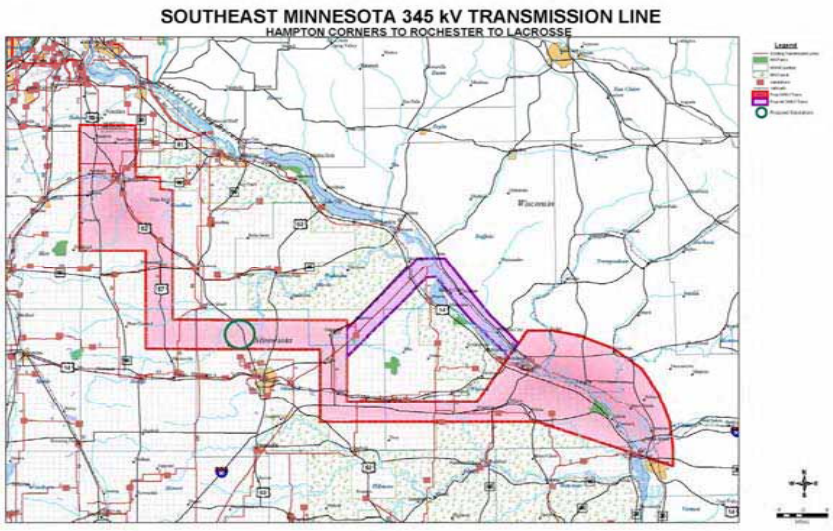

TSSR Appendix B: 2009 Update to the 2006 Rochester / La Crosse Load Serving Study.

2009 Update to the 2006 Rochester / La Crosse Load Serving Study

Xcel Energy/Dairyland Power Cooperative/Rochester Public Utilities

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Contents.

0: Executive Summary.

The purpose of this analysis was to update a load serving study conducted in the period of years from 2003-2006 with newer system models, load forecasts and known topology changes to re-validate the findings for both the project proposal and the lower voltage alternatives for La Crosse and Rochester, with emphasis on the Wisconsin system. Results and analysis from a previous study report created by Dairyland Power Company and Rochester Public Utilities -- the report entitled *Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study, Transmission Analysis for Southeastern Minnesota and Southwestern Wisconsin of March 13, 2006* (Rochester/La Crosse Study)-- were relied on heavily in conducting this updated report. ***This report is anupdate to that study and is not intended to stand-alone without that previous study report as supporting documentation***.

This 2009 update to the 2006 Rochester / La Crosse study has reconfirmed the need for the following facilities to meet the load serving needs of the La Crosse / Winona and Rochester areas, while enhancing greater area system reliability and providing additional generation outlet support:

- A 345 kV transmission line from the Hampton Substation near Hampton, Minnesota (southeast of the Twin Cities), to a new North Rochester Substation near Rochester, Minnesota, to a substation in the area of La Crosse, Wisconsin. Two 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.

1: Background & Scope of Study.

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 – hybrid 345 kV/161 kV –would reliably serve those areas for many years into the future.

The analyses in the original study and this study update focused on determining the most cost-effective way to serve the areas in the long term. Options studied included 161 kV/345 kV options and options employing only 161 kV facilities.

The 345 kV voltage class was chosen because it is a more efficient bulk-delivery voltage class than 161 kV, and there are no voltage classes in the La Crosse and Rochester areas between 161 kV and 345 kV. Introducing a new voltage class such as 230 kV would likely serve the area less reliably for a shorter period of time, and a new type of transformer – 230 kV/161kV – would have to be introduced into the area. Losses would likely be higher with 230 kV, and greater overhead costs would likely be incurred due to the need to carry non-standard spare 230/161 transformers or to install extra 230/161 transformers to prepare for failures of those banks.

The previous study report recommended "construction of a radial 345 kV line from Prairie Island to North Rochester to North La Crosse be constructed at this time to solve load-serving reliability issues in the Rochester, MN and La Crosse, WI areas."[1] In addition, two 161 kV lines were recommended to connect North Rochester substation to the Rochester load serving transmission network.

This updated study evaluated system alternatives for long-term the load serving needs of the Rochester and Winona/La Crosse areas using 2009 forecasts and system topology. The analyses confirmed that the best performing system alternative is a 345 kV transmission line between the Twin Cities with the La Crosse area and two 161 kV transmission line connections to the City of Rochester.

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 previous study is included as an Appendix to this report.

1.1: La Crosse System Reliability Issues.

1.1.1: Existing System.

The La Crosse/Winona area, which has its highest electricity demand during the summer, is also 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; northeast to include Arcadia, Wisconsin; northwest to include the area of Winona/Goodview, Minnesota; and southwest to include La Crescent, Houston and Caledonia, Minnesota.

[1] Page 1, section 1.1 of Rochester/La Crosse Study.

Northern States Power Company, a Minnesota Corporation (Xcel Energy) and Dairyland Power 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 1.1-1.

[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 relative weak transmission source from the east.

Figure 1.1-1
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, 392.5 MW URGE)
    Alma units 1–5 (coal, 190.1 MW URGE)
- Genoa, located about 20 miles south of La Crosse:
- Genoa Unit 3 (coal, 351.3 MW URGE)
- 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)

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. New high voltage transmission in this area will provide transmission support that will alleviate these contingencies.

1.1.2: Reliability Issues.

The capabilities and limitations of the electrical system serving La Crosse were studied in the 2006 Rochester/La Crosse Study. A copy of the Rochester/La Crosse Study is found in Appendix C. The Rochester/La Crosse Study began by recognizing that La Crosse's peak load was 414 MW on August 20, 2003. For the original study, planning engineers then modeled how the system would operate during summer 2009. They estimated peak demand to be 494 MW in 2009 by applying a 3 percent annual growth rate to historical peak demand. Planning engineers found that without further improvements, the existing transmission system would not be able to reliably serve customers at or above the 494 MW level. The critical contingency was the loss of the Genoa–La Crosse–Marshland 161 kV transmission line that results in an overload of the Genoa–Coulee 161 kV transmission line. The contingency scenario analyzed also assumed Alma and Genoa generation were in operation and the French Island peaking units were not operating.

Additionally, analysis was undertaken in the 2006 study to further examine performance of the system and identify critical contingencies under varying generation assumptions. The MAPP 2006 Series 2008 Summer Peak model was used to identify the critical La Crosse area load level for these scenarios. The model was then modified to reflect recent planned additions such as an upgrade to the Genoa–Coulee 161 kV transmission line. The model was configured to represent the French Island Units 1 and 2 (13 MW each) on-line and the French Island Units 3 and 4 (70 MW each) off-line. Units 1 and 2 are fueled with refuse-derived fuel and generally must be run whenever fuel is available. The La Crosse area load in the original 2008 model was scaled upward until transmission power flows were greater than 100 percent of the transmission lines' normal rating and load serving bus voltage was less than 90 percent.

