Final Report –

Southwest Twin Cities – Granite Falls Transmission Upgrade Study

&

Minnesota RES Update Study

Companion Report for the

Southwest Twin Cities – Granite Falls Transmission Upgrade Study Technical Report

and the

Minnesota RES Update Study Technical Report

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The Minnesota Transmission Owners

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Core Study Team

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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.

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.

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I. Executive Summary

Background

A robust transmission system needs to be in place to support the effective growth in consumers' energy needs, including renewable energy development. This transmission system must be developed in order to satisfy all relevant legal requirements as well as all consumer needs.

One important legal requirement arises out of the Next Generation Energy Act of 2007 Renewable Energy Standard (RES) requiring 25 percent of the energy consumed by the state's utility customers to come from renewable sources by 2025. Xcel Energy has been directed to supply 30 percent of customers' electricity needs with renewable resources by 2020. In Minnesota, high potential wind resources used for energy production are located far from the load centers where the majority of energy is consumed.

The Southwest Twin Cities – Granite Falls Transmission Upgrade Study (also called the Corridor Study) and the Minnesota RES Update Study are part of an extensive effort undertaken by the Minnesota Transmission Owners (MTO) to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system that (i) allows the development of generation projects that satisfy all relevant legal requirements, including the Renewable Energy Standard legislation milestones, (ii) continue to enable reliable, low cost energy for our region, and (iii) continue developing a robust and reliable transmission system that meets customers' needs. While the collection of MTO sponsored studies has this common high-level goal, each study has a unique focus with different assumptions, different potential projects, and different outcomes. Therefore, results of one study are not necessarily comparable with that of another without taking note of varying assumptions, analytical processes and other study differences. The wealth of study work can be reviewed to identify trends.

This document is a companion report for the Southwest Twin Cities – Granite Falls Transmission Study Technical Report and the Minnesota RES Update Study Technical Report. The technical reports and their appendices can be found at http://www.minnelectrans.com. This companion report is a summary of each technical report presented together to provide context for the studies' findings given the complementary nature of the study process and analysis. The full significance of each study's results can be understood more clearly when presented together.

Purpose

The objective of the Southwest Twin Cities – Granite Falls Transmission Upgrade Study (also called the Corridor Study) was to confirm that upgrading the existing

230 kV corridor removes a key limiter to increasing generation delivery between western and southwestern Minnesota (as well as points further west) and the load centers in Minnesota. The Corridor Study was also tasked with determining the optimal transmission endpoint configurations for the recommended project. One additional study goal was to determine the generation deliverability gained by the proposed upgrade.

The objective of the Minnesota RES Update Study (also referred as the RES Study) was to investigate and recommend future transmission alternatives to increase generation delivery beyond that enabled by the proposed Corridor project. The RES Update was necessary in order to refine and finalize the endpoints and to verify the results and recommendations of the Corridor Study. The RES Study team identified future limiting facilities on the transmission system with emphasis on several popular generation development zones. The RES Update Study team also conducted a key analysis to determine the operational impact of increasing wind generation in the region on the transmission system.

Process

The Corridor Study and RES Update Study were conducted in tandem and reported together because of their complementary goals, similar timeframes, and common analytical processes. It is important to note that these studies focus on transmission planning, the costs of transmission projects and the level of generation that might be enabled by various transmission upgrades. Based on the Midwest ISO interconnection queue and general interest, the studies assume that a large percentage of the generation that will develop in the study region will be wind-energy generation. The specific wind and non-wind generation projects that develop in the region will be highly dependent upon a variety of factors, including the requirements of Open Access Transmission Tariffs (OATTs) such as the Midwest ISO's tariff. However, for purposes of these studies it is assumed that wind-energy generation is the primary source of generation developed. These studies focused primarily on the transmission solutions necessary to enable generation development, including wind-energy generation, in the study area.

Corridor Study Findings

<u>Upgrade Existing Minnesota Valley – Blue Lake 230 kV Line</u>

The Corridor Study analyzed upgrading the existing 230 kV transmission line between Granite Falls and southwest metro to a double-circuit 345 kV configuration (the "Corridor Upgrade"). One key finding of the Corridor study is that upgrading the existing transmission corridor from Granite Falls, Minnesota to the southwest Twin Cities will provide significant new transmission capacity from southwestern and western Minnesota in the 2016 timeframe. Based on generator interest and the Midwest ISO's current tariff requirements, this additional transmission capacity should result in a robust and reliable transmission system that will allow the development of generation projects to satisfy the 2016 RES milestones established by the State of Minnesota. This Corridor Upgrade works well to facilitate serving Minnesota load with generation located west of Marshall in southwest Minnesota, as well as to the north and into the eastern Dakotas.

Corridor Upgrade Provides Reliability Benefits

The Corridor Upgrade also serves to increase the overall reliability of the transmission system. As the bulk transmission system is called upon to deliver increasing amounts of generation remote from load centers, a robust, reliable, and redundant transmission system will be necessary to minimize generation curtailment (and, thus, variability in generation levels) during transmission system contingencies. Specifically, the Corridor Upgrade's interconnection to the Twin Cities – Brookings line on the western end will allow the Brookings line and the Corridor Upgrade to back one another up very effectively. On the eastern end, the Corridor Upgrade provides a new direct connection to the double-circuit 345 kV loop around the Twin Cities. Combined with the connection to the Helena – Blue Lake 345 kV line and the Helena – Lake Marion – Hampton Corner 345 kV line that is part of the Twin Cities – Brookings project, the Corridor Upgrade will provide for the increased transmission system redundancy necessary to ensure continued reliable electrical service as renewable energy penetration increases.

Corridor Endpoints Established

The transmission system upgrade endpoints were clarified through study findings and verified by the RES Update study results. The two end points of the Corridor Upgrade are the Hazel Creek Substation near Granite Falls, Minnesota to the west and the Blue Lake Substation in Shakopee, Minnesota to the east. The Hazel Creek substation is a proposed substation that is being built in conjunction with the BRIGO facilities and is planned to be used by the Twin Cities – Brookings 345 kV transmission project (assuming all regulatory approvals are obtained).

Corridor Upgrade Supporting Projects

The Corridor study team also assessed the necessary supporting projects to enable full realization of the upgrade benefits. The study results determined the approximate range of capacity or energy carrying capability likely created through installation of the corridor upgrade and supporting project. This assessment is expressed as a range since many outside influences can affect the actual results.

Corridor Study Associated Observations

- Transmission Grid in Western Wisconsin – One observation is that the transmission grid in western Wisconsin, along with interface loading levels along the Minnesota-Wisconsin border, limits the transmission system's ability to deliver more generation from Minnesota and points further west.
- Generation Siting – Another observation is that the actual amount of generation delivery capability gained by the Corridor upgrade will be determined by the actual location of future generation development. To the extent that actual generation development differs from that which was studied, the actual outlet capacity achieved by this system addition may either increase or decrease. The study team selected likely generation development sites based on the best resources available, such as the Midwest ISO generation interconnection queue and utility resource planners in order to provide a reasonable range of results.
- Big Stone II Status – The study team dealt with the ambiguity of whether the Big Stone II project will be built by doing the majority of the analysis without the Big Stone II generation and transmission facilities in place. The key outcome of this analysis showed that it is not necessary to have the Corridor Upgrade project extend west to Big Stone substation to meet the 2016 RES milestone regardless of the status of the Big Stone II generation or transmission facilities. In consideration of the more than 1000 MW of wind generation interconnection requests in the vicinity of Big Stone Substation, system alternative analysis was completed with the proposed 345 kV line extended to Big Stone Substation. The presence or absence of the Big Stone II generation and/or transmission facilities did not materially impact the Corridor Study's conclusions or the benefits of the Corridor Upgrade to serving Minnesota generation or in meeting the 2016 RES milestone.
- Supporting Facilities for Corridor Upgrade –
    - One outcome of studying a Midwest ISO market sink scenario is that the system requires additional facilities to deliver power east from La Crosse, Wisconsin to the rest of the Midwest ISO footprint during low load and high wind periods in the Minnesota and Dakota areas. The Corridor Upgrade facility would then achieve its full potential in the Midwest ISO market dispatch.
    - The Twin Cities metro sink scenario analysis showed that in order to sink as much as 2000 MW of generation from the west to the Twin Cities, many metro area electric generation units must be shut down to allow the imported generation to remain online. To enable this new generation to be sunk in the Twin Cities metro and maintain reliable operation requires a significant list of metro area transmission system upgrades.
- Tipping Point in Transmission System – Following the addition of the Corridor upgrade (and associated underlying system upgrades required with a Twin Cities Metro sink scenario) any future transmission or

generation capacity additions will require a facility from La Crosse to the Madison, Wisconsin area. In other words, without a line to the east of La Crosse the system will reach a tipping point, where additional transmission and generation capacity additions cannot be accommodated due to the need to keep Twin Cities generation online for steady state and dynamic system stability.

RES Update Study Key Findings

<u>Operational Limits with Increased Wind Penetration</u>

The key finding of the RES Update Study is the realization of an operational limit on the amount of wind penetration that can be accepted into the transmission grid in the upper Midwest. Both steady state and dynamic stability analysis point to these operational issues. The RES Update Study verified that installing additional variable or intermittent generation sources (beyond what was assumed in the Corridor Study) would require the larger fossil fuel generators near the Twin Cities to begin backing down. It is also possible that these limits could be observed during very low load periods, requiring the curtailment of wind generation in order to maintain operable output of larger generators.

This impacts system reliability and system operations. This is significant because the fossil fuel plants typically cannot respond to significant changes in load or variable generation sources such as wind. When taken offline, minimum restart times for fossil fuel plants are typically two to three days and not having the units available to deal with fluctuations in wind generation could jeopardize the reliability of transmission service in the upper Midwest.

These findings underscore the need for additional transmission infrastructure to keep the overall system stable as wind penetration increases. In other words, ensuring reliable operation of the overall electric system at increasing levels of renewable generation will require additional transmission facilities.

In addition to the steady state issues identified above, concerns about approaching the region's operational limit for wind penetration were confirmed by the results of the dynamic stability assessment. A larger-scale stability analysis that included substantial levels of wind penetration (7300 MW of wind generation) revealed significant dynamic stability issues for the loss of regional transmission lines.

The results of the RES Update Study show that caution must be exercised as wind penetration in the upper Midwest surpasses the levels contemplated by the Corridor Upgrade. While there have been numerous steady-state studies performed analyzing increasing levels of wind penetration, the stability assessment described here is noteworthy because the study team believes it is the most extensive publicly-available system stability study to include these levels of wind generation.

RES Update Study Identification of Constraints and Sensitivities

Another key finding of the RES Update Study is that future generation development will be constrained beyond the levels contemplated by the BRIGO[1] facilities, the CapX2020 Group I facilities[2], and the Corridor Upgrade. Without improvements to the transmission system, additional generation will be unable to flow to the areas where the energy is needed.

For example,

- prior to the Corridor Upgrade: the Buffalo Ridge area, an area of significant wind development interest in southwestern Minnesota, will be constrained to approximately 1900 MW; generation in southeastern Minnesota will be capped at about 900 MW; and the North Dakota Export will be limited to 2080 MW prior to installation of the CapX2020 Group I facilities.[3]
- after the Corridor Upgrade: the Buffalo Ridge area would increase to nearly 3,900 MW; generation in southeastern Minnesota will be capped at about 900 MW; and generation in North Dakota also receives an indirect benefit from the Corridor Upgrade.

Despite the increase in generation capacity from the Buffalo Ridge area, interest in developing additional generation projects in North Dakota and southeastern Minnesota will remain strong. The RES Update Study lays out the projects that will most beneficially increase those areas and provides support for the Corridor Study and its generation outlet findings.

Sensitivity Analysis Results

The RES Study not only identified the different transmission system upgrades necessary to increase generation outlet, it also investigated the impact these improvements have on each other in each zone. This sensitivity analysis provided useful data for the study recommendations.

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[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] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure reliable and affordable service. Capx2020 projects will be built in phases designed to meet the increasing demand for electricity and support renewable expansion. The Group 1 projects includes the Bemidji – Grand Rapids 230 kV line and the following 345 kV lines: Twin Cities – Brookings, Twin Cities – Fargo, and Twin Cities – La Crosse.

[3] The impact of the CapX2020 Group I facilities on North Dakota Export is still being determined. For purposes of this analysis, the North Dakota Export level was established prior to placing the CapX2020 Group I facilities in the model.

In the North Dakota zone, the upgrade of the Corridor facilities provides a significant benefit to North Dakota-based generation, however, other transmission facilities are necessary to unlock generation potential within North Dakota.

In the southwest zone, transmission improvements provide noteworthy results in terms of generation capacity improvement. The largest benefit for this zone occurs with installation of the La Crosse – Madison 345 kV line which crosses Wisconsin from La Crosse to the Madison area.

This sensitivity test showed that the greatest benefit comes from installation of the Corridor Upgrade and the La Crosse – Madison 345 kV line. The need for the La Crosse – Madison 345 kV line is not caused by the Corridor Upgrade, as benefit to installing the line is seen even in cases in which the Corridor Upgrade is not included. The La Crosse – Madison line is driven by the need to strengthen ties to increase regional reliability under both steady-state and dynamic stability conditions. The line also happens to provide a significant generation delivery benefit.

Installing the Corridor Upgrade and the La Crosse – Madison lines together results in approximately 3600 MW of generation delivery capability above that included in the base case in the model. This is an additional 1600 MW above and beyond the 2000 MW provided by the Corridor Upgrade. This 3600 MW includes locations specified by the Corridor study as well as locations throughout southeastern Minnesota and northeastern Iowa.

Additional sensitivity analysis was performed that investigated simultaneously increasing generation in all the zones being considered. This analysis showed that facilities in and around Sioux Falls, South Dakota will require mitigation prior to significant additional generation delivery from anywhere west of the Buffalo Ridge area.

Overall sensitivity analysis findings highlighted some high potential projects that have impacts to multiple zones and may merit resolution sooner.

- The first is the installation of the La Crosse – Madison 345 kV line which provides significant benefit in all cases.
- The facilities in and around Sioux Falls, South Dakota at the Split Rock substation will also require upgrades. Most of these improvements are necessary due to terminal equipment limitations and would be relatively inexpensive to complete.

Conclusions

The Corridor Study and RES Upgrade Study provide complementary conclusions that direct future transmission expansion planning to enable a robust and reliable transmission system as generation is added in the region.

Upgrading Existing Minnesota Valley – Blue Lake 230 kV Line

Both the Corridor Study and the RES Update Study separately confirmed the need for the existing Minnesota Valley – Blue Lake 230 kV line to be upgraded to double-circuit 345 kV. If significant new generation resources are to be developed in locations west of the Twin Cities, from the Buffalo Ridge into North Dakota, upgrade of the Minnesota Valley – Blue Lake 230 kV line to double-circuit 345 kV is necessary. Completion of this upgrade and necessary underlying system projects will result in an increase in generation delivery on the order of 2000 MW.

Wisconsin Transmission Limits

In addition to this upgrade, a new high-voltage transmission facility is necessary between La Crosse and eastern Wisconsin to ensure reliable operation and enable full dispatch of new generation resources. The Corridor and RES Update Studies assumed a termination in the Madison area. Southern Minnesota currently only has one high voltage tie between Minnesota and eastern Wisconsin (the King – Eau Claire – Arpin 345 kV line). Together with the Corridor upgrade, addition of this facility adds as much as 1600 MW of additional capacity to the system - a total of 3600 MW of new generation delivery capability. The need for a new line to the east is consistent with the findings of the Minnesota Wind Integration Study, the study upon which the Minnesota legislature relied when drafting the RES legislation.

Twin Cities Generation Sink Scenario

Another contributing factor is the Twin Cities generation sink scenario studied in the Corridor Study. Importing approximately 2000 MW of generation into the Twin Cities without additional outlet capacity to the east, as was done in the Corridor Study, required significant Twin Cities generation resources to be turned off. This result is significant because any increase beyond 2000 MW will require generation at Sherburne County to be shut down. With its restart time measured in days, this would make Sherburne County unable to respond to fluctuations in energy demand and wind generation. This scenario is not recommended due to a decrease in reliability that would result.

Stability Assessment Results

An indicative stability assessment was also performed. This assessment confirmed that significant new reactive capability will be necessary as variable and intermittent generation sources increase. 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 generators.

In general, the message these results portray is that wind penetration beyond the levels studied in 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 with variable output 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. 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.

II. Introduction

This report is a synopsis of two important studies – the Southwest Twin Cities – Granite Falls Transmission Upgrade Study (also called the Corridor Study) and the Minnesota Renewable Energy Standard (RES) Update Study (also referred to as the RES Update Study). The Corridor Study sought to assess the additional generation delivery support provided by the transmission system after upgrading the existing 230 kV transmission line from Granite Falls to the Southwest Twin Cities. The RES Update Study takes the outcomes of the Corridor Study and analyzes additional transmission system improvements that will be necessary in order to maintain system reliability, enable reliable, low-cost energy for customers in our region, and for Minnesota utilities to comply with the RES requirements. These studies were undertaken by Minnesota Transmission Owners (MTO).

Fundamentally, additional transmission capacity is needed to bring additional power generated at various points throughout the system to the areas in Minnesota and beyond where the power will be utilized. In light of generator interest (expressed through the Midwest ISO interconnection queue) it is reasonable to assume that a significant portion of the generation enabled by adding additional transmission capacity will be available for renewable sources of generation, in addition to the important system benefits provided by these improvements. The Corridor and RES Update Studies were conducted in tandem and reported together because of their complementary goals, similar timeframes, and common analytical processes.

Transmission planning studies tend to fall into two broad categories: vision studies and Certificate of Need studies. Vision studies take a high level, indicative look at the transmission needs; a Certificate of Need study is a more detailed analysis of the transmission system and is required by regulators to move forward to the next steps of constructing a transmission system. The study work supporting the southwest Twin Cities – Granite Falls upgrade is considered to be Certificate of Need-level work. This study work is the result of both the Corridor Study and the RES Update Study. While the RES Update Study by itself is considered to be a vision-level study, its analysis and results were key inputs in determining the outcome and recommended endpoints of the Corridor Study.

In addition to the effort documented here, an additional study, the Capacity Verification Study (CVS Study) is being pursued separately by the MTO. This high-level analysis is being performed to synthesize the various transmission studies being performed throughout the region and determine the approximate generation delivery capability created by various combinations of the projects being studied. The CVS Study also performs some analysis regarding cost of transmission upgrades based on amount of delivery enabled and considers the cost of underlying system upgrades.

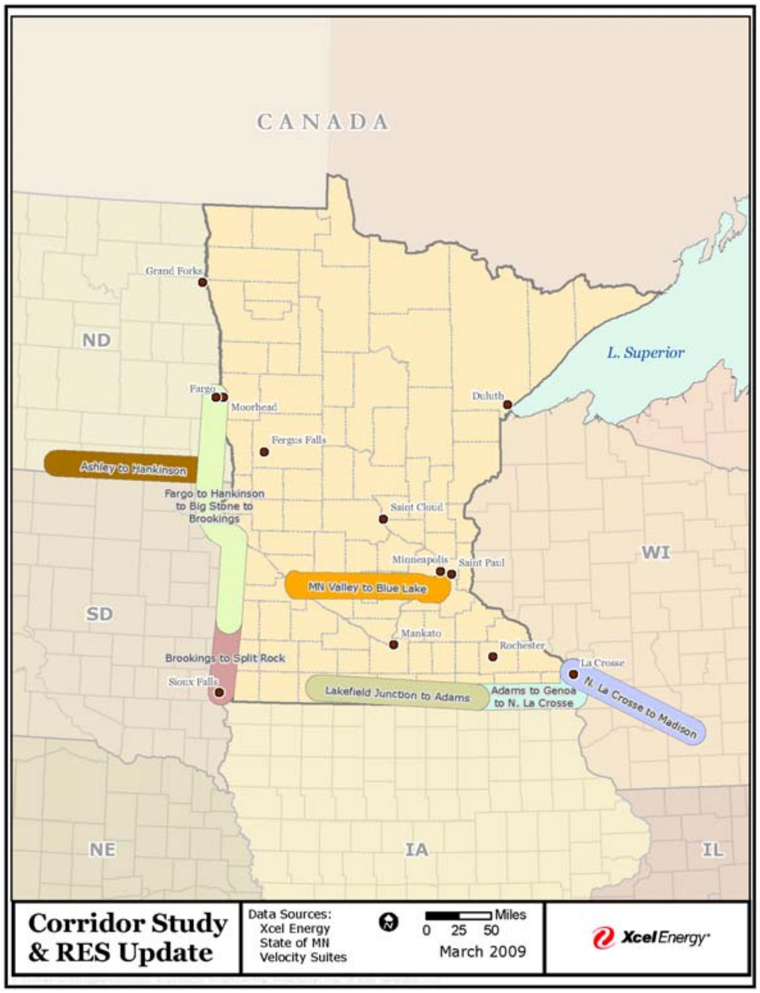
The Corridor Study, RES Update Study, and CVS Study, among other study efforts, are proceeding simultaneously to examine the transmission system impacts as new generation comes online. Since each study has a unique focus, the study teams have examined the cumulative transmission system under different assumptions, with different potential projects, and with different purposes for the various studies. The studies do not precisely mirror one another with regard to generation outlet, limiting facilities, or possible solutions, and this is typical of transmission planning work. As assumptions change among various studies, the results will also change. The most important things to watch for when examining the wealth of study work being completed are trends that develop in the data. For example, when multiple studies with varying assumptions suggest significant outlet can be created with a particular project (or set of projects), this presents a reliable indication that completing the project will result in outlet capability within these general ranges.

This report is organized with information about the Corridor and RES Update Studies' mutual background and scope, and a section describing the initial modeling and assumptions common to both studies. Then, each study team conducted their own analysis to address the scope and goals of their respective studies. The analysis and key findings sections of the report explain the separate efforts and conclusions for each study. The final section describes the common key findings and next steps. This report is accompanied by two more detailed technical reports specifically documenting the assumptions, study methodologies, and results of the Corridor and RES Update Studies.

The Corridor Study's focus is west-central Minnesota where the RES Update Study looks beyond west-central Minnesota. The Corridor Study considers additional transmission capacity through 2016 to achieve a robust and reliable transmission system in light of regional utilities' requirements to develop generation projects to satisfy generation additions through 2016 and the RES Update Study explores transmission improvements needed to provide a robust and reliable transmission system beyond 2016 through 2020. The RES Update Study builds upon the results of the Corridor Study so there is a natural progression of planning concepts and analysis. The Minnesota RES Update Study builds upon the results of the Corridor Study by investigating the best way to integrate the significant interest in generation development in and around Minnesota into the regional transmission system.

The RES Update Study was necessary in order to refine and finalize the endpoints and to verify the results and recommendations of the Corridor Study. In addition, the RES Update Study provided additional insight into the amount of generation delivery that was achievable when the Corridor Upgrade is combined with other project developments. Figure 1 shows the location of the Corridor Upgrade along with the location of the projects considered in conjunction with the RES Update Study.

Figure 1 - Map of Corridor Upgrade and RES Update Projects



The Corridor Study and RES Update Study were conducted in tandem and reported together because of their complementary goals, similar timeframes, and common analytical processes. It is important to note that these studies focus on transmission planning, the costs of transmission projects and the level of generation that might be enabled by various transmission upgrades. Based on the Midwest ISO interconnection queue and general interest, the studies assume that a large percentage of the generation that will develop in the study region will be wind-energy generation. The specific wind and non-wind generation projects that develop in the region will be highly dependent upon a variety of factors, including the requirements of Open Access Transmission Tariffs (OATTs) such as the Midwest ISO's tariff. However, for purposes of these studies it is assumed that wind-energy generation is the primary source of generation developed. These studies focused on the transmission solutions necessary to enable generation development, including wind-energy generation, in the study area.[4] These studies focused on the transmission solutions and did not focus on the overall consumer costs.

Where these studies investigated production cost (PROMOD[5]) impacts, this was a high-level indicative performance. Production cost represents the instantaneous cost to actually produce sufficient energy to meet the load in a region. It does not take into account the value of power purchase contracts in its analysis.

The final component of consumer cost is the generation integration cost. This issue arises because of the variable or intermittent nature of certain types of generation, such as wind-energy generation. This is the cost incurred in order to operate the grid reliably with significant levels of wind integrated into the grid. These costs can include, but are not limited to, the power purchase cost of wind energy, cost of existing generation assets that operate less than originally anticipated in the market, and the cost of maintaining higher levels of spinning reserves in order to absorb rapid fluctuations in levels of wind generation.

This study focuses only on the first of these three factors and does not attempt to examine the other two factors with specificity. To assess the total cost to consumers of any project, additional analysis is required. The issue of importance for the RES Update Study work is ensuring a robust and reliable transmission system exists sufficient for all purposes, including allowing Minnesota utilities to satisfy the RES milestones while maintaining a reliable, operable power system.

A. Background

A robust transmission system needs to be in place to support generation development. The effective growth of renewable energy development is also highly dependent upon the presence of a robust and reliable transmission system. In Minnesota, high potential wind resources used for energy production are located far from the load centers where the majority of energy is consumed.

[4] Note that the actual cost to consumers of new generation is represented by the total of three very distinct factors: transmission cost, production cost, and integration cost. The RES study took a high-level partial look at production cost of wind generation but further analysis is necessary to determine the actual production cost impact. That study did not attempt to address the integration cost. This is the cost incurred to operate the grid reliably with significant levels of wind integrated into the grid. To understand the total cost implication of implementing transmission development assuming specific wind integration plans, additional analysis is required.

[5] PROMOD is a production modeling analysis program that mimics the Midwest ISO's real-time generation market. It can be used to model how a new transmission (or generation) project functions in the market environment. For more information about PROMOD and how it was incorporated in this study work, see Chapter V, Section B.

The distance from likely generation sources to Minnesota's load centers also contributes to the need for a robust and reliable transmission system.

Going back a decade or more, the transmission studies to enable wind delivery were focused on the Buffalo Ridge area in southwest Minnesota where many wind generation projects were planned and have been built. The first significant transmission project focused on enabling wind generation development was a series of smaller transmission system improvement projects (the 425 Project) that provided system support for the development of 425 MW of wind generation capacity in the Buffalo Ridge.

The next major transmission project was designed to increase generation outlet from the Buffalo Ridge to 825 MW (the 825 Project). It included several smaller transmission projects and one 345 kV line in southwest Minnesota from Split Rock near Sioux Falls, South Dakota to Lakefield, Minnesota. The 825 MW Project provided system support for increasing the wind generation capacity in the Buffalo Ridge to approximately 825 MW.

Then, the BRIGO (Buffalo Ridge Incremental Generation Outlet) Project planned three new 115 kV lines in the Buffalo Ridge area and some 345 kV substation work. The BRIGO series of improvements raised the Buffalo Ridge generation output to roughly 1200 MW.

The most recent Buffalo Ridge area project is the Brookings County, South Dakota to Hampton, Minnesota 345 kV line. This line is one of the CapX2020 Group I[6] lines and is currently being permitted. It is planned to run east and west through southern Minnesota and will increase generation capacity to approximately 1900 MW.

Through these projects, a general trend has been observed that the more the transmission grid is improved, the more incremental output each project makes available for generation delivery capability. Each addition to the transmission system tends to add much more capacity as an incremental part of the greater transmission system. While the CapX2020 Group 1 project adds capacity, the Corridor Upgrade is projected to provide a significant step increase in overall system transfer capability. This study work shows that the Corridor Upgrade improvements work with the existing transmission grid to leverage and maximize beneficial impacts of the investments already made in CapX2020.

