REVISED March 2011

Appendix E:
Transmission Studies Summary Report

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CapX2020

Hampton – Rochester – La Crosse 345 kV Project

Technical Studies Summary Report

Xcel Energy / Dairyland Power Cooperative / Rochester Public Utilities

March 2011

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1. Introduction

The electric load in the Rochester, Minnesota and La Crosse, Wisconsin areas have grown over the past decade to the point of approaching the maximum capacity of the existing transmission systems. These systems are comprised of sub-230 kV voltage classes not generally used for bulk delivery of the amount of power now needed to serve the current load levels. The 161 kV lines and 69 kV lines serving those areas are reaching the end of their ability to function as those areas' backbone. Planning engineers evaluated the need for system upgrades and determined that a higher voltage option was needed to reliably serve these areas for many years into the future.

This report summarizes and describes the engineering analyses undertaken to assess electrical system needs in the La Crosse/Winona and Rochester, Minnesota areas and to analyze options to address the identified needs. Various options were considered: (1) alternative lower voltage and higher voltage transmission lines; (2) a "do-nothing" alternative; (3) generation alternatives; and (4) the proposed 345 kV Project. Per the recommendations of the ad hoc study group, this analysis was undertaken without making any assumptions as to the specific route the facility would follow, including whether a route might afford opportunities to co-locate the new transmission lines with existing facilities. Further analysis relating to the impact of routing options on system performance will be examined in the Wisconsin Certificate of Public Convenience and Necessity (CPCN) and Minnesota Route Permit processes.

The recommended alternative is a 345 kilovolt (kV) line project between Hampton, Minnesota (southeast of the Twin Cities) and La Crosse, Wisconsin. The proposed CapX2020 Hampton – Rochester – La Crosse 345 kV line and two associated Rochester area 161 kV lines will hereafter be referred to as the Project or the 345 kV Project.

The Project is the preferred alternative because it best addresses three needs: First, the Project will be a critical component, along with the other CapX 2020 projects, necessary to strengthen the transmission network to meet several thousand megawatts (MW) of additional demand for electrical power anticipated in Minnesota, Wisconsin and parts of surrounding states by 2020. Second, the Project will address the need for additional transmission facilities to provide reliable service to the growing communities in the Rochester and Winona/La Crosse areas. Third, the line will support generation development by providing foundation bulk transmission facilities across the Minnesota/Wisconsin border to enable future power transfers between Minnesota and Wisconsin.

2. Area Study History

In the early to mid-2000s both RPU and DPC were identifying emerging load serving needs in their respective service territories, generally the Rochester and La Crosse/Winona areas. Each utility identified 161 kV alternatives that would address these needs for a period of time. Subsequently, RPU and DPC led a study team which also included planning engineers from Xcel Energy, SMMPA, American Transmission Company (ATC), Alliant Energy and Great River Energy to investigate whether a more regional solution would be appropriate. This study effort resulted in a recommendation for 345 kV and 161 kV facilities.

Around the same time as the regional study effort, the CapX2020 initiate began to develop a long-term transmission plan to ensure that load in Minnesota and portions of surrounding states region could be served reliably through the year 2020. The 345 kV project described in this report was identified by the CapX2020 utilities as one of the recommended 345 kV lines to serve future growth. The CapX2020 group of 11 utilities undertook a high level vision study and identified a need for significant 345 kV additions to the regional transmission system to meet growing customer demands, including 345 kV connections between Minnesota and Wisconsin. [1]

The analyses described in this report began in 2009 and include evaluations of actual substation load data through 2009 and forecast data through 2020. This data is included in **Appendices 1** and **2**. The study was led by Xcel Energy, with participation by Rochester Public Utilities and Dairyland Power Company.

3. Proposed 345 kV Project Description

The recommend plan includes the following facilities:

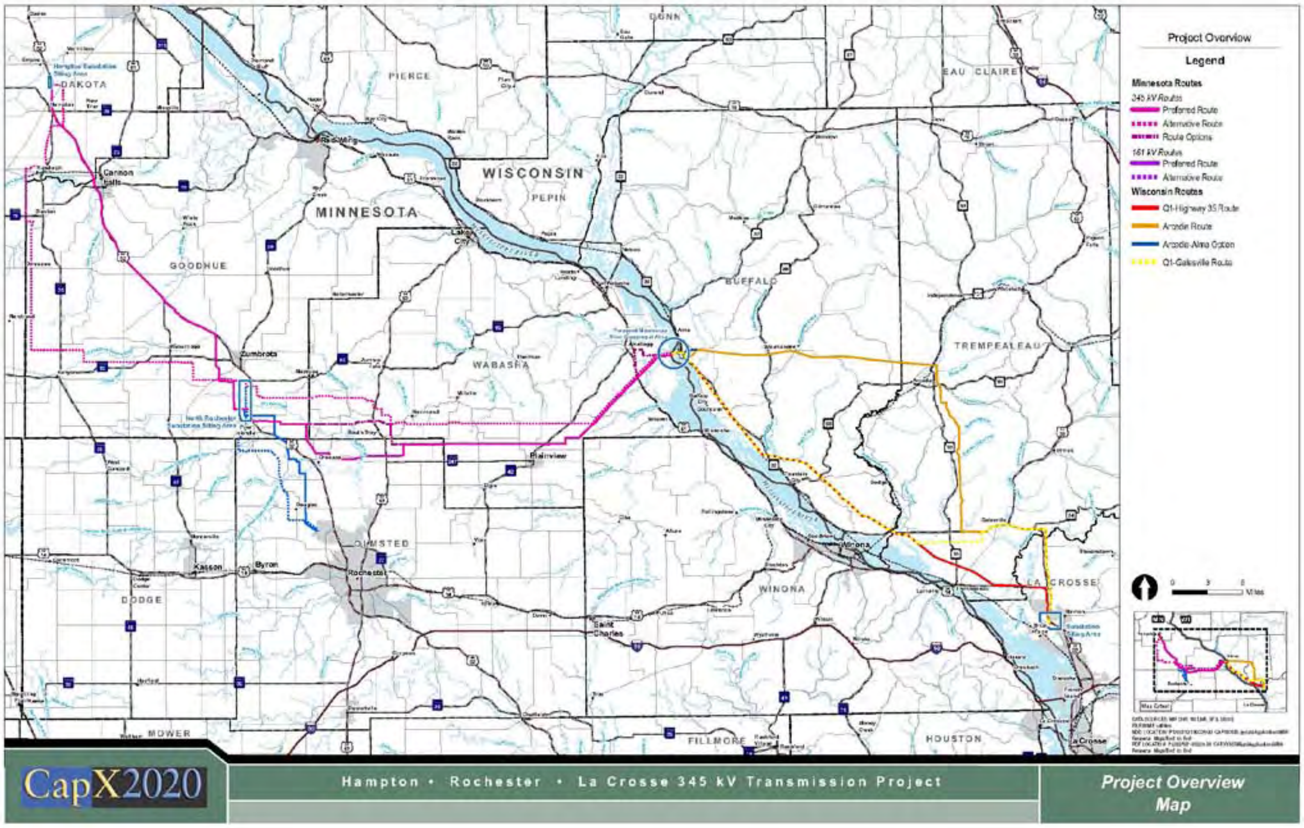
- A 954 bundled ACSS 345 kV transmission line (rated at 1792 MVA) from a new Hampton Substation near Hampton, Minnesota (southeast of the Twin Cities), to a new North Rochester Substation near Rochester, Minnesota, and then east to a substation in the area of La Crosse, Wisconsin. The substation diagram for the new substation proposed in Wisconsin, Briggs Road, with all equipment and ratings is included in the CPCN Docket No. 5-CE-136 of January 2011 – Appendix K, Figure 1.

- Two 795 ACSS 161 kV transmission lines, one between the new North Rochester Substation and the Northern Hills Substation and one between the new North Rochester Substation and the Chester Substation.

Figure 3-1 shows an overview of the Project.

[1] CapX2020 utilities are: Xcel Energy, Otter Tail Power Company, Great River Energy, Minnesota Power, Missouri River Energy Services, Minnkota Power Cooperative, WPPI Energy, Dairyland Power Cooperative, Central Minnesota Municipal Power Agency, Otter Tail Power Company, Rochester Pubic Utilities and Southern Minnesota Municipal Power Agency.

Figure 3-1
Project Overview



4. Minnesota Public Utilities Commission and Wisconsin Public Service Corporation Approvals Required

In Minnesota, the Project requires a Certificate of Need and Route Permit from the Minnesota Public Utilities Commission. Minn. Stat. § 216B.243, subd. 2; Minn. Stat. § 216E.03, subd. 2. The Minnesota Public Utilities Commission granted Certificates of Need for these facilities in May 2009. Xcel Energy filed a route permit application for the Minnesota portion of the 345 kV line and the North Rochester Substation to Northern Hills Substation 161 k V line with the MN PUC in January 2010. A route permit application for the Northern Hills – Chester 161 kV line will be filed separately.

In Wisconsin, a Certificate of Public Convenience and Necessity (CPCN) must be obtained before the Project can be constructed. Wis. Stat. § 196.49, subd. 3. A CPCN application was filed on January 3, 2011; a completeness determination is pending.

5. Criteria, Methodology and Assumptions

a. Criteria

Planning engineers are required to meet the needs of the stakeholders in the electric transmission system while adhering to all reliability criteria established and enforced by the North American Electric Reliability Corporation (NERC). The criteria are designed to ensure that the transmission system will remain stable, all voltages and thermal loadings of the transmission facilities will be within established limits, there will be no cascading outages, and only planned / controlled loss of demand or transfers will occur. These criteria have been developed over decades and are constantly being monitored and changed as deemed necessary to avoid large outages and blackouts. Most often, the criteria are made more rigorous as engineers learn better ways to maintain reliability of the transmission system. The full detail on all NERC Criteria is available at the following link:

http://www.nerc.com/page.php?cid=2%7C20

b. Methodology and Assumptions.

Steady State Models

The base models used for the steady-state (powerflow) analysis were 2014 summer peak load condition models from the 2008 series of models created by Midwest Reliability Organization (MRO). Those models were modified to include the load levels and transmission topology expected in the year 2012. This involved both adjusting the loads in the local study areas from 2014 to 2012 and making the following significant changes to the model:

- The Monroe County capacitor installation was changed to be 2x30 megavolt ampere reactive (MVAR) to accurately represent the installed facility.

- Generator 3 at Nelson Dewey was deleted from the case because the generator has not been granted approval to be built.

- Generation on the Spencer 69 kV bus was removed because it is not expected to be put in service.

- Three 161 kV transmission lines recommended in the 2008 Regional Incremental Generation Outlet (RIGO) Study were excluded. This study was designed to determine the most effective locations for transmission in Southeastern Minnesota to facilitate wind generation interconnection. The RIGO facilities were removed because no approvals from the Minnesota Public Utilities Commission had been received at the time of the analysis. In February and March 2011, Xcel Energy received a Certificate of Need and a Route Permit from the Minnesota Public Utilities Commission for one of the RIGO facilities: the Byron – Pleasant Valley 161 kV line. This line does not tie a new source into the Rochester 161 kV system and therefore does not provide any additional load serving capacity to the Rochester area.

- The French Island two 70 MW generators were turned off because they are peaking generation units – not currently must-run units – and are operated only when necessary for system support. In addition, transmission is more reliable than generation. One purpose of this Project is to address transmission issues with transmission facilities and reduce the reliance on expensive peaking generation units being run out of merit order for transmission system support. At the time the study model was developed it was not public knowledge that Unit 3 had been mothballed. However, since the study was conducted with the two peaking units off this will not affect study results.

- The Wisconsin hydroelectric generators were set to be generating at 50% of their maximum capabilities due to the fact that many of those hydroelectric plants are run-of-river in nature, so a drought could easily decrease their output to 50% of their maximum. The 50% modeling assumption is designed to recognize this fluctuation in hydroelectric generator availability and to ensure that the system can accommodate a 50% level at all times.

- The Lansing – Genoa 161 kV line was set to have both normal and emergency ratings of 223 MVA. (The Lansing – Genoa 161 kV line is presently limited to 223 MVA by substation equipment.)

Model adjustments were also made for the CapX2020 "Group 1" facilities for the 2012 peak case: Fargo – Monticello 345 kV line, Brookings – Hampton 345 kV line, Bemidji – Grand Rapids 230 kV line and this 345 kV project. The Fargo – Monticello 345 kV line was included in the base model because it is remote enough from the study area to not affect the study results. The remaining Group 1 facilities were not included in the base models because the Brookings – Hampton 345 kV line is tied directly to the study area at Hampton. However, for the cases where the Hampton – Rochester – La Crosse 345 kV line was assumed in service, all CapX2020 Group 1 facilities were included.

The primary methodology employed was to use the base load levels in the models and grow those loads to higher levels to determine the load level where facilities would experience overloads or low voltages. To do this, the load at each substation is grown in proportion to its initial load. For instance, if the La Crosse area load were to be grown from its estimated 2012 starting point of 491 MW to a 982 MW level (doubled), a substation with 4 MW of initial load would only increase 4 MW while a 40 MW substation would increase 40 MW. With this study methodology, the values of the loads at each substation are less important than the initial relative distributions of loads. The Rochester area loads included loads served by Dairyland, RPU and SMMPA. The La Crosse area loads included loads served by Dairyland and Xcel Energy. **Appendices 1** and **2** of this report show the load forecasts and they are discussed in detail in Section 5 of this report as part of the Project need discussion.

The following list of steps will walk through the creation of the study models from the MRO base case model as described above. All files referred to below (cases, idev files etc.) were included on a CD previously provided to the PSCW staff (Summer 2009):

1. The source model used for this study was a MRO 2008 series 2014 summer peak base model.

2. Major corrections/changes made to the model (IDEVs run on the model):

a) Turn off French Island large generation.idv

- This turns off the two large generators at French Island. The 140 MW removed from French Island is picked up by Sherco and Prairie Island generation in this IDEV.

- Solve the case.

b) WI Hydro set to 50%.idv

- This changes the dispatch level of NSP Wisconsin hydro to 50% of their max output. This was a study assumption agreed to by Xcel, DPC, and RPU.

- Solve the case.

c) Remove fake generation at Nelson Dewey G3.idv

- Nelson Dewey Generator (NED G3) with a total of 263MW was removed from the case. The Wisconsin PSC denied this generator and MISO recommended the generator be removed. Note: It does not matter what generation is used to pick up loss of NED G3; difference between having Nobles County and TVA Browns Ferry is a total of 3MW of flow on the lines north out of Genoa. TVA Browns Ferry was used in the model.

- Solve the case.

d) Adams-Hazelton 0 impedance 345kV line.idv

- Removes a zero impedance 345kV line between Adams and Hazelton substations.

- Solve the case.

e) Remove RIGO facilities.idv

- For this study, all RIGO facilities are assumed to not be in service.

- Solve the case.

f) RPU 2014SUPK generation and loads fixed.idv

- This was a model error in the base MRO model; some of the load and generation values were wrong. This IDEV corrects this change.

- Solve the case.

g) Delete Monroe County-Council Creek.idv

- This removes the Monroe County to Council Creek 161 kV line.

- Solve the case.

h) MOC cap bank change to 2-30MVAR.idv

- This changes the cap bank at Monroe County substation from one 60 MVAR cap bank to two 30 MVAR cap bank steps.

i) Nobles 400MW generation.idv

- This adds a possible future generator at Nobles substation, generation modeled on the 115 kV bus. This location was chosen because of the distance from the generation to the load centers. By having the generation located far away from the load centers, we were trying to mitigate any errors due to generation assumptions. The generation is turned on-line, but not dispatched.

j) Remove fake generation at Spencer.idv

- This was a model error and not dispatched. The generation was removed to mitigate any confusion.

k) Remove Load at Westside.idv

- This removes the load at Westside substation. This load will not exist in 2012.

l) La Crosse area buses and loads re-zoned to 609.idv

- This moves the buses and loads identified in Attachment A-1 into a specific unused zone.

m) Rochester area buses and loads re-zoned to 608.idv

- This moves the buses and loads identified in Attachment A-2 into a specific unused zone.

- Solve the case.

n) LAX 2012 Loads.idv

- This changes the loads in the defined La Crosse zone of 609 to 2012 levels, as listed in Attachment A-1.

o) RST 2012 Loads.idv

- This changes the loads in the defined Rochester zone of 608 to 2012 levels, as listed in Attachment A-2.

- Solve the case.

NOTE: After running the IDVs listed above on the MRO 2008 Series 2014 SUPK base case model, a 2012 SUPK case has been created.

Analytical Software Tools

The CapX2020 team planning engineers use industry standard software tools for all study work and analyses. The program used for this powerflow and loss analysis was Power System Simulator for Engineering (PSS/E) Version 30.1 by Siemens PTI.

c. Analysis

i. Powerflow Methodology

One of the primary analyses done as part of this study is the amount of load able to be served under first-contingency conditions. This analysis was done separately, while on the same powerflow case, for Rochester and La Crosse, as those two load centers operate in a very electrically separate manner.

One of the methods used for determining the load level which could be served in the Rochester and La Crosse areas was first-contingent incremental transfer capability (FCITC) analysis into each area. Employing this analysis, the amount of power able to be transferred into an area under contingency before a transmission line or transformer overloads is established. This method can also be used to determine the level of load able to be served before any bus has a voltage violation. For each of the lower voltage alternatives the powerflow output showing these load levels with violations are included in Appendix 4 of this report.

ii. Steady State Modeling Assumptions

The initial load level studied for the La Crosse area was 491 MW with 103 MVAr for a power factor of 97.9%.

As load levels in the La Crosse and Rochester areas were increased, Sherco generation, located northwest of the Twin Cities area, was increased to serve the additional load. For simulation of the loss of Genoa generation or John P. Madgett generation, generation at Nobles County was increased to offset the generation loss. The loads increased to simulate load growth are shown in **Appendices 1** and **2**.

All of this work was done with a peak-load case; the transfers in the base case were not changed for the study work. The Midwest Reliability Organization-supplied case already had firm transfers consistent with data submitted for on-peak modeling.

In addition, planning engineers have determined that there are multiple locations for the endpoint for the line. Because substation locations in the La Crosse area perform similarly and provide comparable load serving capability, it is anticipated that the final terminus will be decided based on routing considerations. Potential routes with identified substation locations will be submitted in the Wisconsin CPCN process. Consequently, this study does not assess any one specific endpoint.

iii. Steady State Contingencies Modeled

The contingency list contains the relevant complex NERC Category B and Category C contingencies commonly used for bulk transmission studies in the Rochester and La Crosse areas. A list of those complex contingencies is in the **Appendix 3** showing Complex Contingencies. The following table shows the control areas in which contingencies were taken; all branches (transformers and transmission lines) were taken as contingencies one at a time. Also, all the generators in those areas were taken off line one at a time, and all the transmission ties from those areas were taken as contingencies one at a time.

Contingency Areas.	
Model Area number	**Area name**
600	Northern States Power
613	Southern Minnesota Municipal Power Agency
615	Great River Energy
627	Alliant Energy West
680	Dairyland Power Cooperative
694	Alliant Energy East

iv. Distribution Factor Cutoff

For purposes of screening the overloaded branch results, no branch was included as needing remedy if the portion of the new study load flowing on that branch was less than 3% of the increased load being served for both system-intact and outage conditions. In other words, the power transfer distribution factor (PTDF) cutoff was 3%. As an example, for the case with 300 MW of increased load in the La Crosse area, a branch was only considered affected if that branch loaded at least 9 MW more (3% of 300 MW) due to the load growth.

v. Reactive Power Requirements--Light-load Charging Mitigation

During periods of light loading on any high-voltage transmission line, the charging current tends to increase the voltage of the line. This effect can lead to voltages outside of criteria if no mitigating facilities are installed. It is customary, therefore, to add reactors to the tertiary buses of the transformers involved in an upgrade of a line to a higher voltage. The connection of reactors to the transformer tertiary point tends to be the most inexpensive method of keeping the voltage within criteria during light-load conditions.

The charging from a 345 kV circuit is generally .86 MVAr per mile. The design for the Project includes installing enough shunt reactance to absorb all the 345 kV lines' charging during light-load periods. Each reactor would be automatically switched based on the voltage on the primary or secondary of the transformer connected to the reactor. This way the reactors will only be energized at times they are needed. Therefore, extra capacitors would not have to be installed to compensate for the reactors which were always energized.

Given a maximum distance of 150 miles for the 345 kV segments proposed, the charging current required to be absorbed at light load is 129 MVAr. This charging current could be absorbed with installation of a 65 MVAr reactor on the tertiaries of the 345/161 transformers at North Rochester and North La Crosse.

vi. Power Flow Output and Results

The following is a description of the models used, and steps necessary to replicate the results of the analysis. The models described in this report were previously provided to PSCW Staff on CD in August 2009.

Models Used in Study

Source Model: 2014SUPK_Base.sav

- This case is a base model out of the MRO 2008 series. This case will be modified with the provided IDVs to create a 2012 summer peak model.

Base CPCN Model: 2012SUPK_CPCN.sav

- This case is the base model used in the CPCN re-study. This model has been modified with the provided IDVs to create a 2012 summer peak model.

CPCN Model with CAPX2020: 2012SUPK_CPCN_CAPX2020.sav

- This case is the CPCN base model with the CAPX2020 lines added.

Study Results

Procedure for solving case under contingency:

1. Solve initial case
2. Run contingency
3. Compensate for loss of generation with Nobles Wind, if necessary.
4. Change area interchange and swing bus, if necessary.
5. Solve case.
6. Scale load to appropriate level.

Base CPCN Model: Solving with area interchange, ties and loads. Use Nobles Wind (Bus 603194) as sources for additional generation and modify area interchange.

1. Contingency: JPM offline and loss of Genoa-Coulee 161kV. Drop half of load at JPM generator bus because generation is off-line.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = 320 MW**

2. Contingency: JPM offline and loss of Genoa-Coulee 161kV, running French Island #4.
    - Note: This is the current situation, as French Island unit #3 is mothballed.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = 390 MW**

3. Contingency: JPM offline and loss of Genoa-Coulee 161kV, running French Island #3 & #4.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = 460 MW**

4. Contingency: Loss of Genoa-Coulee 161 kV.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = 446 MW**

5. Contingency: Genoa offline and loss of Alma-Marshland 161 kV.
    - Voltage at French Island near 0.95 p.u.
    - **Critical Load = 430 MW**, assuming Genoa-Lansing terminal equipment upgraded.

CPCN Model with CAPX2020 345 kV Project: Solving with area interchange, ties and loads. Use Nobles Wind (Bus 603194) as sources for additional generation and modify area interchange.

1. Contingency: JPM offline and loss of Genoa-Coulee 161kV.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = greater than 790 MW**

2. Contingency: Loss of Genoa-Coulee 161 kV.
    - Overloads: Genoa-La Crosse Tap 161 kV Line
    - **Critical Load = greater than 790 MW**

3. Contingency: Genoa offline and loss of Alma-Marshland 161 kV.
    - Overloads: Genoa-Lansing 161 kV Line and voltage at French Island below 0.95 p.u.
    - **Critical Load = 750 MW**

The following Figure 5-1 summarizes the load-serving capability of the La Crosse area, without additions, with the Project and with the Project and capacitor additions options. All options were analyzed assuming the Monroe County-Council Creek 161 kV line out of service. The key column in that figure is the column labeled "Most limiting load-serving increment/ MW". That column shows the increment (or decrement, if negative) of load-serving capability over the La Crosse load level forecast for year 2012 (491 MW). All load-serving increments shown are real (MW) increments only; the reactive (MVAr) load was not increased. Note also that for the purpose of this transmission planning study, the evaluation was done assuming that the new transmission line would not be co-located (or double circuited) with existing transmission facilities.

