$1,939,900
2016	Lake Marion-Lk Marion Tap 2.42 mile rebuild to 115 kV double circuit	$1,297,600
2016	Lk Marion Tap-Elko-N. Market 5.6 mile rebuild to 115 kV double circuit	$3,578,400
2016	New Market-Helena 15 mile new 795ACSS 115 kV line	$6,320,000
2018	Glendale 115/69 kV transformers replace with 2-70 MVA	$2,599,000
2018	Elko (MVEC) substation conversion to 115 kV	$350,000
2026	New Market load (MVEC) conversion to 115 kV (new site)	$1,000,000

Generation Options

Generation could defer system upgrades for this area but with the high levels of growth expected it would not be a reliable long-term solution. In addition, any large scale generation in this area would likely be connected to the 115 kV system and not extend the viability of the 69 kV system. Costing of generation is beyond the scope of this study, therefore none are included.

Present Worth

A cost analysis was completed for each of the options including losses. Option 2 has the highest losses and is used as the benchmark for the loss savings calculations. The loss savings from each option in MW are listed as follows:

Option	2011 Summer	2021 Summer	2031 Summer
1	-	1.9	1.7

The present worth is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$32,539	$40,368	$31,730
2	$31,438	$37,962	NA

Viability with Growth

Option 1 is the preferred option for this area. It has the lower present worth cost when the loss savings of this lower loss plan are considered. This option also has the best viability for extra growth since it moves more load to the 115 kV system. Distribution planners are encouraged to consider options to utilize 115 kV sources for the load growth when distribution substation capacity additions or upgrades are required in this area.

Scott-Carver 69 kV Area

The Scott-Carver 69 kV area includes the 69 kV system between the Scott County 115/69 kV substation and the Carver County 115/69 kV substation. This system connects with the 69 kV system of the Southeast Minnesota study area at New Prague and with the West Central Minnesota study area at the Carver County sub. Also, one of the 69 kV lines from the Scott County substation ties to the XEL west metro area. The following forecast is the load served in this area. This load includes GRE, XEL, and municipal utility load.

Season	2011	2021	2031
Summer	134	178	228
Winter	109	160	203

Long-term Deficiencies

There are four main deficient aspects for this area:

1. Supplying the high growth Waconia-Victoria-Chaska-Eden Prairie area;
2. Loading on the Scott County 115/69 kV transformers;
3. Contingency voltage/generation operation in the New Prague area;
4. Contingency loading on the Carver County-Assumption-Belle Plaine 69 kV line.

Also, the Scott County-New Prague-Carver County 69 kV looped system has the highest MW-mile exposure between circuit breakers of any lines supplying GRE load. It has a calculated exposure of 3,036 MW-miles at the forecast 2011 load level.

Xcel Energy has developed plans to address long range supply issues for the Waconia-Victoria-Chaska-Eden Prairie area. Those plans directly affect the Scott-Carver 69 kV system as the loads are presently supplied from the Scott County-Chaska-Carver County 69 kV line and the Scott County-Excelsior-Westgate 69 kV line. While details of the plans are still being analyzed by Xcel Energy, a combination of new facilities and 69 kV conversions are expected to result in a West Waconia-Scott County 115 kV line and a second Scott County-Westgate 115 kV line. Augusta, Victoria, Excelsior, and Deephaven 69 kV loads are expected to be converted to 115 kV reducing the load supplied from the Scott County 115/69 kV transformers. This need is projected for 2011-2012.

The loading on the Scott County 115/69 kV transformers will exceed planning criteria limits starting in 2012 for an outage of one of the two units. The 115 kV conversions discussed above will defer the overloading by several years and could fully resolve the loading issue if additional 115/69 kV transformer capacity is incorporated into the Chaska area plans. A directly related issue is loading on the Scott County-Shakopee 69 kV line. This line is radial supplying the Shakopee substation. The forecast has this load growing above the line's rating. Xcel will either need to upgrade the line or Shakopee will need to limit the load added to the 69 kV source.

The 69 kV system in the New Prague area will experience contingency voltage problems at the present peak load levels. The local peaking generation needs to be run to maintain adequate

voltages during an outage of the Scott County-Gifford Lake-Merriam Junction line or the Jordan-New Prague line.

Starting in about 2014, the Carver County-Assumption 69 kV line will overload for the Scott County-Gifford Lake line outage. The Assumption-Belle Plaine line starts overloading in 2016 for this outage.

Alternatives

There are two basic alternatives for the long-range supply to this area, beyond the plan for the northern area that is being assumed. They are to rely on the local generation during contingencies to maintain voltage or to develop a new transmission source to New Prague. This study proposes a new 115/69 kV substation at New Prague.

Transmission for the new source will need to coordinate with the CapX 2020 projects and the transmission needs of the surrounding areas. The CapX 2020 projects include a 345 kV Helena substation. This plan proposes a 115 kV Helena substation for the same site, although the needs of the 69 kV system do not justify a 345/115 kV connection. The Glendale-Lake Marion area includes a Lake Marion-New Market-Helena 115 kV line, which would connect with the Carver County-Helena 115 kV line in this plan. The New Prague 115/69 kV source would be supplied from the new Helena 115 kV substation. The line to New Prague may be compatible with the plans to address the needs of the LeSueur-Montgomery area in the Southeast Minnesota region.

The Carver County to Helena 115 kV line will convert the existing Carver County-Assumption-Belle Plaine-St. Lawrence 69 kV line. The alternative of converting the Scott County-Jordan 69 kV line to 115 kV was also considered, but that line provides a better source for loads left on the 69 kV system.

Depending on the strength and configuration of the New Prague 115/69 kV source, some of the connected 69 kV lines may be overloaded by through-flows or contingency requirements. Those facilities may require upgrades or operation with normally open connections. Due to the scoping variations and possible plan modifications for compatibility with other high voltage transmission development, these issues were not analyzed in detail.

Reliance on 69 kV system alternatives is not adequate for the long-range, beyond the loads projected for this study, so other options were not evaluated. The comprehensive plan for Scott County includes a large portion of urban development in its ultimate vision. The load associated with urban development requires high voltage transmission facilities.

Further projects to address the Scott County 115/69 kV transformer loading or the Shakopee 69 kV line have not been included in this plan. Xcel Energy is responsible for those needs and they will not directly affect the GRE facilities or loads.

Option 1: Carver County-Helena-Lake Marion 115 kV, New Prague 115/69kV

This option adds capacitors at Veseli and Merriam Junction in 2010 and 2011 to improve contingency voltages for a Scott County-Gifford Lake outage and includes the GRE portion of the Scott County-West Waconia plan. Rebuilding of the Carver County-Assumption 69 kV line to 115 kV is needed in 2014 due to overloading of this line for the Scott County-Gifford Lake outage. The next segment, from Assumption to Belle Plaine, overloads two years later in 2016. This option builds the remaining facilities to complete the Carver County-Helena 115 kV line, the Helena-New Prague 115 kV line, and the New Prague 115/69 kV substation in 2016 as well.

This timing can change based on the acceptability of using local generation to maintain contingency voltages; or to coordinate with other transmission additions.

The following is the estimated timeline for Option 1 installations:

Estimated Year	Facilities	Cost
2010	Veseli 5.4MVar, 69 kV Cap Bank	$236,600
2011	Merriam Jct. 7.2 MVar, 69 kV Cap Bank	$243,800
2011	Scott County-West Waconia Projects (GRE Portions)	$330,000
2014	Carver County-Assumption 5.1 mile rebuild to 795 ACSS 115 kV	$1,983,900
2016	Assumption-Belle Plaine 10.3 mile rebuild to 795 ACSS 115 kV	$4,002,800
2016	Belle Plaine-St. Lawrence Tap 5.5 mile rebuild to 795 ACSS 115 kV	$2,139,500
2016	St. Lawrence-Helena 6.5 mile, new 795 ACSS 115 kV line	$2,717,000
2016	Assumption and St. Lawrence (MVEC) convert to 115 kV operation	$700,000
2016	Belle Plaine (XEL) convert to 115 kV operation	$650,000
2016	Helena 115 kV Substation, 3 breaker ring bus (at 345 kV Site)	$2,379,000
2016	Helena-New Prague 6 mile, new 795 ACSS 115 kV line	$2,508,000
2016	New Prague 112 MVA, 115/69 kV Substation & Transmission	$4,900,000

Generation Options

Generation can defer certain projects in this study area if its operation meets the needs of the system. There is existing generation at New Prague in this study area and at Montgomery just south of New Prague. The plan does utilize the generation to defer the major facility additions to match related construction schedules. Costing of generation is beyond the scope of this study; therefore additional generation is not included in the plan.

Present Worth

Loss analysis was not done for this area since no alternative options were developed. The present worth for this area is summarized as follows (in 1000's):

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$37,773	$47,318	NA

Viability with Growth

This plan is able to accommodate additional growth. However, additional 69 kV facilities will need to be upgraded as load growth exceeds the ratings.

Recommended Plan

The following are the proposed projects for the Dakota-Scott County region:

Estimated Year	Responsible Company	Facility	Cost
2008	GRE & DEA	River Hills (DEA) 69 kV distribution sub double-end	$120,000
2009	XEL	Cannon Falls-Byllesby-Miesville Tap 6.3 mile, 69 kV rebuild to 477 ACSS	$1,323,000
2009	MVEC	St. Lawrence (MVEC) 69 kV distribution substation	$150,000
2009	GRE	St. Lawrence Tap 0.5 mile, 69 kV line & 3-way switch	$150,000
2009	XEL	Pilot Knob-Yankee Doodle 115 kV Line	$1,680,000
2009	GRE	Pilot Knob 115 kV breaker and termination	$500,000
2009	GRE	Eagan 115 kV buswork and switches	$820,000
2009	GRE	Lemay Tap 2-Wescott Tap 0.5 mile, 477 ACSR, 115 kV (operate at 69 kV)	$450,000
2009	GRE	Lemay Tap 2 69 kV 3-way switch	$100,000
2010	GRE & DEA	Ritter Park (DEA) 115 kV distribution substation	$1,170,000
2010	GRE & DEA	Nininger (DEA) 115 kV distribution substation	$800,000
2010	GRE & DEA	Burnscott (DEA) 69 kV distribution substation double-end	$120,000
2010	XEL	Veseli 5.4 MVar, 69 kV Cap Bank	$236,600
2011	GRE	Credit River Tap-Cleary Lake 1.3 mile rebuild to 477 ACSS 115 kV (operate at 69 kV)	$440,700
2011	GRE & DEA	Ravenna (DEA) 161 kV distribution substation	$962,000
2011	GRE	Orchard Lake Switch Motor Operator addition	$50,000
2011	GRE	Merriam Jct. 7.2 MVar, 69 kV Cap Bank	$243,800
2012	GRE & MVEC	Scott County-West Waconia Projects (GRE Portions)	$330,000
2012	GRE & DEA	Rich Valley (DEA) 69 kV distribution substation	$950,000
2012	GRE & DEA	Dodd Park (DEA) 115 kV distribution substation double-end	$185,000
2013	GRE	Byllesby Switches upgrade to 1200 Amp	$10,000
2013	GRE & DEA	Lakeville (DEA) 115 kV distribution substation double-end	$205,000
2013	GRE & DEA	Lemay Lake (DEA) 69 kV distribution substation double-end	$120,000
2013	GRE	Cleary Lake-Credit River 1 mile rebuild to 477 ACSS 115 kV (operate at 69 kV)	$322,050
2014	GRE & DEA	Randolph (DEA) 115 kV distribution substation	$860,000
2014	GRE & DEA	Lake Marion (DEA) 115 kV distribution substation unit	$185,000
2014	GRE	Lake Marion 115/69 kV transformer replace with 140 MVA	$1,939,900
2014	XEL	Burnsville-Lake Marion 11.8 mile, 115 kV reconductor to 795 ACSS	$1,534,000
2015	GRE	Carver County-Assumption 5.1 mile rebuild to 795 ACSS 115 kV	$1,983,900
2015	GRE	Colonial Hills Switch upgrade to 1200 Amp	$10,000
2015	XEL	Kegan Lake-Lebanon Hills 1.6 Mile 69 kV rebuild to 477 ACSR	$336,000
2016	GRE	Miesville Tap Switches upgrade to 1200 Amp	$10,000
2016	GRE	Assumption-Belle Plaine 10.3 mile rebuild to 795 ACSS 115 kV	$4,002,800
2016	XEL	Belle Plaine-St. Lawrence Tap 5.5 mile rebuild to 795 ACSS 115 kV	$2,139,500
2016	XEL	St. Lawrence-Helena 6.5 mile, new 795 ACSS 115 kV line	$2,717,000
2016	GRE & MVEC	Assumption and St. Lawrence conversion to 115 kV	$700,000
2016	XEL	Belle Plaine (XEL) conversion to 115 kV	$650,000
2016	XEL	Helena 115 kV Substation, 3 breaker ring bus (at 345 kV Site)	$2,379,000

GRE Long-Range Transmission Plan

Estimated Year	Responsible Company	Facility	Cost
2016	XEL	Helena-New Prague 6 mile, new 795 ACSS 115 kV line	$2,508,000
2016	XEL	New Prague 112 MVA, 115/69 kV Substation & Transmission	$4,900,000
2016	GRE	Lake Marion-Lk Marion Tap 2.42 mile rebuild to 115 kV double circuit	$1,297,600
2016	GRE	Lk Marion Tap-Elko-New Market 5.6 mile rebuild to 795 ACSS 115 kV	$2,178,400
2016	GRE	New Market-Helena 15 mile new 795 ACSS 115 kV line	$6,320,000
2016	GRE	New Market 115/69 kV, 70 MVA new substation	$3,395,000
2018	GRE & MVEC	Elko (MVEC) substation conversion to 115 kV	$350,000
2020	GRE & MVEC	Prior Lake (MVEC) load conversion to 115 kV (new site)	$2,000,000
2020	XEL	Spring Creek-Burnside 0.1 mile, 69 kV reconductor to 477 ACSS	$25,000
2025	XEL	Black Dog-Glendale 7.3 mile, 115 kV reconductor to 795 ACSS	$949,000
2025	XEL	Black Dog-Savage 4.4 mile, 115 kV reconductor to 795 ACSS	$572,000
2025	XEL	Inver Grove-Pilot Knob 5.7 mile, 115 kV reconductor to 795 ACSS	$741,000
2026	GRE	Eureka (DEA) 115 kV distribution substation & transmission	
2028	GRE & MVEC	New Market (MVEC) load conversion to 115 kV (new location)	$650,000
2028	XEL	Scott Co.-Dean Lake 4.9 mile, 115 kV reconductor to 795 ACSS	$637,000

L: Hennepin and Wright County Region

The Wright-Hennepin region is located in the northwestern Twin Cities suburbs. It is roughly bound by Maple Lake to the west, Saint Bonifacius to the south, Interstate 494 to the east, and the Mississippi River to the north. The member system that serves this territory is:

- Wright-Hennepin Cooperative Electric Association (WHCEA).

Wright Hennepin Electric Association (WHEA) headquartered in Rockford, MN, provides electric services to Wright County including Plymouth and Maple Grove cities, Hennepin and Stearns counties in east central Minnesota. The economy is mainly driven by agriculture, light industry and continued residential and commercial developments. City of Maple Grove is experiencing increased activities where high rising buildings will be constructed in the foreseeable future.

Existing System

The region consists of extensive high voltage transmission network and is where large generation units, such as NSP's Sherco and Monticello generation units are located. The 345 kV transmission systems are used as generation outlet for the generation units in the region including the Dickinson converter station, which is located at the center of the region.

Delivery to the 115 kV system is through Monticello, Dickinson and Sherco 345/115 kV sources. The 69 kV subtransmission system is served from 115/69 sources at Elk River, Parkwood, Crow River, Liberty, Dickinson, Medina and Lake Pulaski

Reliability and Transmission Age Issues

Transmission Lines on List of 50 Worst Composite Reliability Scores

None

Transmission Lines Built before 1980

Line 13	Parkwood 12NB6–Cedar Island 69 kV (PCX, SL)	8 Mi.-1954; 1 Mi.-1969
Line 51	Elk River 6NB6-Maple Lake 1NB1 69 kV (EM, BL)	25 Mi.-1950
Line 52	Becker 50NB4-Maple Lake 1NB5 69 kV (GT, MS)	27 Mi.-1970-78
Line 53	Corcoran 123NB1/2/3–Cedar Island 69 kV (SL, SLT)	7 Mi.-1954
Line 54	Medina 55NB2-Crow River-Corcoran 69 kV (BD, DS, ED)	18 Mi.-1950-55; 14 Mi.-1971
Line 55	Medina 55NB1 69 kV (BD)	8 Mi.-1971
Line 57	Dickinson 62NB13 69 kV (ML)	2 Mi.-1975
Line 58	Dickinson 62NB14-Corcoran 69 kV (ML, MLT, MLX)	12 Mi.-1975
Line 263	Elk River 6NB7-Corcoran 69 kV (ED, OE)	18 Mi.-1950-56; 1 Mi.-1975
Line 269	Hutchinson C3NB2–Victor 69 kV (DS, MC)	16 Mi.-1950; 9 Mi.-1967-79
Line 270	Maple Lake 1NB2-Victor 69 kV (AC)	16 Mi.-1948
Line 300	Crow River 4M62–Victor 208NB4/6 (DS, DX)	14 Mi.-1950

The reliability of this region is significantly better than the GRE average. The Plymouth to Maple Grove 115 kV project completed in 2006 involved the conversion of four substations to 115 kV that will further improve reliability. However, this area has a significant amount of older transmission line; much of which may need to be replaced due to age within the timeframe of this plan. The maintenance reports include the ED line from Elk River to Delano and the DS line from Delano to Svea Tap (Lines 54, 263, 269, and 300 in line age table) with high incidents, with the majority related to pole condition. Also, the SL and EM line sections (Lines 13, 51, and 53)

and the AC line (Line 270) has higher numbers of maintenance, with the majority again related to pole condition.

Existing Deficiencies

The long range plan study in this region identified several equipment or transmission line loading limit violations and low voltage problems. The St. Bonifacius and Dickinson 115/69 kV transformers are overloaded in the 2014 and 2015 timeframe for the loss of Gleason Lake 115/69 kV transformer and Liberty to Hasty 69 kV line respectively. The Delano to Willow 69 kV line and Crow River to Delano 69 kV line are overloaded for the loss of the Dickinson to Rockford 69 kV line and Medina 115/69 kV transformer respectively. The Maple Lake area is found to experience low voltage problems starting the 2022 timeframe during contingencies in the area.

Future Development

Load Forecast

Loads for the region were forecasted as part of the long range plan study process. The following table illustrates the total sum of the forecasted summer and winter peak GRE loads in the Wright Hennepin Region.

Wright-Hennepin Region Load (in MW)			
Season	2011	2021	2031
Summer	239.6	371.1	578.2
Winter	203.5	314.7	485.6

Planned Additions

WHCEA plans to add the following substations over the LRP time period. These subs are planned to unload existing distribution substations or accommodate the load growth that is seen in the WHCEA service territory.

- WHCEA plans to add the Foster Lake distribution substation in the 2011 timeframe. This sub will unload Otsego and Oakwood subs and serve growing loads in the area. This substation will directly tap the ED line between Trialhaven and Otsego tap.
- WHCEA plans to add the Montrose (Woodland) distribution substation in the 2012 timeframe. This sub will unload Howard Lake, Delano and Highland distribution substations. It will directly tap the GRE 69 kV DS line.
- WHCEA plans to add the Enfield distribution substation in the 2013 timeframe. This sub will unload the Silver Creek and Black Lake distribution substations and will serve growing loads in the area. It will likely tap XEL's Lake Constance to Monticello 115 kV line.
- Connexus Energy has proposed a South Dayton substation that is expected around the 2011 timeframe. This substation will directly tap the Elm Creek – Hassan 115 kV line.

Crow River – St. Bonifacius – Gleason Lake

This area is mainly served by two 115/69 kV sources from St. Boni and Gleason Lake and by a 50 MW generator at St. Boni. There are four XEL distribution substations in the area. There is a total of 38.5 miles of 69 kV transmission lines in the area. The following forecast is the load served in the area.

Season	2011	2021	2031
Summer	92.1	138.8	153.7
Winter	75.9	112.4	101.4

Long-term Deficiencies

The area has a good voltage and transmission line loading profile at system intact. Contingency analyses in the area show low voltage concerns starting the 2014 timeframe. The Gleason Lake to Parkers Lake 115 kV double circuit outage and Gleason Lake 115/69 kV source outage are critical in the area. These contingencies cause low voltage problems at XEL's Gleason Lake and Glens Lake distribution substations in 2015. The St. Bonifacius 115/69 kV transformer overloads to 125% in the 2014 timeframe for the loss of Gleason Lake 115/69 kV transformer. The St. Bonifacius to Mound 69 kV line overloads above 110% in the 2014 timeframe for the loss of the Gleason Lake source, or the Gleason Lake to Parkers Lake double circuit 115 kV line.

Alternatives

Two alternatives were developed to address the low voltage and transmission line overload problems in this area. The following are the options.

Option 1: Add a Second 115/69 kV, 70 MVA transformer at St. Boni and Rebuild St. Boni to Mound 8.3 mile 69 kV line

This option involves installing a second 115/69 kV, 70 MVA transformer at St. Boni in the 2015 timeframe. This will eliminate the existing St. Boni transformer overload for the loss of Gleason Lake 115/69 kV transformer and solves the low voltage problem in the 2022 timeframe due to the existing transformer outage. This option also involves rebuilding the 8.3 mile 69 kV line from St. Boni to XEL's Mound substation in the 2014 timeframe with 477 ACSS conductor. The 336 ACSR conductor on the St. Boni – Mound 69 kV line reaches its maximum loading limit in the 2014 timeframe. The following is the estimated timelines and cost of installation for this option:

Estimated Year	Facility	Cost
2014	St. Boni - Install a second 115/69 kV, 70 MVA transformer	$2,073,000
2014	St. Boni-Mound - Re-conductor 69 kV 8.3 mile line with 477 ACSS	$1,743,000

Option 2: Convert Mound sub to 115 kV

This option involves converting XEL's Mound 69 kV sub to 115 kV. The Mound load accounts for nearly 40% of the total load on the Crow River–St. Boni–Gleason Lake 69 kV line.

Converting the Mound substation requires building about 5 miles of radial 115 kV line to Mound on a new corridor tapping the Medina to Crow River 115 kV line. The following is the estimated timeline and cost estimate for converting Mound sub to 115 kV:

Estimated Year	Facility	Cost
2014	Mound - convert sub to 115 kV	$2,065,000

Present Worth

Present worth analysis was performed on each option with option 1 being the benchmark for calculating loss saving. The MW loss saving for each option is tabulated as follows:

Option	2011 Summer	2021 Summer
2	0.1	-0.2

The present worth for each option with loss saving accounted is as follows

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$5,413,000	$8,114,000	NA
2	$3,851,000	$5,764,000	$5,767000

Option 2 is the least expensive plan as compared to Option 1.

Viability with Growth

Both options are able to address the long term transmission needs of the area. Though option 2 is the least cost plan now, it leaves the largest load in the area, Mound, on a 5-mile radial line. Loop feeding this sub is required in the future for a reliable service to the Mound load. This makes option 2 an expensive option. Therefore, option 1 is recommended plan to address the long-term needs of the area.

Elk River - Dickinson - Crow River - Medina Area

This area is served by two 230/69 kV sources from Elk River and three 115/69 kV sources from Dickinson, Crow River and Medina. There are 11 distribution substations currently serving loads along the 108 miles of 69 kV transmission lines in the area. Of these distribution substations, GRE owns 9 and XEL owns 2 distribution subs. WHCEA plans to add the Foster Lake distribution substation on the GRE, 69 kV, ED line in the 2011 timeframe. Loads served in the area are forecasted in the following table.

Season	2011	2021	2031
Summer	96.6	136.3	218.4
Winter	75.5	106	165.4

Long-term Deficiencies

This area has a good voltage profile at system intact, but experiences transmission line loading limit violation in the 2016 timeframe during contingencies. For the loss of Medina 115/69 kV transformer or Dickinson to Rockford 69 kV line outage, the Crow River to Delano 4.0 mile and the Delano to Willow 8.46 mile, 69 kV lines overload starting the 2016 timeframe. Currently, the

Delano to Willow 8.46 mile 69 kV line is at 170° F rating and could be upgraded to 212° F rating for higher flow capability.

Alternatives

The following two options have been developed to address the identified long range deficiencies in the area. Both options include temperature upgrading the Delano – Willow tap 8.46 mile line to the 212 degree rating.

Option 1: 115 kV substation Conversion

This option involves converting load from 69 kV system to the nearest capable 115 kV system in the area. Lawndale is one of the largest loads in the area. It accounts about 16% of the total load served in the area. This option recommends the conversion of the Lawndale sub to 115 kV in the 2016 timeframe. This conversion requires building 2 miles of 115 kV line to Lawndale tapping the Bass Lake to Cedar Mills 115 kV line. The Lawndale sub conversion unloads the Crow River to Delano 4 mile 69 kV line. This conversion also lays the foundation for future 115 kV connection to Dickinson. This option also recommends converting XEL's Orono distribution sub to 115 kV in the 2021 timeframe. This requires building 0.5 mile of 115 kV line to the Orono sub taping the Crow River to Medina 115 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2015	Delano tap - Willow tap 8.46 mile line temperature upgrade	$680,000
2016	Lawndale – Convert 69 kV sub to 115 kV	$1,523,000
2021	Orono - Convert 69 kV sub to 115 kV	$1,000,000

Option 2: 69 kV Rebuild and 115 kV conversion

This option involves rebuilding the existing 6.85-mile 69 kV line from Crow River to Delano tap with 477 ACSS conductor. The Crow River to Delano tap 69 kV line currently has a 4/0 conductor at 212° F rating. Rebuilding this line with 477 ACSS conductor improves the voltage in the area and eliminates the line overload concern. This option recommends converting the Lawndale sub to 115 kV in the 2026 timeframe to keep the voltage within the required limits through the LRP lifetime. The following is the estimated time line and cost of installation for this option.

Estimated Year	Facility	Cost
2015	Delano tap - Willow tap 8.46 mile line temperature upgrade	$680,000
2016	Crow River-Delano – Rebuilt tap 4.13 mile line with 477 ACSS	$1,679,000
2026	Lawndale – Convert 69 kV sub to 115 kV	$1,523,000

Generation Options

Generation Options are not considered in this area.

Present Worth

Cost analysis was performed on each option with loss saving considered for the area. Option 1 was considered as a benchmark for calculating loss savings. The MW loss saving for each option is tabulated as follows:

Option	2011 Summer	2021 Summer
2	0.2	1.2

The present worth and cumulative investment for each option is shown as follows:

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$4,558,000	$5,249,000	NA
2	$7,032,000	$6,526,000	$9,329,000

Option 1 is the least cost plan due to the minimum cumulative investment.

Viability with Growth

Both options address the long-term transmission needs of the area. Option 1 gives more flexibility for future 115 kV expansions to Dickinson and saves losses better than option 2. Option 1 relieves the 69 kV system as it moves two large loads to a strong 115 kV system. Therefore, option 1 is the recommended plan for this area.

Dickinson –Liberty – Elk River Area

This area covers a wide range of the WHCEA service territory and has many sources. It is primarily served by one 230/69 kV source from Elk River and four 115/69 kV sources from Liberty, Dickinson, Lake Pulaski and Crow River. The total mileage for the transmission lines in this area is 63 miles. There are 9 GRE distribution substations and 4 XEL distribution substations in the area. In the 2009 timeframe, XEL will interconnect the Mary Lake sub with Buffalo enabling the Dickinson 115/69 kV sub to serve the Maple Lake area. Loads in the area are forecasted as follows.

Season	2011	2021	2031
Summer	119.1	151.3	304.3
Winter	112.8	135.2	246

Long-term Deficiencies

The transmission system will see line overload concerns starting the 2009 timeframe and low voltage problems in the 2013 timeframe.

- The Mary Lake to Dickinson 69 kV line overloads in 2009 at system intact or contingency conditions. As part of the Mary Lake – Buffalo interconnection project, this line will undergo temperature upgrade from the 120 deg rating (15.1 MVA) to 212 deg rating (75.8 MVA).
- The Liberty to Goose Lake tap 69 kV line overloads starting the 2009 timeframe for the outage of Dickinson transformer. This line is being surveyed and will undergo temperature upgrade.
- The Dickinson 115/69 kV, 72 MVA transformer overloads in the 2016 timeframe at system intact and during contingency.
- The Lake Pulaski to Monticello 115 kV line overloads in the 2016 timeframe for the loss of Dickinson 345/115 kV transformer.

The following are projects are planned and expected to be in-service in the 2009 timeframe.

Estimated Year	Facility	Cost
2009	Liberty - Goose Lake tap 69 kV line temperature upgrade	$1,800,000.0
2009	New Mary Lake to Buffalo 69 kV line (Interconnection)	$2,755,000.0

Alternatives

Three options were developed to address the long-term transmission deficiencies in the area. The following are the options:

Option 1: New 115/69 kV sources and 115 kV transmission upgrade

This option involves establishing a new 115/69 kV, 140 MVA, source at Buffalo and upgrading the Dickinson – Buffalo – Lake Pulaski – Becker 69 kV line to 115 kV. When the Dickinson – Becker 69 kV system is upgraded to 115 kV, the Maple Lake area will lose the Dickinson source. This causes low voltage problems in the Maple Lake area for the loss of Liberty source, or Liberty to Hasty 69 kV line outage. The Buffalo 115/69 kV source is recommended to address the low voltage problems after the completion of the Dickinson to Becker 115 kV upgrade. Buffalo will have two, 70 MVA transformer banks. The Lake Pulaski transformer could be used as one of the two transformers needed at Buffalo. This option also recommends temperature upgrade of the Lake Pulaski to Monticello 115 kV line. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2015	Dickinson - Buffalo-Lake Pulaski - Becker 115 kV upgrade	$7,714,000.0
2015	Lake Pulaski – Move the transformer to the new Buffalo source	NA
2015	Buffalo – Establish a 115/69 kV sub	$4,068,028
2016	Lake Pulaski to Monticello 115 kV line temperature upgrade	$1,210,000

Option 2: Capacitor bank at Maple Lake and a second transformer at Dickinson

This option involves replacing the Dickinson 115/69 kV, 84 MVA, transformer with 140 MVA transformer and installing a 33 MVAr capacitor bank at Maple Lake. This option also involves upgrading the Lake Pulaski to Monticello 115 kV line to its 392 degree rating. The 140 MVA transformer replacement at Dickinson provides Dickinson sub with sufficient capability during system intact or contingency conditions. For the loss of the Dickinson to Mary Lake 69 kV or Watkins to Kimball 69 kV line, the Maple Lake area will have a marginal voltage in the 2022 timeframe. The 33 MVAr capacitor bank is recommended at Maple Lake to address the voltage problems in the area beyond the 2022 timeframe. The following is the estimated timeline and cost of installation for this option.