The need for the Corridor Study was triggered by the findings in the Brookings study work for the Brookings County to Hampton 345 kV transmission line project (Brookings Project) as well as numerous Midwest ISO generation interconnection

[6]CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure reliable and affordable service. Capx2020 projects will be built in phases designed to meet the increasing demand for electricity and support renewable expansion.

studies. The Brookings Study[7] revealed that the 230 kV transmission line from Granite Falls, Minnesota to the southwest corner of the Twin Cities is one of the facilities that limited generation delivery for the Brookings transmission line to approximately 1900 MW.

The Brookings Study showed that the 230 kV corridor cannot be taken out of service without key segments of the proposed Brookings – Twin Cities line being in- service. Removing the 230 kV line without these segments in service will result in significant curtailment of Buffalo Ridge wind generation. This means that if the Corridor Upgrade is ultimately approved for construction prior to completion of the Brookings Project, significant curtailed wind generation from Buffalo Ridge will result. It is beyond the scope of the Corridor Study to analyze the amount of such costs or the parties primarily responsible for those costs. However, it is expected that this issue will need to be addressed as it could impact the timing and cost of the Corridor Upgrade.

The Corridor Upgrade is the next project necessary to deliver more regional generation from western Minnesota, eastern North Dakota and eastern South Dakota to serve load in Minnesota through numerous Midwest Independent Transmission System Operator (Midwest ISO)[8] led interconnection and deliverability studies.

Several factors have contributed to a shift in information needed from the RES Update Study. The original purpose of the RES Update Study was to look at the need for transmission system upgrades beyond those recommended by the Corridor Study to ensure a robust and reliable transmission system is in place to facilitate load serving entities' efforts to meet the legislated 2016 Renewable Energy Standard milestones in Minnesota. Using the results of the RES gap analysis[9] conducted by the Minnesota utilities, preliminary calculations indicated approximately 1,000 MW of generation delivery capability would be needed beyond that which would be provided by the Corridor Upgrade. This was based on a preliminary assumption that the Corridor Upgrade would yield approximately 1,000 MW of generation delivery capability. This gap analysis is adjusted over time as energy demand forecasts and energy production forecasts are defined. As the Corridor study progressed, the study results indicated greater-than-

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[7] The Brookings Study (or EHV Study as it was originally titled) is the technical study analyzing the CapX 2020 Groups 1 345 kV line from Brookings, SD to Hampton Corner substation in the southern Twin Cities.

[8] Midwest ISO is a not-for-profit member-based organization of electric transmission owners, covering a 15 state region from the Dakotas to Pennsylvania. Midwest ISO administers and manages the transmission of electricity within its region.

[9] The original Gap Analysis was conducted by the MTO for inclusion in the 2007 RES Report and calculated the amount of wind energy (in MW) that would be necessary to meet each RES milestone statewide and for each company. The RES Report was required by the 2007 Next Generation Energy act and was filed in conjunction with the 2007 Biennial Transmission Projects Report. A full version of the report can be found on the web at http://www.minnelectrans.com.

expected deliverability from the Corridor Upgrade than the initial projections of 1,000 MW.

In addition, reductions in load growth due to conservation efforts and economic impacts result in load growth forecasts that suggest a slight reduction in the amount of renewable generation that may be necessary.

The third reason the RES Update Study scope has shifted is the fact that existing wind generation in the study area is performing better than expected with higher capacity factors than originally estimated. In the original Gap Analysis, a lack of definitive wind turbine capacity factor information led transmission engineers to conservatively estimate the average capacity factor at 30%. Several years of actual information have now placed the average wind turbine capacity factor at a level closer to 40%. The capacity factor is one way to measure the productivity of a wind turbine or any other power production facility. It compares the plant's actual production over a given period of time with the amount of power the plant would have produced if it had run at full capacity for the same amount of time. In other words, an increase in capacity factor from 30% to almost 40% means fewer turbines are necessary to satisfy the Minnesota RES requirements.[10]

Taking into account these three factors, the results of the Corridor Study suggest that its installation combined with the CapX2020 Group I projects will provide sufficient transmission support to create a robust and reliable transmission system that will allow utilities to develop generation projects sufficient to satisfy their 2016 RES milestone.

B. Summary of Each Study's Scope

<u>Corridor Study Scope</u>

The scope of the Corridor Study involves confirming the upgrade of the existing Minnesota Valley – Blue Lake 230 kV line as the key limiter to increasing generation delivery from western Minnesota and North and South Dakota. The study also included determining the most efficient use of the existing Minnesota Valley – Blue Lake 230 kV transmission corridor, and identifying generation deliverability gained. This upgrade will be available to support new generation in western and southwestern Minnesota and should assist utilities in achieving their RES milestones while maintaining a reliable transmission network.

The Corridor Study team examined various voltage configuration possibilities, including a double-circuit 345 kV and single-circuit 500 kV and 765 kV systems. For each configuration, the team considered the potential loading capability and the present underlying facilities in place in order to determine the best application

[10] Consistent with generation development interest in the upper Midwest, and the fact that Xcel Energy's 2020 RES milestone specifically requires 25% wind generation, it is generally assumed that a majority of the generation necessary for RES compliance will come from wind turbines.

for this situation. The 345 kV double circuit configuration was concluded to be a better choice than 500 kV as it has been shown that one 500 kV circuit provides similar capability and electrical performance as double-circuit 345 kV. Also, 345 kV is a native voltage in this area. In other words, transmission utilities commonly work on and operate 345 kV transmission systems and regularly order and keep inventory of the equipment necessary to operate these systems. After preliminary analysis, the 765 kV voltage option was also ruled out because, at this time, the underlying system along this corridor is not in place to support 765 kV.[11]

RES Update Study Scope

Based on the Corridor Study findings and the trends mentioned above, the RES Update Study's scope evolved to investigate and recommend future transmission alternatives to increase generation delivery beyond that enabled by the Corridor project. The RES Update Study team identified future limiting facilities on the transmission system with emphasis on several popular generation development zones and recommended solutions to alleviate transmission system constraints and increase generation outlet from each zone. The team also pinpointed limiting facilities common to multiple zones, especially those that may merit resolution now.

The RES Update Study team also performed a stability assessment that considered the impact of the new facilities proposed in both the Corridor and RES Update Studies. This assessment is discussed in Chapter VI, Section A and identified important system stability concerns that must be addressed as additional generation (particularly wind) is integrated into the transmission system. Based upon results of the transmission analysis, transmission system improvement projects are recommended that are common to a number of development scenarios and provide optimal flexibility with regard to future deployment of new generation resources.

The zonal generation approach has been complemented with "wide area" sensitivity studies that provide a comprehensive examination of many potential generation development scenarios. This means the results of the RES Update Study will be able to inform future transmission development decisions regardless of how future generation projects are deployed.

[11] This is also important when considering potential impacts of the various recent proposals depicting potential 765 kV overlays through the region. If these were to materialize, a robust underlying 345 kV system would be required and this corridor upgrade would be an integral part of that system. It is the opinion of the study team that regardless of any 765 kV future in the region this upgrade is the best next step for the transmission system.

C. Uncertainties

Uncertainties affecting the results of the Corridor Study and RES Update Study include the following:

- CapX2020 Group I project upsizing – If the Brookings County – Hampton Corner 345 kV CapX2020 project is upsized to double circuit 345 kV, more delivery capability from southwest Minnesota will be possible. In addition, if the second Twin Cities – Fargo 345 kV circuit is added, additional capability from North Dakota will be possible without significantly impacting flow on the Corridor Upgrade.
- Uncertainty of generation location – The study team used the best information available at the time of the study. This study used one set of generation location assumptions and provided a possible range of delivery capability and locations. However, as actual generation is sited in varying locations, this range may be subject to change.
- Generation Interconnection Process – This study work is neither intended to replace the interconnection process of the Midwest ISO or any other regional transmission organization nor is it intended to provide a guarantee of interconnection should a generation project seek to interconnect in a particular location. Specific generators, even those seeking to interconnect in locations at which generation was assumed in this study, will still be required to move through the interconnection process.
- Transmission Cost – Cost estimates for the project were completed using 2007 dollars. Prevailing market conditions could change these estimates due to cost of materials, competitive bidding for crews, and other expenses.
- Generation for delivery outside Minnesota – For the purposes of these studies, all generation sited is assumed to assist in meeting the RES milestones. However, utilities from outside the state and region are not precluded from purchasing some of the generation enabled by these facilities. This would reduce the amount of generation capacity able to be counted for Minnesota's RES milestones.

Recognizing these uncertainties, the study team presents their findings (outlet capability achieved, dollars, timing) in terms of ranges.

D. Legislation

The state of Minnesota has legislative and regulatory requirements that mandate Minnesota's load serving utilities take significant actions to enable substantial growth in the development and use of renewable electricity. Minnesota's Next Generation Energy Act of 2007 enacted the Renewable Energy Standard (RES). The RES requires that 25 percent of the electricity consumed in Minnesota be generated by renewable resources by 2025. This enabling legislation provides interim milestones beginning in 2010 through 2025 with specific renewable energy goals for utilities to use to set a plan in place to meet these objectives. Additionally, the RES requirements hold Xcel Energy to a higher standard, requiring 30 percent of its customers' electricity needs with renewable sources by 2020. Table 1 below shows the renewable energy requirements for each milestone year. The full text of the Next Generation Energy act can be found at https://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=H0436.0.html&session=ls85

Table 1 - Renewable Energy Standards - Percent of Annual Minnesota Retail Sales to be Met with Renewable Generation

Year	Utility Requirement	Xcel Energy
2010	7%[12]	15%
2012	12%	18%
2016	17%	25%
2020	20%	30% - 25% must be wind
2025	25%	30% - 25% must be wind

Another part of Minnesota's Next Generation Energy Act of 2007 requires Transmission Owning (MTO) utilities to analyze and identify specific transmission solutions for serving the renewable energy resources necessary for the load serving utilities to comply with the expanded and accelerated renewable energy standards. The MTO responded with a well-thought-out strategy sponsoring a series of studies that describe the planning steps necessary to meet the transmission needs of the expanded renewable energy standard objectives. The MTO must examine how the complex interconnected electric grid needs to be built in order to support these ambitious milestones and continue to provide a robust, reliable and cost-effective transmission system that will allow load serving entities to continue providing reliable and cost effective electric service. The Corridor and RES Update studies are two of the studies that are intended in part to meet these goals.

E. Stakeholder Involvement

While the enabling legislation did not require specific outside input for the Corridor and RES Update Studies, the Minnesota Transmission Owners (MTO) recognized the value of augmenting the process by seeking ideas from additional technical experts, Minnesota Department of Commerce staff, Office of Energy Security (OES) staff, wind developers and other interested parties.

At regular intervals throughout the study process, the Technical Review Committee (TRC) provided input to the study team on the sink alternatives, study

[12] The 7% milestone in 2010 represents a good faith objective for those utilities that do not own a nuclear generation facility in the state of Minnesota.

approach and scoping of the analytical work. The TRC is an OES appointed group assigned to oversee other legislated studies assigned to the MTO utilities, in particular the Dispersed Renewable Generation (DRG) Transmission Studies (Phase I, Phase II). Since this group met regularly and possessed the applicable technical skills needed, it was prudent to leverage their knowledge to enrich the Corridor and RES Update Studies. The individuals have experience and expertise in electric transmission system engineering and renewable energy generation technology. Their varied backgrounds made them valuable for providing input on all aspects of the study's technical methods and assumptions.

Utility transmission planning engineers were consulted to gather information on new generation data and transmission topology changes that may occur prior to 2016. These planning engineers represent transmission owners in Minnesota, South Dakota, Wisconsin, North Dakota, Manitoba and Iowa.

Regional transmission system planning needs are coordinated with Midwest ISO through the Regional Generator Outlet Study (RGOS) process. RGOS is a study being performed by the Midwest ISO in coordination with its member utilities, state regulatory agencies, and interested non-utility stakeholders seeking to design an appropriate high voltage transmission system to efficiently meet the renewable energy standards of the various states in the upper Midwest.

The Corridor and RES Update study teams made sure that the transmission lines are consistent with the preliminary work on the RGOS. The Corridor Upgrade is represented in every one of the scenarios studied in the RGOS study. In addition, many of the concepts explored and recommended in the RES Update Study are also included in the various RGOS study scenarios. While in some cases the precise facilities may differ, the need for transmission system performance enhancements is conceptually similar. To ensure coordination in both studies, the engineers from all the MTO members are working closely with the Midwest ISO on the RGOS study.

Presentations were given to the Northern MAPP-Missouri Basin Subregional Planning Group (SPG) to provide the opportunity for the study team to incorporate feedback from this group of utility transmission planners into the study scope, assumptions and analysis.

F. Regulatory Context

Electric generation and transmission service is a regulated industry. Care was taken during this study to follow all appropriate regulations. For example, commercially sensitive, non-public market information was handled correctly as related to U.S. Federal Energy Regulatory Commission (FERC) Order 2004 regulations concerning the separation of transmission and resource planning efforts. These standards of conduct are in place to prevent anticompetitive practices between electric transmission providers and their marketing affiliates.

To ensure FERC regulations were enforced and to encourage an open discussion about topics that included potentially market-sensitive information, all members of the OES's Technical Review Committee (TRC) completed a non-disclosure agreement allowing them access to the process and preliminary results.

Transmission-owning utilities that are subject to an OATT like the Midwest ISO tariff are required to provide transmission service on an open-access and non-discriminatory basis. Thus, the MTO does not prejudge and cannot preclude any particular generation source from transmission access within the Midwest ISO's or any other regional transmission organization's footprint. The transmission facilities contemplated by these studies will be available to all generation sources; however, based on generator interest and the Midwest ISO interconnection queue, it appears likely that wind-energy generators make up the substantial majority of likely generators who will use the transmission capability enabled by these facilities.

The study was undertaken in accordance with the North American Electric Reliability Corporation (NERC) Planning Standards. NERC is certified by FERC to be the organization to develop and enforce reliability standards for the bulk power system. The United States electricity industry operates under mandatory, enforceable reliability standards. Utilities and other bulk power industry participants must follow these standards or face fines and other sanctions. The standards describe how reliable systems need to be developed to meet specific performance requirements under normal conditions (TPL-001 or Category A); following the loss of a single bulk electric system element (TPL-002 or Category B); and following the loss of two or more bulk electric system elements (TPL-003 or Category C). The Corridor and RES Update Studies; modeling and analysis followed the standard requirements. Details on NERC standards can be found at http://www.nerc.com/page.php?cid=2|20.

State regulatory review and approval are required in order to construct transmission lines. In Minnesota, two permits are required: a Certificate of Need and a Route Permit. Similar review is required in North Dakota, South Dakota, and Wisconsin. These regulatory timelines are not insignificant, as the process of application preparation, contested cases, and ultimate decision can take as much as two to three years.

G. Schedule

The Corridor and RES Update Studies began their scoping phase in August 2007. Rigorous analytics began in December 2007 and final study results were completed in March 2009.

- From August through November 2007, the MTO comprising the Minnesota Transmission Owners organized a RES Update Study and Corridor Study project team with a core group of engineers who began identifying roles and responsibilities as well as the initial scope of these studies. The team is composed of engineers that are transmission planning experts.

- The study team began the challenging, three-month initial model building process in January 2008. This public process allowed for significant input to define generation sinks and transmission system model choices. Study concepts were adjusted and transmission options chosen based on the ideas brought to the study team from all stakeholders.
- The public meetings were held in the first and second quarter of 2008 and were attended by members of the TRC, Publics Utilities Commission, and members of the public.
- In March 2008, the study team met to discuss high-level ideas for the Certificate of Need expected to be filed in 2009. Given the significant permitting timeline necessary for bulk transmission upgrade projects, the study team thought it was necessary to start laying the groundwork early. Many recent transmission projects have experienced study and permitting timelines of nearly a decade before ultimately being energized.
- The project team worked with the Midwest ISO to perform the PROMOD analyses with the Corridor Study and RES Update Study new transmission facilities envisioned. This process began in August 2008; initial results were available in late October. Additional PROMOD runs were performed in January and February 2009. For more information regarding PROMOD, refer to Chapter V Section B of this report.
- The preliminary study results of the initial scope were complete in early September 2008 and provided to stakeholders for review and feedback.
- Presentations were made to the area Northern MAPP Subregional Planning Group (SPG) in September and December of 2008, incorporating feedback from interested stakeholders as the study analysis moved forward.
- Upon review of these preliminary results, the decision was made to expand the Corridor study scope in two significant ways to provide more complete information. The first scope change was to conduct a sensitivity to the analysis without the Big Stone II generation and transmission facilities in place. The second modification was to add an examination of the sink to Twin Cities area generation rather than just the Midwest ISO generation market footprint. The transmission system models needed to be modified to support this scope addition. Also, the analysis processes needed to be altered to accommodate the changes. The team conducted this rework from November through February 2009.
- The stability analysis was conducted February through March 2009.
- Sensitivity analysis was run against CapX2020 Group I "upsize" plan between January and March 2009. Loss analysis and constructability issues assessment ran from February through March 2009.

The Corridor and RES Update Studies spanned a nineteen-month timeframe during which adjustments were made as new and better information became available with regard to generation development, related transmission projects and load forecasting.

III. Models and Assumptions

One of the most vital steps to ensure meaningful output from the study process is to develop an accurate model of the Minnesota transmission system and the greater integrated electric transmission grid for the study timeframe. Great care was also taken to define accurate assumptions of how the system may be built and operated. The TRC and the study team spent a significant amount of time and effort in defining the study assumptions and the transmission modeling process.

The transmission system in Minnesota and the upper Midwest is a complex network of high voltage bulk transmission lines that transfer generation to load centers, lower voltage lines that distribute power among the load centers, and still lower voltage lines that deliver power within cities and to end-use customers. Utilities in Minnesota have a long history of developing projects jointly for mutual benefit. This extends to the study process and the models that are used as inputs to the development of any projects in the state. A concerted effort to produce a model that accurately represented each of the utilities in the state was necessary in order to ensure the integrity of the study work being performed. An example of the complexity of the transmission system model in Minnesota is shown in Table 2, which gives the number of miles of transmission line currently in service in Minnesota.

Table 2 - Miles of Transmission Line in Minnesota[13]

	<100 kV	100-199 kV	200-299 kV	>300 kV	DC	Total
Miles	8,604	4,728	1,895	1,193	436	16,856

The study team examined both load serving ability and transfer capability because the transmission system is in place to carry power transfers across the greater interconnected power grid as well as provide a feeder system for regional power delivery. The transmission system is primarily needed for load-serving ability during summer peak loads and transfer capability during summer off-peak load conditions. To this end, the decision was made to analyze system performance under both summer peak and summer off-peak load conditions.

A. Transmission and Substation Data Collection and Mapping

Below is a discussion of the discrete steps the study team performed to achieve the transmission and transmission substation modeling effort.

[13] Approximate mileage as reported in the MTO's 2007 Biennial Transmission Projects Report filed with the Minnesota Public Utilities Commission on November 1, 2007. For the full text of the report, see the MTO website at http://www.minnelectrans.com.

2016 Transmission System – Base Model Development

2016 was chosen as the year to study and model the transmission system. The in-service date planned for the conversion of the Southwest Twin Cities – Granite Falls Transmission Corridor is currently the end of year 2015. This provides the added transfer capability currently anticipated to be necessary to support generation projects in that time frame. It also is anticipated to be sufficient for Minnesota's utilities to enter into generation projects that satisfy the State of Minnesota's Renewable Energy Standard goal through 2016.

<u>Steady State Transmission System Model</u>

The first step to build the steady state transmission system model was to take data from a known and widely accepted model from Midwest ISO Transmission Expansion Plan 2007 (MTEP07). MTEP07 is a model series encompassing the entire Midwest region's transmission system as well as future transmission expansion plans. It was released in 2007 and provides a series of models that include models for years 2013 and 2018 years. This 2013 model from MTEP07 is the best topology available for Midwest ISO members and is the model employed in other RES Update Studies and the DRG Studies. The model is suitably documented and well understood. In addition, any PROMOD analysis related to this study will be done with the MTEP07 year 2013 PROMOD model, as that PROMOD model is the best available. So there is good compatibility between the steady-state transmission (Power System Simulator for Engineers – "PSS/E") model chosen and the models to be used for PROMOD work.

MTEP07 created 2013 and 2018 peak and off-peak models. Since the study team needed to look at a 2016 timeframe, the team chose to average the loads of the 2013 and 2018 models to create a 2015 ½ load level for study of the year 2016. In this manner, half a year of load growth was built in as a proxy for the impact of the Minnesota Energy Conservation Improvement Plan (CIP) energy conservation assumptions. In the off-peak case, the study team chose a 61% load level that is more recently used to model a typical off-peak summer load.

One limitation of the MTEP 07 model series is the fact that it includes only the Midwest ISO member utility data. There are utilities in this region (and members of the MTO) that are not Midwest ISO members. To ensure the model was inclusive of Midwest ISO member utility information as well as non-Midwest ISO member utility information, the study team took on the challenging task of aggregating the two sets of data. The non-Midwest ISO member data was obtained from the Midwest Reliability Organization (MRO). The MRO is one of eight regional entities in North America that operate under authority from the US and Canada whose focus is ensuring transmission reliability compliance. The MRO builds the models of the utility facilities in this region, including those utilities that are not members of Midwest ISO. The MRO models were available in 2012 and 2017 versions. A 2015 ½ load level was also created from this initial data set.

The reason the Midwest ISO MTEP 07 model series was chosen as the initial model to build upon was because the study team needed the eastern part of the Midwest ISO footprint to be included in the models for the analysis scenarios in which generation was sunk to the Midwest ISO-wide market. The eastern part of the Midwest ISO footprint is not in the MRO region and therefore is not included in the MRO model.

The next step, transplanting this non-Midwest ISO (MRO) data into the Corridor and 2016 transmission system model, also proved to be quite challenging. Since the study team was using a simulator program called the PSS/E (Power Systems Simulator for Engineering) inputting accurate phase angles was key since they help set the power transfers across lines and transformers. If there is too much difference between a non-transplanted bus and its adjacent transplanted bus, the case will not solve. A bus is a physical electrical interface where many transmission devices share the same electric connection. Each time an MRO area is transplanted into the Midwest ISO model, the model then has to be "nursed" into solving. There is also a possibility that during this process, duplicate or fictitious facilities can be created since bus numbers between models can be inconsistent. Therefore, the model with transplanted information was extensively reviewed for accuracy.

Another detail that complicated the task of transplanting the MRO data was the varying way three-winding transformers are treated in PSS/E. In some instances the three-winding transformers have a PSS/E's built-in construct for such transformers. In other models, the three-winding transformers are depicted the historic way with three explicit branches. Still other three-winding transformers omit the third winding entirely and use PSS/E's construct for two-winding transformers. Therefore, the transformers had to be reviewed for correctness.

Dynamic Models

The base model used for the dynamic stability 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 for the CapX2020 Group 1, BRIGO[14], and RIGO[15] facilities.

Generation Modeling for Base Case

Next, generation source additions needed to be added to depict an accurate 2016 generation picture. The study team used the Midwest ISO Generation Interconnection Queue and other legal requirements to identify reasonably anticipated generation projects that would be online by 2016. The Midwest ISO queue is the process where generation developers' interconnection requests move through a series of studies and tests to achieve interconnection rights with the Midwest ISO transmission system. Because of the significant amount of wind generation projects that maintain favorable queue positions, generation selected for the base case was assumed to be wind-energy generation.

The known transmission projects which will be completed by 2016 and their approximate outlet capabilities are listed in the following table:

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[15] 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 3 - Base Case Transmission Projects and Wind Generation Levels

Prior Amount of Renewable Generation	*Project*	*Addition*	*New Total*
265 MW	425 upgrade project	160 MW	425 MW
425 MW	825 upgrade project	400 MW	825 MW
825 MW	BRIGO	375 MW	1200 MW
1200 MW	Twin Cities – Brookings CapX2020 project	700 MW	1900 MW
1900 MW	RIGO	922 MW[16]	2822 MW

B. Assumptions

Since the performance of any bulk electric system is significantly affected by the power transfers across it, the study team recognized that the model would have to reflect existing firm transfers, new energy transfers, and possibly some non-firm transfers (to allow for the growth of future firm transfers).

As a starting point, the team decided to model only firm transfers in the on-peak models. This choice reflects the realistic way the system operates since often non-firm transfers are not available during on-peak load periods since each utility's generation must serve its native load.

The impact on the Minnesota transmission system imports and exports were assumed to be just as important as the flows from new generation sources. Therefore, another assumption the study team agreed upon to realistically depict off-peak models was to model the highest transfers able to be simultaneously supported on three vital interfaces: the North Dakota Export (NDEX) and the Manitoba Hydro Export (MHEX) and the Minnesota-Wisconsin Export (MWEX).

The transmission models have generation units with power outputs that when combined exactly match the load in the model plus the system power losses. This balance between generation and load plus losses must always be maintained in models as well as in the real electric system. Thus, when new generation is added to the model, either the load must be increased to compensate for the new generation or existing generation must be turned down. The new generation is called the 'source' or the location point of the new generation and the existing generation to be simultaneously turned down to keep

[16] At the time the project models were being developed, the RIGO study was underway and outlet was assumed to be approximately 922 MW. Since this time the RIGO project has been refined, and this outlet level has since been reduced as project financing decisions were finalized. This adjustment is reflected in the final range of deliverability expected with the Corridor upgrade.

the system balanced is the ‘sink’. The magnitude of the ‘source’ is equal to that of the ‘sink’ plus the losses in the electrical system.

The study team decided to look at two different sink assumptions to assess future transmission needs. One view was to assume the power would be delivered only to greater Twin Cities Metro Area. The other view was to look at a dispatch option for the entire Midwest ISO footprint based on merit order of generation. Merit order of generation is the operational methodology of turning down more expensive generation when the newer (typically less expensive) generation is ramped up on the system.

Since it is currently unknown whether or not the Big Stone II generating plant[17] will be built, the study team needed to determine how to treat this area with respect to model building. The assumption is that the capacity reflected in the Big Stone II’s generation plant’s Midwest ISO queue position was assumed to be used by either the Big Stone II generating plant or an equivalent amount (MW) of other generation. Regardless of the status of the Big Stone II project, a large amount of generation is proposed to be built in the immediate vicinity of the Big Stone plant. The Midwest ISO queue showed more than 1000 MW of wind generation requests in a close proximity to Big Stone substation.

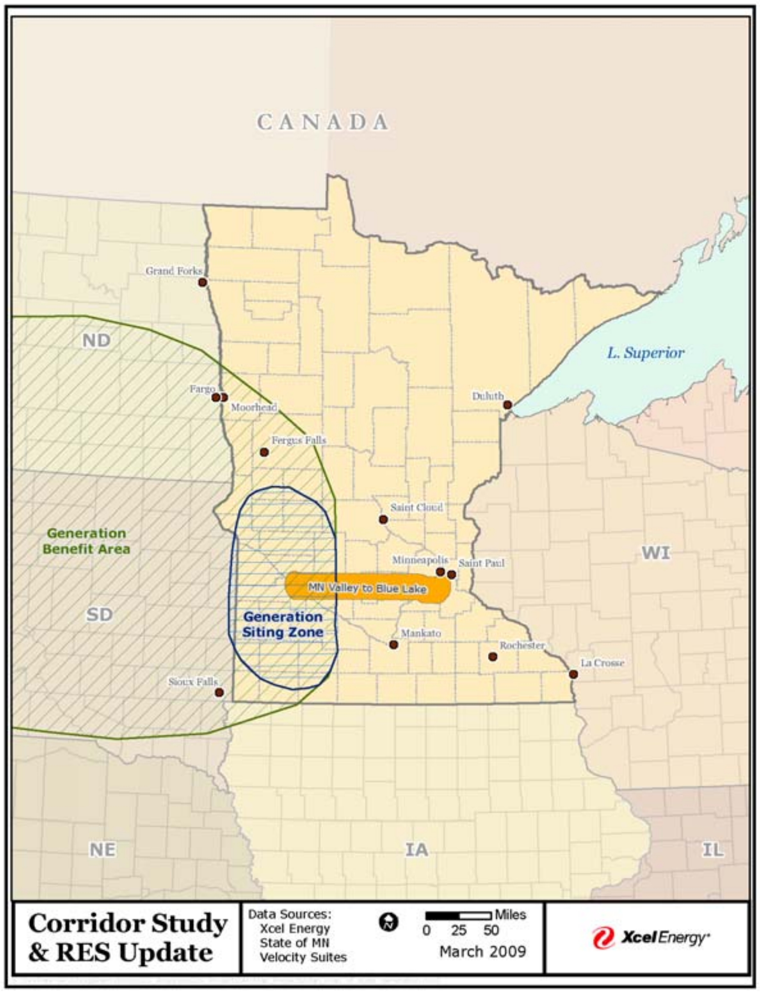
Any type of significant generation near Big Stone II will require a 345 kV connection to Hazel Creek Substation, north of Marshall, Minnesota to tie into the corridor facility and deliver the generation customers in Minnesota. This has been shown with the Big Stone II studies, and a 345 kV line from Big Stone to Hazel Creek is one of the facilities proposed for outlet of the plant.