Figure 5-1
Load serving capability with capacitor bank additions

Year	Option	Route	Capacitor additions	First equipment upgrade assumed	Second equipment upgrade assumed	Base case area load/ MW	Most limiting load-serving increment / MW	Most limiting load-serving level/ MW	Voltage incremental load served/ MW	Voltage Limiter	Contingency	Voltage load served/ MW	Thermal incremental load served/ MW	Thermal Limiter	Contingency	Thermal load served/ MW
2012	Base case		-	Genoa-Lansing 161 (264 MVA emergency rating)	La Crosse-La Crosse Tap (490 MVA emergency rating)	491	-222	269	-18	French Island 95%	Genoa & Alma-Marshland	473	-222	Genoa-La Crosse Tap	JP Madgett & Genoa-Coulee	269
2012	Hampton-Rochester -La Crosse 345	New right of way		Genoa-Lansing 161 (264 MVA emergency rating)	La Crosse-La Crosse Tap (490 MVA emergency rating)	491	125	616	125	French Island 95%	North La Crosse-North Rochester & Genoa	616	319	Genoa-La Crosse Tap	JP Madgett & Genoa-Coulee	810
2012	Hampton-Rochester -La Crosse 345	New right of way	North La Crosse 4x80	Genoa-Lansing 161 (264 MVA emergency rating)	La Crosse-La Crosse Tap (490 MVA emergency rating)	491	300	791	353	French Island 95%	North La Crosse-North Rochester & Genoa	844	300	Genoa-La Crosse Tap	JP Madgett & Genoa-Coulee	791

The figure shows that without any transmission improvements in the La Crosse area, service to customers must be interrupted to avoid overload of the Genoa-La Crosse Tap 161 kV line any time the area load is above 269 MW. The actual area peak load in 2006 was 459 MW. If the 345 kV Project were built, the La Crosse area load-serving capability increases to 616 MW. If, in addition to the 345 kV line, capacitors are added at North La Crosse, the load-serving capability increases to 791 MW – 300 MW above the projected 2012 level.

6. Project Need

a. Community Reliability Needs

i. La Crosse / Winona Area

1. Existing System

The La Crosse/Winona area, which has its highest electricity demand during the summer, is facing reliability issues as a result of population growth and the resulting increase in demand for electricity. The area includes the cities of La Crosse, Onalaska and Holmen, Wisconsin and extends east to include Sparta, Wisconsin; the area extends northeast to include Arcadia, Wisconsin; the area extends northwest to include the area of Winona/Goodview, Minnesota; and the area extends southwest to include La Crescent, Houston and Caledonia, Minnesota.

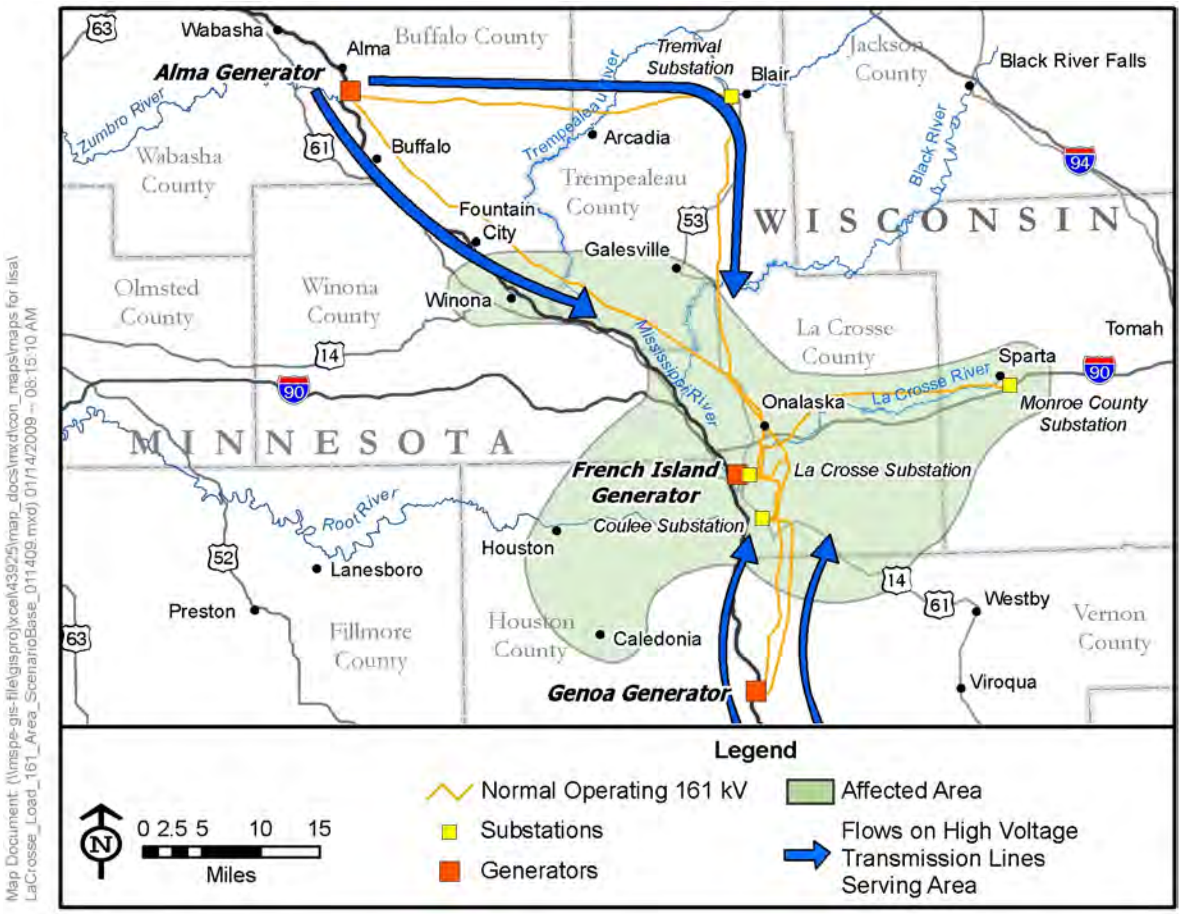
Xcel Energy and Dairyland member distribution cooperatives — Vernon Electric Cooperative, Tri-County Electric Cooperative, Oakdale Electric Cooperative and Riverland Energy Cooperative — serve the La Crosse/Winona area. Power to the area is provided by four 161 kV transmission lines:[2]

- Alma – Marshland–La Crosse 161 kV (Dairyland)
- Alma –Tremval–La Crosse 161 kV (Dairyland and Xcel Energy)
- Genoa – Coulee 161 kV (Dairyland)
- Genoa – La Crosse 161 kV (Dairyland)

The affected area and a graphical depiction of the general power flows on these high voltage transmission lines in the La Crosse/Winona area are shown in Figure 6-1 below.

[2]The La Crosse–Monroe County 161 kV line does not provide a meaningful source to the greater La Crosse area. It is not a meaningful source because it is the strongest source for Sparta and Tomah given the relatively weak transmission source from the east.

Figure 6-1
Affected La Crosse/Winona Area and Flows on High Voltage Transmission Lines Serving Area



The transmission system's ability to reliably serve the area depends on the status of major power plants in the area. The plants and the summer ratings of the units located at each site are listed below:

Alma Generation Site, located about 40 miles northwest of La Crosse:

> John P. Madgett generator (coal, 395.2 MW (net) (2008 Uniform Rating of Generating Equipment ("URGE") test) Alma units 1–5 (coal, 208.2 MW (net) (2008 URGE test)

Genoa, located about 20 miles south of La Crosse:

> Genoa Unit 3 (coal, 377.1 MW (net) (2008 URGE test)

French Island, located within the city of La Crosse:

> French Island Units 1 and 2 (refuse burning baseload units 13 MW each, nameplate, 26 MW total, which only run on weekdays when trash pickup service occurs); French Island Units 3 and 4 (fuel oil, 70 MW each, nameplate, 140 MW total)

Note: French Island Unit 3 is mothballed indefinitely, with no plans to be put back into service. Therefore, all further discussions of French Island in this report would refer only to operational Units 1, 2 and 4; 70 MW from Unit 4 is all that is available for system support.

The transmission system's ability to reliably serve the area depends on the status of major power plants in the area. If plants at Genoa and Alma are in operation and a transmission source fails, 470 MW of power demand can be met. Transmission support to the area can drop to as low as 330 MW if Alma and/or Genoa generation are not operating. Local generation at French Island in La Crosse totaling 70 MW must be run any time demand exceeds these critical load levels. Peak demand reached 447 MW in 2006. These critical system conditions are discussed in detail in the next section of this report entitled "Reliability Issues". New high voltage transmission in this area will provide transmission support that will alleviate these contingencies.

2. Reliability Issues

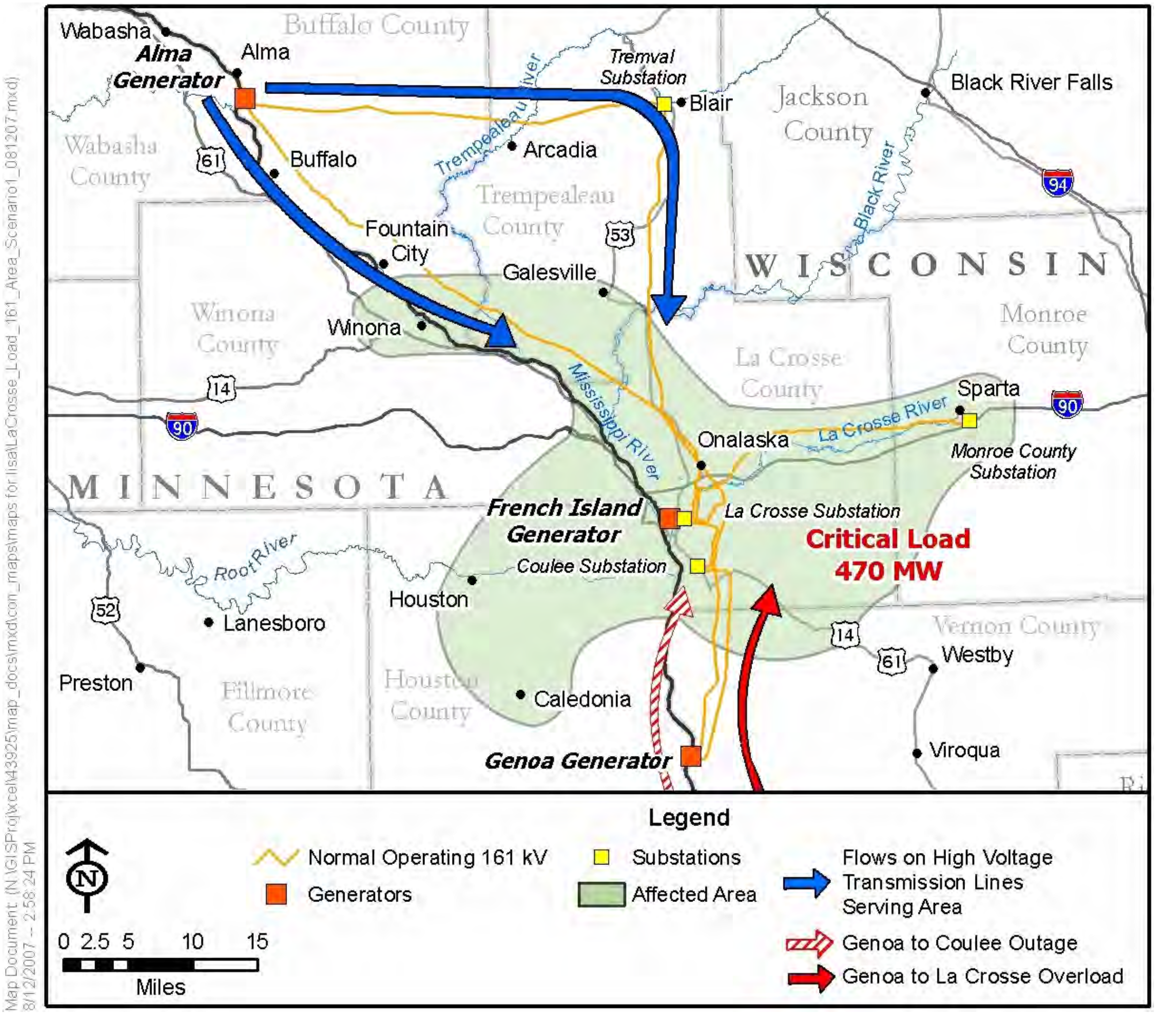
To assess the capabilities and limitations of the electrical system serving La Crosse, planning engineers reviewed historical load data and forecasted future load.

Planning engineers found that without further improvements, the existing transmission system would not be able to reliably serve customers under contingency conditions at the 494 MW level. (On August 12, 2010, actual flows on the transmission lines reached an all-time coincident peak load of 450.2 MW.)

The critical contingency was the loss of the Genoa – La Crosse – Marshland 161 kV transmission line that resulted in overloading the Genoa – Coulee 161 kV transmission line. The scenario analyzed assumed Alma and Genoa generation were in operation and the French Island peaking units were not operating. The French Island units were off line because operating peak generation units as must-run is not reliable or cost effective as an alternative to transmission. (Modeling the units as on in the base case gives them "must-run" status, as serving the load, and then relies on those units generating at the levels assumed in the analyses.)

In the event of the loss of the Genoa – Coulee 161 kV transmission line, the La Crosse area system can reliably serve only 460 MW when generators at Alma and Genoa are running. Two 60 MVAR capacitor blocks were added to the La Crosse area 161 kV system, and the resulting system capability was increased 10 MW to 470 MW. Figure 6-2 illustrates this contingency scenario.

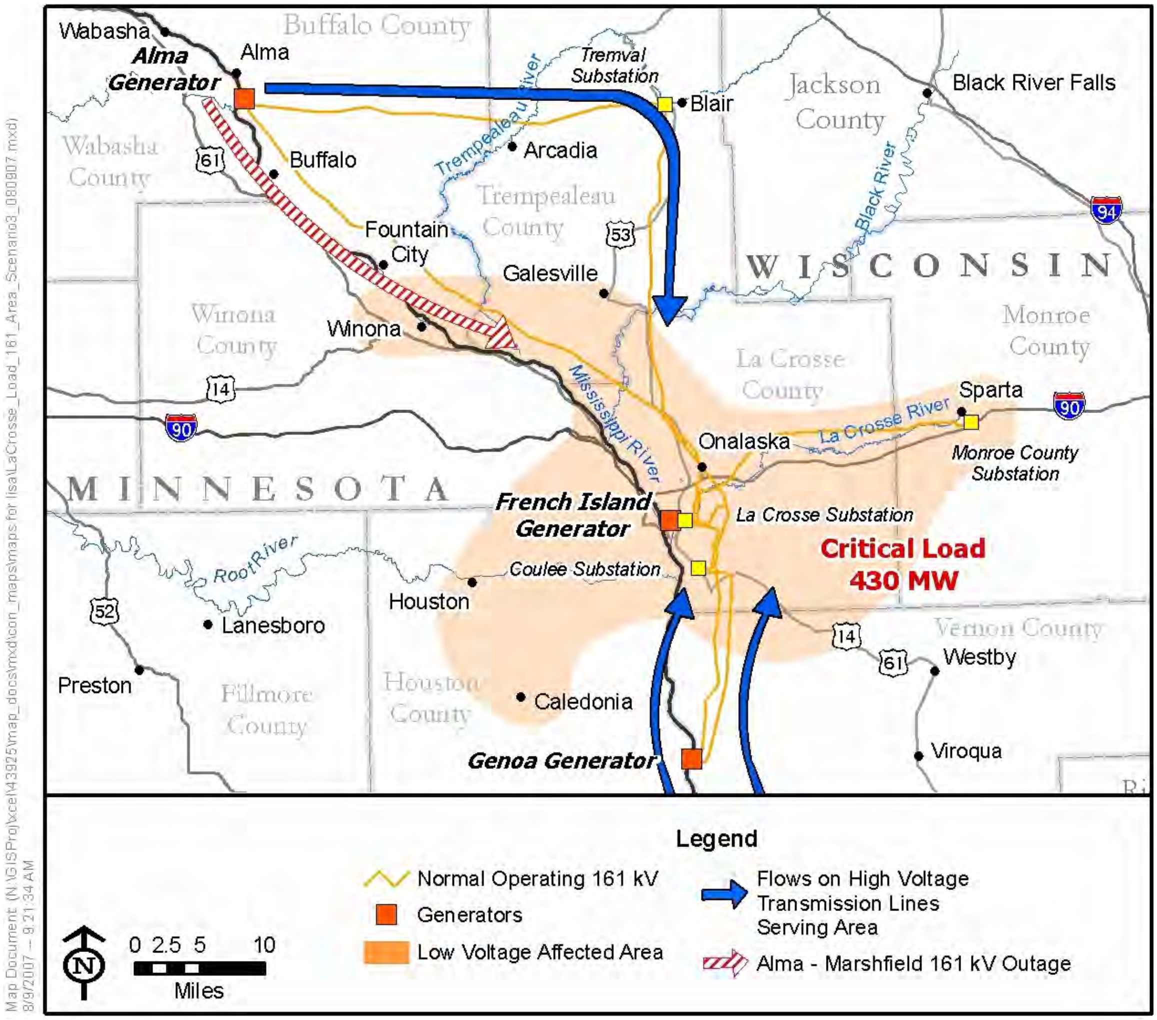
Figure 6-2
La Crosse/Winona Area Genoa – Coulee 161 kV Contingency



The transmission system can be further supported by operating the one operational 70 MW peaking unit at French Island. If this generator was run as system support, the capacity of the system in the event of a Genoa – Coulee 161 kV transmission line outage would increase to approximately 540 MW. While local generation operated in advance of the next line or power plant outage may support additional demand, running generation for system support to prepare for the next line or power plant to go out of service is not a desirable long-term solution because it is less reliable than transmission. In addition, the energy generated from the older facilities is normally more expensive than power purchased from MISO competitive markets. Finally, the number of hours that French Island units can run may be restricted by environmental permitting limitations.

The electrical system's capacity to meet power demands is more limited when generation at Alma or Genoa is off-line. If the Genoa generator is off-line and the Alma – Marshland 161 kV transmission line is disconnected, the La Crosse area experiences low voltage conditions at approximately 430 MW of load. Figure 6-3 shows the system under this contingency scenario.

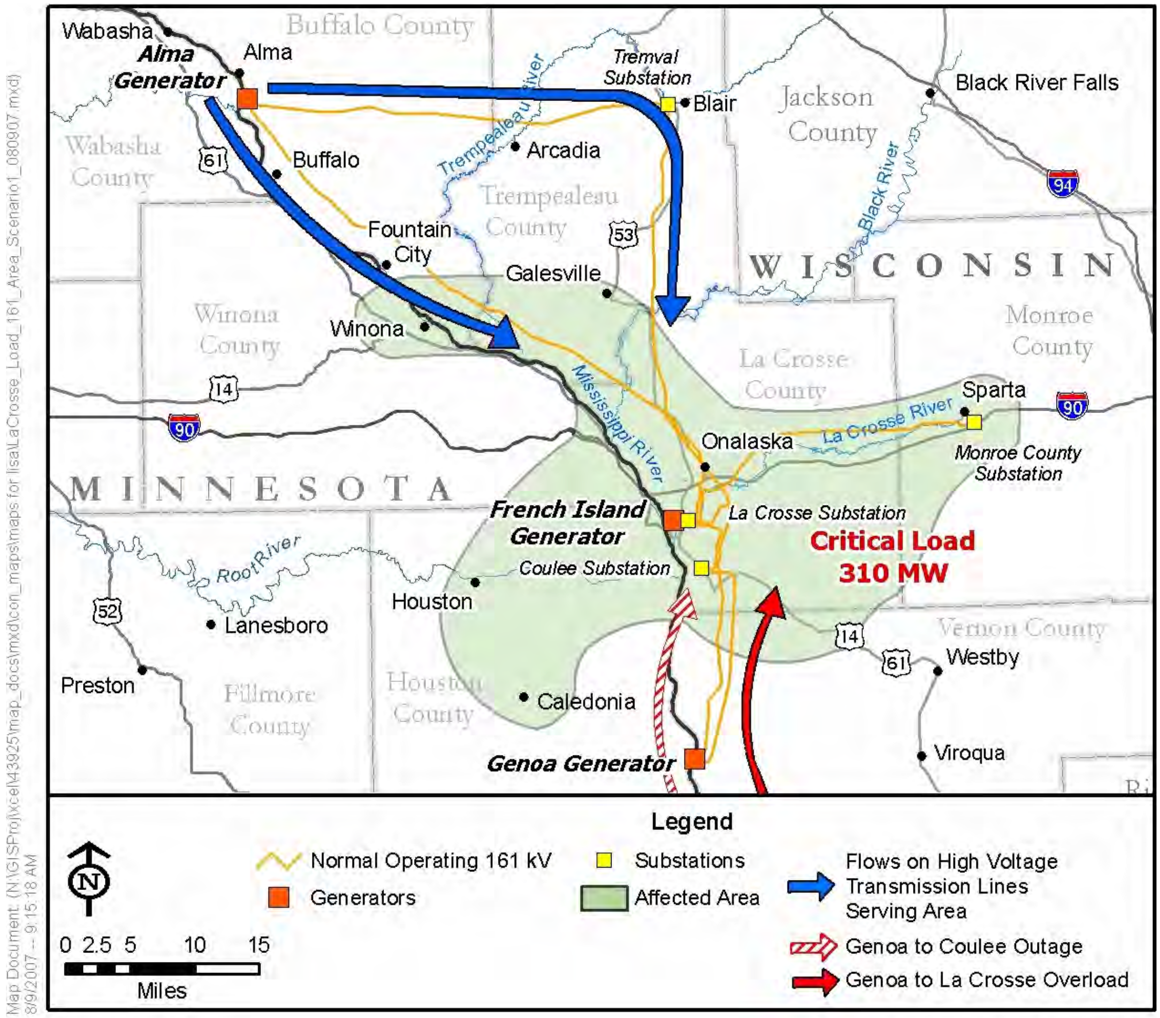
Figure 6-3
La Crosse/Winona Area Genoa Off-line, Alma – Marshland
161 kV Outage Contingency



Under this contingency, once load reaches 430 MW, the Genoa – Lansing 161 kV transmission line overloads. This level has already been exceeded. As mentioned previously, on July 17, 2006, actual flows on the transmission lines reached peak load of 447 MW. In addition, flows on the lines reached an all-time coincident peak load of 450.2 MW on August 12, 2010, with substation loads at the substation in the study area reaching 473 MW. If the 70 MW of French Island peaking generation is available and can be used for system support, the maximum capacity of the system reaches 510 MW.

The system capacity is similarly limited if the John P. Madgett generator is off-line, French Island peaking generation is off-line, and the Genoa – Coulee 161 kV transmission line is lost. In this scenario, the Genoa – La Crosse 161 kV transmission line overloads and the electrical system can reliably serve only 310 MW. Figure 6-4 illustrates this contingency scenario.

Figure 6-4
La Crosse/Winona Area, John P. Madgett Off-line, Genoa – Coulee 161 kV Line Contingency



As in the other two scenarios, French Island generation can supplement the load-serving capability of the system by 70 MW, up to a total of 380 MW.