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. By June 2010, two 60-megavolt ampere reactive (MVAR) capacitor banks will

be added to the La Crosse area 161 kV system and the system capability will be increased 10 MW to 470 MW. Figure 1.1-2 illustrates this contingency scenario.

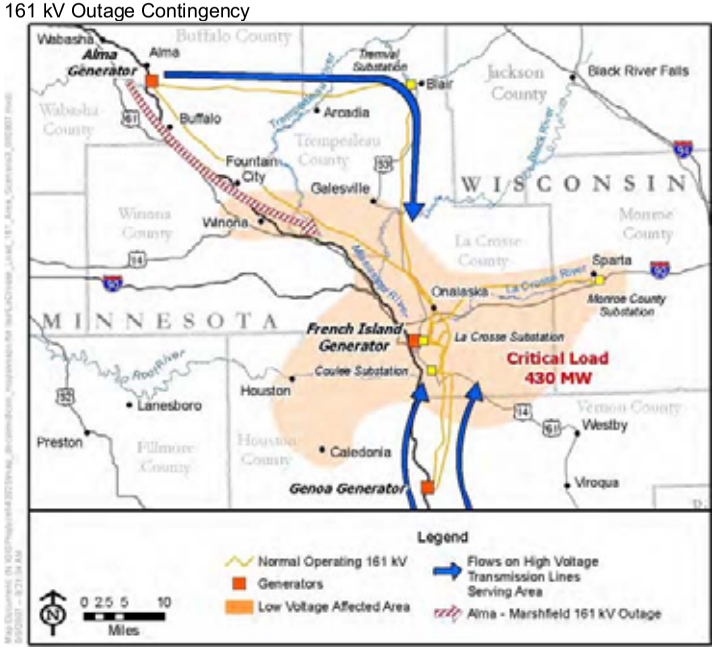
Figure 1.1-2
La Crosse/Winona Area Genoa–Coulee 161 kV Contingency

The transmission system can be further supported by operating the two 70 MW peaking units at French Island. If these generators were 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 610 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. The generators are less reliable than transmission facilities and more expensive to operate than other generation resources. Additionally, 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 1.1-3 shows the system under this contingency scenario.

Figure 1.1-3
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. On July 17, 2006, actual flows on the transmission lines reached an all-time coincident peak load of 447 MW. If French Island peaking generation is used for system support, the maximum

capacity of the system reaches 580 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 1.1-4 illustrates this contingency scenario.

Figure 1.1-4
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 140 MW, up to a total of 450 MW.

1.1.3: 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 seven 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 2008 at each of the substations and then projected loads at each of the substations.

For substations served by Dairyland distribution cooperatives, the forecast was estimated by first calculating an average load for years 2004 to 2008 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 2009–2020 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.

Figure 1.1-5 shows the actual annual peak demand for power at each substation in 2002, 2006 and 2008 and provides a forecast of annual peak demand at each greater La Crosse area substation for 2010, 2015 and 2020.

Figure 1.1-5
Actual and projected Future Substation Loads for the La Crosse/Winona Area (Summer Peak)

La Crosse Area Load Serving Substations	Actual			Future		
	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	4.22	4.43	4.66
Brice	5.12	6.93	6.36	6.29	6.85	7.45
Caledonia City	3.42	3.90	3.51	3.72	4.06	4.44
Cedar Creek	3.54	5.17	4.93	4.54	4.94	5.38

La Crosse Area Load Serving Substations	Actual			Future		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Centerville	2.79	3.34	4.20	3.46	3.76	4.09
Coon Valley	4.29	5.22	3.96	5.31	5.58	5.86
Coulee	53.50	60.30	52.91	63.96	67.40	71.03
East Winona	8.92	9.47	11.09	11.54	12.74	14.07
French Island	19.50	29.04	24.06	35.44	37.34	39.35
Galesville	6.91	6.89	5.50	7.00	7.36	7.73
Goodview	31.78	35.33	33.61	34.13	36.14	38.27
Grand Dad Bluff	1.67	1.91	1.63	1.70	1.85	2.01
Greenfield	2.85	3.43	3.06	3.12	3.39	3.69
Holmen	14.97	13.16	14.91	15.21	15.99	16.80
Houston	3.61	3.78	3.38	3.55	3.88	4.25
Krause	4.12	4.48	4.54	4.29	4.67	5.08
La Crosse	58.43	50.33	46.98	51.70	54.34	57.11
Mayfair	43.90	46.58	45.39	48.29	51.26	54.44
Mound Prairie	2.18	2.02	2.39	2.27	2.49	2.72
Mount La Crosse	1.64	2.00	2.09	1.95	2.12	2.31
New Amsterdam	3.88	4.66	4.46	4.71	5.12	5.57
Onalaska	11.73	12.93	10.48	13.50	14.54	15.67
Pine Creek	2.03	2.36	1.84	2.01	2.20	2.41

La Crosse Area Load Serving Substations	Actual			Future		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Rockland	4.18	4.14	3.10	3.95	4.15	4.37
Sand Lake Coulee	2.99	2.84	2.59	2.73	2.97	3.24
Sparta	29.65	32.47	31.74	33.27	35.84	38.61
Sparta (DPC)	1.15	1.36	1.16	1.24	1.42	1.63
Swift Creek	17.10	24.80	21.83	28.22	29.65	31.17
Trempealeau	4.43	3.94	3.68	4.00	4.20	4.41
West Salem	23.30	24.52	23.97	25.97	27.63	29.41
Wild Turkey	1.17	1.20	1.35	1.31	1.44	1.57
Winona	46.30	51.91	51.19	51.92	55.23	58.77
Total Load MW:	**425.12**	**464.59**	**435.34**	**484.52**	**514.98**	**547.57**

Critical Load Level = 470 MW (Transmission Only with Genoa – Coulee 161 kV Outage)						
MW at risk				**14.53**	**45.01**	**77.57**

Critical Load Level = 450 MW (With JPM outage and Genoa - Coulee 161 kV outage)						
MW at risk				**34.52**	**64.98**	**97.57**

Forecast information based on substation load data 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 2009-2010. 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.

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

1.2: Rochester System Reliability Issues.