The study team conducted the analysis without Big Stone II generation and transmission facilities in place to test sensitivities and maintained an end goal of recommending a facility which will provide transmission capability to assist utilities in meeting the Minnesota 2016 milestone regardless of the status of Big Stone II generation or transmission facilities.

Figure 2 shows the area in which generation was sited for the Corridor Study. The area in which generation will benefit from the Corridor Upgrade is overlaid.

[17] Big Stone II is a power plant proposed to be built in South Dakota.

Figure 2 - Corridor Study Generation Siting vs. Generation Benefit Area



At this point the two study teams conducted separate analyses to achieve their different objectives.

IV Corridor Study Details

A. Corridor Study Purpose

The Corridor Study purpose was to verify the status as a key "next limiter" and determine the most effective use of the existing 230 kV transmission corridor from Granite Falls, Minnesota to the southwest Twin Cities to maximize generation delivery from the area shown in Figure 2 above to the Twin Cities. By resolving this limiter, additional transmission capacity would be available for generation from the west, including generation needed by utilities to meet the RES obligations.

B. Corridor Study Analysis

The Corridor Study team began with the common base model and assumptions developed for both the Corridor Study and RES Update Study. The study team analyzed system performance for both summer peak and off-peak load conditions. The newly proposed facilities were tested to carry existing firm transfers, new energy transfers, and non-firm transfers (to allow room for growth of future firm transfers and non-firm transfers to better allow the best economic use of the generation in the area).

The study team worked with the Midwest ISO to perform the PROMOD (production cost model) analyses to determine two primary results –

(1) the transmission plans studied would be sufficient to allow the Minnesota load-serving entities to meet the applicable milestones in the Renewable Energy Standard legislation and

(2) the economic benefit of the new transmission would reduce average generation costs to end-use customers.

<u>Steady State Simulations</u>

The primary method of analysis for the steady-state (power-flow) simulations was the use of AC contingency analysis in PSS/E (PSS/E is a computer program capable of simulating the steady-state [power-flow] and dynamic performance of the electric system [loads and transmission lines and generators and transformers]. It is used to simulate the system response after outage of transmission or generation facilities).

Power flow analysis under system-intact and outage conditions was done to determine the effect on the electric system of adding the Corridor Study options, one at a time. The analysis simulated approximately 7,000 contingencies. This type of analysis determines the criteria violations caused by the generation additions and transmission options studied.

<u>Dynamic Simulations</u>

The primary method of analysis of the dynamic performance of the Corridor Study options was the use of PSS/E's dynamic simulation routines.

<u>PROMOD Simulations</u>

The study team worked with the Midwest ISO to perform analyses that tested the performance of the proposed facilities within the 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 is 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.

In addition, PROMOD is also a highly processor-intensive program. 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.

The PROMOD analysis for 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 this PROMOD analysis can be found with detailed project information in this report, as well as in the Corridor and RES Update Study Technical Reports.

C. Corridor Study Key Findings

Corridor Upgrade Transmission Capacity

One key finding of the Corridor study is that upgrading the existing transmission corridor to double-circuit 345 kV from Granite Falls, Minnesota to the southwest Twin Cities will provide the necessary transmission capacity to provide additional transmission capacity from the west to the Twin Cities and should be sufficient for utilities to acquire generation projects to satisfy the 2016 Minnesota RES milestones. This upgrade works well to facilitate serving Minnesota load with generation located west of Marshall in southwest Minnesota, as well as to the north, into the eastern Dakotas.

The transmission system upgrade endpoints were clarified through study findings and verified by the RES Update Study results. The two termination end points are the Hazel Creek Substation near Granite Falls, Minnesota to the west and the Blue Lake Substation in Shakopee, Minnesota to the east. The Hazel Creek substation is a proposed substation that is being built in conjunction with the BRIGO facilities and will also be utilized by the Twin Cities – Brookings 345 kV transmission project that is currently being permitted.

In addition, the analysis showed that this upgrade of the Hazel Creek to Blue Lake 230 kV line to a 345 kV double circuit is a pre-requisite to utilizing additional capacity for two CapX2020 lines. Study results showed the existing Minnesota Valley – Blue Lake 230 kV line limits the ability to transfer energy along the Twin Cities – Brookings line and the Twin Cities – Fargo line. Therefore, whether or not the CapX2020 Group I lines are upsized, these lines cannot make use of their full energy carrying capability without the Corridor Upgrade.

The Corridor study team also assessed the necessary supporting projects to enable full realization of the upgrade benefits. The study results determined the approximate range of capacity or energy carrying capability likely created through installation of the corridor upgrade and supporting project. This assessment is expressed as a range since many outside influences can affect the actual results.

Figure 3 - Core 345 kV Corridor Project Map

Corridor Upgrade Project Description

The blue lines in Figure 3 represent the recommended new facilities to upgrade the 230 kV transmission line to a double-circuit 345 kV line from Hazel Creek Substation, near Granite Falls, Minnesota, to Blue Lake Substation, in Shakopee, Minnesota.

- One of these circuits is an “express” line from Hazel Creek – Blue Lake, which means the transmission line does not have any interconnections at substations along the way and does not serve any other load along the way.
- The other circuit of the double circuit upgrade has interconnections going in and out at both the Panther Substation in Renville County, Minnesota and McLeod Substation near Hutchinson, Minnesota to replace the interconnections to the existing 230 kV line.
- A supporting project necessary to fully realize the Corridor Upgrade’s benefits is replacing the existing Hazel Creek – Minnesota Valley 230 kV line. This project is proposed to be completed as part of the Twin Cities – Brookings 345 kV line project.
- Another supporting project is removing existing 230 kV facilities at McLeod and Panther.

D. Corridor Study Associated Observations

As generation in the green benefit area displayed in Figure 2 is delivered to load centers to the east, including the Twin Cities metro area, the existing 230 kV line from Minnesota Valley to Blue Lake is overloaded, therefore limiting the deliverability of the generation. This overload is an issue for both meeting the 2016 RES milestone and to reliably utilizing the entire Midwest ISO operational footprint.

<u>Transmission Grid in Western Wisconsin</u>

One observation is that the transmission grid in western Wisconsin, along with interface loading levels along the Minnesota-Wisconsin border, limits the ability to deliver more generation from Minnesota and points further west.

Currently there is a joint transmission planning study underway to determine the need for a new transmission line from La Crosse, Wisconsin to an endpoint in the Madison area. The study is addressing the long-term load serving support for the western portion of Wisconsin. This study is being led by American Transmission Company (ATC) with participation from other area utilities, including MTO members Xcel Energy, Great River Energy, ITC Midwest, Southern Minnesota Municipal Power Agency, and Dairyland Power Cooperative. Completion of the study is expected in 2010.

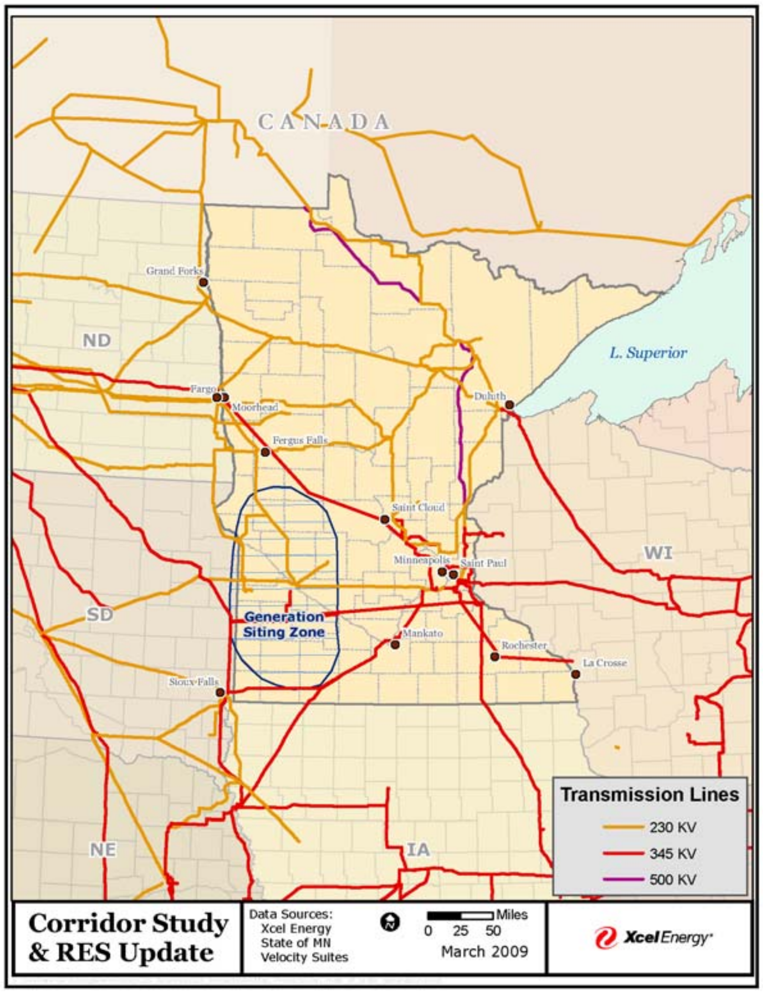
<u>Generation Siting</u>

Another observation is that the actual amount of generation delivery capability gained by the Corridor upgrade will be determined by the actual location of future generation development. To the extent that actual generation development differs from that which was studied, the actual outlet capacity achieved by this system addition may either increase or decrease. The study team selected likely generation development sites based on the best resources available, such as the Midwest ISO generation interconnection queue[18] and utility resource planners in order to provide a reasonable range of results.

The study team met with transmission utility resource planners to gather information about future generation locations and generation capacity amounts. The resource planners provided maps and helped the study team choose new generation sources and placement. The Distributed Renewable Generation (DRG) Transmission Study Phase I[19] team also provided information for potential generation site selection. The study team reviewed the DRG Phase I site scan in combination with the Midwest ISO and WAPA (Western Area Power Administration) generation interconnection queues to decide where to place the generation. The net result is a list of potential generation locations that represent conceptual future locations as reasonably as possible.[20]

[18] The Midwest ISO (Midwest Interconnected Transmission System Operator) queue is the process where generation developers' interconnection requests move through a series of studies and tests to achieve generator interconnection rights with the Midwest ISO transmission system.
[19] The DRG Study can be found at http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881736&programid=536916477&sc3=null&sc2=-536887792&id=-536881351&agency=Commerce
[20] It is important to note that siting generation locations on high voltage buses has the same net effect to the system as spreading the generation around numerous lower voltage buses. Generation sited at higher voltage buses will offset flows through the transmission grid to the local lower voltage system. In addition, the DRG Study verified that power generated on the lower voltage system makes its way to the high voltage system and impacts the higher voltage transmission grid.

Figure 4 - Corridor Study Generation Siting Region



Impact of Corridor Study Generation Sink Scenarios

The Corridor Study team studied two separate generation sink scenarios to determine the impact each alternative might have on the transmission system solution. The first method was to sink the generation to the full Midwest ISO market. This method is a realistic approach to model how the Midwest ISO actually dispatches its generation fleet, as it models the system most closely to real-world dispatch and provides the greatest chances of encountering the system limitations that limit generation dispatch on a real-time basis. Using this dispatch methodology also yields a strong, reliable system in times of high and low wind. In addition, this is the dispatch method the Midwest ISO utilizes in many of their regional studies and thus offers a fair representation of generator delivery capability.

The other method by which the system was analyzed assumed sinking the generation within Minnesota, mainly in the greater Twin Cities metro area. This approach allowed the study team to determine the effects of the significant addition of new energy sources to the energy grid within Minnesota. This tested how the Twin Cities metro area transmission system would react to large amounts of external generation serving the area load. This scenario would logically involve turning down (or off) large amounts of generation within the greater Twin Cities area. Examining this scenario provides valuable information to inform future generation dispatch and planning decisions, as it will help determine just how much distant generation can be dispatched to the greater Twin Cities area without risking the ability of the system to adapt in real-time to fluctuations in remote generation levels. Where the Corridor Study analyzed this impact in the steady-state and thermal realm, the stability analysis discussed within the RES Update Study addressed the real-time operational issues (i.e. system stability) associated with this dispatch scenario.

The Twin Cities generation sink scenario, along with constructing the necessary underlying system upgrades, facilitates approximately 2000 MW of delivery capacity to load centers in Minnesota. However, without the facility from La Crosse to the Madison area, system capacity is limited to the capacity levels resulting from the addition of the Corridor Upgrade and underlying projects. Further upgrades in Minnesota would not provide significant benefit prior to installation of a high-capacity path from La Crosse to the Madison area. As shown in the RES Update Study analysis, all of the next system upgrades necessary to meet future RES milestones require a line to the Madison area. In other words, without a line to the east the system will reach a “tipping point” where no more major capacity additions can be accommodated.

It is widely accepted that wind generation levels can rapidly fluctuate in response to sudden meteorological changes. As larger generation units are turned off and the extent to which the system depends on wind generation increases, these changes in weather patterns can very quickly cause a shortfall in the amount of available generation to serve instantaneous demand. With significant base load generation offline and startup times ranging from several hours to several days, it would not be possible for these units to respond to a sudden drop in available wind generation. The reverse is also a potential issue. If wind generation levels are relatively low, base load generation units are producing at full capacity to meet the system’s real-time demand. However, if wind generation suddenly increases, the larger generators would have to be taken offline in rapid fashion. These sudden tripping operations tend to have a detrimental impact on larger generators and should be avoided. These are some of the steady-state challenges that come with integrating significant levels of wind generation within a transmission-constrained footprint.[21]

[21] On February 26, 2008, a sudden decrease in wind generation levels in Texas led to the interruption of 1100 MW of load to customers in the state.

Big Stone II Status

The study team dealt with the ambiguity of whether the Big Stone II project will be built by studying the situation with and without the Big Stone II generation and transmission facilities in place. The key outcome of this analysis showed that it is not necessary to have the Corridor Upgrade project extend west to Big Stone II to meet the 2016 RES milestone. Rebuilding the 230 kV line from Hazel Creek to Blue Lake to a 345 kV double circuit line is the best alternative from a transmission system performance perspective regardless of the final status of Big Stone II. However, there are benefits provided to additional generation by the Big Stone II transmission facilities. Significant levels of renewable generation projects, aside from Big Stone II, are seeking to interconnect in the vicinity of Big Stone II and the Corridor Study did not seek to make any judgments regarding the feasibility of interconnecting that generation.

Supporting Facilities for Corridor Upgrade

One outcome of studying the Midwest ISO Market sink scenario proved the system requires facilities connecting to the radial 345 kV Twin Cities – La Crosse line to deliver power east from La Crosse, Wisconsin to the rest of the Midwest ISO footprint during low load periods in Minnesota and the Dakotas. Consistent with the findings of the Minnesota Wind Integration Study,[22] this facility is necessary to enable the Minnesota transmission system to accommodate the levels of wind generation envisioned in the RES legislation. This new facility would also allow the Corridor Upgrade to achieve its full potential in the Midwest ISO market dispatch.

The Twin Cities metro sink scenario analysis showed that in order to sink upwards of 2000 MW of renewable generation to the Twin Cities, many of the metro area electric generation units must be shut down to allow the new generation to remain online. To enable the wind generation to be sunk in the Twin Cities metro and maintain reliable operations requires a significant list of metro area transmission system upgrades.

E. Cost Estimates for Corridor Upgrade Project

Based on the Twin Cities metro sink study results:

1. The core portion of the 345 kV double circuit upgrade project is estimated to cost approximately $350 million[23] with an additional $110 million in associated projects required.
2. Of this $110 million in underlying system projects, approximately 60% of them have been otherwise identified in unrelated system analyses, leaving slightly less than half of these underlying projects as totally tied

[22] The Minnesota Wind Integration Study can be found at: http://www.uwig.org/windrpt_vol%201.pdf.
[23] Note that these estimates are preliminary budgetary estimates and are subject to change.

to the Corridor Upgrade. The total cost of this scenario is therefore approximately $400 to $460 million and will result in a transmission system able to deliver roughly 2000 MW of additional generation. The study results are presented in ranges since there are many unknowns that could affect the generation capacity output and the associated costs, as well as the unknowns with the underlying system projects. A full list of the underlying system projects can be found in the technical report.

The Midwest ISO footprint sink scenario cost estimates begin with the same core project price tag of approximately $350 million. Since a 345 kV line needs to be built from La Crosse to Madison, Wisconsin to enable full reliable operation and delivery to the eastern portion of the Midwest ISO footprint, the additional costs are about $325 million[24]. This adds to a total cost estimate of approximately $675 million and, based on the findings of the RES Update Study, will result in a transmission system able to deliver as much as 3600 MW of new generation.

Based on the above results, it can be determined that the Midwest ISO market sink scenario, while having a higher price tag, will achieve a higher outlet capability (MW) per dollar spent than the Twin Cities sink scenario. In addition it will avoid the system stability difficulties prevalent with the Twin Cities dispatch. These stability results are outlined in more detail in Chapter VI, Section A of this report.

As discussed above, PROMOD simulations were conducted to test the behavior of the Corridor facilities within the Midwest ISO market dispatch. Table 4 provides information regarding the results of these analyses.

Table 4 - Cost for Corridor Upgrade

Description	***Cost***
Project Cost	$350,000,000
Underlying System Cost	$110,000,000
70% Production Cost Savings Offset	($35,000,000)
30% Load Cost Savings Offset	($180,000,000)
Loss Savings Offset	($152,000,000)
Net Project Cost	$93,000,000

The cost of the proposed project has been estimated at $350 million. With a Twin Cities dispatch, approximately $110 million in underlying system upgrades is necessary to achieve the full generation delivery capability of the project (2000 MW).

[24] This is an MTO estimate for an project which will be constructed by a non-MTO member, and therefore the estimate is subject to change as the project develops, as well as endpoints are determined.

As demonstrated in the table above, installation of the Corridor Upgrade results in sizeable production cost savings and significant load cost savings over an assumed 40-year project life. The values reflected in the table above represent 70% of the total production cost savings and 30% of the total load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for economic analysis of projects.

In addition to the production cost and load cost savings, the Corridor Upgrade results in approximately 49 MW of loss savings. This equates to a present value of approximately $152 million.

Considering all the costs, the net project cost of the Corridor Upgrade is roughly $93 million. This demonstrates that, while steady state results demonstrate a significant generation delivery increase associated with the Corridor Upgrade, the project also brings about significant cost savings and has a highly beneficial impact on the transmission system in general – in particular with respect to the market dispatch employed by the Midwest ISO. Similar analysis was performed with respect to the facilities studied in the RES Update.

V. RES Update Study Details

A. RES Update Study Purpose

The RES Update Study examines the facilities needed after the Corridor Upgrade to provide a robust and reliable transmission system and to allow load serving entitles to satisfy the next RES goals (2020). It builds upon the results of the Corridor Study by investigating the best way to integrate the significant interest in generation development in and around Minnesota into the regional transmission system. The RES Update Study was designed to support the Corridor study work and included sensitivities to the development explored in the Corridor Study. These sensitivities helped to finalize the endpoints of the Corridor Upgrade and draw conclusions about generation delivery capability unlocked by combining the Corridor Upgrade with other regional transmission improvements. In addition, the final recommendations of the Corridor Study were considered when developing the RES Update Study's recommended facilities.

As mentioned earlier in this report, several factors have contributed to the evolution in information needed from the RES Update Study. The first factor is the greater than expected deliverability from the Corridor Upgrade. When the original Corridor Study project scoping took place**,** preliminary estimates assumed about 1000 MW of new generation delivery as a result of the Corridor Upgrade. Early estimates also projected an additional need of approximately 1000 MW beyond the Corridor Upgrade to meet the 2016 RES milestone.

Therefore, the original scope for the RES Update Study was to identify optimal additional facilities to ensure 2016 RES compliance.

Since the RES Update and Corridor Study teams worked closely together, the RES Update Study team could react to results as they surfaced during the Corridor Study analysis. The analysis from the Corridor Study showed that the generation delivery result from the upgrade could be around 2000 MW of additional generation output capability.

The second factor impacting the RES Update Study scope is the decrease in the rate at which load growth is occurring among regional utilities as a result of conservation efforts and present economic conditions. This fact is viewed cautiously given that history has typically shown that recessionary load levels quickly recover to pre-recessionary levels.

The third factor in the evolution of the RES Update scope is better-than-expected capacity factor from installed wind generation. In the original Gap Analysis[25], a lack of definitive wind generation capacity factor information led transmission planning engineers to conservatively estimate the average capacity factor at 30%. Several years of actual information have now placed the average wind turbine capacity factor at a level closer to 40%. The capacity factor is one way to measure the productivity of a wind turbine or any other power production facility. It compares the plant's actual production over a given period of time with the amount of power the plant would have produced if it had run at full capacity for the same amount of time. In other words, an increase in capacity factor from 30% to almost 40% means more energy is being generated per turbine and it will take fewer turbines to generate the amount of energy needed to satisfy the RES milestones.

Taking into account these three factors, the results of the Corridor Study suggest that its installation will provide sufficient generation delivery capability to meet the 2016 RES milestone.

As a result, the RES Update study evolved to focus on identifying transmission projects that could increase generation outlet capability from several popular generation development zones. These zones are located in North Dakota, southwest Minnesota and eastern South Dakota, and southeastern Minnesota. In addition, an analysis was conducted that attempted to meet the Minnesota 2016 RES milestone using only DRG projects. Table 5 shows the buses that

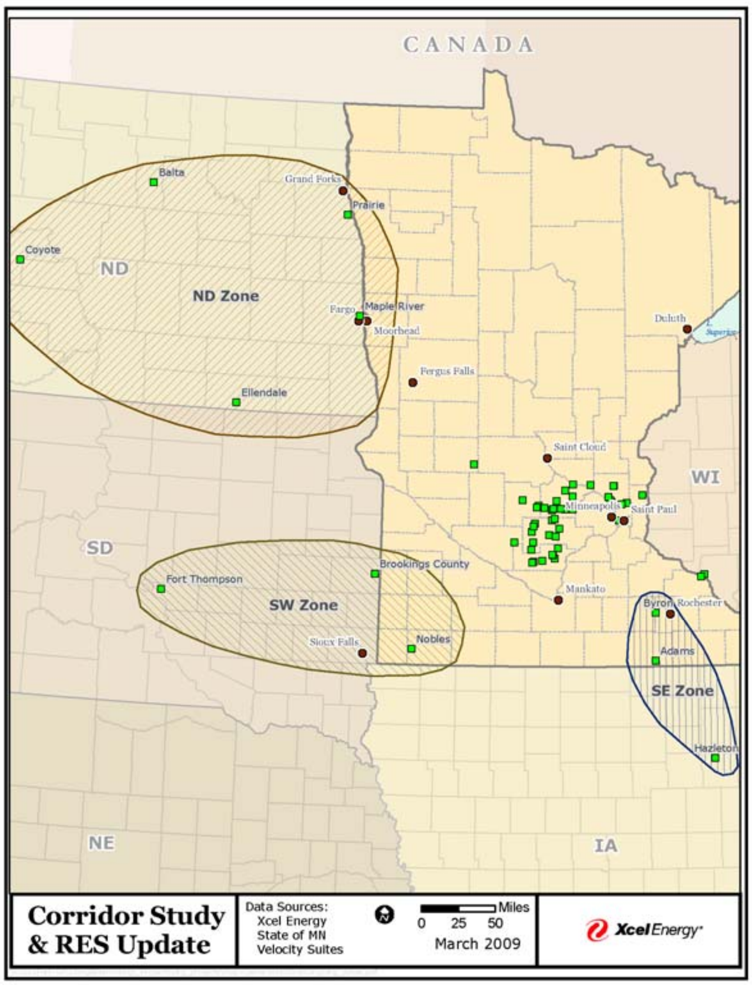
[25] The original Gap Analysis was conducted by the MTO for inclusion in the 2007 RES Report and calculated the amount of wind energy (in MW) that would be necessary to meet each RES milestone statewide and for each company. The RES Report was required by the 2007 Next Generation Energy act and was filed in conjunction with the 2007 Biennial Transmission Projects Report. A full version of the report can be found on the web at http://www.minnelectrans.com. A clarifying filing with additional detail can be found at: https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=5497544.

were analyzed as sources for generation in each zone in the RES Update Study. The locations of these buses can be seen in Figure 5. The buses studied for the DRG scenario are shown in green in Figure 5. A full list of the buses studied for the DRG scenario can be found in the Minnesota RES Update Study Technical Report.

Table 5 - Assumed Generation Sources by Zone

North Dakota Zone	Southwest Zone	Southeast Zone
Balta	Brookings County	Adams
Coyote	Nobles County	Byron
Ellendale	Fort Thompson	Hazleton
Maple River		
Prairie		

Figure 5 - RES Update Generation Zones and DRG Bus Locations



B. RES Update Study Analysis

The RES Update Study team began with the common base model and assumptions developed for both the Corridor Study and the RES Update Study. The study team analyzed system performance for both summer peak and off-peak load conditions. The newly proposed facilities were tested to carry existing firm transfers, new energy transfers, and possibly some non-firm transfers (to allow room for growth of future firm transfers and non-firm transfers to better allow the best economic use of the generation in that area).

Steady State Simulations

The primary method of analysis for the steady-state (power-flow) simulations was the use of AC contingency analysis in PSS/E (Power Systems Simulator for Engineering).

Power flow analysis under system-intact and outage conditions was done to determine the effect on the electric system of adding the Corridor Study options, one at a time. The analysis simulated approximately 7,000 contingencies. This type of analysis determines the criteria violations caused by the generation additions and transmission options studied.

Initial steady state simulations included analysis of numerous options, including several options that extended into Wisconsin, various 345 kV options throughout Minnesota, North Dakota, and South Dakota, and a new 500 kV line from Winnipeg. Planning engineers assumed that the line from Winnipeg would carry additional generation from Manitoba into the United States. While a new 500 kV line was successful in transporting additional power from the north, such a line does not necessarily result in additional transmission that supports the RES. Transmission from Manitoba does not necessarily transport only hydro generation and in any event for purposes of the Minnesota RES, only small hydroelectric power installations qualify as an eligible energy technology. Hydroelectric power from Manitoba is typically sized in the range of several hundred megawatts.

Based on the results of initial simulations, a group of projects were forwarded for additional analysis under several sensitivities. More information on these projects and the sensitivities studied can be found in Chapter V, Section C (Sensitivity Analysis Results) and Chapter V, Section D (RES Update Project Descriptions and Cost Estimates).

