PUBLIC VOLUME

ATTACHMENT F

RES UPDATE STUDY

Minnesota RES Update Study Report

Volume 1

Prepared for the Minnesota Transmission Owners

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Minnesota Transmission Owners (MTO)*

Basin Electric Power Cooperative
(also representing East River Electric Power Cooperative and L&O Power Cooperative)
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
Great River Energy
Heartland Consumers Power District
Interstate Power and Light
Minnesota Municipal Power Agency
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services
(also representing Hutchinson Utilities Commission and Marshall Municipal Utilities)
Northern States Power Company, a Minnesota Corporation (" Xcel Energy")
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency
Willmar Municipal Utilities

- The Minnesota Transmission Owners are utilities that own or operate high voltage transmission lines within Minnesota. When originally formed, this group was made up of those utilities subject to 2001 legislation requiring transmission owners to file a biennial transmission report. Additional utilities have joined the MTO to collaborate on more recent transmission studies.

Great River Energy, Xcel Energy and Otter Tail Power provided leadership for the studies. The Minnesota Transmission Owners-member utility transmission planning engineers provided valuable input to the study process.

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1.0: Background & Scope of Study

In October 2007, a Work Scope was developed to define study work to be performed by Minnesota utilities. This work was intended to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system that (i) allows regional utilities to develop generation projects that satisfy the Renewable Energy Standard legislation milestones, and (ii) continues to enable reliable, low cost energy for our region, and (iii) continues developing a robust and reliable transmission system. That Work Scope "seeks to optimize delivery of reliable power, including renewable energy to Minnesota retail customers to build upon the analyses that have previously been done or that are in progress."

The Corridor Study was the first study to help enable the Minnesota utilities to meet the Renewable Energy Standard law. That study evaluated the upgrade of the 230 kV transmission line corridor from the Granite Falls area to the southwest corner of the Twin Cities metropolitan area to double-circuit 345 kV. Initially, it was surmised that the Corridor Upgrade would lead to an increment of 1000 MW of new generation delivery capability. According to calculations of expected wind generation potential at the time, it was believed an additional 1000 MW of generation delivery capability beyond the Corridor Upgrade would be necessary to meet the 2016 RES milestones. Initially, the RES Update Study was focused on identifying the appropriate project to enable that delivery capability.

Results from the Corridor Study demonstrated that the Corridor Upgrade provide sufficient additional generation outlet capacity to assist Minnesota load-serving entities to meet the 2016 milestones set out in the Renewable Energy Standard law through construction of the facilities associated with that study.

After realization that the Corridor facilities could facilitate achieving the 2016 milestones, the focus for this report evolved to determine what facilities should be pursued so load serving utilities can meet the next milestones set out in the Renewable Energy Standard law. One of the main focuses was to look at sending the power to the Midwest ISO market. This creates a realistic model of the transmission system in which "Locational Margin Pricing" (LMP) drives the dispatch of generation. In addition, utilities in neighboring states are signing power purchase agreements with wind projects located in the state of Minnesota to meet their renewable requirements. This drives a need for utilities to investigate additional options for increasing generation delivery to ensure sufficient capacity is available to allow new renewable generation projects to connect to the transmission grid.

As with the Corridor Study, this study aims to build a foundation to determine the best bulk transmission improvement plan for society. This is not an easy task, as different generation and transmission projects, philosophies, and requirements are constantly changing. Certain assumptions have to be made determining study sources and sinks. This involves creating transmission to enable a certain amount of delivery from the study generation sources to the study generation sinks. The generation sources and sinks used are intended to be indicative of general patterns. Where a particular bus is used as a source, it could represent a future project at that bus or at any bus nearby. Source and sink buses are typically chosen to minimize transmission system limitations in the immediate vicinity of the source bus.

After analysis, the best plan among studied alternatives is recommended. Along with the analysis of the options goes analysis of the underlying system facilities required with each option. The idea is to determine the best plan considering as many effects as possible. However, the inclusion of underlying facilities in this report serves only to aid in weighing the best plan. If new generation develops in a pattern differing from the patterns studied, the underlying facilities may change; those included in this report served only as a basis for determining the total possible costs of the options. With these costs and electrical system study results, a preferred plan can be developed to enable delivery of the new generation sources.

The stakeholders involved in the development of Minnesota-area electric transmission have a desire to maximize the use of existing rights-of-way to the extent possible given the need to meet NERC standards. To this end, transmission developers often look to upgrade the power-carrying capability of existing rights-of-way. But as the transmission system continues to change, new facilities on new right-of-way occasionally need to be developed to help optimize the power grid with these new renewable power resources.

2.0: Conclusion

All the facilities studied provide some level of outlet capability. A few of the projects actually create a 40-year cost savings if the power is delivered to the Midwest ISO market.

The La Crosse – Madison 345 kV line provides the greatest overall system benefits in the studied time frame. This line creates a third path south and east of the Twin Cities towards Chicago. This is proven in the southwest zone thermal analysis by providing up to 3600 MW of generation delivery capability beyond the base model.

The Fargo – Brookings Co. and Ashley-Hankinson 345 kV lines provide great outlet capability for North Dakota and western Minnesota, but this outlet capability is limited for the Midwest ISO Market without the La Crosse – Madison line. The other lines that benefit the system are the Brookings Co – Split Rock, Lakefield – Adams, and Adams – L a Crosse 345 kV lines. Figures 2.0.A and 2.0.B show the full RES facilities and generation benefit area.

Figure 2.0.A – RES Transmission Facilities

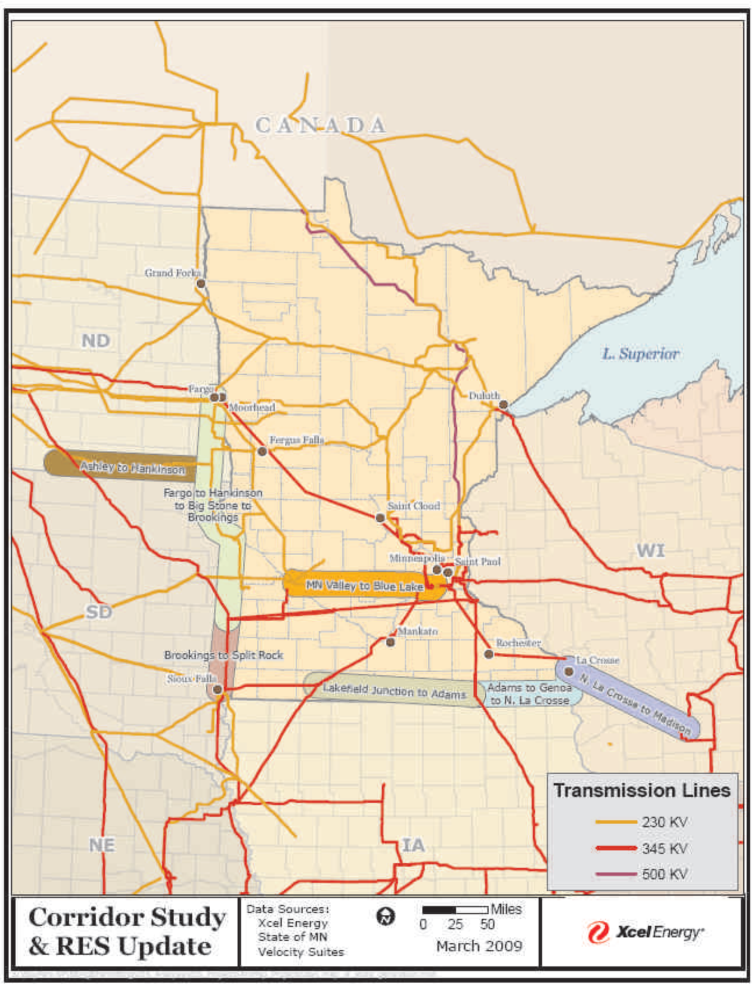
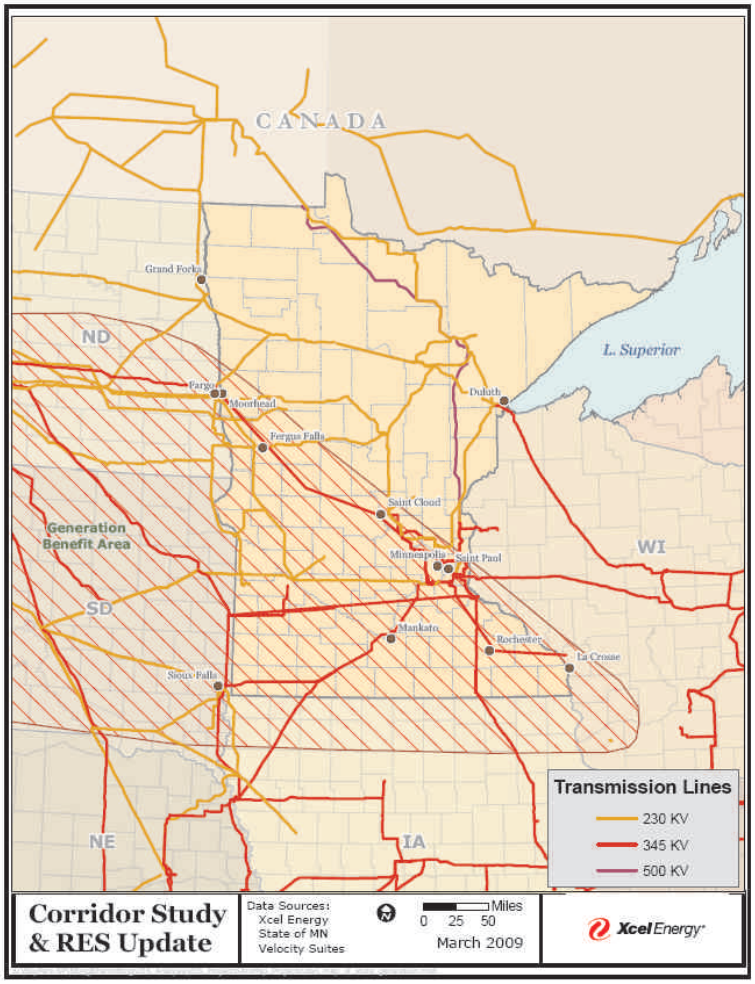


Figure 2.0.B – RES Generation Benefit Area



One key finding was shown in stability analysis. The dynamic stability analysis showed that there could be an operational limit achieved with increased wind penetration. This operational limit is created due to backing off existing generation in the Twin Cities to allow wind generation to interconnect. This causes instability during various disturbances. This phenomenon is especially noticeable when Sherco 3 is tripped and the system spins out of control. Generally, wind generators do not have much inertia, unlike traditional generation plants. The overall system inertia allows the system to recover after a major disturbance.

This instability issue drives the need for new transmission out of the state – either to allow existing generation to remain in-service and provide stability to the system or to tie the system more closely to external generation sources. Additional studies will be needed to determine which transmission facilities will be required to achieve levels of renewable energy penetration beyond the 7000 MW studied here.

3.0: Study History & Participants

As mentioned, in October 2007 the Work Scope covering this study (and other studies) was issued. The following table shows the parties to that Work Scope.

Table 3.0.A – Study Participants

Basin Electric Power Cooperative	Minnesota Power
Central Minnesota Municipal Power Agency	Minnkota Power Cooperative
Dairyland Power Cooperative	Missouri River Energy Services
Heartland Consumers Power District	Northern States Power Company d/b/a Xcel Energy
Great River Energy	Otter Tail Power Company
Interstate Power & Light Company	Rochester Public Utilities
Minnesota Municipal Power Agency	Southern Minnesota Municipal Power Agency
	Willmar Municipal Utilities

In November 2007, initial meetings were held to introduce the study of the upgrade of the Granite Falls-Southwest Twin Cities Area 230 kV line. The study was referred to as the “Corridor Study”. Project Managers, Transmission Planners, and Substation Engineers gathered within Xcel Energy to define roles and a draft scope.

In January 2008, meetings were held to discuss model development and better define the scopes of the RES and Corridor studies. Due to the RES legislation and the many interested stakeholders, it was known that the study would be a very public study. Therefore some parts of the study took longer than in traditional studies, but the time resulted in a better study. An example of this is the model building; as opinions resulted in assumptions changing, the models had to be changed, but the result was a set of accurate, dependable models. The model building was largely completed by April 2008.

In March 2008, anticipating the need to rebuild the existing 230 kV corridor and the difficulty in obtaining construction outages along this corridor, the scheduling of construction and the interaction between the proposed Corridor Study facilities and existing transmission facilities began to be considered. These issues are often referenced by the term “constructability”. Since some transmission facilities may need to be out of service during construction of new facilities, some generation may need to be curtailed during construction. Issues like these have been investigated over the course of the study.

In September 2008, preliminary results were presented to the public at the joint Northern-MAPP Subregional Planning Group (NM-SPG) and Missouri-Basin Subregional Planning Group (MB-SPG) meeting in Duluth, Minnesota.

As part of a separately-legislated effort, the DRG Phase I Study, a group of engineers was assembled by the Minnesota Office of Energy Security. This group was called the

Technical Review Committee (TRC) and was formed to serve as an advisory group to the Dispersed Renewable Generation Study. Given the technical expertise collected in this group, the TRC served as a technical sounding board for the scope, assumptions, and results of the Corridor and RES Update studies. Meetings of this group were held in October 2007, December 2007, February 2008, April 2008, May 2008, September 2008, October 2008, February 2009, and March 2009. At each meeting, the status and findings of this study were presented.

4.0: 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). If those criteria are met, 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 & controlled loss of demand or transfers will occur. These criteria have been developed over decades and are constantly monitored and changed as deemed necessary to avoid large outages and blackouts. Most often, the criteria are made more rigorous in response to real-world events and as engineers learn better ways to ensure reliability of the transmission system. The criteria most applicable to transmission planning are listed in Appendix A.