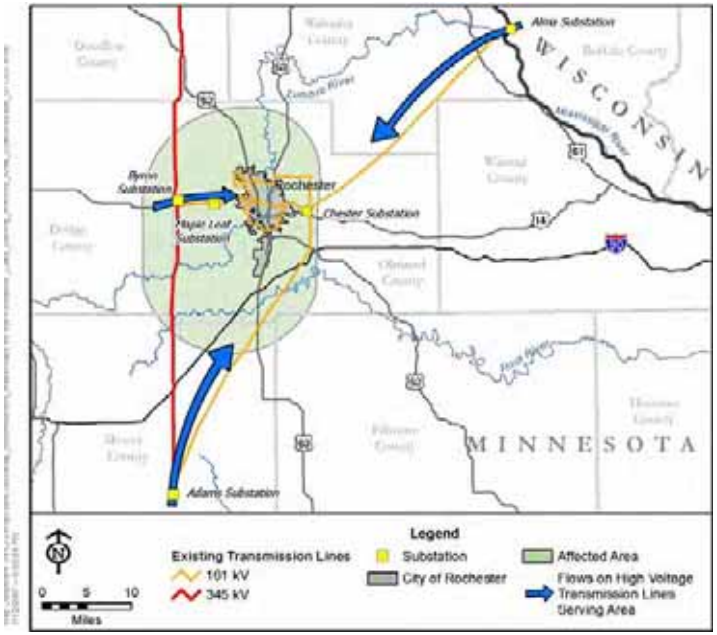
1.2.1: Existing System.

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 substations lower the incoming transmission line voltage and the outgoing distribution lines deliver electrical power to customers. 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 1.2-1 shows the affected area and a graphical depiction of the general power flows on these high voltage transmission lines in the Rochester area.

Figure 1.2-1
Affected Rochester Area and Flows on High Voltage Transmission Lines Serving Area



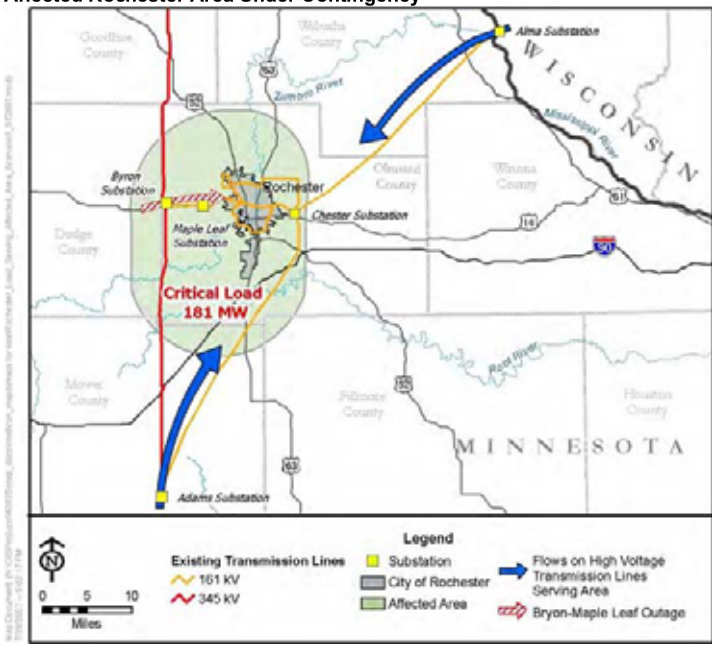
1.2.2: Reliability Issues.

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 in 1985, to 131,400 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, thus, some area generation was being used to serve local load.

Utilities use the term contingency to describe how the system will work when one or more of the existing transmission lines and[BM1] generators are out of service. 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 1.2-2 shows the system with the outage of the Byron–Maple Leaf transmission line and the resulting 181 MW critical load level.

Figure 1.2-2
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 an outage of the Byron – Maple Leaf 161 kV line occur. In 2005, the demand for power on the RPU system exceeded 145 MW for about 5,400 hours.

The Rochester area system peak occurred in 2006 and reached 330 MW. With all local generation operating, the system can support[BM2] 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 alleviate the reliability deficiency, additional power sources into the Rochester area are needed.

1.2.3: Timing of the Need.

To determine the timing of the Rochester area need, planning engineers developed a peak load forecast for the area's distribution substations serving RPU and People's customers. The actual loads from 2002 to 2008 at each of the substations were reviewed and forecasts estimating the amount of electricity that will be used (load) through 2020 were prepared.

The forecast for the Rochester area was based on SMMPA's Integrated Resource Plan for RPU substations. SMMPA's forecast from 2009 – 2035 used a growth rate of 1.92% to 2.84%. For Peoples Cooperative Services substations, the forecast was estimated by first calculating an average load for years 2004 to 2008 and then applying a growth rate of 1.3%. The forecast data included projected impacts from conservation and load management programs to control customer loads. Each of these "demand side management" (DSM) programs is directed at minimizing the peak load at any given moment by reducing or eliminating the 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, some 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 of the day when demand is not so high. The ultimate objectives of DSM programs are to lower rates, delay the need to construct new power plants, improve system efficiency, stimulate consumer interest in more efficient appliances and reduce harmful environmental emissions associated with electrical generation.

Figure 1.2-3 shows the actual summer peak demand for power at each substation in 2002, 2006 and 2008 and provides a forecast of annual peak demand at each Rochester area substation for 2010, 2015 and 2020. Appendix A.3 contains the historical peak data and forecast through 2020.

Figure 1.2-3:
Actual and Projected Substation Loads for Rochester Area (Summer Peak)

Rochester Area Load Serving Substations	Actual			Projected		
	Load MW 2002	Load MW 2006	Load MW 2008	Load MW 2010	Load MW 2015	Load MW 2020
Airport (DPC)	1.97	3.73	2.94	3.30	3.52	3.75
Bamber Valley (RPU)	25.44	28.67	25.09	26.95	32.84	39.33
Canisteo (DPC)	2.35	2.77	2.61	2.65	2.83	3.02
Cascade Creek (RPU)	48.34	54.47	44.58	47.88	56.11	64.14
Chester (DPC)	2.50	2.80	2.38	2.63	2.80	2.99
Genoa (DPC)	4.54	6.06	6.51	5.64	6.02	6.42
IBM (RPU)	25.44	17.20	14.55	15.63	17.88	20.11
Kalmar (DPC)	2.15	2.70	2.63	2.55	2.72	2.90
Marion (DPC)	3.33	3.01	2.91	2.87	3.06	3.26
Marvale (DPC)	3.29	3.31	2.15	3.05	3.25	3.47
Crosstown (RPU)	15.26	28.67	35.68	38.32	43.85	48.02
Northern Hills (RPU)	25.44	22.94	26.18	28.12	32.35	41.08
Oronoco (DPC)	5.69	8.97	5.49	7.11	7.59	8.09
Pleasant Grove (DPC)	1.63	1.83	1.40	1.51	1.62	1.72
Pleasant Valley (DPC)	1.72	2.04	1.75	1.8	1.93	2.06
Ringe (DPC)	4.85	3.67	5.08	3.98	4.25	4.53
Rock Dell (DPC)	1.76	2.38	2.05	1.99	2.12	2.27
Silver Lake (RPU)	48.34	54.47	52.46	56.35	61.30	66.43
Willow Creek (RPU)	27.98	37.27	35.32	37.94	44.66	51.13
Zumbro River (RPU)	38.16	43.01	36.11	38.79	44.62	50.37
Total (MW)	**290.18**	**329.97**	**307.87**	**329.06**	**375.32**	**425.09**

Critical Load Level = 181 MW (transmission only) Byron – Maple Leaf 161 kV Outage						
MW at Risk (rounded)	**109**	**149**	**127**	**148**	**194**	**244**

The historical data and forecast presented above 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.