Dynamic Simulations

The primary method of analysis of the dynamic performance of the Corridor Study options was the use of PSS/E's dynamic simulation routines. Using the NORDAGS models discussed in the model-building section earlier in the report, 16 regional faults were modeled to determine the effect of the projects being proposed on the regional transmission grid.

When minor voltage swing violations are observed, a static VAR compensator (SVC) can be used. SVCs are capable of providing dynamic voltage support and responding quickly to fluctuations in voltage. More significant fluctuations in voltage or unstable conditions cannot typically be resolved through the use of SVCs. In addition, when a system already has a significant level of reactive compensation, the effect of adding more compensation is reduced. Another way of saying this is that there is a law of diminishing returns associated with the addition of reactive support.

A description of the dynamic stability implications of the proposed projects can be found in Chapter VI, Section A (Stability Assessment Results).

PROMOD Simulations

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.

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.

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 being examined.

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 generators. 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 utilities operate in an environment that is generally regulated, it is in the best interest of the utility to minimize the cost to deliver its energy. This promotes efficiency of production and minimizes the amount of generators that have to be run at any one time. In general, the production cost calculation within PROMOD tends to reflect more of a regulated market system. A true market system, on the other hand, 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 the Midwest ISO's methodologies, the same percentages were used for this analysis.

The PROMOD analysis for 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 Chapter V, Section D below.

C. RES Update Study Key Findings

<u>Operational Limits with Increased Wind Penetration</u>

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. 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.

This is significant because the fossil fuel plants typically cannot respond to significant changes in load or variable generation sources such as wind. When taken offline, minimum restart times for fossil fuel plants are typically two to three days and not having the units available for that long to deal with fluctuations in wind generation could jeopardize the reliability of transmission service in the upper Midwest.

These findings underscore the need for additional transmission infrastructure as wind penetration increases. If wind penetration is increased to the point that larger generation units near the Twin Cities have to be shut down, additional transmission will be needed to enable the region to import power when wind generation is not sufficient to serve the demand in the area. However, if there is a desire to keep the larger generators near the Twin Cities online to provide increased reliability, additional transmission will be necessary in order for the transmission system to accept the injection of this much power. In other words, ensuring reliable operation of the electric system at increasing levels of renewable generation will require additional transmission outlet capacity.

In addition to the steady state issues identified above, concerns about approaching the region's operational limit for wind penetration were confirmed by the results of the dynamic stability assessment. A stability assessment with the Corridor Upgrade (and associated generation projects) in service showed only minor issues that needed to be addressed. This case contained approximately 4800 MW of wind generation that was applied toward satisfying the Minnesota RES.

A larger-scale stability analysis that included more significant levels of wind penetration was also conducted. This case included 7300 MW of wind generation and several hundred miles of transmission in addition to the Corridor Upgrade. This case is indicative of an out-year Minnesota RES case or how the system might develop if utilities outside the state begin to seek renewable energy purchases within Minnesota.

This larger-scale stability analysis revealed significant dynamic stability issues for the loss of regional transmission lines (such as King – Eau Claire – Arpin) and large generators (such as Sherburne County Unit 3). Larger generators have a stabilizing influence on the regional transmission system because of their large inertia. When regional faults take place, their inertia allows them to absorb swings in voltage and maintain the integrity of the regional transmission system. In the 7300 MW stability case, a substantial portion of the region's generation needs are being served by smaller generators with less inertia. These smaller units are more susceptible to swings in voltage and can easily contribute to the voltage swings rather than damping them in the manner of a large generating unit.

While the transmission examined in this case may be sufficient to integrate the level of wind on a steady state basis, the instability observed indicates that additional transmission facilities are necessary in order to maintain system stability and associated reliable operation with this level of wind generation in service.

The results of the RES Update Study show that caution must be exercised as wind penetration in the upper Midwest surpasses the levels contemplated by the Corridor Upgrade. While there have been numerous steady-state studies performed analyzing increasing levels of wind penetration, the stability assessment described here is noteworthy because the study team believes it is the most extensive publicly-available system stability study to include these levels of wind generation.

RES Update Study Identification of Constraints and Sensitivities

Another key finding of the RES Update Study was the fact that future generation development will be constrained beyond the levels planned by the CapX2020 Group I facilities and the Corridor Upgrade. In other words, the RES Update Study effectively clarified the next group of transmission constraints beyond those addressed by the CapX2020 Group I projects and the Corridor Upgrade and measured the sensitivities of each area of concern. Without improvements to the specific facilities noted, additional generation will be unable to flow to the areas where the energy is needed.

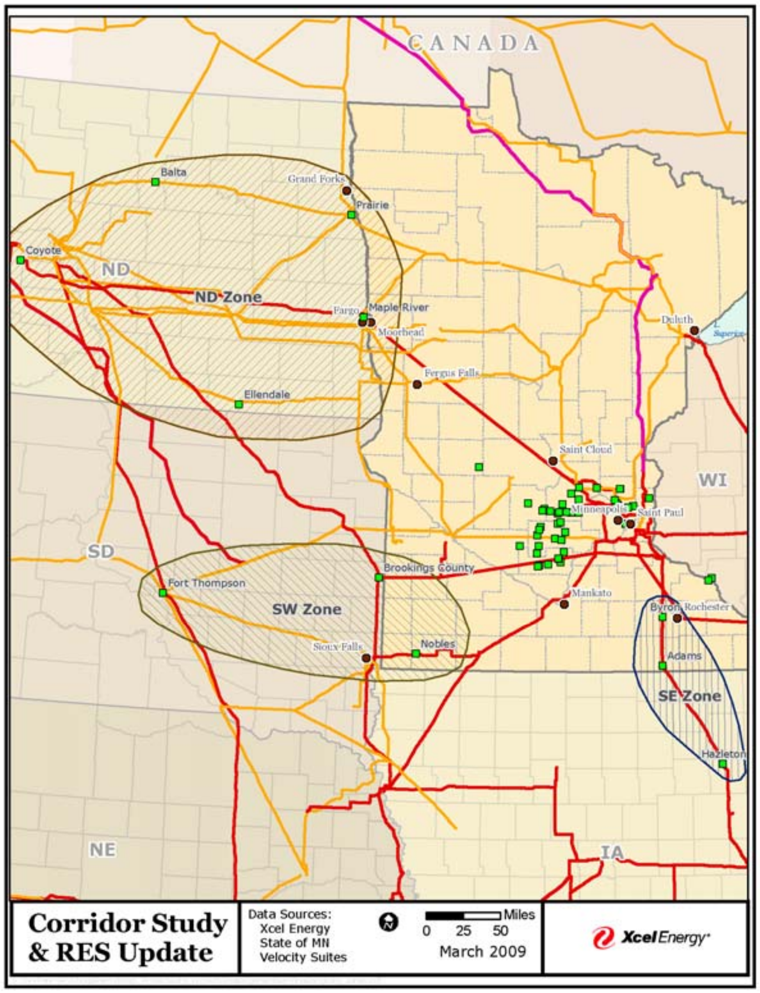
For example, Buffalo Ridge, an area of significant wind development interest in southwestern Minnesota, northwest Iowa, and eastern South Dakota, will be constrained to approximately 1900 MW, generation in southeastern Minnesota will be capped at about 900 MW and the North Dakota Export will be limited to 2080 MW prior to the Corridor Upgrade. Factoring in the Corridor Upgrade, the Buffalo Ridge area would increase to nearly 3,900 MW. Generation in North Dakota receives an indirect benefit from the Corridor Upgrade, but the Southeast Minnesota areas would remain largely unimpacted. Despite the dramatic increase in generation capacity in the Buffalo Ridge area, interest in developing additional generation projects in North Dakota and southeastern Minnesota will remain strong. The RES Update Study lays out the projects that will most beneficially increase those areas.

Results of the RES Update Study also provide support for the Corridor Study and its generation outlet findings. For example the transmission system in western Wisconsin affects the ability to accommodate generation development in Minnesota and points further west.

The study team focused on three popular generation development zones analyzing future limiting transmission facilities and recommending solutions to increase generation outlet from each zone. The RES Update Study investigated the following zones: North Dakota, Southwest Minnesota/South Dakota and Southeast Minnesota. In addition, the study team performed an analysis that relied on the Distributed Renewable Generation Transmission Study to identify sites and transmission upgrades necessary to interconnect approximately 2000 MW of DRG projects. This analysis relied heavily on the study work pioneered in the DRG Study released on June 16, 2008. Details on this study can be found at http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881736&programid=536916477&sc3=null&sc2=-536887792&id=-536881351&agency=Commerce.

Figure 6 identifies the generation zones studied in the RES Update: the North Dakota zone, the Southwest Minnesota/South Dakota zone and the Southeast Minnesota zone. The DRG zone is not shown on the map since these sites are more numerous and spread throughout the state of Minnesota.

Figure 6 - RES Update Zone Map



The RES Update Study shows the next steps necessary to provide a robust transmission system that will allow Minnesota's load serving utilities to meet future Minnesota RES milestones and identifies projects that create outlet for specific generation zones. One observation to these results is that if an individual zone is booming with generation projects to the detriment of development in other zones, the study results will need to be reexamined.

The RES Update Study found that existing infrastructure will constrain generation development beyond the levels illustrated by the CapX2020 Group I facilities. The team identified common limiters impacting Minnesota's transmission system's ability to transmit more energy. The first bottleneck is terminal equipment at White and Sioux City Substations in South Dakota and northwest Iowa. The next is the King – Eau Claire – Arpin transmission line that runs from eastern Minnesota to central Wisconsin. And finally, the study identified the need to upgrade or place additional 345 kV transformers in the Hazleton, Pleasant Valley, Brookings County, Adams and Stone Lake Substations.

The transmission grid in western Wisconsin is primarily comprised of lower-voltage load-serving lines and is not designed for high capacity transfers. Therefore, this part of the regional transmission grid limits the ability to deliver new generation interconnected in Minnesota and points further west.

The lower voltage transmission grid in southeastern Minnesota (161 kV) limits the ability to interconnect generation in southeastern Minnesota and, to a lesser extent, southwestern Minnesota.

The 500 kV system between Winnipeg and the Twin Cities will remain a limiter impeding future generation interconnections in areas west, north, and northwest of the Twin Cities.

Where the Corridor focused on delivery within Minnesota, the RES Update Study expands that scope to ensure that existing barriers to generation delivery within and near Minnesota load centers are addressed. The RES Update Study included sensitivities to the development explored in the Corridor Study and the final recommendations of the Corridor Study were considered when developing the RES Update Study's recommended facilities.

<u>RES Update Study Sensitivity Analysis Results</u>

The RES Update Study not only identified the different facilities' upgrades necessary to increase generation output. The study 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.

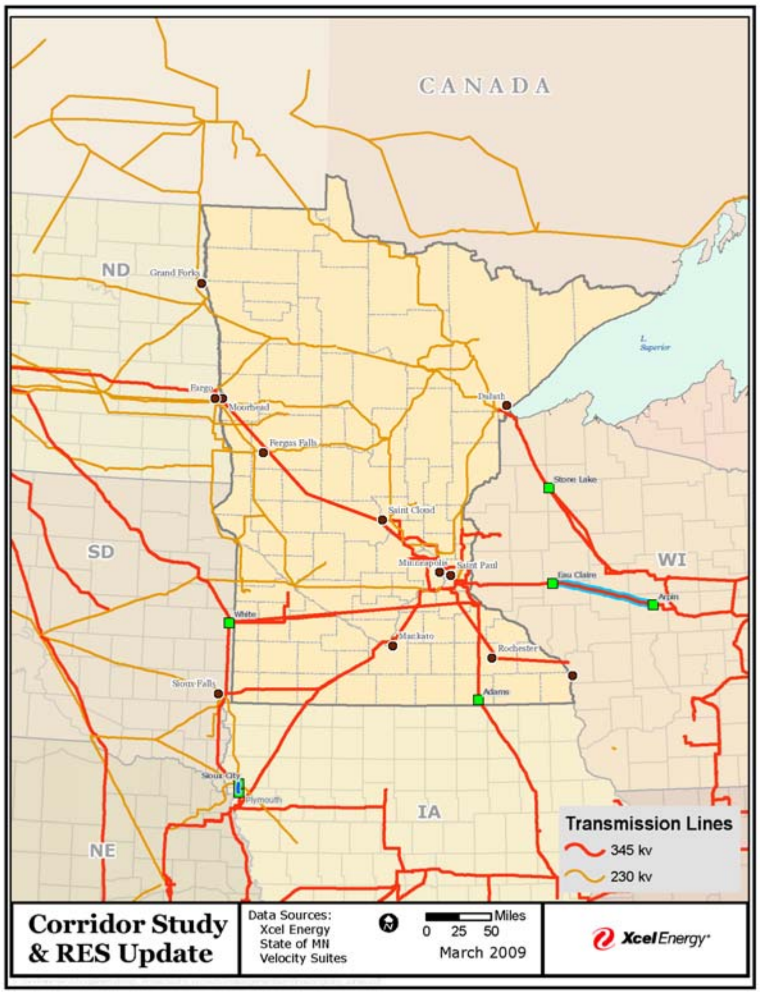
In the North Dakota zone, the upgrade of the Corridor facilities provides a significant benefit to North Dakota-based generation, however, other transmission facilities are necessary to unlock generation potential within North Dakota. For example:

- The installation of the La Crosse – Madison line results in North Dakota generation having fewer impacts on the 500 kV transmission system. The study team identified the need for a line from La Crosse to the Madison, WI area. Columbia was chosen as a proxy due to the abundance of transmission and its proximity to the Madison area. Joint study work is underway with ATC (American Transmission Company), DPC (Dairyland Power Cooperative), and Xcel Energy to identify the best actual endpoint.
- Extending the Corridor upgrade to Big Stone enhances the benefit to North Dakota generation. This could be accomplished either via the Big Stone II transmission facilities or via the double-circuit line that was studied for the Corridor Upgrade.
- Tying the Twin Cities – Fargo, Twin Cities – Brookings, and Twin Cities – Granite Falls lines together on the western end provides regional reliability

benefits and increases the ability of the lines to back one another up under contingencies.

Figure 7 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.

Figure 7 - Common Underlying System Limiters

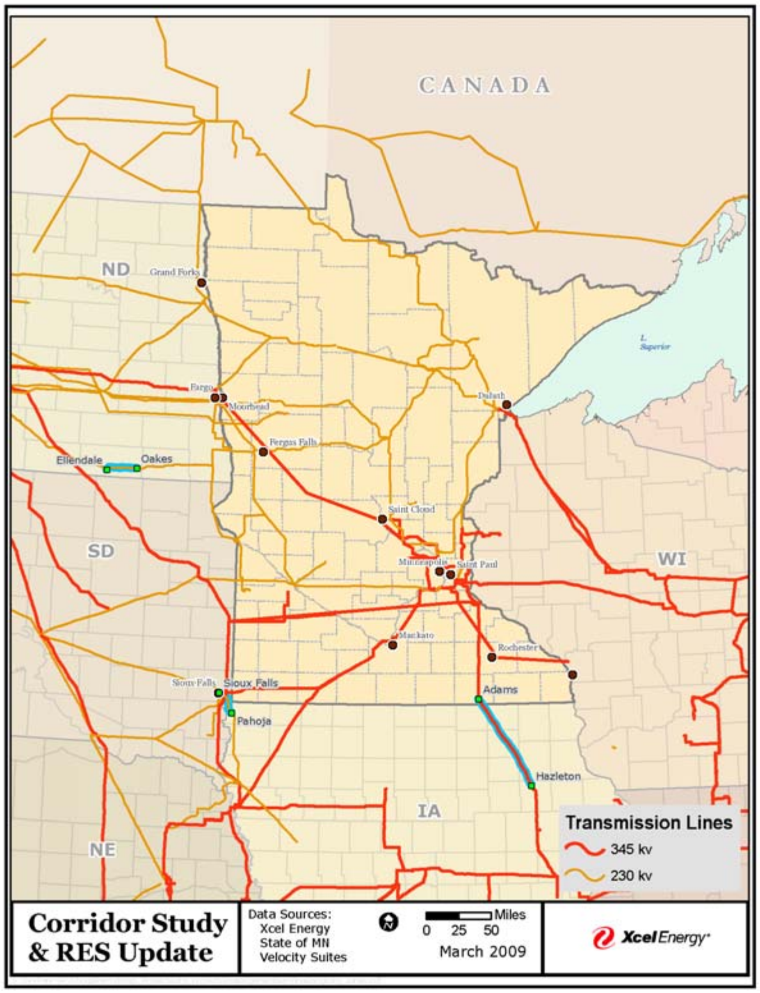


- Stone Lake 345/161 kV Transformer – this transformer is located along the recently completed Arrowhead – Gardner Park 345 kV line. The overload generally shows up for contingencies that involve loss of the Stone Lake – Gardner Park. In addition, a 345 kV breaker failure contingency that causes loss 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.
- 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.

Figure 8 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.

Figure 8 - "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 roughly parallel to the Split Rock – Sioux City 345 kV line and receives much of the flow that is redistributed after the contingency.

For each of the following sensitivity analysis charts, the columns represent the different ways in which the Corridor transmission was modeled in a particular case. The Minnesota Valley – Blue Lake 230 kV column represents the system's performance with the existing 230 kV Corridor. The Hazel Creek – Blue Lake 345 kV Double Circuit column models the Corridor as recommended in the Corridor Study, and the Big Stone – Blue Lake 345 kV Double Circuit column represents the performance of the system if the recommended Corridor Upgrade extends to Big Stone Substation. This system alternative was included due to the burgeoning interest in wind generation projects in the vicinity of Big Stone Substation.

The rows in the tables are various RES Update Study transmission facilities. 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 scenario.

For example, referring to Table 6, in a case with Maple River – Brookings in service and the existing Minnesota Valley – Blue Lake 230 kV line in service, 490 MW of outlet can be obtained. This is limited by overload of the Ellendale – Oakes 230 kV line for loss of the Center – Jamestown 345 kV line. If you move to the next column, installing the Corridor Upgrade results in 1500 MW of outlet. Again this is limited by overload of Ellendale – Oakes this time for the loss of Jamestown – Maple River 345 kV line.

Table 5 - Sensitivity Analysis for North Dakota Zone

	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 - Madison	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 & Broadland Lines Lakefield Jct. – Madison	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

In the southwest zone, transmission improvements provide noteworthy results in terms of generation capacity improvement. The largest benefit for this zone occurs with installation of the La Crosse – Madison 345 kV line which crosses from Wisconsin from La Crosse to the Madison area. The 500 kV line does not seem to be as affected as in other zones because the distribution factor of southwestern generation on the 500 kV line is low enough that the 500 kV facilities do not require attention. Distribution factor is the term that defines the percentage of generated power that flows on a certain transmission facility and is often expressed as a percentage of the generator power output.

Table 6 - Sensitivity Analysis with Southwest Zone

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Madison	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 - Madison	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 - Madison	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 Ashley & Broadland Lines Lakefield Jct. – Madison	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

The sensitivity test of the southeast zone showed that the greatest benefit comes from installation of the Corridor Upgrade and the La Crosse – Madison 345 kV line. This results in approximately 3600 MW of generation delivery capability beyond the base case in the model. The southeast portion of the state benefits from a low distribution factor on the 500 kV line and a relatively robust 345 kV and 161 kV transmission system. There is no occurrence of 500 kV facilities in the analysis of increased southeastern zone generation. Given the distance between the southeast portion of Minnesota and Big Stone and the dominant west-to-east transmission flows, southeast Minnesota generation receives limited benefit from the extension of the Corridor Upgrade to Big Stone.

Table 7 - Sensitivity Analysis for Southeast Zone

	Minnesota Valley - Blue Lake 230 kV	Hazel Creek - Blue Lake 345 kV Double Circuit	Big Stone - Blue Lake 345 kV Double Circuit
La Crosse - Madison	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 - Madison	3000 MW	3000 MW	3551 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Lakefield Jct. - Adams Adams - La Crosse La Crosse - Madison	3000 MW		3418 MW Hazleton-Adams 345 Hilltop-N. LAX 345
Maple River - Split Rock Ashley & Broadland Lines Lakefield Jct. – Madison	3000 MW	2861 MW Hazel-Granite Falls 230 Base Case	3805 MW Hilltop-N. LAX 345 ECL-ARP & ARR-SLK 345

Additional sensitivity analysis was performed that investigated simultaneously increasing generation in all the zones being considered. This analysis showed that facilities in and around Sioux Falls, South Dakota will require mitigation prior to significant additional generation delivery. It also showed no occurrence of 500 kV facilities because there is enough incremental generation growth occurring in southwest and southeast Minnesota that the generation in North Dakota is not sufficient to cause the 500 kV line to overload. The Broadland – Brookings County line is not particularly helpful in adding generation capability.

Overall sensitivity analysis findings highlighted some high potential projects that have impacts to multiple zones and may merit resolution sooner. The first is the installation of the La Crosse – Madison 345 kV line which provides significant benefit in all cases. The facilities in and around Sioux Falls, South Dakota at the Split Rock substation will also require upgrades. Most of these improvements are necessary due to terminal equipment limitation s and would be relatively inexpensive to complete.

Study Methodology Insights

One additional finding was that the effective use of market-wide dispatch enables the transmission system to be studied more closely with respect to how it is actually used than traditional study methodology.

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.

D. RES Update Project Descriptions and Cost Estimates

The projects that were investigated are described below. In addition, some results of various cost analyses are also included. As stated previously, the primary concern of this report is to investigate the cost of the transmission upgrades necessary to create additional generation delivery – just one of the three parts of customer cost of adding new generation. The PROMOD analysis results provide an analysis of the cost to produce enough energy to meet the demand in the model. Not included among these costs is consideration of the additional spinning reserves needed to absorb fluctuations in wind generation levels and power purchase agreement costs. This is an important portion of the cost of renewable energy integration that was not examined here.

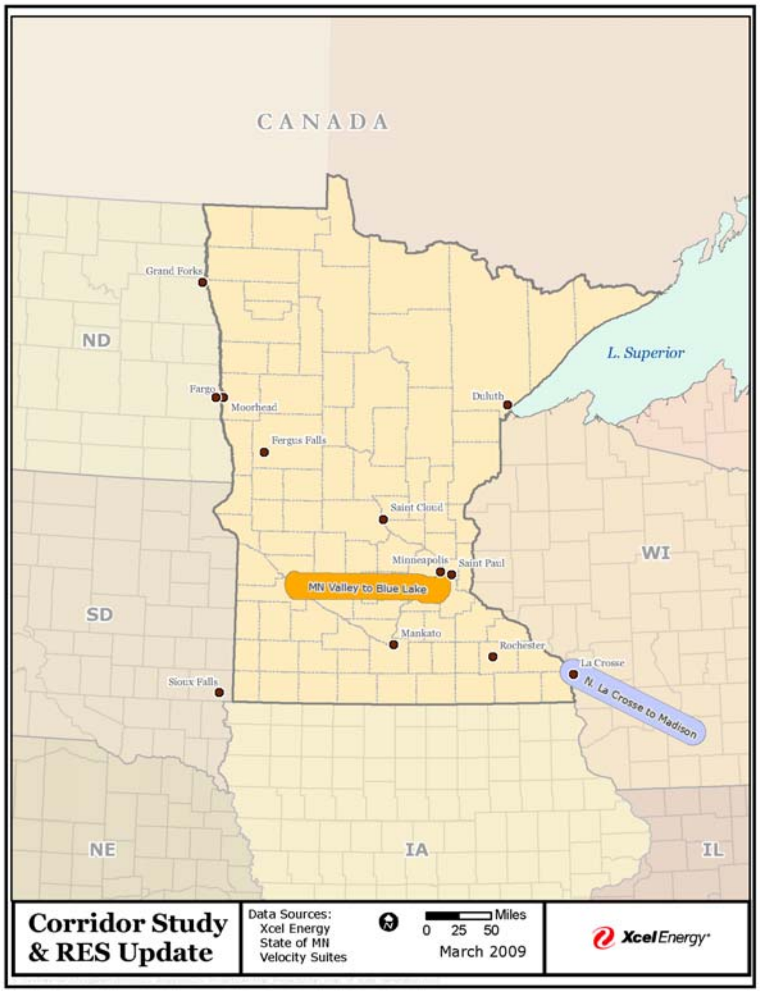
La Crosse – Madison Project

As has been mentioned previously, the La Crosse – Madison project concept is 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 9 - Location of the La Crosse – Madison Project



This project has the reliability benefit of providing a parallel electrical path to the King – Eau Claire – Arpin 345 kV line. Based on the results discussed above, the King – Eau Claire – Arpin line has been shown to limit regional generation delivery.

The total cost of this project is estimated at $350 million. This project estimate is indicative only. A significant amount of the facilities in this estimate are owned and operated by ATC. Because of this, the actual project cost could vary from this number.

Table 9 provides a summary of the costs associated with the La Crosse – Madison project when installed with the preferred Corridor facilities.

Table 8 - Costs for La Crosse - Madison 345 kV Line (Including Corridor Facilities)

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)

The installed cost of the two projects together totals $700 million. Maximizing outlet for these projects (3600 MW) requires an additional $35 million in underlying system upgrades. A complete list of these projects can be found in the Appendices to the Minnesota RES Update Technical Report.

Analyzing these projects in PROMOD demonstrates significant savings in both production cost and load cost over a similar case without the transmission upgrades. The values reflected in the table above represent 70% of the production cost savings and 30% of the load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for analyzing projects. Because the base case included the same generators without the transmission upgrades, the savings reflected above represent savings that are wholly due to the addition of the Corridor Upgrade and the La Crosse – Madison 345 kV line.

The production cost and load cost savings of this project are due to the generation delivery capability across a wide area of the upper Midwest. Keeping the new generation within Minnesota limits the amount of generation that can be produced and generally increases the overall production cost.

In addition to the production and load cost savings, a loss analysis was performed. This resulted in a savings of approximately 43.4 MW. The costs in the table reflect the economic value of those savings over a 40-year period. These savings are created largely due to the off-loading of the constrained King – Eau Claire – Arpin 345 kV line.

Considering these costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $202 million. These costs represent the impact of installing the Corridor Upgrade and the La Crosse – Madison line in tandem. In other words, compared to the post-CapX2020 Group I base case, installing the Corridor Upgrade *and* the La Crosse – Madison project would result in a total net project savings of roughly $295 million.

Comparing the differences between Table 9 and Table 4, the impact of adding the La Crosse – Madison line alone can be determined. This analysis is largely academic, though, as the Corridor Upgrade is necessary in order to achieve a significant increase in generation delivery. Generation throughout southwestern Minnesota and the Dakotas would be constrained by the existing 230 kV Corridor Upgrade unless it is upgraded as recommended in the Corridor Study.

Overall, these results indicate that the $350 million project investment results in new transmission system efficiencies that not only cover the cost of a La Crosse – Madison line but nearly return the full value of its project cost back to the power system in the form of more efficient and less expensive operation.