Estimated Year	Facility	Cost
2015	Dickinson – replace 115/69 kV, 70 MVA transformer with 140 MVA transformer	$1,940,000
2016	Lake Pulaski to Monticello 115 kV line temperature upgrade	$1,210,000

2022	Maple Lake 33 MVAr capacitor bank	$347,000

Generation Options
Generation Options are not considered in this area.

Present Worth
Present worth analysis was performed on each option with option 1 being the benchmark for loss saving. The MW loss saving for each option is tabulated as follows:

Option	2011 Summer	2021 Summer
2	-0.5	-2.2

The present worth and cumulative investment for each option is shown as follows

Option	Cumulative Investment	Present Worth	Present Worth w/ Loss Savings
1	$24,155,000	$34,570,000	NA
2	$5,630,000	$7,477,000	$3,749,000

Option 2 is the least cost plan which involves the minimum cumulative investment.

Viability with Growth
The two considered options are capable to the long-term needs of the area. There is a significant gap in the present values between the two options. Option 2 have better advantage for loss saving and is the least cost plan for the area. Therefore, option 2 is the recommended plan for the area.

Alternative option to the Area
A reconfiguration of the Medina sub was considered as a solution to the problems in this area. The Medina 115/69 kV source mainly serves the Orono and Medina 69 kV loads in the area at system intact. Recent transmission upgrades in the Medina area, such as the Plymouth – Maple grove 115 kV upgrade, makes the Medina sub less essential to the area. The Orono and Medina subs are located nearby a 115 kV transmission line and could be converted 115kV with a minimum transmission cost to unload transmission lines in the area. For economical use of the facility, the Medina sub could be retired once Orono and Medina 69 kV subs are converted to 115 kV. Simultaneously, a 26.4 MVAr capacitor bank needs to be installed at Victor for voltage support in the area. This area will have a stronger voltage when the Lawndale 69 kV sub is converted to 115 kV in the 2014 timeframe.

The following is the estimated timeline and cost of installation for this project.

Estimated Year	Facility	Cost
2014	Lawndale – Convert sub to 115 kV	$1,523,000
2016	XEL's Orono sub convert to 115 kV	$1,000,000
2016	GRE Medina sub convert to 115 kV	$1,000,000
2016	Victor - Install 26.4 MVAr capacitor bank	$320,600
2016	Medina – retire 115/69 kV sub	NA
2019	Delano – Crow River with 336 ACSR	$1,644,000
2022	Dickinson – Rockford 69 kV 3 mile line with 795 ACSS	$892,500

The Medina 84 MVA 115/69 kV transformer could be used to double the Dickinson transformer, which overloads in the 2016 timeframe. The conversion of the Lawndale 69 kV load to 115 kV lays the foundation to continue converting the Corcoran sub to 115 in the 2025 timeframe and have a 115 kV loop with Dickinson. A new 115/69 kV source at Corcoran will be needed to address the transmission needs in the Corcoran area beyond the 2025 timeframe.

Recommended Plan

Estimated Year	Responsible Company	Facility	Cost
2009	GRE	Liberty - Goose Lake tap 69 kV line temperature upgrade	$1,800,000
2009	XEL	New Mary Lake to Buffalo 69 kV line (interconnection)	$2,755,000
2011	GRE	Foster Lake distribution sub	$140,000
2011	WHECE	Foster Lake distribution sub	NA
2011	GRE	South Dayton distribution sub	$205,000
2011	CE	South Dayton distribution sub	NA
2012	GRE	Woodland distribution sub	$1,101,000
2012	WHECE	Woodland distribution sub	NA
2013	GRE	Enfield distribution sub	$950,000
2013	WHECE	Enfield distribution sub	NA
2014	GRE	St. Boni – a second 115/69 kV transformer	$2,073,000
2014	XEL	St. Boni-Mound 69 kV 8.3 mile line with 477 ACSS re-conductor	$1,743,000
2015	GRE	Delano tap - Willow tap 8.46 mile temp upgrade	$680,000
2015	GRE	Dickinson - Replace 115/69 kV, 70 MVA transformer with 140 MVA transformer	$1,940,000
2016	GRE	Lawndale - Convert 69 kV sub to 115 kV	$873,000
2016	WHECE	Lawndale – Convert 69 kV sub to 115 kV	$650,000
2016	XEL	Lake Pulaski to Monticello 115 kV line temperature upgrade	$1,210,000
2021	XEL	Orono – Convert 69 kV sub to 115 kV	$1,000,000
2022	GRE	Maple Lake 33MVAr capacitor bank	$347,000

M: Bulk Transmission System (230 kV and above)

GRE owns and operates high voltage facilities in North Dakota and Minnesota. The high voltage system includes transmission lines 230 kV through 500 kV. A short description of the high voltage facilities GRE owns and operates is presented below. This includes the agreements that CP and UPA entered into prior to their merger into GRE.

North Dakota Facilities

The GRE North Dakota transmission system started with the Transmission Service Agreement signed in 1964 by UPA, Otter Tail Power Company (OTP), and Northern States Power Company (NSP).[1] The Transmission Service Agreement provides a displacement arrangement for delivering the GRE Stanton power plant output to GRE's Minnesota load centers.

Stanton Plant Facilities

Due to the terms of the displacement agreement with OTP and NSP in 1966, UPA constructed a 230 kV transmission line across North Dakota starting from the Stanton plant and connecting to the Prairie Substation located in Grand Forks, North Dakota, including interconnection points at the McHenry and Ramsey substations. The North Dakota facilities, which GRE owns, operates and maintains, are shown in Figure M-1. At the McHenry and Ramsey substations GRE is interconnected with facilities owned by NSP and OTP through 230/115 kV substations. At the Prairie Substation GRE is interconnected with a 230/115 kV substation owned by NSP.

Also, UPA constructed 230 kV transmission lines from the Stanton power plant to the Leland Olds plant of Basin Electric Power Cooperative (BEPC) and to the Milton R. Young plant of Square Butte Electric Cooperative. In 1989 a 230 kV, 40 ohm line reactor was added on the Stanton-Leland Olds 230 kV line to improve system dynamic performance. Both of these systems are interconnected with Western Area Power Administration.

Coal Creek Plant Facilities

In 1973, CP and UPA entered into a Memorandum of Understanding for the construction of the Coal Creek Station in North Dakota and a 400 kV DC transmission line for generation outlet. The intent was that the CP-UPA Project equipment, material and supplies, and other real and personal property would be owned as tenants in common.

The Coal Creek Transmission facilities include: a 435.85-mile, ±400 kV DC line connecting Coal Creek, North Dakota to Dickinson, Minnesota and the Coal Creek 230 kV outlet lines which connect the system to the Stanton Plant 230 kV system.

Balta Station

In 2002, a new 230 kV switching station was constructed near Balta, North Dakota, that provides a new interconnection between the Coal Creek Station, Ottertail Power Company and Manitoba Hydro (via the Glenboro substation). GRE owns and operates a portion of the Balta Station. OTP is the other operator and owner of the portion of the Balta Substation that involves their line facilities.

[1] NSP is now doing business as Xcel Energy.

Minnesota Facilities

GRE owns and operates high voltage facilities in Minnesota. In most instances the facilities (substations and lines) were constructed as part of the CP/NSP/UPA Joint Transmission Network, MP/UPA Integrated Transmission Agreement, or other existing inter-utility agreements. These agreements have been replaced by network agreements between GRE and NSP or MP. These agreements are discussed in Section 5. The high voltage transmission that GRE owns or jointly owns is shown in Figure M-1 and M-2.

Facility Additions

The facility additions listed below are the high voltage additions recommended in the referenced plan. The facilities listed include any 230 kV or above additions that are currently being planned for the LRP study period, are as follows:

- CapX 2020: Several of the transmission owners in Minnesota, including GRE, have initiated a joint effort to construct four transmission projects to improve load serving capabilities and provide additional transmission capacity for wind generation.
    - Bemidji-Grand Rapids 230 kV line
    - Fargo-St. Cloud-Monticello 345 kV line
    - SE Twin Cities-Rochester-La Crosse 345 kV line
    - Brookings, SD-SE Twin Cities 345 kV line
- Prairie - Ramsey 230 kV rebuild: Due to the poor physical condition of major portions of the 230 kV line, this line needs to be rebuilt. GRE will be budgeting for reconstruction of the line over several years beginning in 2013.
- Milaca - Rush City 230 kV line: This project will consist of a new 230 kV line with a new 230/69 kV substation near Dalbo. It is needed to support the growing load serving needs in the North Suburban area. The projected in-service date is 2018. Additional information can be found in the North Suburban section of this report.
- With the Milaca-Dalbo-Rush City 230 kV development, GRE will also need to enhance the north suburban 230 kV voltage to elevate the 230 kV voltage appropriately to maintain the underlying 69 kV system. GRE will approach the CapX regional planning group to discuss the potential of establishing the following facilities by 2018:
    - converting a portion of the Rush City-Red Rock 230 kV line to a Rush City-Chisago County 345 kV line
    - installing a 345/230 kV substation at Rush City
    - double circuiting the Dalbo-Rush City 230 kV line with 345 kV
    - building Dalbo-Benton County 345 kV line
- The high voltage facilities will also be impacted by the MISO generation queue. It is expected that high voltage transmission outlet will be needed for some of the projected generation interconnections in some regions. Figure M-3 indicates the MISO queue generation based on the Minnesota Planning zones.

Figure M-2
North Dakota High Voltage System Diagram

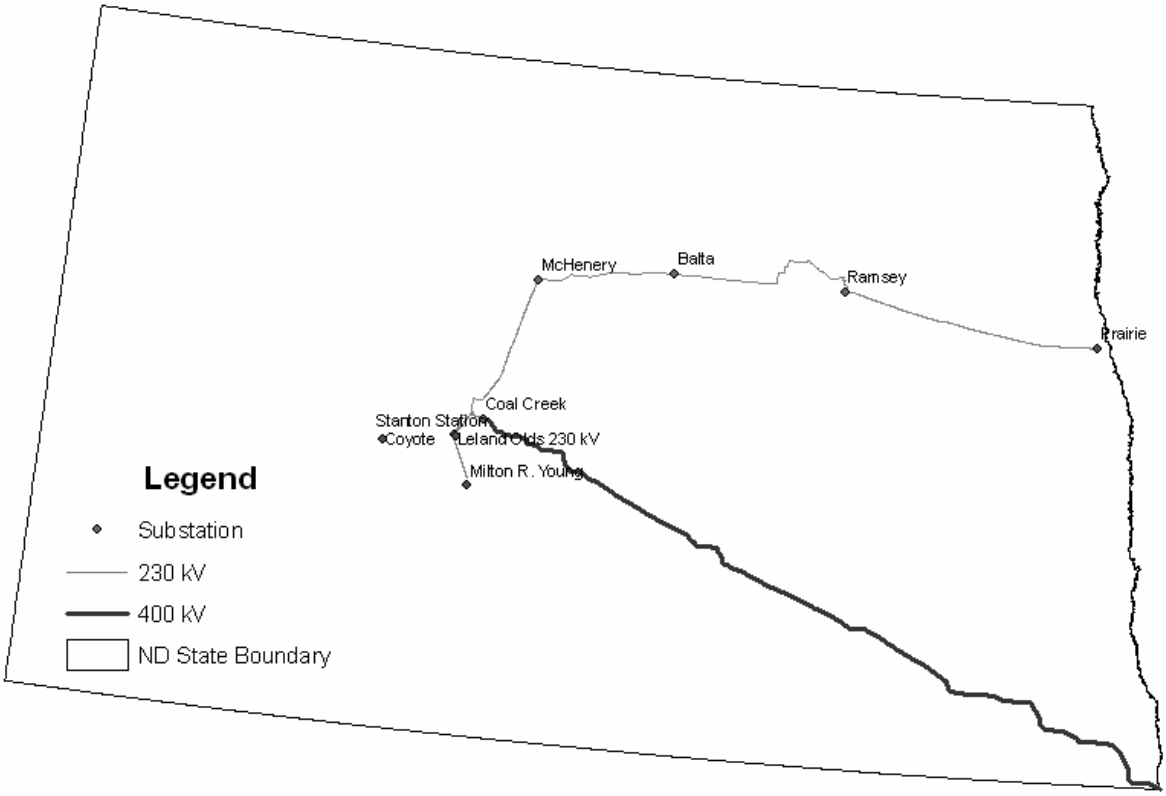
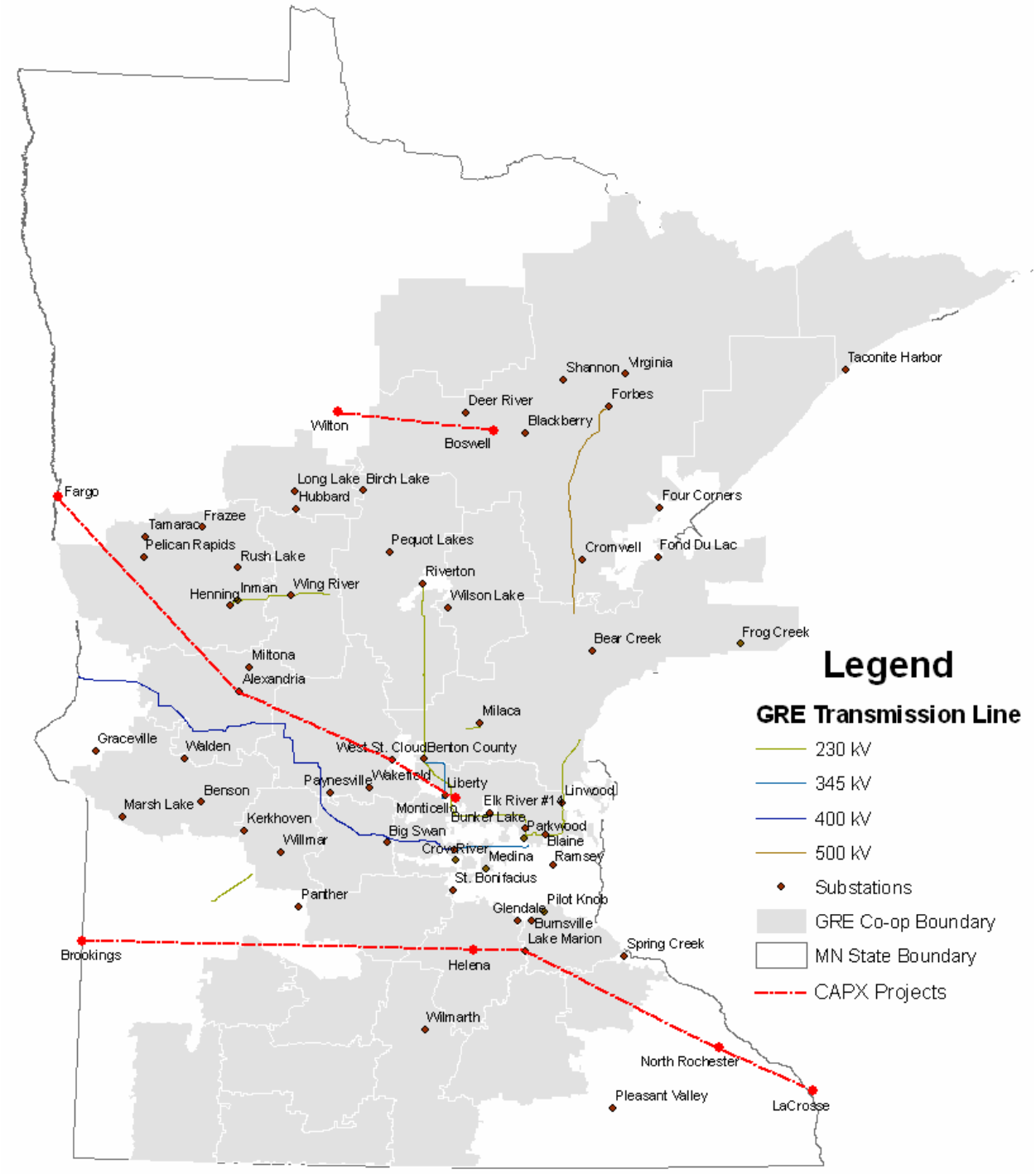
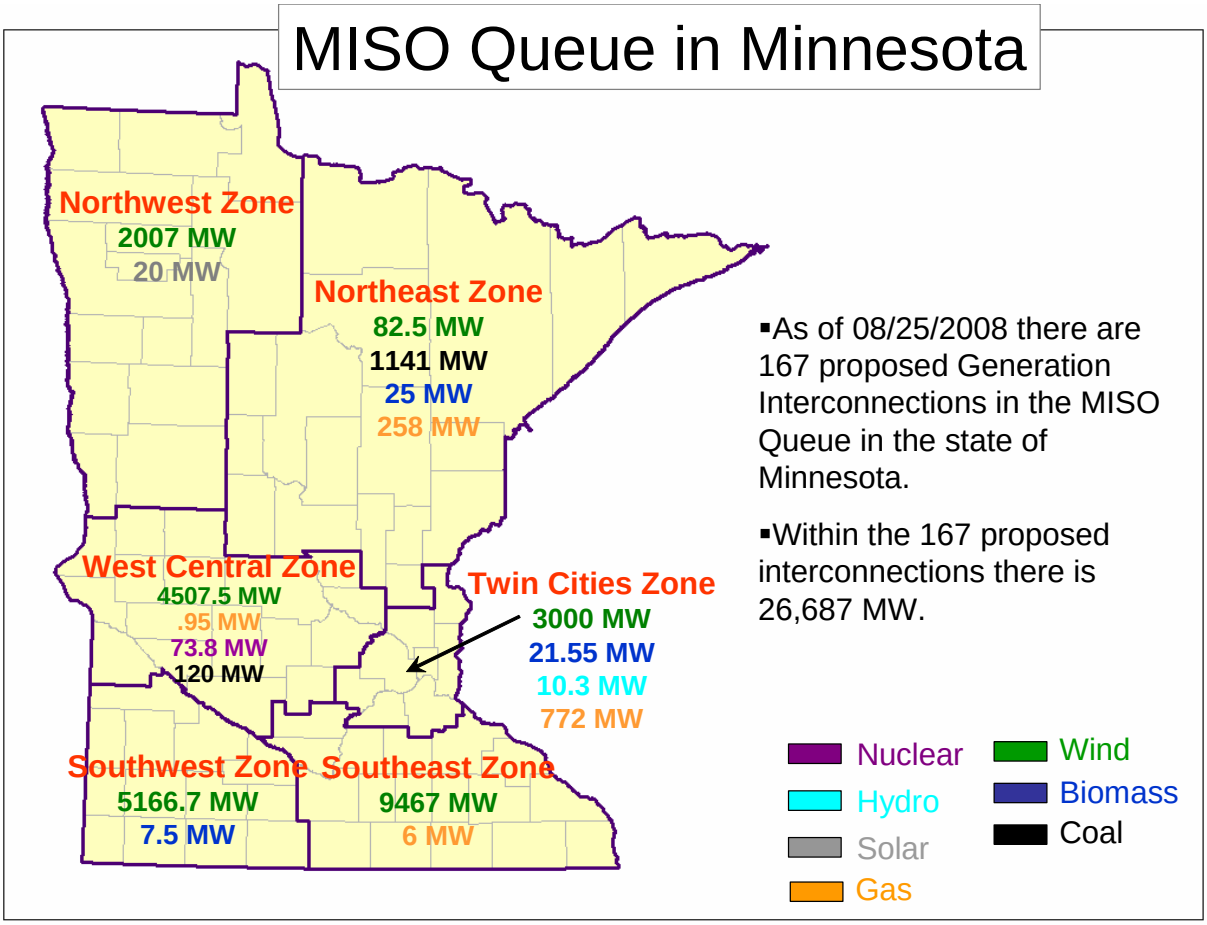


Figure M-2
Minnesota High Voltage System Diagram




MISO Queue in Minnesota
Northwest Zone
2007 MW
20 MW
Northeast Zone
82.5 MW
1141 MW
25 MW
258 MW
West Central Zone
4507.5 MW
.95 MW
73.8 MW
120 MW
Twin Cities Zone
3000 MW
21.55 MW
10.3 MW
772 MW
Southwest Zone
5166.7 MW
7.5 MW
Southeast Zone
9467 MW
6 MW
▪As of 08/25/2008 there are 167 proposed Generation Interconnections in the MISO Queue in the state of Minnesota.
▪Within the 167 proposed interconnections there is 26,687 MW.
Nuclear
Hydro
Solar
Gas
Wind
Biomass
Coal

I: Transmission Line Facilities

Age of Facilities

GRE tracks transmission line ages in the MAXIMO database along with line characteristics, ratings, operation parameters, and maintenance data. The MAXIMO software provides a central database to improve management of the transmission and maintenance data. This results in more consistent information regarding line conditions and maintenance requirements that can be used in transmission planning to address problem areas. While transmission line age analysis is included in this Long Range Plan, no specific age threshold has been established for line replacement decisions.

Facility age is factored into the subjective analysis of alternatives when selecting recommended plans. Some old lines may be replaced as part of system upgrade plans, but other lines will also require replacement during the timeframe of this Long Range Plan. The specific age-based transmission line replacements are not included in the study region plans. These replacements will be identified in future construction work plans based on reliability and maintenance requirements.

The following section of this Appendix provides reliability analysis results from the GRE outage data. Although line age is not the only issue affecting reliability of the transmission system, it is becoming more significant as lines continue to age. GRE owns more than 4,000 miles of transmission line. About 16% of the total is nearly 50 or more years old, with the oldest line being 60 years old. By the end of the Long Range Plan, this oldest line would be 85 years old, and nearly 1700 miles of line (38% of the GRE's total transmission) would be more than 60 years old if not replaced. Presently, another 2,100 miles of line (48% of the total) is between 15 to 35 years old. These lines will be from 40 to 60 years old by the end of the study period. The following table provides a summary of the GRE transmission facility age data.

GRE Transmission Age Summary

	1940s	1950s	1960s	1970s	1980s	1990+	Total
Miles of 34.5kV and lower		20	21	66	31	32	170
Miles of 41.6-46kV		27	98	71	70	9	275
Miles of 69kV	62	607	498	741	238	377	2523
Miles of 115kV		16	59	113	51	130	369
Miles of 161kV			27			22	49
Miles of 230kV			258	180	12	73	523
Miles of 345-500kV & DC				560	12		572
Total Miles Owned by GRE	**62**	**670**	**961**	**1731**	**414**	**643**	**4481**

Lines with significant mileage built before 1980 have been listed in the individual Study Region sections of this Long Range Plan, using the reliability line key number to identify the lines. That data can be correlated to specific line sections in the Transmission Facilities table in this Appendix. The table lists the in-service year and length of each line section built before 1980 (except for short substation taps). It is sorted by the line key number used in the reliability analysis and includes the line name, from and to information, the cooperative area where the line is located, and the line information for voltage, structure type, and conductors.

Reliability Data

GRE has several programs in place to track outage data and improve reliability of its transmission system and of foreign transmission systems supplying GRE delivery points. Actions range from recording and analyzing outage details, performing line patrol and maintenance and initiating construction projects to improve reliability.

Details are recorded for every transmission outage affecting GRE delivery points, including events on other company facilities. Outages are investigated to determine the cause, with line patrol to check for problems and verify the cause of momentary outages as well. An annual review of outages is completed to compile yearly GRE Transmission Reliability Reports. The reports analyze the transmission reliability using several different indices comparing the annual performance to the previous year and to five-year averages. They also compare reliability between the transmission operating companies that serve GRE distribution cooperative loads and to other midwest G&Ts through reliability benchmark studies. Analysis by distribution cooperative includes the details of each outage, a breakdown of outages by cause, and outage totals and averages by substation delivery point.

In addition to the annual Transmission Reliability Report analysis, the outage records are also analyzed for the Delivery Point Service Improvement (DPSI) program, which identifies reliability based projects for the annual construction budget. The DPSI program was set up with input from the GRE member distribution cooperatives to identify the poorest reliability transmission lines and implement various low cost solutions to improve their reliability. Some of the typical improvements from this program have been installation of lightning arresters, remote controlled switches, fault current indicators, vibration and galloping dampers, and ground fault neutralizers (Peterson coils), as well as replacements on some line sections.

The criteria used to identify the worst performing lines is a composite ranking based on their individual rank for six different indices reflecting combinations of consumers affected, substations affected, load magnitude, outage durations, and numbers of long-term and momentary outage events. A table showing the composite ranking for the 50 worst reliability performance lines and values for each of the indices is provided in this Appendix. Transmission lines on this table are also listed in the individual Study Region sections. Another table is included in this Appendix showing the reliability data for all of the transmission lines. It is sorted by line key number and can be used to check the reliability performance of the transmission lines with segments built before 1980 that are listed in the individual Study Regions, but are not on the list of the 50 worst composite reliability scores.

Maintenance Data

Periodic inspections and maintenance of the transmission system are other proactive programs to improve transmission reliability. Line patrol is completed bi-monthly with air patrols and annually with ground patrol of all GRE transmission lines. Pole testing is done every 13 years starting when a line is 17 years old (i.e. when the line age is 17 years, 30 years, 43 years, 56 years, etc.). Problems identified by the line inspections and pole testing are promptly addressed to prevent future outages. GRE uses MAXIMO database software to manage the transmission facility and maintenance data. Tracking maintenance data can help improve the effectiveness of transmission line maintenance and provides additional information for transmission planning to develop projects to address high maintenance lines.

Reliability, Age, and Maintenance Analysis

Along with the ongoing processes established by GRE to insure reliable transmission service, additional analysis of reliability is incorporated into this Long Range Plan. Outage performance, facility age, and maintenance records of specific transmission lines have been reviewed as part of the existing system analysis of each study region. For each study region, the report includes a description and additional details regarding the reliability and maintenance for each of its transmission lines on the worst reliability list. This data is factored into the subjective analysis of alternatives when selecting recommended plans.

Additional outage analysis correlating different factors to the reliability performance has also been completed. It includes correlations to line age, line length exposure, maintenance records, voltage levels, and operating company. Part of this analysis was a review of the five-year average of outage hours and total outage events for each substation to verify that all poor reliability delivery points are identified in the analysis. The results are summarized in the following list.

Reliability Correlation Analysis Results:

A) There is significant correlation between reliability and line age.
- Seven of the 10 lines with the worst composite reliability rank have at least 10 miles of line that is more than 40 years old.
- Twenty eight lines in the 50 worst composite scores have line sections more than 40 years old (not including lines owned by the other utilities).
- However, of lines with at least 20 miles more than 40 years old, 9 are in the worst 50, 5 are ranked between 51 and 100, and 5 are ranked between 101 and 200 out of 242 lines.
- Correlation cannot be fully analyzed because of missing age data for lines not owned or operated by GRE.

B) There is significant correlation between reliability and length of line exposure.
- Of the 10 longest 69 kV or lower voltage lines, 8 are on the list of the 50 worst composite reliability scores.
- Seven of the 10 worst composite reliability scores are for lines longer than 50 miles.
- The line with the worst composite score is also the line with the longest exposure.

C) There is slight correlation between reliability and line maintenance reports.
- Four of the 10 lines with the worst composite reliability rank had comparatively high maintenance.
- Correlation is stronger between line age and maintenance, but is not consistent – many older lines have very little maintenance.
- Correlation cannot be fully analyzed since maintenance data is not available for lines not owned and operated by GRE.

D) There is moderate correlation between reliability and voltage levels of transmission lines.

- There is only one, 115 kV line on the list of the 50 worst composite reliability scores (Rank 36, Arrowhead – Virginia – Eveleth Taconite).
- The 2 shortest lines in the 10 worst composite scores are 41.6 kV.
- Eighteen of the 50 worst composite reliability lines are 23 kV-46 KV lines.

E) Correlation between transmission operating company and reliability is not consistent.

- Normalized ranking of operating company reliability consistently ranks GRE and XCEL with the best reliability of the five operating companies, but seven of the ten worst composite reliability lines are operated by GRE or XCEL.
- Each of the 5 operating companies serving GRE delivery points have lines on the list of the 50 worst composite reliability scores.

F) Using the composite reliability score method and the list of the 50 worst scores is a good selection process for consideration of reliability improvements, but the worst lines for each of the indices used and the worst individual delivery point reliability data still need to be checked.

- The lists of the 10 worst performing lines for each of the 6 indices used includes 6 lines that are not on the 50 worst composite score list (4 of these are due to momentary events).
- Three substations from the 10 delivery points with the worst five-year average ‘outage hours’ are not served by transmission lines on the list of the 50 worst composite scores.
- Three substations from the 10 delivery points with the worst five-year average ‘total outage events’ are not served by transmission lines on the list of the 50 worst composite scores.