To reliably serve the Rochester area demand, new power sources are needed.

1.3: Area Study History.

There are three studies that led to the proposed Twin Cities – La Crosse 345 kV Project. The first two studies, the local Rochester study and the local La Crosse/Winona study, focused on localized solutions. The third study, the Rochester/La Crosse Study, evaluated more regional system alternatives to address the load serving issues in both Rochester and La Crosse.

In the local La Crosse/Winona study, planning engineers screened 23 possible 161 kV alternatives to meet identified load serving needs and further evaluated the top five alternatives. Planning engineers concluded that even the best performing 161 kV option was inadequate to meet identified needs for several reasons.

(1) First, the phase shifting transformer application in the La Crosse area prevented transmission overloads post-contingency in the short-term but did not eliminate the need for additional transmission facilities as the area load increased.

(2) Second, the 161 kV alternative would require more 161 kV transmission facilities to meet need and, in the long run, a 345 kV transmission line likely would be required to serve the load. This is discussed further in Appendix D, the direct testimony of Mr. Jeff Webb. Thus, a 345 kV solution would meet load-serving needs for several decades longer with fewer transmission lines.

The local Rochester area load serving study considered four 161 kV options and three 345 kV options to serve the growing demand in the Rochester area. In that study, the 161 kV alternatives were estimated to last until approximately 2030. The 345

kV options provided more long-term solutions. The best performing and least cost option was a new 345 kV transmission line connected to the Byron to Pleasant Valley 345 kV line connect to the eastern side of Rochester. Planning engineers determined, based on current load growth, that this solution would reliably serve the load until approximately the middle of the century.[3]

These two local studies laid the foundation for the third study, the regional Rochester/La Crosse Study. Based on the local Rochester study's conclusion that the 345 kV solution was optimal for the Rochester area and the La Crosse study's finding that 161 kV alternatives could not meet load serving needs in the La Crosse/Winona area, Rochester Public Utilties (RPU) and Dairyland (DPC) (leading a study team which also included planning engineers from Xcel Energy, Southern Minnesota Municipal Power Agency (SMMPA), American Transmission Company (ATC), Alliant Energy and Great River Energy) undertook the Rochester/La Crosse Study to identify a 345 kV regional solution. To meet the need for load serving support to the 161 kV system in the La Crosse/Winona area, planning engineers focused on a Prairie Island Substation connection and a substation connection in La Crosse in evaluating their options.

1.4: Minnesota Certificate of Need Recommended Plan.

Based on the three previous studies detailed above, Xcel Energy and Northern States Power Company applied to the Minnesota Public Utilities Commission for Certificates of Need to construct the following facilities:

- A 345 kV transmission line from the Hampton Substation near Hampton, Minnesota (southeast of the Twin Cities), to a new North Rochester Substation near Rochester, Minnesota, and a 345 kV transmission line from the new North Rochester Substation to a substation in the area of La Crosse, Wisconsin (this transmission line will of necessity include crossing the Mississippi River). The 345 kV line would be approximately 120 to 140 circuit miles depending on where it is routed. .

- Two 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. The North Rochester – Northern Hills 161 kV line would be approximately 10 to 15 circuit miles long and the North Rochester – Chester 161 kV line would be approximately 20 to 30 circuit miles in length.

The Minnesota Public Utilities Commission granted Certificates of Need for these facilities in April 2009.

[3] Based on the updated load forecasts included in attachment A, the 345 kV/161 kV solution will last long past the mid century time-frame.

2: Study Update Conclusions & Recommended Plan.

This study update has verified the results of the original study for both the recommended solution and the project alternatives using the updated system model described in section 4.2.2 and 2009 load growth projections.

To solve the load serving needs for the Rochester and La Crosse / Winona areas, the recommended plan is to build a 345 kV line from North Rochester to the La Crosse area. 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.

In addition, the recommended plan includes building the Hampton-North Rochester 345 kV line and associated 161 kV lines consistent with the proposal discussed in section 1.4 above.

The Minnesota Public Utilities Commission granted Certificates of Need for these facilities in April 2009. In its order, the Commission authorized construction of the 345 kV transmission line with double circuit structures that would be capable of carrying two 345 kV circuits. One 345 kV line would be installed during construction; a second could be added when conditions warrant.

3: Study History & Participants.

The study participants are listed in the following table.

Parties to Work Scope
Dairyland Power Cooperative
Northern States Power Company (Xcel Energy)
Rochester Public Utilities

In late February 2009 the study participants started meeting to develop the scope of the study and to agree on the models, methodologies and options to be used. The following table shows the schedule created at the beginning of the study. All of the listed activities were performed as part of the study.

Transmission Studies Project Scope Sheet			
Project Name:	La Crosse CapX2020 CPCN Study		
Participants:	Xcel Energy, Dairyland Power Cooperative, Rochester Public Utilities		
Date:	3/10/2009		
Study Phase	**Task**	**Worker**	**Comments**
Powerflow	Create new base system model	Xcel	MRO 2008 Series 2014 SUPK model, including Xcel topology and load corrections, not including RIGO.
Report	Review old report	Xcel	Determine load levels used in previous study.
Report	Create template for report	Xcel	Create template from old report to use for the new report, this will show continuity between the 2 studies. Information will be entered as the study progresses.
Report	Gather information from TO's, review model including distribution of loads	Xcel, DPC, RPU	TO's make sure load is distributed correctly so load pockets can be grown accurately and that system topology is correct
Powerflow	Revise base system model	Xcel	Enter information from TO's into model
Powerflow	Adjust load pockets	Xcel	Adjust each load pocket independently to load levels used in the previous study, while determining what year this will represent with new growth patterns.
Powerflow	Finalize and agree to base system model	Xcel, DPC, RPU	Xcel Energy will finalize model and send it out to be agreed upon by the other TO's. Once the model is agreed to by all participants, the analysis will begin.
Powerflow	Primary analysis, ACCC and AC FCITC	Xcel	This is the analysis that will be completed on the 345/161 kV option, North Rochester-North LaCrosse. Sensitivity will be completed with and without Hampton-North Rochester 345 kV segment included.
Powerflow	Alternative analysis, ACCC and AC FCITC	Xcel	This is the analysis that will be completed on the 161 kV option identified in the previous study. Sensitivity will be completed with and without Hampton-North Rochester 345 kV segment included.
Powerflow	Need analysis, Primary v. Alternative	Xcel, DPC, RPU	This will be a comparison between the 345/161 kV and 161 kV options, interpreting the study results.
Report	Complete and review draft report	Xcel, DPC, RPU	

4: Analysis.