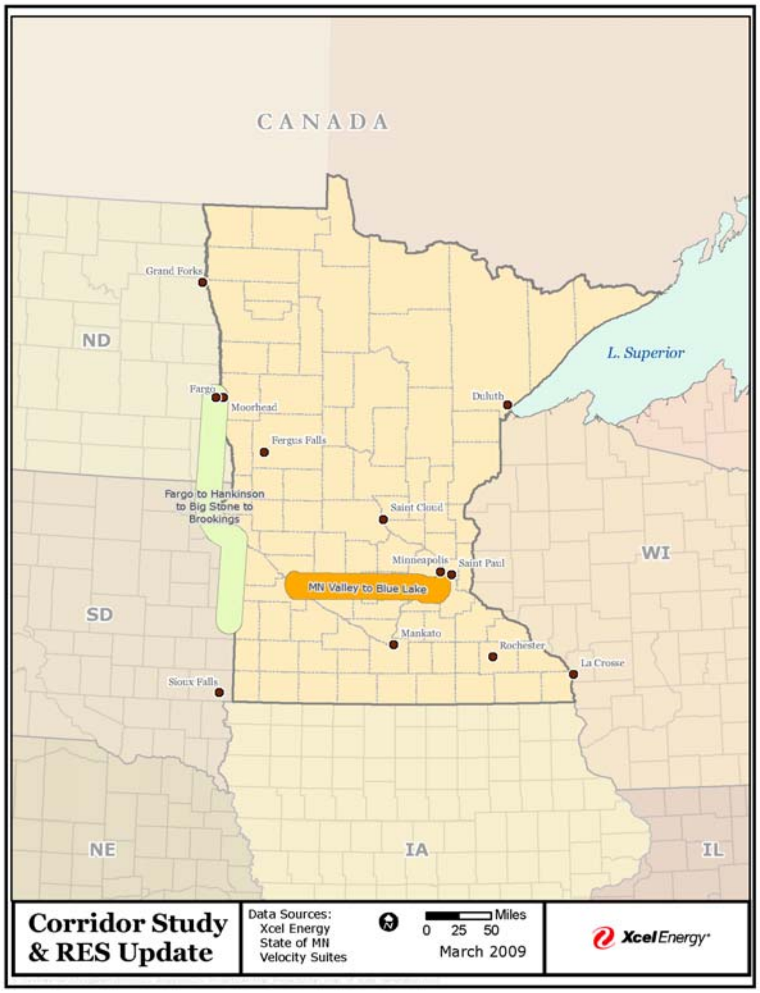
Fargo – Brookings County Project

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 10 - Location of the Fargo – Brookings County Project



Completion of this project would have the benefit of tying together the Twin Cities – Brookings, Twin Cities – Fargo, and Southwest Twin Cities – Granite Falls lines with a large 345 kV backbone. This development would enhance the reliability of these lines by allowing power to transfer more efficiently between them in case of a system contingency.

The total construction cost of this project is estimated at $550 million. This project was analyzed along with a supplemental project, the Ashley – Hankinson project. A detailed cost analysis can be found along with the Ashley – Hankinson project description.

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.

This project is intended to be a supplement to the Fargo – Brookings project, as without the new 345 kV line connecting Fargo with Brookings County, the 345 kV line would dead-end in an already-constrained 230 kV system.

Figure 11 - Location of the Ashley – Hankinson Project

The total cost of the Ashley – Hankinson project is estimated at $175 million.

Table 10 provides a summary of the costs associated with the Fargo – Brookings project and the Ashley Hankinson project when installed together.

Table 9 - Cost of Fargo - Brookings & Ashley Hankinson Projects

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)

The installed cost of the two projects together total $725 million. Maximizing outlet for these projects (1530 MW) requires an additional $45 million in underlying system upgrades. A complete list of these projects can be found in the Appendices to the Minnesota RES Update Technical Report.

Analyzing these projects in PROMOD together with the recommended Corridor Upgrade yields significant savings in both production cost and load cost over an identical case with only the Corridor Upgrade. The values reflected in the table above represent 70% of the total production cost savings and 30% of the total load cost savings. A combination of the two is used to represent the hybrid regulated/deregulated nature of the Midwest ISO market. These proportions are consistent with the Midwest ISO's methods for economic analysis of projects. Because the base case included the Corridor Upgrade, the savings reflected above represent savings that are wholly due to the addition of the Fargo – Brookings and Ashley – Hankinson projects.

The production cost and load cost savings associated with this project are due to the project's ability to unlock the potential for additional wind resources and the alleviation of transmission constraints in North Dakota and western Minnesota.

In addition to the production and load cost savings, a loss analysis was performed. This resulted in a savings of approximately 11.4 MW. The costs in the table reflect the economic value of those savings over a 40-year period.

Taking these costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $12 million.

A key finding of both the Corridor and RES Update Studies is the need to increase the transmission ties between Minnesota and Wisconsin. Combining the Fargo – Brookings and Ashley – Hankinson projects with the La Crosse – Madison project yields additional savings. Table 11 provides a summary of the costs associated with these three projects together.

Table 10 - Cost of Fargo - Brookings & Ashley - Hankinson Projects with La Crosse - Madison 345 kV Line

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)

Addition of the La Crosse – Madison 345 kV line increases the project cost by roughly $350 million and simultaneously reduces the underlying system costs by $15 million.

Significant increases in production cost savings, load cost savings, and loss savings are also realized by adding the La Crosse – Madison 345 kV line.

Another benefit that cannot be easily quantified is the benefit of increasing ties to Wisconsin – doing so enables the system to handle greater quantities of variable generation (such as wind). By enabling greater access to both load and generation in Wisconsin, the La Crosse – Madison line benefits the system in Minnesota, North Dakota, and South Dakota by serving as a buffer to absorb fluctuations in wind generation levels.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is a savings of approximately $58 million. As with the case above, to compare the performance of this scenario with the transmission grid as it would exist post-CapX2020 Group I, simply add the net project cost from this scenario with the net project cost achieved with the Corridor Upgrade in Part E of Section IV.

<u>Brookings – Split Rock Project</u>

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 12 - Location of the Brookings – Split Rock Project

The total cost of the Brookings – Split Rock project is estimated at $250 million. This project was intended as an extension of the Fargo – Brookings project and, from a cost analysis standpoint, was analyzed as such. Table 12 provides a summary of the costs associated with the Brookings – Split Rock line. Note that these benefits are in addition to the Corridor Upgrade and assume the La Crosse – Madison, Fargo – Brookings, and Ashley – Hankinson projects are in service.

Table 11 - Costs for Fargo - Brookings - Split Rock Project with Ashley - Hankinson & La Crosse - Madison

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

The cost of all these upgrades is $1.325 billion and an additional $40 million in underlying system upgrades is needed to achieve the full project outlet (3450 MW). The base case that was used for comparison included the Corridor Upgrade, so the costs reflected above only show the impact of adding the Fargo – Brookings – Split Rock and Ashley – Hankinson projects.

The production cost and load cost savings achieved from the addition of these projects are significant – over $1 billion between the two. In addition, this project achieves the most significant loss savings observed relative to the other Fargo – Brookings – Split Rock projects.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is approximately $145 million.

The most significant benefit to construction of this suite of projects is not financial. The reliability benefit obtained by tying the Twin Cities – Fargo, Twin Cities – Brookings, the Corridor Upgrade, and the Split Rock – Lakefield Junction 345 kV lines together on their western end is significant and cannot be easily quantified through economic analysis. As generation levels increase in Minnesota and the Dakotas, a well designed, robust transmission system will be necessary in order to ensure outlet capability exists for the new generation. In addition, as the stability assessment indicated, significant new transmission additions will be necessary as generation levels eclipse those levels envisioned in the Corridor study.

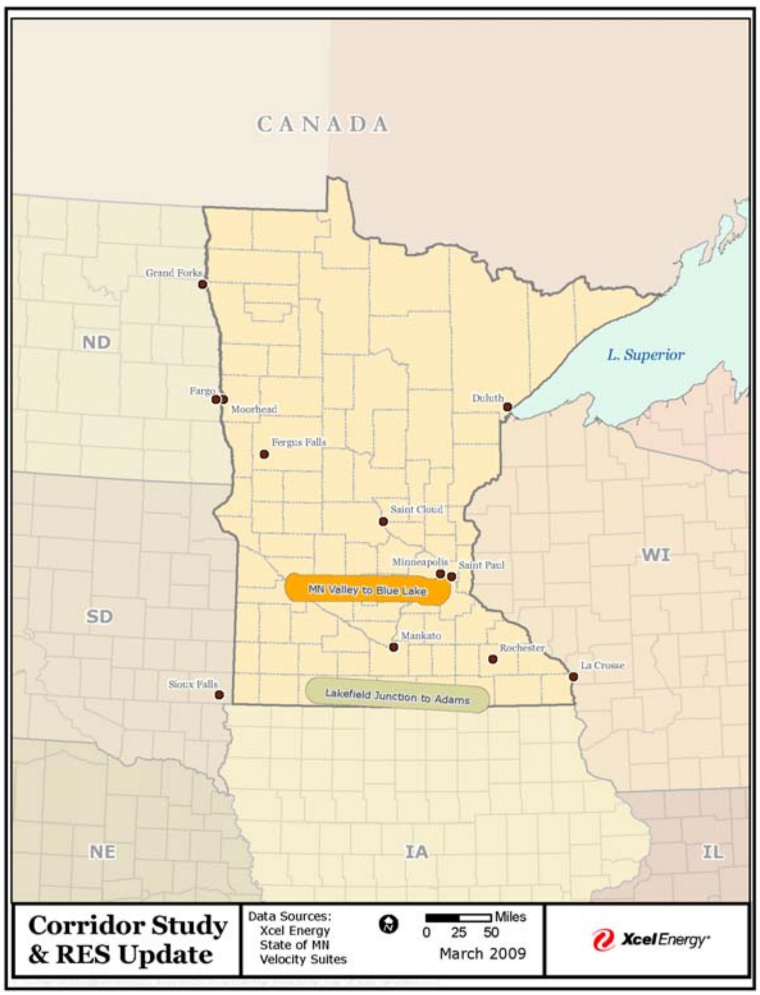
Lakefield – Adams Project

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 13 - Location of the Lakefield – Adams Project



The total cost of this project is estimated at $375 million. This project was analyzed along with the Adams – La Crosse and La Crosse – Madison projects.

A detailed cost analysis can be found along with the Adams – La Crosse project description.

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 14 - Location of the Adams – North La Crosse Project

The total cost of this project is estimated at $300 million. Table 13 provides a summary of the costs associated with the Adams – La Crosse line. Note that these benefits are in addition to the Corridor Upgrade and assume the La Crosse – Madison project is in service.

Table 12 - Cost for Adams - La Crosse Project with La Crosse - Madison Line

Description	*Cost*
Project Cost	$650,000,000
Underlying System Cost	$20,000,000
70% Production Cost Savings (40-year)	($115,000,000)
30% Load Cost Savings (40-year)	($265,000,000)
Loss Savings (40-year)	($167,000,000)
Net Project Cost	$123,000,000

The installed cost of the two projects is approximately $650 million and approximately $20 million of associated system upgrades are necessary to achieve maximum generation delivery (3600 MW).

The production cost and load cost savings achieved with these projects are real, but not as significant as the savings realized by constructing the Fargo – Brookings – Split Rock project. The loss savings are also significant – particularly considering that this case contains less new transmission than the Fargo – Brookings – Split Rock project and still achieves nearly the same level of loss savings. It is worth noting that a significant amount of this savings is due to completion of the La Crosse – Madison project.

Considering all the costs together, the net project cost – taking into account construction costs as well as savings brought about by new efficiencies in the power system is approximately $123 million.

The cost analyses were also performed that added the Lakefield – Adams project to the Adams – La Crosse and La Crosse – Madison projects. Table 14 provides a summary of these costs.

Table 13 - Cost for Lakefield - Adams and Adams - La Crosse Projects with La Crosse - Madison Line

Description	***Cost***
Project Cost	$1,025,000,000
Underlying System Cost	$15,000,000
70% Production Cost Savings (40-year)	($203,000,000)
30% Load Cost Savings (40-year)	($420,000,000)
Loss Savings (40-year)	($225,000,000)
Net Project Cost	$192,000,000

Once again, these results include the Corridor Upgrade as part of the base case, so these costs are indicative of the costs associated with the upgrades named above. Comparing the results of this to the results of the Adams – La Crosse and La Crosse – Madison projects, sharp increases in production cost, load cost, and loss savings are observed. However, the cost increase is not sufficient to offset the cost of the Lakefield – Adams project.

The main benefit to the Lakefield – Adams project is a reliability benefit with some generation delivery associated with it. The existing Lakefield – Adams 161 kV line was primarily designed for load serving and is reaching its capacity. Its upgrade will be necessary in the relatively near future and, from a reliability perspective, it makes sense to tie the southwest Minnesota and southeast Minnesota 345 kV systems together.

Fargo – Split Rock & Lakefield – Madison Projects

The stability assessment performed as part of this study work found that the Fargo – Split Rock and Lakefield – Madison 345 kV lines were necessary to ensure system stability. Given its findings of stability-related concerns at high levels of wind penetration, an analysis of the facilities assumed in the stability assessment was also conducted. Table 15 provides an assessment of the costs associated with those projects.

Table 14 - Costs for Fargo - Split Rock & Lakefield - Madison Projects

Description	***Cost***
Project Cost	$2,000,000,000
Underlying System Cost	$30,000,000
70% Production Cost Savings (40-year)	($500,000,000)
30% Load Cost Savings (40-year)	($791,000,000)
Loss Savings (40-year)	($288,000,000)
Net Project Cost	$451,000,000

With $2 billion in transmission and an additional $30 million in underlying system upgrades, this scenario represents a significant increase in construction cost from the other scenarios analyzed. At the same time, this scenario also demonstrates significant production cost and load cost savings. In addition, nearly $300 million worth of loss savings also provides a significant offset to the cost of the projects.

Despite the increases in production cost, load cost, and loss savings, these projects still represent a net project cost of approximately $451 million.

VI. Corridor Study and RES Update Study Conclusions

A. Corridor Study and RES Update Study Key Results

Upgrade Existing Minnesota Valley – Blue Lake 230 kV line

Both the Corridor Study and the RES Update Study separately confirmed the need for the existing Minnesota Valley – Blue Lake 230 kV line to be upgraded to double-circuit 345 kV. Calling on past study work identifying the Minnesota Valley – Blue Lake 230 kV line as a limiting facility, the Corridor Study independently assessed the most prudent course of action to alleviate this significant system constraint.

As far back as the 825 MW series of projects, the Minnesota Valley – Blue Lake 230 kV line has been viewed as a facility that limits the delivery of energy generated in southwest Minnesota as well as from South Dakota and North

Dakota. The Twin Cities – Brookings line identified the facility as a significant limiter as well. In addition, recent study work focused on identifying projects to increase transfer capability from North Dakota has also identified the Minnesota Valley – Blue Lake 230 kV line as a constraint.

The areas west of the Twin Cities are generally sparsely populated and the transmission grid is, in general, similarly meager. If significant new generation resources are to be developed in locations west of the Twin Cities, from the Buffalo Ridge into North Dakota, upgrade of the Minnesota Valley – Blue Lake 230 kV line to double-circuit 345 kV is necessary. Completion of this upgrade will result in an increase in Buffalo Ridge generation delivery on the order of 2000 MW.

Wisconsin Transmission Limits

In addition to this upgrade, a new high-voltage transmission facility is necessary between La Crosse and eastern Wisconsin to ensure reliable operation and enable full market dispatch of new generation resources. The Corridor and RES Update Studies assumed a termination in the Madison area, but study work is ongoing to determine the precise topology of such a circuit. Southern Minnesota currently only has one high voltage tie between Minnesota and eastern Wisconsin (the King – Eau Claire – Arpin 345 kV line). Together with the Corridor Upgrade, addition of this facility adds as much as 1600 MW of additional capacity to the system - a total of 3600 MW of new generation delivery capability.

The Twin Cities – La Crosse line being pursued as part of the CapX2020 Group I development will bring a new high voltage line to the La Crosse area, but it will not significantly increase bulk transmission ties with other utilities in Wisconsin as it terminates a radial 345 kV line into the 161 kV system in La Crosse.

The La Crosse – Madison 345 kV line is necessary because the King – Eau Claire – Arpin 345 kV line is approaching its operable limit. In the Midwest region, the Midwest ISO operates generators in a market that runs the least-cost units first. Because wind units have no fuel cost, they are typically the first to turn on. This fact, combined with the prevalence of wind within and west of Minnesota, causes a significant west-to-east bias in transmission flow in the region as units in the east are turned down due to their higher cost.

The benefit shown by adding a La Crosse – Madison 345 kV line is consistent with the findings of the Minnesota Wind Integration Study. The Wind Integration Study found that a new 345 kV line stretching into Wisconsin was necessary to enable the Minnesota transmission system to accommodate the levels of wind penetration envisioned in the RES legislation. The Wind Integration Study was one of the inputs considered by the Minnesota legislature when drafting the RES legislation.

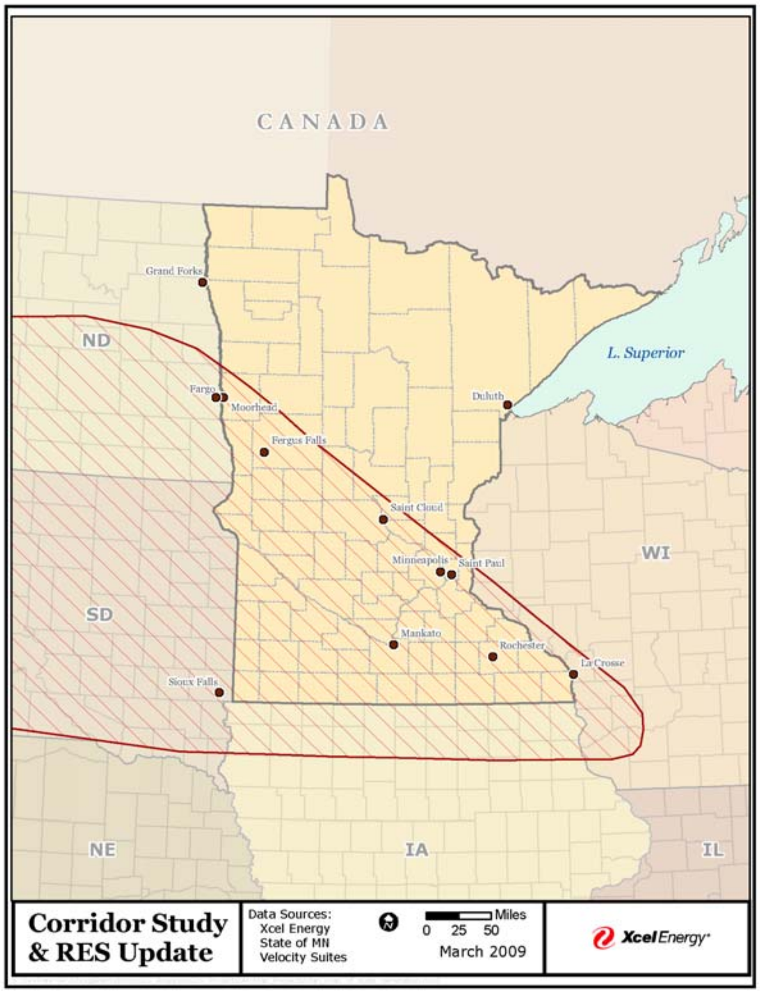
Twin Cities Generation Sink Scenario

Another contributing factor is the Twin Cities generation sink scenario studied in the Corridor Study. Importing approximately 2000 MW of generation into the Twin Cities without additional outlet capacity to the east, as was done in the Corridor Study, required significant Twin Cities generation resources to be turned off. Among these was the Sherburne County generating plant operating at its minimum possible level and the High Bridge, Riverside, and Black Dog plants not in operation at all. This result is significant because any increase beyond 2000 MW will require generation at Sherburne County to be shut down. With its restart time measured in days, this would make Sherburne County unable to respond to fluctuations in demand and wind generation. This scenario is not recommended due to a decrease in reliability that would result.

Constructing a new facility between La Crosse and eastern Wisconsin will result in an increase in reliability and ease the significant operational challenge of absorbing the levels of wind being proposed in Minnesota and the Dakotas. As the levels of generation fluctuate, Minnesota will need to rely on its surrounding states to both import and export power to maintain regional system stability. Establishing stronger ties with eastern Wisconsin is an important part of that effort.

In addition to reliability benefits, study work has shown that constructing a La Crosse – Madison 345 kV circuit in conjunction with the Hazel Creek – Blue Lake 345 kV project could increase generation delivery from the region shown in Figure 15 by as much as 3600 MW.

Figure 15 - Generation Benefit Area for Installation of La Crosse – Madison Project



<u>500 kV Facilities Impact</u>

Much has been made of the occurrence of 500 kV facilities as limits to the ability to interconnect generation in Minnesota and points further west. This study work has shown that the 500 kV facilities remain a significant limitation, particularly for generation delivery from North Dakota. Completion of the Corridor Upgrade in tandem with a La Crosse – Madison 345 kV line reduces the loop flow through the 500 kV system.

Due to the low impedance of the 500 kV system, it acts like a “big hose” and tends to attract power flow from remote locations to it in order to send the power down to the Twin Cities. By installing new bulk transmission ties, the impedance of other parts of the system is reduced, thereby reducing system’s unintended dependence on the 500 kV system. While the La Crosse - Madison line itself does not represent a solution to the 500 kV system loading concerns, it does help defer the 500 kV overloads that limit generation interconnections in the region. As the Manitoba Hydro Transmission Service Request study proceeds and more is known about the future topology of the 500 kV system, a more permanent solution to the 500 kV system loading concerns will be able to be addressed. For the time being, the 500 kV system remains an issue that requires attention in order to enable new generation delivery.

DRG Scenario Results

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 CapX2020 Group I projects. Under a Midwest ISO market dispatch scenario, it was concluded that using DRG projects to meet the 2016 RES milestone was not 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 Midwest ISO market 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 methods by which the Midwest ISO studies and thus approves generation interconnection requests. In addition, this is not indicative of how power is dispatched in the real-time Midwest ISO market. Thus, this wider Twin Cities dispatch simply assumes that 2000 MW of DRG capacity will replace 2000 MW of existing Minnesota capacity under the real-time market dispatch. It is debatable whether adding this amount of new generation without additional bulk transmission and utilizing the unusual dispatch scenario described is realistically feasible. This scenario would result in significant existing generation in Minnesota that could not operate.

The green squares in Figure 5 earlier in this report indicate the locations of DRG substation sites. In all, 42 sites were used in the final analysis. Due to the new transmission facilities in the model being fully subscribed and 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 capacity. 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.[26]

[26] 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

Another locational consideration is the impact that capacity factor will have on the number of wind projects that must be installed to meet the 2016 RES milestone. 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 located in the Twin Cities area are producing less of the time and more turbines would be required to produce an equivalent amount of energy as those in more favorable wind areas. This is important because the investment cost of wind turbines is much greater than the investment cost of transmission on a cost per MW basis.[27]

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 that are larger than 672 MVA, increasing the size of the transformers 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 magnitude 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.

Considering all of these qualifications and while using all of the assumptions noted in this section, the DRG analysis showed that approximately 2000 MW of generation could be modeled using a Twin Cities dispatch.

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

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

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focused on safety, land values, and noise concerns among other issues. The GRE wind turbine was approved, while the Woodbury wind turbine was not.

[27] 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 energy at 25% capacity factor, approximately 2400 MW of wind turbines would be necessary. Information from Windustry for wind generation projects in 2007 indicates installed costs can range from $1.2 million to $2.6 million per MW. At those costs, this extra 400 MW results in an additional cost of $480 million to $1.04 billion.

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.

Stability Assessment Results

An indicative stability assessment was also performed. This assessment confirmed that as load serving utilities 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 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.

The stability assessment performed in conjunction with these studies showed the system behaves normally up to the generation levels envisioned with the Corridor Upgrade. This case includes approximately 4800 MW of wind generation in Minnesota and the adjacent parts of neighboring states.

With additional reactive support installed at numerous locations throughout the system, the system appeared to function normally for the contingencies studied.

With the ultimate proposed system build out, including lines from Fargo to Sioux Falls and on to Madison, is built, the additional 2500 MW of wind generation contemplated caused significant voltage issues under faulted conditions for loss of the King – Eau Claire – Arpin 345 kV line. These issues can be resolved by the addition of a Static Var Compensator (SVC) at Stone Lake or a nearby location.

The most significant stability-related result was a significant occurrence of low voltage transients throughout the region for loss of Sherburne County Unit 3. 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. The increased penetration of wind generators (over 7000 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 Sherburne County Unit 3 were resolved by removing 500 MW of generation at several buses in the system.

At these reduced generation levels, the system was shown to be able to ride through the loss of Sherburne County Unit 3. System voltage fluctuations were still evident, but remained within the limits provided by NERC standards. Voltage violations were still observed for loss of the King – Eau Claire – Arpin 345 kV line. These issues would still be required to be resolved – most likely through the addition of a SVC at Stone Lake Substation.

In general, the message these results portray is that wind penetration beyond the levels studied in connection 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. 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 turning down greater Twin Cities generation to allow the 2000 MW of generation to come online would lower the system's inertia. Replacing large generators capable of absorbing system faults with a number of smaller units that are typically more susceptible to being impacted by faults results in degradation in the general stability of the electric system.

B. Corridor Study and RES Update Study Result Conditions

The generation outlet values reflected in this study represent those obtained from one set of generation assumptions that were developed based on the Midwest ISO interconnection queue. Transmission planning engineers performed significant due diligence to ensure their assumptions were realistic and reflected plausible future generation locations. However, to the extent actual generation development differs from the assumptions in this study, the amount of generation delivery enabled by the projects documented in this study will vary.

Transmission construction costs reflected here represent only one part of the cost to consumers. There are two other very important parts that were not investigated with specificity in the completion of these studies. The costs of actual generation production – the instantaneous fuel cost of the generators running at any given time, have not been examined in detail. In addition, the purchased-power cost of wind generation and other generation types has also not been factored into these studies. This wind integration cost, along with other integration costs, such as the expense of converting generators to run as synchronous condensers or project-specific reactive-control devices, have not been investigated.

Because the load serving utilities in Minnesota are required to supply increasing amounts of renewable energy to their customers, such an examination is largely academic – the issue of import is ensuring sufficient transmission exists to allow those utilities to provide qualifying energy to their customers consistent with the RES milestones.

While an indicative stability assessment was performed that indicated the need for significant reactive capability, this assessment will not replace the need for detailed stability studies in conjunction with system interconnection requests. As locational generation trends develop, a more precise, all-encompassing reactive support strategy will be able to be formed. This study did not attempt to optimize reactive support and merely ensured that, with sufficient reactive support, the system functioned within normal limits.

The costs encompassed in this study are scoping-level only. Detailed project analysis with respect to environmental, routing, and right-of-way costs were not performed. The ultimate cost of any projects pursued as a result of study work will likely differ from the costs reflected in this study. As detailed engineering and environmental examination takes place, more accurate estimates will be developed.

These studies do not replace the generation interconnection queue process. Any proposed generation will need to go through project –specific studies to determine viability.

C. Corridor Study and RES Update Study Next Steps.

A Certificate of Need is anticipated for the recommended upgrade of the Minnesota Valley – Blue Lake 230 kV line. Precise schedule is being determined and project participants are unknown, but study work has consistently shown this facility to be the next constraint to development of future generation resources in Minnesota and North and South Dakota.

A detailed analysis of transmission options for a line segment east of La Crosse, Wisconsin is underway. American Transmission Company (ATC) is leading this study with input from various utilities in the region. Completion of that study will be necessary to document the benefits of each configuration under consideration.

The most significant transmission planning follow-up to this effort will be a detailed review of the transmission facilities that provides a robust system sufficient to facilitate load serving entities' compliance with the 2025 RES milestone. This effort will encompass the results of this study, along with the facilities pursued as a result of it, and look forward using the latest load forecasts, generation performance data, and generation location information.

Definition of Terms

Bus: A physical electrical interface where many transmission devices share the same electric connection. For example, a bus is a point in the transmission grid where transmission lines, transformers and other transmission devices connect at a common location.

Capacity: The load-carrying ability, expressed in megawatts (MW), of generation, transmission or other electrical equipment.

CapX2020: CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service. The new transmission lines will be built in phases designed to meet this increasing demand as well as to support renewable energy expansion.

Conservation: Practice of decreasing the quantity of energy used while achieving a similar outcome. Generally, conservation reduces the energy consumption and energy demand per capita, and thus offsets the growth in energy supply needed to keep up with population growth.

Contingency: An outage of a transmission line, generator or other piece of equipment, which affects the flow of power on the transmission network and impacts other network elements.