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
1	ES	1950	1.75	ANDOVER	BUNKER LAKE TAP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
1	ES	1950	3.24	BUNKER LAKE TAP	PSX LINE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
1	ES	1950	4.93	EPX LINE	ANOKA	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
1	ES	1950	5.44	ANOKA	ANDOVER	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
1	PEX	1969	1.9	BA LINE	BUNKER LAKE	Connexus	69	B86-2	ACSR	IBIS 397 26/7	7/16
1	EPX	1970	0.36	ES LINE WEST	ES LINE EAST	Connexus	69	TP-6AG	ACSR	PARTRIDGE 266 26/7	3/8
1	PSX	1971	0.34	ES LINE	SODERVILLE	Connexus	69	TP-6AG	ACSR	PARTRIDGE 266 26/7	3/8
1	ES	1974	0.15	ELK RIVER #14	EPX LINE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
2	EP	1969	1.57	ANOKA MUNI SW	RAMSEY SW.	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
2	EP	1969	3	DAYTONPORT	ANOKA MUNI SW	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
2	EP	1969	4.7	RAMSEY SW.	FUTURE BA/EP TAP	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
2	EPX	1970	0.36	EP LINE WEST	EP LINE EAST	Connexus	69	TP-6AG	ACSR	IBIS 397 26/7	3/8
2	EP	1974	0.21	ELK RIVER #6	EPX LINE	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
2	EP	1974	0.7	EPX LINE	RDF TAP	Connexus	69	TS-1A	ACSR	IBIS 397 26/7	3/8
2	EP	1974	4.14	RDF TAP	DAYTONPORT	Connexus	69	TS-1A	ACSR	IBIS 397 26/7	3/8
3	EL	1950	0.46	PIPELINE #1 TP	ELK RIVER MUNI NORTH	Connexus	69	THP-69	ACSS	HAWK 477 26/7	3/8
3	EL	1950	2.18	BALDWIN	PRINCTN CTY TP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
3	EL	1950	2.64	ELK RIVER MUNI NORTH	RICE LAKE SWITCH ELSM	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
3	EL	1950	4.98	RICE LAKE SWITCH ELSI	ZIMMERMAN	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
3	EL	1950	5.07	ZIMMERMAN	BALDWIN	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
3	EL	1950	5.12	PRINCTN CTY TP	PRINCETON S.S.	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
3	ELT	1956	0.58	CONDUCTOR CHG.	PRINCETN CITY	Connexus	69	TS-1A	ACSR	RAVEN 1/0 6/1	3/8
3	ELT	1978	2.27	PRINCTN CTY TP	CONDUCTOR CHG.	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	HU	1950	2.13	COND CHNG	HUGO JCT HUSM3	Connexus	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
6	NU	1972	1.24	JCT. RHX LINE	NORTH B. MUNI.	East Central	69	TS-P1	ACSR	PIGEON 3/0 6/1	NONE
6	NU	1972	0.84	JCT. RHX LINE	NORTH B. MUNI.	East Central	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
6	RH	1972	5.78	RX LINE	HARRIS	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	RH	1972	6.31	HARRIS	NORTH BRANCH	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	RHX	1972	0.7	NORTH BRANCH	NU LINE	East Central	69	TP-6AG	ACSR	PIGEON 3/0 6/1	3/8
6	RHX	1972	0.7	NORTH BRANCH	RH LINE	East Central	69	TP-6AG	ACSR	PARTRIDGE 266 26/7	3/8
6	RH	1975	4.27	MA LINE TAP	FOREST LAKE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	RH	1975	7.78	FOREST LAKE	HUGO	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	RH	1975	11.49	RHX LINE	MA LINE TAP	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
6	HU	1976	0.59	BLAINE	CONST CHANGE	Connexus	69	TV-P1	ACSR	PARTRIDGE 266 26/7	NONE
7	SP	1950	10.79	SODERVILLE	BLAINE TAP	Connexus	69	TS-P1	ACSR	PIGEON 3/0 6/1	NONE
8	LD	1950	0.48	DUELM SW.	DUELM	East Central	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
8	EW	1966	3.21	END DBL CKT.	DUELM SW.	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
8	CB	1978	3.53	CABLE	BG JCT SW CBS3	Connexus	69	TS-1A	ACSR	IBIS 397 26/7	3/8
8	CB	1978	5.54	BG JCT SW CBS2	EW JCT CBS1	Connexus	69	TS-1A	ACSR	IBIS 397 26/7	3/8
9	CR	1965	1.01	HIWAY 65 SW.	AIRPORT SUB	Connexus	69	TS-1S	ACSS	PARTRIDGE 266 26/7	3/8
9	CR	1965	1.43	NORTHTOWN	WOODCREST	Connexus	69	TS-1S	ACSS	PARTRIDGE 266 26/7	3/8
9	CR	1965	2.48	WOODCREST	PARKWOOD	Connexus	69	TS-1S	ACSS	PARTRIDGE 266 26/7	3/8
9	CR	1965	3.24	AIRPORT SUB	NORTHTOWN	Connexus	69	TS-1S	ACSS	PARTRIDGE 266 26/7	3/8
10	EW	1966	0	E.R.CTY TAP SW WEST	E R CTY TAP SW EAST	Connexus	69	ZERO IMPEDANCE			
10	EW	1966	1.35	E.R.CTY TAP SW WEST	CONSTR CHNG	Connexus	69	TV-P1	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1966	1.38	NSP TAP	BECKER SW.	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1966	1.44	CONSTR CHANGE	EAST BIG LAKE TAP SWIT	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1966	1.48	EAST BIG LAKE TAP SWI	BIG LAKE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1966	2.46	ELK RIVER #14	E R CTY TAP SW WEST	Connexus	69	TV-P1	ACSS	PARTRIDGE 266 26/7	3/8
10	EW	1967	2.43	BIG LAKE	REMMELE TAP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1967	3.79	THMPSN LAKE	NSP TAP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
10	EW	1967	6.42	REMMELE TAP	THMPSN LAKE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
11	PEX	1969	0.9	VILLAGE TEN	PARKWOOD	Connexus	69	B86-2	ACSR	IBIS 397 26/7	7/16
11	PEX	1969	2.6	BUNKER LAKE DIST	VILLAGE TEN	Connexus	69	B86-2	ACSR	IBIS 397 26/7	7/16
11	EP	1978	0.19	BUNKER LAKE 30NS17	BUNKER LAKE DIST	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
12	PRX	1970	5.2	PARKWOOD	JOHNSVILLE-PS LINE	Connexus	69	B17422	ACSR	IBIS 397 26/7	7/16
12	PS	1970	0.38	HAM LAKE	PSX LINE	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
12	PS	1970	5.8	JOHNSVILLE-PRX LINE	HAM LAKE	Connexus	69	TV-P1	ACSR	IBIS 397 26/7	3/8
12	PSX	1971	0.34	PS LINE	SODERVILLE	Connexus	69	TP-6AG	ACSR	IBIS 397 26/7	3/8
13	SL	1954	7.79	HENNEPIN	PCX LINE	Connexus	69	TS-1	ACSR	PARTRIDGE 266 26/7	3/8
13	PCX	1969	0.82	PARKWOOD	SL LINE	Connexus	69	TVP4-2PC	ACSR	PARTRIDGE 266 26/7	7/16 HSS
21	DO	1965	8.91	WILSON LAKE	SPIRIT LK. SW.	Mille Lacs	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
21	RW	1972	3.32	P. CNTR TP SW	WILSON LAKE	Mille Lacs	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
21	RW	1972	7.24	RIVERTON TAP	OAK LAWN TAP	Crow Wing	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
21	RW	1972	7.3	OAK LAWN TAP	P. CNTR TP SW	Crow Wing	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
21	RWT	1972	0.24	OAK LAWN TAP	OAK LAWN	Crow Wing	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
24	HW	1956	2.96	BIRCH LAKE SUB	PLEASANT LAKE	Crow Wing	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
24	HW	1956	5.92	PLEASANT LAKE	CONSTR. CHANGE	Crow Wing	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
24	HW	1967	0.16	WABEDO SWITCH	WABEDO	Crow Wing	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
24	HW	1967	3.58	CONSTR. CHANGE	WABEDO SWITCH	Crow Wing	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
25	PL	1958	8.29	MP&L LASTRUP	LASTRUP	Crow Wing	34.5	TP-3	ACSR	RAVEN 1/0 6/1	NONE
28	BE	1971	3.47	BALL CLUB SUB.	SW XBE3	Lake Country	69	TPS-1	ACSR	WAXWING 266 18/1	NONE
28	BE	1971	6.39	RBX LINE	BALL CLUB SUB.	Lake Country	69	TPS-1	ACSR	WAXWING 266 18/1	NONE
28	BE	1971	14.9	SW XBE3	BENA	Lake Country	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
28	RBX	1973	1.4	UPA DEER RIVER	BE LINE	North Itasca	69	TP-6A	ACSR	PARTRIDGE 266 26/7	NONE
28	BO	1978	9.41	SALEM SWITCH	BOY RIVER	Lake Country	69	TP-3A	CWC	4A	NONE
28	BO	1978	11.48	SW XBE3	SALEM SWITCH	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
28	TL	1978	8.56	SALEM SWITCH	REMER	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
28	TL	1978	10.9	REMER	THUNDER LAKE	Crow Wing	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
28	TL	1978	16.77	THUNDER LAKE	BLIND LAKE	Crow Wing	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
29	TW-WA	1974	8.32	WARD	WARD TAP	Todd Wadena	34.5	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
31	OL	1949	1.57	PRINCETON	LONG SIDING	East Central	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
31	BM	1975	0	MILACA	MILACA DIST	East Central	69	ZERO IMPEDANCE			
31	BM	1975	0.2	MILACA DIST	BCX LINE	East Central	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
31	BM	1975	8.66	BCX LINE	LONG SIDING	East Central	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
33	JC	1948	18.98	JX LINE	GILMAN	East Central	69	TP-3A	ACSR	PIGEON 3/0 6/1	NONE
33	MP	1967	2.04	PIPELINE#2 TAP	BP JCT SW MPS4	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	MP	1967	3.02	MAYHEW TAP SW.	PIPELINE#2 TAP	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	MP	1967	5.03	BP JCT SW MPS5	MAYHEW	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	MPT	1967	0.43	PIPELINE#2 TAP	PIPELINE#2	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	WG	1967	1.99	MAYHEW TAP	WGT SWITCH	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	WG	1967	6.68	GILMAN	MAYHEW TAP	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	WG	1967	7.03	WGT SWITCH	DUELM SW.	East Central	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
33	JX	1970	1.64	MILACA	JC LINE	East Central	69	TP-6A	ACSR	PENGUIN 4/0 6/1	NONE
36	CP	1950	9.23	CPT LINE TAP	PX LINE	East Central	69	TS-1	ACSR	PARTRIDGE 266 26/7	#7CW
36	CPT	1950	1.48	CP LINE TAP	RUSH CITY DIST	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
36	PX	1950	0.71	COND. CHANGE	ROCK LAKE TAP	East Central	69	TDC-1G	ACSR	PENGUIN 4/0 6/1	#6CU
36	PX	1950	1.1	PINE CITY	COND. CHANGE	East Central	69	TDC-1G	ACSR	PARTRIDGE 266 26/7	#6CU
36	PX	1950	2.28	PINE CITY	CP LINE	East Central	69	TDC-1G	ACSR	PARTRIDGE 266 26/7	#6CU
36	TR	1972	0.41	ADRIAN ROBINSON	RUSH CITY DIST	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
36	TR	1972	3.15	RUSH CITY	ADRIAN ROBINSON	East Central	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
37	PG	1957	9.21	MORA	OGILVIE	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
37	PG	1957	12.69	OGILVIE	MILACA	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
37	PG	1957	13.65	GRASSTON JCT	MORA	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
37	MT	1966	2.62	PG LINE	MORA MUNICIPAL	East Central	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	5/16
38	DT	1970	0.93	DALBO TAP	DALBO SUB	East Central	69	TS-P1	ACSR	PIGEON 3/0 6/1	NONE
39	DL	1965	1.81	SPIRIT LK. SW.	SPIRIT LAKE	Mille Lacs	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
39	DO	1965	10.78	SPIRIT LK. SW.	GLEN	Mille Lacs	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
39	DO	1972	12.5	GLEN	OI LINE	Mille Lacs	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
39	DO	1974	0.5	OI LINE	OPSTEAD	Mille Lacs	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
39	OI	1974	8.15	DO LINE	ISLE SUB	Mille Lacs	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
43	BW	1976	7.07	CRYSTAL LAKE TAP	WASCOTT	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
43	BW	1976	12.63	DAIRYLAND	CRYSTAL LAKE TAP	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
44	DF	1966	10	FOND DU LAC	BARDON JCT.	East Central	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
47	MM	1968	4.23	MP&L MAHTOWA	PETERSON	East Central	22	TP-1A	ACSR	RAVEN 1/0 6/1	NONE
51	EM	1950	1.06	END DBL. CKT.	OTSEGO	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
51	EM	1950	5.19	BLACK LAKE TAP	MAPLE LAKE	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
51	EM	1950	7.29	OTSEGO	ALBERTVILLE	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
51	EM	1950	11.79	ALBERTVILLE	BLACK LAKE TAP	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	MS	1970	0.12	MAPLE LAKE SUB	PEAKING PLANT	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	MS	1970	1.15	PEAKING PLANT	GOOSE LAKE JCT	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	MS	1975	4.57	GOOSE LAKE JCT	SILVER CREEK	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	MS	1975	5.41	SILVER CREEK	HASTY	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	MS	1975	6.79	HASTY	BECKER	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
52	GT	1978	9.42	MS LINE JCT.	GOOSE LAKE	Wright Henn.	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
53	SL	1954	2.04	CORCORAN SW.	CORCORAN	Wright Henn.	69	TS-1	ACSR	PARTRIDGE 266 26/7	3/8
53	SL	1954	2.26	CORCORAN	Lawndale Tap	Wright Henn.	69	TS-1	ACSR	PARTRIDGE 266 26/7	3/8
53	SL	1954	2.26	Lawndale Tap	BASS LAKE TAP	Wright Henn.	69	TS-1	ACSR	PARTRIDGE 266 26/7	3/8
54	DS	1950	4.13	DELANO	DX LINE	Wright Henn.	69	TS-1AC	ACSR	PENGUIN 4/0 6/1	3/8
54	ED	1950	2.63	CORCORAN SW.	WILLOW TAP	Wright Henn.	69	TS-1AC	ACSR	PARTRIDGE 266 26/7	3/8
54	ED	1950	8.46	WILLOW TAP	DELANO	Wright Henn.	69	TS-1AC	ACSR	PARTRIDGE 266 26/7	3/8
54	DX	1955	2.72	DS LINE EAST	CROW RVR (NSP)	Wright Henn.	69	TS-6	ACSR	PENGUIN 4/0 6/1	3/8
54	BD	1971	3.2	CONSTR CHANGE	ORONO NSP TAP	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
54	BD	1971	11.07	ORONO NSP TAP	DELANO	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
55	BD	1971	0	MEDINA DIST	MEDINA	Wright Henn.	69	ZERO IMPEDANCE			
55	BD	1971	3.39	BDT LINE B	NSP HOLLYDALE	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
55	BD	1971	4.7	NSP HOLLYDALE	MEDINA DIST	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
57	ML	1975	2.19	MARY LAKE	DICKINSON JCT.	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
58	ML	1975	2.99	DICKINSON JCT.	MLT LINE	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
58	ML	1975	8.44	MLT LINE	MLX LINE	Wright Henn.	69	TV-P1	ACSR	IBIS 397 26/7	3/8
58	MLX	1975	0.25	ML LINE	NSP (GRNFLD)	Wright Henn.	69	TP-6AG	ACSR	IBIS 397 26/7	3/8
58	MLX	1975	0.75	NSP (GRNFLD)	CORCORAN SW.	Wright Henn.	69	TP-6AG	ACSR	IBIS 397 26/7	3/8
59	HE	1948	9.43	O.N.GRAVGRD	PW LINE TAP	Kandiyohi	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
59	SH	1950	3.32	SPICER TAP	KANDIYOHI	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
59	SH	1950	6.56	O.N. GRVGRRD	GREEN LAKE	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
59	SH	1950	7.12	GREEN LAKE	SPICER TAP	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
59	SH	1950	8.88	KANDIYOHI	XCEL 230 KV	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
60	HE	1948	7.17	PW LINE TAP	SUNBURG	Kandiyohi	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
60	WS	1958	2.95	WILLMAR SOUTHWEST T	WMU JOINT STR	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
60	WS	1970	10.28	OWNER CHANGE	SUNBURG	Kandiyohi	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
60	WS	1970	1.24	COND CHANGE	OWNER CHANGE	Kandiyohi	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
60	WS		1.5	UNDERGROUND	WILLMAR SOUTHWEST TA	Kandiyohi	69	TV-P1	ACSR	ROOK 636 24/7	3/8
60	WST		1.74	WILLMAR PLANT	WSW TAP	Kandiyohi	69	TV-P1	ACSR	ROOK 636 24/7	3/8
60	WST		2.9	COND CHANGE	WSW LIne	Kandiyohi	69	TV-P1	ACSR	ROOK 636 24/7	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
60	WSW		1.6	WILLMAR SOUTHWEST	WST TAP	Kandiyohi	69	TV-P1	ACSR	ROOK 636 24/7	3/8
61	DS	1950	9.17	HN LINE	LITCHFIELD TAP	Meeker	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
61	DS	1950	24.73	LITCHFIELD TAP	SVEA TAP	Kandiyohi	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
61	SH	1950	1.01	SVEA TAP	SVEA	Kandiyohi	69	TS-1AC	ACSR	RAVEN 1/0 6/1	3/8
61	SH	1950	4.57	WILLMAR	SVEA TAP	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
61	HN	1955	8.69	DS LINE	OWNER CHNG	McLeod	69	TS-1	ACSR	PENGUIN 4/0 6/1	3/8
61	HN	1955	1.28	OWNER CHNG	HUTCHINSON	McLeod	69	TS-1	ACSR	PENGUIN 4/0 6/1	3/8
61	LT	1955	11.51	LITCHFIELD TAP	LITCHFIELD	Meeker	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
62	BR	1958	4.03	WMU JOINT STR	PENNOCK TAP	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
62	BR	1958	33.72	PENNOCK TAP	GRANITE FALLS	Kandiyohi	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
62	BRT	1958	1.47	PENNOCK TAP	PENNOCK SUB	Kandiyohi	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
62	BR	1970	5.1	WILLMAR	WMU JOINT STR	Kandiyohi	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
66	FT	1974	4.06	MP LINE 128	FINLAND	Co-op L&P	115	TP-115	ACSR	PIGEON 3/0 6/1	NONE
68	JX	1970	1.64	MILACA	MI LINE	East Central	69	TP-6A	ACSR	PENGUIN 4/0 6/1	NONE
68	MI	1975	1.37	ONAMIA	VINELAND TAP	Mille Lacs	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
68	MI	1975	2.9	CONDUCTOR CHGE	JX LINE	Mille Lacs	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
68	MI	1975	9.9	ISLE	ONAMIA	Mille Lacs	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
68	MI	1975	17.03	VINELAND TAP	CONDUCTOR CHG.	Mille Lacs	69	TS-P1	ACSR	PARTRIDGE 266 26/7	NONE
69	CV	1959	0.53	GOWAN SW.	GOWAN	Lake Country	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
69	CV	1959	6.72	CROMWELL 115KV	CROMWELL DIST.	Lake Country	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
69	CV	1959	13.8	CROMWELL DIST.	GOWAN SW.	Lake Country	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
69	CV	1959	17.09	GOWAN	CEDAR VALLEY	Lake Country	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
69	RL	1965	7.31	CROMWELL DIST.	WRIGHT	Lake Country	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
69	RL	1965	10.96	WRIGHT	ROUND LAKE	Lake Country	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
70	SG	1956	0.48	COLVILL TAP	MAPLE HILL	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 6/1	NONE
70	SG	1956	1.5	COND. CHNG.	SCHROEDER	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 @ 200 Deg	NONE
70	SG	1956	3.68	GR. MARAIS TAP	COLVILL TAP	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 6/1	NONE
70	SG	1956	5.17	CASCADE	GR. MARAIS TAP	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 @ 160 Deg	NONE
70	SG	1956	12.85	LUTSEN	CASCADE	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 @ 160 Deg	NONE
70	SG	1958	10.98	SCHROEDER	CONSTR CHNG.	Arrowhead	69	TPS-1	ACSR	PIGEON 3/0 @ 190 Deg	NONE
70	GM	1971	1.02	GR. MARAIS Muni	GRAND MARAIS	Arrowhead	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
70	GM	1971	1.69	GR. MARAIS TAP	GRAND MARAIS Muni	Arrowhead	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
71	RB	1966	7.16	WIRT JCT	BIGFORK	North Itasca	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
71	RB	1966	8.97	JESSIE LAKE	WIRT JCT.	North Itasca	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
71	RB	1966	14.02	CNSTR.CHANGE	JESSIE LAKE	North Itasca	69	TP-3A	ACSR	WAXWING 266 18/1	NONE
71	TW	1969	8.1	WIRT JCT.	WIRT	North Itasca	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
71	RB	1973	2.5	RBX LINE	CONSTR. CHNG	North Itasca	69	TSP-1	ACSR	PARTRIDGE 266 26/7	NONE
71	RBX	1973	1.4	UPA DEER RIVER	RB LINE	North Itasca	69	TP-6A	ACSR	PARTRIDGE 266 26/7	NONE
76	HO	1960	4.75	MP&L 520 LINE	ONIGUM	Lake Country	34.5	TP-1	ACSR	RAVEN 1/0 6/1	NONE
78	DG	1950	1.52	GUNN	CNSTR. CHANGE	Lake Country	69	TP-S1	ACSR	PARTRIDGE 266 26/7	NONE
78	LB	1971	1.04	BLACKBERRY	LKHD BLKBRY SW	Lake Country	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
78	LB	1971	7.3	WARBA SWITCH	GOODLAND	Lake Country	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
78	BB	1979	3.9	MPL BLACKBERRY	WARBA SWITCH	Lake Country	69	TSZ-1	ACSR	IBIS 397 26/7	3/8
79	CY	1973	0.8	MP&L	DEER RIVER	Lake Country	115	TV-P4	ACSR	IBIS 397 26/7	3/8
81	NC	1958	4.85	MPL CRK.LK.TAP	NASHWAUK TAP	Lake Country	22	TP-1	ACSR	SPARROW 2 6/1	NONE
81	NC	1958	6.45	NASHWAUK TAP	CROOKED LAKE	Lake Country	22	TP-1	ACSR	SPARROW 2 6/1	NONE
81	NW	1977	1	NC LINE	NASHWAUK	Lake Country	22	VC1-2H	ACSR	RAVEN 1/0 6/1	NONE
83	GS	1978	1.15	FOUR CORNERS	SOLWAY	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
83	GS	1978	8.72	SOLWAY	GRAND LAKE	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
83	SA	1978	5.5	FOUR CORNERS	ARROWHEAD	Lake Country	115	TSZ-11	ACSR	TERN 795 45/7	3/8
85	TT	1970	0.19	MP LINE #16	COTTON	Lake Country	115	HS	ACSR	LINNET 336 26/7	NONE
86	SM	1950	15.1	SIDE LAKE	MEADOWBROOK	Lake Country	69	TP-3A	ACSR	PARTRIDGE 266 26/7	NONE
86	PK	1962	4.04	POTLATCH TAP	COOK	Lake Country	69	TPS-1	ACSR	PIGEON 3/0 6/1	NONE
86	LG	1977	14.1	COOK	MEADOWBROOK	Lake Country	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
86	SM	1977	8.86	CONSTR. CHNG.	SIDE LAKE	Lake Country	69	TP-3A	ACSR	PARTRIDGE 266 26/7	NONE
86	SM	1978	5.14	SHANNON	CONSTR. CHANGE	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
88	WE	1959	0.22	WINTON	MP&L LINE #33	Lake Country	46	TP-3	ACSR	RAVEN 1/0 6/1	NONE
93	LP	1962	1.92	SAND LAKE JCT.	SAND LAKE	Lake Country	69	TPS-1	ACSR	RAVEN 1/0 6/1	NONE
93	PK	1962	1.45	COND CHNG	POTLATCH TAP	Lake Country	69	TPS-1	ACSR	PIGEON 3/0 6/1	NONE
93	PK	1962	7.47	PIKE RIVER	SAND LAKE JCT.	Lake Country	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
93	PK	1962	10.03	SAND LAKE JCT	COND CHNG	Lake Country	69	TPS-1	ACSR	PARTRIDGE 266 26/7	NONE
93	VP	1978	3.25	VIRGINIA	EX. 30-32 TIE	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
93	VP	1978	7.93	EX. 30-32 TIE	PIKE RIVER	Lake Country	69	TP-3R1	ACSR	PENGUIN 4/0 6/1	NONE
95	AG-AA	1969	8.03	AKRON TAP	ARTICHOKE TAP	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
95	AG-AK	1969	0.02	AKRON TAP	AKRON	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
95	AG-AR	1969	1	ARTICHOKE TAP	ARTICHOKE	Agralite	41.6	TP-1A	ACSR	PENGUIN 4/0 6/1	NONE
95	AG-MA	1969	4.07	MARSH LAKE 41.6	AKRON TAP	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
95	AG-AF	1970	9.8	FAIRFIELD SWITCH	ARTICHOKE TAP	Agralite	41.6	TP-1A	ACSR	PENGUIN 4/0 6/1	NONE
97	AG-AM	1962	2.98	ALBERTA JUNCTION	ALBERTA	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
99	AG-MB	1970	5.05	WALDEN 115	Hancock Tap	Agralite	115	TH-1A	ACSR	HAWK 477 26/7	3/8
99	AG-MB	1970	6	MORRIS	MORRIS OTP	Agralite	115	TH-1A	ACSR	HAWK 477 26/7	3/8
99	AG-MB	1970	7.7	MORRIS OTP	WALDEN 115	Agralite	115	TH-1A	ACSR	HAWK 477 26/7	3/8
99	AG-MB	1970	14.75	Hancock Tap	BENSON 115	Agralite	115	TH-1A	ACSR	HAWK 477 26/7	3/8
100	AG-CA	1958	5.4	CASHEL	CASHEL TAP	Agralite	41.6	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
101	AG-CL	1958	0.25	CLINTON DIST	CLINTON TAP	Agralite	41.6	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
102	AG-JG	1970	5.19	JOHNSON JUNCTION	GRACEVILLE	Agralite	115	TH-1A	ACSR	PARTRIDGE 266 26/7	3/8
102	AG-MJ	1970	15.4	MORRIS	JOHNSON JUNCTION	Agralite	115	TH-1A	ACSR	PARTRIDGE 266 26/7	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
106	AG-BS	1950	15.3	BENSON	SWIFT FALLS	Agralite	41.6	TP-1	CWC	2F	NONE
106	AG-SG	1965	5.4	COND CHG	GILCHRIST	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
106	AG-SG	1965	5.6	SWIFT FALLS	COND CHG	Agralite	41.6	TP-3A	CWC	2F	NONE
106	AG-GW	1976	3.93	GILCHRIST	WILLIAMS	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
108	AG-RK	1964	10.11	KERKHOVEN TAP	KERKHOVEN 115	Agralite	115	HS	ACSR	PARTRIDGE 266 26/7	3/8
109	ST-BAT	1967	6.28	BANGOR	BANGOR TAP	Stearns	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
109	AG-WL	1977	3.94	WILLIAMS 69	LAKE JOHANNA	Agralite	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
109	AG-WL	1977	4.02	LAKE JOHANNA	WILLIAMS TAP	Agralite	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
111	AG-SLT	1977	2.01	SHIBLE LAKE	SHIBLE LAKE TAP	Agralite	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
112	BR-SE	1960	0.5	SEARLES	SEARLES TAP	Brown	69	W-1	ACSR	QUAIL 2/0 6/1	3/8
112	BR-DL	1968	0.15	DOTSON ALLIANT	DOTSON	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
112	BR-DL	1968	7.95	DOTSON	LEVENWORTH	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
112	BR-LS	1970	3.33	ALBIN JUNCTION	SEARLES TAP	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
112	BR-LS	1970	6.5	ALBIN	ALBIN JUNCTION	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
112	BR-LS	1970	8.45	LEVENWORTH	ALBIN	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
113	RE-WS	1953	3	JOHNSONVILLE TAP	WANDA	Redwood	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
113	RE-WS	1953	7	WANDA	SUNDOWN	Redwood	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
113	RE-JOT	1955	6.99	JOHNSONVILLE TAP	JOHNSONVILLE	Redwood	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
113	RE-SB	1976	6.01	SUNDOWN	BROOKVILLE	Redwood	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
115	BR-SL	1951	3.03	SLEEPY EYE	HOME TAP	Brown	69	W-1	ACSR	QUAIL 2/0 6/1	5/16
115	Xcel 07	1951	1	SLEEPY EYE	HOME TAP	Brown	69	W-1	ACSR	QUAIL 2/0 6/1	5/16
115	BR-SE	1960	8.16	SEARLES TAP	SEARLES JUNCTION	Brown	69	W-1	ACSR	QUAIL 2/0 6/1	3/8
117	BR-SC	1973	3.63	SCHILLING	SCHILLING TAP	Brown	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
121	GO-VA	1969	2.97	VASA	VASA TAP	Goodhue	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
121	GO-GS	1974	4.18	Burnside Sub	SPRING CREEK TAP	Goodhue	69	TS-SM1	ACSR	PENGUIN 4/0 6/1	3/8
121	GO-SB	1974	0.12	SPRING CREEK	BURNSIDE	Goodhue	69	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
121	DA-HA	1977	0.5	COND CHG	WEST HASTINGS	Dakota	69	TSZ-1A	ACSR	LINNET 336 26/7	3/8
121	DA-HA	1977	3.12	HASTINGS	COND CHG	Dakota	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
123	MV-GO	1965	1	BURNSCOTT END	COLONIAL HILLS TAP	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
123	MV-GO	1965	1.65	GLENDALE 69 END	BURNSCOTT END	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
127	DA-LL	1974	0.71	LEMAY LAKE	LEMAY LAKE TAP	Dakota	69	TP-69R	ACSR	LINNET 336 26/7	3/8
135	FE-FD	1956	3	FOX LAKE TAP	DUNNELL	Federated	69	W-1	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-FD	1956	6.28	FOX LAKE	FOX LAKE TAP	Federated	69	W-1	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-DJ	1960	1.7	MIDDLETOWN TAP	ENTERPRISE SWITCH	Federated	69	W-1			3/8
135	FE-DJ	1960	10.3	DUNNELL	MIDDLETOWN TAP	Federated	69	W-1	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-FW	1966	3.75	FOX LAKE TAP	CEYLON TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-FW	1966	7.25	CEYLON TAP	WILBERT	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-WB	1971	0	BLUE EARTH	BLUE EARTH TAP	Federated	69	ZERO IMPEDANCE			
135	FE-WB	1971	7.45	WILBERT	EAST CHAIN	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-WB	1971	13.55	EAST CHAIN	BLUE EARTH	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
135	FE-MIT	1974	1.97	MIDDLETOWN	MIDDLETOWN TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-JAT	1960	1.5	JACKSON MUNI #1	ENTERPRISE SWITCH	Federated	69	TP-69R	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RH	1969	0.75	CHRISTOFFER-JUHL	WEST LAKEFIELD TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RH	1969	3.05	ROUND LAKE TAP	ROUND LAKE	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RH	1969	3.8	WEST LAKEFIELD TAP	ROUND LAKE TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RH	1969	7.8	MILOMA	CHRISTOFFER-JUHL	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RH	1969	8.37	HERON LAKE 69	MILOMA	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RJ	1969	10.11	ROUND LAKE TAP	MINNEOTA TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-RJ	1969	10.11	MINNEOTA TAP	ENTERPRISE SWITCH	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
136	FE-ENT	1978	0.88	STRUCTURE CHANGE	JACKSON MUNI #2	Federated	69	TP-69R	ACSR	PARTRIDGE 266 26/7	3/8
136	FE-ENT	1978	1.15	JACKSON MUNI #2	STRUCTURE CHANGE	Federated	69	TP-69R			3/8
136	FE-ENT	1978	1.23	ENTERPRISE SWITCH	STRUCTURE CHANGE	Federated	69	TSZ-1A	ACSR	PARTRIDGE 266 26/7	3/8
136	FE-ENT	1978	4.98	STRUCTURE CHANGE	ENTERPRISE	Federated	69	TSZ-1A	ACSR	PARTRIDGE 266 26/7	3/8
136	FE-WL	1978	3.59	WEST LAKEFIELD	WEST LAKEFIELD TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
137	FE-WE	1966	1.67	WELCOME	WELCOME TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
138	FE-TRT	1966	1.71	TRUMAN	TRUMAN TAP	Federated	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
140	BE-BRT	1958	1.35	BRICELYN	BRICELYN TAP	BENCO	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
142	BE-MD	1951	4.02	POHL ROAD TAP	DECORIA	BENCO	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
142	BE-BUT	1952	4.5	BUTTERNUT TAP	BUTTERNUT	BENCO	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
142	BE-SC	1958	1.5	DECORIA	ST CLAIR TAP	BENCO	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
142	BE-SC	1958	4.5	ST CLAIR	ST CLAIR TAP	BENCO	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
142	SW-DM	1964	8.02	MATAWAN	DANVILLE	Steele Waseca	69	TSZ-1	ACSR	RAVEN 1/0 6/1	3/8
142	BE-DM	1967	4	MAPLETON	HIGHWAY 30 TAP	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
142	BE-DM	1967	4.5	HIGHWAY 30 TAP	MINNESOTA LAKE	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
142	BE-DM	1967	10.51	ST CLAIR TAP	MAPLETON	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
142	SW-MD	1968	5.98	HIGHWAY 30 TAP	DANVILLE	Steele Waseca	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
142	BE-PO	1972	0.02	POHL DIST	POHL DIST TAP	BENCO	69	THP-1	ACSR	PENGUIN 4/0 6/1	3/8
142	BE-PO	1972	0.45	POHL	POHL TAP	BENCO	69	THP-1	ACSR	PENGUIN 4/0 6/1	3/8
143	BE-WIT	1975	0.48	WINNEBAGO	WINNEBAGO TAP	BENCO	69	B428	ACSR	PIGEON 3/0 6/1	3/8
144	BE-JA	1969	1.5	JAMESTOWN	JAMESTOWN TAP	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
144	BE-JA	1969	2.8	JAMESTOWN TAP	EAGLE LAKE (CLEVELAND	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
145	BE-SCT	1975	3.99	STERLING CENTER	STERLING CTR TAP	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
145	BE-WC	1975	7.13	WILLOW CREEK	WILLOW CREEK TAP	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
145	BE-GC	1978	2.47	GARDEN CITY	GARDEN CITY TAP	BENCO	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
148	BE-NST	1966	7.36	NEW SWEDEN	NEW SWEDEN TAP	BENCO	69	HP-1	ACSR	RAVEN 1/0 6/1	3/8
148	MV-JET	1969	1.07	JESSENLAND	JESSENLAND TAP	Minn Valley	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
149	BE-JO	1974	0.89	JOHNSON	JOHNSON NORTH TAP	BENCO	69	TP-69	ACSR	PENGUIN 4/0 6/1	NONE