4.1: NERC Criteria.

Transmission 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 voltage and thermal limits of the transmission facilities will be within established limits, there will be no cascading outages, and only planned and 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 criteria most applicable to transmission planning are listed in the Appendix showing NERC criteria.

4.2: Models employed.

4.2.1: Steady State models used in 2006 Rochester / La Crosse study.

The base models used for the analysis in the original 2006 study are discussed in section 3.0 on page 67 of the Rochester / La Crosse Study included with this report in Appendix C. The model used was the 2009 summer peak case from the 2003 series of models developed by the Midwest ISO.

4.2.2: Steady State models used in current study update.

The base models used for the steady-state (powerflow) analysis are the models of the year 2014 summer peak load conditions from the 2008 series of models created by Midwest Reliability Organization. Those models were modified to include the load levels and transmission topology expected in the year 2012. The significant changes to the model are in the following bulleted list.

- The Monroe County capacitor installation was changed to be 2x30 MVAr.
- Generator 3 at Nelson Dewey was deleted from the case; that generator has not been granted approval to be built.
- Generation on the Spencer 69 kV bus was removed. This generation is not expected to be put in service.
- RIGO facilities were removed from the model. The implications of the additions of these 161 kV lines is discussed in section 6.4 of this report, timing of the Rochester area need.
- The French Island two 70 MW peaking generators were turned off.

- The Wisconsin hydroelectric generators were set to be generating at 50% of their maximum capabilities.
- For the cases modeling the Hampton-Rochester-La Crosse 345 kV line, the CapX 2020 Group 1 facilities[4] were all included.
- The Lansing-Genoa 161 kV line is presently limited to 223 MVA (800 A) by substation equipment under both normal and emergency. This equipment is assumed upgraded in the study model.

The generation and transmission improvements required for the Regional Incremental Generation Outlet (RIGO or Pleasant Valley Improvements) project were not included in the study update models. As discussed in section 6.4 of this report, if the remaining two RIGO lines go in service, some Rochester load serving capability is realized. The CapX2020 Group 1 facilities were also not included in the base models for this analysis.

The primary study methodology employed in this study was using the base load levels in the models and growing those load levels to higher levels to determine the system "breaking points". To do this, the load at each substation is grown in proportion to its initial load. For instance, if the La Crosse area load is to be grown from its 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. This is consistent with the fact smaller substations' loads tend to grow more slowly since they tend to be more rural than large substations' loads. With this study methodology, the absolute values of loads at each substation are less important than the initial relative distributions of loads. In this study, the initial loads were well defined. The loads used were the same as used in the Alternative Evaluation Study (AES) conducted by the project team for the Rural Utilities Service for the Rochester area and La Crosse area load-serving needs, and were based on spring 2009 forecasts. Attachment A to this report shows the load forecasts used.

The Rochester area loads included loads served by Dairyland Power Cooperative, RPU, and SMMPA.

The La Crosse area loads included loads served by Dairyland Power Cooperative and Xcel Energy.

4.2.3: Steady State model comparison.

The purpose of this study update was to confirm that with updated load forecasts and topology for the study area, the proposed project is still the best way to reliability serve

[4] The CapX 2020 Group 1 facilities include the following four projects: Fargo – Twin Cities 345 kV line, Brookings Co. SD – Twin Cities 345 kV line, Bemidji – Grand Rapids 230 kV line, and this Proposal, Twin Cities – La Crosse 345 kV line.

the load. In comparing the 2003 series model used for the Rochester / La Crosse study with the 2008 series used in this update the following observations can be made:

- For the Rochester area there have been no infrastructure upgrades of significance to the transmission system. Therefore, the only relevant difference between the two models for the Rochester area is the upgraded load growth forecast.
- For the La Crosse/Winona area the only significant topology difference is the placement of capacitor banks. In the 2003 series models there were 2 x 60 MVAR banks placed at La Crosse. This configuration has been corrected in the updated study models to have one of the banks at La Crosse, and one at Monroe County. This change is not significant enough to change the results of the planning study. Therefore, similar to Rochester, the only significant difference between the two models for the La Crosse / Winona area is the upgraded load growth forecast.

4.3: Conditions studied.

4.3.1: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%. Analysis was done while only growing the real (MW) load.

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 Appendix A.

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.

4.3.2: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 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

4.3.3: 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.

4.4: Options evaluated.

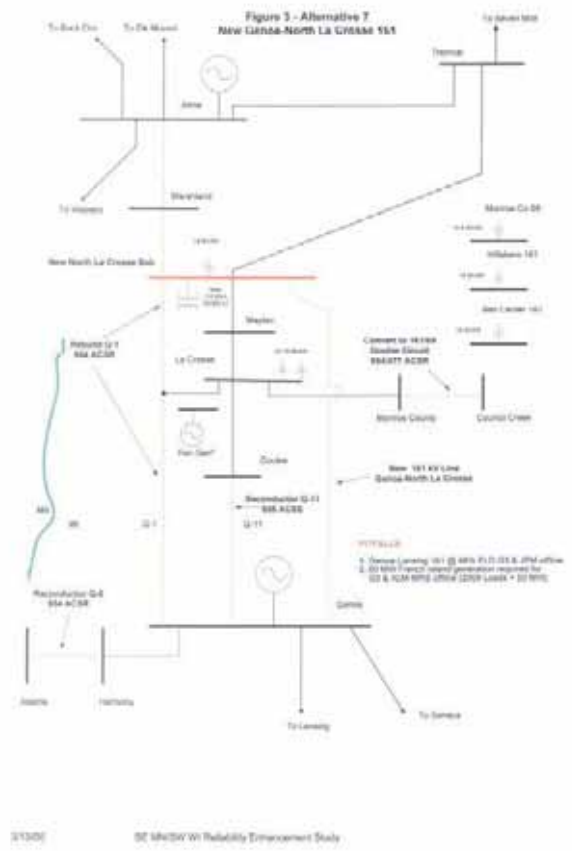
4.4.1: La Crosse & Rochester Primary option.

The primary option for serving load growth in the La Crosse/Winona and Rochester areas is a 345 kV line from Hampton Corner to a new North Rochester substation North of the city of Rochester, Minnesota, and then continuing on to cross the Mississippi River and connect to the La Crosse existing 161 kV transmission system. In addition, two 161kV lines are proposed from North Rochester substation to Northern Hills and Chester substations to connect the new 345 kV line to the existing 161 kV Rochester transmission system. This option will provide a reliable outside source for the vital loads in those growing areas.