Current: The movement or flow of electricity. It can be considered a type of "pressure" that drives electrical charges through a circuit. Current is measured in amperes.

Demand: The amount of electric energy being delivered to or by a system or part of a system at a given instant or averaged over any designated interval of time. Demand is generally expressed in kilowatts (kW) or megawatts (MW).

Direct current (DC): The constant flow of electric charge.

Distribution factor (DF): The percentage or proportion of a transfer that flows across a particular transmission facility. If the distribution factor is associated with a system intact condition, it is typically referred to as a Power Transfer Distribution Factor (PTDF). If the distribution factor is associated with an outage (contingency) condition, it is typically referred to as an Outage Transfer Distribution Factor (OTDF). DFs can be positive, negative or zero.

Double circuit: Two sets of independent circuits with the same beginning and ending points.

Eligible energy technology: (as defined in Minnesota legislation) "Unless otherwise specified in law, 'eligible energy technology' means an energy technology that generates electricity from the following renewable energy sources: (1) solar; (2) wind; (3) hydroelectric with a capacity of less than 100 megawatts; (4) hydrogen, provided that after January 1, 2010, the hydrogen must be generated from the resources listed in this clause; or (5) biomass, which includes, without limitation, landfill gas, an anaerobic digester system, and an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel."

Energy source: Raw materials that are converted to electricity through chemical, mechanical or other means. Energy sources can include coal, gas, water, wind, biomass and solar.

FERC: Federal Energy Regulatory Commission; an independent agency that regulates the interstate transmission of natural gas, oil and electricity.

Generation: The act of converting various forms of energy input (thermal, mechanical, chemical and/or nuclear energy) into electric power. The amount of electric energy produced is usually expressed in kilowatt hours (kWh) or megawatt hours (MWh).

Generation sink: The chosen destination for generation added during a power system study. In order for a power system model to function, the generation in the model must equal the sum of the load and losses in the system. When new generation is studied, generation elsewhere must be turned down to enable the model to handle the new energy.

Grid: The interconnected transmission and distribution networks operated by electrical utilities that deliver electricity to end users.

Heavy loads: High volume of electricity flowing on a line, transformer or other equipment to meet a high demand for electricity, usually during hot weather in this region.

Import/export: Ability of the transmission system to bring power into or out of an area in order to serve load.

Kilovolt (kV): A kilovolt is equal to one thousand volts (V).

Kilowatt (kW): A unit of electrical power equal to one thousand watts.

Kilowatt hour (kWh): One kWh represents the use of one thousands watts of electricity for one hour. Put another way, one kWh equals 10 100-watt light bulbs burning simultaneously for one hour.

Load: All the devices that consume electricity and make up the total demand for power at any given moment or the total power drawn from the system.

Market dispatch: The use of generators in a power system model according to least-cost principles. The most expensive units are those that are turned off first.

Megawatt (MW): A megawatt is equal to one million watts and is enough power to serve the residential demand of approximately 800 to 1000 homes.

Megawatt-hour (MWh): One MWh equals 1 million watt hours.

MHEX: The Manitoba Hydro EXporting (MHEX) is the sum of the flows on the three 230 kV and the 500 kV tie lines that cross the Manitoba and the Minnesota and North Dakota borders.

MRO: The Midwest Reliability Organization is a not-for-profit organization dedicated to ensuring the reliability of the bulk power system in the Midwest part of North America. The MRO is one of eight regional reliability organizations that are part of NERC. The primary focus of MRO is developing and ensuring compliance with regional and international standards and performing assessments of the grid's ability to meet the demands for electricity. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers.

Midwest ISO: Midwest Independent Transmission System Operator; a not-for-profit member-based organization of electric transmission owners, covering a 15 state region from the Dakotas to Pennsylvania. Midwest ISO administers and manages the transmission of electricity within its region.

Midwest ISO Queue: The Midwest ISO interconnection queue is the list of generators interested in obtaining permission to interconnect to the region's electric transmission system.

MWEX: Minnesota-Wisconsin Export (MWEX) is the sum of the flows on the Arrowhead-Stone Lake and the King Eau Claire 345 kV lines.

NDEX: The North Dakota Export (NDEX) is the sum of the flows on 18 lines that make up the "North Dakota Export" Boundary.

NERC: North American Electric Reliability Council is a not-for-profit corporation formed by the electric utility industry following the New York blackout in 1968 to ensure the reliability of the electricity supply in North America. NERC consists of eight Regional Reliability Organizations whose members account for virtually all the electricity supplied in the United States, Canada and the northern portion of

Mexico. NERC's planning standards apply primarily to the bulk electric system, meaning the electric generation resources, transmission lines and interconnections generally operated above 100-kV.

Network: A system of interconnected lines and electrical equipment.

OTDF: The Outage Transfer Distribution Factor (OTDF) is the proportion of the incremental (power) transfer that is observed on the particular facility of interest during an outage of another facility. For example, if a 100 MW source to sink power transfer is simulated during an outage of a facility and the flow on a particular line or transformer increases by 3 MW, the OTDF is reported as 0.03 or 3 percent.

Outage: The unavailability of electrical equipment, possibly as a result of planned for maintenance or unplanned (forced) problems caused by weather or equipment failures.

Phase: One of three elements of a transmission circuit that has a distinct voltage and current. Each phase has maximum and minimum voltage peaks at different times than the other phases.

Power flows: Electricity moving through lines or other equipment.

PTDF: The Power Transfer Distribution Factor (PTDF) is the proportion of the incremental transfer that is observed on the facility of interest. For example, if a 100 MW source to sink power transfer is simulated, and the flow on a transmission facility increases by 2 MW, the PTDF is reported as 0.02 or 2 percent. PTDFs are usually used in reference to system intact conditions.

Rebuild: Removing an existing line and replacing it with a new, higher capacity line.

Reliability: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. It is the ability to deliver uninterrupted electricity to customers on demand and to withstand sudden disturbances such as short circuits or loss of system components.

Renewable resource: A power source that is renewed by nature, such as solar, wind, hydroelectric, geothermal, biomass or similar sources of energy.

SAF: Significantly Affected Facilities (SAF) are those facilities which are overloaded in the base case OR that become overloaded as a result of the new generation AND the new generation causes increased overloading with a Power Transfer Distribution Factor (PTDF) > 5% or an Outage Transfer Distribution Factor (OTDF) > 3%. 3% [DPK: is 3% correct for OTDF?].

Serve load: The ability to reliably deliver the amounts of electricity necessary to match customer needs at any given time.

Single circuit: A circuit with three sets of conductors.

Stability: The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Structures: Towers or poles that support transmission lines.

Substation: A facility that monitors and controls electrical power flows, uses high voltage circuit breakers to protect power lines, and transforms voltage levels to meet the needs of end users.

System planning: The process by which the performance of the electric system is evaluated and future changes and additions to the bulk electric system are determined.

Thermal rating: The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage from overheating or before it violates public safety requirements.

Thermal overloads: Power flows on lines or equipment that exceed their capacity limits.

Transfer capability: The measure of the ability of the interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines between those areas under specified system conditions.

Transformers: Devices that change voltage levels.

Transmission: An interconnected group of lines and equipment for transporting electric energy in bulk on a high voltage power lines between power sources (e.g. power plants) and major substations where the voltage is 'stepped down' for distribution to customers. Transmission is considered to end where the line connects to a distribution station.

Upsized: During the CapX2020 Group I Certificate of Need process, the Applicants responded to pressure to increase the capacity of the lines by proposing to "upsize" the projects. This meant they were proposing to build single-circuit 345 kV lines capable of having a second circuit strung on them. In general, “upsized” CapX2020 Group I lines means lines with the second circuit constructed.

Voltage: The difference in electrical charge between two points in a circuit. In power systems, voltage is generally an indication of the potentisl capacity of a line, Higher voltage lines generally carry power longer distances.

Voltage stability: The system is able to maintain the proper voltages needed to serve load during system faults and other outage conditions.

Watt (W): Unit of power equal to volts x amps.

Watt-hour (Wh): The total amount of energy used in one hour by a device that requires one watt of power for continuous operation.

Wind net annual capacity: This is found by dividing the expected annual energy production of the wind generator by the theoretical maximum energy production if the generator were running at its rated power all year. Net annual capacity factor is commonly expressed as a percentage.

Study Report of Electric Transmission Corridor Upgrade from Granite Falls Area to Southwest Twin Cities

Volume 1

Minnesota Transmission Owners

Principal contributors: Warren Hess; Amanda King

March 2009

Contents.

1: Background & Scope of Study

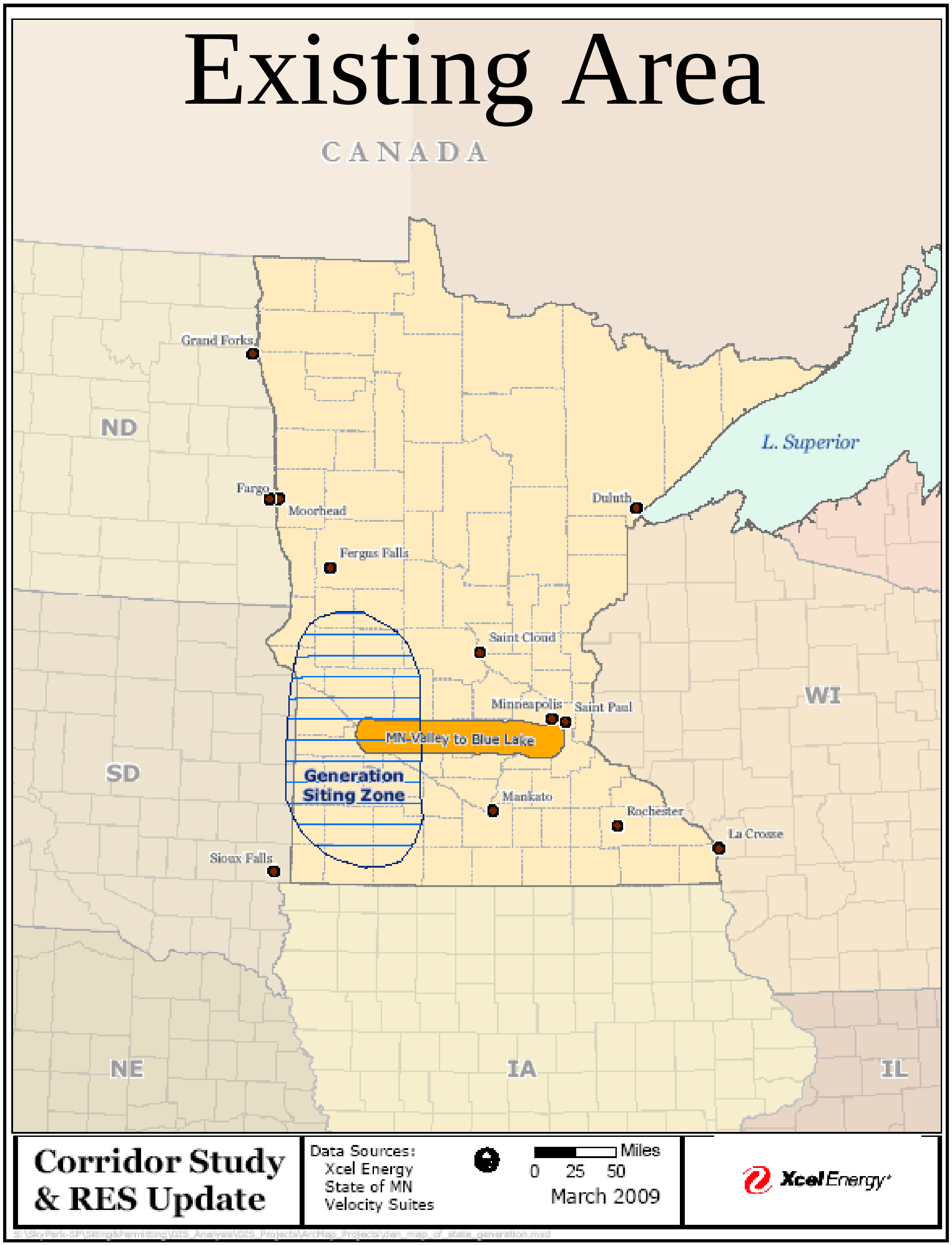
In October 2007, a Work Scope was developed to define the work to be performed by Minnesota utilities to assess the transmission system in the upper Midwest for improvements necessary to develop a robust and reliable transmission system to meet the following three objectives.

(1) Allow regional load-serving utilities to develop generation projects to satisfy the Renewable Energy Standard legislation milestones.
(2) Continue to enable reliable, low-cost energy for our region.
(3) Continue developing a robust and reliable transmission system.

That Work Scope seeks to "optimize delivery of renewable energy to Minnesota retail customers" and to "build upon the analyses that have previously been done or that are in progress".

Speaking to the issue of building upon previous analyses, previous studies have identified a need for more bulk electric transmission capacity in southern Minnesota to carry power eastward from the southwest part of the state. Midwest ISO has performed many such studies during their "Group studies" of their interconnection queue requests seeking interconnection in southwest Minnesota.

Speaking to the issue of optimizing delivery, previous studies have also identified the need to upgrade the 230 kV transmission line corridor from the Granite Falls area to the southwest corner of the Twin Cities metropolitan area. One such study was the study of the "Brookings County-Twin Cities 345 kV line" entitled "Southwest Minnesota-->Twin Cities EHV Development Electric Transmission Study". A map of the study area is shown on the following diagram. The approximate zone for modeled generation is shown in the cross-hatched area, and the corridor for that 230 kV line is highlighted.



Therefore, the scope of the analysis performed as part of the subject of this report, the Corridor Study, was to determine the most effective way to take the first step to open the bulk electric transmission paths heading eastward out of southwest Minnesota and eastern South Dakota. Opening those paths will provide transmission infrastructure necessary to provide a robust and reliable transmission system and help enable Minnesota load-serving utilities to develop generation projects to meet the Renewable Energy Standard law.

Specifically, this study was to determine the facilities needed to provide transmission improvements sufficient to enable Minnesota load-serving entities to meet the 2016 milestones set out in that Renewable Energy Standard law. The main idea in such a study is to determine the best bulk transmission improvement plan under the circumstances. This involves looking at creating transmission to enable a certain amount of delivery from the study generation sources to the study generation sinks. Then the best plan 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; from those totals, a preferred plan can be developed to start 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. As mentioned, in the study of the 345 kV line to be built from Brookings County Substation to Hampton Corner Substation, the 230 kV line from Minnesota Valley Substation to Blue Lake Substation was identified as a limiter to moving generation to Minnesota loads from the southwest Minnesota and eastern South Dakota areas. This presented an opportunity to meet the need for more transmission capacity while using an existing transmission corridor – that 230 kV corridor could be used for a higher capacity transmission line.

A benefit to upgrading the Granite Falls-Twin Cities 230 kV transmission is constructability of future lines will be less difficult. Once that known 230 kV bottleneck is removed, other lines in parallel with that corridor could be taken out of service with less impact to the system. The operational impacts would be lessened; once a new line is in service, lines parallel to the new line can be taken out with less operational risk of blackout. Also, the economic impact is lessened as less generation is likely to need to be curtailed.

Another benefit to upgrading that 230 kV corridor is it gives the bulk electric system in the area a better supporting system for future large developments of 345 kV or 500 kV or 765 kV lines. Given the climate in Minnesota receptive to development of renewable generation, and given the most efficient wind areas are remote from large load centers, a more robust transmission system is needed between the wind areas and the load centers.

As corridors inefficiently used are upgraded to accommodate more robust transmission, the bulk electric system is better able to endure the loss of any of its members without violation of NERC criteria.

The primary options studied were as follow.

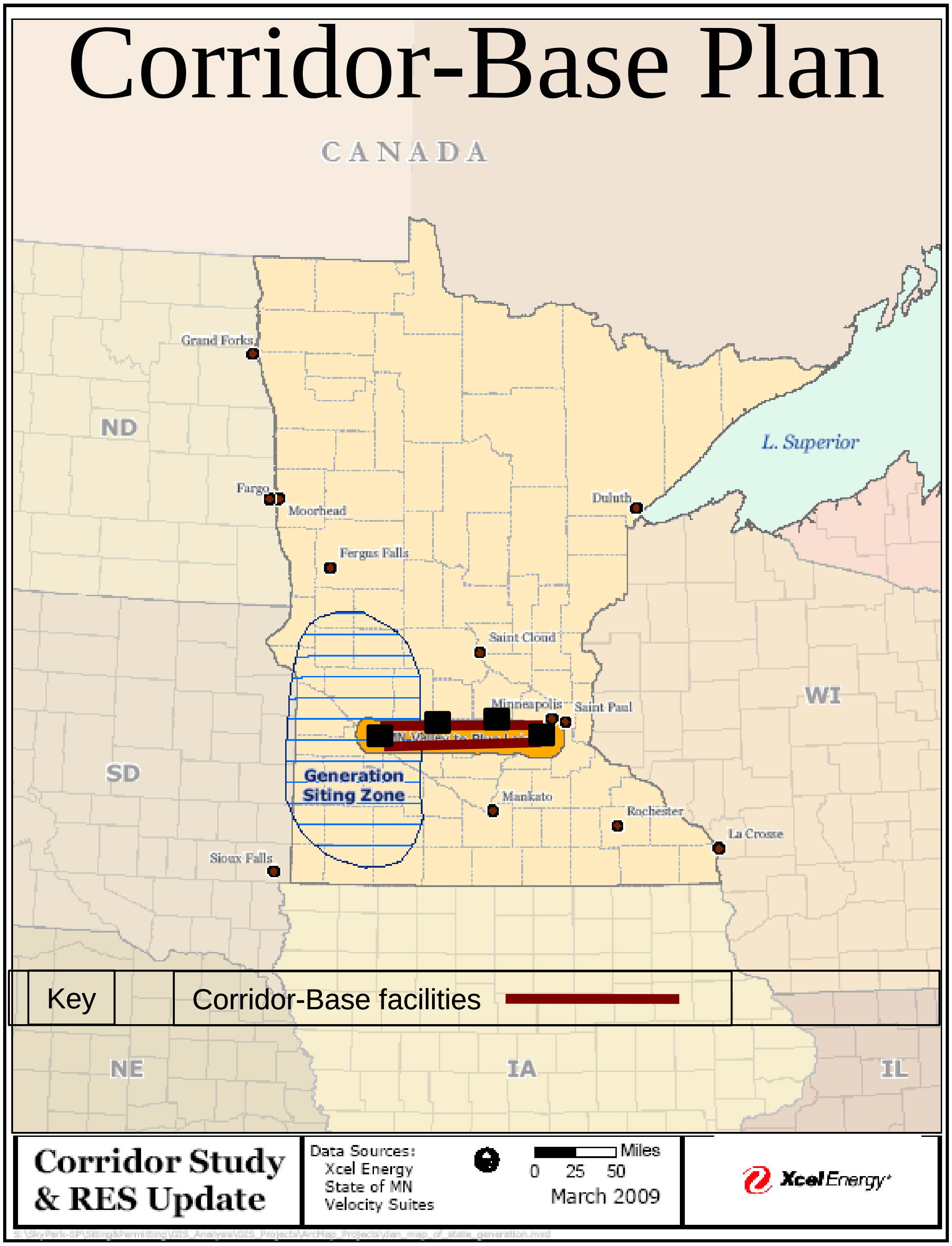
- The option called Corridor-Base (“Double-circuit 345 kV 1 express”) consists of a Hazel Creek-Panther-McLeod-Blue Lake double circuit 345 kV line with one

circuit not tapping Panther or McLeod. With this option, the Minnesota Valley-Panther-McLeod-Blue Lake 230 kV line would be removed to allow that corridor to be put to better use with the double-circuit 345 kV line. The primary benefits of this option are
(1) that 230 kV corridor is used efficiently,
(2) the system losses benefits are good,
(3) a large incremental generation interconnection benefit is achieved while laying the backbone for other area developments.

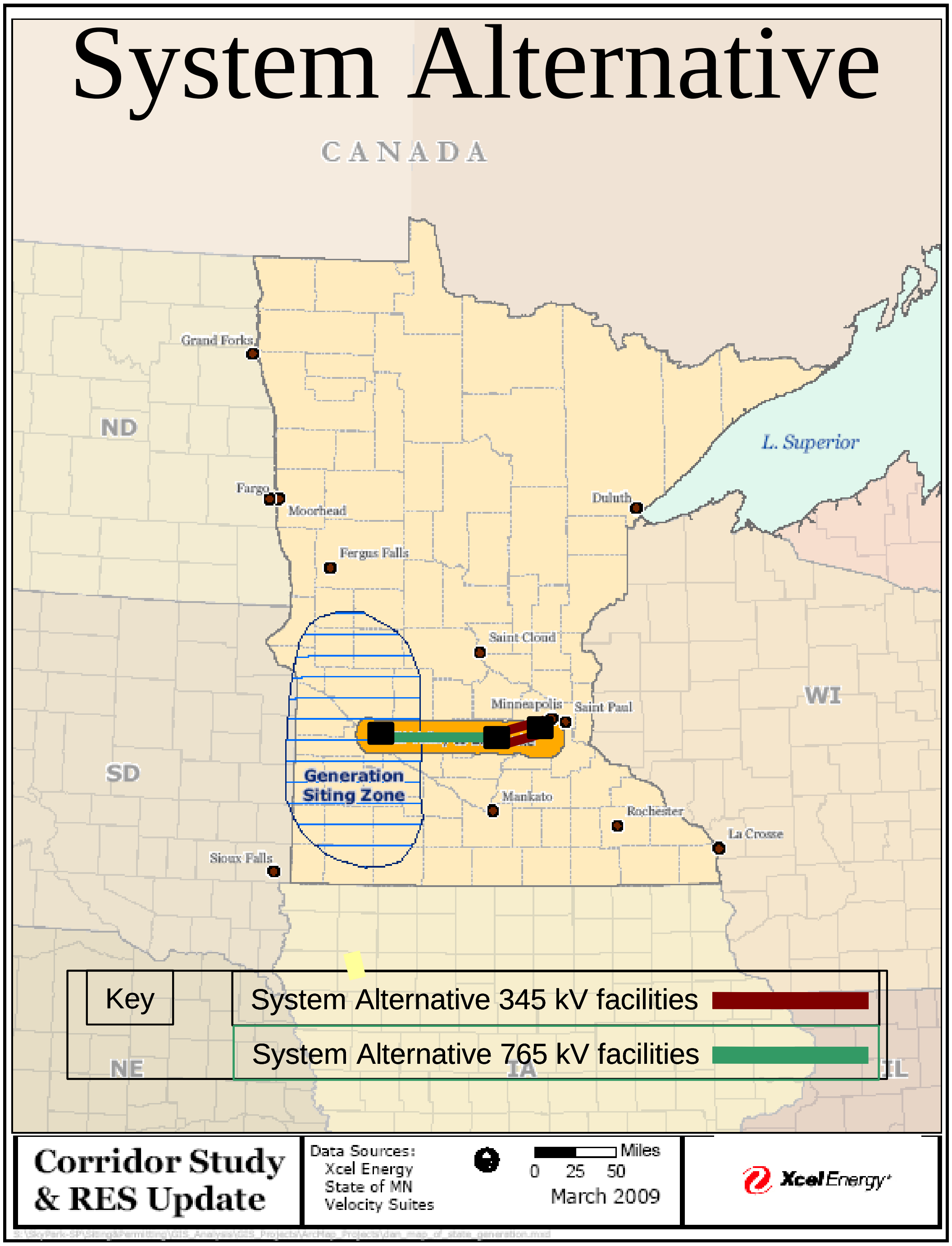
- The option called System Alternative (“765 kV New ROW”) entails a 765 kV line from Hazel Creek to the West Waconia area with a double circuit 345 kV line from West Waconia to Blue Lake. This option has a great benefit if one of the recent proposals for such an area 765 kV development is successfully developed. This option also has the best loss savings. The primary drawback of this option is the cost; as a practical matter, it really has to be part of a larger plan to be viable.
- The option called “Do Nothing” entails only incrementally upgrading transmission as new generation is added in southwest Minnesota and eastern South Dakota. The primary drawbacks of this are as follow.
  (1) The transmission corridors are not used efficiently.
  (2) The system MW losses are high, so additional generation has to be built to compensate for those losses.
  (3) The administrative and engineering work can be onerous and delay generation interconnections since so many facilities are involved.
  (4) There is no large incremental benefit to the system from one or a few new facilities.
  (5) This option does not create the framework for supporting the large interest in interconnecting substantial additional generation in the study area.

2: Conclusions & Recommended Plan

From the discussion of benefits and drawbacks above, the recommended plan is the “Double-circuit 345 kV 1 express” option also referred to as “Corridor-Base”. The Corridor-Base option also is seen to be the least-cost option based on the total evaluated cost elsewhere in this report. A diagram of that plan is shown in the following picture.



A map of the System Alternative is shown in the following diagram.



3: 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.

Parties to Work Scope
Basin Electric Power Cooperative
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
Heartland Consumers Power District
Great River Energy
Interstate Power & Light Company
Minnesota Municipal Power Agency
Missouri River Energy Services
Northern States Power Company d/b/a Xcel Energy
Otter Tail Power Company
Rochester Public Utilities
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 and 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 study. The study was a very public study due to the many interested stakeholders. 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 good models. The model building was largely done by April 2008.

In March 2008, planning for the Certificate of Need began. A related issue is determining the scheduling of construction and the interaction between the proposed Corridor Study facilities and the existing facilities – both generation and transmission; 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 Northern-MAPP Sub-regional Planning Group (NM-SPG) meeting in Duluth Minnesota.

A group called the Technical Review Committee (TRC) was created. Meetings of that 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 of those meetings, the status and findings of this study were presented.

4: Analysis

4.1: NERC Criteria

Transmission Planning Engineers are required to meet the needs of the stakeholders in the electric transmission system while adhering to all reliability criteria established and enforced by the North American Electric Reliability Corporation – “NERC”. 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 being monitored and changed as deemed necessary to avoid large outages and blackouts; most often, the criteria are made more rigorous as engineers learn better ways to ensure reliability of the transmission system. The criteria most applicable to transmission planning are listed in the Appendix showing NERC criteria.

4.2: Models employed

4.2.1: Steady State models

The base models used for the steady-state (powerflow) 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 Plans (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 United States “Interconnect”,
- they are being used for other similar studies (the “DRG” study, for one),
- they are well documented and well understood.

4.2.2: Dynamics models

The base models used for the dynamic analysis are from the “NORDAGS” group 1 models. The reasons for choosing these models are as follow.

- They align with the study timeframe of the year 2016.
- They are compatible with the NMORWG stability package widely used in Midwest Reliability Organization and Mid-Continent Area Power Pool (MAPP) studies in the Minnesota area.
- They are built from the same base operating model as used in the NMORWG package.
- They have been used in other recent studies (the “NORDAGS” study, for one).
- They have been extensively reviewed and documented.

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 the end of year 2015. This timing is due to the desire to have added transfer capability to support load-serving entities' efforts to satisfy the State of Minnesota's Renewable Energy Standard for the entire year 2016. Therefore, the year 2016 was chosen as the year to study.

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 not Conservation Improvement Program. In the off-peak case, the load level chosen from a Midwest ISO analysis of highest line loading was 61.2%; the load levels were 61% of those in the peak model. The below table shows the control areas included in the Study Area.

Study Area control areas for load scaling.	
Model Area number	**Area name**
331	Alliant West
600	Northern States Power
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 new generation sources are listed in the following table. At this time it is unclear and unknown whether the Big Stone II generation and transmission projects will be completed. The study team dealt with the ambiguity of the Big Stone II project by studying the situation without the Big Stone II generation and transmission facilities in place. The reason for the non-round amounts is originally 300 MW of generation source was included at Big Stone. Thus, that 300 MW was distributed over the following buses on a pro-rata basis relative to their original generation amounts.