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
150	GO-WC	1968	0.5	GOODHUE	WELLS CREEK	Goodhue	69	TC0301	ACSR	PENGUIN 4/0 6/1	3/8
150	GO-BM	1973	8.8	BELVIDERE MILLS	BELVIDERE MILLS TAP	Goodhue	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
150	GO-SG	1974	1.4	BELVIDERE MILLS TAP	GOODHUE	Goodhue	69	TSZ-1A	ACSR	LINNET 336 26/7	3/8
150	GO-SG	1974	7.6	SPRING CREEK TAP	BELVIDERE MILLS TAP	Goodhue	69	TSZ-1A	ACSR	LINNET 336 26/7	3/8
150	GO-WZ	1974	9.99	WELLS CREEK	ZUMBROTA	Goodhue	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
151	GO-CG	1963	4	CHERRY GROVE	CHERRY GROVE TAP	Goodhue	69	TJ2.1701	ACSR	QUAIL 2/0 6/1	3/8
151	SW-WC	1967	4.03	CLAREMONT	CLAREMONT JUNCTION	Steele Waseca	69	TSZ-1	ACSR	RAVEN 1/0 6/1	3/8
153	GO-LE	1964	1	LENA	LENA TAP	Goodhue	69	TJ2.1701	ACSR	QUAIL 2/0 6/1	3/8
154	LR-MA	1975	4	NORTH KRISTIE JUNCTI	MAINE TAP	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
154	LR-MA	1975	8	MAINE	NORTH KRISTIE JUNCTIOI	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
154	LR-UN	1977	2.27	UNDERWOOD	UNDERWOOD TAP	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
156	LR-EP	1964	5.7	BUTLER TAP	NORTH PERHAM JUNCTIC	Lake Region	41.6	TP-3	ACSR	PIGEON 3/0 6/1	NONE
156	LR-EP	1964	8	EVERGREEN	BUTLER TAP	Lake Region	41.6	TP-3	ACSR	QUAIL 2/0 6/1	NONE
156	LR-BU	1975	4.76	BUTLER	BUTLER TAP	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
157	LR-PC	1954	1.5	CORMORANT	CORMORANT JCT	Lake Region	115	HS	ACSR	PARTRIDGE 266 26/7	3/8
157	LR-PC	1954	7.14	TAMARAC 115	PELICAN RAPIDS	Lake Region	115	HS	ACSR	PARTRIDGE 266 26/7	3/8
157	LR-PC	1954	7.3	CORMORANT	TAMARAC 115	Lake Region	115	HS	ACSR	PARTRIDGE 266 26/7	3/8
157	LR-CF	1969	14.95	CORMORANT JUNCTION	FRAZEE 115	Lake Region	115	HS	ACSR	PARTRIDGE 266 26/7	3/8
158	LR-RT	1978	2.87	ROTHSAY	ROTHSAY TAP	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
159	LR-DE	1960	10.33	DENT	DENT TAP	Lake Region	41.6	TP-3	ACSR	QUAIL 2/0 6/1	NONE
159	LR-EP	1964	1	NORTH PERHAM JUNCTI	OWNER CHANGE (DENT)	Lake Region	41.6	TP-3	ACSR	PIGEON 3/0 6/1	NONE
163	LR-SLT	1974	9.01	STALKER LAKE	STALKER LAKE TAP	Lake Region	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
165	LR-LET	1968	10.21	LAKE EUNICE	LAKE EUNICE TAP	Lake Region	41.6	TP-3	ACSR	PIGEON 3/0 6/1	NONE
166	LR-RLX	1975	0.41	RUSH LAKE 41.6	RUSH LAKE TAP-OTTO	Lake Region	41.6	TP-6A	ACSR	PARTRIDGE 266 26/7	NONE
167	LR-HR	1975	11.61	INMAN	RUSH LAKE 115	Lake Region	115	TH-230	ACSR	TERN 795 45/7	3/8
169	LR-RLX	1975	0.41	RUSH LAKE 41.6	RUSH LAKE TAP-NYMILLS	Lake Region	41.6	TP-6A	ACSR	PARTRIDGE 266 26/7	NONE
170	LR-PP	1952	1.92	PARKERS PRAIRIE	PARKERS PRAIRIE TAP	Lake Region	41.6	TP-3AR	ACSR	PIGEON 3/0 6/1	NONE
170	RU-MP	1965	8.16	MILTONA	PARKERS PRAIRIE SWITC	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
172	LR-RO	1955	3.67	ROBERTS	ROBERTS SWITCH	Lake Region	41.6	TP-3	ACSR	QUAIL 2/0 6/1	NONE
173	LR-TAT	1964	7	TANSEM	TAMARAC DBL CKT	Lake Region	41.6	TP-3	ACSR	PIGEON 3/0 6/1	NONE
176	MC-WV	1946	9	COND CHANGE	WINTHROP	McLeod	69	T1W	ACSR	QUAIL 2/0 6/1	#2
176	MC-WE	1959	5	WINTHROP	BROWNTON TAP	McLeod	69	T1W	ACSR	RAVEN 1/0 6/1	1/0
176	MC-WE	1959	7	BROWNTON TAP	BELL	McLeod	69	T1W	ACSR	RAVEN 1/0 6/1	1/0
176	MC-GB	1966	10.8	HELEN	HASSAN JUNCTION	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
176	MC-HB	1966	4	BELL	HASSAN JUNCTION	McLeod	69	TP-69	ACSR	PENGUIN 4/0 6/1	NONE
176	MC-HB	1967	3.37	HASSAN JUNCTION	HUTCHINSON JCT	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
176	MC-HB	1970	1.24	HUTCHINSON JCT	HUTCHINSON 69	McLeod	69	TPHP-69	ACSR	PENGUIN 4/0 6/1	3/8
176	Xcel 0781		0.51	WINTHROP	COND CHANGE	McLeod	69		ACSR	PENGUIN 4/0 6/1	
178	MC-HIT	1965	7.31	BISCAY JUNCTION	HIGH ISLAND	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
178	MC-GB	1966	1.6	GLENCOE	BISCAY JUNCTION	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
178	MC-GB	1966	2	BISCAY JUNCTION	HELEN	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
179	MC-HO	1965	2	HOLLYWOOD	HOLLYWOOD TAP	McLeod	69	TPS-1	ACSR	SPARROW 2 6/1	NONE
179	MC-LN	1965	2.32	NEW GERMANY TAP	LESTER PRAIRIE TAP	McLeod	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
181	LN	1968	2	LITCHFIELD	NSP LINE	Meeker	69	TV-P1	ACSR	PENGUIN 4/0 6/1	3/8
181	ME-CM	1972	8.34	CEDAR MILLS	CEDAR MILLS TAP	Meeker	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
181	MC-ME	1978	4.52	MELVILLE	MELVILLE TAP	McLeod	69	TSZ-1A	ACSR	PARTRIDGE 266 26/7	3/8
184	ST-FIT	1969	9.03	FAIRHAVEN	FAIRHAVEN TAP	Stearns	69	TSZ-1	ACSR	RAVEN 1/0 6/1	3/8
184	ST-LUT	1978	1.16	LUXEMBURG	LUXEMBURG TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
187	MV-CA	1967	5.1	CARVER CO	ASSUMPTION	Minn Valley	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
187	MV-AB	1969	1.23	STRUCTURE CHANGE	STRUCTURE CHANGE	Minn Valley	69	TH-HT1	ACSR	LINNET 336 26/7	3/8
187	MV-AB	1969	1.87	STRUCTURE CHANGE	BELLE PLAINE	Minn Valley	69	TS-SM1	ACSR	LINNET 336 26/7	3/8
187	MV-AB	1969	7.17	ASSUMPTION	STRUCTURE CHANGE	Minn Valley	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
192	MV-ST	1962	1	ST THOMAS	LE SUEUR TAP	Minn Valley	69	TSZ-1	ACSR	PIGEON 3/0 6/1	3/8
192	MV-ST	1962	3.45	LE SUEUR TAP	ST THOMAS TAP	Minn Valley	69	TSZ-1	ACSR	PIGEON 3/0 6/1	3/8
194	MV-PL	1965	1.15	PRIOR LAKE (MV-GPX)	PRIOR LAKE JUNCTION	Minn Valley	69	TP-69RPT	ACSR	LINNET 336 26/7	3/8
194	MV-PN	1970	0.16	ELKO Tap	LAKE MARION TAP	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
194	MV-PN	1970	3.51	CREDIT RIVER TAP	PRIOR LAKE JUNCTION	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
194	MV-PN	1970	5.42	NEW MARKET	ELKO Tap	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
194	MV-PN	1970	7.99	LAKE MARION TAP	CREDIT RIVER TAP	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
194	MV-CR	1974	0.95	CLEARY LAKE TAP	CREDIT RIVER	Minn Valley	69	TC0301	ACSR	PENGUIN 4/0 6/1	3/8
194	MV-CR	1974	1.31	CREDIT RIVER TAP	CLEARY LAKE TAP	Minn Valley	69	TC0301	ACSR	PENGUIN 4/0 6/1	3/8
194	MV-SL	1977	3.68	SPRING LAKE	CREDIT RIVER	Minn Valley	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
196	MV-GP	1965	0.12	GLENDALE 69	COND CHG	Minn Valley	69	TP-69RPT	ACSR	LINNET 336 26/7	3/8
196	MV-GP	1965	0.95	COND CHG	COND CHG	Minn Valley	69	TV-P1	ACSR	ROOK 636 24/7	3/8
200	NO-WF	1973	8.58	ELK	FULDA	Nobles	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
201	NO-CH	1960	7.3	CHANDLER	CHANDLER TAP	Nobles	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
205	NO-WC	1962	0.48	WORTHINGTON WEST T	WORTHINGTON EAST TAF	Nobles	69	TP-69	ACSR	LINNET 336 26/7	NONE
205	NO-WC	1962	1.49	WORTHINGTON EAST TA	COND CHG	Nobles	69	TP-69	ACSR	LINNET 336 26/7	NONE
205	NO-WR	1962	0.1	WORTHINGTON MUNI TA	WORTHINGTON MUNI	Nobles	69	TSZ-1AX	ACSR	RAVEN 1/0 6/1	3/8
205	NO-WR	1962	1.37	WORTHINGTON TAP	WORTHINGTON MUNI TAF	Nobles	69	TSZ-1AX	ACSR	RAVEN 1/0 6/1	3/8
205	NO-WR	1962	2.01	COND CHG	WORTHINGTON TAP	Nobles	69	TSZ-1AX	ACSR	RAVEN 1/0 6/1	3/8
205	NO-WT	1962	0	WORTHINGTON DIST TA	WORTHINGTON MUNI TAF	Nobles	69	ZERO IMPEDANCE			
205	NO-WT	1962	0.44	WORTHINGTON DIST TA	WORTHINGTON	Nobles	69	TH-2	ACSR	RAVEN 1/0 6/1	3/8
205	NO-WT	1962	2	WORTHINGTON TAP	WORTHINGTON DIST TAP	Nobles	69	TH-2	ACSR	RAVEN 1/0 6/1	3/8
207	RE-FR	1955	1.07	REDWOOD	CITY OF REDWOOD FALLS	Redwood	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
207	RE-FR	1955	13.5	CITY OF REDWOOD FALI	FRANKLIN	Redwood	69	TSW-1	ACSR	QUAIL 2/0 6/1	3/8
207	RE-SR	1955	3.96	SHERIDAN	SHERIDAN TAP	Redwood	69	TSW-1	ACSR	RAVEN 1/0 6/1	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
207	RE-SR	1955	8.01	SHERIDAN TAP	REDWOOD	Redwood	69	TSW-1	ACSR	RAVEN 1/0 6/1	3/8
207	RE-WA	1961	5.77	SHERIDAN TAP	WABASSO ISP	Redwood	69	TSW-1G	ACSR	PENGUIN 4/0 6/1	3/8
208	RU-SA	1956	0.55	SANFORD	SANFORD TAP	Runestone	41.6	TP-3	ACSR	RAVEN 1/0 6/1	NONE
209	RU-AH	1965	0.1	ALEXANDRIA	LAKE MARY TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-AH	1965	4.5	LAKE MARY TAP	HUDSON TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-HM	1965	2.31	CARLOS JUNCTION	CARLOS	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-HM	1965	3.07	LE HOMME DIEU	CARLOS JUNCTION	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-HM	1965	7.78	HUDSON TAP	LE HOMME DIEU	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-LM	1969	1.93	LAKE MARY	LAKE MARY TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
209	RU-HM	1973	0.6	HUDSON	HUDSON TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
211	RU-HM	1965	0.77	CARLOS	MILTONA SW RU-HMS1	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
211	RU-BE	1973	7.01	BELLE RIVER	RU-MIX	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
212	RU-GL	1971	3.19	LAGRANDE TAP	LAGRANDE	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
213	RU-FR	1966	0.17	FRAMNAS	FRAMNAS TAP	Runestone	41.6	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
213	RU-WC	1970	6.26	WALDEN 41.6	CYRUS	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
213	RU-HC	1973	5.08	HOLMES CITY	HOLMES CITY TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
214	RU-LE	1961	0.2	LEVEN DIST	LEVEN TAP	Runestone	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
216	SC-BL	1979	1.96	BINGHAM LAKE	BINGHAM LAKE TAP	South Central	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
218	SC-JE	1974	4.52	JEFFERS	JEFFERS TAP	South Central	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
219	SC-ML	1967	0.5	MOUNTAIN LAKE	MOUNTAIN LAKE MUN	South Central	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
220	ST-MIT	1967	1.2	MILLWOOD	MILLWOOD TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
220	ST-ALT	1971	4.51	ALBANY	ALBANY BREAKER STATIC	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
221	ST-RF	1973	2.48	FARMING	BIG FISH TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
221	ST-RF	1973	3.52	BIG FISH TAP	FARMING TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
221	ST-RO	1978	5.09	ROSCOE	ROSCOE TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
222	ST-BR	1965	6.83	BROCKWAY	BROCKWAY TAP	Stearns	69	HP-1	ACSR	RAVEN 1/0 6/1	3/8
222	ST-WL	1969	1.58	LE SAUK	LE SAUK TAP	Stearns	69	TP-3AX	ACSR	PENGUIN 4/0 6/1	NONE
222	ST-SS	1974	6.47	ST STEPHENS	BROCKWAY	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
223	ST-EL	1960	4.89	ELROSA	ELROSA TAP	Stearns	69	HP-1	ACSR	RAVEN 1/0 6/1	3/8
223	ST-ZI	1978	1.47	ZION	ZION TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
224	ST-FN	1969	8.4	FLENSBURG	NORTH PARKER JUNCTIO	Stearns	34.5	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
224	ST-SU	1971	3.22	SWANVILLE	BURTRUM	Stearns	34.5	HPA2	ACSR	LINNET 336 26/7	3/8
225	ST-KA	1976	3.94	KANDOTA	KANDOTA TAP	Stearns	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
231	ST-SU	1971	6.74	BURTRUM	UPSALA	Stearns	34.5	HPA2	ACSR	LINNET 336 26/7	3/8
231	ST-US	1975	5.97	UPSALA	SOBIESKI	Stearns	34.5	TP-34	ACSR	LINNET 336 26/7	NONE
235	SW-RB	1953	9.14	RIVER POINT	BIXBY	Steele Waseca	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
236	SW-FC	1959	0.2	Change in Construction	VALLEY GROVE JUNCTIOI	Steele Waseca	69	THP-69	ACSR	PENGUIN 4/0 6/1	3/8
236	SW-FC	1959	2.5	FARIBAULT	Change in construction	Steele Waseca	69	W-1	ACSR	RAVEN 1/0 6/1	3/8
236	SW-FC	1959	6.9	CIRCLE LAKE	FARIBAULT	Steele Waseca	69	W-1	ACSR	RAVEN 1/0 6/1	3/8
236	SW-VG	1973	4.79	VALLEY GROVE	VALLEY GROVE TAP	Steele Waseca	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
237	SW-OM	1952	6.48	OWATONNA	MERTON	Steele Waseca	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
239	SW-MB	1950	11.01	ST OLAF	MATAWAN	Steele Waseca	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
244	TW-LR	1962	3.9	LEAF RIVER	LEAF RIVER TAP	Todd Wadena	34.5	TP-1	ACSR	RAVEN 1/0 6/1	NONE
245	TW-ME	1971	2.8	MENAHGA	MP SPIRIT LAKE	Todd Wadena	34.5	TP-3	ACSR	PENGUIN 4/0 6/1	NONE
245	TW-ME	1971	3.5	MP SPIRIT LAKE	MENAHGA TAP	Todd Wadena	34.5	TP-3	ACSR	PENGUIN 4/0 6/1	NONE
251	RU-GL	1971	0.19	GARFIELD	COND CHG	Runestone	41.6	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
251	RU-GL	1971	1.62	COND CHG	LAGRANDE TAP	Runestone	41.6	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
253	MV-AU	1970	2.5	CARVER CO UB	END UB	Minn Valley	69	TP-69R	ACSR	LINNET 336 26/7	3/8
261	CP	1950	1.5	RC LINE TAP	CPT LINE TAP	East Central	69	TS-1	ACSR	PARTRIDGE 266 26/7	#7CW
262	RO	1970	23.74	OGILVIE	ISLE SUB	East Central	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
263	ED	1950	1.03	EMX Double Ckt	OE Line	Wright Henn.	69	TS-1AC	ACSR	PARTRIDGE 266 26/7	3/8
263	ED	1950	14.45	OE Line	MLX LINE	Wright Henn.	69	TS-1AC	ACSR	PARTRIDGE 266 26/7	3/8
263	EMX	1950	1.25	ER #6 6NB7	END DBL. CKT.	Wright Henn.	69	TS-6	ACSR	PARTRIDGE 266 26/7	3/8
263	OE	1956	0.4	ED LINE	CONSTRUCTION CHNG	Wright Henn.	69	TSZ-1	ACSR	Merlin 336 18/1	3/8
263	OE	1956	0.83	CONSTRUCTION CHNG	OTSEGO SUB	Wright Henn.	69	TSZ-1	ACSR	Merlin 336 18/1	3/8
263	MLX	1975	1	ED LINE	CORCORAN SW.	Wright Henn.	69	TP-6AG	ACSR	PARTRIDGE 266 26/7	3/8
264	PG	1957	9.47	PINE CITY	GRASSTON JCT.	East Central	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
266	NO-AD	1961	5.06	ADRIAN CP	ADRIAN	Nobles	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
266	NO-RU	1973	5.01	RUSHMORE	RUSHMORE TAP	Nobles	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
269	DS	1950	2.77	MC LINE	LK JENNIE TAP	Meeker	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
269	DS	1950	3.45	LK JENNIE TAP	HN LINE	Meeker	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
269	DS	1950	9.6	WINSTED TAP	MC LINE	Wright Henn.	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
269	MC-HL	1967	0.83	HOOK LAKE DIST	HOOK LAKE	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
269	MC	1970	7.39	DS LINE	OWNER CHNG.	McLeod	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
269	ME-LJ	1979	1	LAKE JENNIE	LAKE JENNIE SWITCH	Meeker	69	TSZ-1A	ACSR	PENGUIN 4/0 6/1	3/8
270	AC	1948	6.99	CNSTR. CHANGE	HIGHLAND	Wright Henn.	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
270	AC	1948	9.04	HIGHLAND	HOWARD LAKE	Wright Henn.	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
271	ME-DA	1952	1.04	DASSEL	DASSEL TAP	Meeker	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
271	MC-SH	1971	2.06	SHERMAN	SHERMAN TAP	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
275	RE-MIT	1978	6.53	MILROY	MILROY TAP	Redwood	69	TSZ-1A	ACSR	PARTRIDGE 266 26/7	3/8
276	RE-WG	1979	6.02	WALNUT GROVE	WALNUT GROVE TAP	Redwood	69	TSZ-1A	ACSR	PARTRIDGE 266 26/7	3/8
277	PD	1952	5.3	EC-PAX TAP	HRRY MSR SUB.	East Central	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
277	PD	1952	8.3	HRRY MSR SUB.	DENHAM	East Central	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
277	KC	1959	7.05	KETTLE RIVER	CROMWELL 115	Lake Country	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
277	PAT	1962	0.93	EC-PAX	MP&L SANDSTONE	East Central	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
277	KS	1978	1.43	MOOSE LAKE TAP	KST JCT SW KSS4	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
277	KS	1978	2.9	KST JCT SW KSS5	STURGEON LAKE	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
277	KS	1978	6.67	KETTLE RIVER	MOOSE LAKE	Lake Country	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
277	DK	1979	15.16	DENHAM	KETTLE RIVER	East Central	69	TS-1	ACSR	RAVEN 1/0 6/1	3/8
278	PA	1962	3.99	BEAR CREEK TAP	SANDSTONE	East Central	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
280	SL	1954	0.37	CO-SLX 23NB4	SP LINE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
280	SL	1954	0.88	LEXINGTON	CO-SLX 23NB3	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
280	SL	1954	1.84	SPRING LK PARK	HIWAY 65 SW.	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
280	SL	1954	2.54	PARKWOOD	SPRING LK PARK	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
280	SL	1954	3.21	HIWAY 65 SW.	LEXINGTON	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
281	SP	1950	0.94	SL LINE TAP	CIRCLE PINE	Connexus	69	TS-P1	ACSR	PIGEON 3/0 6/1	NONE
281	CH	1965	1.71	NSP TIE	WHITE BEAR TWP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
281	CH	1965	3.68	HUGO	NSP TIE	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
281	CH	1965	6.61	WHITE BEAR TWP	CIRCLE PINES	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	3/8
284	MC-BR	1973	6	BROOKFIELD	BROOKFIELD TAP	McLeod	69	TSZ-1	ACSR	PENGUIN 4/0 6/1	3/8
289	OT	1976	0.53	MP&L #515 LINE	HP LINE JCT	Itasca Mantrap	34.5	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
289	OT	1976	14.34	RT TAP SW.	OSAGE	Itasca Mantrap	34.5	TP-3A	ACSR	PENGUIN 4/0 6/1	NONE
297	SC-SH	1955	0.21	SHERBURN DIST	SHERBURN TAP	South Central	69	TP-3A	ACSR	RAVEN 1/0 6/1	NONE
297	SC-OD	1961	5.6	ODIN	ODIN TAP	South Central	69	TP-3A	ACSR	PIGEON 3/0 6/1	NONE
300	DS	1950	14.32	DX LINE	VICTOR	Wright Henn.	69	TS-1A	ACSR	PENGUIN 4/0 6/1	3/8
300	DX	1955	2.78	CROW RVR (NSP)	DS LINE WEST	Wright Henn.	69	TS-6	ACSR	PENGUIN 4/0 6/1	3/8
301	CO	1966	3.34	CROSS LAKE SW.	CROSS LAKE CITY	Crow Wing	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
301	CO	1966	4.67	OX LAKE	FIFTY LAKES SW. (EC LINE	Crow Wing	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
301	CO	1966	5.31	CROSS LAKE CITY	FIFTY LAKES SW. (EC LINE	Crow Wing	69	TPS-1	ACSR	QUAIL 2/0 6/1	NONE
301	EC	1974	4.1	FIFTY LAKES SW. (CO LI	EMILY SUB	Crow Wing	69	TS-P1	ACSR	PENGUIN 4/0 6/1	NONE
301	TL	1978	8.44	BLIND LAKE	OX LAKE	Crow Wing	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
302	PP	1977	2.25	BREEZY PT. SW.	BREEZY POINT	Crow Wing	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
302	PQ	1978	4.2	PEQUOT LAKES	PP LINE JCT.	Crow Wing	69	TSZ-1	ACSR	IBIS 397 26/7	3/8
302	PQ	1978	4.25	PP LINE JCT.	CO LINE JCT.	Crow Wing	69	TSZ-1	ACSR	IBIS 397 26/7	3/8
302	ST	1979	13.08	PEQUOT LAKES	STONYBROOK	Crow Wing	69	TSZ-1	ACSR	PARTRIDGE 266 26/7	3/8
303	RV	1972	0.5	Const change	RIVERTON TAP RVX	Crow Wing	69	TPS-1	ACSR	IBIS 397 26/7	NONE
310	PC	1969	2.54	END DBL.CKT.	NSP CROOKED LK	Connexus	115	TV-P4	ACSR	TERN 795 45/7	7/16
310	PCX	1969	0.82	PARKWOOD	PC LINE	Connexus	115	TVP4-2P(	ACSR	TERN 795 45/7	'/16 HSS
312	ELP	1963	0.17	CO-SP	PIPELINE #1SUB	Connexus	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
314	SC	1950	2.5	EAST BETHEL	SODERVILLE	Connexus	69	TS-1A			#8CW
314	SC	1950	3.08	ATHENS	COOPERS CORNER	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
314	SC	1950	6.4	COOPERS CORNER	EAST BETHEL	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
315	SC	1950	2.5	CAMBRIDGE	S CAMBRIDGE TAP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
315	SC	1950	3.42	ISANTI TAP	ATHENS	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
315	SC	1950	6.17	S CAMBRIDGE TAP	ISANTI TAP	Connexus	69	TS-1A	ACSR	PARTRIDGE 266 26/7	#8CW
315	IT	1964	3.32	ISANTI TAP	ISANTI	Connexus	69	TS-1A	ACSR	PIGEON 3/0 6/1	3/8
	PX	1950	0.09	ROCK LAKE TAP	R.L.PEAK PLANT	East Central	69	TS-5G-D	ACSR	PARTRIDGE 266 26/7	3/8
	PX	1950	0.46	P LINE	R.L.PEAK PLANT	East Central	69	TDC-1G	ACSR	PENGUIN 4/0 6/1	#6CU
	RP	1965	0.78	PARKWOOD	CONSTR. CHANGE	Connexus	115	TVP6/2	SSAC	DRAKE 795 26/7	3/8
	RP	1965	1.42	CONSTR. CHANGE	NSP COON CRK LN	Connexus	115	TH-1AA	SSAC	DRAKE 795 26/7	3/8
	Xcel 08	1965	1.2	NSP COON CRK LN	COON CREEK	Connexus	115		SSAC	DRAKE 795 26/7	
	EE	1969	0.22	ELK RIVER #6	ELK RIVER #14	Connexus	69	TV-P1	ACSR	TERN 795 45/7	3/8
	ME-BW	1969	3.5	BIG SWAN 115	SWAN LAKE TAP	Meeker	115	TH-1A	ACSR	HAWK 477 26/7	3/8
	ME-BW	1969	24.86	SWAN LAKE TAP	WAKEFIELD	Meeker	115	TH-1A	ACSR	HAWK 477 26/7	3/8
	DA-DE	1970	1.75	DEERWOOD	DEERWOOD TAP	Dakota	69	TP-69R	ACSR	PENGUIN 4/0 6/1	3/8
	DA-RE	1970	1.5	RIVER HILLS	DEERWOOD TAP	Dakota	69	TP-69R	ACSR	LINNET 336 26/7	3/8
	DA-RE	1970	1.5	PILOT KNOB TAP	LEBANON HILLS JUNCTIO	Dakota	69	TP-69R	ACSR	LINNET 336 26/7	3/8
	DA-RE	1970	2	DEERWOOD TAP	PILOT KNOB TAP	Dakota	69	TP-69R	ACSR	LINNET 336 26/7	3/8
	MV-CC	1970	0.17	COND CHG	WEST WACONIA	Minn Valley	115	TPDC-11	ACSS	TERN 795 45/7	3/8
	MV-CC	1970	0.21	WEST WACONIA	COND CHG	Minn Valley	115	TPDC-11	ACSS	TERN 795 45/7	3/8
	MV-CC	1970	0.7	STRUCTURE CHANGE	COND CHG	Minn Valley	115	TS-D11	ACSR	TERN 795 45/7	3/8
	MV-CC	1970	3.59	CARVER CO	STRUCTURE CHANGE	Minn Valley	115	TD-0422	ACSR	DRAKE 795 26/7	3/8
	MV-CC	1970	8.05	COND CHG	ST. BONIFACIUS 115	Minn Valley	115	TS-D11	ACSR	TERN 795 45/7	3/8
	MV-CC	1970	11.7	ST. BONIFACIUS 115	DRX LINE	Minn Valley	115	TS-D11	ACSR	TERN 795 45/7	3/8
	DA-PK	1973	0.46	PILOT KNOB 69	PILOT KNOB TAP	Dakota	69	TD-69DC	ACSR	LINNET 336 26/7	3/8
	DA-PK	1973	0.46	PILOT KNOB 69	PILOT KNOB TAP	Dakota	69	TD-69DC	ACSR	LINNET 336 26/7	3/8
	NO-WF	1973	2.52	WORTHINGTON WEST T	ELK	Nobles	69	TSZ-1A	ACSR	LINNET 336 26/7	3/8
	AG-BC	1974	7.36	BIG STONE	CANBY	Transmission	115	HS	ACSR	HAWK 477 26/7	3/8
	AG-BO	1974	2.03	BIG STONE	HIGHWAY 12	Transmission	115	HS	ACSR	HAWK T2-477 26/7	3/8
	AG-BO	1974	3.14	HIGHWAY 12	OTP OWNERSIP	Transmission	115	HS	ACSR	HAWK T2-477 26/7	3/8
	OTP Li	1974	1.33	OTP OWNERSHIP	ORTONVILLE	Transmission	115	HS	ACSR	HAWK T2-477 26/7	3/8