The terminus in La Crosse is dependent on the Mississippi River crossing chosen through the route permit process. Three potential river crossing areas have been identified: Alma, Winona and La Crescent. The following map depicts, at a general level, the potential river crossing options.

4.4.2: La Crosse System Alternative.

The system alternative for the La Crosse area 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 have four 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. This area alternative as studied in the original Rochester/La Crosse Study is shown below. It is discussed at length in the original Rochester & La Crosse planning study, which is included in the Appendix C of this report.



4.2.3: Performance of La Crosse 161 kV alternative.

Following the original 2006 Rochester/ La Crosse Study and in preparation for the Minnesota Certificate of Need hearings in 2008, Midwest Independent System Operator (MISO) did an independent review of the need to produce testimony. The testimony of Mr. Jeff Webb, an engineer at MISO, is attached to this report as Appendix D. MISO's independent evaluation was done using a third study model, the MTEP 2006 series with the most current load forecasts available at that time. It was Mr. Webb's finding that the 161 kV alternative 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 and would render 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 the 345 kV proposed 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 proposed 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.

This result was confirmed with this new study update. Based on the powerflow results, the 161 kV option allows for 6 MW of load serving capability. Based on the loading forecasts including in Attachment A of this report, that will reliably serve the La Crosse / Winona area until approximately 2013 assuming the new lower growth forecasts are realized. The next transmission fix for the area would then be a new 345 kV source which the proposed facilities will provide.

In the previous study, the 161 kV alternative was shown to last until approximately the 2026-2028 timeframe. This differs from the results found in this study due to the following major drivers.

- The voltage criteria for the French Island generator buses was refined in this study. The French Island voltage was said to meet criteria only if it was at least .95 pu.
- The System Alternative studied in this study – the Genoa-North La Crosse 161 kV line – did not include other line work (re-conductors or rebuilds) as did the original Rochester & La Crosse study.

4.4.3: Rochester Load Serving Analysis.

To meet the load serving needs for the Rochester area, a new North Rochester Substation is proposed to be connected to the Prairie Island to Byron 345 kV line. This substation will then be connected to the Rochester load serving transmission system via two 161 kV lines to Northern Hills Substation and Chester Substation. This

configuration will serve Rochester load levels past the mid century time-frame.

As part of this updated study, planning engineers conducted a sensitivity analysis regarding the Hampton – North Rochester segment of the 345 kV transmission line. Planning engineers determined that the new Hampton source enhances regional reliability by creating a second 345 kV source into the Rochester area. If the Prairie Island – North Rochester – Byron 345 kV transmission line is out of service, the Hampton Corner – North Rochester 345 kV transmission line could be relied upon to provide service.

The Hampton Corner – North Rochester 345 kV connection will also provide long-term load serving benefits to the Rochester area. The existing high voltage transmission system in the Rochester area with the addition of the North Rochester – La Crosse area segments of the 345 kV , the potential RIGO improvements and the reconductor of the Rochester – Adams 161 kV line) will not be able to reliably serve the Rochester area as early as 2032 (dependent on load forecasts as discussed in Section 6.1). The limitation arises when there is a prior outage of the Prairie Island – North Rochester 345 kV line and a subsequent fault and outage of any segment of the 345 kV line between North Rochester Substation and Hazleton Substation (Iowa). The worst-case contingency would be on the North Rochester – Byron 345 kV segment which limits load serving capability to approximately 655 MW. The Rochester area is expected to reach this demand level by approximately 2032-2049 depending on load growth patterns following the current downturn in demand. With the Hampton Corner – North Rochester 345 kV segment, the system capability increases to 974 MW, which could serve the area load well beyond the mid-century timeframe.

4.5: Performance of steady state evaluation methods.

Some studies use a very wide footprint of loads as their sink; this allows fewer loads in any one area to be increased, so no one area is likely to experience voltage issues; in such an analysis, the DC contingency analysis suffices. But this study could not use that faster form of analysis. Therefore, AC contingency analysis was employed, in order to capture those voltage issues.

The below table shows the areas monitored for transmission facility violations. Transmission Branches 69 kV and above in those areas and emanating from those areas were monitored for overloads. Also, voltages on buses 100 kV and above in those areas were monitored, as were the voltages of generator buses in the area.

Monitored 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

5: Results of detailed analyses.

5.1: Powerflow (system intact & contingency).

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.

The following table summarizes the load-serving capability of the La Crosse area under various transmission options. All options have the Monroe County-Council Creek 161 kV line out of service. The key column in that table 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.

As can be seen from the following table, without any transmission improvements in the La Crosse area, service to customers would need to 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 Hampton-Rochester-La Crosse 345 kV line is 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.

The following table 5.1.1 shows the system capabilities of the 345 kV transmission line with and without the capacitor additions. Note that again, for the purpose of this transmission planning study update, this evaluation was done assuming that the new transmission line would not be co-located (or double circuited) with existing transmission facilities.

Table 5.1.1 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 (480 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 (480 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 Crosse4x80	Genoa-Lansing 161 (264 MVA emergency rating)	La Crosse-La Crosse Tap (480 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

5.2: Reactive Power Requirements.

5.2.1: 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 this 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.

5.4: Losses: Technical Evaluation.

The below table 5.4.1 summarizes the losses for cases studied.

Table 5.4.1: Losses

Year	Case	Peak System Losses/ MW	Loss difference from base case/ MW	Annual energy loss savings/ GWh
2012	Base case as revised	18732		
2012	Alternative 1: Hampton Corner-Rochester-North La Crosse 345 kV line and Rochester area 161 kV lines added	18694	-38	100
2012	Alternative 2: 161kV La Crosse Alternative added	18698	-34	90

Concentrating on the peak losses, a few observations can be made from the above table.

- Adding transmission in the area reduces losses.
- The 345 kV option reduces losses more than the 161 kV option.

5.5: Losses: Economic Evaluation.

The below worksheet shows the derivation of the loss benefit in terms of the amount of transmission investment able to be supported by a loss savings. One important result on that worksheet is the 5.4 M$/MW (million dollars per megawatt) of Cumulative Present Value of Losses. This value represents the result that any transmission improvement causing 1 MW of loss savings saves the electric system 5.4 M$ of present value generation cost that would otherwise be incurred to supply the capacity and energy for that 1 MW of losses.

Computation of Equivalent Capitalized Value for Losses
(based on 1.00 MW loss on -peak)
(pool reserve requirement of 15%)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	11.92	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.65	< Transmission
Discount rate	8	%/yr			
Energy value	$46.19	MWh			
Loss Factor	0.30				
Transmission FCR	0.15				

< .35 is based on ASK-ECL 345 loss factor (ave. 2000 and 2001). Proxy for MN to Western WI flows; .3 is based on Justin's analysis of 54% average loading on Twin Cities transmission lines and losses are based on I^2*R so the 54%^2 = 29% (~30%).