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

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

BRIGO	**MW Additional**
Fenton	187.5
Yankee	187.5
TOTAL	**375**
RIGO	**MW Additional**
Pleasant Valley	722
TOTAL	**722**
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. Those transfers 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, that 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 *Appendi*x 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 Outlet (RIGO) study were included; this includes approximately 700 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. 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 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 caused the system-intact voltage at Arpin to be below .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 such 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 under contingency there was very low without those capacitors.

Big Stone II generation and transmission were not included in the models used to arrive at the conclusions and recommendations stated in this report. 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.

An initial analysis was done with Big Stone II generation in the models. However, as the ambiguity of the Big Stone II project grew, the study team dealt with that ambiguity by doing the remainder of the analysis without the Big Stone II generation and transmission facilities modeled. With approximately 1000 MW of requests in the Midwest ISO interconnection queue near Big Stone, this sensitivity analysis with a 345 kV line extended to Big Stone Substation was thought prudent. This sensitivity analysis included the Big Stone II generation plus an additional 300 MW of generation; the transmission modeled was a double-circuit 345 kV line from Big Stone to Hazel Creek. The Big Stone II partners' transmission options were not modeled.

The key outcome from this decision was the analysis showed no necessity for the Corridor Study options to extend to Big Stone Substation to enable Minnesota's load-serving utilities to meet the 2016 Renewable Energy Standard milestone regardless of the status of the Big Stone II generation and transmission facilities (assuming the Big Stone II development partners build enough transmission to meet their delivery obligations without need of the Corridor Study facilities). In fact, the presence or absence of the Big Stone II generation with its transmission did not materially impact this study's conclusions or the benefits of this study's recommended plan (the Corridor-Base option) to serving Minnesota load and generation needs and meeting the 2016 Renewable Energy Standard milestone.

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' new generation plans and existing generation not running in the models. The table below shows those replacement power sources.

The following table summarizes the models used.

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
IA wind	770	
MB wind	0	
MN wind (prior to study generation)	2582	
ND wind	411	
NE wind	0	
SD wind	160	
WI wind	95	
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 Outlet (RIGO) study were included; this includes approximately 700 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.	
Source Locations	Nobles County 345 kV; Brookings County 345 kV; Fenton 34.5 kV; Yankee 34.5 kV; Lyon County 345 kV; Granite Falls 230 kV; Morris 230 kV	
Sink Locations	Twin Cities generation	
Steady- State Analysis	See section 5.1.	
Stability Analysis	See section 5.2.	
Voltage Analysis	See sections 5.1 and 5.2.	
Losses Analysis	See sections 5.5 and 5.6.	

4.3.2: Steady state contingencies modeled

The contingency list used was produced by the Midwest Reliability Organization; it contains the complex NERC Category B and Category C contingencies commonly used for bulk transmission studies in the Minnesota area. A list of those complex contingencies is in the Appendix showing Complex Contingencies. The following table shows the control areas used for taking contingencies; all 100 kV and above branches (transformers and transmission lines) were taken as contingencies one at a time. Also all the generators in those areas were taken off line one at a time, and all the 100 kV and above ties from those areas were taken as contingencies one at a time.

Contingency areas.	
Model 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	Northern States Power
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

4.3.3: Twin Cities sink assumption benefits and drawbacks

The primary benefit to using the Twin Cities as a sink is the study participants can better assure sufficient transmission exists to facilitate load-serving entities' efforts to meet the Renewable Energy Standard law. The primary drawback is possibly spending time and money on unnecessary facilities.

Original screening analyses used the greater Midwest ISO footprint generators as the sink. This is the way the generation and transmission system works absent transmission constraints. However, because of transmission constraints at some times of the year, reservations on constrained interfaces do not allow some amounts of generation to be delivered east out of Minnesota.

In particular, the Minnesota-Wisconsin Export Interface, often referred to as "MWEX", may at times in the future be loaded to its limit of 1525 MW. This was, in fact, the base assumption in the off-peak models used for this study. This assumption is based on the fact the new generation sources used in this study could, in fact, be last in line to sell to the east out of Minnesota; this could happen if other entities make reservations on the MWEX interface before the new sources can do so. As noted previously, for purposes of this study that generation was assumed to be wind generation. In that case, since wind generation has a 0 $/MWh variable cost, the wind generation would still run based on Midwest ISO's dispatch of low-variable-cost units first, but other generation would have to back down or shut off to make room for that wind generation; since Great River Energy and Xcel Energy are expected to make most use of new generation sources in the generation source area studied (other load serving entities in Minnesota generally appear to have plans to meet their renewable energy standards obligations with generation in northern Minnesota, North Dakota, or very close to their headquarters), it made most sense to use Twin Cities generation as the sink.

The alternative to using Twin Cities-area generation as the sink would be to assume a new high-capacity transmission line and associated reactive-support facilities would be added to allow more delivery of energy from Minnesota to eastern Wisconsin and beyond by 2016. Though studies of such a line have been initiated and are being led by American Transmission Company in Wisconsin, there are no guarantees such a line will be studied, developed, and constructed prior to 2016, so the study participants decided it was best to establish a plan based wholly on issues within their control.

Decreasing the Twin Cities generation causes the need for more 345/115 transformation in the Twin Cities area; much of the generation is connected to the 115 kV buses to serve the 115 kV loads directly. If that generation is decreased in favor of remote generation, the remote generation tends to travel to the Twin Cities on the 345 kV system and then increase the flow through the 345/115 transformers to get to the area load.

Decreasing so much Twin Cities generation also disrupts the way the system has been designed, so area transmission lines may also need to be upgraded.

Another possible facility need in such a generation pattern is reactive support devices to keep voltages within criteria. Most generators, including all the Twin Cities generators, have reactive voltage support capability in addition to their ability to produce real power near the load to decrease reactive losses to serve that load. But if such a generator is off, both the real and reactive voltage support benefits are lost. If the assumption for the Twin Cities is the urban generators will be off much of the time, then voltage support devices (capacitors and static-VAr compensators [SVCs]) will be specified.

The primary drawback, therefore, to using the Twin Cities generators as a sink is the possibility of overestimating the real facility needs. The transformers and lines and voltage support devices may be specified as being needed based on the assumption there will be no reliable path to deliver generation to the Midwest ISO-wide footprint. But if a line is built across Wisconsin to allow delivery to that greater footprint, the Twin Cities facilities may be somewhat overbuilt. (Even if a line across Wisconsin is built creating a high capacity path to the Midwest ISO-wide footprint, the Twin Cities support facilities will be useful and will provide a robust and reliable system for the long-term growth in this metropolitan area. In fact, some of the Twin Cities facilities identified in this study as needing upgrade have also been seen in other studies to need upgrade in the coming years.)

4.3.4: Distribution Factor Cutoff

For purposes of screening the overloaded branch results, no branch was included as needing remedy if the portion of the 2000 MW of new study generation flowing on that branch was less than 3% (60 MW) for both system-intact and outage conditions. In other words, the power transfer distribution factor (PTDF) cutoff was 3%.

As was the case in the CapX 2020 initiative, the “underlying-system” facilities resulting simply from adding the new transmission were investigated as part of this analysis. That will require further study.

4.4: Options evaluated

The types of transmission lines studied for the 230 kV corridor from the Granite Falls area to the Shakopee area are

- double-circuit 345 kV replacing the 230 kV line and
- single-circuit 765 kV alongside the 230 kV line.

The basis for selecting these types to study is as follows.

- A great amount of bulk electric transmission capacity is needed in the corridors between southwest Minnesota and the southeastern quadrant of Minnesota; therefore, the second circuit of a double-circuit 345 kV will be used and useful.
- The use of a voltage class lower than 345 kV would not provide sufficient capacity.
- The use of 500 kV does not lend itself to double-circuit construction due to the long clearances needed at that voltage class.
- A single 500 kV line with its associated 500/345 transformers performs approximately the same as a double-circuit 345 kV line.
- Single-circuit 345 kV lines do not make good use of the rights-of-way. Adding a second circuit to a 345 kV line adds only 50-to-70% of the cost of the first circuit, so the second circuit comes at a significant discount.
- It is impractical to convert to 765 kV the 230 kV substations along that 230 kV line.
- The 765 kV voltage class is consistent with recent proposals by area stakeholders such as Midwest ISO. It was thought if one such spur were built, it could be integrated into future 765 kV transmission in the area.

Each of the improvement options was studied under both peak and off-peak conditions.

4.4.1: Primary option

The primary option evaluated was called “Corridor-Base” and entails a Hazel Creek-Panther-McLeod-Blue Lake double-circuit 345 kV line to replace the 230 kV line along that corridor. In this option, the chief configuration studied involved only tapping one of those double-circuit 345 kV lines at McLeod and Panther and leaving the other 345 kV circuit as an “express” circuit from Hazel Creek to Blue Lake. The main reason for configuring the option this way is to save costs for circuit breakers at McLeod and Panther. This option still provides the high-voltage sources to McLeod and Panther, but does not result in unnecessary facilities.

4.4.2: System Alternative

The System Alternative entails building a 765 kV line from Hazel Creek Substation to West Waconia Substation with 765/345 transformers at each of those substations and a double-circuit 345 kV line from West Waconia to Blue Lake Substation.

Adding conductors to each phase can increase the surge impedance loading of a line. The high-surge impedance loading line is attractive due to its lower impedance and concomitant higher loading along with its tight width allowing a double circuit of such a line to exist in approximately the same right of way as a traditional single circuit line of the same voltage class.

4.5: Selection of termini and intermediate connection points

Due to the past study work showing the Granite Falls-Shakopee 230 kV line to be a limiter to further southwest Minnesota generation delivery, the termini and connection points for all the options in this study centered around that corridor.

For the Corridor-Base option, 345 kV class developments were chosen. Due to the difficulty expanding Minnesota Valley Substation to accommodate 345 kV equipment, Hazel Creek was chosen as the initial terminus of this option. Since the idea was to better use the Granite Falls-Shakopee 230 kV corridor, this option involved removing that 230 kV line and replacing it with a double-circuit 345 kV line. Given that decision, the sources for the intermediate substations along that line – Panther and McLeod – needed to be maintained, so step-down transformers were added – 345/69 at Panther and 345/115 at McLeod.

The plan now is also to only bring one of the 345 kV circuits of the double-circuit line into Panther and McLeod. This maintains at least as good reliability to Panther and McLeod as they would have being served at 230 kV, and it avoids circuit breakers needed if both circuits went in and out of each of those substations.

Speaking to reliability to McLeod and Panther, the following table shows the outage rates compiled by Xcel Energy for varying voltage classes; as can be seen, serving Panther and McLeod at 345 kV is expected to cut their outage rates in half.

Voltage	Outage rate
69 kV Line	8.00%
115 kV Line	4.00%
161 kV Line	3.50%
230 kV Line	2.00%
345 kV line	1.00%

On the Twin Cities end, the existing 230 kV line terminates at Blue Lake Substation in Shakopee. Investigations by Substation Engineering and Transmission Engineering confirmed there is enough room for the two new 345 kV lines both to get into the substation (Transmission Engineering's expertise) and to terminate in the substation with proper protection (Substation Engineering's expertise). Blue Lake, then, is the logical east-end terminus for the Corridor-Base plan.

For the System Alternative option, again Minnesota Valley does not have sufficient room to accommodate a new extra-high-voltage yard. So Hazel Creek is again the logical west terminus. But from that point, the System Alternative departs from the Corridor-Base option.

In the System Alternative option, the 765 kV line is envisioned to run alongside the existing Granite Falls-Shakopee 230 kV line. This was done for the following two reasons.

- The development of generator outlet transmission is often best done on new corridors. This is due to the fact generator outlet is usually best done at very high voltage classes if it is for large generation additions. Given the very high voltage class, it is generally not feasible to use an existing lower-voltage corridor and convert all the transformers along the way to the higher voltage class. Then the very high-voltage transmission can serve as generator outlet while the lower-voltage lines continue to serve load.
- It is expensive to develop a 765 kV yard at a substation. By not converting Panther and McLeod away from their 230 kV service, those costs are avoided.

The System Alternative option also includes a 765/345 substation at or near the existing West Waconia 115 kV substation. It is impractical to bring a 765 kV line all the way to Blue Lake. From West Waconia a double-circuit 345 kV line would be build to Blue Lake, since Blue Lake is the nearest existing 345 kV station.

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 AC contingency analysis in PSS/E. Due to the use of primarily Twin Cities generation as sinks, much internal Twin Cities generation had to be shut off. As generation like this is turned off in a large load center like the Twin Cities, there is concern of low voltage due to the loss of the generators' voltage support and the increased reactive losses from serving the load from a great distance. Some studies use as their sink a much wider footprint of generators; this allows fewer generators in any one area to be shut off, so no area is likely to experience voltage issues; in such an analysis, the DC contingency analysis suffices. But this study could not use that faster form of analysis.

The below table shows the areas monitored for violations. Branches 69 kV and above in those areas and emanating from those areas were monitored for overload. Also, voltages on buses 100 kV and above in those areas were monitored.

Control Areas monitored.	
Model 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
672	SaskPower
680	Dairyland Power Cooperative

4.6.2: Dynamics

The primary method of analysis of the dynamic performance of the Corridor Study options was the use of PSS/E's dynamic simulation routines.

5: Results of detailed analyses

5.1: Powerflow (system intact & contingency)

In planning most any bulk electric transmission improvement, the facilities needing to be installed are the base project facilities and the “underlying system” facilities. The base project facilities are the facilities directly associated with the bulk improvement, and the underlying-system facilities are those facilities affected by either the installation of the base-project facilities or the future use of the base-project facilities.

Using a road analogy, if a large interstate is extended into a metropolitan business district, the base project facilities would be the interstate freeway extension, and the underlying-system facilities would be new lanes and signage in the business district necessary to accommodate the increased traffic at the point of intersection of the new freeway extension.

There are generally three types of underlying facilities.

- There are thermal underlying facilities; these facilities are needed to alleviate overloads on the power system due to the installation of the base-project facilities or to the increased loading allowed after the base-project facilities are in place. In the case of this study, the increased loading is due to the 2000 MW of study source generation being transferred to the Twin Cities area. These thermal underlying facilities are generally needed to alleviate overload of facilities of lower voltage class (69 kV & 115 kV) than the base-project facilities (345 kV or 765 kV), but some such facilities could be in the 345 kV class.
- Reactive support underlying facilities are required to either increase or decrease the voltage at given substation buses once the base-project facilities are installed. The base-project facilities can cause increased power flow on some facilities resulting in depressed voltage; this causes the need to install voltage-support facilities. The base-project facilities can also decrease the power flow in some areas, and this may cause high voltages; therefore, facilities to decrease the voltage (reactors) may need to be installed.
- In some studies, facilities to alleviate constrained interface flows may be needed. In this study, no such needs were found.

5.1.1: Corridor-Base Underlying Thermal Facilities

For the Corridor-Base option, the base-project facilities are the double circuit 345 kV line and the 345 kV transformers and 345 kV substation work connected to that line. The following table estimates the total installed costs of the underlying-system facilities for the Corridor Base option. These underlying-system facilities are those required to be installed to achieve 2000 MW of transfer of new study generation to the Twin Cities. This table has removed from it any double-counted facilities as listed in the Corridor-Base options in the Appendix showing the FCITC Branch results. The shaded rows in the below table show facilities required only due to this study using the Twin Cities as the sink. The total for those rows is approximately 71 M$; this leaves approximately 39 M$ for underlying facilities not related to the sink.

Table 5.1b: Corridor Base Underlying Facilities required for 2000 MW new study generation

Facility	contingency	remedy	Rating required for desired FCITC	rating achieved/ MVA	cost/ $	FCITC
Eden Prairie 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	698.6	773	8920000	-2132
Eden Prairie 345/115 10	60262 EDEN PR3 345 60263 EDEN PR7 115 9	replace with 345/115 672 MVA transformer	638.1	773	8920000	-1787
Red Rock 345/115 10	NSP STK 8P23 BKR RED ROCK	replace with 345/115 672 MVA transformer	738.9	773	8920000	-1541
Parkers Lake 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	594.4	773	8920000	-1105
Blue Lake 345/115 9	705 1	replace with 345/115 672 MVA transformer	501.6	773	8920000	-836
Parkers Lake 345/115 10	60233 PARKERS3 345 61490 PKLMID1Y 110 9	replace with 345/115 672 MVA transformer	568.6	773	8920000	-455
Sheyenne-Fargo 230 kV	63369 JAMESTN3 345 66791 CENTER 3 345 1	reconductor 230 kV 795 ACSS	475.1	687	1221200	-409
Brookings County 345/115 1	60382 BRKNGCO7 115 60383 BRKNGCO3 345 2	replace with 345/115 672 MVA transformer	700.3	773	8920000	-120
Brookings County 345/115 2	60382 BRKNGCO7 115 60383 BRKNGCO3 345 1	replace with 345/115 672 MVA transformer	700.3	773	8920000	-120
Goose Lake-Vadnais Tap 115 kV	917 1	rebuild 115 kV line 350 MVA	266.3	350	741960	655
Kohlman Lake 345/115 10	KOL-CNC/TER	existing 515 MVA rating is sufficient	502.2	515	0	763
Edina-Saint Louis Park 115 kV	960	rebuild 115 kV line 390 MVA & switch at EDA	305	368	78800	814
Split Rock A-White 345 kV	60383 BRKNGCO3 345 60500 LYON CO3 345 C1	change relay settings SPK-WHT (O&M)	946.6	1643	0	826
Wilmarth-Eastwood 115 kV	60110 WILMART7 115 60380 SUMMIT 115 1	reconductor 115 kV 795 ACSS	253.6	349.8	73080	848
Edina-Eden Prairie 115 kV	NSP WESTGATE	replace 2 115 kV breakers & disconnect switch all 3000A at EDA	552.1	598	465000	866
Air Lake-Lake Marion 115 kV	NSP STK 8P23 BKR RED ROCK	replace 2 115 kV CTs & a disconnect switch all 2000A	277.9	308	73000	944
Minnesota Valley-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	already upgraded	207.5	239	0	984
Franklin-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	will be 795 ACSS after BRIGO	202.4	350	0	1028
Lexington-Vadnais Tap 115 kV	917 1	reconductor 115 kV 795 ACSS	246.4	349.8	1221480	1109
Grant County-Morris 115 kV	510	reconductor 115 kV 266 ACSS	134.9	138.6	6439500	1117
Hutchinson Muni-Hutchinson 3M 115 kV	MCLBLLHZLBLL	reconductor 115 kV 636 ACSS	205.1	292.6	195320	1122
Prairie Island 345/161 10	PRI-RRK-DBL	replace with 345/161 672 MVA transformer	272.6	773	8920000	1154
Council Creek-Council Creek DPC 69 kV	ASK-ARP	Fixed by MOC-COC 161 kV	144.1	9999	0	1161
West Faribault-Loon Lake Tap 115 kV	CAPX6	good for 239 MVA	197.5	239	0	1196
McLeod-Hutchinson 3M 115 kV	MCLBLLHZLBLL	reconductor 115 kV 795 ACSS	223.1	349.8	1359810	1336
Aldrich-Fifth Street 115 kV	917 1	FST bus & 2 switches	243.3	276	95000	1345
Mount Vernon-Bertram 161 kV	34126 MQOKETA5 161 34127 WYOMING5 161 1	reconductor 161 kV 636 ACSS	279.8	410.3	2337500	1369
NIW-Lime Creek 161 kV	Byron-PL Valley + PL Valley-Adams	reconductor 161 kV 477 ACSS	231.6	338.8	135000	1378
Blue Lake-Eden Prairie 345 kV	NSP STK 8M26 BKR BLUE LAKE	reconductor 345 kV 2x795 ACSS	1325.7	2088	3256000	1403
Stinson phase shifter	ASK-ARP	solution error	249.7	9999	0	1443
Hazel Creek 345/230 2	60507 HAZEL 3 345 60508 HAZEL 4 230 C1	install larger unit	375.9	772.8	0	1493
Hazel Creek 345/230 1	60507 HAZEL 3 345 60508 HAZEL 4 230 C2	install larger unit	375.9	772.8	0	1493
Wheaton-Elk Mound 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	330.1	434	1022400	1542
Wheaton-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	330	434	0	1543
Eau Claire-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	328.2	434	0	1564
Parkers Lake-Basset Creek 115 kV	917 1	rebuild 115 kV 2x795 ACSS	426.2	598	1252800	1592
High Bridge-Rogers Lake 115 kV	917 1	replace 115 kV wavetrap with 3000 A unit on HBR-RLK	431.2	598	125000	1624
Ravenna-Spring Creek 161 kV	PRI-RRK-DBL	reconductor 161 kV 636 ACSS	256.1	410.3	1298000	1626
Prairie Island-Ravenna 161 kV	PRI-RRK-DBL	reconductor 161 kV 636 ACSS	256	410.3	143000	1627
Split Rock B-Sioux City 345 kV	NSP LAKEFIELD 1	change relay settings SPK-SXC (O&M)	835.2	1416	0	1637
Inver Hills 345/115 9	60505 LKMARN 3 345 62234 LKMARN 7 115 C1	existing 633 MVA rating is sufficient	576.4	633	0	1725
Arrowhead Phase Shifter-Arrowhead 230 kV	NSP STK 8P5 BKR KING	phase shifter control will reduce flow	810.1	9999	0	1930
Galesburg-Oak Grove 161 kV	ATC_C3-4	reconductor 161 kV 477 ACSS	217.3	338.8	8640000	1941
Total					110,453,850	2000

5.1.2: System Alternative Thermal Underlying Facilities

The following table estimates the total installed costs of the underlying-system facilities for the System Alternative. These underlying system facilities are those required to be installed to achieve 2000 MW of transfer of new study generation to the Twin Cities with the System Alternative. This table has removed from it any double-counted facilities as listed in the System Alternative options in the Appendix showing the FCITC branch results. The shaded rows in the below table show facilities required only due to this study using the Twin Cities as the sink.

Table 5.1d: System Alternative Underlying Facilities

Facility	contingency	remedy	Rating required for desired FCITC	rating achieved/ MVA	cost/ $	FCITC
Eden Prairie 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	698.5	773	8920000	-2224
Eden Prairie 345/115 10	60262 EDEN PR3 345 60263 EDEN PR7 115 9	replace with 345/115 672 MVA transformer	634.5	773	8920000	-1841
Red Rock 345/115 10	NSP STK 8P23 BKR RED ROCK	replace with 345/115 672 MVA transformer	732.7	773	8920000	-1539
Parkers Lake 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	598.4	773	8920000	-1219
Blue Lake 345/115 9	705 1	replace with 345/115 672 MVA transformer	441.8	773	8920000	-706
Parkers Lake 345/115 10	60233 PARKERS3 345 61490 PKLMID1Y 110 9	replace with 345/115 672 MVA transformer	574.9	773	8920000	-578
Sheyenne-Fargo 230 kV	63369 JAMESTN3 345 66791 CENTER 3 345 1	reconductor 230 kV 795 ACSS	463.9	687	1221200	-318
Brookings County 345/115 1	60382 BRKNGCO7 115 60383 BRKNGCO3 345 2	replace with 345/115 672 MVA transformer	701	773	8920000	-150
Brookings County 345/115 2	60382 BRKNGCO7 115 60383 BRKNGCO3 345 1	replace with 345/115 672 MVA transformer	701	773	8920000	-150
Edina-Saint Louis Park 115 kV	960	rebuild 115 kV line 390 MVA & switch at EDA	313.7	368	78800	699
Goose Lake-Vadnais Tap 115 kV	917 1	rebuild 115 kV line 350 MVA	262.3	350	741960	709
Kohlman Lake 345/115 10	KOL-CNC/TER	existing 515 MVA rating is sufficient	499.7	515	0	793
Minn Valley Tap-Granite Falls 230 kV	60508 HAZEL 4 230 66550 GRANITF4 230 C1	rebuild 230 kV line 840 MVA	575.1	840	0	836
Hillsboro-Hillsboro Tap 69 kV	ATC-ARP-OG3	rebuild 69 kV line 145 MVA	136	145	2284800	889
Stinson phase shifter	ATC_C3-9	solution error	314.4	9999	0	898
Wilmarth-Eastwood 115 kV	60110 WILMART7 115 60380 SUMMIT 115 1	reconductor 115 kV 795 ACSS	250.9	349.8	73080	899
Edina-Eden Prairie 115 kV	NSP WESTGATE	replace 2 115 kV breakers & disconnect switch all 3000A at EDA	545.7	598	465000	920
Hilltop-Mauston 69 kV	ATC-ARP-OG3	rebuild 69 kV line 145 MVA	119.8	145	2777600	942
Hillsboro Tap-UC tap 69 kV	ATC-ARP-OG3	rebuild 69 kV line 145 MVA	130.7	145	2912000	957
Split Rock A-White 345 kV	60383 BRKNGCO3 345 60500 LYON CO3 345 C1	change relay settings SPK-WHT (O&M)	921.5	1643	0	973
Air Lake-Lake Marion 115 kV	NSP STK 8P23 BKR RED ROCK	replace 2 115 kV CTs & a disconnect switch all 2000A	274.9	308	73000	1001
UC tap-Mauston 69 kV	ATC-ARP-OG3	rebuild 69 kV line 145 MVA	121.8	145	5107200	1098
Lexington-Vadnais Tap 115 kV	917 1	reconductor 115 kV 795 ACSS	242.5	349.8	1221480	1176
Dahlberg-Stinson WI 115 kV	ATC_C3-9	solution error	133.1	9999	0	1179
Prairie Island 345/161 10	PRI-RRK-DBL	replace with 345/161 672 MVA transformer	270.4	773	8920000	1182
Blue Lake-Eden Prairie 345 kV	NSP STK 8M27 BKR BLUE LAKE	reconductor 345 kV 2x795 ACSS	1375.3	2088	3256000	1288
Aldrich-Fifth Street 115 kV	917 1	FST bus & 2 switches	245.1	276	95000	1315
NIW-Lime Creek 161 kV	Byron-PL Valley + PL Valley-Adams	reconductor 161 kV 477 ACSS	232.9	338.8	135000	1361
Minnesota Valley-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	already upgraded	178.3	239	0	1485
Franklin-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	will be 795 ACSS after BRIGO	173.2	350	0	1521
Wheaton-Elk Mound 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	330.8	434	1022400	1534
Wheaton-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	330.7	434	0	1535
Eau Claire-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	328.9	434	0	1556
Parkers Lake-Basset Creek 115 kV	917 1	rebuild 115 kV 2x795 ACSS	424.9	598	1252800	1609
Split Rock B-Sioux City 345 kV	NSP LAKEFIELD 1	change relay settings SPK-SXC (O&M)	823	1416	0	1734
Inver Hills 345/115 9	60505 LKMARN 3 345 62234 LKMARN 7 115 C1	existing 633 MVA rating is sufficient	574.5	633	0	1741
Arrowhead Phase Shifter-Arrowhead 230 kV	ATC-ARP-OG2	phase shifter control will reduce flow	840.5	9999	0	1747
Galesburg-Oak Grove 161 kV	ATC-ARP-OG2	reconductor 161 kV 477 ACSS	220.3	338.8	8640000	1868
Total					111,637,320	2000

The following table shows the estimated total installed costs of the underlying-system facilities for the Do Nothing option. These underlying-system facilities are those required to achieve 2000 MW of transfer of new study generation to the Twin Cities area assuming no new lines are built. The facilities on the highlighted rows are those required only due to using the Twin Cities as a sink.