4.2: Models Employed

4.2.1: Steady-State Models

The base models used for the steady-state (power flow) analysis are the models of the year 2013 summer peak load and summer off-peak load conditions from the MTEP07 series of models created by Midwest ISO for the Midwest ISO Transmission Expansion Plan (MTEP) process. These models were chosen for study work because

- they are consistent with the models most used by Midwest ISO for steady-state work,
- they afford the best topology available for the Eastern Interconnect – the electric system spanning all of the United States east of the Rocky Mountains and outside of Texas.,
- they are being used for other similar studies (the DRG study, for one),
- they are well documented and well understood.

In addition, any PROMOD analysis related to this study was created and performed by Midwest ISO on a PROMOD MTEP model which was best available. So there is good compatibility between the steady-state transmission (PSS/E) model chosen and the models to be used for PROMOD work.

4.2.2: Dynamics Models

The base model used for the dynamic analysis came from the NORDAGS (Midwest ISO's North Dakota Group Study) Group 1 models. The reasons for choosing this model were that it aligns well with the study timeframe of the year 2015 and is compatible with the NMORWG (Northern Mid-Continent Area Power Pool (MAPP) Operating Review Working Group) stability package. The NMORWG stability package is widely used for MRO and MAPP studies in the upper Midwest area. The NORDAGS model was built from the same base operating model used in the 2006 NMORWG package and updated for the recent System Impact Studies for NORDAGS. The validity of the stability model is also of particular importance because these models have been reviewed and documented quite extensively and their accuracy has been confirmed by utilities throughout the region. After the appropriate model from NORDAGS was selected, the topology had to be updated along with the corresponding files in the package to make the model used in the steady-state analysis. These changes include updates to the CapX 2020 Group 1, BRIGO[1], and RIGO[2] facilities.

4.3: Conditions Studied

4.3.1: Steady-State Modeling Assumptions

The in-service date planned for the conversion of the Minnesota Valley-Blue Lake 230 kV line corridor is 2016. This timing is due to the desire to have added transfer capability to support load serving entities' to satisfy the State of Minnesota's Renewable Energy Standard for 2016. This study piggy-backed the Corridor Study so therefore, the year 2016 was chosen as the year to study along with using the same models.

Due to the need to look at both load-serving ability and transfer capability, the decision was made to analyze system performance under both summer peak and summer off-peak load conditions. To accommodate the Minnesota Conservation Improvement Program (CIP), the decision was made to have the loads not quite as high as they would be otherwise. In the peak-load case, the loads in the 2013 case were scaled up to be not quite at the 2016 level with no Conservation Improvement Program. The off-peak load levels were 61% of those in the peak model based on a Midwest ISO analysis that showed the highest line loadings happened at 61.2%. The table below shows the control areas included in the Study Area

[1] The BRIGO (Buffalo Ridge Incremental Generation Outlet Study) focused on increasing wind outlet capacity of the transmission system in the Buffalo Ridge area.

[2] The RIGO (Regional Incremental Generation Outlet Study) focused on increasing wind outlet capacity of the transmission system in areas outside the Buffalo Ridge area. This transmission study looked at west-central Minnesota and southeastern Minnesota 115 kV or 161 kV line improvements with an in-service goal of 2011. Since the time models were developed, the number has decreased slightly and is a factor in the range of generation deliverability that will exist by 2016.

Table 4.3.1.A – Control Area for Load Scaling

Area Number	Area Name
331	Alliant West
600	Xcel Energy
608	Minnesota Power
613	Southern Minnesota Municipal Power Agency
618	Great River Energy
626	Otter Tail Power
633	Muscatine Power & Water
635	MidAmerican Energy
640	Nebraska Public Power District
645	Omaha Public Power District
650	Lincoln Electric System
652	Western Area Power Administration
667	Manitoba Hydro
672	SaskPower
680	Dairyland Power Cooperative

The generation levels used for previously planned projects are shown in the following Table 4.3.1.B. The sinks for generation added were the Black Dog, Blue Lake, Inver Hills, and Riverside generators in the Twin Cities.

Table 4.3.1.B – Additional Generation Added

BRIGO	MW Additional
Fenton	187.5
Yankee	187.5
TOTAL	**375**
RIGO	**MW Additional**
Pleasant Valley	722
Pleasant Valley	200
TOTAL	**922**
Brookings Study	**MW Additional**
Toronto	105
Canby	70
Yankee	105
Brookings Co.	105
Fenton	105
Nobles	105
Lakefield	105
TOTAL	**700**

The performance of any bulk electrical system is significantly affected by the power transfers across it. For the study, it was recognized the new facilities proposed would have to enable the system to carry existing firm transfers, new energy transfers, and possibly some non-firm transfers (to allow room for growth of future firm transfers). Therefore, in the off-peak case, transfers were changed to be consistent with the "maximum simultaneous" transfers often studied in the MAPP region. The existing transfer limits are

- North Dakota Export (NDEX) of 2080 MW,
- Manitoba Export (MHEX) of 2175 MW,
- Minnesota-Wisconsin Export (MWEX) of 1525 MW,
- Boundary Dam phase shifter southward flow of 150 MW,
- International Falls phase shifter southward flow of 100 MW.

In the peak-load case, the transfers in the base case were not changed for the study work. The Midwest ISO-supplied case already had firm transfers consistent with data submitted for on-peak modeling.

Since the definition of export interfaces such as NDEX can change as future transmission lines are added, it is customary to set the transfer levels in a case prior to any major new transmission lines being added to that model. This was the case for this study. The CapX 2020 lines and future lines under study were not part of the model as the export levels were set. This avoids skewing the export levels under study.

Due to the fact the MTEP07 models contained the 2004 version of the Midwest Reliability Organization's (MRO's) electric power system for non-members of Midwest ISO, which system's representation had to be updated in the MTEP07 models by taking that system's representation from the MRO 2007 models and incorporating it into the MTEP07 models.

The major model modifications are as follow:

- The only Midwest ISO-planned facilities left in the models are those in Appendix A of the Midwest ISO Transmission Expansion Plan; those planned facilities with less certainty – such as those in Appendix B or C – were removed.
- Similarly uncertain facilities from MAPP's 10-year plan were removed.
- Facilities from the Buffalo Ridge Incremental Generation Outlet (BRIGO) study were included.
- Facilities from the Regional Incremental Generation Oultet (RIGO) study were included; this includes approximately 922 MW of new generation.
- The CapX 2020 Group 1 base facilities were added.
- Fictitious generators added by Midwest ISO and known as Strategist Units were removed.
- Generation in the southwest Minnesota area was set to be 1900 MW; this includes the "825 MW" plus the BRIGO generation up to approximately 1200 MW and another 700 MW enabled by the Brookings County-Twin Cities 345 kV development. Based on Midwest ISO interconnection queue information, all of this generation was assumed to be wind.
- The Lakefield Generation gas and wind units were assumed to be running at 550 MW total.

The models required addition of five 100 MVAR shunt capacitor banks on the Arpin 345 kV bus; without those capacitors, the high MWEX flows caused the system-intact voltage at Arpin Substation to be below 0.95 pu. The model showed the need for those capacitors to be on the 345 kV bus. The Arpin 138 kV bus already has two 50 MVAR capacitors; if more 50 MVAR capacitors were added there, the flow up to the 345 kV bus overloaded the Arpin 345/138 transformer. A similar bank of nine 75 MVAR shunt capacitor banks was added to the Columbia 345 kV bus; voltage at this bus under contingency was very low without those capacitors.

During the study, the study team became uncertain about the future of Big Stone II and whether it will proceed in light of current circumstances. Therefore, for the bulk of the study work, Big Stone II generation and transmission were not included in the models. Big Stone II generation and transmission were not included in the models used to arrive at the conclusions and recommendations stated in this report.

Modeling of the scenario of no Big Stone II generation or related transmission was accomplished by turning off the Big Stone II generator and the associated transmission. The replacement power for Big Stone II generation came from each of the Big Stone II partners' generation plans and existing generation not running in the models. The table below shows those replacement power sources. This study also performed sensitivity with respect to Big Stone II generation and transmission.

The three scenarios studied in the steady-state analysis included the following:

1. Existing 230 kV Corridor
   - Without Big Stone II
2. Corridor double circuit 345 kV Upgrade with from Hazel Creek to Blue Lake
   - Without Big Stone II
3. Corridor double circuit 345 kV Upgrade back to Big Stone
   - Big Stone II
   - Corridor generation

Table 4.3.1.C – Base Model Descriptions

Parameter	Peak model	Off-peak model
Generation Changes	• Black Dog and Blue Lake and Inver Hills and Riverside generators in the Twin Cities used as sinks for wind from "825", BRIGO, "Brookings", and RIGO studies.	• Black Dog and Blue Lake and Inver Hills and Riverside generators in the Twin Cities used as sinks for wind from "825", BRIGO, "Brookings", and RIGO studies. • Study area generation reduced to the levels needed for the 60% load level.
MHEX	Unchanged from Midwest ISO-supplied model	2175 MW
NDEX	Unchanged from Midwest ISO-supplied model	2080 MW
MWEX	Unchanged from Midwest ISO-supplied model	1525 MW
MN Wind	2582 MW	
ND Wind	411 MW	
SD Wind	160 MW	
IA Wind	770 MW	
WI Wind	95 MW	
MB Wind	0 MW	
Transmission Changes	• The only Midwest ISO-planned facilities left in the models are those in Appendix A of the Midwest ISO Transmission Expansion Plan; those planned facilities with less certainty – such as those in Appendix B or C – were removed.	

	• Similarly uncertain facilities from MAPP's 10-year plan were removed. • Facilities from the Buffalo Ridge Incremental Generation Outlet (BRIGO) study were included. • Facilities from the Regional Incremental Generation Oultet (RIGO) study were included; this includes approximately 922 MW of generation. • The CapX 2020 Group 1 base facilities were added. • Fictitious generators added by Midwest ISO and known as Strategist Units were removed. • Generation in the southwest Minnesota area was set to be 1900 MW; this includes the "825 MW" plus the BRIGO generation up to approximately 1200 MW and another 700 MW enabled by the Brookings County-Twin Cities 345 kV development. • The Lakefield Generation gas and wind units were assumed running at 550 MW total.
Facility Rating Changes	Xcel Energy ratings as of 2008.12.27 were used; other companies' ratings were mostly unchanged from the model supplied by Midwest ISO except for those changed in the "MRO model" transplant and as suggested by reviewers.
Study Timeframe	Year 2016.

In addition to the Corridor generation sources, the following tables show the sources under the various sensitivity scenarios.

Table 4.3.1.D – Corridor Generation Sources

Bus identifier	Bus name	Generation MW
60286	Nobles County 345 kV	235
60383	Brookings County 345 kV	471
60393	Fenton 34.5 kV	176
60394	Yankee 34.5 kV	176
60500	Lyon County 345 kV	353
66550	Granite Falls 230 kV	353
66554	Morris 230 kV	235
	Total	2000

Figure 4.3.1.E – Additional Sourcing Zones

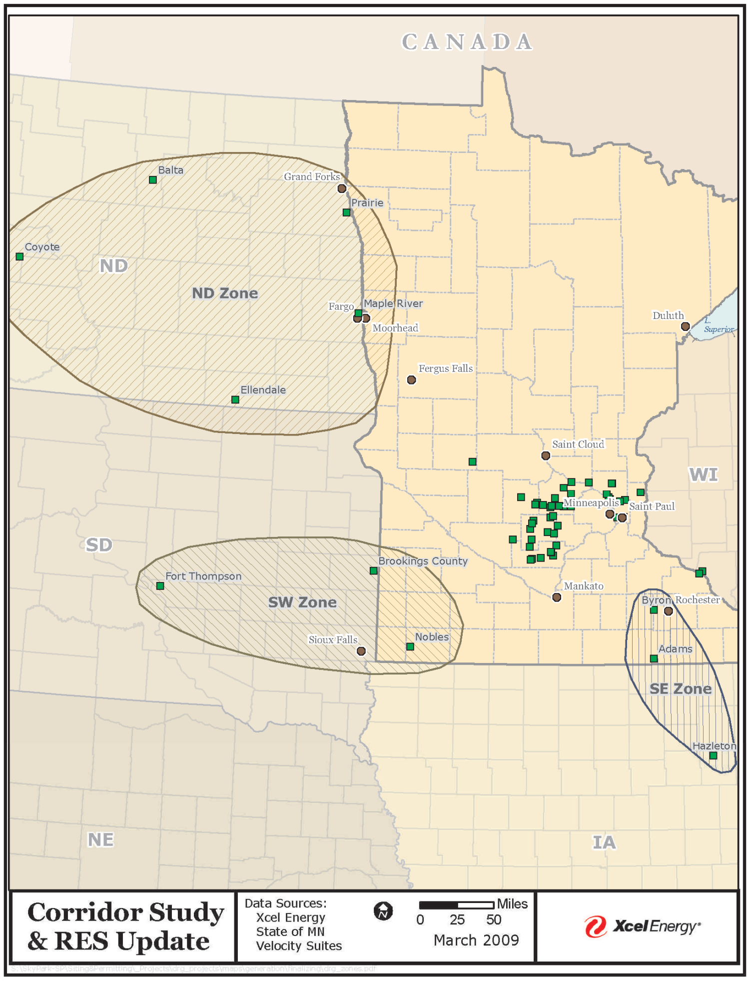


Table 4.3.1.F – SE Zone Sources

Bus identifier	Bus name	Generation Source
60102	Adams 345 kV	750
61950	Byron 345 kV	750
34018	Hazleton 345 kV	500
	Total	2000

Table 4.3.1.G – SW Zone Sources

Bus identifier	Bus name	Generation MW
60286	Nobles County 345 kV	750
60383	Brookings County 345 kV	750
60393	Big Bend 230 kV	500

	Total	2000

Table 4.3.1.H – ND Zone Sources

Bus identifier	Bus name	Generation MW
67315	Coyote 24 kV	200
63053	Balta 230 kV	300
66755	Prairie 230 kV	400
67326	Ellendale 230 kV	500
66754	Maple River 230 kV	600
	Total	2000

Table 4.3.1.I – Overall Sources

Bus identifier	Bus name	Generation MW
67315	Coyote 24 kV	100
63053	Balta 230 kV	100
66755	Prairie 230 kV	150
67326	Ellendale 230 kV	200
66754	Maple River 230 kV	250
60102	Adams 345 kV	300
61950	Byron 345 kV	300
34018	Hazleton 345 kV	250
60286	Nobles County 345 kV	300
60383	Brookings County 345 kV	300
60393	Big Bend 230 kV	250
	Total	2500

4.3.2: Dynamic Modeling Assumptions

Using the NORDAGS Study Package, the 2015 Summer off-peak "A04" model fits well with time frame of the this study. This case was updated to include all CapX 2020 Group 1, BRIGO, and RIGO facilities. As well as a few modeling changes to match the steady-state topology. A special sensitivity was also performed to evaluate the Big Stone II generation and transmission impacts. A total of eighteen scenarios were evaluated in this analysis. The table below shows a summary of the cases.