3. Timing of the Need

To better understand the timing of the La Crosse/Winona area need, planning engineers developed a peak load forecast for substations operating in the affected La Crosse/Winona areas. Planning engineers gathered eight years of historical data and estimates of projected peak load growth. For the forecast, Xcel Energy and Dairyland provided the actual loads from 2002 to 2010 at each of the substations and then projected loads at each of the substations. This timing analysis was completed using the most current load forecast information available in 2010.

For substations served by Dairyland distribution cooperatives, the forecast was estimated by first calculating an average load for years 2004 to 2009 for each substation. To create a forecast to the year 2020, planning engineers then applied a growth rate based on the historical peak growth rates of the distribution cooperatives: Vernon Electric Cooperative at 3.4 percent, Oakdale Electric Cooperative at 2.8 percent, Tri-County Electric Cooperative's growth rate at 1.8 percent and Riverland Energy Cooperative at 1.7 percent.

The 2010–2020 forecast for the Xcel Energy substations was based on an analysis of historical loads and anticipated growth rates. Xcel Energy used the peak demand for 2006 and grew that load by 1.2 percent through the year 2020.[3]

Figure 6-5 shows the actual non-coincident annual peak demand for power at each substation in 2002, 2006, 2008 and 2010 and provides a forecast of annual peak demand at each greater La Crosse area substation for 2015 and 2020.

Figure 6-5
Actual and projected Future Substation Loads for the La Crosse/Winona Area (Summer Peak)

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual				Projected	
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Bangor	4.08	4.17	3.46	3.3	4.43	4.66
Brice	5.12	6.93	6.36	3.5	3.81	4.15
Caledonia City	3.42	3.9	3.51	3.65	4.06	4.44
Cedar Creek	3.54	5.17	4.93	5	4.94	5.38
Centerville	2.79	3.34	4.2	3.05	3.76	4.09
Coon Valley	4.29	5.22	3.96	3.99	5.58	5.86
Coulee	53.5	60.3	52.91	61.44	67.4	71.03
East Winona	8.92	9.47	11.09	7	12.74	14.07
French Island	19.5	29.04	24.06	38.73	37.34	39.35
Galesville	6.91	6.89	5.5	5.79	7.36	7.73
Goodview	31.78	35.33	33.61	31.67	36.14	38.27
Grand Dad Bluff	1.67	1.91	1.63	1.68	1.85	2.01
Greenfield	2.85	3.43	3.06	2.93	3.39	3.69
Holland	-	-	-	4.74	5.16	5.61
Holmen	14.97	13.16	14.91	18.36	15.99	16.8
Houston	3.61	3.78	3.38	3.75	3.88	4.25
Krause	4.12	4.48	4.54	5.02	4.67	5.08
La Crosse	58.43	50.33	46.98	47.63	54.34	57.11
Mayfair	43.9	46.58	45.39	56.45	51.26	54.44
Mound Prairie	2.18	2.02	2.39	2.24	2.49	2.72
Mount La Crosse	1.64	2	2.09	2.15	2.12	2.31

[3] Actual loads for 2010 were obtained after the analyses were completed. The actual loads rather than forecast loads for 2010 are presented in this figure.

LA CROSSE AREA LOAD SERVING SUBSTATIONS	Actual				Projected	
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
New Amsterdam	3.88	4.66	4.46	3.47	3.78	4.11
Onalaska	11.73	12.93	10.48	13.77	14.54	15.67
Pine Creek	2.03	2.36	1.84	1.93	2.2	2.41
Rockland	4.18	4.14	3.1	3.66	4.15	4.37
Sand Lake Coulee	2.99	2.84	2.59	3.01	2.97	3.24
Sparta	29.65	32.47	31.74	30.9	35.84	38.61
Sparta (Dairyland)	1.15	1.36	1.16	1.14	1.42	1.63
Swift Creek	17.1	24.8	21.83	23.75	29.65	31.17
Trempealeau	4.43	3.94	3.68	2.68	4.2	4.41
West Salem	23.3	24.52	23.97	22.8	27.63	29.41
Wild Turkey	1.17	1.2	1.35	2.69	1.44	1.57
Winona	46.3	51.91	51.19	51.17	55.23	58.77
Total Load MW:	425.12	464.59	435.34	473.04	514.98	547.57

Critical Load Level = 470 MW (Transmission Only with Genoa-Coulee 161 kV Outage)						
MW at risk				3.04	45.01	77.57

Critical Load Level = 450 MW (With JPM outage and Genoa-Coulee 161 kV outage)						
MW at risk				23.04	64.98	97.57

Actual loads shows that the La Crosse/Winona area began exceeding the ability of the transmission system alone to provide power in 2010 in the event of critical transmission line failure. In 2015, demand will exceed the system's capability by 45 MW (470 MW of capacity versus 515 MW of demand). This means that in 2015, approximately 45 MW of load would be at risk of service interruption.

Appendix 1 following this report shows how much load is affected by year for the critical loads described above for the La Crosse/Winona area.

ii. Rochester Area

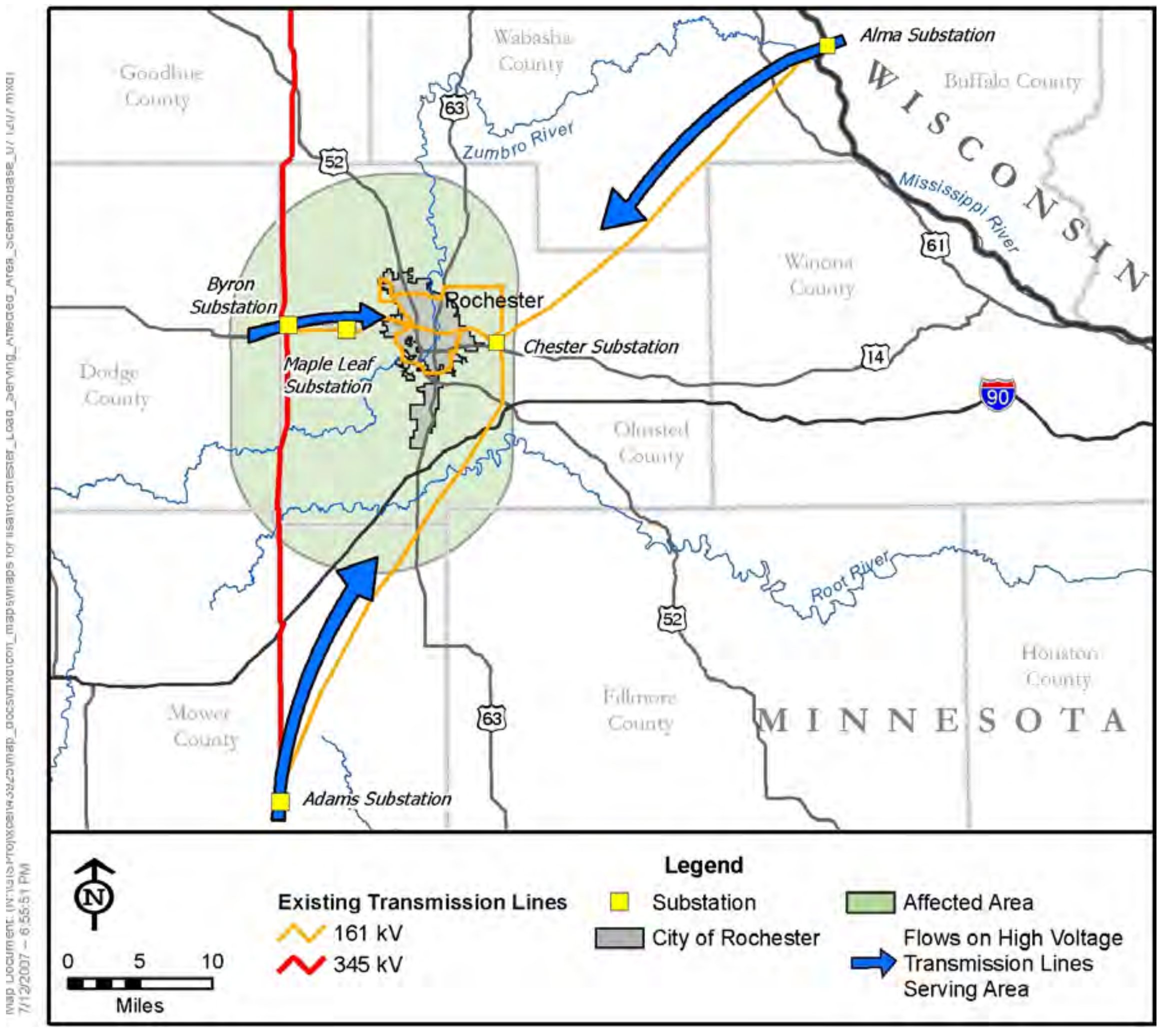
1. Existing System

RPU is the municipal electric utility serving the city of Rochester. Dairyland and its member, Peoples Cooperative Services, serve rural customers around the city. This area sees its greatest use of electricity during the summer months. The Rochester area is served by three 161 kV transmission lines: the Byron – Maple Leaf 161 kV transmission line from the west that connects the city to the Prairie Island – Byron 345 kV transmission line, a transmission line from the Alma Substation that enters northeast Rochester and a transmission line entering south Rochester from the Adams Substation.

The transmission system delivers power to several substations in and around Rochester. The area is also supported by 181 MW of generation located within the city of Rochester: four gas/coal units at Silver Lake totaling 102 MW, two hydro units on the Zumbro River totaling 2.4 MW, and two natural gas/oil units at Cascade Creek totaling 77 MW.

Figure 6-6 shows the affected area and a graphical depiction of the general power flows on these high voltage transmission lines in the Rochester area.

Figure 6-6
Affected Rochester Area and Flows on High Voltage Transmission Lines Serving Area



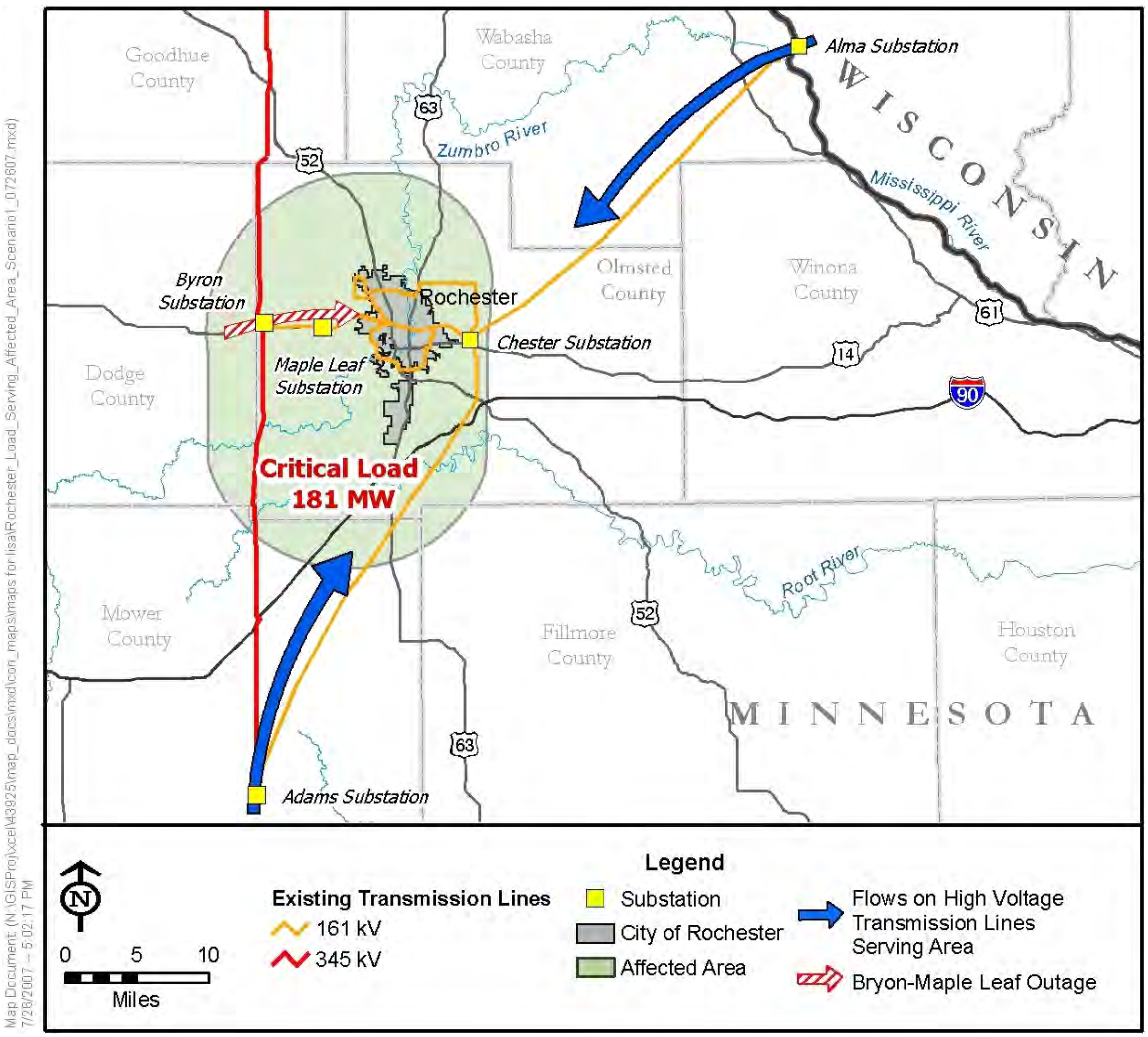
2. Reliability Issues

In the Rochester area, electric reliability issues have arisen that are related to population growth and associated increase in electric power demands. The population of the Rochester Metropolitan Statistical Area has grown by 34 percent from 98,400 residents in 1985, to 131,400 residents in 2003.

During that same period, peak electric power requirements for RPU increased by 88 percent, from 139 MW to 262 MW, and the peak electric power requirements for Peoples Cooperative Services increased 63 percent, from 22.4 MW to 36.7 MW. When the demand for electrical power exceeds 181 MW in the Rochester area, the failure of a single transmission line could cause service interruptions. The actual load at the substations in the Rochester area reached 330 MW in 2006.

If the transmission line from Byron, Minnesota to a substation on the east side of Rochester called Maple Leaf (Byron – Maple Leaf) is out of service, the remaining transmission system can only reliably deliver 181 MW of power to area substations. Figure 6-7 shows the system with the outage of the Byron – Maple Leaf transmission line and the resulting 181 MW critical load level.

Figure 6-7
Affected Rochester Area Under Contingency



Under this critical contingency, there are only two 161 kV ties remaining to serve customers of RPU and Peoples Cooperative Services. The two remaining Dairyland 161 kV lines provide the 181 MW import capability. Due to this limitation, RPU must run local generation when RPU's demand exceeds 145 MW to ensure reliable service to customers should the Byron – Maple Leaf 161 kV line lose service. In 2005, the demand for power on the RPU system exceeded 145 MW for about 5,400 hours.

The system peak occurred in 2006 and reached 330 MW, and on August 12, 2010 the system reached 314 MW. With all local generation operating, the system can support up to 362 MW of demand in the Rochester area should a transmission line be out of service. While local generation operated in advance of the next line or power plant outage may support additional demand, running generation for system support to prepare for the next line or power plant to go out of service is not a desirable long-term solution because it is less reliable than transmission. In addition, the energy generated from the older facilities is normally more expensive than power purchased from MISO competitive markets. To address these needs, additional power sources into the Rochester area are needed.

Appendix 2 following this report shows how much load is forecast to be at risk annually in the Rochester area.

b. Regional Reliability

The 345 kV line from the Twin Cities to Rochester and on to La Crosse will serve as an important first step in a greater regional transmission system build-out. Additional bulk facilities are needed to serve thousands of megawatts of demand anticipated in the region. The Project will not only add 345 kV facilities, the Project will help alleviate a major interface constraint between Minnesota and Wisconsin which will enable transfers between the two states to meet power requirements.

c. Generator Outlet / Renewable Energy Support

The 345 kV Project is also designed to provide generation support. In Wisconsin, the transmission grid in the western portion of the state, along with interface loading levels across the Minnesota – Wisconsin border, limit the ability to interconnect new generation in Minnesota as well as generation from points further west. Planning engineers have identified the lack of a 345 kV facilities between Minnesota, La Crosse and points east as the impediment to further transfers. While preliminary stability analysis shows that the 345 kV Project will not impact on the Minnesota Wisconsin Export (MWEX) interface, it will provide the foundation for future power transfers into Wisconsin. ATC has announced its intentions to construct a 345 kV transmission line from La Crosse to the Madison area ("Badger—Coulee Project") which will help address this deficit. The Project meets independent needs and will also enhance the system benefits provided by the Badger—Coulee Project.

In addition, the Regional Generation Outlet Study (RGOS), completed in 2010, was a study led by Midwest Independent Transmission System Operator, Inc. (MISO) to determine a recommended set of high voltage transmission lines necessary to deliver high levels of renewable generation to load pockets both within and outside of the MISO footprint. Analyses aimed at identifying high voltage (e.g. 765 kV) overlay transmission system for delivering large amounts of generation from points east uniformly call for enhancement of the 345 kV system serving the region. Indeed, the SMART and Green Power Express plans identify the Hampton - Rochester – La Crosse 345 kV Transmission Project as an important underlying facility. The interregional Joint Coordinated System Plan ("JCSP"), released in 2009, also included the Hampton - Rochester – La Crosse 345 kV Transmission Project as an underlying facility. Similarly, in the Regional Generation Outlet Study

("RGOS") due out this year, the ("MISO") is evaluating six scenarios to deliver high levels of renewable generation to load pockets within and outside the MISO footprint. All six scenarios include the Hampton - Rochester – La Crosse 345 kV Transmission Project.

d. Project In-Service Date Risk

Forecast information based on the most recent substation load data (and included in Section 5-3 of this report) shows that the La Crosse/Winona area will begin exceeding the ability of the transmission system alone to provide power in the event of critical transmission line failure beginning in approximately 2012. In 2015, demand will exceed the system's capability by 45 MW (470 MW of capacity versus 515 MW of demand). This means that by 2015, approximately 45 MW of load would be at risk of service interruption during contingency conditions.

Similarly for the Rochester area, the historical data and forecast demonstrate that demand in the Rochester area currently exceeds the level at which the electrical system can reliably serve customers during peak demand operating conditions. As a result, system operators must cut service to customers in the event of a critical outage to maintain the stability of the electrical system during peak times. The risk of service interruptions currently exists in the event of a Byron – Maple Leaf 161 kV transmission line outage unless all internal generation is running. As the system is currently configured, that risk is expected to be reached, even if all internal generation is running, as early as 2014.

7. MISO Evaluation of Need

In preparation for the Minnesota Certificate of Need proceedings, MISO did an independent review of the need and filed testimony from MISO's Director of Expansion Planning, Jeffrey Webb summarizing MISO's analysis. A copy of Mr. Webb's Direct Testimony is attached as **Appendix 5**. MISO did not complete a published transmission study for the Project, but did evaluate several power flow models of the MISO system to study the reliability of the transmission system. Models were prepared for summer and winter peak periods for the planning years 2011 and 2016.

MISO determined that without additional transmission improvements in the Rochester area, even with all available generation running, numerous line overload conditions would be caused by forced outages. The Adams – Rochester 161 kV line, for example, would overload under six combinations of line and/or generator forced outages resulting in loading as high as 118 percent of rating for loss of the Byron – Maple Leaf and Alma – Wabaco 161 kV lines.

MISO used a third study model, the MISO Transmission Expansion Planning (MTEP) 2006 series with the most current load forecasts available at that time. Mr. Webb testified that the 161 kV alternative for the La Crosse/Winona area did not perform as long as the 345 kV alternative and when the 161 kV alternative reached the end of its life, in the 2025-2030 timeframe, the now proposed 345 kV line would be the next project, therefore rendering the 161 kV improvements redundant at that point in time. In addition, the 161 kV alternative for La Crosse does not improve reliability for the Rochester area or increase the greater region's reliability as well as the 345 kV Project does. The 161 kV options have the likely effect of causing the need for more rights of way than would be needed for the 345 kV option. In addition, Mr. Webb noted that the 345 kV Project meets Rochester's load serving needs as described, and that the proposal is made up of the correct facilities to serve the larger regional needs.

MISO's analysis confirmed that the transmission system in Winona/La Crosse area has significant reliability issues. For 2011, the worst contingency scenario is the loss of the Genoa – Coulee 161 kV line and John P. Madgett which creates loading on the Genoa – La Crosse 161 kV line of 124 percent. MISO also determined that the loss of the Genoa – North La Crosse 161 kV line and the John P. Madgett generating unit creates loading on the Coulee – La Crosse 161 kV line of 113 percent and loading on the Genoa –Coulee 161 kV line of 103 percent.

8. Alternatives Evaluation

a. Alternatives Evaluation for Rochester area

The best performing alternative for the Rochester area included two new 161 kV transmission lines, expansion of three existing substations and a new 161 kV Quarry Hill Substation as well as a 345/161 kV transformer addition at the Byron Substation. This alternative is estimated to provide sufficient load serving capacity through mid-century based on the load projections in Appendix 2. It is important to note that when assessing lower voltage alternatives for the Project, lower voltage options for both the Rochester and Winona / La Crosse areas must be considered because the 345 kV Project provides load serving capacity to both areas.

b. Alternatives Evaluation for La Crosse/Winona

For the Winona/La Crosse area, planning engineers evaluated higher and lower voltage alternatives, generation as an alternative and the no action alternative. Applicants concluded that while the lower voltage alternatives might meet the short-term community reliability need, none of the alternatives would meet the three needs identified: community service reliability, generation outlet and regional reliability. This analysis is provided below. In addition, Powerflow output for the reconductor option and each lower voltage alternative are included in **Appendix 4** of this report. This Powerflow output shows the system overloads for each alternative, illustrating the load serving capability of each option.

i. Reconductor

The reconductor alternative would require multiple transmission line upgrades, new transformers and substation expansions. This alternative, as detailed in Figure 8-1, would serve the load in the La Crosse area to the approximately 600 MW load level, or approximately 2028 using the load forecasts included in Appendix 1. However, there is less improvement to regional reliability and reduced load serving capability with this alternative than with the proposed 345 kV line project.

To improve the load serving capability of the La Crosse/ Winona area without a new transmission source, a number of existing 161 kV lines in the area would need to be rebuilt to help the existing system handle the load growth. Figure 8-1 below shows the facilities that would need to be upgraded. Upgrading these facilities would allow the transmission system to reliably serve load until 600 MW or approximately 2028. To improve the load serving capability past the 600 MW load level, the La Crosse/Winona system needs a new transmission source. At this point a 345 kV line or a 161 kV line could be added as a source.

Figure 8-1
La Crosse Area Reconductor Option[4]

161 kV Line Rebuilds	Miles
Genoa - La Crosse Tap	21
Coulee - La Crosse	8.5
Genoa - Coulee	19
Genoa - Lansing	20
Alma - Marshland	27
La Crosse - Mayfair	4
Marshland - La Crosse Tap	24
Total Miles of Rebuilt 161 kV	**123.5**

New 161/69 kV Transformers	Size
Tremval Upgrade existing	112 MVA
Coulee #3	112 MVA
Marshland #3	112 MVA
La Crosse #1	112 MVA
La Crosse #2	112 MVA
Coulee #1	112 MVA
Monroe County #2	70 MVA

69 kV Line Rebuilds	Miles
Coulee - Swift Creek	2
Coulee - Mt. La Crosse	5
Total Miles of Rebuilt 69 kV	**7**

Substations (New and Expansions)	
Coulee	Expansion
Marshland	Expansion

ii. La Crosse Area Lower Voltage Alternatives

All powerflow cases for alternatives described below were provided to the PSCW on CD in February 2011 CD.