GREAT RIVER ENERGY - TRANSMISSION FACILITIES - LINES BUILT BEFORE 1980

Reliability Line Number	Line Name	In-Service Year	Miles	From Name	To Name	Co-op Area	Voltage	Struct. Type	Cond. Type	Cond. Size	Shld Wire
Transmission Lines (161kV and above)											
	LR-HI	1964	3.72	HENNING 230	INMAN 230	Transmission	230	KT-230	ACSR	TERN 795 45/7	3/8
	LR-IW	1964	8.56	INMAN 230	OTP CONSTR. CHANGE	Transmission	230	KT-230	ACSR	TERN 795 45/7	3/8
	LR-IW	1964	9.57	OTP CONSTR. CHANGE	MP CONSTR. CHANGE	Transmission	230	KT-230	ACSR	TERN 795 45/7	3/8
	CS	1966	0.63	STANTON ND	SVX LINE ND	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	CS	1966	6.1	SVX LINE ND	COAL CREEK JCT	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	CS	1966	4.5	COAL CREEK JCT	CSX	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	DV	1966	43.44	BALTA	MCHENRY N.D.	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	GD	1966	12.24	RAMSEY N.D.	US #2 WEST	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	GD	1966	68.5	US #2 EAST	PRAIRIE N.D.	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SB	1966	1.02	STANTON N.D.	BASIN N.D.	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SB	1966	0	STANTON N.D.	BASIN N.D.	Transmission	230	REACTOR			
	SHN	1966	16.27	STANTON N.D.	SQUARE BUTTE	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SHN	1969	1.91	SQUARE BUTTE	CENTER N.D.	Transmission	230	TH-230	ACSR	RAIL 954 45/7	3/8
	SV	1966	48.77	COAL CRK TAP	MCHENRY JCT	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	LR-IW	1968	1.31	MP CONSTR. CHANGE	WING RIVER	Transmission	230	HS-230	ACSR	TERN 795 45/7	3/8
	TW-RW	1968	13.32	WING RIVER	RIVERTON OWNER CHAN	Transmission	230	HS-230	ACSR	TERN 795 45/7	3/8
	DA-SC	1969	20.61	SPRING CREEK 161	CANNON FALLS	Transmission	161	TE-0103	ACSR	ROOK 636 24/7	3/8
	DA-SC	1969	1.2	DA-SC LINE	SPRING CREEK 161	Transmission	161	NH-48633	ACSR	ROOK 636 24/7	3/8
	DA-SC	1969	1.2	DA-SP LINE	SPRING CREEK 161	Transmission	161	NH-48633	ACSR	ROOK 636 24/7	3/8
	DA-SP	1969	4.04	PRAIRIE ISLAND	SPRING CREEK 161	Transmission	161	NH-48633	ACSR	ROOK 636 24/7	3/8
	PE	1969	14.3	ELK RIVER	PEX LINE	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	PEX	1969	1.89	PE LINE	BUNKER LAKE	Transmission	230	B86-2	ACSR	TERN 795 45/7 @ 160 D	7/16
	PEX	1969	3.45	BUNKER LAKE	PRX LINE	Transmission	230	B86-2	ACSR	TERN 795 45/7	7/16
	EO	1970	16.9	ELK RIVER #14	MONTICELLO	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	MR	1970	8.22	MUD LAKE TAP	RIVERTON	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	MR	1970	21.61	MONTICELLO	BENTON COUNTY	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	MR	1970	51.44	MRX LINE	MUD LAKE TAP	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	PR	1970	4.29	PRX LINE	BLAINE	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	PR	1970	41	BLAINE	RUSH CITY	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	PRX	1970	5.2	PEX LINE	PR LINE	Transmission	230	B17422	ACSR	TERN 795 45/7	7/16
	WB	1970	13.05	WILLMAR	OWNER CHANGE	Transmission	230	TH-230	ACSR	TERN 795 45/7	3/8
	WB	1970	17.85	OWNER CHANGE	GRANITE FALLS	Transmission	230	TH-230	ACSR	TERN 795 45/7	3/8
	RMN	1972	0.59	RUSH CITY	NSP ARROWHEAD	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	RMS	1972	0.59	RUSH CITY	NSP RED ROCK	Transmission	230	TH-230	ACSR	TERN 795 45/7	7/16
	CSX	1978	0.63	C. CRK JCT(CS)	COAL CREEK	Transmission	230	3JS	ACSR	RAIL 954 45/7	3/8
	CSX	1978	0.63	C. CRK JCT(SV)	COAL CREEK	Transmission	230	3JS	ACSR	RAIL 954 45/7	3/8
	SV	1978	0.63	STANTON ND	SVX LINE ND	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SV	1978	7.6	SVX LINE	COAL CRK JCT	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SV	1978	1.47	COAL CRK JCT	COAL CRK TAP	Transmission	230	TH-230	ACSR	RAIL 954 45/7	7/16
	SVX	1978	0.91	CS LINE N.D.	CS LINE N.D.	Transmission	230	3P	ACSR	RAIL 954 45/7	7/16
	SVX	1978	0.91	SV LINE N.D.	SV LINE N.D.	Transmission	230	3P	ACSR	RAIL 954 45/7	7/16
	CDX	1978	18.57	DICKINSON	MAPL GRVE TAP	Transmission	345	3J-SPI	ACSR	RAIL 2-954 45/7	3/8
	CDX	1978	18.57	DICKINSON	MAPL GRVE TAP	Transmission	345	3J-SPI	ACSR	RAIL 2-954 45/7	3/8
	CDX	1978	8.39	MAPL GRVE TAP	COON CREEK	Transmission	345	3J-SPV	ACSR	RAIL 2-954 45/7	3/8
	CDX	1978	8.39	MAPL GRVE TAP	COON CREEK	Transmission	345	3J-SPV	ACSR	RAIL 2-954 45/7	3/8
	DC	1979	435.85	COAL CREEK	DICKINSON	Transmission	400	DCT	ACSR	LAPWING 1590 45/7	1/2
	ME	1979	12.5	DICKINSON	GROUND ELECTRODE	Transmission	22				
	NE		6.6	CSX LINE	ND GROUND ELECTRODE	Transmission	22				
	VX	1979	61.65	NSP OWNERSHIP	CONST. CHNG.	Transmission	500	NALT	ACSR	BUNTING 1192.5 45/7	7/16
	VX	1979	8.12	CONST. CHNG.	MP OWNERSHIP	Transmission	500	NLT	ACSR	BUNTING 1192.5 45/7	7/16

Transmission Line Reliability Summary - 50 Worst Reliability Lines by Composite Rank

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
142	Wilmarth 4S43/4S45 - Madelia 761 (BE-MD, BE-SC, BE-DM, BE-MH, SW-MD, SW- D	1,376,801	121,157	61,068	57.6	15.6	11.20	**1**
154	Hoot Lake 145 (LR-MAT)	1,782,004	164,492	37,417	29.6	7.6	4.76	**2**
71	Deer River 21NB4 (RB, RBX, TW, SQ)	1,325,777	177,640	29,654	32.0	4.0	5.14	**3**
33	Benton Co. 41NB13 - Milaca 5NB3 (BP, JC, JX, MP, MPT, WG, WGT)	2,060,862	94,520	81,750	17.0	4.0	6.18	**4**
70	Taconite Harbor 42WB1 (GC, GM, SG, TH)	3,002,952	74,537	95,055	15.2	5.8	9.77	**5**
213	Walden 415 (RU-WC)	852,738	149,770	27,565	51.0	5.0	5.15	**6**
159	Frazee 235 (LR-FEX, LR-DOT, LR-DET, LR-DN)	1,572,519	110,407	35,426	20.0	5.6	3.95	**7**
184	Wakefield 4N114 - GRE Maple Lake 1NB3	1,552,779	67,399	51,733	15.0	6.0	5.67	**8**
135	Fox Lake 735 (FE-DJ, FE-FD, FE-FW, FE-WB)	658,432	60,139	36,726	32.6	13.2	5.67	**9**
176	Hutchinson C3NB9 - Winthrop 4S54 (MC-GB, MC-HB, MC-WB, MC-WW)	1,530,911	62,559	80,187	16.2	3.8	10.50	**10**
25	Little Falls 526FM (PL)	835,954	127,242	29,296	26.6	5.6	2.94	**11**
181	Big Swan 4N2 - Panther 4N66/4N71 - Litchfield C7NB7	536,540	86,622	22,880	33.2	9.4	4.15	**12**
6	Blaine 23NB5 - Rush City 9NB2 (HU, MA, NU, RH, RHX, RX)	988,444	288,596	29,273	30.8	5.6	1.68	**13**
144	Wilmarth 4S40,4S42 - Cleveland 4S100 - Waterville 193 (BE-CA, BE-CJ, BE-JA)	1,171,558	66,080	29,112	15.6	7.6	4.10	**14**
78	Blackberry 20WB1 - Deer River 21NB2 (BB, DG, DH, LB, LH)	1,200,434	75,413	31,879	13.0	2.2	4.04	**15**
163	Henning 625 (LR-SLT)	839,988	84,786	18,196	15.6	5.2	2.45	**16**
224	Blanchard 508F (ST-FN, ST-NPT)	533,505	72,688	16,298	23.6	6.4	2.94	**17**
192	Cleveland 4S99/4S100 (MV-CLX)	912,549	52,567	37,235	12.6	3.4	3.56	**18**
201	Pipestone 4X742 - Tracy 700 (NO-CHT, NO-RC)	517,428	37,817	16,776	18.2	9.8	5.29	**19**
244	Verndale 510FM (TW-LRT)	834,377	30,666	27,652	11.4	7.0	5.19	**20**
235	West Owatonna 4S73 (SW-RB)	765,589	31,715	27,736	11.4	7.8	4.62	**21**
136	Heron Lake 830 (FE-DJ, FE-ENT, FE-RH, FE-RJ)	385,113	39,887	22,709	26.0	4.4	4.07	**22**
138	Madelia 760 - Rutland 711	372,829	32,925	23,489	21.0	5.4	3.99	**23**
289	Long Lake 545F (OT, RT)	1,291,291	32,923	49,145	6.6	4.0	3.56	**24**
158	Hoot Lake 135 (LR-RTT)	399,484	57,835	14,637	25.8	3.0	3.69	**25**
222	Albany 4N86/4N90 - West St. Cloud 4N51 (ST-BR, ST-WL, ST-WW)	1,117,230	60,830	34,736	8.8	1.6	3.00	**26**

Transmission Line Reliability Summary - 50 Worst Reliability Lines by Composite Rank

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
172	Wahpeton 225 (LR-ROT)	977,358	26,304	54,060	12.8	1.2	7.93	**27**
93	Virginia 27WB1 - Potlatch 17NB3 (LP, PK, VP)	805,892	68,884	23,846	13.6	1.2	2.64	**28**
109	Glenwood 4N29 - Paynesville 4N58	265,805	44,487	13,505	27.6	4.6	2.72	**29**
239	Albert Lea Westside 629 (SW-MB)	472,090	37,780	17,058	13.4	2.4	2.85	**30**
209	Alexandria 345 (RU-AH, RU-HM)	434,411	71,340	13,665	14.0	3.0	1.43	**31**
208	Brandon 325	416,671	67,917	12,479	18.4	1.8	1.76	**32**
225	Black Oak 4N19/4N20 - Douglas County 4N25 (ST-KAT)	458,276	47,481	16,757	12.6	2.0	1.91	**33**
221	Albany 4N86/4N87 - Paynesville 4N32 - Wakefield 4N113 (ST-AF, ST-RF, ST-ROT	497,904	38,564	16,335	10.0	2.8	2.13	**34**
38	Cambridge 2NB3 - Princeton 8NB2 (DT, OP)	951,014	53,618	19,108	7.6	1.2	2.25	**35**
85	Arrowhead 16L - Virginia 16L - Eveleth Tac 16L (16 line)	988,728	28,420	21,449	6.0	1.6	3.66	**36**
194	Glendale 4M9 - Lake Marion 4S60 (MV-CR, MV-PN)	901,140	62,479	30,292	6.2	1.4	1.53	**37**
243	Long Prairie 501FM (TW-HAT, TW-IOT)	456,572	28,550	13,342	10.0	3.4	2.58	**38**
168	Hoot Lake 165	409,512	20,890	14,199	11.0	3.4	3.19	**39**
121	Cannon Falls 105 - Spring Creek 4H7/4H8 - W. Hastings 4P78 (DA-HA, DA-HM, D	180,049	133,658	7,697	23.2	1.8	1.23	**40**
44	Fond du Lac 24KB1 (DF)	405,931	76,344	7,207	13.2	2.0	1.17	**41**
3	Elk River 14NB3 - Princeton 8NB1 (CO-ELX, EB,EL, ELT)	394,574	116,844	16,890	9.8	2.2	0.60	**42**
31	Milaca 5NB1 - Princeton 8NB1/8NB2 (BCX, BM, OL)	578,395	130,591	13,465	9.2	1.6	0.68	**43**
199	Fulda 826 (NO-BL)	396,800	13,888	17,360	11.2	1.6	5.33	**44**
145	Winnebago Local 746	260,651	28,652	11,634	17.4	1.6	2.55	**45**
29	Dog Lake 1T	698,445	22,572	17,098	4.8	2.8	2.49	**46**
10	Becker 50NB2 - Elk River 14NB9 (EW, EWT)	562,154	68,850	16,784	6.0	1.8	0.81	**47**
203	Magnolia 816	592,812	11,725	29,502	4.8	2.0	3.96	**48**
218	Heron Lake 833 - Lamberton 855 (SC-JET)	205,809	17,072	11,051	13.2	3.6	2.51	**49**
15	Arden Hills 4P92 - St. Croix Falls 4A37	812,448	28,586	18,024	4.2	1.6	1.95	**50**
150	Spring Creek 4H6/4H9 - Zumbrota 4H15 (GO-SG, GO-WG, GO-WZ)	448,223	23,394	17,289	8.4	1.4	2.69	**50**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
1	Elk River 14NB1-Soderville 7NB4-Bunker Lake 30NB9/30NB10 (EPX, ES, PSX,	372,192	38,770	10,571	2.0	1.2	0.32	**83**
2	Bunker Lake 30NB10/30NB11 - Elk River 6NB4 (EP,EPX)	88,856	142,420	4,420	16.0	1.6	0.26	**68**
3	Elk River 14NB3 - Princeton 8NB1 (CO-ELX, EB,EL, ELT)	394,574	116,844	16,890	9.8	2.2	0.60	**42**
6	Blaine 23NB5 - Rush City 9NB2 (HU, MA, NU, RH, RHX, RX)	988,444	288,596	29,273	30.8	5.6	1.68	**13**
7	Blaine 23NB2 - Soderville 7NB3 (SP)	30,366	20,244	923	1.2	0.4	0.03	**145**
8	Becker 50NB1 - Benton Co. 41NB14 (BG, CB, EW)		125,064		17.0			**128**
9	Parkwood 12NB2 (CR)	93,537	10,393	3,857	0.8	0.8	0.12	**125**
10	Becker 50NB2 - Elk River 14NB9 (EW, EWT)	562,154	68,850	16,784	6.0	1.8	0.81	**47**
11	Bunker Lake 30NB11/30NB14 - Parkwood 12NB5 (PEX)	9,962	59,772	306	2.4	0.4	0.01	**141**
12	Parkwood 12NB1 - Soderville 7NB1 (PRX, PS, PSX)	239,445	108,812	6,812	4.4	1.0	0.15	**83**
14	Goose Lake 5P40 - Lexington 5P55		1,122		0.2			**232**
15	Arden Hills 4P92 - St. Croix Falls 4A37	812,448	28,586	18,024	4.2	1.6	1.95	**50**
16	Crooked Lake 12.5KV bus	154,284	2,967	24	0.2	0.2	0.17	**178**
19	Pequot Lakes 507FM	17,320	15,155	371	1.4	0.2	0.03	**163**
21	Riverton 25NB1 - Vineland 57NB1 (DO, PO, PT, RW, RWT)		64,933		6.6			**148**
22	Little Falls - Mud Lake (46 line)	85,520	20,311	2,624	3.8	0.4	0.27	**109**
24	Blind Lake 58NB1/58NB2 - Birch Lake 54NB3 (BH, HW)	645,648	37,480	12,275	3.2	0.8	0.94	**75**
25	Little Falls 526FM (PL)	835,954	127,242	29,296	26.6	5.6	2.94	**11**
27	Baxter 534F	236,028	1,326	5,358	0.2	0.8	0.59	**130**
28	Blind Lake 58NB2 - Deer River 21NB3 (BE, BO, RBX, TL)		88,301		16.8			**131**
29	Dog Lake 1T	698,445	22,572	17,098	4.8	2.8	2.49	**46**
30	Badoura 40L - Dog Lake 24-40MW (40 line)		1,881		0.4			**221**
31	Milaca 5NB1 - Princeton 8NB1/8NB2 (BCX, BM, OL)	578,395	130,591	13,465	9.2	1.6	0.68	**43**
32	Cambridge 69KV bus		4,397		0.4			**216**
33	Benton Co. 41NB13 - Milaca 5NB3 (BP, JC, JX, MP, MPT, WG, WGT)	2,060,862	94,520	81,750	17.0	4.0	6.18	**4**
35	Cambridge 2NB4 - Grasston 15NB1 (CM)		88,556		5.2			**147**
36	Pine City 4NB1 - Rush City 9NB4 (CP, CPT, PX, TR)	44,119	3,598	1,530	0.4	0.8	0.07	**159**
37	Grasston 15NB2-Milaca 5NB4-Ogilvie 3NB1 (MT, PG)	12,024	174,348	231	11.6	0.4	0.01	**108**
38	Cambridge 2NB3 - Princeton 8NB2 (DT, OP)	951,014	53,618	19,108	7.6	1.2	2.25	**35**
39	Isle 56NB1/56NB2 (DO,OI)	14,948	64,772	275	7.0	0.8	0.03	**114**
42	Stinson 147WB1 (BS, BN, AM)		6,686		1.0			**205**
43	Frog Creek 48NB3 (BW, FC, FCX)	318,637	46,708	4,504	11.6	2.2	1.29	**52**
44	Fond du Lac 24KB1 (DF)	405,931	76,344	7,207	13.2	2.0	1.17	**41**
45	Thomson 23L - Sandstone 23LM (23 line)	68,036	7,313	1,249	1.8	0.6	0.21	**136**
46	Stone Lake 6R1 - Stinson 6T	38,654	6,678	535	1.8	1.4	0.16	**138**
47	Mahtowa 430F (MM)	92,040		1,593		0.2	0.98	**169**
51	Elk River 6NB6 - Maple Lake 1NB1 (BL, EM, EMX)	384,976	34,083	14,518	4.2	1.6	0.93	**67**
52	Becker 50NB4 - Maple Lake 1NB5 (GT, MS)		78,536		6.2			**146**
54	Medina 55NB2 - Crow River 4M64 - Corcoran 123NB2 (BD, DS, DX, ED, WH-	57,360	19,120	2,284	1.6	0.2	0.08	**135**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
55	Medina 55NB1 (BD)	42,500	2,502	2,895	1.2	0.4	0.23	**151**
56	Crow River 5M72/5M76 - Medina 55WB2/55NB1/55NB2		1,250		0.4			**224**
57	Dickinson 62NB13 (ML)	9,096		314		0.2	0.01	**220**
58	Dickinson 62NB14 - Corcoran 123NB1 (ML, MLT, MLX)		11,652		1.0			**198**
59	Willmar 13NB5 (HE, SH)	143,583	51,048	7,234	12.0	0.6	0.57	**78**
60	Willmar 13NB1 - WMUC 6P4 (HE, PWT, SWS, WS, WST, WSW)	285,034	52,866	9,336	8.8	1.6	0.77	**62**
61	Willmar 13NB3 - Hutchinson C3NB1 - Litchfield C7NB6 (DS, HN, LT, MC, SH)	206,615	26,908	8,948	5.6	2.4	0.72	**71**
62	Willmar 13NB2 - Granite Falls 4352 (BR, BRT, BX)	397	5,558	22	2.8	0.2		**190**
64	Colbyville 42L - Silver Bay 42L (42 line)	100,500	11,262	3,624	1.2	1.4	0.18	**114**
65	Ridgeview 253FX	281,187	13,659	7,005	5.8	1.0	1.99	**79**
66	Silver Bay 128L - Taconite Harbor 128L (128 line)	404,712	1,314	8,367	0.2	0.8	1.03	**114**
67	Cromwell 18WB4 - Riverton 13L (13 line)	91,593	74,368	2,272	16.8	1.8	0.29	**73**
68	Milaca 5NB2 - Isle 56NB1 - Vineland 57NB1 (MI, PO)		53,460		8.0			**148**
69	Cromwell 18NB2 - Gowan Breaker Station 118NB1 (CV, RL)		181,915		27.6			**124**
70	Taconite Harbor 42WB1 (GC, GM, SG, TH)	3,002,952	74,537	95,055	15.2	5.8	9.77	**5**
71	Deer River 21NB4 (RB, RBX, TW, SQ)	1,325,777	177,640	29,654	32.0	4.0	5.14	**3**
75	Badoura 48L - Hubbard 48L (48 line)	19,165		1,079		0.8	0.07	**193**
76	Badoura 507FM - Birch Lake 516F	18,612	9,024	342	3.2	1.0	0.11	**140**
77	Birch Lake 509F	516,215	10,535	11,805	1.4	1.0	1.14	**91**
78	Blackberry 20WB1 - Deer River 21NB2 (BB, DG, DH, LB, LH)	1,200,434	75,413	31,879	13.0	2.2	4.04	**15**
79	Nashwauk 28L - Clay Boswell 28L - Deer River 21NB1 (28 line)	154,156		3,956		0.2	0.23	**173**
80	Grand Rapids 11L - Riverton 11L (11 line)	212,856	8,232	5,152	1.4	0.4	0.60	**110**
81	Nashwauk Tap 22GB1 (NC, NW)	1,276,055	10,220	24,185	2.0	1.6	4.07	**56**
82	Nashwauk 314F	186,004	23,273	3,569	4.6	1.2	0.61	**93**
83	Four Corners 40NB1 - Gowan Breaker Station 118NB2 (GL, GS, GST)	204,473	26,770	6,511	8.0	2.4	1.50	**65**
84	Gowan Breaker Station 118NB1/118NB2 (CV)	279,110	11,121	6,202	3.2	1.2	1.02	**94**
85	Arrowhead 16L - Virginia 16L - Eveleth Tac 16L (16 line)	988,728	28,420	21,449	6.0	1.6	3.66	**36**
86	Shannon 26WB1 - Potlatch 17NB1 (LG, PK, SM)	238,968	96,300	5,835	10.8	0.6	0.41	**77**
87	Hibbing 25L - Virginia 25L (25 line)	52,812	652	1,796	0.2	0.2	0.27	**178**
88	Winton 33L (33 line)	415,727	2,938	9,716	0.4	1.0	0.94	**103**
89	Virginia 32L - Winton 32L (32 line)	272,135	88,143	5,875	13.2	1.2	0.75	**60**
91	Babbitt 31L - Winton 31L (31 line)	21,325	7,677	429	1.8	0.4	0.08	**157**
92	Syl Laskin 39LM - Virginia 39L (39 line)	9,508		196		0.4	0.01	**213**
93	Virginia 27WB1 - Potlatch 17NB3 (LP, PK, VP)	805,892	68,884	23,846	13.6	1.2	2.64	**28**
94	Potlatch 17NB1/17NB3 (PKT)		4		0.8			**227**
95	Marsh Lake 475 (AG-AA, AG-FA, AG-MA)	75,931	41,941	3,882	36.6	3.2	1.03	**59**
96	Ortonville 1465 - Appleton 1449		11,928		11.2			**167**
99	Morris 1662 - Benson 1555 (AG-MB)	136,817	17,270	17,332	10.6	4.0	1.15	**55**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
100	Benson 785	63,698	9,310	3,536	14.0	1.6	1.13	**87**
101	Graceville 555	32,850	7,446	1,050	3.4	0.4	0.25	**139**
102	Morris 1762 - Ortonville 1445 - Graceville 1515 (AG-JG, AG-MJ)	24,966	438	798	0.2	0.4	0.19	**187**
104	Benson 1565 (AG-VHT)	9,548		5,083		0.6	0.15	**184**
105	Morris 3132	91,560	11,772	4,302	5.4	0.8	0.70	**99**
106	Benson 735 (AG-BS, AG-GW, AG-SG, AG-SW)	141,519	22,854	4,111	10.4	1.2	1.07	**79**
107	Kerkhoven 655	4,095	3,900	250	4.0	0.2	0.07	**175**
108	Benson 1515/1525 - Willmar 13WB1 - Maynard 5N88 (AG-BK, AG-RK, WX)	2,145	195	131	0.2	0.2	0.04	**217**
109	Glenwood 4N29 - Paynesville 4N58	265,805	44,487	13,505	27.6	4.6	2.72	**29**
110	Benson 765	4,462	6,288	273	4.8	1.2	0.06	**144**
111	Appleton 845	12,157	5,563	699	6.4	0.8	0.18	**136**
112	Dotson Corner 862 - Madelia 765	173,510	15,871	8,230	9.4	1.4	1.88	**72**
113	Dotson Corner 860 - Lamberton 855	117,420	14,158	5,607	14.4	1.6	2.06	**69**
114	Franklin 4N111 - Winthrop 4S56	17,020	740	730	1.0	0.6	0.38	**168**
115	Fort Ridgely 4S51 - Franklin 4N112	29,192	6,600	1,504	4.0	0.8	0.31	**127**
116	Arlington 4S192 - Winthrop 4S53		116		0.8			**226**
117	Fort Ridgely 4S49 - Winthrop 4S57	1,232	2,464	77	1.6	0.4	0.01	**191**
118	Johnny Cake 5P176/5P179 - Koch 5P153 (DA-BK)	79,078	16,648	2,729	0.8	0.6	0.06	**132**
119	Black Dog 5M251 - Burnsville 5M195/5M197		7,281		0.2			**214**
120	Burnsville 5M195/5M201 - Johnny Cake 5P178/5P179 (DA-BK)	59,692	14,923	2,112	0.6	0.6	0.04	**143**
121	Cannon Falls 105 - Spring Creek 4H7/4H8 - W. Hastings 4P78 (DA-HA, DA-	180,049	133,658	7,697	23.2	1.8	1.23	**40**
122	Farmington 4P36/4P37 - Northfield 4S27	69,639	14,534	2,386	7.4	1.2	0.69	**96**
123	Burnsville 4M73/4M88 - Glendale 4M8 (DA-BC, DA-CO, MV-GO, MV-GOX)		35,064		2.4			**171**
124	Burnsville 5M200 - Lake Marion 5S32/TR1		21,981		1.0			**188**
125	Pilot Knob 4P46/TR2 (DA-PD)		14,976		0.4			**202**
126	Johnny Cake 5P176/5P178 - Air Lake 5P40 (DA-BKX, DA-JA, DA-JAX, DA-DA,		11,643		0.4			**204**
127	Pilot Knob 4P45/TR3 (DA-LL, DA-PL, DA-WW)		37,094		4.4			**164**
130	Inver Grove 4P9	481,481	42,328	15,001	1.6	0.4	0.30	**88**
131	Burnsville 4M87 (DA-OL)	12,642		362		0.2	0.01	**219**
133	Burnsville 4M76 (DA-BR)		37,850		1.0			**181**
134	Inver Grove 4P8	160	474	1,052	0.8	0.2	0.03	**199**
135	Fox Lake 735 (FE-DJ, FE-FD, FE-FW, FE-WB)	658,432	60,139	36,726	32.6	13.2	5.67	**9**
136	Heron Lake 830 (FE-DJ, FE-ENT, FE-RH, FE-RJ)	385,113	39,887	22,709	26.0	4.4	4.07	**22**
137	Fairmont 701 - Fox Lake 734	29,561	3,526	4,665	2.6	1.8	0.41	**113**
138	Madelia 760 - Rutland 711	372,829	32,925	23,489	21.0	5.4	3.99	**23**
139	Lakefield 882 - Windom 897	33,768	12,328	1,153	4.6	0.2	0.21	**134**
140	Bricelyn 720 - Winnco 34NB42	169,320	9,690	7,736	3.8	0.4	1.11	**98**
141	Walters 615 - Winnco 34NB42	5,610	20,400	256	8.0	0.6	0.04	**133**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
142	Wilmarth 4S43/4S45 - Madelia 761 (BE-MD, BE-SC, BE-DM, BE-MH, SW-MD,	1,376,801	121,157	61,068	57.6	15.6	11.20	**1**
143	Walters 628 - Winnebago Jct. 791	103,080	5,470	3,667	3.0	0.6	0.97	**111**
144	Wilmarth 4S40,4S42 - Cleveland 4S100 - Waterville 193 (BE-CA, BE-CJ, BE-	1,171,558	66,080	29,112	15.6	7.6	4.10	**14**
145	Winnebago Local 746	260,651	28,652	11,634	17.4	1.6	2.55	**45**
146	Winnebago Jct. 793	46,436		2,037		1.2	0.47	**161**
147	Wilmarth 4S39/4S48	9,736	12,170	573	2.0	0.4	0.03	**155**
148	Arlington 4S199 - Traverse 39NB1	132,300	27,300	5,828	10.4	1.6	0.84	**76**
149	Wilmarth 4S46/4S48 - Traverse 39NB2	66,495	6,006	1,993	2.8	1.2	0.52	**117**
150	Spring Creek 4H6/4H9 - Zumbrota 4H15 (GO-SG, GO-WG, GO-WZ)	448,223	23,394	17,289	8.4	1.4	2.69	**50**
152	Cannon Falls 168 - Zumbrota 4H14		5,178		1.2			**208**
153	Zumbrota 4H13	26,850	5,677	1,001	2.2	0.2	0.17	**158**
154	Hoot Lake 145 (LR-MAT)	1,782,004	164,492	37,417	29.6	7.6	4.76	**2**
156	Frazee 255 (LR-EP, LR-FE)	385,400	27,880	12,490	6.8	2.0	1.57	**53**
157	Audubon 1425 - Hoot Lake 1275 - Frazee 1325 (LR-CF, LR-PC)		21,847		4.6			**170**
158	Hoot Lake 135 (LR-RTT)	399,484	57,835	14,637	25.8	3.0	3.69	**25**
159	Frazee 235 (LR-FEX, LR-DOT, LR-DET, LR-DN)	1,572,519	110,407	35,426	20.0	5.6	3.95	**7**
160	Alexandria Poleyard 1565 - Inman 1515/1555 (LR-IA)		41,254		8.8			**152**
161	Pelican Rapids 465	25,347	15,691	747	2.6	0.4	0.07	**142**
162	Wahpeton 215	46,110	10,182	2,234	6.6	0.8	0.53	**105**
163	Henning 625 (LR-SLT)	839,988	84,786	18,196	15.6	5.2	2.45	**16**
164	Fergus Falls 2265 - Inman 2820 (LR-HI)	21,740	4,348	477	0.8	0.4	0.07	**174**
165	Audubon 555 (LR-LET)	759,320	35,188	18,143	3.8	1.2	1.37	**58**
166	Rush Lake 525 (LR-RLX)	4,936	4,936	142	0.8	0.2	0.01	**196**
167	Frazee 1325/1345 - Inman 1525/1555 (LR-HR, LR-PR, LR-PRX)	32,720	46,968	936	9.6	0.4	0.10	**104**
168	Hoot Lake 165	409,512	20,890	14,199	11.0	3.4	3.19	**39**
169	Rush Lake 515 (LR-NR, LR-RLX)	110,619	7,230	3,017	2.0	0.2	0.51	**126**
170	Miltona 187KB3/187KB4 (LR-PPT, RU-MP)	146,410	17,545	5,118	5.8	1.0	0.81	**92**
172	Wahpeton 225 (LR-ROT)	977,358	26,304	54,060	12.8	1.2	7.93	**27**
173	Tamarac 445 (LR-TAT)		11,021		3.8			**185**
175	Grant County 1345 - Alexandria 1615/1665	60,378	2,811	1,832	0.8	2.2	0.27	**129**
176	Hutchinson C3NB9 - Winthrop 4S54 (MC-GB, MC-HB, MC-WB, MC-WW)	1,530,911	62,559	80,187	16.2	3.8	10.50	**10**
178	Carver County 4M51	250,505	8,190	11,256	2.8	2.0	1.36	**82**
179	St. Bonifacious 4M24 (MC-LN, MC-SN)	143,295	15,145	4,553	5.2	2.0	0.82	**86**
181	Big Swan 4N2 - Panther 4N66/4N71 - Litchfield C7NB7	536,540	86,622	22,880	33.2	9.4	4.15	**12**
184	Wakefield 4N114 - GRE Maple Lake 1NB3	1,552,779	67,399	51,733	15.0	6.0	5.67	**8**
186	Paynesville 3N14	571,179	17,979	19,445	2.6	0.8	1.38	**74**
187	Carver Co. 4M52 - Scott Co. 4M44 - New Prague 658 (MV-AB, MV-CA)	194,003	46,027	6,720	9.4	1.6	0.58	**69**
188	Scott County 4M41	6,261	4,174	278	0.8	0.4	0.02	**186**
189	Minnesota River 5M419 - Westgate 5M5/5M7		1,874		0.2			**230**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
191	Minnesota River 5M419/5M422 - Scott County 5M108/5M221		1,730		0.4			**222**
192	Cleveland 4S99/4S100 (MV-CLX)	912,549	52,567	37,235	12.6	3.4	3.56	**18**
193	Black Dog 5M258 - Scott Co. 5M219/5M220		105		0.2			**237**
194	Glendale 4M9 - Lake Marion 4S60 (MV-CR, MV-PN)	901,140	62,479	30,292	6.2	1.4	1.53	**37**
195	Montgomery 657 - New Prague 658		8,845		1.0			**203**
196	Glendale 4M10/TR2 (MV-GP)		2,022		0.2			**229**
199	Fulda 826 (NO-BL)	396,800	13,888	17,360	11.2	1.6	5.33	**44**
200	Elk 845 (NO-WF)	422	1,092	17	0.6	0.2		**212**
201	Pipestone 4X742 - Tracy 700 (NO-CHT, NO-RC)	517,428	37,817	16,776	18.2	9.8	5.29	**19**
202	Chanarambie 5X92/5X93 - Lake Yankton 5X14/5X15	3,588	2,760	138	2.0	0.2	0.04	**189**
203	Magnolia 816	592,812	11,725	29,502	4.8	2.0	3.96	**48**
205	Elk 847 (NO-EW, NO-WO, NO-WR, NO-WT)	1,350	1,350	69	0.4	0.4	0.01	**206**
207	Franklin 4N108 (RE-FR, RE-SR, RE-WA)	112,930	4,910	5,211	2.0	0.4	0.77	**118**
208	Brandon 325	416,671	67,917	12,479	18.4	1.8	1.76	**32**
209	Alexandria 345 (RU-AH, RU-HM)	434,411	71,340	13,665	14.0	3.0	1.43	**31**
211	Miltona 187KB1/187KB2 (RU-HM, RU-MIX, RU-BET)		16,579		3.4			**180**
212	Miltona 187KB1/187KB4 (RU-ML, RU-GL)	126,192	28,512	4,061	4.8	0.6	0.33	**97**
213	Walden 415 (RU-WC)	852,738	149,770	27,565	51.0	5.0	5.15	**6**
214	Douglas County 4N26 - Glenwood 4N28	204,595	24,874	9,655	12.0	1.6	1.67	**61**
215	Elbow Lake 535	14,500	26,346	556	9.0	0.6	0.08	**119**
216	Mountain Lake 893 - Windom 896	86,040	5,022	3,837	7.2	2.8	1.81	**89**
218	Heron Lake 833 - Lamberton 855 (SC-JET)	205,809	17,072	11,051	13.2	3.6	2.51	**49**
219	Dotson Corner 861 - Mountain Lake 892 (SC-MLT)		2,148		1.2			**210**
220	Albany 4N87/4N90 - Black Oak 4N18/4N19 (ST-ALT, ST-MIT)	140,125	6,671	6,732	2.2	1.4	0.83	**100**
221	Albany 4N86/4N87 - Paynesville 4N32 - Wakefield 4N113 (ST-AF, ST-RF, ST-	497,904	38,564	16,335	10.0	2.8	2.13	**34**
222	Albany 4N86/4N90 - West St. Cloud 4N51 (ST-BR, ST-WL, ST-WW)	1,117,230	60,830	34,736	8.8	1.6	3.00	**26**
223	Black Oak 4N18/4N20 - Paynesville 4N31 (ST-ELT, ST-ZIT)	90,814	2,193	5,710	1.4	1.2	0.89	**112**
224	Blanchard 508F (ST-FN, ST-NPT)	533,505	72,688	16,298	23.6	6.4	2.94	**17**
225	Black Oak 4N19/4N20 - Douglas County 4N25 (ST-KAT)	458,276	47,481	16,757	12.6	2.0	1.91	**33**
226	I-94 115KV bus		400		0.4			**230**
227	Long Prairie 867L - Douglas County 5N606/TR1		905		0.2			**234**
228	Long Prairie 527FM	253,729	14,607	7,785	5.4	1.0	1.56	**81**
231	Blanchard 524F (ST-SB, ST-US, ST-SU)	81,605	22,334	2,948	5.2	0.8	0.32	**101**
232	St. Cloud 5N32 - Wakefield 5N28/4N113/4N114 - I94 10WB2 (ST-SI)		6,595		1.0			**206**
233	West St. Cloud 5N43 - Little Falls 868L (ST-FHT)	5,930	4,825	183	1.0	0.2	0.03	**192**
235	West Owatonna 4S73 (SW-RB)	765,589	31,715	27,736	11.4	7.8	4.62	**21**
236	Faribault 4S61 - Northfield 4S28 - West Faribault 4S34 (SW-CV, SW-FC)	385,368	31,331	11,367	7.4	1.2	1.57	**64**
237	Waseca 647 - West Owatonna 4S76 (SW-CM, SW-MO, SW-OM)	347,102	9,382	13,832	6.0	3.8	3.73	**57**
238	Montgomery 655 - Waseca 646 (SW-FLT)	4,208	8,416	75	1.6	0.2	0.01	**183**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
239	Albert Lea Westside 629 (SW-MB)	472,090	37,780	17,058	13.4	2.4	2.85	**30**
240	Waterville 184 - West Faribault 4S17 (SW-WAT)	17,232	11,168	829	4.2	1.6	0.11	**123**
241	Verndale 533FM (TW-COT)	25,276	2,848	1,593	1.6	0.2	0.24	**161**
243	Long Prairie 501FM (TW-HAT, TW-IOT)	456,572	28,550	13,342	10.0	3.4	2.58	**38**
244	Verndale 510FM (TW-LRT)	834,377	30,666	27,652	11.4	7.0	5.19	**20**
245	Hubbard 515F (TW-MET, TW-ORT)	491,023	11,420	34,487	4.4	2.0	2.03	**54**
246	Verndale 503FM	76,320	18,379	2,585	5.2	0.8	0.32	**102**
247	Baxter 24L - Dog Lake 24-40MW - Verndale 24L (24 line)	16,146	5,006	848	1.6	0.8	0.09	**154**
261	Cambridge 2NB2 - Rush City 9NB3							**239**
262	Ogilvie 3NB1 - Isle 56NB2							**239**
263	Elk River 6NB7 - Corcoran 123NB3	51,540		1,227		0.4	0.07	**194**
264	Pine City 4NB3 - Grasston 15NB1/NB2		3,406		0.2			**224**
265	Traverse 39NB1/NB2 - Saint Peter 4S105							**239**
266	Magnolia 819 - Sibley 6490 (NO-ADT, NO-RUT)	167,255	7,645	10,095	4.4	1.6	1.69	**85**
268	Byron 6S28/6S29 - West Owatonna 6S3/3TR	2,351	311	1,920	0.6	1.8	0.10	**164**
269	Hutchinson C3NB2 - Victor 208NB1/208NB2 (DSX,DS,MC,MCX)	284,210	1,394	8,773	0.4	1.0	1.43	**105**
270	Maple Lake 1NB2 - Victor 208NB2/208NB3 (AC,ACX)		17,017		2.8			**182**
271	Big Swan 4N3 - Victor 208NB1/208NB6 (WH-VW,DSX,MC-SHT,ME-DAT)	7,288	7,288	233	1.6	0.4	0.03	**172**
272	Baxter 130L - Riverton 130L (130 Line) (CW-BAT)		2,825		0.4			**218**
274	Frazee 245 (LR-BRT)	66,759	561	2,100	0.2	0.4	0.40	**166**
275	Lyon County 4N153 - Tracy 713	16,740	1,080	637	0.8	0.4	0.21	**176**
276	Lyon County 4N151 - Minnesota Valley 472	40,860	908	2,175	0.8	0.6	0.60	**150**
277	Bear Creek 210NB4 - Cromwell 18NB3 - Sandstone 4TM (EC-PAX, PD, DK,	819,228	12,076	14,830	1.6	3.0	1.78	**66**
278	Bear Creek 210NB3 - Pine City 4NB2 - Hinckley 1T (PA, EC-PAX, PD, HR, HC)	49,848	31,713	4,644	4.0	0.2	0.31	**107**
279	Granite City 5N40/5N105 - W. St. Cloud 5N43/4N51 - Sauk Rvr 5N101 (ST-		1		0.2			**238**
280	Blaine 23NB3 - Parkwood 12NB3 (SL, CO-SLX)	332,487	7,434	7,681	0.4	0.4	0.22	**122**
281	Blaine 23NB4 (CO-SLX, SP, CH, CHT)	29,617		857		0.4	0.05	**199**
284	Bird Island 4N337/4N426 - Panther 4N67/4N71	162,936	1,966	15,989	1.6	2.4	2.28	**90**
285	Faribault Energy Park 5S40/5S42 - West Faribault 5S6		34		0.4			**233**
288	Wing River 47L - Long Prairie 47L (47 line)	65,274		2,078		1.8	0.43	**152**
289	Long Lake 545F (OT, RT)	1,291,291	32,923	49,145	6.6	4.0	3.56	**24**
291	Eagle Valley 513F (TW-EBT)	25,568	752	978	0.4	1.2	0.23	**160**
292	Eagle Valley 517F (TW-IOT)	2,284	13,704	68	4.8	0.4	0.01	**156**
293	Verndale 519FM (TW-HET)	80,000	5,376	2,935	1.8	1.0	0.43	**121**
296	Mountain Lake 891 - Watonwan 4S346 (SC-SVT)	41,002	247	1,942	0.2	0.2	0.55	**177**
297	Fox Lake 736 - Watonwan 4S348 (SC-KLT,SC-ODT,SC-TRT,SC-SHT)	139,492	14,243	7,240	10.8	8.6	1.75	**63**
298	Heron Lake 839 - Elk 8380	175,174	496	8,535	0.4	0.8	0.98	**120**
300	Crow River 4M62 - Victor 208NB4/208NB6 (DS,DX)							**239**
301	Blind Lake 58NB1 - Mission 240NB3 (TL,CO,EC,CW-CCT,CW-COX)		12,096		1.2			**195**