Table 4.3.2.A – Dynamic Case Descriptions

Case Name	BS II Status	Transmission Additions	Generation Level
R00	OUT	CapX, BRIGO, RIGO facilities	Exising Modeled
R02	OUT	CapX, BRIGO, RIGO facilities	2822 MW
R04	OUT	CapX, BRIGO, RIGO facilities	4822 MW
RC2	OUT	R02, Corridor facilities	2822 MW
RC4	OUT	R02, Corridor facilities	4822 MW
RL4	OUT	RC2, La Crosse-Columbia 345 kV	4822 MW
RE4	OUT	RC2, RES facilities	4822 MW
RE6	OUT	RC2, RES facilities	6822 MW
RE7	OUT	RC2, RES facilities	7322 MW
B00	IN	CapX, BRIGO, RIGO facilities	Exising Modeled
B02	IN	CapX, BRIGO, RIGO facilities	2822 MW
B04	IN	CapX, BRIGO, RIGO facilities	4822 MW
BC2	IN	B02, Corridor facilities	2822 MW
BC4	IN	B02, Corridor facilities	4822 MW
BL4	IN	BC2, La Crosse-Columbia 345 kV	4822 MW
BE4	IN	BC2, RES facilities	4822 MW
BE6	IN	BC2, RES facilities	6822 MW
BE7	IN	BC2, RES facilities	7322 MW

The Corridor facilities include replacing the Minnesota Valley-Blue Lake 230 kV line with a double circuit 345 kV line from Hazel Creek to Blue Lake. The RES facilities include a Maple River-Hankinson-Big Stone-Brookings County 345 kV line, an Ashley-Ellendale-Hankinson 345 kV line, Brookings County-Pipestone-Split Rock 345 kV line, Lakefield-Winnebago-Hayward-Adams 345 kV line, Adams-Genoa-North La Crosse 345 KV line, and the North La Crosse-Hilltop-Columbia 345 kV line.

The generation additions added to the model incorporate user-written dynamic models for Clipper, GE, and Vestas turbines. The generation additions were split among the three at each source bus. These splits include 70% for GE (Type III), 15% for Clipper (Type IV), and 15% for Vestas (Type II). This division of wind turbines was developed in consultation with the TRC and was intended to provide an approximation of future generation projects required to fulfill the 2822, 4822, and 7322 MW levels.

4.4: Conditions Studied

4.4.1: Steady-state Contingencies Modeled

The contingency list used was produced by the Midwest Reliability Organization and Midwest ISO; it contains the complex NERC Category B and Category C contingencies commonly used for bulk transmission studies in the Minnesota area. A list of the approximately 7,000 complex contingencies can be found in Appendix B. The following table shows the control areas used for taking single contingencies; all 100 kV and above branches (transformers and transmission lines) were taken as contingencies one at a time. In addition, all the generators in those areas were taken out of service one at a time, and all the 100 kV and above ties from those areas were taken as contingencies one at a time.

Table 4.4.1.A – Contingency Areas

Area Number	Area Name
331	Alliant West
364	Alliant East
365	Wisconsin Energy
366	Wisconsin Public Service
367	Madison Gas & Electric
368	Upper Peninsula Power Company
600	Xcel Energy
608	Minnesota Power
613	Southern Minnesota Municipal Power Agency
618	Great River Energy
626	Otter Tail Power
633	Muscatine Power & Water
635	MidAmerican Energy
640	Nebraska Public Power District
645	Omaha Public Power District
650	Lincoln Electric System
652	Western Area Power Administration
667	Manitoba Hydro
680	Dairyland Power Cooperative

4.4.2: Dynamic Disturbances Modeled

The table below lists the regional disturbances that were analyzed for this system impact study. These disturbances have been used consistently when evaluating projects in the Northern MAPP region. Appendix C contains the description of all fault files that were included in the stability analysis and the dynamic models used for the new generation.

Table 4.4.2.A – Regional Disturbances

Fault Name	Faulted Bus	Fault Type	Clearing Time (cycles)	Initial Clearing	Backup Clearing (cycles)	Backup Clearing
AG1	Leland Olds 345kV	SLGBF	4	Leland Olds-Ft Thompson line	11	FLTD Line
AG3	Leland Olds 345kV	3-phase	4	Leland Olds-Ft Thompson line		
EI2	Coal Creek 230kV	fault	10	CU HVDC bipole	7	Coal Creek 1&2
EQ1	Coal Creek 230kV	SLGBF	4.5	CU HVDC #1	11	Coal Creek #2
FD9	Square Butte 230kV	3-phase	4	Square Butte-Stanton 230kV line		
MAD	Dorsey 500kV	3-phase	4	Dorsey – Forbes 500kV line		
MQS	Sherco	SLGBF	4	Sherco #3	9	Sherco-Benton Co
MSS	Sherco	SLGBF	4	Sherco-Coon Creek 345 kV line	9	Coon Ck 345/115 Tx
MTS	Monticello 345kV	SLGBF	5	Monticello-Elm Creek line	9	Monticello bus
NAD	Forbes 500kV	3-phase	4	Forbes – Dorsey 500kV line		100% DC reduction
NMZ	Chisago Co 500kV	3-phase	4	Chisago Co – Forbes 500kV line		100% DC reduction
PAS	Forbes 500kV	SLGBF	4	Forbes – Dorsey 500kV line	13	Forbes-Chisago Co
PCS	King 345kV	SLGBF	4	King – Eau Claire 345kV line	14	King-Chisago Co
PCT	King 345kV	Trip	-	King – Eau Claire 345kV line		
PYS	Prairie Island 345kV	SLGBF	4	Prairie Island - Byron 345kV line	14	PI 345/161 Tx
PYT	Prairie Island 345kV	Trip	-	Prairie Island - Byron 345kV line		

4.5: Options Evaluated

The transmission line projects studied for completion after the Corridor Upgrade included the following:

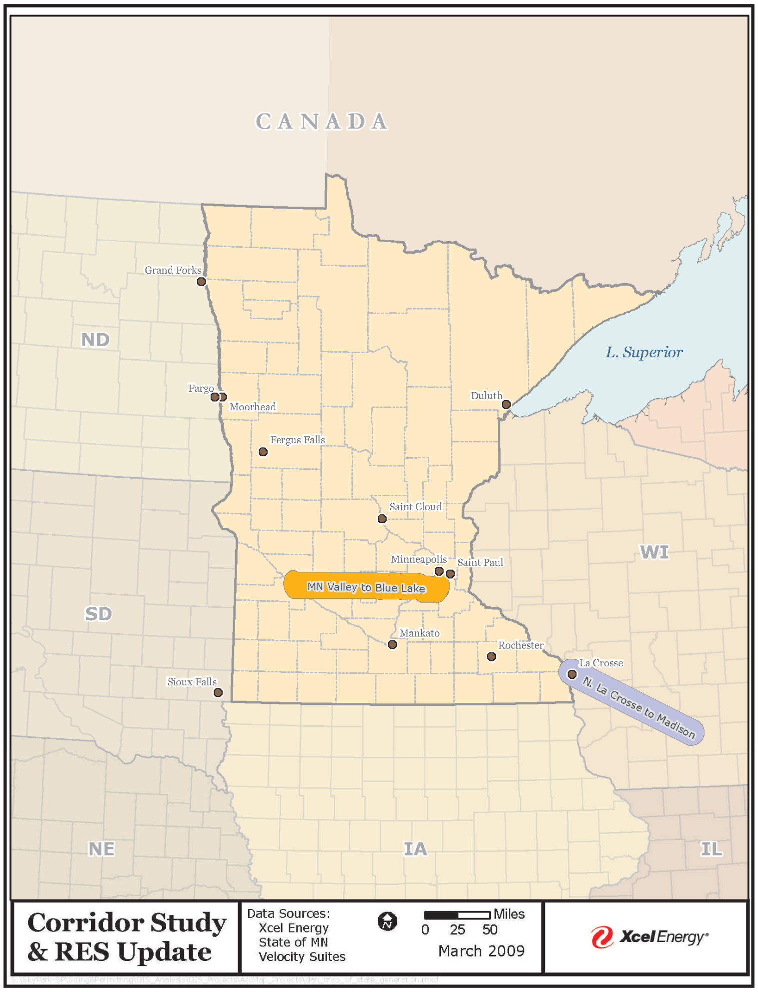
4.5.1: La Crosse - Madison Project

Due to constraints in the transmission system in Wisconsin, the possibility of a new facility extending further into Wisconsin was studied. The La Crosse – Madison project concept is currently being reviewed by engineers at several regional utilities to determine the most effective topology for the proposed facility. For purposes of this study, such a line was assumed to begin at North La Crosse and end at Columbia power plant north of Madison.

This assumption was made with the knowledge that it is difficult to route additional transmission facilities into Columbia Substation. However, given the existing transmission at the Columbia plant, it served as a desirable proxy for the line to avoid dealing with unforeseen transmission constraints at the Madison end of the proposed line that would likely be addressed by any ultimate project configuration. It is the opinion of the study team that any eventual La Crosse – Madison project topology would produce substantially similar electrical results as the proposal that was studied.

From North La Crosse Substation, the assumed project constructed 75 miles of new double-circuit 345 kV line to the existing Hilltop Substation. Expansion of Hilltop Substation to include 345 kV transformation was assumed. From Hilltop Substation, approximately 65 miles of double-circuit 345 kV line was constructed to Columbia Substation.

Figure 4.5.1.A – La Crosse-Madison Project



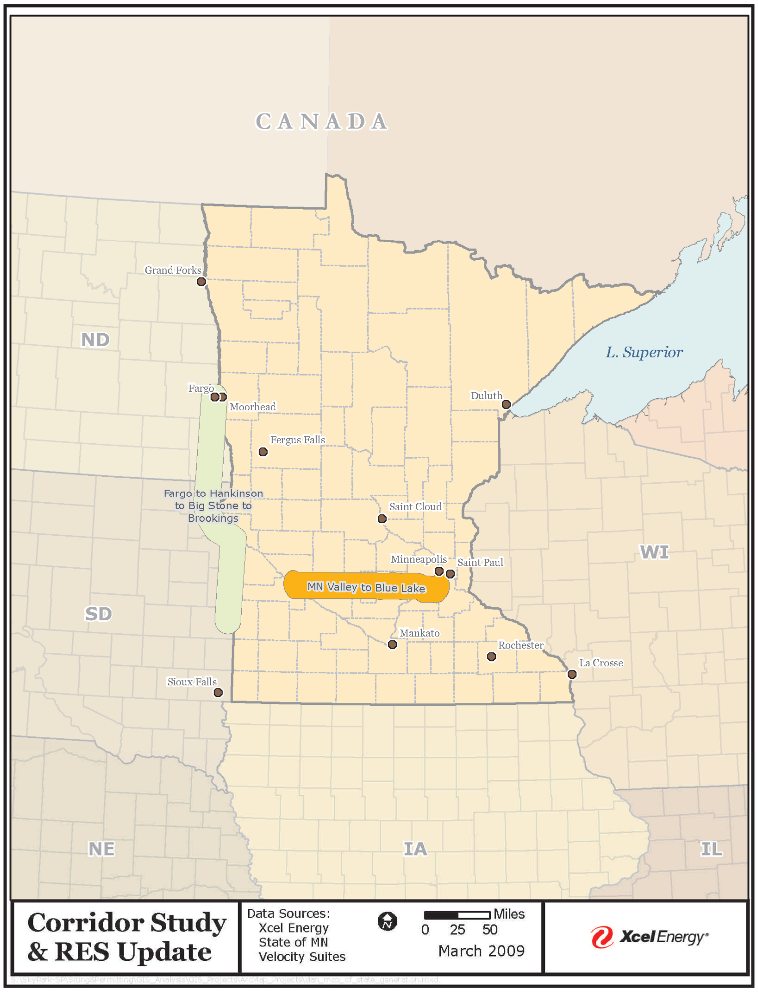
4.5.2: Fargo-Brookings County Project

The Fargo – Brookings County project is a double-circuit 345 kV line utilizing both new and existing right-of-way between Fargo, North Dakota and the existing Brookings County Substation in South Dakota. The project begins with approximately 60 miles of new double-circuit 345 kV line between Fargo and the existing Hankinson 230 kV Substation. At Hankinson, a new 345/230 kV transformation would be installed to serve as a high-voltage injection point for new generation sourced in North Dakota.