Calculation

						Generation FCR	Levelized Annual Revenue Rqmt	Cum PW of Rev Req
Capacity value:	50	% peaking @	$800	/kW		0.15	$60,000	
	50	% baseload @	$3,000	/kW		0.15	$225,000	
							$ 285,000	$
add 15% reserve requirement:							327,750	3,908,292
Energy Value:	1.00	8760 hr/yr	0.30	$46	/MWh		121,387	$ 1,447,497
			Total annual cost, capacity & energy:				$ 449,137	5,355,789
			Present Value Annuity factor Losses				11.92	
			Cum PV Losses				$ 5,355,789	

The installed capacity values used for base-load and peaking generation are from the latest estimates by resource planners. The energy value used is from the 2008 average real-time energy price for the "MINNHUB" pricing point in the Midwest ISO market. That value was used because it is a good indication of the actual average energy price of the

most-expensive block of 1 MW served during that year. If losses were reduced by 1 MW, that is a good indication of the energy cost avoided.

6: Relevant Concerns.

6.1: Load-Growth Issues.

Since the completion of the original study report in 2006, the load growth profile for the region has decreased with the current economic recession. One of the main reasons for this study update was to confirm that given this demand reduction, that this proposed project is still the correct solution to reliably serve the study areas, and if it is, that the need for the project is still within the originally projected timeframe of 2013-2015. Historically, load growth slowdowns have been followed with a sharp increase where the load growth has resumed the previous trend within three to five years. For this reason, the load serving capabilities in this report are reflected in a range of years. The later end of the range is using the current lower growth of approximately 1% as shown in attachment A of this report, while the earlier date is from the load growth trend used in development of the Minnesota Certificate of need, 2.3%-3% depending on the specific area.

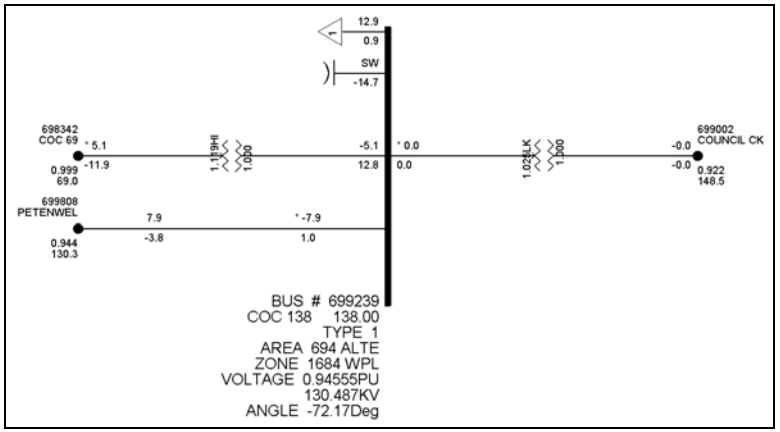
6.2: Regional Project vs. Local Solutions.

As described in the opening section of this report, in the early 2000s both RPU and DPC were independently working to determine the best system improvements to solve their upcoming load serving needs. For each load-serving pocket -- Rochester and La Crosse/Winona -- the planning engineers found a 161 kV solution that served load for each region for a period of time. At this point in the study process, they each began to investigate whether a 345 kV alternative would better serve the need, while also improving the greater region's system reliability. Following the individual study work, the planning engineers at RPU and DPC began work on a joint study to determine if one higher voltage solution could solve the load serving needs for both regions further into the future than the 161 kV alternatives, while also improving area reliability. It was from this joint study work that the proposed project was developed. The study work described above is laid out in detail in the attached study in Appendix C of this report.

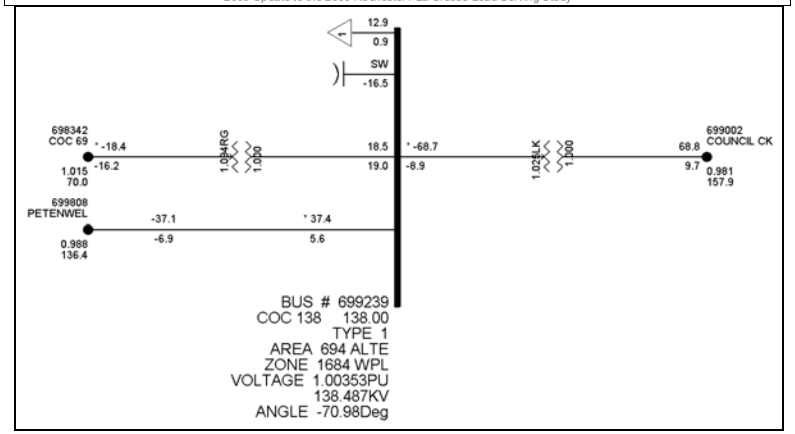
6.3: Facilities Assumed In Place[BM3].

For this study, the Monroe County-Council Creek 161 kV line was assumed not in service. With that line in service, the effective La Crosse load-serving area is expanded to include the Petenwell and Saratoga loads northeast of Council Creek. With the Monroe County-Council Creek 161 kV line not in service, the flow on the Petenwell-

Council Creek 138 kV line tends to be toward Council Creek. The following diagram shows this situation.



With the Monroe County-Council Creek 161 kV line in service, the flow on the Petenwell-Council Creek 138 kV line tends to be toward Petenwell. The Monroe County-Council Creek 161 kV line then causes Council Creek to be a stronger source than the Saratoga-Petenwell 138 kV line. The following diagram depicts this situation.



6.4: Anticipated Rochester Area Improvements

The proposed 345 kV transmission line from the Twin Cities to La Crosse and the proposed Northern Hills – North Rochester and Northern Hills – Chester 161 kV lines will provide significant load serving capability to the system.