Transmission Line Reliability Summary - All Lines by Line Key Number

Line Key Number	Line Description	Avg Cons. Min. Out	Avg Cons. Momentaries	Avg. Lost Energy kWh	Avg. Subst. Momentaries	Avg. Subst. Long Term	Avg Subst. Hours Out	Rank
	Average Value for Category:	**252,407**	**28,671**	**8,462**	**6.5**	**1.4**	**1.1**	
	Highest Value for Category:	**3,002,952**	**288,596**	**95,055**	**57.6**	**15.6**	**11.2**	
303	Mission 240NB1 - Riverton 25NB2 (RV,RVX)		3,558		0.2			**223**
308	Madelia 762 - Watonwan 4S347 (SC-SJT)		383		0.2			**236**
310	Crooked Lake 5M272/3TR - Parkwood 12WB2/12NB4 (PCX, PC)		5,934		0.4			**211**
311	Heron Lake 831 (SC-WST)	11,352	264	143	0.4	0.2	0.29	**197**
312	Elk River 14NB2 - Athens 204NB2/204NB3 (CO-ELX, CO-SP, SF)		11,710		0.8			**199**
313	Carver County 4M48		385		0.2			**235**
314	Soderville 7NB2 - Athens 204NB3/204NB4 (SC,CO-EBT)		4,566		0.4			**215**
315	Cambridge 2NB1 - Athens 204NB2/204NB4 (SC,IT,SCT)		8,496		0.6			**209**
316	Akeley 544F	568,509	8,799	14,014	0.8	1.0	0.87	**95**
318	Graceville 575 - Morris 3232 (AG-AJ, AG-AM)		670		0.4			**228**

II: Unit Cost Estimates

The equipment below has the following costs valued in 2008 dollars. These costs are estimates and may change depending on the availability of materials and specific circumstances of a facility.

Transmission Lines

kV	ACSR	Construction Type[1]	Right of Way Width (Feet)		Line Construction (Per Mile)	Right of Way and Construction (Per Mile)		
			Rural	Metro		Rural	Metro	Urban
69	336	SWP	100	70	$200,000	$315,000	$749,000	$1,219,000
	477	SWP	100	70	$210,000	$325,000	$759,000	$1,219,000
	795	SWP	100	70	$240,000	$355,000	$789,000	$1,259,000
115	336	SWP	100	80	$230,000	$358,000	$840,000	$1,363,000
	477	SWP	100	80	$240,000	$368,000	$850,000	$1,373,000
	795	SWP	100	80	$290,000	$418,000	$900,000	$1,423,000
	795	STP	100	80	$360,000	$488,000	$970,000	$1,493,000
161	795	SWP	100	90	$330,000	$471,000	$1,027,000	$1,576,000
	795	STP	100	90	$420,000	$561,000	$1,117,000	$1,666,000
	954	STP	100	90	$460,000	$601,000	$1,157,000	$1,706,000
	954	H	120	100	$310,000	$463,000	$1,042,000	$1,669,000
230	795	STP	110	110	$450,000	$623,000	$1,274,000	$1,979,000
	795	H	130	130	$390,000	$594,000	$1,365,000	$2,202,000
	954	STP	110	110	$500,000	$673,000	$1,324,000	$2,029,000
	954	H	130	130	$440,000	$644,000	$1,415,000	$2,252,000
345	2-795	STP	160	160	$650,000	$898,000	$1,840,000	$2,858,000
	2-795	H	160	160	$600,000	$848,000	$1,790,000	$2,808,000
	2-954	STP	160	160	$720,000	$968,000	$1,910,000	$2,928,000
	2-954	H	160	160	$660,000	$908,000	$1,850,000	$2,868,000
	2-1272	STP	160	160	$810,000	$1,058,000	$2,000,000	$3,018,000

Notes:: SWP – Single-wood pole H – Wooden H-frame STP – Single-shaft steel pole

All lines are single-circuit construction. Double-circuit construction is 1.5 times the cost of the circuit with the highest voltage and conductor. Deconstruction cost of existing lines is $35,000/mile. Add $50,000/mile to all lines being constructed through low lands (bogs, swamps, etc.).

GRE has a standard 4-wire construction for 69 kV lines that are used for lower voltages of 23 kV to 46 kV. If 3-wire construction is desired, the per mile cost reduction is $30,000 for 41.6 and 46 kV, $40,000 for 34.5 kV, and $50,000 for 23 kV. Costs of lines do not include distribution underbuild. A typical incremental cost for underbuild is $80,000/mile based on 4-wire, 3-phase, and 12.5 kV underbuild on a 69 kV transmission line.

Reconductoring ACSR to ACSS:

kV	Conductor	Cost/Mile
69	477	$80,000
115	795	$130,000

High Voltage Transmission Line Permitting

Certificate of Need and Routing Permit: $350,000

Transmission Substations

Transformers:

Non-LTC Transformers

kV	300 MVA Top Base	Multiplier/50 MVA
345/230	$5,344,000	20%
345/115	$4,415,000	20%
230/115	$4,183,000	20%
kV	30 MVA Top Base	Multiplier/30 MVA
115/46	$929,400	---
69/34.5	$698,000	---
69/12.5	$582,000	---

Example: 448 MVA, 345/115 kV Transformer

$4,415,000 * 1.2 ^ ((448-300)/50) = $7,573,700

LTC Transformers

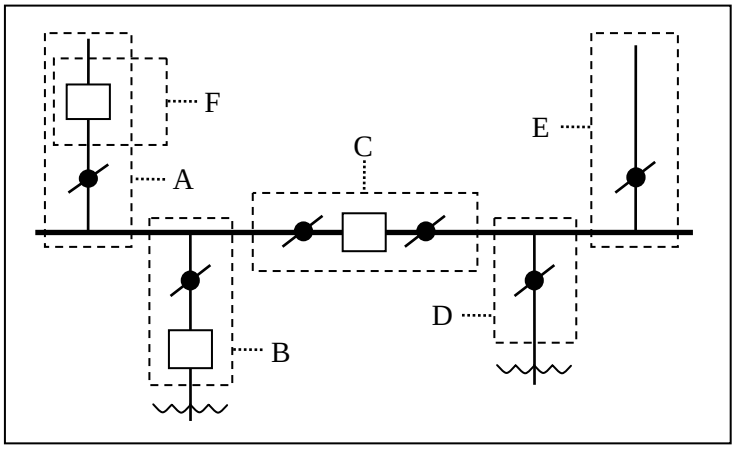
kV	30 MVA Top Base	Multiplier/30 MVA
230/115	$2,906,000	15%
230/69	$1,744,000	15%
115/69	$1,162,000	15%
115/34.5	$929,400	15%

Example: 180 MVA, 230/69 kV Transformer

$1,744,000 * 1.15 ^ ((180-30)/30) = $3,507,800

Circuit Breakers:

Figure IV-1



Modifications of Existing Substation (See Figure IV-1)**:**

	Figure & Facility	34.5-69 kV	115-161 kV	230 kV	345 kV
A	Breaker & deadend	$420,000	$500,000	$535,000	$820,000
B	Brkr & transf. pos.	$307,000	$354,000	$530,000	$815,000
C	Brkr in ring bus	$335,000	$383,000	$467,000	$692,000
D	Transf. Position (m.o. switch)	$254,000	$290,000	$298,000	$315,000
E	Deadend (m.o. switch)	$304,000	$410,000	$462,000	$495,000
F	Breaker Replacement	$215,000	$238,000	$329,000	$515,000
	Site development	$179,000	$189,000	$378,000	$756,000
	SCADA	$32,000	$32,000	$32,000	$32,000

Land Acquisition:

	34.5-69 kV (5 Acre)	115-161 kV (10 Acre)	230 kV (20 Acre)	345 kV (20 Acre)
Rural	$25,000	$50,000	$100,000	$100,000
Metro	$331,700	$663,400	$1,326,800	$1,326,800
Urban	$653,400	$1,306,800	$2,613,600	$2,613,600

Capacitors:

	Voltage	
	69 kV	115 kV
$/MVAR bank	$4,000	$2,000
Capacitor switching (Bkr)	$215,000	$238,000

Line Airbreak Switches (3-way):

Type	**Voltage**	
	69 kV	115 kV
Manual	$100,000	$165,000
Motor-operated	$135,000	$200,000

230 kV one-way motor-operated switch: $62,000

Distribution Substations:

MVA	Voltage			
	69/12 kV[1]	69/24 kV[2]	115/12 kV[1]	115/24 kV[2]
2.5/3.5	$610,000	$610,000	$670,000	$670,000
5.0/7.0	$750,000	$770,000	$905,000	$925,000
7.5/10.5	$940,000	$940,000	$1,090,000	$1,110,000
15.0/28.0	$1,450,000	$1,470,000	$1,625,000	$1,645,000

Notes: 1: 12 kV bus is low profile. Conversion to 25 kV not possible unless conventional design is used.

2: 24 kV bus is conventional design (not low profile).

- Three-phase reclosers are included with transformers 7.5/10.5 MVA and larger.
- All costs above assume a four-circuit station with four sets of reclosers.
- Add $7500/MVA for a dual-voltage transformer. Station only uses one distribution voltage.
- Distribution stations at 34.5 kV and 46 kV assumed to cost the same as a 69 kV substation.

Dual-Voltage Substations:

Contact GRE for cost estimates if 12 kV and 24 kV are required simultaneously from a substation.

Metal-Enclosed Substations:

Contact GRE for cost estimates.

Distribution Substation Voltage Conversions:

Each substation cost should be based on available space although a basic conversion cost is as follows:

MVA	To 69 kV	To 115 kV
<15	$300,000	$350,000
>15	$600,000	$650,000

III: MW-Mile Analysis

MW-mile is a planning tool used to determine when additional facilities may be needed to establish reliability and system support to GRE customers. This tool contains two forms of MW-mile analysis which consist of radial line exposure and looped exposure between circuit breakers. Guidelines have been established to determine when facilities will need to be examined for each of these scenarios; however, action may not be initiated if system performance is reliable.

Radial MW-Mile Analysis

This analysis involves radial fed loads on the GRE system. MW-mile calculations are used to determine when radial fed substations may be qualified to receive looped service. Criteria for such examination are when the summation of the flow across each radial line segment times the mileage of the respective segment is greater than 100 MW-mile. If the line exceeds 100 MW-mile using the 2011 peaks, further investigation of other factors will be examined before a looped system is needed. Other factors include:

- The reliability of the radials
- The cost of looping the system
- Effects of the loop on the system power flow
- Future needs in the area
- Backfeeding capability of the distribution system

Table III-1 lists the radial line facilities that have been identified as possible looping candidates.

TABLE III-1

RADIAL LINES WHICH EXCEED 100 MW-MILE

Substations	MW-Mile	
	Summer	Winter
Schroeder, Lutsen, Maple Hill, Colvill 69 kV	435.6	766.1
Wirt, Evenson, Big Fork, Jessie Lake 69 kV	332.1	579.5
Osage, Pinepoint 34.5 kV	229.5	263.3
Palisade, Round Lake, Wright, Big Sandy 69 kV	193.3	316.1
Lake Eunice, MPC Erie 41.6 kV	121.4	150.6
Lawndale, Corcoran 69 kV	111.6	71.3
Sturgeon Lake, Moose Lake Municipal 69 kV	107.4	125.2
Goose Lake 69 kV	99.4	116.5
Bass Lake, Stonybrook 69 kV	97.6	102.4

Breaker MW-Mile Analysis

This analysis involves looped transmission system between circuit breakers. MW-mile calculations are used to determine when line exposure between two circuit breakers affect the load being served by the respective line, which may lead to additions of sectionalizing equipment to limit the load outage. Sectionalizing will consist of new circuit breakers, motor-operated switches, or normally open switches on the system. Timing of system restoration is also a factor. Circuit breakers can return a load almost instantaneously; whereas, switching operations will take a few minutes with motor-operated switches and possibly a few hours to open or close manual switches in limited access areas.

MW-mile calculations are based on the product of the total load of the line between the circuit breakers and the total line mileage of the same line between the same circuit breakers. The magnitude of the breaker MW-mile analysis gives some indication of the system reliability between circuit breakers. The larger the number, the more the load or line conductor is at risk to faults. Criteria for this type of analysis have the following guidelines:

- MW-mile magnitudes of less than 1000 are typical and are acceptable.
- MW-mile magnitudes between 1000 and 2000 are higher than usual. If records indicate poor reliability, then corrective action should be investigated.
- MW-mile magnitudes higher than 2000 indicate a high amount of exposure and risk to the system. Corrective action should be investigated.

Table III-2 lists the facilities that significantly exceed a magnitude of 1000 using the 2011 substation summer or winter peak loads.

TABLE III-2
LINE SEGMENTS BETWEEN CIRCUIT BREAKERS
WHICH EXCEED 1000 MW-MILE

Description	Circuit Miles	2011 Load	MW-Mile
Scott County-New Prague-Carver County 69 kV	50.6	60	3036
Panther-Litchfield-Big Swan	78.0	35.9	2803
Maple Lake-Watkins-Wakefield 69 kV	53.6	42.9	2298
Pipestone-Tracy 69 kV	86.1	26.5	2282
Spring Creek-West Hastings-Cannon Falls 69 kV	44.6	48.2	2153
Elk River-Waco-Princeton 69 kV	33.0	59.3	1957
Northfield-Faribault-West Faribault 69 kV	38.1	50.7	1932
Elk River-Bunker Lake 69 kV	20.8	82.5	1713
Wilmarth-Cleveland-Waterville 69 kV	45.2	37.5	1696
Blind Lake-Deer River 69 kV	83.3	20	1663
Scott County-Blackdog 115 kV	21.5	72.5	1561
Shannon-Potlatch 69 kV	62.1	24.7	1534
Taconite Harbor-Colvill 69 kV	51.7	29	1500
Milaca-Benton County 69 kV	59.3	24.8	1472

Description	Circuit Miles	2011 Load	MW-Mile
Cromwell-Bear Creek 69 kV	54.3	25.2	1371
Benton County-Liberty 69 kV	36.3	36.3	1319
Arlington-Le Seuer-Traverse 69 kV	38.8	33.4	1298
Crow River-Medina-Corcoran 69 kV	32.8	38.2	1252
Glendale-Lake Marion 69 kV	26.0	45.7	1187
Franklin-Fort Ridgely-New Ulm 69 kV	49.7	23.7	1178
Deer River-Blackberry 69 kV	47.8	24.6	1175
Deer River-Evenson-Big Fork 69 kV	62.1	18.4	1140
Elk River-Athens 69 kV	26.0	40.4	1052
Wakefield-Paynesville-Albany 69 kV	46.2	22.6	1043
Cromwell-Gowan 69 kV	56.1	18.1	1012

IV: Economic Conductor Analysis

Performing an Economic Conductor Analysis is the basis for determining the optimum conductor size for new or rebuilt transmission lines. This analysis considers the cost of the line construction and the line losses based on the conductor current flow. A larger conductor requires a greater construction cost; however has a less cost factor for losses than a smaller conductor. In some cases, line loss savings can offset the cost of the construction by the installation of a larger conductor.

This analysis uses the financial factors established in Section III (Design Criteria). A load growth of 3.0 percent was used for the first ten years of the lines life; thereafter, a constant load was used. This was done to give a conservative result and it takes into account that new facilities on the system will help to reduce existing power flow.

The results of the study are presented using the following graphs. These graphs are useful in identifying the type of conductor to use during system intact conditions, based on expected initial line loading. However, line conductor should also be considered during system contingencies when power flow may exceed the economic conductor line rating. Other factors that need to be considered before selecting the actual conductor are:

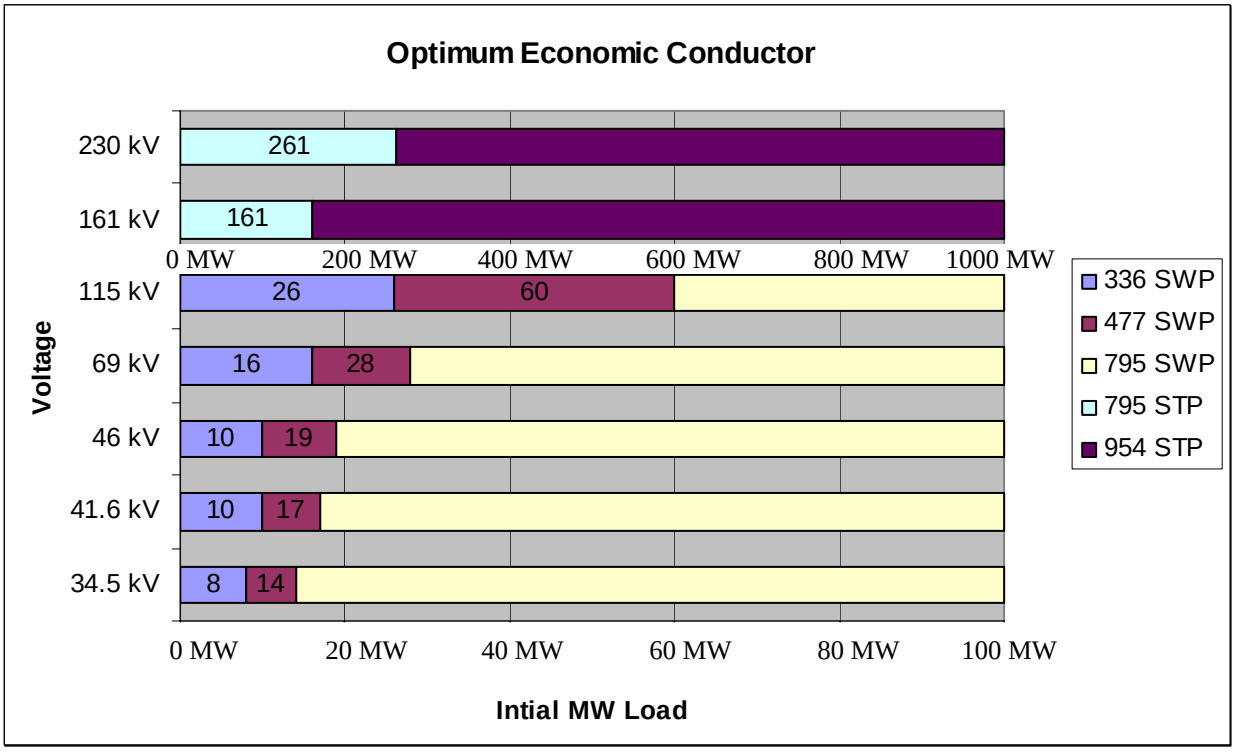
- Unanticipated load
- New facilities on the system
- Construction cost changes
- Corona levels
- Voltage drop

New Line Construction

An economic conductor analysis was performed on all of the new lines that are being installed in this Long-Range Transmission Plan. The conductor size was also determined by the load growth in the area and power flows across the line during contingencies. The optimum economic conductor for line rebuilds was found to have the same result as the new line rebuilds. Figure IV-1 identifies the economic conductor with the initial line loading.