From Hankinson Substation, the existing Hankinson – Big Stone 230 kV line would be removed and replaced with a double-circuit 345 kV line. The total mileage of this segment is 70 miles. In the middle of this segment is the existing 230/41.6 kV Browns Valley Substation. This is a load-serving substation that serves a portion of Otter Tail Power Company load in South Dakota and Minnesota. As part of this project, Browns Valley would be converted to a 345/115/41.6 kV substation. The 41.6 kV load would be served off the transformer tertiary and the 115 kV secondary would be available to serve future load-serving or generation delivery projects.

Extending south from Big Stone, 75 miles of new double-circuit 345 kV line would be built to ultimately connect to the existing Brookings County Substation.

Figure 4.5.2.A – Fargo-Brookings County Project



4.5.3: Ashley-Hankinson Project

The Ashley – Hankinson 345 kV project is a 345 kV spur from eastern North Dakota extending into central North Dakota. The general territory through which this line would pass includes some of the most prominent wind regimes in the upper Midwest.

Where the existing Leland Olds – Groton 345 kV line crosses the Ellendale – Wishek 230 kV line, this project would propose to build Ashley Substation. Currently, the rich wind regime in this area is limited in delivery capability by the 230 kV line that was designed to serve load in the area. Ashley Substation would be a new 345/230 kV substation that would insert a new injection point into the 345 kV transmission system. From there, a 125-mile single-circuit 345 kV line would be constructed along new right-of-way to Hankinson Substation. New right-of-way would be necessary because the existing system in this area is limited by outage of Ellendale – Forman – Hankinson 230 kV line – the only possible double-circuit candidate.

Figure 4.5.3.A – Ashley-Hankinson Project

4.5.4: Brookings-Split Rock Project

The Brookings – Split Rock project is a new double-circuit 345 kV line that connects the existing Brookings County Substation to Split Rock Substation. From Brookings County Substation, 45 miles of new double-circuit 345 kV transmission line would be constructed to the existing Pipestone Substation.

One of the significant benefits to this project is that Pipestone Substation, an existing 115 kV substation, would be expanded to become a new injection point into the 345 kV transmission grid. With the addition of 345/115 kV transformation, Pipestone would join Brookings County, Nobles County, and Lyon County as significant injection points that enable generation resources to reach load centers. This expansion becomes increasingly necessary as the amount of wind generation that depends on transformation at Brookings County continues to grow.

From Pipestone Substation, 50 miles of new double-circuit 345 kV line would be constructed to Split Rock Substation near Sioux Falls, South Dakota. The completion of this circuit would expand the reliability benefits of the Fargo – Brookings County project to include the recently-constructed Split Rock – Lakefield Junction 345 kV transmission line. With a Fargo – Brookings County – Split Rock 345 kV transmission line in place, all four 345 kV lines between the Twin Cities and points to the west would be connected.

Figure 4.5.4.A – Brookings County-Split Rock Project

4.5.5: Lakefield-Adams Project

Lakefield and Adams Substations are currently connected via a single-circuit 161 kV transmission line that serves a number of communities in southern Minnesota. ITC Midwest has announced tentative plans to increase the capacity of this line, but this study assumed the upgrade of this path to double-circuit 345 kV.

From Lakefield Substation, the 161 kV line to Winnebago Substation was replaced with 55 miles of double-circuit 345 kV line. Winnebago Substation was assumed to be upgraded to 345/161 kV in order to ensure it would still be able to serve load in the surrounding area. Leaving Winnebago Substation, the existing 161 kV line to Hayward Substation was replaced with 50 miles of new double-circuit 345 kV line. Similar to Winnebago Substation, Hayward Substation was also converted to include 345/161 kV transformation. Each of these transformations is significant because it also provides a new injection point for generation to reach the high-voltage transmission grid.

From Hayward Substation, the existing Hayward – Adams 161 kV line was replaced with 37 miles of 345 kV double-circuit line.

Figure 4.5.5.A – Lakefield-Adams Project

4.5.6: Adams-La Crosse Project

With the significant interest in siting generation in southeastern Minnesota, it was necessary to investigate projects sited to enable additional generation to develop in that area. The Adams – North La Crosse project was designed with that in mind. From the existing Adams 345/161 kV substation, the existing Adams – Harmony 161 kV line was replaced with approximately 35 miles of new double-circuit 345 kV line. This construction would require the expansion of Harmony to include 345/161 kV transformation.

From Harmony Substation, the existing Harmony – Genoa 161 kV line would be replaced with approximately 45 miles of double-circuit 345 kV line. Similar to Harmony Substation, Genoa Substation would be expanded to include 345/161 kV transformation. From Genoa, approximately 20 miles of double-circuit 345 kV line would be constructed to the north, ultimately tying into the existing North La Crosse 345 kV substation.

This project would also have the dual benefit of bringing a new injection point into the La Crosse area. As load in the La Crosse area grows, the existence of a single 345 kV transmission source at North La Crosse will eventually strain the ability of the transmission grid to serve area load for loss of the 161 kV circuit extending south of North La Crosse into the La Crosse area. Inserting this 345/161 kV injection point at Genoa Substation will provide a new injection point remote from North La Crosse Substation.

Figure 4.5.6.A – Adams-La Crosse Project

4.5.7: Additional Projects Initially Reviewed

Beyond the six facilities previously discussed, seven other facilities were initially evaluated. These projects were studied as possible alternatives for the Minnesota RES evaluation. These projects include the following:

- Dorsey-Prairie-Maple River 500 kV line
- Center-Jamestown-Maple River 345 kV line #2
- Center-Jamestown-Prairie 345 kV line
- Broadland-Brookings Co 345 kV line
- Wilmarth-North Rochester 345 kV line
- Genoa-Salem 345 kV line

The Dorsey-Prairie-Maple River 500 kV line was evaluated due to the current Manitoba Hydro Transmission Service Request (TSR) which is currently being studied to deliver future hydro generation in Manitoba to load centers in the United States. Due to the timing of these two studies and unknown facilities required by the TSR, future studies will be required to evaluate its impact.

Both the Center-Jamestown-Maple River 345 kV line #2 and Center-Jamestown-Prairie 345 line are potential options currently being studied by Minnkota Power Cooperative for their load serving and existing generation outlet capability needs. A new line from Center will be required to provide outlet capability when they take solo ownership of Young 2 and release their ownership of Square Butte DC line. Both lines provide an opportunity for generation outlet from central North Dakota but only get to the Red River Valley for load serving needs. An additional line would be required to provide power to the Midwest ISO market.

The Broadland-Brookings Co 345 kV line provides great opportunity for East Central South Dakota, but has the biggest impacts on the Intergrated System[3] (IS) in the MAPP region. Due to adversely impacting the IS system, a large number of underlying facilities would be required and the cost of the faculties would increase as a result. This project would work better if invoked internally by the IS.

The Wilmarth-North Rochester 345 kV line provided marginal improvements to the system beyond the CapX 2020 facilities. This line provides minimal benefit for Lakefield Junction, Pleasant Valley, and Adams Substations which are all common generation interconnection facilities.

The Genoa-Salem 345 kV line would be a great Phase 2 project for RES, but the La Crosse-Madison 345 kV provides greater benefit overall. Since the King-Eau Claire-Arpin 345 kV line is an existing limiter of the Corridor Study, adding the Genoa-Salem 345 kV line would be less successful at off-loading the King-Eau Claire-Arpin line than the La Crosse-Madison 345 kV line. This is due to the Genoa-Salem line's electrical distance from Eau Claire and Madison.

[3] Intergrated System in the MAPP region include the intergrated transmission system of Western Area Power Administration, Basin Electric Power Cooperative, and Heartland Consumers Power District.

4.6: Performance Evaluation Methods

4.6.1: Steady State

The primary method of analysis for the steady-state (power-flow) simulations was the use of DC contingency analysis in PSS/E. This was the quickest way to study using the Midwest ISO market as a sink and with generation inside Minnesota at such high levels. Future studies will need to further refine the details of how much generation can be supported and the increased reactive losses from serving the load from a great distance. This study used a much wider footprint of generators as a sink than the Corridor Study; this allowed fewer generators in any one area to be turned down and helped reduce the potential of voltage issues.

The table below shows the areas monitored for violations. Branches 100 kV and above within and emanating from those areas were monitored for overloads.

Table 4.6.A – Monitored Areas

Area Number	Area Name
331	Alliant West
364	Alliant East
365	Wisconsin Energy
366	Wisconsin Public Service
367	Madison Gas & Electric
368	Upper Peninsula Power Company
600	Xcel Energy
608	Minnesota Power
613	Southern Minnesota Municipal Power Agency
618	Great River Energy
626	Otter Tail Power
633	Muscatine Power & Water
635	MidAmerican Energy
640	Nebraska Public Power District
645	Omaha Public Power District
650	Lincoln Electric System
652	Western Area Power Administration
667	Manitoba Hydro
680	Dairyland Power Cooperative

4.6.2: Dynamics

To understand the impact of the proposed generation and transmission additions upon the performance of the northern MAPP transmission system, an extensive set of transient stability simulations was performed. Voltage profiles and system damping were reviewed to ensure that the transmission grid will function within acceptable levels following a transient event on the transmission system.

4.6.3: Market Dispatch

The North American electrical system is a complex interconnected grid in which power generators are interconnected through many miles of transmission lines comprising a high voltage grid that transports electric power to consumers. The bulk transmission system with limited access points acts like the interstate highway system, moving electric power long distances.

The market-wide dispatch model used for the analysis of this RES Update Study mirrors the way electricity is generated and moves through the system.

Another concern with the traditional or more localized study methodology is that it has the effect of “hiding” transmission violations like low voltage that occur during Midwest ISO market dispatch by not allowing the generation to participate in true market dispatch. The study team sought to ensure adding the generation would not constrain the transmission system with something that is masked by the Midwest ISO market dispatch model. At the same time, some violations can occur that would not normally occur in market dispatch based on increased transmission flows through areas created by traditional dispatch.

Market dispatch methodology better enables generation to interconnect and be delivered by studying transmission projects in the manner they will be used once in operation.

The power system is operated in real-time via security-constrained economic dispatch. What this means is that the transmission system operators work to run the most reliable and low-cost generation units first and then the higher cost generation units as needed to accommodate the electricity demand. This minimizes cost of generation that runs while avoiding contingent system violations. Therefore, the RES Update Study’s use of market-wide dispatch provided more accurate results. Generally, higher cost generation is east of Minnesota, lower cost generation is west of Minnesota, so often a west-to-east bias of power flow occurs until facilities within the system limit that bias.

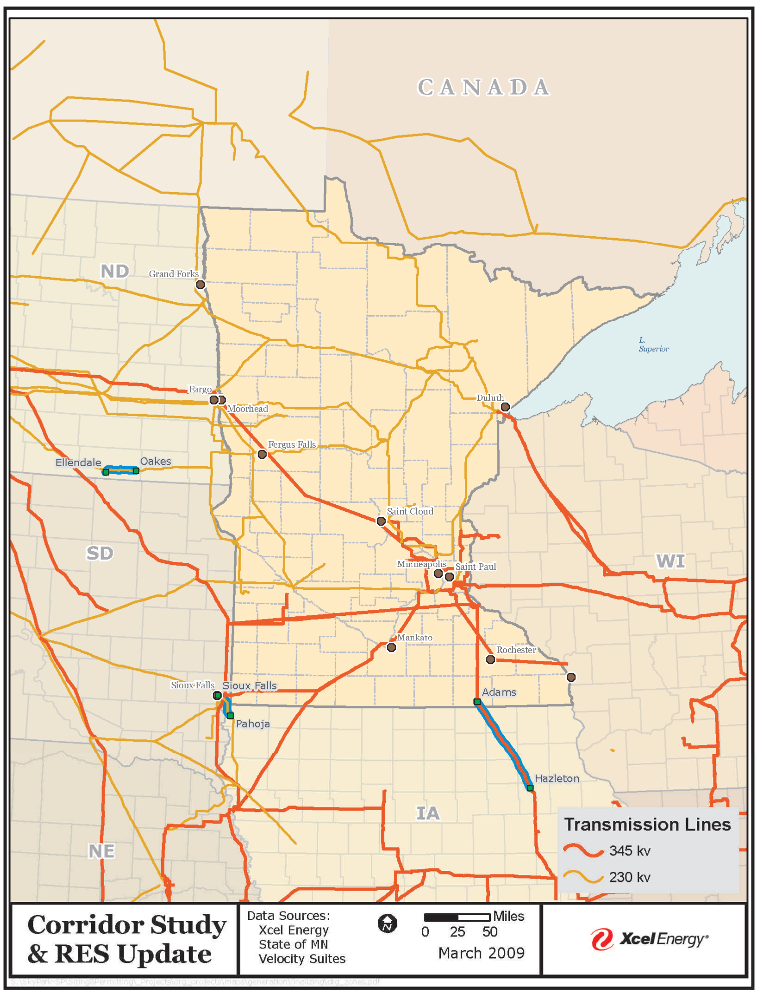
5.0: Results

5.1: Steady-State Analysis

The RES Update Study not only identified the different facilities' upgrades necessary to increase generation output but also investigated the impact the various improvements have on each other in each zone. This sensitivity analysis provided useful data for the RES Update and Corridor Study recommendations.

Figure 5.1.A provides a map of the three most common limiters that were deemed to be significant enough to limit additional generation delivery within a given sensitivity. A short description of each limitation is provided below.