1. 2006 161 kV La Crosse Alternative

The first system alternative ("2006 161 kV Alternative") for the La Crosse area was initially studied in the local area study in 2006. The 2006 161 kV Alternative is a new 161 kV line from Genoa to a new 161 kV switching station called North La Crosse. The North La Crosse switching station would be created to include five 161 kV line terminations by bringing both the Tremval – Mayfair 161 kV line and the Marshland – La Crosse Tap 161 kV line into that new substation. (The fifth termination is for the 161 kV alternative line. Another termination may be required for a 161/69 transformer.)

The 2006 161 kV Alternative would provide an additional 6 MW of load serving capability assuming a required voltage at French Island generation bus of 0.95 pu. Based on the loading forecasts for the La Crosse/Winona area, this additional capacity would reliably serve the La Crosse/Winona area until approximately 2013. The next major transmission fix for the area would then be a new 345 kV source – similar to the 345 kV Project.

[4] In addition to the upgrades listed on Figures 8.1 and 8.2, there are 14 existing 161 kV and 69 kV lines which need clearance and terminal limits addressed.

2. 2010 161 kV La Crosse Alternative

A second 161 kV La Crosse Alternative, "2010 161 kV La Crosse Alternative", was also evaluated. This alternative includes a new approximately 100-mile 161 kV line from Red Wing, Minnesota to La Crosse, Wisconsin with ties in at the following substations: Spring Creek, Lake City, Alma, Marshland, Onalaska and La Crosse.

The case used in the 2010 La Crosse 161 kV Alternative was created using the topology of a 2012 summer peak case and included a baseline load level of 491 MW in the La Crosse area.

In each of the identified contingencies, multiple existing lines needed to be rebuilt to solve the short-term needs and for the long-term needs an additional source needed to be added to the area. The identified new 161 kV source came from the Prairie Island generating plant and tied in to the existing sources in the area in an effort to decrease the impact of future outages while increasing system stability at the same time.

This 161 kV source, in addition to the list of system upgrades in the reconductor option, Figure 8-2, could serve load growth in the La Crosse / Winona area to the 750 MW load level, or approximately 2045. This is the same load level that the Project could serve. . This complete alternative is shown in Figure 8-2 below.

Figure 8-2
161 kV Alternative Facilities

161 kV Line Rebuilds	Miles
Genoa - La Crosse Tap	21
Coulee - La Crosse	8.5
Genoa - Coulee	19
Genoa - Lansing	20
Alma - Marshland	27
La Crosse - Mayfair	4
Marshland - La Crosse Tap	24
Total Miles of Rebuilt 161 kV	**125.5**

69 kV Line Rebuilds	Miles
Coulee - Swift Creek	2
Coulee - Mt. La Crosse	5
Total Miles of Rebuilt 69 kV	**7**

New 161 kV Lines	Miles
Alma - Marshland #2	28
Marshland - Onalaska	26
Onalaska - La Crosse	5
Spring Creek - Lake City	20
Lake City - Alma	22
Total Miles of New 161 kV	**101**

New 161/69 kV Transformers	Size
Tremval Upgrade existing	112 MVA
Coulee #3	112 MVA
Marshland #3	112 MVA
La Crosse #1	112 MVA
La Crosse #2	112 MVA
Coulee #1	112 MVA
Monroe County #2	70 MVA
Jackson Co Upgrade Existing	112 MVA
Lake City #2	70 MVA
Onalaska #1 and #2	112 MVA

Substations (New and Expansions)	
Coulee	Expansion
Marshland	Expansion
Alma	New
Spring Creek	Expansion
Onalaska	New
Lake City	Expansion

iii. Single 161 kV Line Between North Rochester and La Crosse

Adding a single 161 kV line between North Rochester and Briggs Road 161 kV buses in the powerflow model instead of the proposed 345 kV line was capable of reliably serving load until the 550 MW load level. Using the most recent load forecast, this corresponds to approximately the year 2021.

At that point multiple bulk system transformers and 161 kV transmission lines in the immediate La Crosse area will overload requiring significant system improvements. The first facilities to overload at the 550 MW level are:

- Coulee 161/69 TR #1
- Coulee 161/69 TR #2
- Marshland 161/69 TR #1
- Marshland 161/69 TR #2
- Coulee - Swift Creek 69 kV line
- Caledonia SS – Brownsville Tap 69 kV line
- Genoa – Brownsville Tap 69 kV line
- Genoa – La Crosse Tap 161 kV line (361 MVA minimum required)

iv. Double Circuit 161 kV Line North Rochester--La Crosse

Similar to the 161 kV Rochester to La Crosse option, adding a double circuit 161 kV line between North Rochester and Briggs Road 161 kV buses in the powerflow model instead of the proposed 345 kV line was capable of reliably serving load until the 600 MW load level. Using the most recent load forecast, this corresponds to approximately the year 2028. Due to the double circuit line being treated as a single transmission element contingency, this provided no more benefit than the single 161 kV alternative in question 5 above.

At the 600 MW level, the following list of facilities will overload under contingency:

- Coulee 161/69 TR #1
- Coulee 161/69 TR #2
- Marshland 161/69 TR #1
- Marshland 161/69 TR #2
- Coulee - Swift Creek 69 kV line
- Caledonia SS – Brownsville Tap 69 kV line
- Genoa – Brownsville Tap 69 kV line
- Genoa – La Crosse Tap 161 kV line (361 MVA minimum required)

As is the case with a single circuit 161 kV alternative, regional reliability and regional transfer capability is not increased with a single circuit 161 kV alternative.

In addition, the proposed 345 kV project assumes co-location with existing 161 kV and 69 kV transmission lines for a majority of the route. If the line were to be built as double circuit 161 kV, a new route would need to be identified. In particular, a new location for the crossing of the

Mississippi River would likely be required. The proposed Alma crossing utilizes an existing crossing and requires the addition of only one new circuit at this time. If two circuits had to be added, additional right-of-way would be required at the river crossing area, presenting significant United States Fish and Wildlife Service permitting issues.

v. Single Circuit 230 kV Line North Rochester --La Crosse

Planning engineers determined that although a 230 kV alternative is feasible, past planning efforts for other areas indicated it would provide system benefits comparable to the 161 kV alternatives for each community (approximately 550 MW or 2021), but at a higher cost due to the need for major installations to accommodate the new voltage. There are also other reasons that the study team does not endorse a 230 kV alternative.

The primary reason is that a 230 kV alternative would introduce a new voltage in each of the three areas where the Project connects: SE Twin Cities (Prairie Island/Hampton area), Rochester, and La Crosse. In these areas 345 kV, 161 kV and 69 kV voltages are the primary transmission voltages. When a new voltage is introduced there are significant cost implications to incorporate the non-standard transformers and substation equipment necessary to transform from 345 kV to 230 kV, and then to the local area lower voltages of 161 kV and 69 kV. Since there were no existing 230 kV lines in the area and no plans in the future, 230 kV was not included.

230/161 kV transformers are not industry standard, and are extremely rare. 25 out of 18,174 transformers, or approximately 0.14%, of the total transformers in the MRO models are 230/161 kV units.

vi. Comparison of Lower Voltage Alternatives

As described above, the alternatives studied provide varying levels of local load serving capability. In addition, the alternatives vary significantly generation transfer capability and regional system benefits and cost. These benefits are summarized in an option summary figure in Section 9 of this report. Significantly, none of the lower voltage options provides regional reliability or generation outlet support.

1. Regional Reliability

To improve regional reliability, additional 345 kV facilities are needed between Minnesota and Wisconsin. Accordingly, none of lower voltage options would provide regional reliability benefits.

This analysis to study 161 kV and 230 kV alternatives to the 345 kV project has helped support the 345 kV project as the best alternative both for the load serving areas of Rochester and La Crosse / Winona, and the greater region.

The 2006 and 2010 161 kV Alternatives would provide increased load serving capacity to the Winona/La Crosse areas, but would not further enhance the reliability of the regional bulk transmission grid or contribute to future transfer capability between Wisconsin and Minnesota.

The 2010 161 kV Alternative would not address the need for additional 345 kV facilities between Wisconsin and Minnesota. This 161 kV alternative would require building a 100 mile 161 kV line across the Mississippi River, but would have none of the regional benefits realized by the 345 kV project:

The 345 kV line from Hampton to Rochester and on to La Crosse serves as an important first step in a greater regional transmission system buildout. The Hampton-Rochester-La Crosse 345 kV Project will provide foundational facilities for the necessary 345 kV connection between Wisconsin and Minnesota to provide transfer capability. Additional 345 kV facilities from La Crosse to the Madison area have been proposed by ATC ("Badger—Coulee Project").

2. Generation Outlet

In Wisconsin, the transmission grid in the western portion of the state, along with interface loading levels across the Minnesota – Wisconsin border, limit the ability to interconnect new generation in Minnesota as well as generation from points further west. Additional 345 kV facilities are needed to address this deficit. The 345 kV Project is also designed to provide generation support, including support for renewable generation, in southeast Minnesota. These benefits will not be realized with a 161 kV line.

3. Cost Comparison

For the cost analysis, an "apples to apples" comparison of alternatives needed to address project-wide needs was undertaken. A chart showing a cost and performance comparison of the alternatives considered is shown in Figure 9.2 in Section 9 of this report.

It is important to note that all alternative cost estimates are planning level estimates. They DO NOT include escalation, AFUDC, overheads and costs for potential siting and right of way issues. These siting issues are noted when applicable in the cost and performance comparison in Figure 9.2. When the 345 kV Project cost is included, it is the fully estimated cost including all items discussed above.

(a) 2006 161 kV La Crosse Alternative

To identify the comparable overall project cost for an alternative comparable to the Project with respect to load serving, planning engineers assessed the required facilities to provide similar local load serving capability.

First, the costs of the two local 161 kV alternatives, the 2010 La Crosse Alternative and the 161 kV Rochester Alternative were added for a total of $151 million. As discussed earlier in this report, the 161 kV Alternative will meet the load serving needs of the Rochester area until approximately mid-century. However, it can only meet the load growth in the Winona/La Crosse area until 2013 due to voltage issues at the French Island generating peaking unit which make it unable to run for necessary system support.[5] At that point in time, a new source will required for the area. MISO concluded in its study work for the Minnesota Certificate of Need process that the 345 kV Project (the 345 kV line from the Twin Cities) is a viable option following the 161 kV Alternative. Therefore, to serve

[5] At the 2013 load level, one of the large French Island units is required to run. Study analysis has shown that under the critical contingency, the voltage at the generating units is below minimum required to operate. Therefore, as discussed, the 2006 161kV Alternative can only serve La Crosse load until the year 2013.

the Rochester and La Crosse / Winona areas until a comparable timeframe as the 345 kV Project (approximately 2050) the costs would be as follows:

Rochester 161 kV Alternative Cost	$47 million
2006 La Crosse 161 kV Alternative Cost:	$104 million
Future 345 kV Project	$487 million
Total 2006 161 kV Alternative Cost:	$638 million

(b) 2010 161 kV La Crosse Alternative

Cost analysis for the 2010 161 kV alternative was completed in 2010 dollars to be comparable with the 345 kV Project costs. To ensure comparability between the 345 kV Project which addresses load serving deficits in the Rochester and La Crosse/Winona areas, and alternatives, the costs of the Rochester 161 kV alternative and the La Crosse/Winona 161 kV alternative were included. The 2010 161kV La Crosse Alternative includes a new 161 kV river crossing which would have significant right of way and regulatory costs. These potential costs are not reflected in these planning level estimates. The costs are provided below:

Rochester 161 kV Alternative Cost:	$47 million
2010 La Crosse 161 kV Alternative Cost:	$330 million
Total 2010 161 kV Alternative Cost:	$377 million

Detailed cost analysis for each segment of the 161 kV Alternative is included in **Appendix 6**.

(c) Single 161 kV Line Between North Rochester and La Crosse

Cost analysis for a single 161 kV line between the North Rochester Substation and the La Crosse endpoint substation, Briggs Road, was completed in 2010 dollars. This estimate, as well as the two below in sub-sections (d) and (e), include a $77.7 million dollar planning level estimate for Hampton Substation and a 345 kV line from Hampton to the North Rochester Substation.

Similar to above, to address load serving deficits in both the Rochester and La Crosse/Winona areas, the costs for Rochester 161 kV alternative were included. The alternative costs are provided below:

Rochester 161 kV Alternative Cost:	$47 million
Single 161 kV Alternative Cost:	$201.7 million
Total Single 161 kV Alternative Cost	$248.7 million

(d) Double 161 kV Line Between North Rochester and La Crosse

Cost analysis for a double circuit 161 kV line between North Rochester substation and the La Crosse endpoint substation, Briggs Road, was completed in 2010 dollars. Similar to above, to address load serving deficits in both the Rochester and La Crosse/Winona areas, the costs for the

Rochester 161 kV Alternative were included. For this option, there would be a significant cost adder to the cost below due to complete new right of way needed for the new double circuit line as no co-locating could be done with existing 161 kV lines. These potential costs are not included in these planning level estimates. The alternative costs are provided below:

Rochester 161 kV Alternative Cost:	$47 million
Double Circuit 161 kV Alternative Cost:	$255.7 million
Total Single 161 kV Alternative Cost	$302.7 million

(e) Single 230 kV Line Between North Rochester and La Crosse

Cost analysis for a single 230 kV line between North Rochester Substation and the La Crosse endpoint substation, Briggs Road, was completed in 2010 dollars. Similar to above, to address load serving deficits in both the Rochester and La Crosse/Winona areas, the costs for Rochester 161 kV alternative were included. The costs are provided below:

Rochester 161kV Alternative Cost:	$47 million
Single 230 kV Alternative Cost:	$246.7 million
Total Single 161kV Alternative Cost	$293.7 million

c. Higher Voltage Alternative

When studying the proposed facilities, planning engineers considered the availability of different line voltages and alternative types of conductors. For the 345 kV project proposed, higher voltages lines were considered. In conducting this analysis an important factor was the make up of the existing high voltage transmission system in the Twin Cities, the State's largest load center, and the region. The current high voltage transmission system around the Twin Cities consists of a ring of double circuit 345 kV lines with 345 kV line connections to other parts of the State and surrounding states. The neighboring states, which are electrically interconnected to Minnesota and transfer large amounts of power back and forth, also maintain 345 kV systems. This recommended project is designed to expand and strengthen the existing 345 kV system.

Higher voltage lines, such as 500 kV or 765 kV transmission lines, could be used to provide high capacity transmission of power, but would have several limitations with respect to the needs in this analysis. Higher voltage lines would allow for higher flows of electricity over those lines. The higher flows, however, would be limited by the amount of flow that can be handled by the lower voltage system. The existing transmission system, in conjunction with the higher voltage additions, would not be able to withstand the outage of a 500/765 kV line because the redistributed flows would create overload conditions. As a result, additional 345 kV lines would have to be built to provide underlying support to the 500 or 765 kV transmission lines.

The existing system in and around SW Wisconsin and SE Minnesota includes 161 kV and 345 kV facilities. Expanding that existing system takes advantage of the existing facilities, avoids the need to implement additional infrastructure and provides a logical method for expanding customer needs in these areas.

Second, a 500 kV or 765 kV transmission line would cost considerably more to install than the proposed 345 kV facility. Overall, it is estimated to cost close to 50% more to install 500 kV than 345 kV.

Third, 500 kV and above lines are not well-suited for community service reliability purposes. The existing system is comprised of 345 kV lines with 161 and 69 kV lines for support and local area reliability.

d. No Action or Generation as an Alternative

The initial consideration in addressing the reliability of a transmission system strained by increasing load growth is whether both load growth and existing electrical system facilities can be managed to avoid altogether building additional facilities to handle the projected growth. The following discussion of the "no-action" alternative focuses on whether the use of load-management measures and conservation measures to limit energy load growth can successfully address the demand needs. This section also discusses whether existing generation can address these needs.

i. Demand Side Management Programs

Demand Side Management (DSM) programs are directed at minimizing the peak load at any given moment by reducing or eliminating load of certain customers at certain times. For example, some residential customers have agreed to have their air conditioners turned off on hot summer afternoons for short periods of time. Similarly, certain industrial customers have agreed to curtail their demand for energy during peak periods of energy usage by shifting their work production to other time periods when electric system demand is not so high.

Utilities' consideration of load management is reflected in their forecasts of future load growth in the Winona/ La Crosse areas. It is not realistic to expect that DSM savings significantly greater than what has been already forecasted will be achievable and thus eliminate or substantially reduce the projected load growth for these areas.

ii. Existing Generation as an Alternative to Transmission Area

The Winona/La Crosse area similarly would continue to face reliability issues if no action were taken. Under summer peak loading conditions, if the Genoa – Coulee 161 kV line goes down, the area can serve only 470 MW of load. If this contingency occurs and the John P. Madgett generator is off-line, only 310 MW of power demand can be met.

One of the French Island peaking units owned by Xcel Energy can be brought on-line to provide additional generation support, but this unit is very expensive to run for transmission system support, and its operation may be limited by environmental permits. Relying on local generation will result in continually increased exposure to periods where loads are high enough to cause interrupted service to customers in the Winona/La Crosse area.

In Rochester, anytime the demand for power exceeds 181 MW, the failure of a single transmission line could cause service interruptions. RPU's ability to import power is restricted by the "Rochester Area Import Prior Outage Standing Operating Guide" of MISO, which requires RPU to use local generation when RPU's demand exceeds 145 MW to prepare for the next contingency. Since 2005, that amount is exceeded more than 4000 hours annually. Even if all of Rochester's available 181 MW of local generation was operated for system protection, the electrical system could only reliably serve 362 MW of load. According to the most recent load forecasts, this amount is expected to be exceeded by the year 2015.

iii. No Action Alternative Conclusion

The utilities have and continue to execute load management and conservation improvement programs to manage load growth in the Winona/La Crosse and Rochester areas. However, the no-action alternative cannot meet community reliability needs. In both areas, demand for power has already exceeded the capacity of the transmission system alone under contingency conditions. It is not reasonable to assume that load management and conservation efforts can create a decline in the actual peak demand, and the forecasts demonstrate that even with these load management measures, demand will continue to outstrip the capability of the electrical system. The no-action alternative is also not a feasible alternative to meet the need for additional transmission facilities for regional reliability and to support generation outlet capability in southeastern Minnesota. To meet these needs, transmission facilities must be constructed.

9. Losses Evaluation

New transmission lines added to the electric system affect the resistive losses of the system. In turn, the costs for capacity and energy for the system are affected. If adding a new transmission line reduces losses, capacity and energy costs are reduced.

Loss effects have been analyzed for the 345 kV Project and 161 kV alternatives. Based on the spreadsheet in Figure 9-1 below, $4,225,454 is the present value of cost of capacity and energy for a 1 MW loss reduction.

Figure 9-1
Computation of Equivalent Capitalized Value for Losses

Computation of Equivalent Capitalized Value for Losses using 2010 $
(based on 1.00 MW loss on -peak)
(pool reserve requirement of x% specified below)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	11.54	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.30	< Transmission
Discount rate	8.31	%/yr			
Energy value	$29.09	MWh			
Loss Factor	0.30				
Transmission FCR	0.1403				

Calculation

						Generation FCR	Levelized Annual Revenue Rqmt	Cum PW of Rev Req
Capacity value:	50	% peaking @	$615	/kW		0.1275	$39,218	
	50	% baseload @	$3,370	/kW		0.1275	$214,833	
						$	254,051 $	
	15%	reserve requirement:					292,158	3,372,815
Energy Value:	1.00	8760 hr/yr	0.30	$29	/MWh		76,456 $	882,639
			Total annual cost, capacity & energy:			$	368,614	4,255,454
			Present Value Annuity factor Losses				11.54	
			Cum PV Losses			$	4,255,454	
			Equivalent Transmission investment			$	**2,683,995**	
			is Cum PV Losses / FCR trans / PVA trans					

Xcel Energy Services

Figure 9-2 below shows the losses performance comparison of the 345 kV Project and lower voltage alternatives for serving La Crosse area load growth. The loss improvements shown are relative to the base model used for the analysis of the 345 kV Project and lower voltage alternatives.

Figure 9-2
Losses Performance Comparison

Total model losses/MW	Year	Case	System Capacity Loss Savings from Base Case/MW	Annual Energy Loss Savings/ GWh **	Present Value of Capacity and Energy Cost Savings/M$
18702.45	2012	Base Model	-10	-25	-41
18692.79	2012	Proposed 345 kV Project Added	0	0	0
18698.73	2012	2006 161 kV La Crosse Area Alternative	-6	-16	-25
18691.64	2012	2010 161 kV La Crosse Area Alternative	1	3	5
18694.24	2012	230 kV North Rochester - Briggs Road Alternative	-1	-4	-6
18695.65	2012	161 kV North Rochester - Briggs Road Alternative	-3	-8	-12
18694.06	2012	Double circuit 161 kV North Rochester - Briggs Road Alternative	-1	-3	-5

** all values using 2010 $

10. Conclusion

It has been nearly three decades since the electrical network serving Minnesota and the surrounding area, including western Wisconsin, has been expanded to any significant degree. At the same time, the demand for power has continued to grow. .

Forecasting data demonstrates that demand in the Rochester area currently exceeds the level at which the electrical system can reliably serve customers. As growth continues, this deficit will increase.

Forecast information shows that the La Crosse/Winona area began exceeding the ability of the transmission system alone to provide power in the event of critical transmission line failure beginning load levels in 2010. The local system also relies heavily on Genoa and/or Alma generation to maintain the reliability of service to the area. If a transmission line should fail, the outage of either of those plants severely restricts the amount of power that can be delivered, even with French Island peaking generator on.

. Planning engineers adequately studied alternatives including different voltages, generation and a no-action alternative and concluded that these alternatives cannot meet the identified needs.

As detailed in Figure 10-1 below, the 345 kV line from Hampton to Rochester to La Crosse and associated 161 kV facilities in the Rochester area is the best alternative to address the identified regional, local and generation needs. This Project will provide community support for the Rochester and Winona / La Crosse areas until mid century. The 345 kV line will also help strengthen the 345 kV backbone regional transmission system and will support generation outlet and improved transfer capability in the southeastern Minnesota/southwestern Wisconsin area.

Figure 10-1
Project Option Summary

Option	La Crosse Area Load Serving Capability (in MW)	Total Project Cost	Regional System Reliability Issues for Alternatives	Siting and Land Acquisition Issues for Alternatives
345 kV Proposed project	750 MW	$487 million		
2006 161 kV La Crosse Area Alternative	750 MW	$638 million		
2010 161kV La Crosse Area Alternative	750 MW	$377 million	No further enhancement to the reliability of the regional bulk transmission grid. No contribution to future transfer capability between Wisconsin and Minnesota	Many miles of new 161 kV ROW necessary for this alternative, including potential for a new river crossing. Major routing hurdles and resulting cost additions expected.
161 kV line from North Rochester - Briggs Road alternative	550 MW	$249 million	Regional reliability and regional transfer capability not increased	None
Double circuit 161 kV line from North Rochester - Briggs Road alternative	600 MW	$303 million + significant cost addition for new right of way	Comparable performance to 161 kV options with higher cost Regional reliability and regional transfer capability not increased	Double circuit 161 kV requires new ROW and route. Alternative route from existing DPC 161 kV Q1 line would be desired. Likely to require different river crossing. Major routing hurdles expected if not using existing ROW.
230 kV line from North Rochester - Briggs Road alternative	550 MW	$294 million	Comparable performance to single 161 kV options with higher cost New voltage introduced into both Rochester and La Crosse area. Non-standard 230/161kV transformers (0.14% of tx's on MRO model)	None

NOTE:
- Estimates are in 2010 dollars
- All alternatives are planning level estimates only. These estimates do not include AFUDC, overheads or escalation. The estimate for the Proposed Project is a full detailed estimate including all of these additions.
- 345 kV, 230 kV and 161 kV alternatives all assume the same routes and configurations as proposed in Wisconsin CPCN and Minnesota route permit application, which includes plans to double
- 161 kV/161 kV scenario assumes building adjacent to the existing underlying transmission facilities. It is important to note that feasability of this adjacent configuration has not been investigated. In some places, such as portions of the Q1 route, there is no room for building adjacent to the existing 161 kV line.