FIGURE IV-1

OPTIMUM ECONOMIC CONDUCTOR SIZE FOR NEW LINES



V: System Study Maps

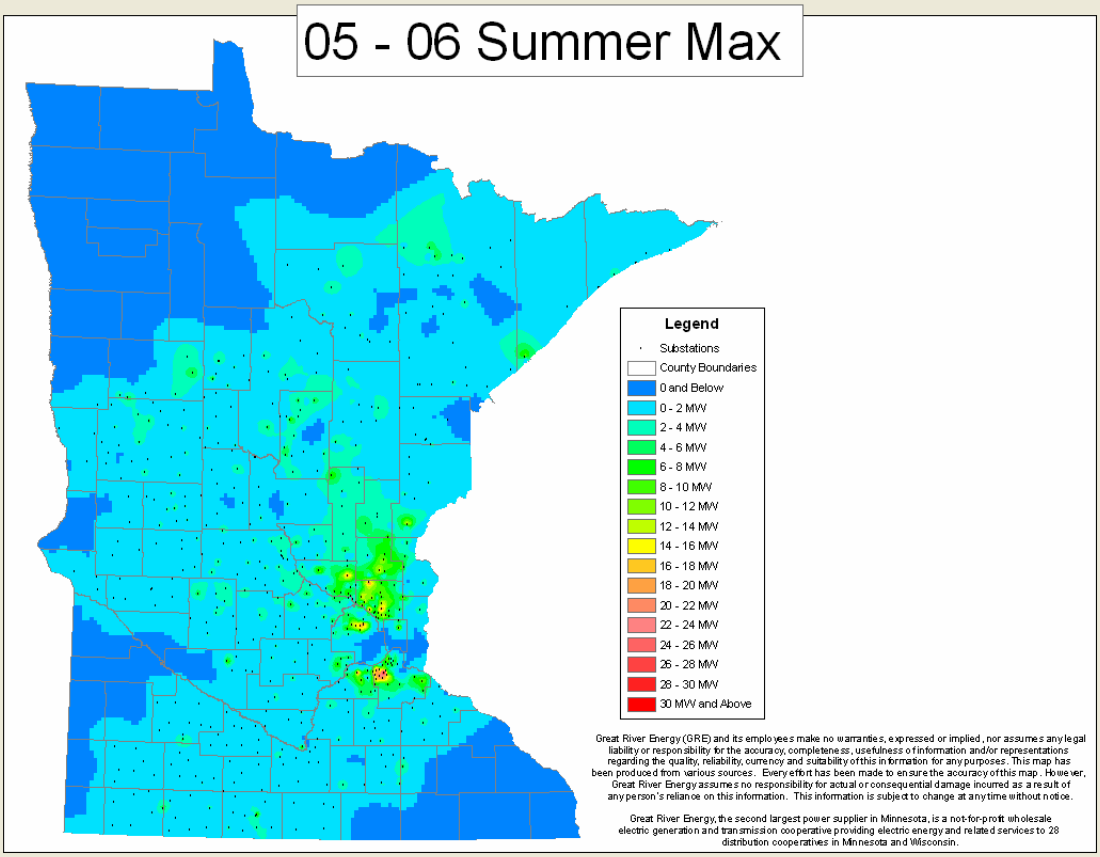
Through the LRP process, GRE engineers created maps to assist in defining load levels across the state of Minnesota as projected by the Member System engineers. The load projections are estimated based on the historical growth, projected growth, present economic conditions and in some cases engineering judgement based on land use practices. GRE has created multiple contour maps showing these load forecast and the projected growth as provided within this appendix.

The LRP proposed transmission projects map and a line age map are also provided within the pocket. The maps are provided in the following order

A. Historical Load Maps (V-2 to V-4)
- 2005 or 2006 Historical Summer Peak Load
- 2005-6 or 2006-7 Historical Winter Peak Load
- 2002 through 2006 Summer Growth Rate
- 2002 through 2006 Winter Growth Rate
- Annualized 2002-6 Summer Growth Rate
- Annualized 2002-6 Winter Growth Rate

B. Projected Load Maps (V-5 to V-10)
- 2011 Summer Peak
- 2011 Winter Peak
- 2021 Summer Peak
- 2021 Winter Peak
- 2031 Summer Peak
- 2031 Winter Peak
- 5 Year Summer Growth Rate
- 5 Year Winter Growth Rate
- 15 Year Summer Growth Rate
- 15 Year Winter Growth Rate
- 25 Year Summer Growth Rate
- 25 Year Winter Growth Rate

C. Transmission System Maps (Pocket)
- GRE Proposed Transmission Map
- GRE Transmission Line Age Map


05 - 06 Summer Max
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
14 - 16 MW
16 - 18 MW
18 - 20 MW
20 - 22 MW
22 - 24 MW
24 - 26 MW
26 - 28 MW
28 - 30 MW
30 MW and Above
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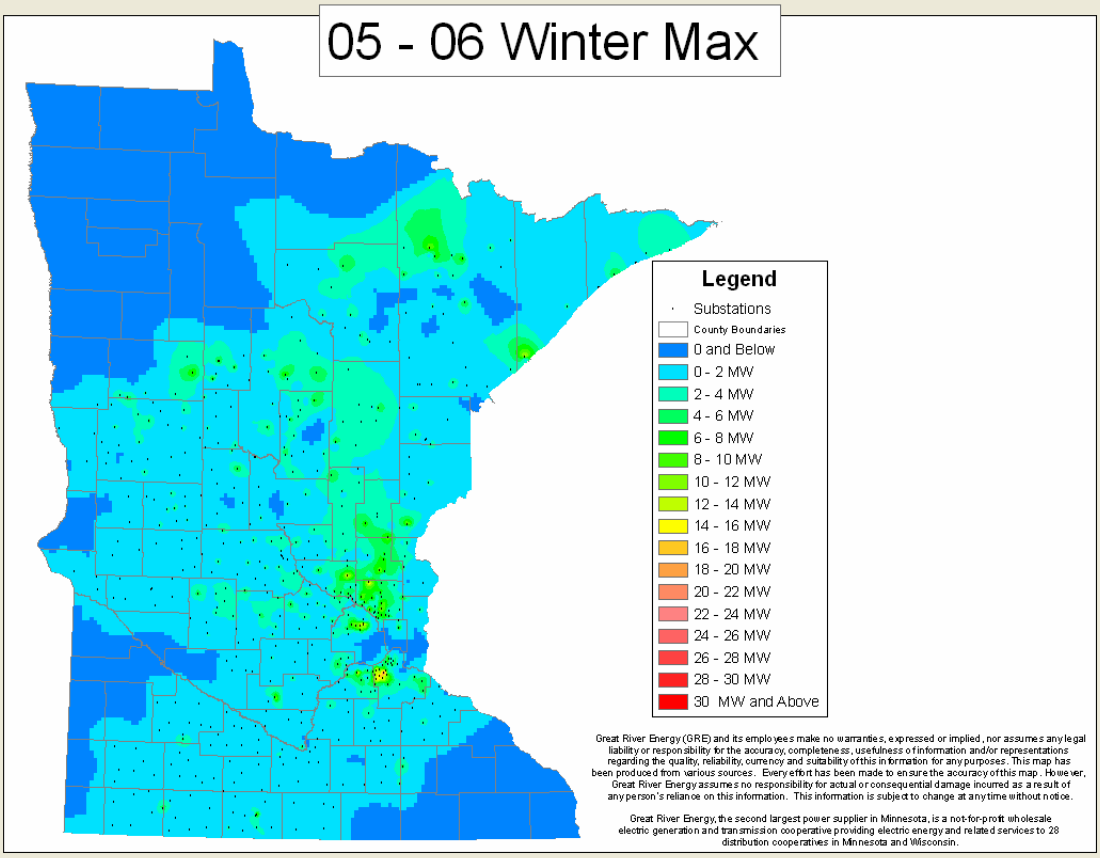
05 - 06 Winter Max
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
14 - 16 MW
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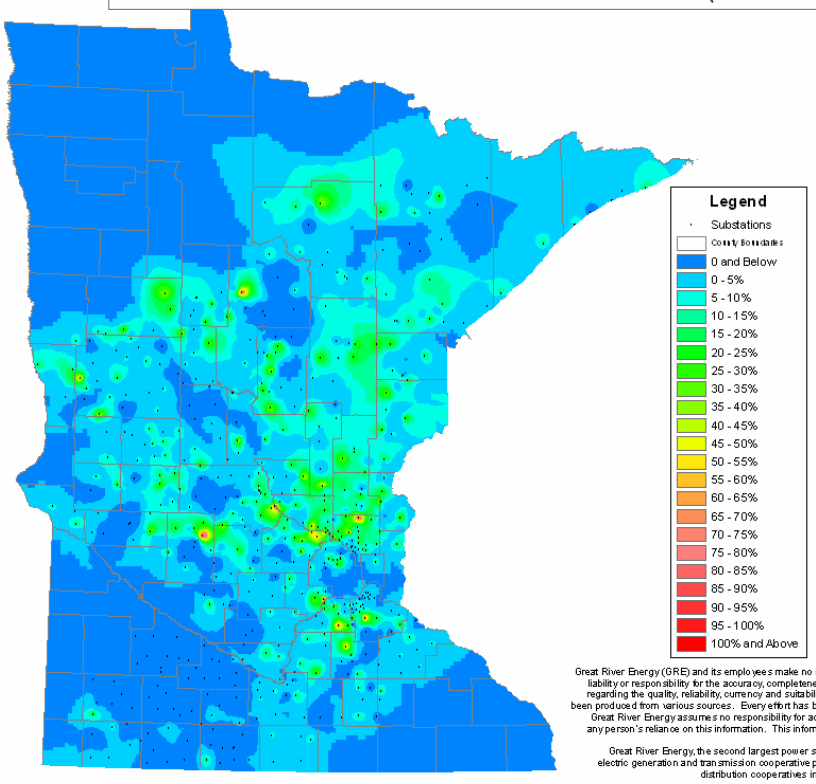
Historical Summer Growth Rates (2002 - 2006)



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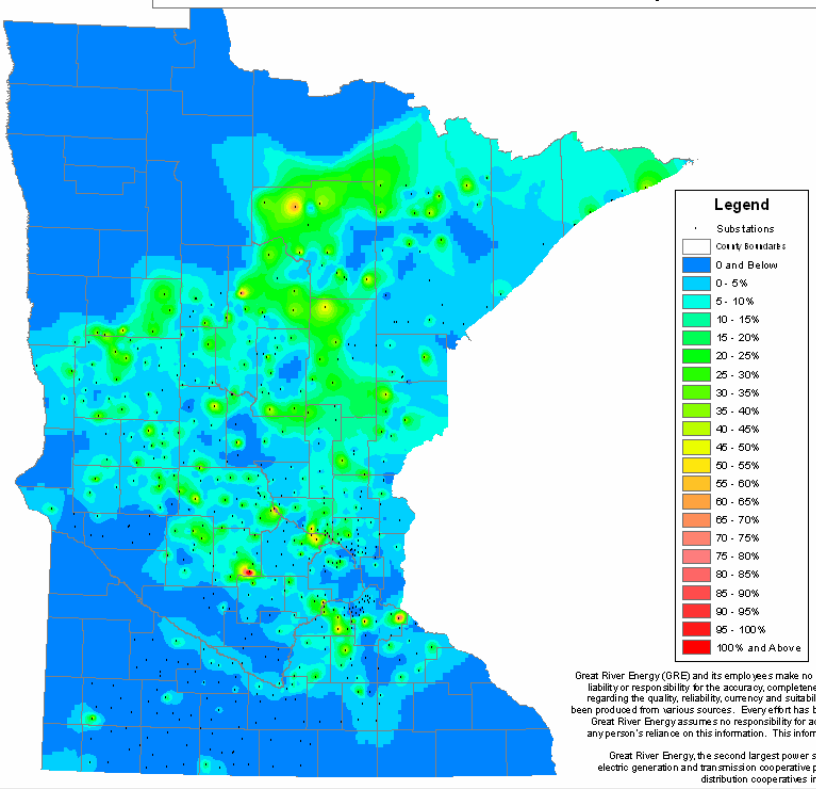
Historical Winter Growth Map 2002 - 2006



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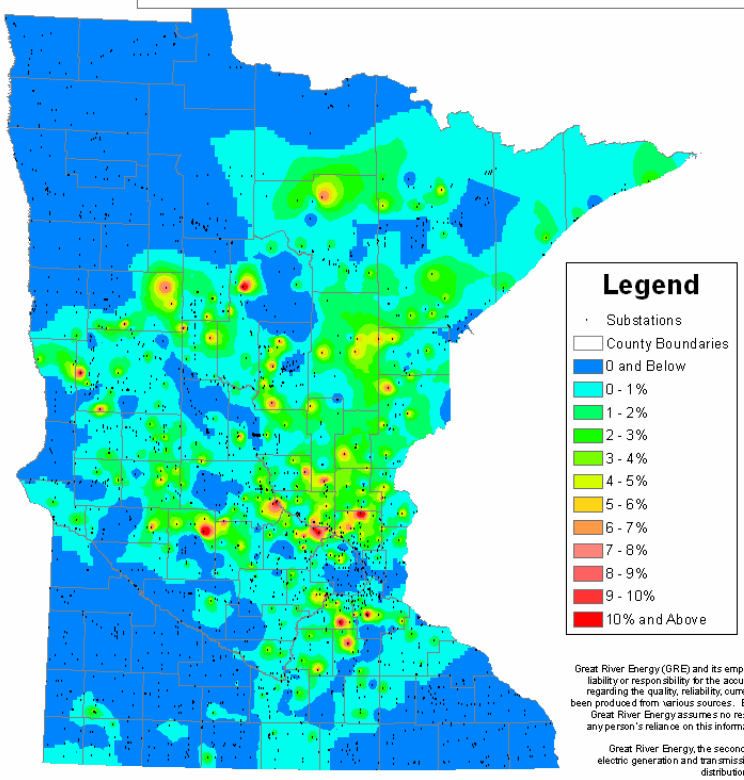
Historical Summer Annual Growth



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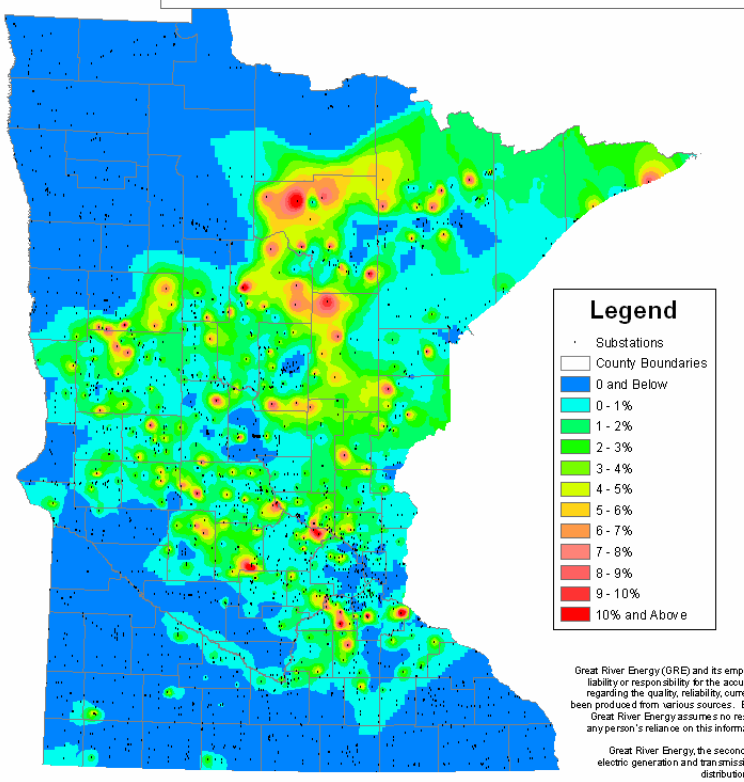
Historical Winter Annual Growth