Table 5.1.A – "Stopping Point" Limiters



- Ellendale – Oakes 230 kV Line – this line is the primary limit in cases without the Ashley – Hankinson 345 kV line. The interest in new generation development in the Ellendale area is the primary driver for this line overload.

- Hazleton – Adams 345 kV Line – this line limits generation delivery in a number of cases. Based on commitments made by ITC Midwest, it is anticipated that a new 345 kV line from Hazleton to Salem Substation will be constructed. This helps to provide generation outlet from southeastern Minnesota and northern Iowa. However, at higher levels of generation loss of 345 kV circuits between the Rochester area and La Crosse or Madison causes significant additional power to flow on the Hazleton – Adams 345 kV line as it attempts to reach the Hazleton – Salem line.

- Sioux Falls – Pahoja 230 kV Line – as generation interest in southwestern Minnesota and the Dakotas increases, loss of the Split Rock – Sioux City 345 kV line will overload the Sioux Falls – Pahoja line. This line runs

Figure 5.1.B shows a map of the underlying system limiters that were common throughout most, if not all scenarios studied. A short description of the limiters is provided below.

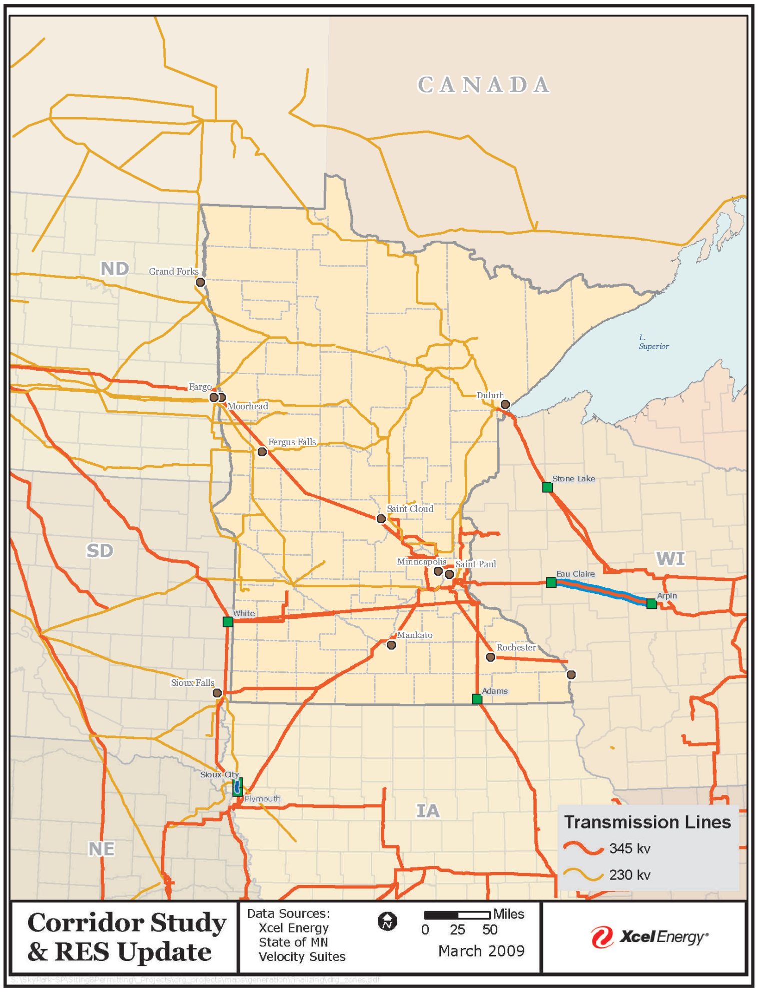
- Stone Lake 345/161 kV Transformer – this transformer is located along the recently completed Arrowhead – Gardner Park 345 kV line. The overload generally shows up for contingencies that involve loss of the Stone Lake – Gardner Park. In addition, a 345 kV breaker failure contingency that causes loss of both the Arrowhead – Stone Lake and Stone Lake – Gardner Park line segments causes overload of the King – Eau Claire – Arpin 345 kV line. Adding a second transformer at Stone Lake would eliminate the breaker-failure contingency concern.

- Eau Claire 345/161 kV Transformer – this overload occurs for a stuck breaker contingency on the 161 kV bus at Eau Claire Substation. Alleviating this overload would require either upgrading both 345/161 kV transformers or constructing a breaker-and-a-half scheme on the 161 kV bus at Eau Claire.

- Adams 161 kV Bus – overload of this bus segment occurs due to loss of the Byron – Pleasant Valley – Adams 345 kV line or a 345 kV breaker failure at Hazleton Substation that causes loss of the Hazleton – Adams line. Both of these contingencies force more power through the 161 kV system at Adams.

- White Substation 345 kV Relay Settings – the relay settings at White Substation are set in such a way that flow on the White – Split Rock 345 kV line is limited. This overload occurs for loss of the Brookings County – Lyon County 345 kV line, as this contingency forces power at Brookings County to flow south to Split Rock Substation.

Table 5.1.B – Common Underlying System Limiters



- Sioux City Substation 345 kV Relay Settings – the relay settings at Sioux City Substation are set in such a way that flow on the Sioux City – Split Rock 345 kV line is limited. This overload occurs for loss of the Lakefield – Nobles 345 kV line, as this contingency forces power at Split Rock to flow north to White Substation and south to Sioux City Substation.

- Adams 345/161 kV Transformer – this transformer is located in southeastern Minnesota and its overload mainly occurs for loss of the Byron – Pleasant Valley – Adams line.

- King 345 kV Bus Arrangement – the bus arrangement at King Substation northeast of the Twin Cities currently makes it possible that a single contingency could cause the loss of the King – Chisago, King – Red Rock, and King – Eau Claire 345 kV lines. Loss of King – Eau Claire also initiates tripping of the Eau Claire – Arpin 345 kV line. This contingency was shown to trigger several overloads throughout the system. By adding 345 kV breakers at King Substation, this contingency can be eliminated so only one facility is lost due to any contingency.

- Plymouth – Sioux City 161 kV Line – this overload occurs for loss of the Brookings County – Lyon County 345 kV line, as additional power is forced to flow south through Sioux Falls and Sioux City and then back up to the Twin Cities.

In the following off-peak tables, the rows RES Update Study transmission facilities configurations. Within each cell, the first line represents the generation level that can be reached with particular transmission assumptions. The second line represents the facility whose overload represents the system limit. The third line represents the contingency that limits the generation delivery under that off-peak scenario.

For example, referring to Table 5.1.1A, in a case with La Crosse – Columbia in service and the existing Minnesota Valley – Blue Lake 230 kV line in service, 2394 MW of outlet can be obtained. This is limited by overload of the Hazleton – Adams 345 kV line for loss of the Byron – North Rochester 345 kV line. If you move to the next column, installing the Corridor Upgrade results in 3600 MW of outlet. Again this is limited by overload of Hazleton – Adams this time for system intact. Full detail of all underlying and overloaded facilities can be found in Appendix D.

5.1.1: Southeast Zone Source

Table 5.1.1.A – Southeast Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2394 MW Hazleton-Adams 345 Byron-N. Roch. 345	3600 MW Hazleton-Adams 345 Base Case	3682 MW Hazleton-Adams 345 Base Case
Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3551 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3418 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Maple River - Split Rock Lakefield Jct. - La Crosse La Crosse - Columbia	3000+ MW	2861 MW Hazel-Granite Falls 230 Base Case	3805 MW Hilltop-N. LAX 345 ECL-ARP & ARR-SLK 345

Table 5.1.1.B – Southeast Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2761 MW Hazleton-Adams 345 Byron-PV-Adams 345	3000+ MW	4340 MW Hazleton-Adams 345 Byron-N Roch. 345
Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3000+ MW
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3000+ MW
Maple River - Split Rock Lakefield Jct. - La Crosse La Crosse - Columbia	3000+ MW	3000+ MW	3000+ MW

5.1.2: Southwest Zone Source

Table 5.1.2.A – Southwest Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2572 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2435 MW Hazel-Granite Falls 230 Base Case	2645 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Adams - La Crosse **La Crosse - Columbia**	2566 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2433 MW Hazel-Granite Falls 230 Base Case	2651 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Lakefield Jct. - Adams **Adams - La Crosse** **La Crosse - Columbia**	2700 MW Split Rock-Nobles 345 Nobles-Lakefield Jct.	2473 MW Hazel-Granite Falls 230 Base Case	2728 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Maple River - Split Rock **Lakefield Jct. - La Crosse** **La Crosse - Columbia**	1998 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345	2150 MW Hazel Creek 345/230 Parallel Outage	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

Table 5.1.2.B – Southwest Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Columbia	2188 MW Blue Lake-Helena 345 Helena-Lake Marion 345	3000+ MW	4058 MW Blue Lake-Helena 345 McLeod-Panther 345 dbl
Adams - La Crosse **La Crosse - Columbia**	2224 MW Blue Lake-Helena 345 Helena-Lake Marion 345	3000+ MW	4108 MW Blue Lake-Helena 345 McLeod-Panther 345 dbl
Lakefield Jct. - Adams **Adams - La Crosse** **La Crosse - Columbia**	2986 MW Blue Lake-Helena 345 Helena-Lake Marion 345.	3000+ MW	4637 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345
Maple River - Split Rock **Lakefield Jct. - La Crosse** **La Crosse - Columbia**	3000+ MW	3000+ MW	4545 MW Sioux Falls-Pahoja 230 Split Rock-Sx City 345

5.1.3: North Dakota Zone Sources

Table 5.1.3.A – North Dakota Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Brookings	490 MW Ellendale-Oakes 230 Center-Jamestown 345	1501 MW Ellendale-Oakes Jamestown-Maple River 345	2022 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson	1049 MW ARR Phase Shifter Base Case	1530 MW ARR Phase Shifter Base Case	2006 MW Hazleton-Adams 345 ECL-ARP & ARR-SLK
Maple River - Brookings Ashley - Hankinson La Crosse - Columbia	1440 MW ARR Phase Shifter Base Case	1581 MW ARR Phase Shifter Base Case	2688 MW ARR Phase Shifter Base Case
Maple River - Split Rock Ashley - Hankinson Lakefield Jct. - Columbia	1588 MW ARR Phase Shifter Base Case	1653 MW Hazel-Granite Falls 230 Base Case	2285 MW Sioux Falls-Pahoja 230 SPK-NOB & SPK-SXC 345

Table 5.1.3.B – North Dakota Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Brookings	490 MW Ellendale-Oakes 230 Center-Jamestown 345	922 MW Ellendale-Oakes 230 Center-Jamestown 345	2828 MW Ellendale-Oakes 230 Center-Jamestown 345
Maple River - Brookings Ashley - Hankinson	1443 MW Ellendale-Oakes 230 Base Case	2225 MW Ellendale-Oakes 230 Ashley 345/230 Tx	3284 MW Ellendale-Oakes 230 Ashley 345/230 Tx
Maple River - Brookings Ashley - Hankinson La Crosse - Columbia	1436 MW Ellendale-Oakes 230 Base Case	3000+ MW	3275 MW Ellendale-Oakes 230 Ashley 345/230 Tx
Maple River - Split Rock Ashley - Hankinson Lakefield Jct. - Columbia	1511 MW Ellendale-Oakes 230 Base Case	2296 MW Ellendale-Oakes 230 Ashley 345/230 Tx	3300 MW Ellendale-Oakes 230 Ashley 345/230 Tx

5.1.4: All Sources

Table 5.1.4.A – Summer Off-Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Split Rock Ashley - Hankinson La Crosse - Columbia	3215 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK	3110 MW Sioux Falls-Pahoja SPK-NOB & SPK-SXC 345	3379 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK
Maple River - Split Rock Ashley & Broadland Lines La Crosse - Columbia	3181 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK	3000 MW Sioux Falls-Pahoja SPK-NOB & SPK-SXC 345	3369 MW Hazleton-Adams 345 ARP-ECL & ARR-SLK
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. - Columbia	3536 MW Hazleton-Adams 345 Hilltop-NLAX 345	3453 MW Hazleton-Adams Hilltop-NLAX 345	3465 MW Adams-Pleasant Valley 345 N.Roch-NLAX 345

Table 5.1.4.B – Summer Peak

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
Maple River - Split Rock Ashley - Hankinson La Crosse - Columbia	5000 MW	5000 MW	6202 MW Hazleton-Adams 345 NLAX-Columbia 345
Maple River - Split Rock Ashley & Broadland Lines La Crosse - Columbia	5000 MW	5000 MW	6190 MW Hazleton-Adams 345 NLAX-Columbia 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. - Columbia	5000 MW	5000 MW	6350 MW Hazleton-Adams 345 NLAX-Columbia 345

5.1.5: Dispersed Renewable Generation

A generation scenario was run that generally mimicked the process used in the DRG Phase I study and attempted to model 2000 MW of new generation facilities on the lower voltage transmission system assuming no new transmission facilities beyond the CapX 2020 Group I projects. Using a market scenario, using DRG projects was concluded to not be feasible for several reasons.

Constraints in Wisconsin prevented the Midwest ISO market from being able to accept 2000 MW without the addition of new bulk transmission facilities. In response to this result, the dispatch was changed to mimic the dispatch used in the DRG Phase I study. This dispatch turned down generation in the greater Twin Cities metro area and also at Lakefield and Pleasant Valley in order to allow additional generation on the system. This shift in dispatch is noteworthy, because it does not reflect the way power is dispatched in the real-time Midwest ISO market. Thus, it simply assumes that 2000

MW of capacity will be available on the transmission grid under the real-time market dispatch to accept new generation projects. Whether adding this amount of new generation without additional bulk transmission or the unusual dispatch scenario described are feasible is open to debate. This scenario would result in significant existing generation in Minnesota that could not operate.