Appendix 1: La Crosse Area Summer Peak Load Information (2002-2020)

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La Crosse Area Distribution Substation	Load MW 2002	Load MW 2003	Load MW 2004	Load MW 2005	Load MW 2006	Load MW 2007	Load MW 2008	Load MW 2009	Load MW 2010	Load MW 2011	Load MW 2012	Load MW 2013	Load MW 2014	Load MW 2015	Load MW 2016	Load MW 2017	Load MW 2018	Load MW 2019	Load MW 2020
Banger	4.08	3.82	3.53	4.14	4.17	4.21	3.46	4.18	4.22	4.26	4.3	4.35	4.39	4.43	4.48	4.52	4.57	4.61	4.66
Brice	5.12	5.63	5.09	5.95	6.93	6.1	6.36	6.19	6.29	6.4	6.51	6.62	6.73	6.85	6.96	7.08	7.2	7.32	7.45
Caledonia city	3.42	3.47	3.12	3.24	3.9	4.16	3.51	3.65	3.72	3.78	3.85	3.92	3.99	4.06	4.14	4.21	4.29	4.36	4.44
Centerville	2.79	3.59	2.61	3.32	3.34	3.25	4.2	3.4	3.46	3.52	3.58	3.64	3.7	3.76	3.82	3.89	3.96	4.02	4.09
Coon Valley	4.29	4.8	4.08	5.28	5.22	4.62	3.96	5.26	5.31	5.36	5.42	5.47	5.53	5.58	5.64	5.69	5.75	5.81	5.86
Coulee	53.5	57.94	50.14	58.98	60.3	57.09	52.91	63.29	63.96	64.63	65.31	66	66.7	67.4	68.11	68.83	69.55	70.29	71.03
East Winona	8.92	9.31	8.82	9.03	9.47	10.58	11.09	11.32	11.54	11.77	12.01	12.25	12.49	12.74	13	13.26	13.52	13.79	14.07
French Island	19.5	30.02	29.92	30.18	29.04	30.2	24.06	35.07	35.44	35.81	36.19	36.57	36.95	37.34	37.73	38.13	38.53	38.94	39.35
Galesville	6.91	6.57	5.95	6.82	6.89	6.82	5.5	6.93	7	7.07	7.14	7.21	7.28	7.36	7.43	7.5	7.58	7.65	7.73
Goodview	31.78	34.79	31.46	31.92	35.33	34.06	33.61	33.74	34.13	34.52	34.92	35.32	35.72	36.14	36.55	36.97	37.4	37.83	38.27
Grand Dad Bluff	1.67	1.63	1.35	1.73	1.91	1.6	1.63	1.67	1.7	1.73	1.76	1.79	1.82	1.85	1.88	1.91	1.95	1.98	2.01
Greenfield	2.85	3.2	2.67	2.99	3.43	2.92	3.06	3.06	3.12	3.17	3.22	3.28	3.33	3.39	3.45	3.51	3.57	3.63	3.69
Holmen	14.97	13.52	14.03	15.2	13.16	13.42	14.91	15.06	15.21	15.36	15.52	15.67	15.83	15.99	16.15	16.31	16.47	16.63	16.8
Houston	3.61	3.58	3.02	3.57	3.78	3.4	3.38	3.49	3.55	3.62	3.68	3.75	3.82	3.88	3.95	4.03	4.1	4.17	4.25
Krause	4.12	4.82	3.07	4.26	4.48	4.38	4.54	4.22	4.29	4.36	4.44	4.51	4.59	4.67	4.74	4.83	4.91	4.99	5.08
La Crosse	58.43	44.98	41.52	45.31	50.33	46.79	46.98	51.19	51.7	52.22	52.74	53.27	53.8	54.34	54.89	55.43	55.99	56.55	57.11
Mayfair	43.9	45.08	45.14	46.05	46.58	46.64	45.39	47.72	48.29	48.87	49.46	50.05	50.65	51.26	51.88	52.51	53.14	53.79	54.44
Mound Prairie	2.18	1.96	2.05	2.33	2.02	2.19	2.39	2.23	2.27	2.32	2.36	2.4	2.44	2.49	2.53	2.58	2.62	2.67	2.72
Mount La Crosse	1.64	1.76	1.54	1.99	2	1.82	2.09	1.92	1.95	1.99	2.02	2.05	2.09	2.12	2.16	2.2	2.23	2.27	2.31
New Amsterdam	3.88	4.18	4.3	5.31	4.66	4.05	4.46	4.63	4.71	4.79	4.87	4.95	5.04	5.12	5.21	5.3	5.39	5.48	5.57
Onalaska	11.73	11.86	12.48	12.74	12.93	13.25	10.48	13.3	13.5	13.28	13.48	13.69	13.93	14.54	14.76	14.98	15.21	15.44	15.67
Pine Creek	2.03	2.19	1.75	1.9	2.36	1.87	1.84	1.98	2.01	2.05	2.09	2.12	2.16	2.2	2.24	2.28	2.32	2.36	2.41
Rockland	4.18	3.14	4.14	4.14	4.14	3.89	3.1	3.91	3.95	3.99	4.03	4.07	4.11	4.15	4.2	4.24	4.28	4.32	4.37
Sand Lake Coulee	2.99	3.08	2.81	2.5	2.84	2.48	2.59	2.69	2.73	2.78	2.83	2.88	2.92	2.97	3.03	3.08	3.13	3.18	3.24
Sparta (DPC)	1.15	1.25	1.04	1.21	1.36	1.1	1.16	1.21	1.24	1.27	1.31	1.35	1.38	1.42	1.46	1.5	1.55	1.59	1.63
Sparta	29.65	31.16	30.9	34.06	32.47	31.51	31.74	32.78	33.27	33.77	34.28	34.79	35.31	35.84	36.38	36.92	37.48	38.04	38.61
Swift Creek	17.1	21.07	20.11	22.32	24.8	23.74	21.83	27.94	28.22	28.5	28.78	29.07	29.36	29.65	29.95	30.25	30.55	30.86	31.17
Trempealeau	4.43	4.21	4.05	4.93	3.94	3.54	3.68	3.96	4	4.04	4.08	4.12	4.16	4.2	4.24	4.28	4.33	4.37	4.41
West Salem	23.3	23.62	22.4	27.1	24.52	22.96	23.97	25.65	25.97	26.29	26.62	26.96	27.29	27.63	27.98	28.33	28.68	29.04	29.41
Wild Turkey	1.17	1.13	1.13	1.33	1.2	1.6	1.35	1.29	1.31	1.34	1.36	1.39	1.41	1.44	1.46	1.49	1.52	1.54	1.57
Winona	46.3	46.75	45.67	46.75	51.91	49.61	51.19	51.29	51.92	52.57	53.22	53.88	54.55	55.23	55.92	56.62	57.33	58.04	58.77
Total Load MW:	**421.59**	**434.11**	**409.89**	**446.58**	**459.41**	**443.85**	**430.42**	**474.22**	**479.98**	**485.43**	**491.38**	**497.39**	**503.47**	**510.04**	**516.32**	**522.66**	**529.1**	**535.56**	**542.19**
												7.39	13.47	20.04	26.32	32.66	39.1	45.56	52.19
Critical Load Level Transmission Only Genoa - Coulee 161kV	**MW at risk**							28.22	33.98	39.43	45.38	51.39	57.47	64.04	70.32	76.66	83.1	89.56	96.19
Critical Load Level With JPM Outage & Genoa-Coulee 161kV & French Island 140MW	**MW at risk**								3.98	9.43	15.38	21.39	27.47	34.04	40.32	46.66	53.1	59.56	66.19
Critical Load Level With JPM Outage & Genoa-Coulee 161kV Transmission Only : 336 MW	**MW at risk**	98.11	73.89	110.58	123.41	107.85	94.42	138.22	143.98	149.43	155.38	161.39	167.47	174.04	180.32	186.66	193.1	199.56	206.19

Appendix 2: Rochester Area Summer Peak Load Information (2002-2020)

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Rochester Distribution Substation	Load MW 2002	Load MW 2003	Load MW 2004	Load MW 2005	Load MW 2006	Load MW 2007	Load MW 2008	Load MW 2009	Load MW 2010	Load MW 2011	Load MW 2012	Load MW 2013	Load MW 2014	Load MW 2015	Load MW 2016	Load MW 2017	Load MW 2018	Load MW 2019	Load MW 2020
Airport	1.97	2.13	2.66	3.4	3.73	3.33	2.94	3.25	3.3	3.34	3.38	3.43	3.47	3.52	3.56	3.61	3.66	3.7	3.75
Bamber Valley	25.44	26.19	24.87	26.38	28.67	25.37	25.09	26.88	27.45	28.04	28.63	29.21	30.35	32.18	32.97	34.18	35.25	36.22	37.04
Canisteo	2.35	2.3	2.28	2.68	2.77	2.59	2.61	2.62	2.65	2.69	2.72	2.76	2.79	2.83	2.87	2.9	2.94	2.98	3.02
Cascade Creek	48.34	44.52	47.25	50.12	54.47	46.84	44.58	47.76	48.78	49.82	50.86	51.91	53.35	54.99	56.03	57.04	58.61	59.49	60.41
Chester	2.5	2.71	2.68	2.52	2.8	2.42	2.38	2.6	2.63	2.66	2.7	2.73	2.77	2.8	2.84	2.88	2.92	2.95	2.99
Genoa	4.54	4.57	4.33	5.19	6.06	5.4	6.51	5.57	5.64	5.72	5.79	5.87	5.94	6.02	6.1	6.18	6.26	6.34	6.42
IBM	25.44	28.81	14.92	15.83	17.2	14.97	14.55	15.59	15.92	16.26	16.6	16.94	17.28	17.52	17.89	18.02	18.26	18.65	18.94
Kalmar	2.15	2.14	1.87	2.63	2.7	2.59	2.63	2.52	2.55	2.58	2.62	2.65	2.68	2.72	2.76	2.79	2.83	2.86	2.9
Marion	3.33	3.32	2.88	2.63	3.01	2.55	2.91	2.83	2.87	2.91	2.94	2.98	3.02	3.06	3.1	3.14	3.18	3.22	3.26
Marvale	3.29	3.27	2.84	3.45	3.31	3.11	2.15	3.01	3.05	3.09	3.13	3.17	3.21	3.25	3.29	3.34	3.38	3.42	3.47
Crosstown	15.26	18.33	24.87	26.38	28.67	33.22	35.68	38.22	39.04	39.88	40.71	41.54	42.68	42.97	43.21	43.97	44.05	44.67	45.23
Northern Hills	25.44	28.81	19.9	21.1	22.94	25.72	26.18	28.05	28.65	29.26	29.87	30.63	31.09	31.71	33.32	34.59	36.23	37.44	38.69
Oronoco	5.69	5.87	5.09	7.48	8.97	7.62	5.49	7.02	7.11	7.2	7.3	7.39	7.49	7.59	7.68	7.78	7.89	7.99	8.09
Pleasant Grove	1.63	1.95	1.17	1.64	1.83	1.33	1.4	1.5	1.51	1.53	1.55	1.57	1.6	1.62	1.64	1.66	1.68	1.7	1.72
Pleasant Valley	1.72	1.81	1.6	1.8	2.04	1.62	1.75	1.78	1.81	1.83	1.85	1.88	1.9	1.93	1.95	1.98	2	2.03	2.06
Ringe	4.85	4.87	4.63	3.02	3.67	3.01	5.08	3.93	3.98	4.04	4.09	4.14	4.2	4.25	4.31	4.36	4.42	4.48	4.53
Rock Dell	1.76	1.72	1.58	1.73	2.38	1.96	2.05	1.97	1.99	2.02	2.04	2.07	2.1	2.12	2.15	2.18	2.21	2.24	2.27
Silver Lake	48.34	52.38	47.25	50.12	54.47	54.81	52.46	56.2	57.4	58.63	59.86	59.86	60.05	60.08	60.15	60.51	61.14	61.97	62.57
Willow Creek	27.98	34.05	32.33	34.29	37.27	37.55	35.32	37.84	38.65	39.47	40.3	42.04	42.95	43.77	44.86	45.78	46.28	47.15	48.16
Zumbro	38.16	28.81	37.31	39.57	43.01	38.42	36.11	38.68	39.51	40.36	41.2	42.21	42.89	43.73	44.82	45.47	46.05	46.58	47.44
Total Load MW:	**290.18**	**298.56**	**282.31**	**301.96**	**329.97**	**314.43**	**307.87**	**327.82**	**334.49**	**341.33**	**348.14**	**354.98**	**361.81**	**368.66**	**375.5**	**382.36**	**389.24**	**396.08**	**402.96**
Critical Load Level Transmission Only 161kV Outage and Operational	MW at risk	117.56	101.31	120.96	148.97	133.43	126.87	146.82	153.49	160.33	167.14	173.98	180.81	187.66	194.5	201.36	208.24	215.08	221.96
Critical Load Level With 161kV outage, Op Guide, and all internal generation	MW at risk											-7.02	-0.19	6.66	13.5	20.36	27.24	34.08	40.96

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Appendix 3: Contingencies Studied

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SINGLE BRANCH IN SYSTEM LAX_AREA
SINGLE TIE FROM SYSTEM LAX_AREA
SINGLE UNIT OUTAGE IN SYSTEM LAX_AREA

COM START 69&345 DOUBLE CIRCUITS

CONTINGENCY 'NX3INDNCKGNO'
TRIP LINE FROM BUS 680166 TO BUS 680499 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'NX3NCKARCGNO'
TRIP LINE FROM BUS 680499 TO BUS 680430 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'NX3ARCTFRGNO'
TRIP LINE FROM BUS 680430 TO BUS 680428 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'NX3TFRCNVGNO'
TRIP LINE FROM BUS 680428 TO BUS 680160 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'NX3CNVMRSGNO'
TRIP LINE FROM BUS 605320 TO BUS 680160 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM END 69&345 DOUBLE CIRCUITS



COM LA CROSSE AREA 161&345 OUTAGES WITHOUT GNO LOSS

COM ALMA-TREMVAL WITH 345
CONTINGENCY 'NX3+ALM-TRM'
TRIP LINE FROM BUS 681543 TO BUS 602029 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
END

COM TREMVAL-NLC+345
CONTINGENCY 'NX3+TRM-NLC'
TRIP LINE FROM BUS 602029 TO BUS 601043 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
END

COM ALMA-MARSHLAND WITH 345
CONTINGENCY 'NX3ALMMRS'
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
END

COM NLC-MARSHLAND WITH 345
CONTINGENCY 'NX3NLCMRS'
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
```

```
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
END


COM LA CROSSE AREA 161&345 OUTAGES WITH GNO LOSS

COM ALMA-TREMVAL WITH 345 & GNO
CONTINGENCY 'NX3ALMTRMGNO'
TRIP LINE FROM BUS 681543 TO BUS 602029 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM TREMVAL-NLC+345 & GNO
CONTINGENCY 'NX3TRMNLCGNO'
TRIP LINE FROM BUS 602029 TO BUS 601043 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM ALMA-MARSHLAND WITH 345 & GNO
CONTINGENCY 'NX3ALMMRSGNO'
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM NLC-MARSHLAND WITH 345 & GNO
CONTINGENCY 'NX3NLCMRSGNO'
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM START OTHER NLC 345 CONTINGENCIES

CONTINGENCY 'NLC-NRO+GNO'
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM 'NSP  Defined as multi-circuit'
CONTINGENCY 'NRONLCALMWAB'
TRIP LINE FROM BUS 681543 TO BUS 681532 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
END

COM 'NSP  Defined as multi-circuit'
CONTINGENCY 'NRONLCWABROC'
TRIP LINE FROM BUS 681532 TO BUS 681537 CKT 1
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
END

COM 'NSP  Defined as multi-circuit'
CONTINGENCY 'NRONLCROCCHS'
TRIP LINE FROM BUS 681537 TO BUS 625445 CKT 15
TRIP LINE FROM BUS 601044 TO BUS 601039 CKT 1
END

COM 'NSP  Defined as multi-circuit'
CONTINGENCY 'NRONLCNROCHS'
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
TRIP LINE FROM BUS 601040 TO BUS 625445 CKT 1
END

COM 'NSP  Defined as multi-circuit'
```

```
CONTINGENCY 'NRONLCNRONHI'
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
TRIP LINE FROM BUS 601040 TO BUS 625415 CKT 1
END

CONTINGENCY 'NROC-NLAX3'
TRIP LINE FROM BUS 601039 TO BUS 601044 CKT 1
END

COM END OTHER NLC 345 CONTINGENCIES


COM begin Q1 double circuits

CONTINGENCY 'Q1+ALM-RVR-1'
TRIP LINE FROM BUS 680173 TO BUS 680480 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+RVR-BUF-2'
TRIP LINE FROM BUS 680480 TO BUS 680174 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+BUF-CCH-3'
TRIP LINE FROM BUS 680174 TO BUS 605323 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+CCH-MERT4'
TRIP LINE FROM BUS 605323 TO BUS 680478 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+MERT-MER5'
TRIP LINE FROM BUS 680478 TO BUS 605324 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+MER-GVWT6'
TRIP LINE FROM BUS 605324 TO BUS 605404 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+GVWTWINT7'
TRIP LINE FROM BUS 605404 TO BUS 605285 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+WINT-MRS8'
TRIP LINE FROM BUS 605285 TO BUS 605320 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+EWI-MRS-9'
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```
TRIP LINE FROM BUS 605134 TO BUS 605320 CKT 1
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+MRS-CNV10'
TRIP LINE FROM BUS 605320 TO BUS 680160 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+MRS-TRE11'
TRIP LINE FROM BUS 605320 TO BUS 605319 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+TRE-GAL12'
TRIP LINE FROM BUS 605319 TO BUS 605318 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+GAL-NAM13'
TRIP LINE FROM BUS 605318 TO BUS 680402 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+NAM-HOL14'
TRIP LINE FROM BUS 680402 TO BUS 680529 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

CONTINGENCY 'Q1+HOL-NLC15'
TRIP LINE FROM BUS 680529 TO BUS 680403 CKT 1
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM end Q1 double circuits

COM TREMVAL-NLC 161 & GENOA
CONTINGENCY 'TRMNLC+GNO'
TRIP LINE FROM BUS 602029 TO BUS 601043 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM MARSHLAND-NLC 161 & GENOA
CONTINGENCY 'MRS-NLC+GNO'
TRIP LINE FROM BUS 601043 TO BUS 602024 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END

COM NLC-MAYFAIR + GNO
CONTINGENCY 'NLCMAF+GNO'
TRIP LINE FROM BUS 601043 TO BUS 602026 CKT 1
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
END
```

```
COM GENOA-LAXT-NLC + JPM
CONTINGENCY 'GNOLXTNLCJPM'
TRIP LINE FROM BUS 601043 TO BUS 681531 CKT 1
TRIP LINE FROM BUS 602023 TO BUS 681531 CKT 1
SET BUS 603194 GENERATION TO 400 MW
DISCONNECT BUS 681542
END

COM LOSS OF BYRON-MAPLE LEAF 161KV
CONTINGENCY 'BYN-MLF'
TRIP LINE FROM BUS 613070 TO BUS 613130 CKT 1
END


COM LOSS OF ROCHESTER-WABACO 161KV
CONTINGENCY 'RCH-WBC'
TRIP LINE FROM BUS 681537 TO BUS 681532 CKT 1
END


COM LOSS OF ROCHESTER-ADAMS 161KV
CONTINGENCY 'RCH-ADM'
TRIP LINE FROM BUS 681537 TO BUS 631122 CKT 1
END


COM LOSS OF BYRON-MAPLE LEAF 161KV
COM LOSS OF ROCHESTER-WABACO 161KV
CONTINGENCY 'BYNMLFRCHWBC'
TRIP LINE FROM BUS 613070 TO BUS 613130 CKT 1
TRIP LINE FROM BUS 681537 TO BUS 681532 CKT 1
END


COM LOSS OF BYRON-MAPLE LEAF 161KV
COM LOSS OF ROCHESTER-ADAMS 161KV
CONTINGENCY 'BYNMLFRCHADM'
TRIP LINE FROM BUS 613070 TO BUS 613130 CKT 1
TRIP LINE FROM BUS 681537 TO BUS 631122 CKT 1
END


COM LOSS OF BYRON-MAPLE LEAF 161KV
COM LOSS OF NORTH ROCHESTER-NORTHERN HILLS
COM CONTINGENCY 'BYNMLFNRC-NHI'
COM TRIP LINE FROM BUS 613070 TO BUS 613130 CKT 1
COM TRIP LINE FROM BUS 601040 TO BUS 625415 CKT 1
COM END


COM JPM OFFLINE
COM LOSS OF GENOA-LA CROSSE TAP-MARSHLAND 161KV
CONTINGENCY 'JPMGNOLXTMRS'
SET BUS 603194 GENERATION TO 400 MW
DISCONNECT BUS 681542
DISCONNECT BUS 681531
END


COM JPM OFFLINE
COM LOSS OF GENOA-COULEE 161KV
CONTINGENCY 'JPM+GNO-COU'
SET BUS 603194 GENERATION TO 400 MW
DISCONNECT BUS 681542
TRIP LINE FROM BUS 681523 TO BUS 602020 CKT 1
END