In addition, there are two other recent transmission proposals that could further enhance the transmissions system's capabilities. These two projects are being proposed for the same general geographic area as the two Rochester area 161 kV lines. These projects do not change the need for additional transmission improvements, but may affect the specific timing of when the Northern Hills—North Rochester and Northern Hills—Chester 161 kV lines could be needed. The two transmission proposals are as follows:

- The Pleasant Valley 161 kV lines (RIGO): The Pleasant Valley 161 kV lines are a group of three 161 kV transmission lines needed to enable two new wind farms to reliably deliver power and to increase generation outlet capability in the area. These improvements were identified by a MISO Generation Interconnection Study dated August 17, 2007 as well as the Regional Incremental Generation Outlet (RIGO) Study dated August 19, 2008. One of the 161 kV lines, a proposed connection between Pleasant Valley Substation and Willow Creek Substation, will also provide additional

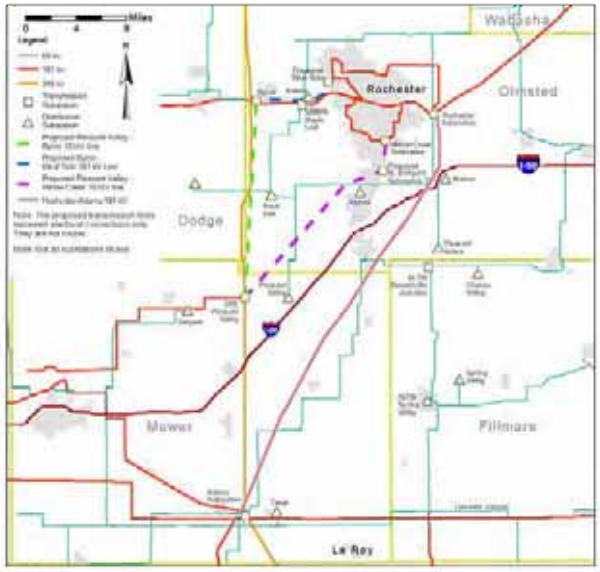
import capability for the Rochester area. The two other lines identified by the RIGO study are: 1) a 161 kV line from Pleasant Valley Substation to Byron Substation; and 2) a 161 kV transmission line connecting the Byron Substation to an RPU planned West Side Substation.

Certificates of Need from the Minnesota Public Utilities Commission are required for the first two lines. As of the date of this report, no Certificate of Need application has been filed.

- The second project is proposed by Dairyland—a reconductor of the Rochester – Adams 161 kV transmission line. The reconductor project, currently planned by Dairyland, will increase the capacity of the line and the capability of the system and is anticipated to be completed by the end of 2009. The current proposal is to reconductor the line to 380 million volt-amp (MVA).

The Pleasant Valley 161 kV lines and the Chester—Adams 161 kV reconductor project are shown in Figure 6.4-1 below.

Figure 6.4-1
Pleasant Valley 161 kV Lines and Chester—Adams 161 kV Reconductor Project



Assuming construction of the 345 kV line from the Twin Cities to La Crosse, if the Northern Hills – North Rochester 161 kV line or the Pleasant Valley – Willow Creek 161 kV line and the Rochester – Adams 161 kV line is reconductored at 380 MVA, the transmission system would have approximately 468 MW of capacity. This level of capacity could potentially meet local Rochester area needs until approximately 2025, if the current SMMPA forecast growth rates of 1.92% to 2.84% are realized. If the higher growth rates that the rapidly expanding Rochester area has experienced historically (more than 3.0 percent) return in the near term, the area load could exceed the improved transmission system's capacity by approximately 2019. To meet demand beyond this time, a second 161 kV source must be added to the system. If a third 161 kV line were constructed, it would increase the capability of the system considerably into the future, beyond the 2050 timeframe.

Attachment A-2 following this report shows how much load is affected by year for the critical loads described above for the Rochester area.

6.5: Transmission Study Work.

American Transmission Company (ATC) and Xcel Energy are currently studying a 345 kV line connecting La Crosse area to potential endpoints to the south and east. The study is expected to be completed in the first half of 2010. The ATC/Xcel Energy potential project is an independent project. The preferred alternative recommended in this study will meet the identified needs regardless of whether additional facilities are constructed to the east. However, it is recognized that additional high voltage connections to La Crosse will likely provide additional electrical system benefits.

Attachment A: Load forecasts used.

The load forecasts follow. To determine timing of need for new facilities beyond 2020 – the last year of the formal load forecasts – the load increase rates from 2019 to 2020 were used to extrapolate the loads.

The following table shows the load forecast used for the La Crosse area for year 2012.

La Crosse Area	Load MW
Distribution Substation	**2012**
Banger	4.30
Brice	6.51
Caledonia city	3.85
Centerville	3.58
Coon Valley	5.42
Coulee	65.31
East Winona	12.01
French Island	36.19
Galesville	7.14
Goodview	34.92
Grand Dad Bluff	1.76
Greenfield	3.22
Holmen	15.52
Houston	3.68
Krause	4.44
La Crosse	52.74
Mayfair	49.46
Mound Prairie	2.36
Mount La Crosse	2.02
New Amsterdam	4.87
Onalaska	13.48
Pine Creek	2.09
Rockland	4.03
Sand Lake Coulee	2.83
Sparta (DPC)	1.31
Sparta	34.28
Swift Creek	28.78
Trempealeau	4.08
West Salem	26.62
Wild Turkey	1.36
Winona	53.22
Total Load MW:	**491.38**

The following table shows the total La Crosse area load from year 2002 to year 2020.

Year	Load/ MW
2002	422
2003	434
2004	410
2005	447
2006	459
2007	444
2008	430
2009	474
2010	480
2011	485
2012	491
2013	497
2014	503
2015	510
2016	516
2017	523
2018	529
2019	536
2020	542

The following table shows the load forecast for the Rochester area for year 2012.

Rochester Distribution Substation	Load MW 2012
Airport	3.38
Bamber Valley	28.63
Canisteo	2.72
Cascade Creek	50.86
Chester	2.7
Genoa	5.79
IBM	16.6
Kalmar	2.62
Marion	2.94
Marvale	3.13
Crosstown	40.71
Northern Hills	29.87
Oronoco	7.3
Pleasant Grove	1.55
Pleasant Valley	1.85
Ringe	4.09
Rock Dell	2.04
Silver Lake	59.86
Willow Creek	40.3
Zumbro	41.2
Total Load MW:	**348.14**

The following table shows the Rochester area load from year 2002 to year 2020.

Year	Load/ MW
2002	290.18
2003	298.56
2004	282.31
2005	301.96
2006	329.97
2007	314.43
2008	307.87
2009	327.82
2010	334.49
2011	341.33
2012	348.14
2013	354.98
2014	361.81
2015	368.66
2016	375.50
2017	382.36
2018	389.24
2019	396.08
2020	402.96

Attachment A-1: La Crosse Critical Loading Spreadsheet.

(See Appendix D of the TSSR - TSSR Pages 407-408).

Attachment A-2: Rochester Critical Loading Spreadsheet

(See Appendix E of the TSSR - TSSR Pages 409 - 410).

Appendix B: Contingencies studied.

```
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
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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'
 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
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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

END
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Appendix C: Southeastern Minnesota – Southwestern Wisconsin Reliability Enhancement Study, Transmission Analysis for Southeastern Minnesota and Southwestern Wisconsin of March 13, 2006.

(See Appendix A of the TSSR - TSSR Pages 33 - 217).