Using the assumptions noted above, the DRG analysis showed that approximately 2000 MW of generation could be modeled using a Twin Cities dispatch with about $85 million in transmission upgrades.

Modeling 2000 MW of DRG spread around the greater Twin Cities area would require approximately $85 million in transmission upgrades under these location and dispatch assumptions.

The analysis started with the summer off-peak case containing the Corridor Upgrade. All buses within the state of Minnesota were initially selected to run first contingency incremental transfer capability sinking to the Twin Cities generation. The output for each bus, limited by its first violation, was sorted to remove any negative transfers and buses over 100 kV. From this short list, the sites to be used in the final analysis were derived based on the incremental transfer capability determined for each site.

The green squares in Figure 4.3.1.E earlier in this report indicate the locations of DRG substation sites. In all, 42 sites were used in the final analysis. To avoid impacting transmission facilities, most of these sites were modeled just outside the Twin Cities metro area. Modeling these sites closer to the sinks in the Twin Cities area generally enables greater levels of generation to be located. Whether this is a realistic locational assumption is open for debate, as the population density in these areas is much greater than in more remote areas studied (e.g., Buffalo Ridge, Western Minnesota, Southeastern Minnesota). Attempts to site generation in these areas may be met with public opposition, as there will be more affected landowners per project.[4]

Another locational consideration is the impact of capacity factor on the amount of wind projects that must be installed. Where wind projects on the Buffalo Ridge may have capacity factors approaching 40% or more, the capacity factor closer to the Twin Cities is approximately 30%. This means the wind turbines are producing less of the time and more turbines would be required to produce an equivalent amount of power. This is

[4] Two examples of this public opposition can be found in the exhaustive permitting process experienced by Great River Energy to site a small wind turbine at their corporate headquarters in a commercial area of Maple Grove, Minnesota and an effort by East Ridge High School in Woodbury, Minnesota to site a small wind turbine on its property. In both cases, opposition arose related safety, land values, and noise concerns. The GRE wind turbine was approved, while the Woodbury wind turbine was not.

important because the investment cost of wind turbines greatly dwarfs the investment cost of transmission on a cost per MW basis.[5]

A specific loss analysis was not undertaken as part of the DRG scenario, however, the DRG Phase I study showed mixed results between summer peak and summer off-peak models. The summer off-peak models, due to the reduced loads and high wind generation, result in power needing to travel greater distances. Doing so on lower-voltage systems (where DRG tends to be installed) results in a loss increase. The DRG Phase I results are indicative of the loss results that could be expected from the DRG scenario in this study. This is important because, where several of the projects examined in this study introduce significant loss savings that dramatically impact the total cost of the project, the DRG scenario either would not introduce any savings or would only introduce very small savings and would likely result in greater generation installation costs.

One key finding of the DRG scenario was that turning down the Twin Cities generation to enable DRG to come online resulted in an overload of the 345/115 kV transformers at Terminal Substation northeast of Minneapolis. This overload occurred at roughly 900 MW of DRG penetration. A solution for this overload is not known. What is known is that the transformers at Terminal Substation cannot be any larger. The two transformers are already 672 MVA units. Due to the size of units larger than 672 MVA, any larger unit would require the use of single-phase transformers. Doing this would require six single-phase transformers – a solution for which space at Terminal Substation does not exist. Compounding this problem is the fact that the 115 kV circuit breakers at Terminal are approaching their operable limits for the size of faults they can safely interrupt.

The project that was assumed to resolve this issue has not been fully vetted to ensure it will resolve the transformer overload. It represents the best judgment of planning engineers based on currently available information to devise a solution to a problem that has challenged engineers for several years.

[5] For example, 2000 MW at 30% capacity factor would produce approximately 5.25 million MWh per year. In order to produce the same amount of power at 25% capacity factor, approximately 2400 MW of wind turbines would be necessary. Assuming an installed cost of $1 million to $1.5 million per MW, this extra 400 MW results in an additional cost of $400 million to $600 million.

5.2: Dynamic Stability

An indicative stability assessment was also performed. The inputs and faults studied are discussed above in Chapter 4. This assessment confirmed that as load serving entities approach final compliance with current renewable energy standards requirements, significant new reactive capability will be necessary. This is due in large part to generation being located a significant distance from load centers. At the same time, some larger generators are being turned down to make room for the new wind generators.

The power system relies on the inertia of generators to “weigh” the system down and absorb the voltage and power swings that follow a system fault. Larger generators have more inertia than smaller generators and are typically better at absorbing those swings. Smaller units tend to be more susceptible to swings, as their lesser inertia makes it easier for the units’ power output to change. As the generation in the system increasingly shifts to smaller units further from load centers, there will be increased sensitivity to faults on major regional lines and large generation units.

With the addition of the Corridor Upgrade and its associated 2000 MW of generation, low voltages are observed on the 161 kV system between Stinson and Stone Lake for the PCS disturbance (SLGBF on King-Eau Claire 345 kV line). This issue has been showing up in other recent studies as well. The issue appears to only be a transient voltage issue since the steady-state voltages are relatively good. A potential fix would be to add a Static Var Compensator (SVC) in the Minong or Stone Lake region. The Lakefield-Columbia 345 kV line does mitigate the issue at 4800 MW, but it re-appears at the 6800 MW level.

The most significant stability-related result was a significant occurrence of instability for the region is for loss of Sherco Unit 3 (MQS). This is the largest single unit in the area and its loss causes an instantaneous reversal of direction on regional tie lines to fill the void left by the unit. This shift in regional transmission flow causes the system to go unstable. The increased penetration of wind generators (over 7300 MW of Minnesota and nearby wind) contributes to these swings as they are unable to absorb these swings as effectively as other regional generators. The voltage swing issues for loss of Sherco Unit 3 were resolved by removing 500 MW of generation at several buses in the system. The voltage swings at Watertown 345 kV show the instability at 7300 MW of wind in Figures 5.2.1.A and 5.2.1.B.

These plots show the potential of interconnecting large amounts of wind turbines and turning of synchronous generators with higher inertia values. The possibility the system reaches instability during various disturbances becomes more and more likely to happen if not transmission is built to strengthen the tie between Chicago and the Twin Cities.

Figure 5.2.1.A – Watertown 345 kV Voltage without Big Stone II

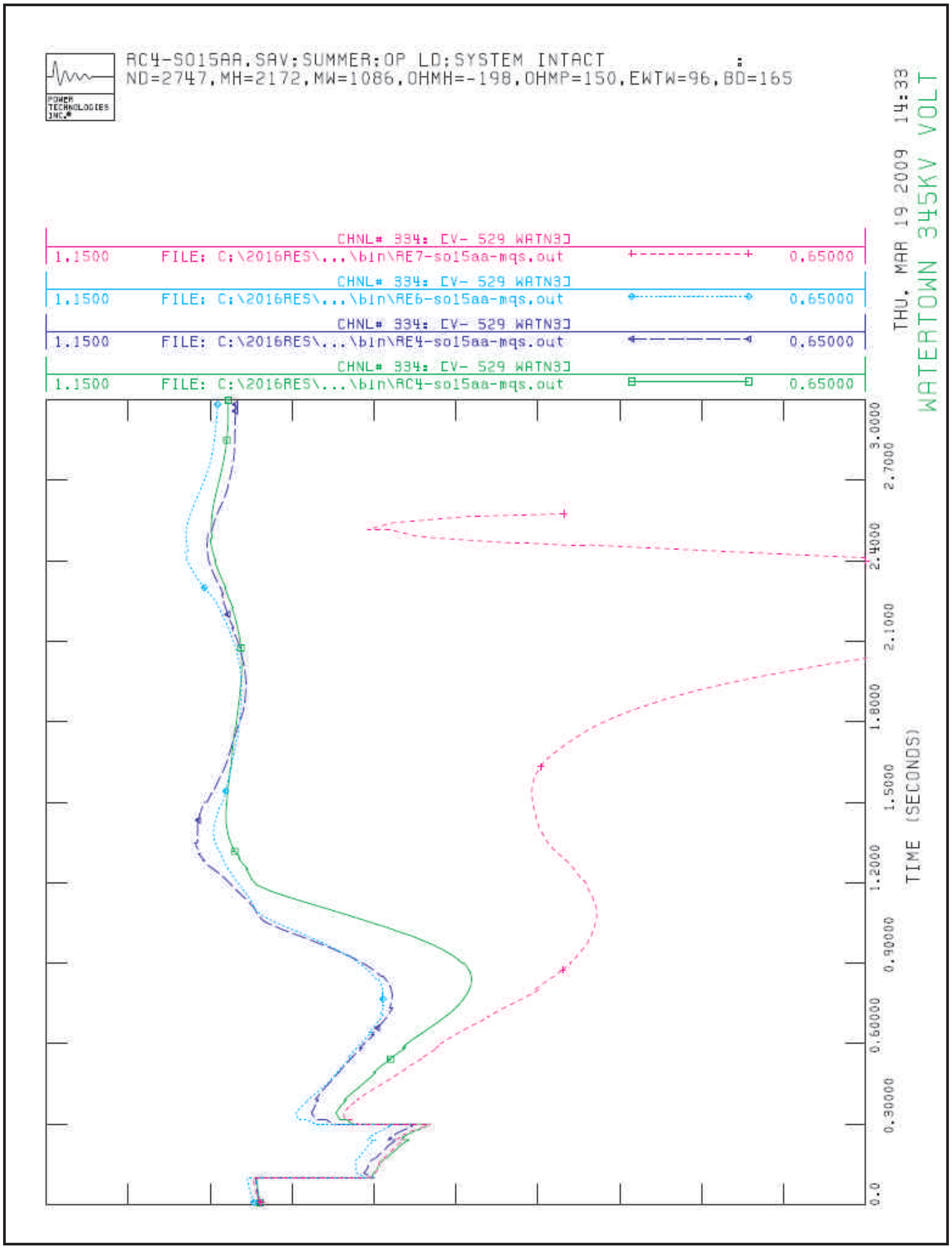
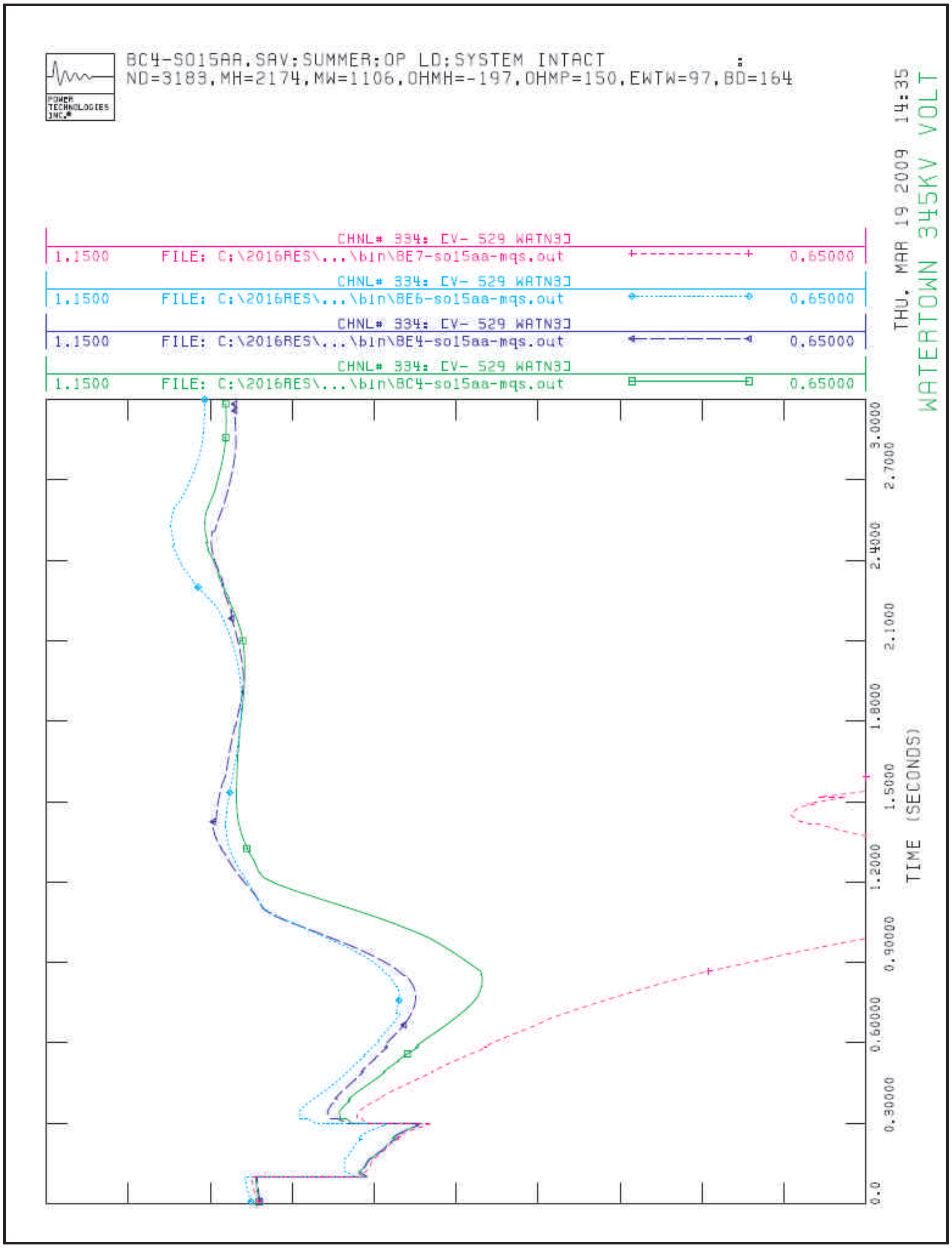


Figure 5.2.1.B – Watertown 345 kV Voltage with Big Stone II



The figures above show the voltage at the Watertown 345 kV bus during the loss of Sherco Unit 3. The colors of the lines represent various system configurations. Watertown is shown here because it has been shown to be the limiting bus with respect to voltage swings in many regional studies – as was the case in this study. Note that several of the configurations remain stable. The pink line shows rapidly decaying voltage represents the case with 7300 MW of generation. Both of these cases demonstrated dynamic system voltage collapse. Voltage (and frequency) swings proved to be too much for units to maintain operation.