COM GENOA OFFLINE
COM LOSS OF ALMA-MARSHLAND
CONTINGENCY 'GNO+AMA-MRS'
```

```
SET BUS 603194 GENERATION TO 370 MW
DISCONNECT BUS 681522
TRIP LINE FROM BUS 681543 TO BUS 602024 CKT 1
END

COM LOSS OF GENOA-COULEE 161KV
CONTINGENCY 'GNO-COU'
TRIP LINE FROM BUS 681523 TO BUS 602020 CKT 1
END

COM LOSS OF GENOA-LA CROSSE-MARSHLAND 161KV
CONTINGENCY 'GNO-LAXT-MRS'
DISCONNECT BUS 681531
END

COM LOSS OF KING-EAU CLAIRE-ARPON 345KV
CONTINGENCY 'ASK-ECL-ARP'
DISCONNECT BUS 601028
END
```

Appendix 4: Powerflow Data for Alternatives

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Overload Facilities at Critical Load Levels

Single 161 kV line from North Rochester 345 kV Substation Option requires the following at 550 MW:

- Add Coulee Ave 3rd 161/69 kV transformer – likely requires a new substation due to site limitations at Coulee Ave sub
- Add Marshland 3rd 161/69 kV transformer – likely requires major changes to existing substation and may require a new substation all together to due to site limitations
- Add Jackson Country 2nd 161/69 kV transformer
- Rebuild Genoa – La Crosse Tap 161 kV line to 795 ACSS
- Rebuild Coulee – Swift Creek 69 kV line to 795 ACSR
- Rebuild Coulee – Mt. La Crosse 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Genoa 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Caledonia 69 kV line to 477 ACSR

Double 161 kV lines from North Rochester 345 kV Substation Option requires the following at 600 MW:

- Add Coulee Ave 3rd 161/69 kV transformer – likely requires a new substation due to site limitations at Coulee Ave sub
- Add Marshland 3rd 161/69 kV transformer – likely requires major changes to existing substation and may require a new substation all together to due to site limitations
- Add Jackson Country 2nd 161/69 kV transformer
- Upgrade La Crosse 161/69 kV transformer #1
- Upgrade La Crosse 161/69 kV transformer #2
- Upgrade Genoa 161/69 kV transformer #1
- Rebuild Genoa – La Crosse Tap 161 kV line to 795 ACSS
- Rebuild Coulee – Swift Creek 69 kV line to 795 ACSR
- Rebuild Coulee – Mt. La Crosse 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Genoa 69 kV line to 477 ACSR

Single 230 kV line from North Rochester 345 kV Substation Option requires the following at 550 MW:

- Add Coulee Ave 3rd 161/69 kV transformer – likely requires a new substation due to site limitations at Coulee Ave sub
- Add Marshland 3rd 161/69 kV transformer – likely requires major changes to existing substation and may require a new substation all together to due to site limitations
- Add Jackson Country 2nd 161/69 kV transformer
- Add Tremval 2nd 161/69 kV transformer
- Upgrade Genoa 161/69 kV transformer #1
- Rebuild Genoa – La Crosse Tap 161 kV line to 795 ACSS
- Rebuild Coulee – Swift Creek 69 kV line to 795 ACSR
- Rebuild Brownton Tap – Genoa 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Caledonia 69 kV line to 477 ACSR

Complete 2010 Alternative Option requires the following at 750 MW:

- Upgrade La Crosse 161/69 kV transformer #1
- Upgrade La Crosse 161/69 kV transformer #2
- Rebuild Genoa – Coulee 161 kV line to higher clearance 795 ACSS or larger conductor
- Rebuild Coulee – Mt. La Crosse 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Genoa 69 kV line to 477 ACSR
- Rebuild Brownton Tap – Caledonia 69 kV line to 477 ACSR
- Rebuild North La Crosse – Holland Hill 69 kV to 795 ACSR

AC Branch Violations

Case.File 2012SUPK_CPCN_750MW_R6.sav

************** Report on violations ********************

Branches with MVA flow more than 100.0 % of nominal rating

** From bus			** ** To bus			** CKT	Type	ContMVA	BaseFlow	Rating	Loading %	Ncon	Contingency Description
602020	COULEE 5	161	681523	GENOA 5	161	1	LN	434.8	256.6	414.0	105.0	480	JPM+GNO-LAXT-MRS
602020	COULEE 5	161	681523	GENOA 5	161	1	LN	430.4	256.6	414.0	104.0	481	JPM+GNO-LAXT-MRS_2
602023	LACROSS5	161	605316	LAX 8	69.0	1	TR	94.9	50.2	80.5	117.9	361	D:COULEE 8-SW CRK 81 +ONALASK8-LAX 81
602023	LACROSS5	161	605316	LAX 8	69.0	2	TR	95.3	50.4	80.5	118.4	361	D:COULEE 8-SW CRK 81 +ONALASK8-LAX 81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.1	28.7	51.7	104.7	66	605314 HOLMEN 8 69.0 605315 ONALASK8 69.0 1
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.2	28.7	51.7	104.8	329	D:BANGOR 8-WSTSALE81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	56.6	28.7	51.7	109.6	360	D:COULEE 8-SW CRK 81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.5	28.7	51.7	105.4	275	D:E WINON8-WINONA 81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	53.9	28.7	51.7	104.2	407	D:HOLMEN 8-ONALASK81 +CAL CITY-WILDTUR81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	78.9	28.7	51.7	152.5	406	D:HOLMEN 8-ONALASK81 +GALESVI8-NEW AMST1
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	95.8	28.7	51.7	185.3	405	D:HOLMEN 8-ONALASK81 +GALESVI8-TREMPLO81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	53.9	28.7	51.7	104.2	408	D:HOLMEN 8-ONALASK81 +HOUSTON -WILDTUR81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.1	28.7	51.7	104.7	403	D:HOLMEN 8-ONALASK81 +LAX 8-FRENCH G1
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.1	28.7	51.7	104.7	404	D:HOLMEN 8-ONALASK81 +LAX 8-FRENCH G2
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.0	28.7	51.7	104.4	409	D:HOLMEN 8-ONALASK81 +MND PRAR-PINE CK 1
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	52.8	28.7	51.7	102.2	400	D:HOLMEN 8-ONALASK81 +ONALASK8-LAX 81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	53.8	28.7	51.7	104.0	401	D:HOLMEN 8-ONALASK81 +ONALASK8-ONALASKA1
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	53.8	28.7	51.7	104.0	402	D:HOLMEN 8-ONALASK81 +ONALASK8-ONALASKA2
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.1	28.7	51.7	104.6	312	D:ROCKLND8-BANGOR 81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.4	28.7	51.7	105.3	387	D:SW CRK 8-LAX 81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	52.6	28.7	51.7	101.7	294	D:WINONA 8-GOODV1 81 +HOLMEN 8-ONALASK81
605310	COULEE 8	69.0	680393	MT LAX	69.0	1	LN	54.8	28.7	51.7	106.1	345	D:WSTSALE8-LAX 81 +HOLMEN 8-ONALASK81
680037	T BRN	69.0	680091	CLDNA SS	69.0	1	LN	52.9	16.5	52.0	101.7	442	D:LAX 8-FRENCH G1 +LAX 8-FRENCH G2
680037	T BRN	69.0	680110	GENOA	69.0	1	LN	55.8	19.4	52.0	107.2	442	D:LAX 8-FRENCH G1 +LAX 8-FRENCH G2
680403	NRTHLAX8	69.0	680529	HOLLAND	69.0	1	LN	104.7	13.3	79.2	132.2	374	D:COULEE 8-MT LAX 1 +HOLMEN 8-ONALASK81

AC Branch Violations

Case.File 2012SUPK_CPCN_Option1-Single_230_550MW.sav

*************** Report on violations ********************

Branches with MVA flow more than 100.0 % of nominal rating

** From bus ** ** To bus ** CKT	Type	ContMVA	BaseFlow	Rating	Loading %	Ncon	Contingency Description
602020 COULEE 5 161 605310 COULEE 8 69.0 1	TR	132.7	83.1	128.8	103.1	16	602020 COULEE 5 161 605310 COULEE 8 69.0 2
602020 COULEE 5 161 605310 COULEE 8 69.0 2	TR	132.7	83.1	128.8	103.1	15	602020 COULEE 5 161 605310 COULEE 8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	51.1	41.9	47.0	108.7	22	602023 LACROSS5 161 602025 MONROCO5 161 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	54.2	41.9	47.0	115.3	31	602029 TREMVAL5 161 605322 TREMVAL8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	67.9	41.9	47.0	144.5	45	605292 MONROCO8 69.0 605298 SPARTA28 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	48.8	41.9	47.0	103.8	53	605298 SPARTA28 69.0 605299 MCCOY 8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	54.5	41.9	47.0	116.0	183	605322 TREMVAL8 69.0 605328 BLAIR 8 69.0 1
602024 MRSHLND5 161 605320 MARSHLA8 69.0 1	TR	132.1	72.7	128.8	102.6	165	602024 MRSHLND5 161 605320 MARSHLA8 69.0 2
602024 MRSHLND5 161 605320 MARSHLA8 69.0 2	TR	133.9	77.2	128.8	104.0	164	602024 MRSHLND5 161 605320 MARSHLA8 69.0 1
602029 TREMVAL5 161 605322 TREMVAL8 69.0 1	TR	79.0	63.2	77.0	102.6	214	680172 CREAM 69.0 680173 ALMA 8 69.0 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	75.7	59.0	72.6	104.3	14	602020 COULEE 5 161 602023 LACROSS5 161 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	81.3	59.0	72.6	111.9	24	602023 LACROSS5 161 605316 LAX 8 69.0 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	81.4	59.0	72.6	112.1	25	602023 LACROSS5 161 605316 LAX 8 69.0 2
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	77.3	59.0	72.6	106.5	57	605310 COULEE 8 69.0 680393 MT LAX 69.0 1
680037 T BRN 69.0 680091 CLDNA SS 69.0 1	LN	27.9	17.3	27.5	101.3	247	JPM+GNO-COU
680037 T BRN 69.0 680091 CLDNA SS 69.0 1	LN	27.5	17.3	27.5	100.0	248	JPM+GNO-COU_2
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	29.8	20.2	27.5	108.2	17	602020 COULEE 5 161 681523 GENOA 5 161 1
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.2	20.2	27.5	109.9	205	680026 HARMNY 69.0 681528 HARMONY5 161 1
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	27.8	20.2	27.5	101.1	245	JPM+GNO-LAXT-MRS
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.9	20.2	27.5	112.3	247	JPM+GNO-COU
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.5	20.2	27.5	110.9	248	JPM+GNO-COU_2
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	29.3	20.2	27.5	106.6	251	GNO-COU_2
680110 GENOA 69.0 681523 GENOA 5 161 1	TR	66.1	37.7	66.0	100.1	107	680110 GENOA 69.0 681523 GENOA 5 161 2
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	315.6	180.3	306.9	102.8	17	602020 COULEE 5 161 681523 GENOA 5 161 1
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	349.8	180.3	306.9	114.0	247	JPM+GNO-COU
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	341.0	180.3	306.9	111.1	248	JPM+GNO-COU_2

AC Branch Violations

Case.File 2012SUPK_CPCN_Option2-Double_161_600MW.sav

************** Report on violations ********************

Branches with MVA flow more than 100.0 % of nominal rating

** From bus **	** To bus **	** CKT	Type	ContMVA	BaseFlow	Rating	Loading %	Ncon	Contingency Description
602020 COULEE 5 161	605310 COULEE 8 69.0	1	TR	143.6	89.8	128.8	111.5	16	602020 COULEE 5 161 605310 COULEE 8 69.0 2
602020 COULEE 5 161	605310 COULEE 8 69.0	2	TR	143.6	89.8	128.8	111.5	15	602020 COULEE 5 161 605310 COULEE 8 69.0 1
602022 JACKSON5 161	605309 JACKCO 8 69.0	1	TR	51.6	42.4	47.0	109.8	22	602023 LACROSS5 161 602025 MONROCO5 161 1
602022 JACKSON5 161	605309 JACKCO 8 69.0	1	TR	54.8	42.4	47.0	116.6	31	602029 TREMVAL5 161 605322 TREMVAL8 69.0 1
602022 JACKSON5 161	605309 JACKCO 8 69.0	1	TR	54.9	42.4	47.0	116.8	183	605322 TREMVAL8 69.0 605328 BLAIR 8 69.0 1
602023 LACROSS5 161	605316 LAX 8 69.0	1	TR	83.7	64.1	80.5	104.0	56	605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1
602023 LACROSS5 161	605316 LAX 8 69.0	1	TR	87.2	64.1	80.5	108.3	25	602023 LACROSS5 161 605316 LAX 8 69.0 2
602023 LACROSS5 161	605316 LAX 8 69.0	2	TR	84.1	64.4	80.5	104.4	56	605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1
602023 LACROSS5 161	605316 LAX 8 69.0	2	TR	87.4	64.4	80.5	108.6	24	602023 LACROSS5 161 605316 LAX 8 69.0 1
602024 MRSHLND5 161	605320 MARSHLA8 69.0	1	TR	142.3	78.0	128.8	110.5	165	602024 MRSHLND5 161 605320 MARSHLA8 69.0 2
602024 MRSHLND5 161	605320 MARSHLA8 69.0	2	TR	144.2	82.8	128.8	111.9	164	602024 MRSHLND5 161 605320 MARSHLA8 69.0 1
602029 TREMVAL5 161	605322 TREMVAL8 69.0	1	TR	79.6	63.5	77.0	103.4	214	680172 CREAM 69.0 680173 ALMA 8 69.0 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	73.4	62.8	72.6	101.1	246	JPM+GNO-LAXT-MRS_2
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	73.5	62.8	72.6	101.2	22	602023 LACROSS5 161 602025 MONROCO5 161 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	74.6	62.8	72.6	102.8	245	JPM+GNO-LAXT-MRS
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	74.9	62.8	72.6	103.1	222	680393 MT LAX 69.0 680394 T GREEN 69.0 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	77.5	62.8	72.6	106.7	14	602020 COULEE 5 161 602023 LACROSS5 161 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	82.8	62.8	72.6	114.1	57	605310 COULEE 8 69.0 680393 MT LAX 69.0 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	87.5	62.8	72.6	120.5	24	602023 LACROSS5 161 605316 LAX 8 69.0 1
605310 COULEE 8 69.0	605311 SW CRK 8 69.0	1	LN	87.6	62.8	72.6	120.7	25	602023 LACROSS5 161 605316 LAX 8 69.0 2
605310 COULEE 8 69.0	680393 MT LAX 69.0	1	LN	56.2	34.4	51.7	108.7	62	605315 ONALASK8 69.0 605316 LAX 8 69.0 1
680037 T BRN 69.0	680091 CLDNA SS 69.0	1	LN	27.7	18.2	27.5	100.7	251	GNO-COU_2
680037 T BRN 69.0	680091 CLDNA SS 69.0	1	LN	28.1	18.2	27.5	102.0	17	602020 COULEE 5 161 681523 GENOA 5 161 1
680037 T BRN 69.0	680091 CLDNA SS 69.0	1	LN	28.2	18.2	27.5	102.6	205	680026 HARMNY 69.0 681528 HARMONY5 161 1
680037 T BRN 69.0	680091 CLDNA SS 69.0	1	LN	28.9	18.2	27.5	105.2	248	JPM+GNO-COU_2
680037 T BRN 69.0	680091 CLDNA SS 69.0	1	LN	29.2	18.2	27.5	106.2	247	JPM+GNO-COU
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	27.6	21.2	27.5	100.4	41	605288 NSPGENO8 69.0 680107 T RM 69.0 1
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	27.7	21.2	27.5	100.8	135	681523 GENOA 5 161 681531 LAC TAP5 161 1
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	27.7	21.2	27.5	100.9	252	GNO-LAXT-MRS
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	28.2	21.2	27.5	102.4	42	605288 NSPGENO8 69.0 680110 GENOA 69.0 1
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	28.6	21.2	27.5	103.9	246	JPM+GNO-LAXT-MRS_2
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	28.9	21.2	27.5	105.0	245	JPM+GNO-LAXT-MRS
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	30.7	21.2	27.5	111.7	251	GNO-COU_2
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	31.1	21.2	27.5	113.0	17	602020 COULEE 5 161 681523 GENOA 5 161 1
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	31.2	21.2	27.5	113.5	205	680026 HARMNY 69.0 681528 HARMONY5 161 1
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	31.9	21.2	27.5	116.2	248	JPM+GNO-COU_2
680037 T BRN 69.0	680110 GENOA 69.0	1	LN	32.2	21.2	27.5	117.2	247	JPM+GNO-COU
680110 GENOA 69.0	681523 GENOA 5 161	1	TR	67.1	38.2	66.0	101.6	107	680110 GENOA 69.0 681523 GENOA 5 161 2
681523 GENOA 5 161	681531 LAC TAP5 161	1	LN	311.3	182.3	306.9	101.4	251	GNO-COU_2
681523 GENOA 5 161	681531 LAC TAP5 161	1	LN	321.1	182.3	306.9	104.6	17	602020 COULEE 5 161 681523 GENOA 5 161 1
681523 GENOA 5 161	681531 LAC TAP5 161	1	LN	347.4	182.3	306.9	113.2	248	JPM+GNO-COU_2
681523 GENOA 5 161	681531 LAC TAP5 161	1	LN	355.1	182.3	306.9	115.7	247	JPM+GNO-COU

AC Branch Violations

Case.File 2012SUPK_CPCN_Option1-Single_161_550MW.sav

************** Report on violations ********************

Branches with MVA flow more than 100.0 % of nominal rating

** From bus ** ** To bus ** CKT	Type	ContMVA	BaseFlow	Rating	Loading %	Ncon	Contingency Description
602020 COULEE 5 161 605310 COULEE 8 69.0 1	TR	132.8	83.1	128.8	103.1	16	602020 COULEE 5 161 605310 COULEE 8 69.0 2
602020 COULEE 5 161 605310 COULEE 8 69.0 2	TR	132.8	83.1	128.8	103.1	15	602020 COULEE 5 161 605310 COULEE 8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	48.5	41.6	47.0	103.2	53	605298 SPARTA28 69.0 605299 MCCOY 8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	50.7	41.6	47.0	107.8	22	602023 LACROSS5 161 602025 MONROCO5 161 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	53.9	41.6	47.0	114.7	31	602029 TREMVAL5 161 605322 TREMVAL8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	54.2	41.6	47.0	115.3	183	605322 TREMVAL8 69.0 605328 BLAIR 8 69.0 1
602022 JACKSON5 161 605309 JACKCO 8 69.0 1	TR	67.7	41.6	47.0	144.0	45	605292 MONROCO8 69.0 605298 SPARTA28 69.0 1
602024 MRSHLND5 161 605320 MARSHLA8 69.0 1	TR	131.6	72.4	128.8	102.2	165	602024 MRSHLND5 161 605320 MARSHLA8 69.0 2
602024 MRSHLND5 161 605320 MARSHLA8 69.0 2	TR	133.4	76.9	128.8	103.6	164	602024 MRSHLND5 161 605320 MARSHLA8 69.0 1
602029 TREMVAL5 161 605322 TREMVAL8 69.0 1	TR	78.6	62.8	77.0	102.1	214	680172 CREAM 69.0 680173 ALMA 8 69.0 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	77.2	59.2	72.6	106.3	14	602020 COULEE 5 161 602023 LACROSS5 161 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	77.5	59.2	72.6	106.7	57	605310 COULEE 8 69.0 680393 MT LAX 69.0 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	81.2	59.2	72.6	111.8	24	602023 LACROSS5 161 605316 LAX 8 69.0 1
605310 COULEE 8 69.0 605311 SW CRK 8 69.0 1	LN	81.3	59.2	72.6	112.0	25	602023 LACROSS5 161 605316 LAX 8 69.0 2
680037 T BRN 69.0 680091 CLDNA SS 69.0 1	LN	27.6	17.1	27.5	100.3	248	JPM+GNO-COU_2
680037 T BRN 69.0 680091 CLDNA SS 69.0 1	LN	27.9	17.1	27.5	101.4	247	JPM+GNO-COU
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	27.6	20.1	27.5	100.2	246	JPM+GNO-LAXT-MRS_2
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	27.9	20.1	27.5	101.4	245	JPM+GNO-LAXT-MRS
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	29.4	20.1	27.5	106.8	251	GNO-COU_2
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	29.8	20.1	27.5	108.4	17	602020 COULEE 5 161 681523 GENOA 5 161 1
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.0	20.1	27.5	109.1	205	680026 HARMNY 69.0 681528 HARMONY5 161 1
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.6	20.1	27.5	111.2	248	JPM+GNO-COU_2
680037 T BRN 69.0 680110 GENOA 69.0 1	LN	30.9	20.1	27.5	112.3	247	JPM+GNO-COU
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	314.4	186.1	306.9	102.5	251	GNO-COU_2
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	325.4	186.1	306.9	106.0	17	602020 COULEE 5 161 681523 GENOA 5 161 1
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	353.5	186.1	306.9	115.2	248	JPM+GNO-COU_2
681523 GENOA 5 161 681531 LAC TAP5 161 1	LN	361.8	186.1	306.9	117.9	247	JPM+GNO-COU

Appendix 5: Direct Testimony of Jeffrey R. Webb dated May 23, 2008 filed on behalf of the Midwest Independent Transmission System Operator Inc. in the Minnesota Certificate of Need Proceeding

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BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE PETITION
FOR CERTIFICATES OF NEED FOR
THREE 345 kV TRANSMISSION LINE
PROJECTS WITH ASSOCIATED
SYSTEM CONNECTIONS

MPUC No. ET2, E-002 *et al*/CN-06-1115; OAH No. 15-2500-19350-2

DIRECT TESTIMONY OF JEFFREY R. WEBB

ON BEHALF

OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR

MAY 23, 2008

Q: Please state your name, title and business address.

A: My name is Jeffrey R. Webb, I am the Director of Expansion Planning for the Midwest Independent Transmission System Operator, Inc. (hereinafter the "Midwest ISO"). My business address is P.O. Box 4202, Carmel, Indiana.

Q: What are your duties with the Midwest ISO?

A: My duties include directing the evaluation of reliability studies in support of development of the Midwest ISO Transmission Expansion Plan, and the overall coordination of planning study results into a cohesive regional transmission expansion plan.

Q: Please describe your education and professional background.

A: I hold a bachelor's degree and a master's degree in electrical power engineering from Rensselaer Polytechnic Institute. I have also taken a variety of courses and seminars in utility planning and engineering during my career. I have taught courses in circuit analysis, distribution system analysis and electric power system analysis at the Illinois Institute of Technology. In addition, I have served on national and regional groups dedicated to ensuring transmission system reliability. I have served as a member of the Planning Committee of the Mid-America Interconnected Network ("MAIN") a Regional Reliability Organization that has now merged to form the Reliability First Corporation. I have served as past Chairman of the Transmission Task Force, the Data Bank Group, and Standards Compliance Task Force of MAIN. I have served as a member of the NERC Planning Committee representing the RTO sector, and the NERC Planning Standards Subcommittee

("NERC PSS"). As a member of the NERC PSS, I have participated in the development of the NERC Reliability Standards related to transmission planning. I facilitate a number of stakeholder groups related to transmission planning at the Midwest ISO including the Planning Subcommittee and the Regional Expansion Criteria and Benefits Task Force that developed the present transmission investment cost allocation mechanism in place today under the Midwest ISO Energy Markets Tariff. Throughout my career, I have analyzed and planned electric transmission and distribution systems, with a focus on transmission. I began my professional career working for Commonwealth Edison Company ("ComEd") in 1976 as a transmission planning engineer. Between 1988 and September of 2000, I held a variety of supervisory and management positions in the bulk power planning area of ComEd, including Technical Studies Supervisor, Bulk Power Planning Supervisor, System Planning Engineer, and Transmission Planning Manager. As Transmission Planning Manager, I led a department responsible for analyzing the transmission lines, substations, and interconnections that form ComEd's bulk-power transmission network in order to determine when modifications and reinforcements are necessary to maintain adequate, efficient and reliable service to customers. My Responsibilities as Transmission Planning Manager included ensuring that ComEd's transmission grid could meet regional and national adequacy and reliability standards, and whenever appropriate, developing and analyzing cost effective available alternatives for modifications or expansion that best meet those requirements. I have provided testimony before the Illinois Commerce Commission in several dockets involving transmission line certification. I have also provided testimony before the Wisconsin Public Service Commission involving certification of the Arrowhead to Weston 345 kV transmission line certification.

Q: What is the Midwest ISO?

A: The Midwest ISO is the nation's first Federal Energy Regulatory Commission ("FERC") approved Regional Transmission Organization ("RTO"). It encompasses 1.1 million square miles of member transmission systems from Manitoba, Canada to Kentucky and from western Pennsylvania to eastern Nebraska.

Q: What are the Midwest ISO's responsibilities?

A: As an RTO, the Midwest ISO is responsible for operational oversight and control, market operations, and planning of the transmission systems of its member Transmission Owners. Among many other responsibilities, the Midwest ISO also monitors and calculates Available Flowgate Capability ("AFC"), and provides tariff administration for its Open Access Transmission Tariff ("OATT"). The Midwest ISO is the Reliability Coordinator for its footprint, providing real-time operational monitoring and control of the transmission system. The Midwest ISO operates a real-time and a day-ahead locational marginal price based energy market in which each market participant's offer to supply energy are matched to demand and are cleared based on a security constrained economic dispatch process. In addition the Midwest ISO operates a market for Financial Transmission Rights which are used by market participants to hedge against congestion costs. The Midwest ISO is responsible for approving transmission service, new generation interconnections, and new transmission interconnections to and within the Midwest ISO footprint, and for ensuring that the system is planned to reliably and efficiently provide for existing and forecast uses of the transmission system. The Midwest ISO is the Planning Coordinator for the footprint and performs planning functions collaboratively with its Transmission Owners with stakeholder input throughout, while also providing an independent assessment and perspective of the needs of the transmission system overall.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to describe the planning functions performed by the Midwest ISO, including the results of computer simulations that the Midwest ISO performed as a part of our planning responsibilities. Those particular efforts were to review and assess the need and effectiveness of the proposed transmission facilities that are the subject of this hearing. In addition, my testimony describes the Midwest ISO's planning processes and the impact of the proposed CapX facilities on regional system performance.

MIDWEST ISO TRANSMISSION EXPANSION PLAN

Q: With regard to the Midwest ISO's planning activities, does the Midwest ISO have a transmission construction and upgrade plan for the entire Midwest ISO footprint?

A: Yes. The Board of Directors of the Midwest ISO approves updates to the Midwest ISO Transmission Expansion Plan ("MTEP") annually. Since start of operations at the Midwest ISO, we have produced four region plan reports known as MTEP 03, MTEP 05, MTEP 06, and MTEP 07. The most recently approved MTEP is MTEP 07 that was approved by the Board of Directors on December 13, 2007. The approved MTEP 07 Plan can be viewed in its entirety on line at: http://www.midwestiso.org/publish/Folder/193f68_1118e81057f_-7f900a48324a .

Q: What is the purpose of MTEP?

A: The objective of the MTEP is to identify transmission system expansions that will ensure the reliability of the transmission system that is under the operational and planning control of the Midwest ISO, and to identify expansion that is critically needed to support the competitive supply of electric power by this system.

Q: What does it mean for a project to be approved by the Midwest ISO Board of Directors as a part of the MTEP?

A: In accordance with the *Agreement Of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc. a Delaware Non-Stock Corporation* ("TOA" or "Midwest ISO Agreement"), approval of the Midwest ISO Plan by the Board certifies it as the Midwest ISO's plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities.

Q: How does the Midwest ISO develop the MTEP?

A: The Midwest ISO uses a "bottom-up, top down" approach in developing this plan. The "bottom-up" portion relies on the ongoing responsibilities of the individual Transmission Owners to continuously review and plan for reliably meeting the needs of their local systems. The Midwest ISO then reviews these local planning activities with stakeholders and performs a top-down review of the adequacy of and appropriateness of these local plans in meeting needs. In addition, the Midwest ISO considers together with stakeholders, opportunities for expansions that would reduce consumer costs by providing access to new low cost resources that are consistent with and required by evolving energy legislative policies. Our planning process examines congestion that may limit access to the most efficient resources, and considers upgrades that may be needed to meet applicable statutory energy requirements. In the initial stages of developing the MTEP, the Midwest ISO Transmission Owners ("TOs") provide the Midwest ISO with proposed transmission plans necessary to ensure system performance meets the applicable planning criteria of the TO. The TOs provided descriptions of the projects, anticipated service dates and estimated costs, and summary support and rationale for the need for the projects and alternatives considered. The Midwest ISO then prepares several models of the power system in order to establish recommended transmission system expansions. These models include power flow simulation models, economic generation expansion models, and production cost models.