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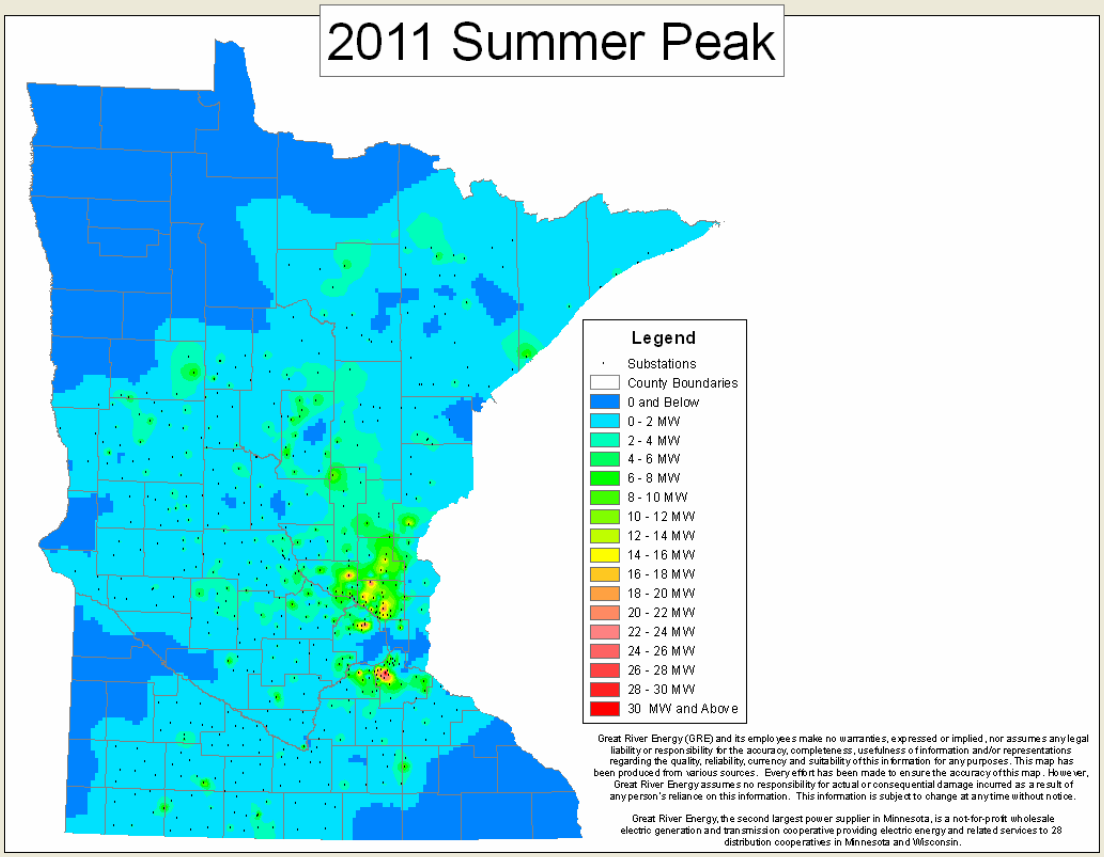
2011 Summer Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
14 - 16 MW
16 - 18 MW
18 - 20 MW
20 - 22 MW
22 - 24 MW
24 - 26 MW
26 - 28 MW
28 - 30 MW
30 MW and Above
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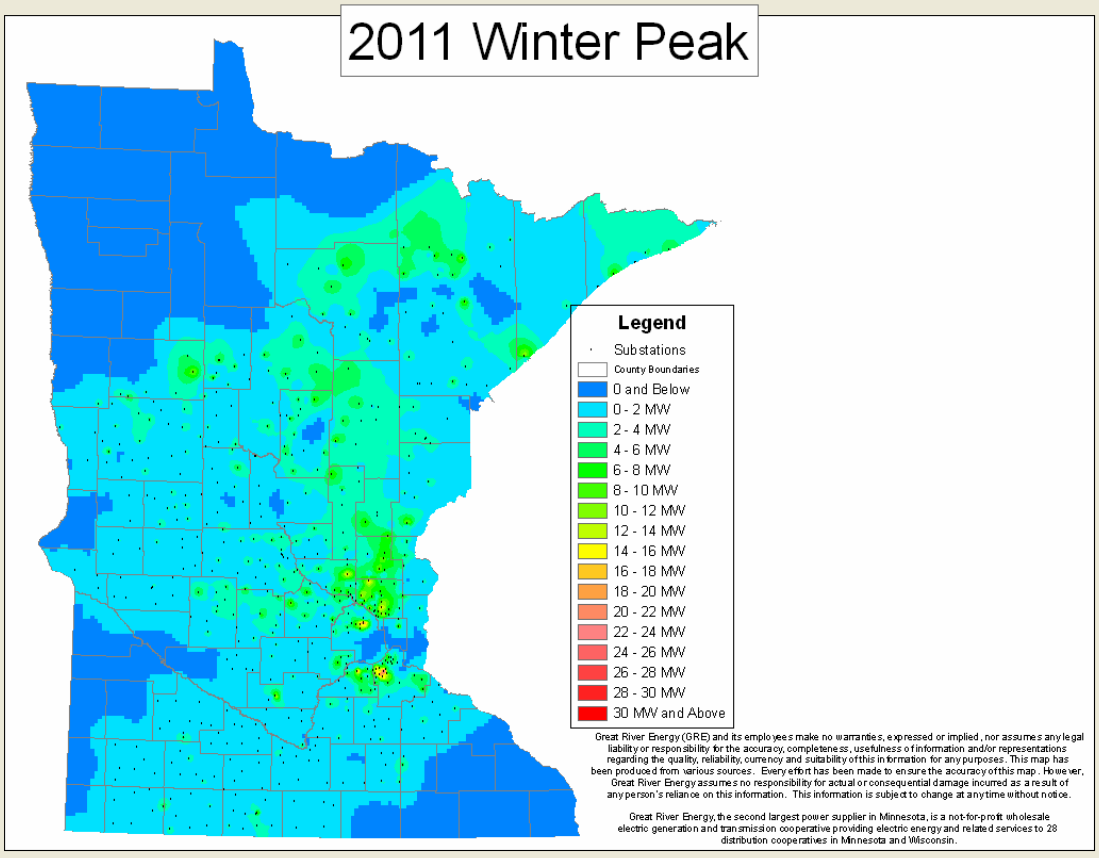
2011 Winter Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
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28 - 30 MW
30 MW and Above
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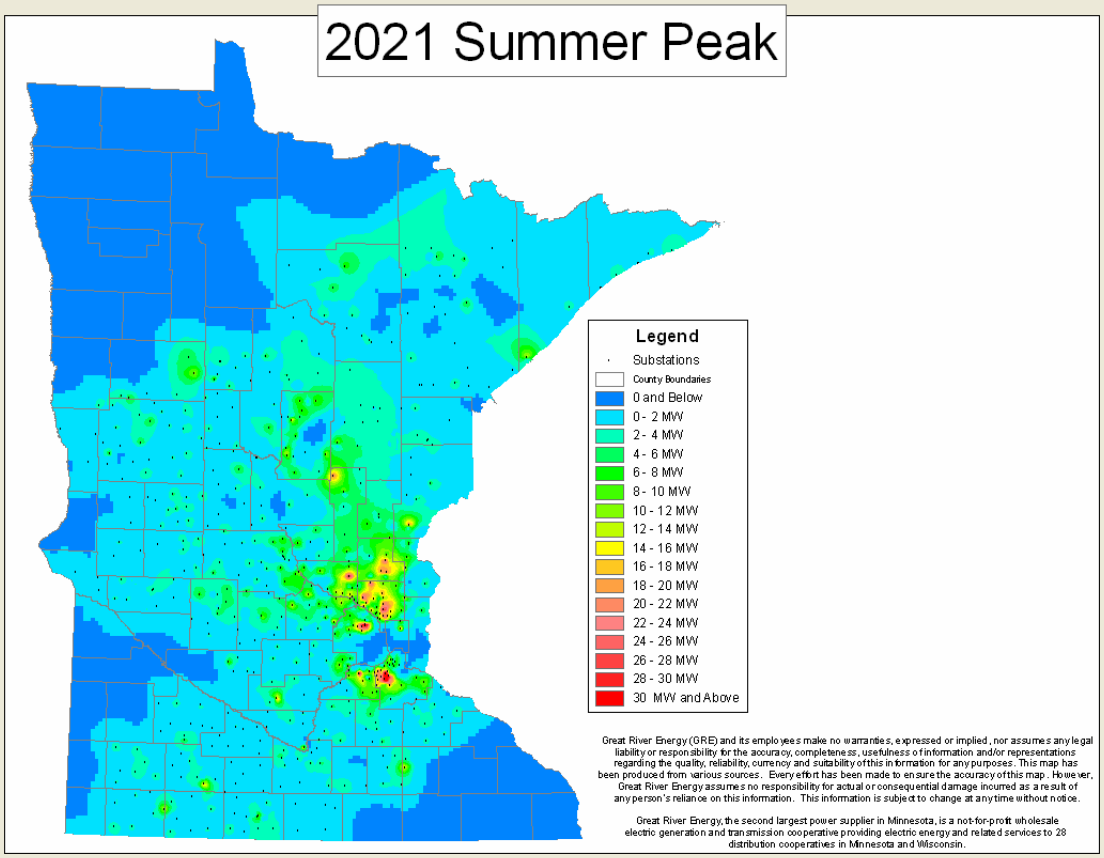
2021 Summer Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
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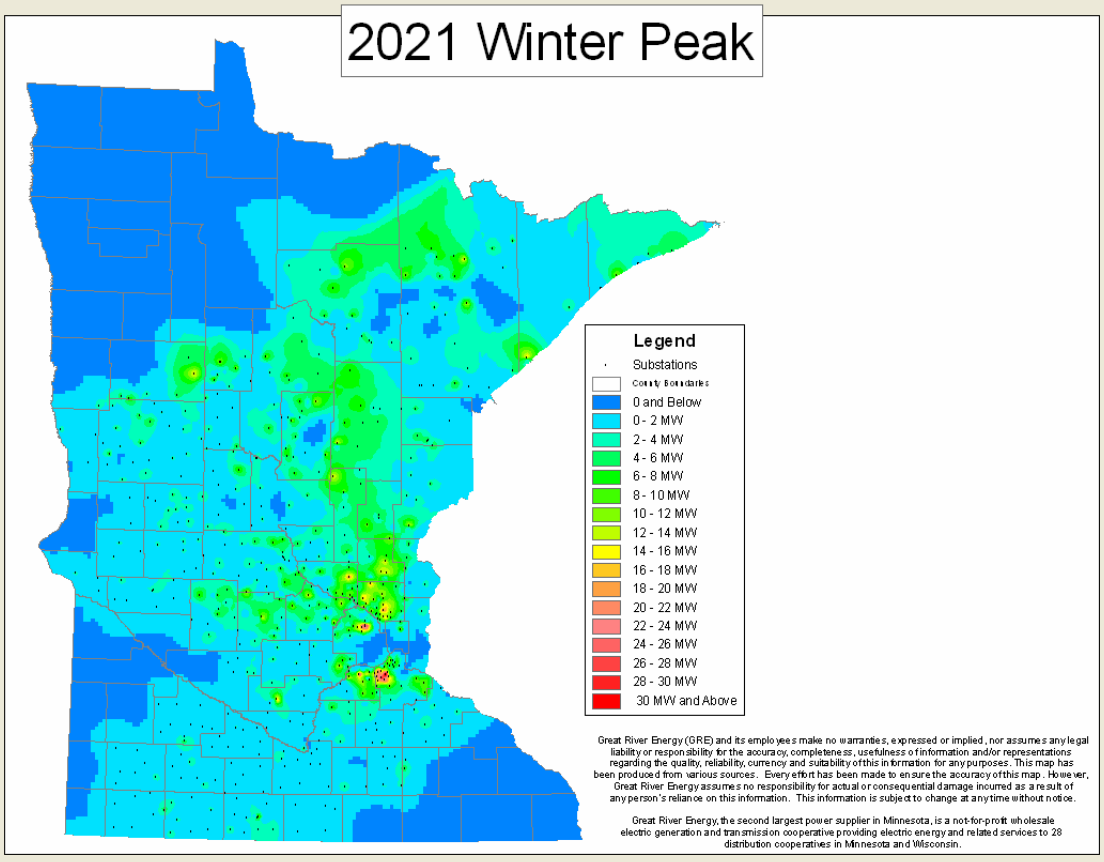
2021 Winter Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
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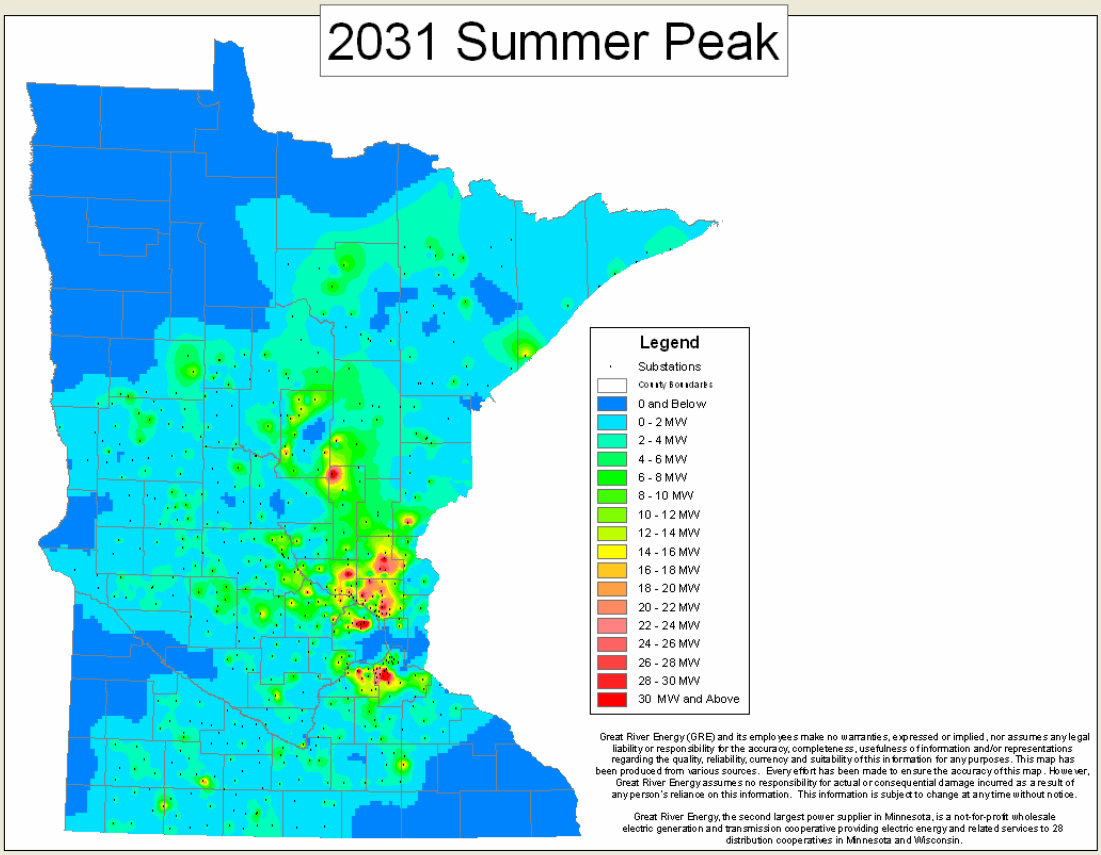
2031 Summer Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8 - 10 MW
10 - 12 MW
12 - 14 MW
14 - 16 MW
16 - 18 MW
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20 - 22 MW
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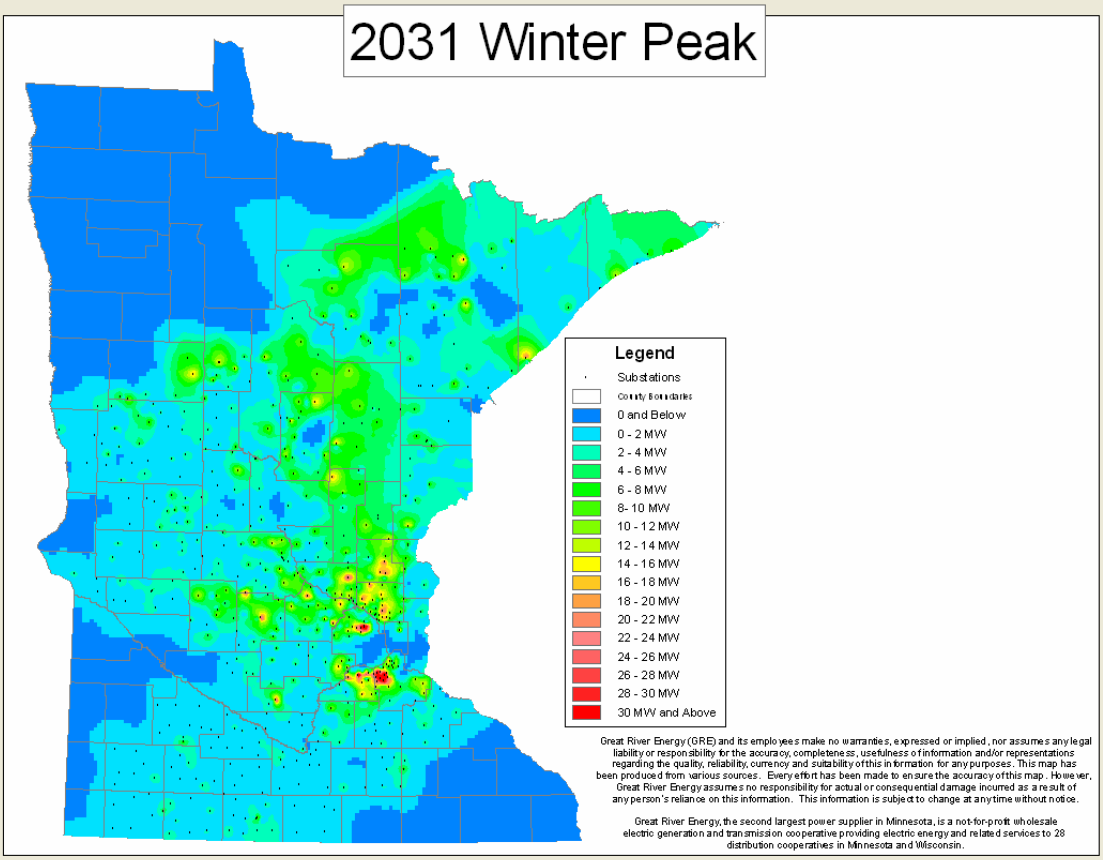
2031 Winter Peak
Legend
Substations
County Boundaries
0 and Below
0 - 2 MW
2 - 4 MW
4 - 6 MW
6 - 8 MW
8- 10 MW
10 - 12 MW
12 - 14 MW
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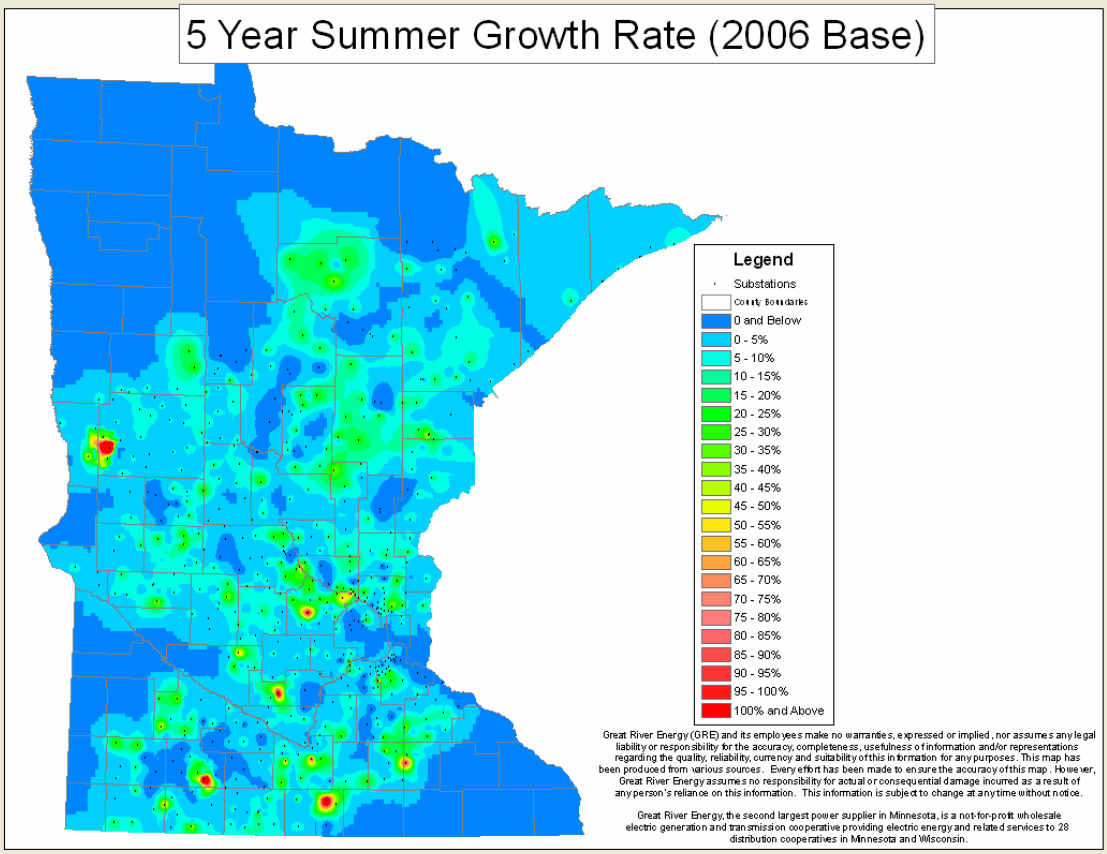
5 Year Summer Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Below
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
45 - 50%
50 - 55%
55 - 60%
60 - 65%
65 - 70%
70 - 75%
75 - 80%
80 - 85%
85 - 90%
90 - 95%
95 - 100%
100% and Above
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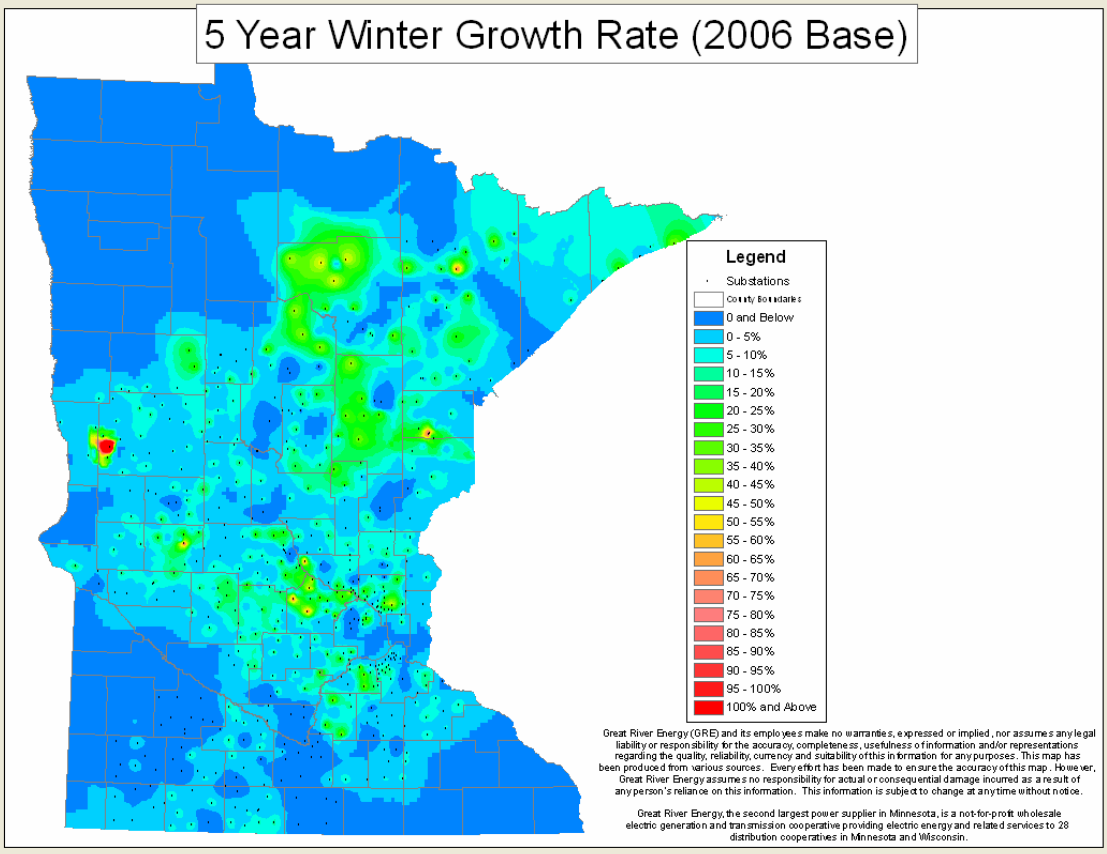
5 Year Winter Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Below
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
45 - 50%
50 - 55%
55 - 60%
60 - 65%
65 - 70%
70 - 75%
75 - 80%
80 - 85%
85 - 90%
90 - 95%
95 - 100%
100% and Above
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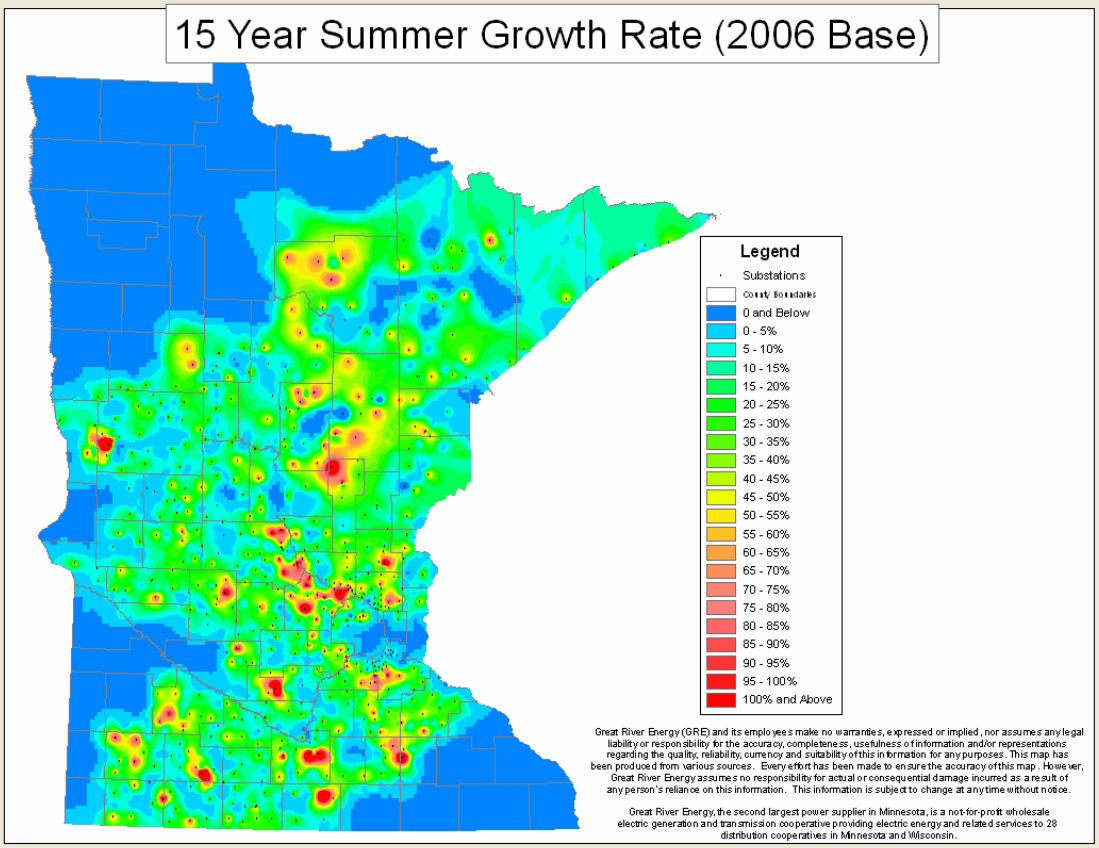
15 Year Summer Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Below
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
45 - 50%
50 - 55%
55 - 60%
60 - 65%
65 - 70%
70 - 75%
75 - 80%
80 - 85%
85 - 90%
90 - 95%
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100% and Above
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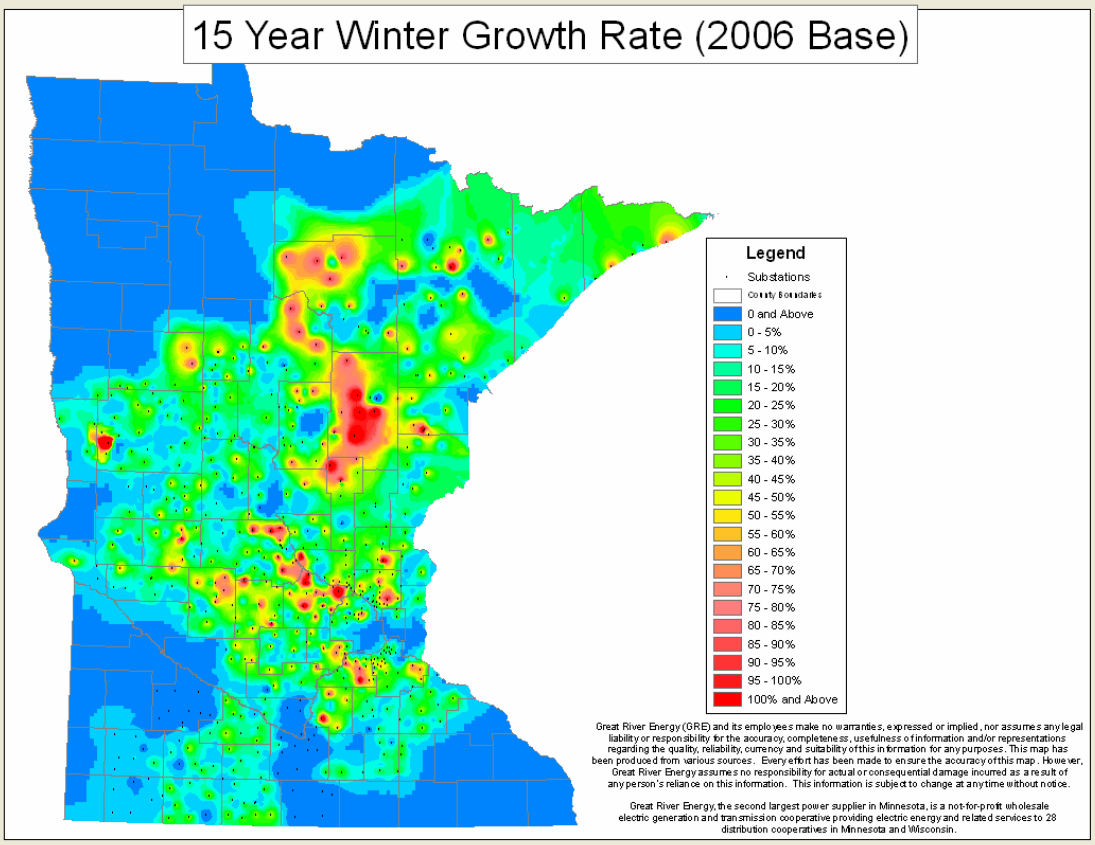
15 Year Winter Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Above
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
45 - 50%
50 - 55%
55 - 60%
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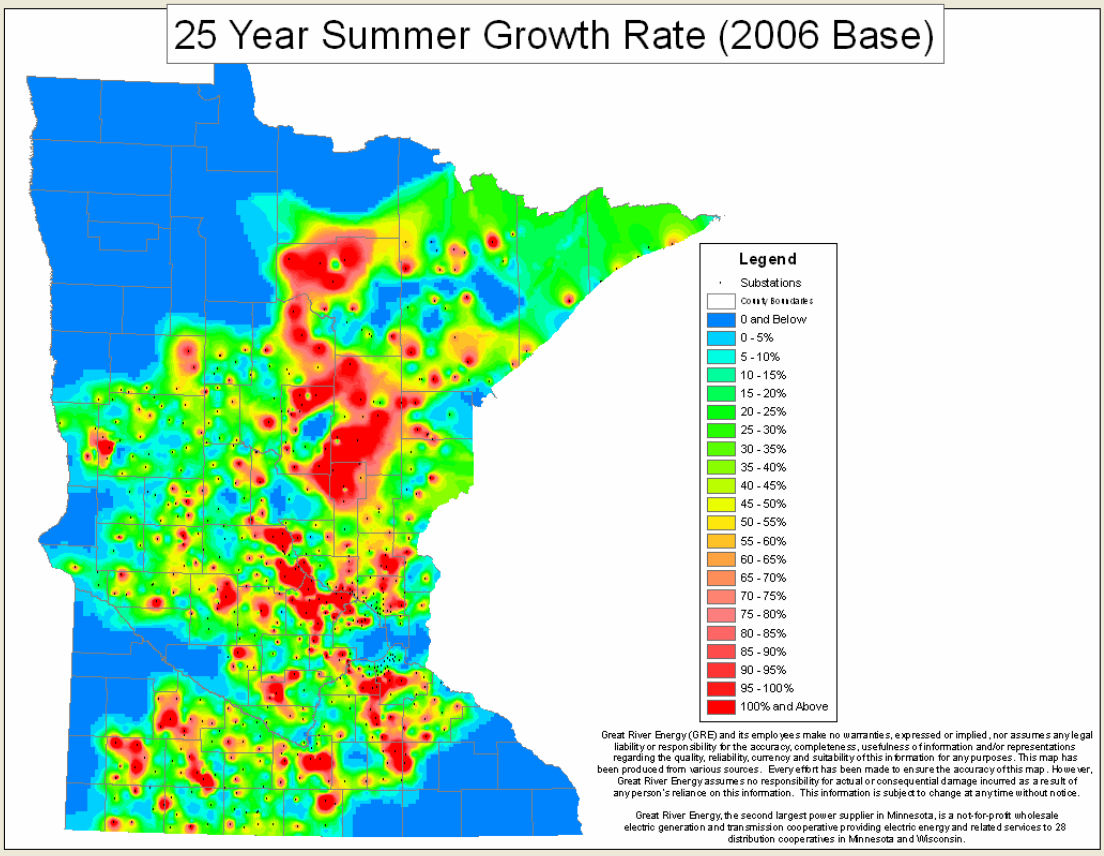
25 Year Summer Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Below
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
45 - 50%
50 - 55%
55 - 60%
60 - 65%
65 - 70%
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85 - 90%
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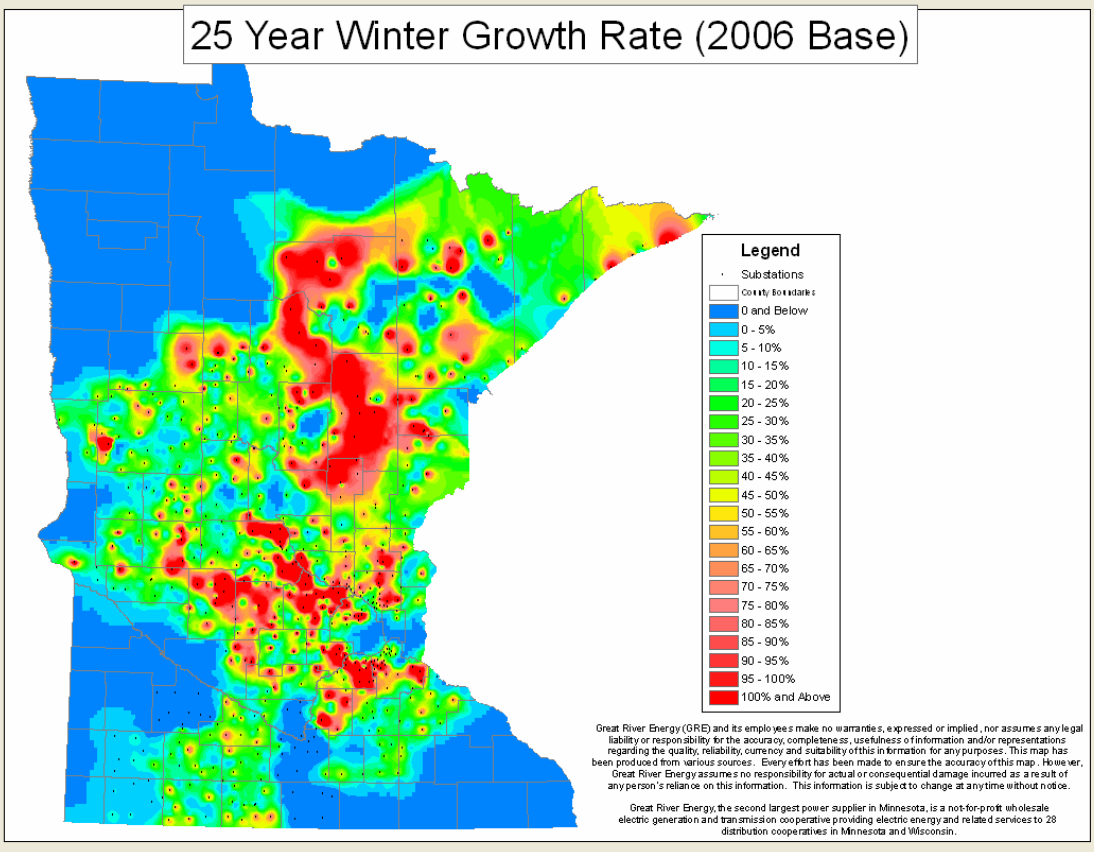
25 Year Winter Growth Rate (2006 Base)
Legend
Substations
County Boundaries
0 and Below
0 - 5%
5 - 10%
10 - 15%
15 - 20%
20 - 25%
25 - 30%
30 - 35%
35 - 40%
40 - 45%
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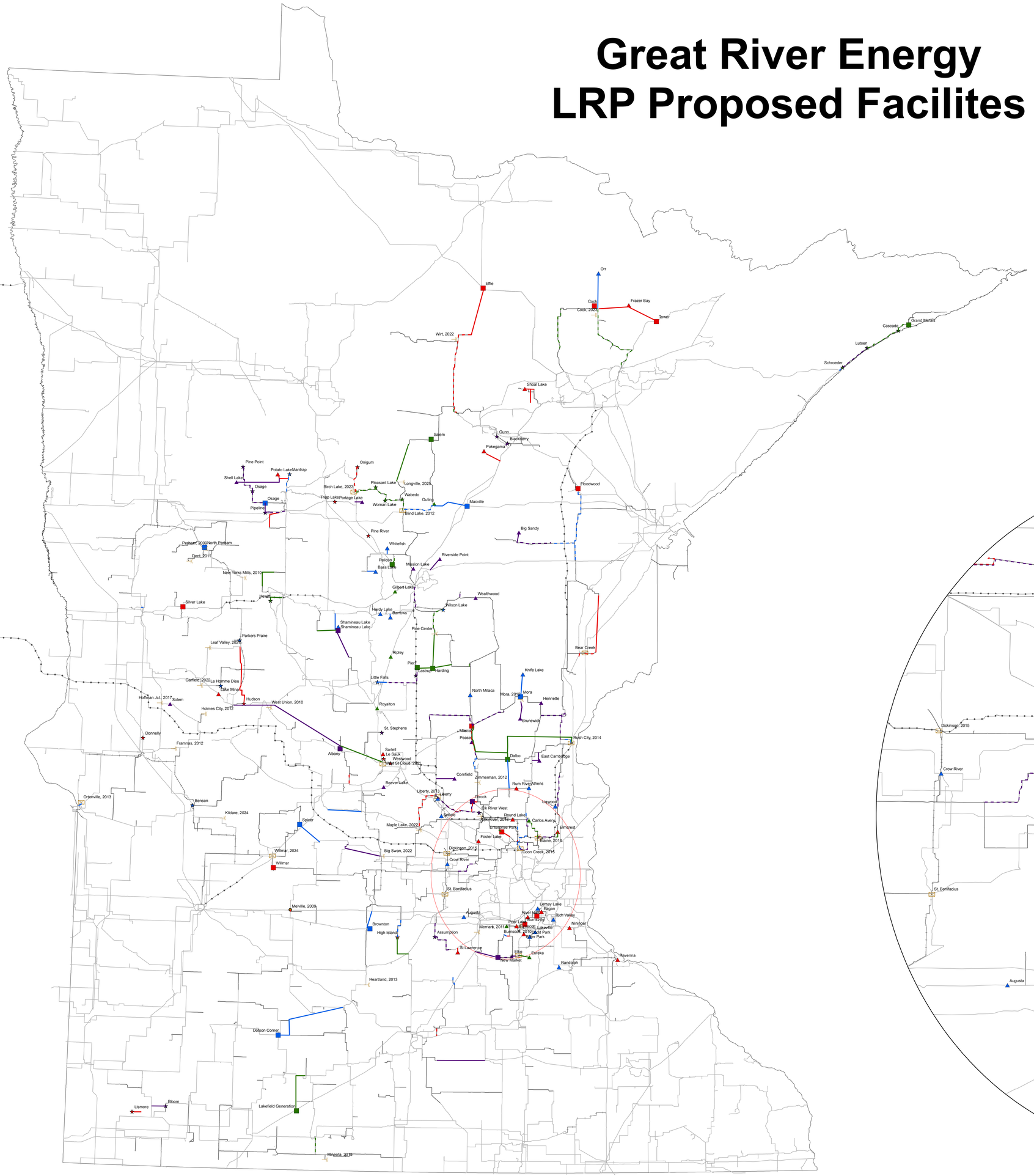
Great River Energy
LRP Proposed Facilites

Legend

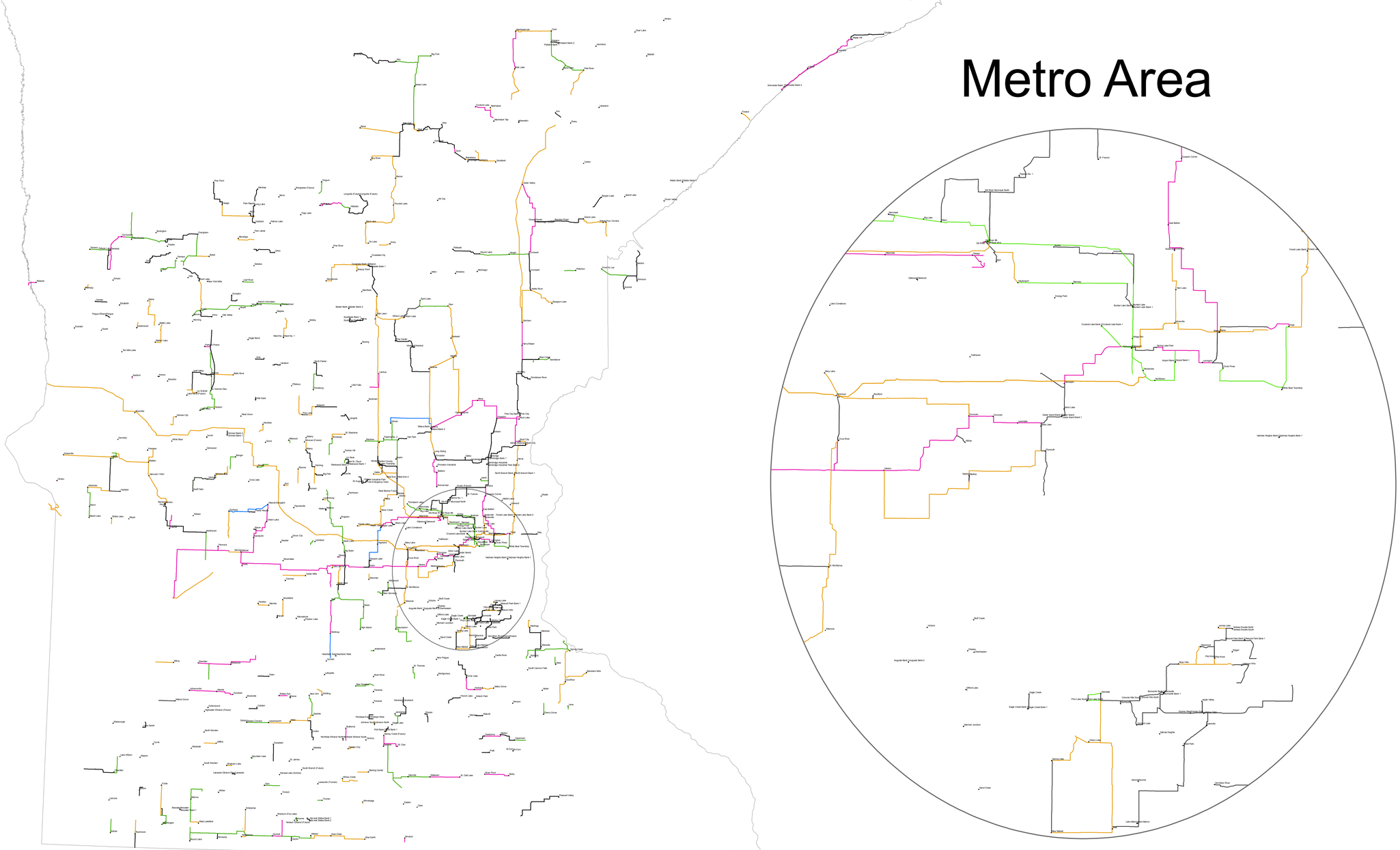
- Capacitor
- Breaker
- Transformer
- Bulk Substation 2008 - 2011
- Bulk Substation 2012 - 2014
- Bulk Substation 2015 - 2019
- Bulk Substation 2020 - Beyond
- Distribution Substation 2008 - 2011
- Distribution Substation 2012 - 2014
- Distribution Substation 2015 - 2019
- Distribution Substation 2020 and Beyond
- Distribution Substations Conversions 2008 - 2011
- Distribution Substations Conversions 2012 - 2014
- Distribution Substations Conversions 2015 - 2019
- Distribution Substations Conversions 2020 and Beyond
- Future Line 2008 - 2011
- Future Line 2012 - 2014
- Future Line 2015 - 2019
- Future Line 2020 - Beyond
- Line Rebuild 2008 - 2011
- Line Rebuild 2012 - 2014
- Line Rebuild 2015 - 2019
- Line Rebuild 2020 - Beyond
- Foreign Transmission Lines
- GRE Transmission 69kV and Below
- GRE Transmission 115kV to 161kV
- GRE Transmission 230kV and Above
- Metro Area
- MN County Boundary

Metro Area



GRE Long Range Plan

Age of Transmission Lines



Metro Area

Decade of In-Service

- 1940
- 1950
- 1960
- 1970
- 1980 and Newer
- GRE Substations