In real-time, these graphs indicate that loss of Sherco Unit 3 would result in a first swing voltage that fell well below 60%. This is notable, because NERC first-swing voltage criteria requires that first-swing voltage remain above 70%. In fact, some cases showed first-swing voltage as low as 29%. With a voltage swing this substantial, the frequency would increase significantly, generators would trip based on their overfrequency protection, and within a matter of seconds, the collapse would cascade throughout the region.

At the reduced generation level of 6800 MW, the system was shown to be able to ride through the loss of Sherco Unit 3. System voltage fluctuations were still evident, but remained within the limits provided by NERC standards. Voltage violations were still observed for the PCS disturbance. These issues would still be required to be resolved – most likely through the addition of a SVC at Stone Lake Substation.

Both the 6800 and the 7300 MW cases required significant capacitor additions (1740 MVAR) just to raise the steady-state voltage of the system prior to performing any fault simulations. This was done primarily by adding capacitors on the new 345 kV lines. Table 5.2.1.C shows the size and placement of these caps. Full details of stability tables and plots can be found in Appendix E.

These capacitors were assumed to be placed on the 345 kV bus at the substation in question. However, due to the cost of 345 kV capacitors, it may be desirable to place this reactive support on the lower voltage (115 or 161 kV) buses. While this possibility was not explicitly studied, these capacitor additions would likely increase in size to account for losses through the transformer. In addition transformer increases may be necessary as these reactive power additions may result in transformer overloads.

Figure 5.2.1.C – Capacitor Additions

Location	Size (MVAR)
North La Crosse	4 x 60
Brookings Co	4 x 60
Helena	4 x 60
Hampton	3 x 60
Lyon Co	3 x 60
Lakefield Jct	4 x 60
Adams	4 x 60
Hazleton	3 x 60

In general, the message these results portray is that wind penetration beyond the levels studied in conjunction with the Corridor Upgrade must be pursued with the utmost caution. As the stabilizing influence of larger generators is reduced or those units are replaced by smaller generators that are more susceptible to voltage swings, additional bulk transmission lines will be needed in order to effectively absorb the impacts of regional faults and generator outages. The 7300 MW case for this stability study included approximately 800 miles of new transmission (beyond the CapX2020 Group I lines) and represented a significant expansion in the generation delivery capability of the regional transmission grid. Despite the inclusion of a significant amount of new transmission infrastructure to increase regional stability, observable limits to wind penetration in the upper Midwest were observed.

As this stability study demonstrates, a lack of sufficient transmission resources will expose the upper Midwest region to degraded reliability and the potential for relatively innocuous transmission contingencies to cascade into large-scale regional concerns.

While a specific stability assessment was not conducted for the DRG scenario, the no-build stability analysis conducted in conjunction with the Corridor and RES Update Studies is indicative of the type of results that can be expected from a DRG stability assessment. Installing 2000 MW of wind generation while not building any new transmission to tie the Twin Cities more closely with larger generators and then turning down greater Twin Cities generation to allow the 2000 MW of generation to come online would lower the system's inertia. With replacing the large generators that are capable of riding through system faults with a large number of smaller wind generating turbines results in degradation in the overall system stability in the upper Midwest.

The key finding of the RES Update Study is the realization of an operational limit to the extent to which wind penetration can be accepted into the transmission grid in the upper Midwest. In the steady state realm, this limit began to manifest itself as generation in the Twin Cities was turned down in order to enable increasing amounts of wind to be turned on. Some Twin Cities generators are natural gas units that can be turned on and off with relative ease, but others are fossil or nuclear units that cannot be rapidly taken offline and then brought back online. However, the Corridor and RES Update studies verified that beyond the renewable generation levels envisioned with the Corridor Upgrade, additional intermittent generation would require the larger fossil fuel generators near the Twin Cities to begin backing down.

5.3: Transmission System Losses

5.3.1: Technical Evaluation

The loss benefits are significant for justifying transmission projects. A MW of loss savings is equivalent to a MW that does not need to be produced by a generator. These results in lower fuel costs and, thus, a reduction in the costs passed on to ratepayers. The following table shows the relative losses from varying scenarios of transmission options implemented. The level of generation that was studied is also shown and matches the steady-state analysis in Section 5.1 with the Hazel-Blue Lake Corridor facilities. The loss values are based on the whole Eastern Interconnect losses during Summer Peak conditions. Details of the losses can be found in Appendix F.

Table 5.3.1.A – Losses Summary

			Transmission Only			With Generation		
Facilities	Generation MW	Source	Loss Without Facilities MW	Loss Without Facilities MW	Delta MW	Loss Without Facilities MW	Loss Without Facilities MW	Delta MW
Maple River-Brookings Ashley-Hankinson	1530	ND / Cord	17500.5	17491.6	-8.9	17686.1	17674.7	-11.4
Maple River-Brookings Ashley-Hankinson LaCrosse-Columbia	1581	ND / Cord	17500.5	17465.2	-35.3	17694.5	17652.8	-41.7
LaCrosse-Columbia	3600	ND / Cord	17500.5	17474.3	-26.2	18115.6	18072.2	-43.4
Adams-LaCrosse LaCrosse-Columbia	3600	SE / Cord	17500.5	17468.3	-32.2	18115.6	18061.4	-54.2
Lakefield-Adams Adams-LaCrosse LaCrosse-Columbia	3600	SE / Cord	17500.5	17460.3	-40.2	18115.6	18042.5	-73.1
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock LaCrosse-Columbia	3450	ALL / Cord	17500.5	17459	-41.5	18005.5	17945.4	-60.1
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock Lakefield-Adams Adams-LaCrosse LaCrosse-Columbia	3450	ALL / Cord	17500.5	17440.3	-60.2	18005.5	17911.8	-93.7

The La Crosse-Madison 345 kV line creates the most MW loss savings as shown in the difference in the first two facilities Table 5.3.1.A. This large loss savings is created by the addition of a new 345 kV line to the Midwest ISO market outside Minnesota. Due to the general bias of transmission flows in the region, the lower-voltage system that this line spans carries a significant amount of through-flow beyond the load-serving needs for which it was primarily designed. Installing this new 345 kV line provides a more efficient path for that flow on the lower voltage system and results in fewer losses.

5.3.2: Economic Evaluation

Figure 5.3.2.A 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 4.4 M$/MW of Cumulative Present Value of Losses. This value represents the result that any transmission improvement causing 1 MW of loss savings saves the electric system 4.4 M$ of present value generation cost that would otherwise be incurred to supply the capacity and energy for that 1 MW of losses.

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.

The key result on the following worksheet for this study is the 3.1 M$/MW of Equivalent Transmission Investment. This is the amount of “supportable transmission investment” per MW of loss savings.

Figure 5.3.2.A – Equivalent Capitalized Value for Losses

Computation of Equivalent Capitalized Value for Losses
(pool reserve requirement of 15%)

Input Assumptions

Term of loss reduction	40	yrs	Present Value of Annuity factor	12.29	< Losses
Assumed life, xmsn	35	yrs	Present Value of Annuity factor	11.99	< Transmission
Discount rate	7.72	%/yr			
Energy value	$46	MWh			
Loss Factor	30.00		< ASK-ECL 345 loss factor (ave. 2000 and 2001). Proxy for MN to Western WI flows		
Transmission FCR	0.15				

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	4,028,660
Energy Value:	1.00	8760 hr/yr	0.30	$46	/MWh			121,387	$ 1,492,077
					Total annual cost, capacity & energy:		$	449,137	5,520,737

Present Value Annuity factor Losses	12.29
Cum PV Losses $	5,520,737
Equivalent Transmission investment $	**3,068,625**
is Cum PV Losses / FCR trans / PVA trans	

As an example, the table below demonstrates that, based on the 3.1 M$/MW value, the "loss reduction" investment credit for building the Maple River-Brookings Co and Ashley-Hankinson plan is 35 M$ (11.4 MW loss savings multiplied by 3.1 M$/MW). A full of loss savings can be found in Table 5.3.2.B.

Table 5.3.2.B – 40 Year Loss Savings

Facilities	Loss Savings MW	40-Year Loss Savings $
Maple River-Brookings Ashley-Hankinson	11.4	35,000,000
Maple River-Brookings Ashley-Hankinson LaCrosse-Columbia	41.7	128,000,000
LaCrosse-Columbia	43.4	134,000,000
Adams-LaCrosse LaCrosse-Columbia	54.2	167,000,000
Lakefield-Adams Adams-LaCrosse LaCrosse-Columbia	73.1	225,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock LaCrosse-Columbia	60.1	184,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock Lakefield-Adams Adams-LaCrosse LaCrosse-Columbia	93.7	288,000,000

6.0: PROMOD Simulations

6.1: Background

During the scoping phase of the RES Update, the TRC and other stakeholders expressed a desire for analysis of the economic performance of the facilities being studied. In response to this input, the study team worked with the Midwest ISO to perform analyses that tested the performance of the proposed facilities within the Midwest ISO's market dispatch. Short for PROduction MODeling, PROMOD is a software package developed by Ventyx that is capable of modeling the performance of the generation market. It can factor in transmission constraints, manipulate generation dispatch to avoid overloading constrained transmission interfaces, and minimizes the generation cost to do so.

PROMOD is a highly data-intensive program. A small selection of the type of information that is necessary to conduct an effective PROMOD study includes data such as fuel charges, fuel consumption rates for individual generators, possible generation increments for individual generators, and the startup time, shutdown time, and individual unit ramp rates for any generators that participate in a given market dispatch. PROMOD also requires a dependable transmission system model in order to determine with accuracy the amount of time a given interface is constrained and limits generation dispatch.

In addition, PROMOD is also a highly processor-intensive program. PROMOD uses its generation and transmission information, along with location-specific wind profile data to model the transmission system for every hour of an entire year. The wind farms modeled within PROMOD can be tied to the location-specific wind profile data so neighboring wind farms can theoretically see slightly different wind regimes. The extent to which each of these wind farms (and every other generator in the system) impacts every transmission line in the system is then recorded and that information is used to determine which units should be backed down to alleviate a transmission constraint.

PROMOD is highly detailed and highly intensive, with run-times on dedicated servers for cases with significant wind penetration spanning two full weeks.

Given the amount of confidential, market-sensitive information that is used in a PROMOD run, Midwest ISO engineers are widely-regarded as having some of the best-available production modeling information in the Midwest. For this reason, their assistance was sought to ensure the PROMOD study was conducted with the best information available.

While PROMOD can provide information such as Locational Marginal Prices (LMP) for various constraints and the value of alleviating that constraint, the information that bears the most relevance to this analysis is that of the production cost savings and load cost savings brought to bear by the projects under consideration.

6.2: Production Cost and Load Cost Explained

The production cost of a PROMOD study is the cost to produce sufficient generation to meet the demand being modeled. By running a “base case” and comparing the production cost of that case with one that includes the project in question, it is possible to determine the annual cost savings that will be realized by completing a particular project. The load cost of a PROMOD study is calculated by multiplying the LMP for each load center by the amount of load in that load center and then summing all the values for the various load centers in the market.

Because regulated utilities have customers with fixed rates, it is in the best interest of the utility to minimize the cost to deliver that energy. This promotes efficiency of production and minimizes the number of generators that must be run and the level at which those generators must run at any one time. In general, the production cost calculation within PROMOD tends to reflect more of a regulated market system.

On the other hand, a true market system will seek to minimize the cost observed by the load. When rates of service vary based on the constraints present on the transmission system, a utility will be most interested in what the cost to its loads would be. In this way, the load cost calculation within PROMOD reflects a more market-based system.

Given the mixture of regulated and market-based entities within the Midwest ISO footprint, the Midwest ISO typically considers 70 percent of the production cost savings and 30 percent of the load cost savings when evaluating the economic worth of a project. To maintain consistency with Midwest ISO methodologies, the same percentages were used for this analysis.

The PROMOD analysis of the RES Update Study facilities was conducted with the preferred Corridor facilities in service to ensure the most accurate post-project simulations occurred. The results of these analyses can be found in below.

6.3: Generation Siting

The first task in developing a base case PROMOD model was to ensure the locations of the “existing” modeled wind generation were accurate. Consistent with the steady state analysis, base case wind generation on the Buffalo Ridge was set at 1900 MW. The initially-planned RIGO facilities were also modeled, as was the associated 922 MW of generation. This brought the total “base case” wind generation in Minnesota to the same 2822 MW of generation included in the steady state power flow model.

The next task was to model the potential locations of generation that would be enabled by the projects being considered. Given the steady state results of the Corridor Upgrade, 2000 MW of potential generation (in addition to the 2822 MW in the base case) was modeled as shown in Table 6.3.A.