Q: In preparing the MTEP regional plans, what considerations are taken into effect by the Midwest ISO?

A: There are numerous considerations in planning for a regional transmission system, however two considerations are crucial. First, the security of the transmission system must be maintained, that is, the transmission system must be able to withstand disturbances (generator and/or transmission facility outages) without interruption of service to load. This is achieved, in part, by assuring that disturbances do not lead to cascading loss of other generator and transmission facilities. Second, the transmission system must be adequately planned to be able to accommodate load growth and/or changes in load and load growth patterns, as well as changes in generation and generation dispatch patterns without causing equipment to perform outside of design capability. In addition to these two crucial considerations a third consideration in the regional planning process is the identification of transmission constraints to the most efficient regional generation dispatch patterns and that limit access to potential future generation development scenarios, along with devising and implementing solutions to those constraints.

Q: What planning horizon does the Midwest ISO consider and employ in its planning process?

A: We plan the system to meet objectives I've outlined in the short, intermediate and long-range planning horizons. By this I mean over the 1-5 year, 6-10 year, and 10-20 year horizons, respectively.

Q: What factors come into play in developing transmission plans in each of these planning horizons?

A: All of the considerations I have mentioned are considered to various degrees over the entire planning horizon. However, generally speaking, in the short and intermediate term plans tend to focus on ensuring system reliability and efficiency in meeting load growth with existing generation, or generation that is emerging as committed generation via the generation interconnection request process under the tariff. The longer term plans beyond about 10 years must consider possible generation expansion patterns that are not as definitive as for the earlier periods.

Q: How does the Midwest ISO plan for this entire period in a manner that will produce near term plans that will be consistent with an efficient an reliable plan that meets the longer term needs?

A: The planning process is a series of continuous cycles, and we work the development of plans for these various time periods in parallel, with input and guidance from stakeholders to the Midwest ISO planning process. Results of analyses of needs for the short term planning cycle informs the longer term planning process, becoming base plans upon which the longer term plans are developed. In turn, once longer term planning concepts are developed and sufficiently analyzed to demonstrate preferred options these options provide a blueprint to guide the construction of more near term projects as the planning cycles proceed.

Q: Please describe the Midwest ISO efforts to develop a long range transmission plan for the region?

A: This effort is underway and has been since late 2006. We described the evolving planning process in our MTEP 06 report and have been working with stakeholders to develop long term planning concepts that are based on several different possible "futures". These futures differ in certain basic assumptions that could impact decisions about the most prudent transmission expansion that should be developed in order to most efficiently and reliably deliver future generation to meet future demand levels. Four possible futures have been developed. Among the variables that define these futures are 1) capital costs of resource technologies; 2) load and energy growth forecasts; 3) fuel price and availability; 4) environmental costs and initiatives; 5) economic conditions such as inflation, discount rates, wind credits etc. Preliminary transmission concepts have been developed that are postulated to be necessary and sufficient to meet the underlying assumptions about demand, generation fuel mix that is economic and meets regulatory assumptions, and generation siting assumptions based on a variety of indicators. These concepts are in the process of being tested for relative value in terms of energy costs, and performance in reliably delivering projected generation to load under the various future scenarios.

Q: How do the CapX2020 projects that are the subject of this Docket fit into these planning horizons and with the long-range planning concepts?

A: Based on our analyses, these three projects fall into what we would call the short to intermediate term planning horizons, meaning that they will be needed within the next 5 to 7 years. In addition, there are fundamental near term local reliability needs that are the primary drivers for two of the three projects, and the third is needed to reliably deliver new generation developments for the near term as well. As such, in developing our long range planning concepts we have included these projects as a part of the base plans upon which the longer term plans are being developed and analyzed.

Q: Do the longer term conceptual plans that have been developed to date indicate that any of the CapX projects should be built any differently than as being proposed?

A: No, they do not. First, the longer term plans are not sufficiently developed at this stage to dictate definitively that the proposed projects should be altered. Second, the long term plan concept as presently viewed, will require in addition to higher voltage facilities, a build-out of additional 345 kV as well to collectively meet large volume long distance transfers of power, along with more sub regional power transfers and local reliability needs. While meeting longer term needs with a higher voltage system such as 765 kV may prove to be an efficient solution to longer term needs, the underlying 345 kV system will still need to be robust enough to handle flow patterns resulting from contingent conditions affecting the higher voltage grid. Moreover, the conceptual higher voltage plans developed to this point do not propose to occupy the same rights-of-way for the higher voltage lines as would be occupied by the CapX projects proposed in this Docket, and so the CapX projects are compatible with these future conceptual plans.

Q: What is the status of the CapX projects that are the subject of this docket with respect to the MTEP regional plan?

A: These projects were introduced to the regional planning process in MTEP 05 which had a planning horizon through the summer peak of 2009 and which was published in June of 2005. They were described as proposed plans in MTEP 05 that were expected to have a service date beyond the 2009 planning horizon, and that were undergoing analysis to establish their need and final design. They were also included in MTEP 06 and MTEP 07 which provided recommended regional plans for the years 2011 and 2013 respectively. As of MTEP 07, published in December of 2007, the CapX projects were listed as Appendix B projects meaning again that full analysis of the projects had not been completed and the project were not yet being recommended to the Midwest ISO BOD for approval. The Midwest ISO is currently developing MTEP 08 which covers a planning horizon through 2018. We expect to seek BOD approval for MTEP 08 in October of 2008 and the CapX 2020 projects will be included as a part of the MTEP 08 regional plan as recommended plans.

Reliability Planning Considerations

Q: What factors must be considered in planning, operating and maintaining an adequate, efficient, and reliable transmission system?

A: A transmission system must have capacity sufficient to meet projected power flows while maintaining required voltage levels and system stability.

Q: How do you determine if a transmission system has capacity sufficient to meet projected power flows while maintaining required voltage levels and stability?

A: This requires an engineering evaluation of the system as a whole, as well as of critical individual system components (transformers, lines, switchgear), under both normal and contingency conditions (conditions where one or more system components are out of service). Power system simulation models are developed for use in these analyses. Projected peak load power flows for each major component are checked to ensure that rated capacities are not exceeded. Voltage levels are also checked to ensure that voltage levels are maintained above the minimums required for safe operation of the system and above the minimums required for supply of adequate voltage to customers. The model system is tested for both generator and voltage stability following severe disturbances.

Q: Why is it necessary to provide capacity to meet projected power flows?

A: Several reasons. First, overloaded equipment threatens the system's ability to continue to provide adequate and reliable service to its customers. Overloaded equipment can fail and cause brownouts and blackouts (which, for major transmission components, can be widespread and extended) as well as potentially dangerous conditions. In addition, overloads reduce the service life of equipment and tend to increase the probability of component failure in the future.

Q: Why is it necessary to ensure that voltage levels are maintained?

A: Transmission voltages must be maintained within specified tolerances both to ensure that adequate customer voltage is maintained and to ensure that relays and other voltage-sensitive equipment operate properly. Customer voltage is dependent on a number of variable factors, which include transmission voltage level, load magnitude, and load power factor. In the case of the 230 kV and 100 kV class systems, voltage generally must be maintained between 0.92 and 1.05 of nominal.

Q: Why is it necessary to ensure that system stability is maintained?

A: Certain conditions could cause a generating unit to lose synchronism with the rest of the system or cause bulk power voltages to decline rapidly in an uncontrolled manner. These severe contingencies, while unlikely, must be tested for to ensure that the transmission system is strong enough to prevent their occurrence, or that in such instances protective systems act to regain control of the system, either by rapid tripping of the out-of-step generator, or by controlled shedding of load to arrest voltage decline. Without these measures in place, such disturbances could affect the secure operation of wide areas of the inter-connected transmission systems of the state and of the nation.

Q: Why do you study contingency conditions as well as normal operating conditions?

A: Generating units and major transmission system components cannot be assumed to be in operation 100% of the time. In addition to scheduled maintenance requirements, unscheduled outages can occur. Therefore, a level of reliability must be maintained appropriate to the number of customers at risk to possible system failures, balanced by providing service at a reasonable cost. For example, the transmission system must, at a minimum, continue to operate adequately with any single line or transformer in an area out of service. In addition, where the behavior of the transmission system in an area is heavily dependant on the output of a particular generating unit or units, it is necessary to consider the ability of the system to continue to operate when those generating unit are unavailable.

Q: Are there any other factors which must be considered in evaluating alternative plans, once the need for transmission system reinforcement is demonstrated?

A: Yes. Effects on other portions of the existing transmission system must be considered. A plan must also be capable of being constructed and operated within the time required to meet the need. For example, required real estate must be available. The plan should avoid excessive equipment damage or widespread service outages in case events more severe than planned occur. Finally, a suitably robust plan should also consider longer-range requirements for system operation with future growth, and should be compatible with or support energy supply policies such as state renewable energy standards (RES).

Q: Does the Midwest ISO regularly assess the adequacy and reliability of the transmission system within its area including within the State of Minnesota?

A: Yes. The Midwest ISO constantly monitors data on the power flows and voltage levels on all major components of its transmission system. In addition, planners collect data on the forecast loads to be experienced in the future and prepare system models that extend over the planning horizon. These models are used to perform a variety of studies like those that I outlined above to determine if and when changes are required to the transmission system.

Q: What actions are taken based upon these studies?

A: When the data and analysis shows that a change is required, Midwest ISO employees in the planning area consider information provided from our member Transmission Owners about transmission expansion plans that the Transmission Owners are considering to meet their local system needs. When a proposed local plan exists that appears to be effective in addressing identified system needs, the Midwest ISO tests the effectiveness of these plans in meeting applicable planning criteria. The Midwest ISO then considers other potentially feasible means of meeting the need that are consistent with sound engineering and system planning practices. Depending on the nature of the need, there may be many or few such alternative plans. We then determine which of the alternatives are technically feasible, legal, consistent with the Midwest ISO and the member Transmission Owner's obligations to provide efficient and reliable service to its customers. Where there is more than one such option, we assess the advantages and disadvantages of the various alternatives and select as the proposed plan the preferred option that would provide adequate, efficient, and reliable service to customers.

Q: How is the effectiveness of a proposed project evaluated against system reliability criteria?

A: Among the models prepared are power flow models that are used primarily to identify system contingency conditions that may result in reliability of service below reliability criteria. These models are generally developed for the five-to-ten year planning horizon. In order to evaluate the need and effectiveness of proposed projects, the Midwest ISO tests models both without and with the proposed projects to see if there are projected reliability issues that demonstrate the need for possible expansions, and to see if proposed expansions are suitable solutions to issues identified. Similar tests are applied to alternative proposals until the preferred alternative is selected.

MIDWEST ISO ANALYSIS OF AREA RELIABILITY NEEDS

Q: Has the Midwest ISO performed an analysis of the need and effectiveness of the CapX2020 projects that will support the inclusion of these projects into the regional plan?

A: Yes.

Q: Please describe that analysis.

A: The Midwest ISO evaluated several different power flow models of the Midwest ISO transmission system in order to study the reliability of the transmission system. Models were prepared for summer and winter peak periods for the planning years of 2011 and 2016.

Q: What assumptions were applied about generation, load and system topology in those models?

A: Generation supplies were assumed to be generators existing in 2007 plus generally any new generators that have proceeded through the Midwest ISO generation interconnection queue process and that have executed Interconnection Agreements with the Midwest ISO. Load modeled was provided by the Midwest ISO Transmission Owners through power flow models of their respective systems for the study periods. Transmission system topology in the area of study was consistent with the MTEP 07 2013 planning model and included all existing transmission plus any expansions approved by the Midwest ISO BOD for service on or before the study periods.

<u>TWIN CITIES TO FARGO 345 KV PROJECT</u>

Q: What did the study show with respect to the Twin Cities – Fargo proposed transmission project?

A: Our study evaluated three general load serving area along the path of this proposed line; the Red River Valley Area ("RRV Area"), the Alexandria Area, and the St. Cloud Area. In the RRV Area our models demonstrated that under peak load conditions, and absent the construction and operation of the Twin Cities – Fargo line, there are numerous contingency conditions involving the forced outage of existing transmission facilities that will result in loadings on other existing facilities beyond their safe design capability. In addition other conditions will result in transmission level voltages below design criteria, and for certain conditions could result in voltage instability with resultant wide-area loss of load. Each of these conditions fall within the conditions prescribed by the North American Electric Reliability Council ("NERC") to be tested for and for which the system should perform within design standards and/or remain in stable operation.

Q: What kind of problems did the Midwest ISO identify in the Red River Valley area?

A: The Red River Valley is a winter peaking area with an approximate load of 2,200 MW modeled in the Midwest ISO 2011 model, and 2,367 MW in the 2016 model. There is about 565 MW of generation within this area, and therefore the area relies on power transported into the area on the single Jamestown-Maple River 345 kV line and other 230 kV transmission lines in the area, in order to meet the majority of its load serving needs. The Midwest ISO analyzed the loss of the single 345 kV line supporting the area at Maple River near Fargo, along with one of these 230 kV lines and found that this condition could lead to an unstable decline in voltages in the region, with the potential for uncontrolled loss of large amounts of load across the region.

Q: Could operators take reasonable operating steps after the loss of one of these lines that would mitigate the severity of the loss of the second line?

A: No. The unstable condition can result even with all available generation within the area on-line, so that generation redispatch is not a solution here. Instability could be averted by the controlled interruption of load by operator action after the first contingency, but the amount of load that would need to be interrupted to avert this condition in 2016 would be excessive. Analysis showed that an area load level of about 545 MW less than the 2016 load levels modeled can be supported for this severe contingency condition. This difference represents about a 23% reduction in load within the Red River Valley area. Although with targeted controlled load shedding less load reduction may be needed to secure the system, it is the opinion of the Midwest ISO that this indicates that an excessive and unacceptable amount of load would need to be curtailed after a single transmission line outage.

Q: How does the proposed line resolve these conditions?

A: The proposed project provides a second 345 kV supply to the Maple River 345 kV bus in the Fargo area, so that the system will remain secure for contingent loss of the single existing 345 kV supply to the area.

Q: Are there any other reliability issues projected for the RRV area?

A: Yes. We also found that the Fargo 230 kV to 115 kV transformers will overload for the 2016 winter peak conditions for four conditions involving two transmission elements out of service. In addition, under single contingency conditions the Mud Lake to Brainerd 115 kV line would overload, and six 115 kV substations would experience low voltage conditions.

Q: **Did the Midwest ISO consider alternative transmission upgrade solutions?**

A: Yes. The Midwest ISO considered the addition of voltage support equipment in the area such as capacitor banks. However, the area already has a very large amount of such voltage support devices in the area, more in fact than the amount of reactive load in the area. When a system is so heavily compensated with reactive support devices, it can become susceptible to voltage collapse without a significant drop in voltage preceding the collapse. Our analyses indicated that by 2016, for the critical contingency, voltage instability could occur when the voltage in the area as high as

98% of nominal. A system in this state is sometimes referred to as voltage "brittle" and is a concern because, with voltages at this level, operators may have little indication that there is a critical voltage condition existing on the grid, and may fail to take appropriate action. It is also an indication that the addition of further reactive supplies in the area such as capacitor banks will have little or no effect on the potential for voltage instability. In addition to considering the addition of capacitors in the area, the Midwest ISO considered the addition of a second 230 kV line between the Boswell, Wilton, and Winger substations. This line addition would also mitigate the voltage collapse condition, but with not as much margin as the proposed line. In addition, this alternative is estimated to cost about $161 M and would not provide any relief to other areas along the route of the proposed line such as in the Alexandria and St. Cloud areas. We also considered alternative new 345 kV transmission line extensions that would similarly support the Maple River 345 kV bus, such as a second Center to Jamestown to Maple River 345 kV circuit, or a new Dorsey to Maple River line. These alternatives would involve about the same or more miles of new 345 kV circuit, at similar costs, and would also not provide necessary relief to the Alexandria and St. Cloud areas that the proposed project will.

Q: Please describe the reliability issues in the Alexandria area that the Midwest ISO identified would also be resolved by the proposed transmission line.

A: The Alexandria area is described electrically by the demand at 12 substations in and around Alexandria. This area is served by three 115 kV transmission lines: Inman to Elmo; Douglas County to Long Prairie, and; Grant County to Elbow Lake. The

Midwest ISO looked at the conditions in this area for projected 2011 winter peak conditions and for 2016 winter peak conditions. This analysis showed that for the modeled 2011 conditions there will be severe line overloads as high as 154% of design capability, and critically low voltages of 52% of design in this area for loss of two of the three 115 kV lines I mentioned. These conditions will deteriorate as load grows in the area beyond 2011. For example, by the winter peak of 2016, even a single contingency loss of the Grant County to Elbow Lake line will result in voltage below design at Elbow Lake. Should the double contingency outage occur in 2016, without the proposed project, voltages at Elbow Lake and surrounding areas would be as low as 47% of nominal, and the Long Prairie to Douglas line would overload by 60%. At these voltage levels, load service could not be sustained in the area.

Q: You mention problems for double line outages. Isn't this a low probability event?

A: It is. However, in actual operations, NERC reliability standards require that the system be adjusted in order to withstand the "next" contingency. This means that after the loss of a single line, system adjustments must be made in order to withstand the next event. Since the next event in this case could result in voltages as low as 47% and loadings and 160% of rating, some action would need to be taken pre-contingency to mitigate the amount of load that could be impacted should the next contingency occur. As there is not sufficient generating facilities in the affected area to mitigate conditions, load shedding of up to 50 MW would be required after a single contingency in order to withstand the next contingency to avoid line overloads. This represents about 27% of the total load in the area for projected 2016 winter. Furthermore, to withstand the next contingency while maintaining adequate system voltages, load shedding of up to 61 MW or nearly one-third of the area load would be required after a single contingency.

Q: How does the proposed Twin Cities to Fargo line resolve the reliability problems identified in the Alexandria area?

A: The project extends a 345 kV line supply from Monticello through St. Cloud to Alexandria, and then continues this line to connect to the Fargo area 345 kV substation. At the Alexandria substation a new step down transformer will be installed that will directly inject into and support the heavily stressed 115 kV system in the area.

Q: After the project is installed, what are the resulting loading and voltage levels for the single and double contingency conditions on the Alexandria area 115 kV lines?

A: For the worst single line loss condition in 2016 I described, the post-project voltage is increased from 89.5% to 100% of nominal. For the double line outage condition line loadings are reduced from 160% to under 65% of rating, and voltage is improved from 47% to 100% of nominal, providing a secure system and substantial margin for load growth for many years in this area.

Q: Did the Midwest ISO consider alternative solutions to resolving the Alexandria area reliability issues you identified?

A: Yes. Redispatch of generation is not an option since there is very little generation available in the area to support the load. We considered the addition of capacitor banks in the Alexandria area as a means of improving voltage conditions. We have already assumed that a 25 Mvar capacitor bank will be installed at Alexandria by 2011 and the effects of this improvement were included in the case results I have already described. If a second 25 Mvar capacitor bank were installed voltages would improve from 47% to 52% of design for the worst condition I have described in 2016, and would still be well below design. The capacitor bank would not materially reduce the line overload conditions expected. We conclude that at best the addition of capacitor banks in the area would only minimally forestall the need for additional means of increasing the supply capability to the area. Therefore, we considered alternative ways to provide additional support to the area instead of extending the Monticello 345 kV to Alexandria. One consideration was to provide the support from the nearest available 230 kV supply points. This would involve extending a 230 kV line from either the Henning 230 kV substation approximately 45 miles to the north of Alexandria, or from the Morris substation about 63 miles to the southwest of the Alexandria 115 kV substation. When we tested these alternative supply options, we found that the reliability margin provided by these solutions was far short of the proposed project. With a new 230 kV support line from the Henning substation alone, which would be the less expensive of the two options, the loading and voltage conditions for the critical single and double contingencies were marginal in the 2011 winter peak case. For example with the 230 kV option in place, voltages at Elbow Lake are improved from 89.5% to 96.1%

for the single 115 kV line outage of Grant County to Elbow Lake, and from 47% to 93.7% for the double line outage of Grant County to Elbow Lake and Inman to Elmo. Because this alternative 230 kV solution does not provide the strength of support that the 345 kV proposal provides, it would be a shorter lived solution. For example, the proposed line can support a load level in the area of about 293 MW before double contingency conditions result in future reliability concerns, while the alternative 230 kV solution could support only 212 MW in the area. This is a difference of about 23 years at an estimated 1.6% load growth rate.

Q: Are there any other reliability issues needing resolution for which the proposed Twin Cities to Fargo line provides the best solution?

A: Yes there are. The St. Cloud area is vulnerable to a number of different contingency conditions that can cause overloading of existing supply lines, low voltage conditions, and loss of load service. Under the present configuration at the Granite City substation, if there was a loss of the Benton County to Granite City tower line involving both circuits, the St. Regis load of approximately 89 MW would be automatically isolated from supply, and in addition, the St. Cloud to Sauk River line would overload to 133% of rating. Lesser overloads would also occur on three other 115 kV lines between St. Cloud and W. St. Cloud and between W. St. Cloud and Granite City. Low voltage will also occur on several 115 kV buses, for example, the Crossroads 115 kV bus would have a voltage of 86.8% of design. If the Granite City substation was re-configured such that the St. Regis load could be maintained for this outage, this additional load during the contingency condition would cause line overloads approaching 233% of rating, unless an additional source of power is introduced into this area.

Q: Are there other conditions of concern in the St. Cloud Area?

A: Yes. We also project that again for 2011 summer peak conditions, in the event of the loss of two Benton 230/115 kV transformers the St. Cloud to Wakefield 115 kV line would overload by 42% of its design rating, as would the St. Cloud to Benton County line by 6%. Voltages at eighteen 115 kV buses would be below design with one as low as 81%.

Q: Describe how the proposed project will mitigate the St. Cloud area reliability issues you have identified.

A: The Twin Cities to Fargo 345 kV line will be tapped at a new Quarry substation on the west side of the city of St. Cloud, and a new 345/115 kV transformer will be installed to support the area. After this project is in service, Granite City substation can be reconfigured to maintain the St. Regis load connection for the double line outage condition I have described. The post contingency line loadings are improved from 133% with the St. Regis load not served, to less than 65% with the St. Regis load intact, and voltage is improved from 86.8% to 101% for these conditions, providing substantial margin for load growth for many years in this area.

Q: Are there any comparable alternative ways of resolving the reliability risks in the area other than the proposed Twin Cities to Fargo transmission line project?

A: No. There are four peaking units at the Granite City substation totaling 77 MW. However, even if all of these units were available and operating during the critical contingency identified, loading on the St. Cloud to Sauk River line segment would still be 104% of rating and this is with the St. Regis 89 MW load still required to be dropped. Reconductoring the overloaded line segments was considered, but we found that even if the overloaded lines were increased in capacity, the entire load in the area can not be served without exceeding equipment ratings at 2011 projected load levels unless at least three of the Granite City generating units were operated pre-contingency. For example, the Crossroads to Westwood line would still be overloaded to 131% for the most critical contingency, if the Granite City generation was off-line. If two of the generating units were operated in anticipation of the contingency, the critical line loading would be 105% of its rating. Finally, we considered how much load would need to be dropped in the area to maintain existing facilities within design capability and found that about 85 MW would need to be shed in the area in addition to the automatic dropping of the 89 MW St. Regis load, which represents about 42% of the total load in the area and is an excessive amount of load shed for the contingencies studied.

<u>TWIN CITIES TO LA CROSSE 345 KV PROJECT</u>

Q: Turning to the proposed Twin Cities to La Crosse 345 kV line project, please describe the Midwest ISO evaluation of the need for and effectiveness of this aspect of the CapX2020 project?

A: We reviewed the projected loadings and voltage conditions in the Rochester and La Crosse areas for the 2011 summer peak period, and also at load levels somewhat higher than the projected 2011 peak as I will describe. That analysis demonstrates that both of these areas can be expected to experience significant reliability problems unless new capacity is introduced into the area.

Q: Please describe these reliability issues.

A: The Rochester area is supplied by three 161 kV lines and supported by 181 MW of installed generation at the Silver Lake and Cascade Creek stations, and two small hydro units on the Zumbro river. Some of this generation can reasonably be assumed to be available to support the system locally in the 2011 timeframe. However, the older less efficient local generating units may be retired in the future, or may not be available for service to relieve contingent conditions in all circumstances. Therefore we evaluated the area reliability with all available generation assumed to be on, and also with the Silver Lake 1, 2 and 3 units and the Cascade 1 unit unavailable to provide local support as a potential scenario. In our 2011 peak period study, even with all local generation on we found numerous line overload conditions will result for various combinations of facility forced outages. For example, the Adams to Rochester 161 kV line will overload for six different combinations involving line and/or generator forced contingencies, with loading as high as 118% of rating for the loss of the Byron to Maple Leaf 161 kV line and the Alma to Wabaco 161 kV line. The same line will be overloaded at 116% of rating for the loss of the Byron to Maple Leaf 161 kV line during the longer duration outage of the Alma JPM generating unit. For the same generator off-line condition, the subsequent loss of a Byron 345/161 kV transformer would also overload this line. The prior outage of the Silver Lake #4 generating unit will cause the Adams to Rochester line to load to 95% of its rating in 2011 for the next contingency loss of the Byron to Maple Leaf line, and would exceed its rating about two years later. The supply line from Alma may also experience overload conditions in the event that the other two supply line routes from Byron and Adams are out of service, even with all local generation in the area assumed available.

If the smaller peaking units that may potentially be retired earlier (Silver Lk 1,2,3 and Cascade 1) are not available, the worst double contingency condition I have described could result in loadings as high as 173% in the 2011 timeframe, and in addition the Adams to Rochester 161 kV line will be loaded to 97% of rating for the single contingency loss of either the Byron to Maple Leaf line, or the Byron 345/161 kV transformer.

Q: How does the proposed project resolve the reliability issues you have identified?

A: The project will install a new North Rochester 345 kV to 161 kV substation with a step down transformer between the 345 kV Prairie Island to Byron 345 kV line and the 161 kV. A 10.5 mile 161 kV line will be built between the new substation and the Northern Hills substation in Rochester. This new transformer and line will parallel the Byron transformer, and the Byron to Maple Leaf 161 kV line which is a critical outage for the area as I have described. When this line is out, the new parallel line will carry additional flow to Rochester to reduce loadings on otherwise overloaded existing 161 kV supply lines remaining in service. The worst overloaded line for example, the Adams to Rochester line will be loaded to only 71% even with none of the local generation on, as compared to 173% for this same condition without the project.

Q: What alternative solutions did the Midwest ISO consider to address the reliability issues you have identified in the Rochester area?

A: Since the reliability issues will begin to occur in the future even with all local generation available, there are no local generation dispatch options that will provide solutions into the future. Other than dropping load, which we estimate would require up to 55 MW or more than 14% of the entire Rochester load in order to maintain a secure system post contingency, we considered uprating of the existing 161 kV supply system. One alternative that would provide relief to the Rochester area issues I have identified would be to install a second Byron transformer, and a new Byron to Northern Hills 161 kV line. This alternative would be very similar in cost to the Rochester area upgrades provided by the proposed project, but would not address any of the reliability issues in the La Crosse area as the proposed project will.

Q: Please describe the projected reliability conditions in the La Crosse area that the proposed project will address.

A: This area is supplied primarily by four 161 kV lines: Alma - Marshland – La Crosse; Alma – Tremval – La Crosse; Genoa – Coulee: and Genoa – La Crosse. There is 1144 MW of generation in and adjacent to the load area, with 610 MW at Alma to the north, 368 MW at Genoa to the south of Lacrosse, 26 MW of refuse burning units, and 140 MW of gas turbine peaking units at French Island in central La Crosse. The load projected for the 2011 summer peak is 492 MW. For this load level, the Midwest ISO analysis found numerous reliability issues associated with serving this area with the existing system. Table 1 in my direct testimony summarizes some of the problem conditions we found.

Table 1

2011 Summer Peak French Island 3& 4 Peakers off		**Loading Level (% Rating)**	
Critical Facility	**Contingency Event**	**Without Project**	**With Project**
Genoa – La Crosse 161 kV Line	Genoa – Coulee 161 kV Line	104%	<65%
Genoa – La Crosse 161 kV Line	Alma JPM Unit + Genoa – Coulee 161 kV Line	124 %	<65%
Coulee – La Crosse 161 kV Line	Alma JPM Unit + Genoa – N. La Crosse 161 kV Line	113%	<65%
Genoa – Coulee 161 kV Line	Alma JPM Unit + Genoa – La Crosse 161 kV Line	103%	<65%
Lansing – Genoa 161 kV Line	Genoa #3 + Genoa – Harmony 161 kV Line	109%	<65%
	Genoa #3 + Alma - Marshland 161 kV Line	105%	<65%
	Genoa #3 + Alma JPM Unit	100%	<65%
Alma – Marshland 161 kV Line	Genoa – Coulee 161 kV Line + Genoa – La Crosse 161 kV Line	100%	<65%
	Genoa #3 + Alma - Tremval 161 kV Line	97%	<65%
Alma – Tremval 161 kV Line	Genoa #3 + Alma - Marshland 161 kV Line	100%	<65%

Q: How does the proposed project resolve these issues?

A: The project will introduce a strong 345 V source into the area by terminating the 345 kV N. Rochester to N. Lacrosse line with a 345/161 kV transformer that will tie into this area centrally. With this new source the worst loading conditions that I described will be relieved for many years into the future, as shown in Table 1. For example the 104% single contingency overload anticipated on the Genoa – La Crosse line would be reduced after the project to less than 65% of capability. Similarly the 124% overload anticipated for the Genoa – Coulee line while the Alma JPM generator is off line would be reduced after the project to less than 65% as well.

Q: What alternatives did you consider for resolving the reliability issues you have identified in the La Crosse area?

A: We considered the effect of operating the only remaining generators in the area that were modeled off-line in the study; the two oils fired peaking units at French Island. However, this option will not relieve all of the overload conditions identified in the area for projected 2011 conditions. We also considered a 161 kV rebuild option for the area. Because each of the four supply routes are subject to overloading this would require a near complete rebuild of the local area system at an estimated cost of more than $173 million. This expenditure would not provide the level of support that is provided by the proposed project nor the ability to accommodate future load growth in the area to a comparable degree. As an example, for the worst loading condition that I have described, the 124 % loading level on the Genoa – La Crosse line, this loading would be reduced after rebuilding to 86% of loading as compared to 48% with the proposed project. This means that loadings on these same upgraded lines will become problematic in the future long before they would with the proposed project in place. In addition, other lines around the area would reach their limits even before these upgraded lines did, which would add to the cost of the alternative in this area.

Q: How would you summarize the effectiveness of both the Twin Cities to Fargo line, and the Twin Cities to La Crosse line in meeting expected local reliability needs?

A: These two 345 kV projects are especially effective in addressing future reliability needs in the Twin Cities and surrounding areas and will provide for sustained reliability for many years. The projects will provide for long term local reliability in both the northern and southern the Red River Valley areas, as well as in the Alexandria, St. Cloud, Rochester, and La Crosse areas. As such, the projects represent a prudent application of higher voltage supply solutions to address a variety of reliability needs in many different areas of the system simultaneously and to provide for those needs for the foreseeable future.

<u>TWIN CITIES TO BROOKINGS COUNTY 345 KV PROJECT</u>

Q: Has the Midwest ISO considered the needs and benefits of the Brookings to Twin Cities 345 kV project proposed by the Applicants?

A: Yes we have.

Q: What, in your opinion, is the primary issue driving the need for this project?

A: The Twin Cities to Brookings County Project ("Brookings project") is essential to the delivery of renewable energy resources requesting interconnection to the transmission system in the vicinity of this project.

Q: Approximately how many generation interconnection requests are pending in the Midwest ISO interconnection queue at this time related to this portion of transmission system?

A: There are nearly 60 generator interconnection requests along or near the counties where the Brookings County - Twin Cities 345 kV line is intended to be routed. This represents a total of approximately 15,940 MW of requests in the general area of project, with over 7,460 MW specifically within the counties along the preliminary Brookings to Twin Cities project route.

Q: Please explain your understanding of why there are so many requests?

A: The State of Minnesota has mandated the local utilities to meet a newly enacted renewable energy standard (RES) requiring 25% of the energy in the state to be generated by renewable resources by 2025 is surely a contributing factor. Xcel Energy, the state's largest utility, has additional requirements. Additionally, Southwestern Minnesota is the strongest area for wind resources within the State of Minnesota; therefore, generation developers are making generation interconnection requests in this area in anticipation of being available and selected by the utilities to meet these new renewable energy standards.

Q: To what extent will the proposed Brookings to Twin Cities project provide necessary incremental capacity to support the delivery of renewable energy that is requesting to be interconnected in the vicinity of the project?

A: Studies by the Applicants have indicated that the project will provide firm incremental power transfer of about 700 MW, taking into account contingency conditions.

Q: What percentage of Minnesota RES could be delivered by the Brookings project?

A: About 700 MW of the estimated 5600 MW of equivalent wind capacity requirement, or about 13% of the RES requirement. This assumes a 35% average capacity factor for the wind turbines in the area, and appropriately sited renewable resources to take advantage of the full 700 MW of incremental transfer capability that the project would provide.

Q: What has been the assumption about this project that the Midwest ISO has applied when studying recent interconnection requests that are in proximity to the route of the line?

A: We have studied these requests both with and without this transmission line in service as a base case project to see how the project impacts the ability of the generators to interconnect and deliver their output to the grid reliably.

Q: To your knowledge, how many interconnection studies and associated generation capacity in MW have been studied assuming the Brookings line project was a part of the base plan conditions?

A: To date, 58 projects have been or are being studied with the Brookings line project as part of the base case. These projects represent 4358 MW of generation.

Q: Why did you make that assumption?

A: The Applicants have indicated the need for and convictions to support he statutory mandates and that based on studies that they have performed and the Twin Cities to Brookings county line is a critical component in meeting the obligations under the RES. We also reviewed their analysis and also believe that the Brookings to Twin Cities line is necessary to accommodate the extensive amount of new generation request we are seeing in that area.

Q: Has MISO been able to confirm that there would be a material impact on the reliability of the system if these new generators are connected and the Brookings to Twin Cities line does not go into service?

A: Yes we have.

Q: Please explain?

A: For some of these new generators requesting interconnection, shorter term solutions may be able to be identified that will enable interconnection and operation for a limited period of time. For others there may be no possible alternative upgrades that can be identified unless and until this Brookings to Twin Cities line is built and placed into service.

Q: How does this project fit into the long-term plan for the area?

A: As I described earlier, this project is needed to reliably deliver new generation developments in the near term, as there are many more interconnection requests in queue today in the area of the line than the present transmission system can reliably accommodate. As such, in developing our long range planning concepts we have included the CapX projects as a part of the base plans upon which the longer term plans are being developed and analyzed. Simply stated, the Brookings County - Twin Cities 345 kV line is, in our opinion necessary to reasonably meet the milestone targets of the Minnesota Renewable Energy standard. Additional facilities will be required to meet the total requirements of the RES which, in our estimation, will require approximately 5,600 MW of total nameplate capacity from renewables. The additional longer term facilities will be designed to work in concert with existing system and expansion plans in the area, including the proposed lines.

Q: Are there other system needs that the new Brookings to Twin Cities line will address?

A: Yes. The line will also provide local reliability benefits to the area.

Q: How will these additional local reliability benefits be achieved?

A: In addition to transferring renewable energy from the wind resource-rich southwest Minnesota area to the 345 kV grid in the Minneapolis area, the project will support the underlying lower voltage transmission systems along the route by installing step-down transformers at Lyon County, Franklin, and Lake Marion, and at a new Hazel Creek substation near Granite Falls. These step-down transformers will reduce loadings on 115 kV and 69 kV circuits extending into these areas from more distant supply sources by injecting a strong source of power at these step-down points along the route. Voltages on these systems will also be supported to provide for better service quality under contingent conditions involving the local transmission systems.

<u>**Additional Benefits of the Proposed Projects**</u>

Q: In your opinion, are there other benefits that you believe the three projects that are the subject of this docket will provide beyond addressing local reliability needs, load growth, and interconnection of renewable resources as you have discussed?

A: Yes. The combined projects connect the Twin Cities area to adjacent areas of the transmission system either directly at or near to existing 345 kV networks and in geographically diverse directions to the northwest, southwest and southeast. This design will provide for a great deal of flexibility in providing access to both existing and future resources within the Midwest ISO market. This high capacity interconnectivity can be expected to have a lowering effect on average marginal energy prices in the upper Midwest part of the Midwest ISO market in the near term. In the long term, this interconnectivity will help to ensure adequate supplies will be available to market participants in the Twin Cities and surrounding areas, and will provide for more options in selection by those market participants of preferred sources of supply.

Q: Does this conclude your testimony?

A: Yes it does.

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Appendix 6: Cost Data

For detailed cost information on the Wisconsin portion of the Proposed 345 kV Project, please see section 2.1.7 of the CPCN, Docket No. 5-CE-136 of January 2011.

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Estimates for 2006 161 kV Alternative and Rochester 161 kV Alternative

2010 La Crosse 161 kV Alternative	Original 2006 Cost in Millions	Updated 2010 Estimate in Millions
Hillsboro 161 kV 30 MVAR bank	1.3	2.4
La Crosse 161 kV 60 MVAR bank	1.8	2.5
Monroe Co 69kV 2-30MVAR bank	2.6	2.6
Rebuild Genoa - La Crosse Tap 161 kV line	9.522	14.49
Rebuild Genoa - Coulee 161 kV line	3.546	5.617
Uprate Adams - Harmony 161 kV line	4.628	10.68
New Genoa - N. La Crosse 161 kV line	17.538	25.9
New Double Circuit tapping the Tremval - Mayfair 161kV line	0.375	0.375
Rebuild Alma - La Crosse Tap 161 kV line	23.509	34.72
N. La Crosse 161kV Substation	4.2	5.2
TOTAL:	**$69**	**$104**

Deficiencies: Assumes French Island bus is at 0.95pu voltage which is required to start the generators

Rochester 161 kV Alternative	Original 2006 Cost in Millions	Updated 2010 Estimate in Millions
Pleasant Valley - Quarry Hill 161 kV line	13.2	23.1
Byron - Northern Hills 161 kV line	4.8	8.4
Pleasant Valley Substation Expansion	1.15	1.15
Quarry Hill Substation	0.7	1.7
Northern Hills Substation Expansion	0.65	1.73
Byron Substation Expansion	1.15	1.15
345/161 kV Transformer and ring bus bay at Byron Substation	4.3	10
TOTAL:	**$26**	**$47**

Total Cost for Alternative to the Proposed 345 kV Project - For the Rochester area the alternative will last until mid-century. However, the alternative will only last until approximately 2013 for the La Crosse/Winona area.	**$152 million**

Total Cost for Proposed 345 kV Project	**$375 million**

2010 La Crosse 161 kV Alternative Cost Analysis

September 2010 161 kV alternative

Rebuilds	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**161**	**69**	**69**	
	Genoa - La Crosse Tap	**Coulee - La Crosse**	**Genoa - Coulee**	**Genoa - Lansing**	**Alma - Marshland**	**La Crosse - Mayfair**	**Marshland - La Crosse Tap**	**Tremval - Alma**	**Tremval - Mayfair**	**Coulee - Swift Creek**	**Coulee - Mt. La Crosse**	**Total**
Length	21	8.5	19.5	20.5	27	4	24	34	31	2	5	197
Install	$12,500,000	$5,060,000	$11,600,000	$12,200,000	$16,070,000	$2,380,000	$14,280,000	$20,230,000	$18,450,000	$500,000	$1,250,000	
ROW	$250,000	$100,000	$240,000	$250,000	$330,000	$50,000	$290,000	$410,000	$380,000	$20,000	$60,000	
Overheads		$370,000	$840,000	$880,000	$1,160,000	$170,000	$1,030,000	$1,460,000	$1,340,000	$40,000	$90,000	
Removal	$920,000	$370,000	$860,000	$900,000	$1,190,000	$180,000	$1,060,000	$1,500,000	$1,360,000	$78,000	$195,000	
Environ fee	$640,000	$260,000	$590,000	$620,000	$820,000	$120,000	$730,000	$1,030,000	$940,000	$0	$0	
subtotal	$14,310,000	$6,160,000	$14,130,000	$14,850,000	$19,570,000	$2,900,000	$17,390,000	$24,630,000	$22,470,000	$638,000	$1,595,000	
Permitting, contingency	$2,150,000	$920,000	$2,120,000	$2,230,000	$2,940,000	$440,000	$2,610,000	$3,690,000	$3,370,000	$100,000	$240,000	
	$16,460,000	$7,080,000	$16,250,000	$17,080,000	$22,510,000	$3,340,000	$20,000,000	$28,320,000	$25,840,000	$738,000	$1,835,000	$159,453,000
Per mile	$783,810	$832,941	$833,333	$833,171	$833,704	$835,000	$833,333	$832,941	$833,548	$369,000	$367,000	

New Line	**161**	**161**	**161**	**161**	**161**	
	Alma - Marshland #2	**Marshland - Onalaska**	**Onalaska - La Crosse**	**Spring Creek - Lake City**	**Lake City - Alma**	**Total**
Length	28	26	5	20	22	101
Install	$16,660,000	$15,470,000	$2,980,000	$11,900,000	$13,090,000	
ROW	$1,360,000	$1,260,000	$240,000	$970,000	$1,070,000	
Overheads	$1,280,000	$1,190,000	$230,000	$910,000	$1,000,000	
Removal	$1,230,000	$1,140,000	$220,000	$880,000	$970,000	
Environ fee	$900,000	$840,000	$160,000	n/a	n/a	
River Crossing					$10,000,000	
subtotal	$21,430,000	$19,900,000	$3,830,000	$14,660,000	$26,130,000	
Permitting, contingency	$3,210,000	$2,990,000	$570,000	$2,200,000	$3,920,000	
	$24,640,000	$22,890,000	$4,400,000	$16,860,000	$30,050,000	$98,840,000
Per mile	$880,000	$880,385	$880,000	$843,000	$1,365,909	

Substation/Transformers

298

$258,293,000

		Tremval	**Jackson Co**	**La Crosse**	**Coulee**	**Marshland**	**Onalaska**	**Lake City**	**Spring Creek**	
	Install and land	$2,195,000	$2,311,000	$4,720,000	$11,033,000	$8,230,000	$13,363,000	$13,363,000	$2,195,000	$868,212
3.09%	Overheads	$67,826	$71,410	$145,848	$340,920	$254,307	$412,917	$412,917	$67,826	
5%	Environmental Fee	$109,750	$115,550	$236,000	$551,650	$411,500	$668,150	$668,150	$109,750	
	Subtotal	$2,372,576	$2,497,960	$5,101,848	$11,925,570	$8,895,807	$14,444,067	$14,444,067	$2,372,576	
15%	Permitting, contingency	$355,886	$374,694	$765,277	$1,788,835	$1,334,371	$2,166,610	$2,166,610	$355,886	
		$2,728,462	$2,872,654	$5,867,125	$13,714,405	$10,230,178	$16,610,677	$16,610,677	$2,728,462	$71,362,639

$329,655,639

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