Table 6.3.A – PROMOD Generation Locations for 4822 MW

Substation	***Generation Size***
Base Generation	2822
Yankee	150
Fenton	150
Lyon Co.	300
Nobles	200
Brookings Co.	400
Granite Falls	300
Morris	200
Big Stone	300
TOTAL	**4822**

Table 6.3.B – PROMOD Generation Locations for 5822 MW "A"

Substation	***Generation Size***
Base Generation	4822
Hankinson	300
Ellendale	300
Maple River	400
TOTAL	**5822**

Table 6.3.C – PROMOD Generation Locations for 5822 MW "B"

Substation	*Generation Size*
Base Generation	4822
Adams	300
Byron	300
Split Rock	200
Lakefield	200
TOTAL	**5822**

Finally, initial steady state results indicated that a total of 7322 MW of generation may have been attainable with installation of the Corridor Upgrade, the Fargo to Split Rock project, and the Lakefield to Madison project. In order to model this, a specific generation source list was developed for this case. Those sources are shown in Table 6.3.D below.

Table 6.3.D – PROMOD Generation Locations for 7322 MW

Substation	*Generation Size*
Base Generation	4822
Hankinson	300
Ellendale	300
Maple River	400
Pipestone	300
Winnebago	200
Adams	300
Byron	300
Split Rock	200
Lakefield	200
TOTAL	**7322**

6.4: Project Selection

Based on the results of steady state analysis, a series of projects were presented for economic analysis. In order to determine the benefit of projects and minimize the number of cases to be run, some qualitative judgments were made regarding appropriate projects for analysis. Table 6.4.A shows a list of the projects that were analyzed and the generation levels that were studied. Unless noted otherwise, all scenarios include the recommended Corridor Upgrade facilities in the base case.

Table 6.4.A – PROMOD Case and Generation Levels

Case	*Facilities Studied*	*Generation Level*
1A	Base Case - Post CapX Group I	4822 MW
6A	Maple River - Brookings Ashley - Hankinson	4822 MW
7A	La Crosse - Madison	4822 MW
Base-1	Base Case - Corridor Upgrade	5822 MW "A"
6B	Maple River - Brookings Ashley - Hankinson	5822 MW "A"
7B	Maple River - Brookings Ashley - Hankinson La Crosse - Madison	5822 MW "A"
Base-2	Base Case - Corridor Upgrade	5822 MW "B"
8A	Lakefield - Adams	5822 MW "B"
8B	Lakefield - Adams La Crosse - Madison	5822 MW "B"
9A	Adams - La Crosse La Crosse - Madison	5822 MW "B"
9B	Lakefield - Adams Adams - La Crosse La Crosse - Madison	5822 MW "B"
Base-3	Base Case - Corridor Upgrade	7322 MW
10	Maple River - Brookings Ashley - Hankinson Brookings - Split Rock Lakefield - Adams Adams - La Crosse La Crosse - Madison	7322 MW

Note that each generation level contains what is labeled as a “base case.” To serve as a basis for comparison, this case contains the recommended Corridor Upgrade facilities as the anticipated starting point for the generation development envisioned for these projects. The various transmission project combinations are then added, in turn, to the case and the simulation is run. By comparing the PROMOD output with these projects in the case to the output of the respective base case, an idea of the economic worth of a project can be ascertained. The full output of PROMOD can be found in Appendix G.

Consistent with the Midwest ISO methodology discussed above, the production cost savings and load cost savings associated with each of the projects studied are summarized in Table 6.4.B. The values given represent those for the entire Midwest ISO market since that is the sink to which the power is being dispatched. Note that the savings are based on the base case scenario at each respective generation level.

Table 6.4.B – PROMOD Production and Load Cost Savings

Case	*Generation Level*	*70% Production Cost Savings*	*30% Load Cost Savings*
6A	4822 MW	$28,000,000	$79,000,000
7A	4822 MW	$16,000,000	$50,000,000
6B	5822 MW "A"	$21,000,000	$40,000,000
7B	5822 MW "A"	$29,000,000	$55,000,000
8A	5822 MW "B"	$1,000,000	($12,000,000)
8B	5822 MW "B"	$2,000,000	($3,000,000)
9A	5822 MW "B"	$9,000,000	$21,000,000
9B	5822 MW "B"	$16,000,000	$34,000,000
10	7322 MW	$41,000,000	$64,000,000

Table 6.4.C gives the 40-year production and load cost savings and total economic benefit associated with these projects.

Table 6.4.C – PROMOD 40-Year Production and Load Cost Savings

Case	*Generation Level*	*40-Year Production Cost Savings*	*40-Year Load Cost Savings*	*Total 40-Year Economic Benefit*
6A	4822 MW	$347,000,000	$973,000,000	$1,320,000,000
7A	4822 MW	$191,000,000	$612,000,000	$803,000,000
6B	5822 MW "A"	$253,000,000	$494,000,000	$746,000,000
7B	5822 MW "A"	$356,000,000	$679,000,000	$1,034,000,000
8A	5822 MW "B"	$18,000,000	($154,000,000)	($136,000,000)
8B	5822 MW "B"	$28,000,000	($36,000,000)	($8,000,000)
9A	5822 MW "B"	$115,000,000	$265,000,000	$380,000,000
9B	5822 MW "B"	$203,000,000	$420,000,000	$623,000,000
10	7322 MW	$500,000,000	$791,000,000	$1,291,000,000

6.5: PROMOD Conclusion

Immediately, two cases jump out as having a negative 40-year economic benefit. These cases are the Lakefield-Adams and Lakefield-Adams-La Crosse projects. While perhaps surprising, this result is understandable, as the Lakefield-Adams and Adams-La Crosse projects would provide parallel paths to other 345 kV lines that are relatively unconstrained in the real-time market. With the installation of the Brookings-Twin Cities line, power can easily travel along the Lakefield-Wilmarth-Helena 345 kV line and then utilize the transmission system in the Twin Cities and existing transmission connecting to the Rochester area. Installing the Lakefield-Adams-La Crosse lines would serve to offload those facilities, but if they are not constrained to a great degree, then their installation will not provide a significant market benefit.

The benefit to installing the Lakefield-Adams and Adams-La Crosse lines lies mainly in regional reliability. The regional transmission system must be designed to serve load during peak and off-peak periods and under various contingencies during those conditions. Installing the Lakefield-Adams-La Crosse lines will provide a method for the existing transmission system to back itself up under those contingencies and avoid NERC criteria violations.

In addition, both of these lines follow existing 161 kV rights-of-way. The Lakefield-Adams line specifically has already been identified as being undersized and outdated; ITC Midwest has expressed a desire to improve the capacity and, so long as the existing 161 kV line is being updated, it makes sense to consider an upgrade that involves 345 kV.

The 40-year economic benefit totals generally show that the most significant benefits come in cases in which the Fargo-Brookings and Ashley-Hankinson lines are installed. This is logical, as the transmission system in North Dakota and South Dakota is constrained and the wind regime gives a very high capacity factor for those wind farms that are installed. As wind generation has no instantaneous production cost (i.e. fuel cost), enabling it to produce yields a significant production cost savings. It is noteworthy that three of the four cases in which the Maple River-Brookings and Ashley-Hankinson lines are included total more than $1 billion in 40-year net present value for their economic benefit.

Another project that shows significant economic value is the La Crosse-Madison line. Case 7A, which includes the La Crosse-Madison line in addition to the Corridor Upgrade provides a 40-year economic benefit of over $800 million – a dramatic economic benefit for two lines that are relatively short. The present value economic benefit of these projects, without including the value of loss savings, actually exceeds the installation cost of the lines by over $50 million.

These results are indicative of the magnitude of economic benefit that could be expected from installation of these facilities. Precise generation locations, sizes, fuel types, and dispatch would have an impact on which transmission constraints exist in any given model. Two of the same PROMOD models are actually capable of producing slightly different results – this accounts for the variability in wind generation and other market influences.

Based on the economic benefits demonstrated in the PROMOD results for the RES Update Study, the Fargo-Brookings, Ashley-Hankinson, and La Crosse-Madison projects are all recommended based on their economic performance and the benefits to the generation market.

7.0: Economic Analysis

7.1: Installed Cost

The following tables represent estimated planning cost for the various alternatives. These cost tables were created to provide a general installed cost bases on substation and line lengths.

7.1.1: La Crosse - Madison Project

	Acreage	Length	
Substations			
North La Crosse Substation	--		$8,000,000
Hilltop Substation	10		$20,000,000
Columbia Substation	5		$8,000,000
Lines			
North La Crosse-Hilltop 345 kV Dbl Ckt.		75	$180,000,000
Hilltop-Columbia 345 kV Dbl Ckt		65	$134,000,000
Total	15	140	**$350,000,000**

7.1.2: Fargo-Brookings County Project

	Acreage	Length	
Substations			
Flint Substation	15		$25,000,000
Hankinson Substation	10		$15,000,000
Browns Valley Substation	10		$20,000,000
Big Stone Substation	--		$15,000,000
Brookings County Substation	--		$8,000,000
Lines			
Sheyenne-Audubon 230 kV In-and-Out		2	$2,000,000
Maple River-Frontier 230 kV In-and-Out		1	$2,000,000
Alexandria SS-Bison 345 kV In-and-Out		1	$2,000,000
Bison-Flint 345 kV Ckt #2		20	$6,000,000
Flint Hankinson 345 kV Dbl Ckt.		60	$130,000,000
Hankinson-Browns Valley 345 kV Dbl Ckt.		35	$80,000,000
Browns Valley-Big Stone 345 kV Dbl Ckt.		35	$80,000,000
Big Stone-Brookings Co. 345 kV Dbl Ckt.		75	$165,000,000
Total	35	229	**$550,000,000**

7.1.3: Ashley-Hankinson Project

	Acreage	Length	
Substations			
Ashley Substation	10		$15,000,000
Hankinson Substation	--		$5,000,000
Lines			
Ashley-Hankinson 345 kV		125	$155,000,000
Total	10	125	**$175,000,000**

7.1.4: Brookings-Split Rock Project

	Acreage	Length	
Substations			
Brookings County	--		$8,000,000
Pipestone Substation	10		$20,000,000
Split Rock Substation	--		$8,000,000
Lines			
Brookings-Pipestone 345 kV Dbl Ckt.		50	$112,000,000
Pipestone-Split Rock 345 kV Dbl Ckt.		45	$100,000,000
Total	10	95	**$250,000,000**

7.1.5: Lakefield-Adams Project

	Acreage	Length	
Substations			
Lakefield Junction Substation	5		$8,000,000
Winnebago Substation	10		$20,000,000
Hayward Substation	10		$20,000,000
Adams Substation	5		$8,000,000
Lines			
Lakefield Jct.-Winnebago 345 kV Dbl Ckt.		55	$125,000,000
Winnebago-Hayward 345 kV Dbl Ckt.		50	$110,000,000
Hayward-Adams 345 kV Dbl Ckt.		37	$84,000,000
Total	30	142	**$375,000,000**

7.1.6: Adams-La Crosse Project

	Acreage	Length	
Substations			
Adams Substation	5		$8,000,000
Harmony Substation	10		$20,000,000
Genoa Substation	10		$20,000,000
North La Crosse Substation	--		$8,000,000
Lines			
Adams-Harmony 345 kV Dbl Ckt		35	$84,000,000
Harmony-Genoa 345 kV Dbl Ckt		45	$110,000,000
Genoa-North La Crosse 345 kV Dbl Ckt.		20	$50,000,000
Total	25	100	**$300,000,000**

7.2: Evaluated Cost (with losses)

The following tables show the total evaluated cost for the various alternatives evaluated. The evaluated cost include installed and underlying system costs including production cost savings, load cost savings, and loss savings

7.1.1: La Crosse - Madison Project with Corridor

Description	***Cost***
Project Cost	$700,000,000
Underlying System Cost	$35,000,000
70% Production Cost Savings Offset	($191,000,000)
30% Load Cost Savings Offset	($612,000,000)
Loss Savings Offset	($134,000,000)
Net Project Cost	($202,000,000)

7.1.2: Fargo-Brookings Co. & Ashley Hankinson Project

Description	***Cost***
Project Cost	$725,000,000
Underlying System Cost	$45,000,000
70% Production Cost Savings Offset	($253,000,000)
30% Load Cost Savings Offset	($494,000,000)
Loss Savings Offset	($35,000,000)
Net Project Cost	($12,000,000)

7.1.3: Fargo-Brookings Co., Ashley Hankinson, & La Crosse Madison Project

Description	***Cost***
Project Cost	$1,075,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($128,000,000)
Net Project Cost	($58,000,000)

7.1.4: Adams-La Crosse & La Crosse Madison Project

Description	***Cost***
Project Cost	$650,000,000
Underlying System Cost	$20,000,000
70% Production Cost Savings Offset	($115,000,000)
30% Load Cost Savings Offset	($265,000,000)
Loss Savings Offset	($167,000,000)
Net Project Cost	$123,000,000

7.1.5: Lakefield-Adams-La Crosse & La Crosse Madison Project

Description	***Cost***
Project Cost	$1,025,000,000
Underlying System Cost	$15,000,000
70% Production Cost Savings Offset	($203,000,000)
30% Load Cost Savings Offset	($420,000,000)
Loss Savings Offset	($225,000,000)
Net Project Cost	$192,000,000

7.1.6: Fargo-Brookings Co-Split Rock, Ashley Hankinson, & La Crosse Madison Project

Description	***Cost***
Project Cost	$1,325,000,000
Underlying System Cost	$40,000,000
70% Production Cost Savings Offset	($356,000,000)
30% Load Cost Savings Offset	($679,000,000)
Loss Savings Offset	($185,000,000)
Net Project Cost	$145,000,000

7.1.7: Fargo-Brookings Co-Split Rock, Ashley Hankinson, Lakefield-Adams-La Crosse, & La Crosse Madison Project

Description	***Cost***
Project Cost	$2,000,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings Offset	($500,000,000)
30% Load Cost Savings Offset	($791,000,000)
Loss Savings Offset	($288,000,000)
Net Project Cost	$451,000,000