Table 5.1e: Do Nothing Underlying Facilities

Facility	contingency	remedy	Rating required for desired FCITC	rating achieved/ MVA	cost/ $	FCITC
Eden Prairie 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	654.6	773	8,920,000	-2238
Eden Prairie 345/115 10	60262 EDEN PR3 345 60263 EDEN PR7 115 9	replace with 345/115 672 MVA transformer	602.1	773	8,920,000	-1782
Red Rock 345/115 10	NSP STK 8P23 BKR RED ROCK	replace with 345/115 672 MVA transformer	740.6	773	8,920,000	-1553
Parkers Lake 345/115 9	NSP STK 8M16 BKR PARKERS LAKE	replace with 345/115 672 MVA transformer	577	773	8,920,000	-1057
Sheyenne-Fargo 230 kV	63369 JAMESTN3 345 66791 CENTER 3 345 1	reconductor 230 kV 795 ACSS	500.6	687	1,221,200	-547
Parkers Lake 345/115 10	60233 PARKERS3 345 61490 PKLMID1Y 110 9	replace with 345/115 672 MVA transformer	548.2	773	8,920,000	-319
Brookings County 345/115 1	60382 BRKNGCO7 115 60383 BRKNGCO3 345 2	replace with 345/115 672 MVA transformer	700.6	773	8,920,000	-122
Brookings County 345/115 2	60382 BRKNGCO7 115 60383 BRKNGCO3 345 1	replace with 345/115 672 MVA transformer	700.6	773	8,920,000	-122
Minnesota Valley-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	will be 795 ACSS after BRIGO	295.3	350	-	133
Franklin-Redwood Falls Tap 115 kV	LYC-FRA-DBL1	will be 795 ACSS after BRIGO	290.1	350	-	162
Coon Creek 345/115 9	NSP STK 8M36 BKR COON CREEK	add 345 kV breaker & move a line	775.2	9999	900,000	461
Split Rock A-White 345 kV	LYC-FRA-DBL1	change relay settings SPK-WHT (O&M)	1063.1	1643	-	523
Coon Creek 345/115 10	NSP STK 8M35 BKR COON CREEK	existing 773 MVA rating is sufficient	768.7	773	-	547
Goose Lake-Vadnais Tap 115 kV	917 1	rebuild 115 kV line 350 MVA	273	350	741,960	587
Kohlman Lake 345/115 10	KOL-CNC/TER	existing 515 MVA rating is sufficient	508.2	515	-	661
Wilmarth-Eastwood 115 kV	60110 WILMART7 115 60380 SUMMIT 115 1	reconductor 115 kV 795 ACSS	262.9	349.8	73,080	700
Edina-Saint Louis Park 115 kV	960	rebuild 115 kV line 390 MVA & switch at EDA	301	368	78,800	852
Air Lake-Lake Marion 115 kV	62234 LKMARN 7 115 62237 KENRICK7 115 1	replace 2 115 kV CTs & a disconnect switch all 2000A	273.5	308	73,000	854
West Faribault-Loon Lake Tap 115 kV	CAPX6	good for 239 MVA	219.5	239	-	894
Stinson phase shifter	39244 ARP 345 345 60304 EAU CL 3 345 1	solution error	300.8	9999	-	961
McLeod-Panther 230 kV	FRA-HSS-DBL	rebuild 230 kV line 840 MVA	434	840	19,548,000	975
Grant County-Morris 115 kV	510	rebuild 115 kV line 350 MVA	143.2	350	12,356,840	995
Lexington-Vadnais Tap 115 kV	917 1	reconductor 115 kV 795 ACSS	252.9	349.8	1,221,480	1016
Terminal 345/115 10	60251 TERMINL3 345 61491 TERMID2Y 110 9	Build bifurcated TER-RAM-RPL-KOL 115 kV double circuit	776.3	9999	8,198,085	1045
Prairie Island 345/161 10	PRI-RRK-DBL	replace with 345/161 672 MVA transformer	278.8	773	8,920,000	1086
Winnebago 161 kV bus tie	CAPX6	market related	195.6	9999	-	1109
Tioga-Boundary Dam 230 kV	67STK	solution error	315.8	9999	-	1127
Council Creek-Council Creek DPC 69 kV	ECL-ARP	Fixed by MOC-COC 161 kV	143.9	9999	-	1150
Blue Lake-Helena 345 kV	60502 HELNASS3 345 60505 LKMARN 3 345 C1	Rebuild 345 kV 2294 MVA	1838.4	2294	24,160,500	1177
Split Rock B-Sioux City 345 kV	NSP LAKEFIELD 1	change relay settings SPK-SXC (O&M)	901.9	1416	-	1209
Edina-Eden Prairie 115 kV	NSP WESTGATE	replace 2 115 kV breakers & disconnect switch all 3000A at EDA	520.1	598	465,000	1256
Fort Ridgely-Franklin 115 kV	FRA-HSS-DBL	reconductor 115 kV 477 ACSS	158	242	6,425,000	1314
Boundary Dam phase shifter P	67STK	solution error	329.1	9999	-	1374
Aldrich-Fifth Street 115 kV	917 1	FST bus & 2 switches	237.6	276	95,000	1418
NIW-Lime Creek 161 kV	PLEASANT VALLEY 19JB2 STUCK	reconductor 161 kV 477 ACSS	227.4	338.8	135,000	1426
High Bridge-Rogers Lake 115 kV	917 1	replace 115 kV wavetrap with 3000 A unit on HBR-RLK	439.8	598	125,000	1548
Ravenna-Spring Creek 161 kV	PRI-RRK-DBL	reconductor 161 kV 636 ACSS	260.5	410.3	1,298,000	1560
Prairie Island-Ravenna 161 kV	PRI-RRK-DBL	reconductor 161 kV 636 ACSS	260.4	410.3	143,000	1562
Wheaton-Elk Mound 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	327.2	434	1,022,400	1566
Wheaton-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	327.1	434	-	1567

Table 5.1e: Do Nothing Underlying Facilities

Facility	contingency	remedy	Rating required for desired FCITC	rating achieved/ MVA	cost/ $	FCITC
Eau Claire-Presto Tap 161 kV	NSP STK 8P5 BKR KING	reconductor 161 kV 795 ACSS	325.3	434	-	1589
Boundary Dam phase shifter V	67STK	solution error	309.2	9999	-	1600
Hankinson-Wahpeton 230 kV	63369 JAMESTN3 345 66791 CENTER 3 345 1	reconductor 230 kV 795 ACSS	365.9	687	7,256,200	1622
Parkers Lake-Basset Creek 115 kV	917 1	rebuild 115 kV 2x795 ACSS	420.8	598	1,252,800	1666
Minn Valley Tap-Granite Falls 230 kV	60383 BRKNGCO3 345 60500 LYON CO3 345 C1	rebuild 230 kV line 840 MVA	439.3	840	-	1844
Inver Hills 345/115 9	60505 LKMARN 3 345 62234 LKMARN 7 115 C1	existing 633 MVA rating is sufficient	563.5	633	-	1855
Lakefield 345/161 1	60331 LKFLDXL3 345 60364 FIELD_N3 345 1	replace with 345/161 672 MVA transformer	338.6	773	8,920,000	1909
Lakefield 345/161 2	60331 LKFLDXL3 345 60364 FIELD_N3 345 1	replace with 345/161 672 MVA transformer	338.6	773	8,920,000	1909
Arrowhead Phase Shifter-Arrowhead 230 kV	NSP STK 8P5 BKR KING	phase shifter control will reduce flow	807.5	9999	-	1946
	total				175,990,345	2000

5.2: Constrained Interface Analysis

All of the constrained interfaces commonly monitored by Midwest ISO were monitored for violations of their limits. The Appendix for Constrained Interface results shows the detailed results of the analysis performed for constrained interfaces. The following table summarizes those results. (Constrained Interfaces are also commonly referred to as "flowgates".)

- The off-peak cases for both the Corridor-Base option and the System Alternative show no flowgate violations.
- The peak cases for both the Corridor-Base option and the System Alternative show the Forbes-Chisago System Intact flowgate. In both cases that flowgate is not overloaded in the models.
- The peak case for the System Alternative also shows the Arnold-Hazleton 345 kV For Loss Of Montezuma-Bondurant 345 kV. This flowgate is not overloaded in the models.

While performing analyses of the electric transmission system, it is important to monitor constrained interfaces. The constrained interfaces have been developed in part to prevent generation changes in one geographic area from causing overloads of transmission facilities in other areas. Since the AC transmission system in Minnesota is interconnected with the AC transmission systems all the way to the Atlantic ocean and to the Gulf of Mexico, generation increases in Minnesota can cause overloads in Iowa or Wisconsin or further away.

The general rules for flowgates are as follow.

- If a generation addition causes less than 3% flow increase on any given contingent flowgate (like the Arnold-Hazleton 345 kV For Loss Of Montezuma-Bondurant 345 kV), that generation is exempted from having to address that flowgate.
- If a generation addition causes less that 5% flow increase on any given system-intact flowgate (like Forbes-Chisago 500 kV System Intact), that generation is exempted from having to address that flowgate.
- If either of the 3% or 5% above criteria are violated for any flowgate, but there is sufficient Available Transfer Capability (ATC) on that flowgate to accommodate the new generations impact on that flowgate, no facility upgrades to that flowgate are required; however, the generation owners will likely have to purchase transmission service on that flowgate.

The Available Transfer Capabilities on the bulk transmission facilities are generally known only out as many as three years. Beyond that time, the postings of Available Transfer Capability are generally not available. Due to the fact the facilities in this study are recommended to be in service by the end of year 2015, there is no good way to determine the actual Available Transfer Capability on either of the flowgates with violations of the distribution-factor cutoff (3% or 5% as applicable).

Therefore, the next best option is to use the flows in the power-flow models as obtained from Midwest ISO. The peak model obtained from Midwest ISO was the basis for both the peak and off-peak models (load in the peak model was decreased to create the off-peak model). In the peak model were the firm transfers as set by Midwest ISO. So with those firm transfers and the 2000 MW of study generation, no flowgates overloaded in the peak models. Even with the high transfers added to the off-peak model – the high MHEX and NDEX and MWEX – there were no flowgate violations shown.

The fact none of the constrained interfaces are overloaded is important. That result indicates with the study generation of 2000 MW, the transmission options chosen were both good at transferring that generation to the study sink – the Twin Cities-area generators – with no need to either improve flowgate facilities or purchase transmission service on a flowgate.

Case	**Constrained Interface**	**Power Transfer Distribution Factor cutoff**	**Power Transfer Distribution Factor**	**Resolution**
Corridor-Base Off-peak	none			
Corridor-Base Peak	Forbes-Chisago 500 kV system intact	5.0%	5.8%	not overloaded (loading @ 2000 MW study generation is 1020 MVA with a 1655 MVA rating)
System Alternative Off-peak	none			
System Alternative Peak	Forbes-Chisago 500 kV system intact	5.0%	5.5%	not overloaded (loading @ 2000 MW study generation is 1005 MVA with a 1655 MVA rating)
System Alternative Peak	Arnold-Hazleton 345 kV for loss of Montezuma-Bondurant 345 kV	3.0%	3.0%	not overloaded (loading @ 2000 MW study generation is 178 MVA with a 601 MVA rating)

5.3: Reactive Power Requirements

The voltage results of this study showed there is not a great deal of need for adding reactive power facilities to support voltage under system-intact and contingent conditions. The below table shows the reactive-support facilities required for the 2000 MW level of study-source generation transfer to load. As is customary in bulk transmission studies, voltage changes less than 1% were ignored.

5.3.1: Corridor-Base Voltage Underlying Facilities

The Corridor-Base voltage underlying facilities are shown in detail in the Appendix for voltage results. The below table shows the summary.

Bus name	**Contingency**	**Remedy**	**Location**	**units required**	**cost per unit**	**Cost/ $**
Eden -138	ASK-ARP	Add 40 MVAr 138 kV capacitor	Eden	1	935000	935,000
Arrowhead 345-345	ASK-ARP	Add 80 MVAr 345 kV capacitor	Arrowhead	1	1500000	1,500,000
Council Creek -138	ASK-ARP	Add 14 MVAr 138 kV capacitor	Council Creek	2	935000	1,870,000
Frazee-115	1275STK1	Add 14 MVAr 115 kV capacitor	Frazee	1	935000	935,000
Miltona-115	1625STK	Add 14 MVAr 115 kV capacitor	Miltona	1	935000	935,000
total						6,175,000

5.3.2: System Alternative Voltage Underlying Facilities

The System Alternative voltage underlying facilities are shown in detail in the Appendix for voltage results. The below table summarizes those facilities.

Bus	Contingency	Remedy	Location	units required	cost per unit	Cost
Frazee-115	1275STK1	Add 14 MVAr 115 kV capacitor	Frazee	1	935000	935000
Miltona-115	1625STK	Add 14 MVAr 115 kV capacitor	Miltona	1	935000	935000
total						1870000

5.3.3: Light-load Charging Mitigation

During periods of light loading on any high-voltage transmission line, the charging current tends to increase the voltage at the endpoints of the line; this effect can lead to voltages outside of criteria if no mitigating facilities are installed. It is customary, therefore, to add reactors to the tertiary buses of the transformers involved in upgrade of a line to a higher voltage. This tends to be the most inexpensive way to keep the voltage within criteria during light-load periods.

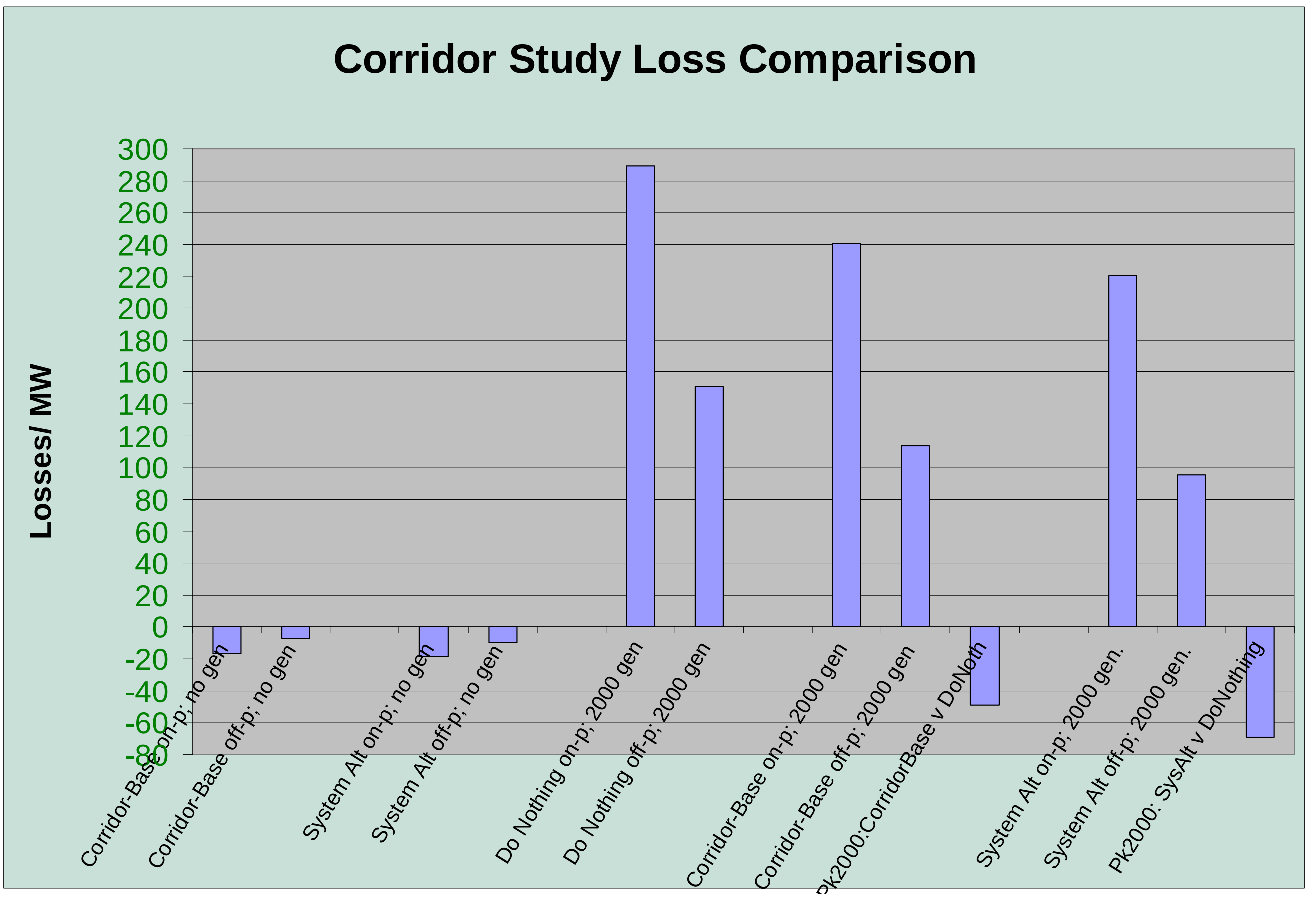
The charging from a 345 kV circuit is generally .86 MVAr per mile. The design for this project includes installing enough shunt reactance to absorb all the 345 kV lines' charging during light-load periods. Each reactor would be automatically switched based on the voltage on the primary or secondary of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

The total 345 kV line mileage for the project is expected to be approximately 122 miles per circuit. This results in approximately 200 MVAr -- 100 MVAr per circuit -- at the .86 MVAr/mile rate. This works out nicely to four 50 MVAr reactors. To give as flat a voltage profile as possible, the proposal is to add one 50 MVAr reactor to the tertiary of a transformer at Hazel Creek and Panther and McLeod and Blue Lake.

For 765 kV lines, the charging is 4.2 MVAr/mile. For the 86 mile 765 kV line in the System Alternative, 361 MVAr would have to be absorbed during light-load periods. Also, the 36 mile double-circuit 345 kV line from West Waconia to Blue Lake would result in the need to absorb another 62 MVAr. The total reactors needed for the System Alternative would be approximately 420 MVAr.

5.4: Losses: Technical Evaluation

The losses benefits are significant for both the Corridor-Base option and the System Alternative. The following chart shows the relative losses from varying scenarios of transmission option implemented and level of study generation – 0 MW or 2000 MW.



The below table summarizes the losses for cases studied. The chart above is based on the following table.

Case	Condition	Losses/ MW	Loss increase/ MW	Portion of 2000 gen.	Explanation of difference
1a	Off-peak base case	17564			
1b	Case 1a with 2000 MW new generation	17715	151	8%	2000 MW source generation
2a	Peak base case	17488			
2b	Case 2a with 2000 MW new generation	17777	289	14%	2000 MW source generation
5a	Off-peak base case with Corridor-Base	17558	-7		Added Corridor-Base
5b	Case 5a with 2000 MW new generation	17671	114	6%	2000 MW source generation
6a	Peak base case with Corridor-Base	17472	-17		Added Corridor-Base
6b	Case 6a with 2000 MW new generation	17712	240	12%	2000 MW source generation
7a	Off-peak base case with System Alternative	17554	-10		Added System Alternative
7b	Case 7a with 2000 MW new generation	17650	96	5%	2000 MW source generation
8a	Peak base case with System Alternative	17469	-19		Added System Alternative
8b	Case 8a with 2000 MW new generation	17689	220	11%	2000 MW source generation

Concentrating on the peak losses, one can make a few observations from the above table.

- Adding 2000 MW of generation in the "Do Nothing" option results in loss of 14% of that generation.
- If the Corridor-Base option is built, only 12% of that generation is lost.
- If the System Alternative option is built, only 11% of that generation is lost.
- Adding the Corridor-Base option with no new generation results in a peak loss reduction of 17 MW.
- Adding the System Alternative option with no new generation results in a peak loss reduction of 19 MW.

5.5: Losses: Economic Evaluation

The below worksheet shows the derivation of the loss benefit in terms of the amount of transmission investment able to be supported by a loss savings. One important result on that worksheet is the 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$/MW of Equivalent Transmission Investment. This is the amount of "supportable transmission investment" per MW of loss savings. For example, a good investment would be to install an additional 20 M$ of transmission facilities to save 10 MW of losses, as that would require 2.0 M$/MW, and is below the 3.1 M$/MW point of economic indifference.

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

Input Assumptions

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

Calculation

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

Present Value Annuity factor Losses		11.92
Cum PV Losses	$	5,355,789
Equivalent Transmission investment	$	**3,063,628**
is Cum PV Losses / FCR trans / PVA trans		

Xcel Energy Services

Based on the 3.1 M$/MW value, the "loss reduction" investment credit for building the Corridor-Base plan with no added study source generation is 53 M$ (17 MW loss savings multiplied by 3.1 M$/MW). This amount is a credit to the total installed cost of the Corridor-Base plan. The investment credit for building the System Alternative with no added generation is 59 M$ (19 MW loss savings multiplied by 3.1 M$/MW).

5.6: Dynamic Stability

The dynamic stability analyses showed one criteria violation for the Corridor-Base option with 2000 MW of added study generation. The System Alternative was not studied in the dynamics realm since its initial cost is so great. As stated elsewhere, the System Alternative is not viable without a wider 765 kV proposed development. If such a development were to materialize, it would be studied in detail in the dynamics realm.

However, since the Corridor-Base dynamics analysis showed only one violation in northern Wisconsin, it was assumed the same violation would appear for the System Alternative. The violation is remote from the study generation, and it is caused by loss of the King-Eau Claire-Arpin 345 kV line and the King-Chisago 345 kV line. With loss of that line from Minnesota to Wisconsin, power flow from Minnesota to Wisconsin is diverted to flow from the Duluth area southeast into Wisconsin. This causes a low-voltage violation at Minong Substation. This effect is expected to be independent of the voltage class built (345 kV or 765 kV) between Hazel Creek Substation and Blue Lake

Substation. Therefore the same cost of an SVC – 10 M$ -- has been assigned to the stability facility costs for both the Corridor-Base option and the System Alternative.

The same Minong Substation low-voltage violation appears in the Do Nothing option, but the Do Nothing option also has a violation at Jamestown, North Dakota; for the Do-Nothing option, an SVC at each of Minong Substation and Jamestown Substation are required. The total cost for those two SVCs is expected to be 20 M$.

The detailed results for the dynamic simulations are in the Appendix showing dynamics simulation results.

5.7: Production Cost Modeling Results

Production-cost and load-cost modeling was done with the computer program called PROMOD.

The below table shows the summary of the 40-year present value savings from constructing the Corridor-Base transmission with 2000 MW of new study generation; if that transmission is built, the 40-year present value of weighted production-cost savings (70% weight) and load-cost savings (30% weight) is 214 M$ versus the Do Nothing option.

Corridor Project (Metro Sink for Underlying Costs)	
Description	***Cost***
70% Production Cost Savings (40-year)	$34,685,192
30% Load Cost Savings (40-year)	$179,723,682
total	$214,408,874

6: Economic Analysis

6.1: Total Evaluated Costs

The total evaluated costs for all options were compiled from the

- costs for the base facilities,
- the underlying-system costs,
- the facilities required to keep the power system within criteria following dynamic disturbances,
- the 40-year present value of load-cost and production-cost penalties,
- and the 40-year present value cost of losses.

Considering all the cost factors of the Corridor-Base option, the System Alternative, and the Do Nothing option, the Corridor-Base option is seen to be the least-cost option.

Not included are the costs of the central and eastern Wisconsin capacitors since those facilities are expected to be required even without any of the options analyzed as part of this study. The high transfers from Minnesota to eastern Wisconsin are the drivers for those capacitors.

The following table summarizes the options' total costs.

Table 6.1: Overall Cost Summary

Option	Base Project Installed Cost/ M$	Underlying System Installed Cost for 2000 MW delivery/ M$	Losses cost/ M$	Cost of Facilities for Dynamic Stability/ M$	Production-cost & load-cost penalty/ M$	Total Installed Cost for 2000 MW delivery/ M$
Corridor-Base	349	117	0	10	0	**476**
System Alternative	583	114	-61	10	0	**646**
Do Nothing	0	176	150	20	214	**560**

The following table shows the total evaluated cost for the Corridor-Base option.

Table 6.1a: Corridor-Base option total costs

Project	**Hazel-Blue Lake double 345 kV with 1 express**			
Sum of Facility cost/ M$				
Type	**Location**	**Facility**	**units**	**Total**
base project	Blue Lake	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	1	1,000,000
	Hazel Creek	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	1	1,000,000
	Hazel Creek-Minnesota Valley vicinity	string second circuit on existing double-circuit 345 kV towers	6	3,000,000
	McLeod	develop 345 kV yard with 2 345 kV terminations	1	10,000,000
		tertiary shunt reactor	1	1,000,000
	McLeod-Blue Lake	build 345 kV double circuit	56	151,000,000
	Minnesota Valley vicinity-Panther	build 345 kV double circuit	30	81,000,000
	Panther	develop 345 kV yard with 2 345 kV terminations	1	10,000,000
		tertiary shunt reactor	1	1,000,000
	Panther-McLeod	build 345 kV double circuit	28	76,000,000
base project Total				349,000,000
losses	various	Corridor-Base losses cost	1	0
losses Total				0
production cost penalty	various	no production cost penalty	1	0
production cost penalty Total				0
underlying facilities	Corridor-Base	Hazel Creek-Blue Lake double 345 kV one express underlying facilities	1	111,000,000
	various	Corridor-Base reactive support	1	6,000,000
underlying facilities Total				117,000,000
Grand Total				**466,000,000**

The following table shows the total evaluated cost for the System Alternative. Since the electrical performance of the System Alternative and Corridor-Base options are very similar, the load-cost and production-cost penalties for those options are assumed equal.

Table 6.1b: System Alternative total costs

Project	**Hazel-West Waconia 765 kV**			
Sum of Facility cost/ M$				
Type	**Location**	**Facility**	**units**	**Total**
base project	Blue Lake	add 2 345 kV terminations	1	7,000,000
		tertiary shunt reactor	2	3,000,000
	Hazel Creek	develop 765 kV ring bus, 2 terminations, 765/345 transformer	1	60,000,000
		tertiary shunt reactor	3	4,000,000
	Hazel Creek-West Waconia	build 765 kV line	93	372,000,000
	West Waconia	develop 765 kV ring bus, 2 terminations, 765/345 transformer	1	60,000,000
		tertiary shunt reactor	3	4,000,000
	West Waconia-Blue Lake	build 345 kV double circuit	27	73,000,000
base project Total				***583,000,000***
losses	various	System Alternative losses cost	1	-61,000,000
losses Total				***-61,000,000***
production cost penalty	various	no production cost penalty	1	0
production cost penalty Total				***0***
underlying facilities	System Alternative	Hazel Creek-West Waconia 765 kV line underlying facilities	1	112,000,000
	various	System Alternative reactive support	1	2,000,000
underlying facilities Total				***114,000,000***
Grand Total				**636,000,000**

The following table shows the total evaluated cost for the Do Nothing option.

Table 6.1c: Do Nothing total costs

Project	**Do Nothing**			
Sum of Facility cost/ M$				
Type	**Location**	**Facility**	**units**	**Total**
losses	various	Do Nothing Losses Cost	1	150,000,000
losses Total				150,000,000
production cost penalty	various	70% Production Cost Increase + 30% Load Cost Increase over Corridor-Base	1	214,000,000
production cost penalty Total				214,000,000
stability facilities	various	Do Nothing Stability Facilities	1	20,000,000
stability facilities Total				20,000,000
underlying facilities	various	Do Nothing Underlying System Costs	1	176,000,000
underlying facilities Total				176,000,000
Grand Total				**560,000,000**

7: Relevant Concerns

7.1: Load-Serving Issues

Though this study was not primarily focused as an analysis of the load-serving benefits from the options studied, load-serving benefit is expected from the Corridor-Base option. Installation of an in-and-out 345 kV arrangement at Panther and McLeod substations is expected to defer any load-serving facilities for those substations for many years.

7.2: Constructability & Schedule Considerations

7.2.1: Constructability

The main constructability issue is the existing need for the 230 kV line from Granite Falls to the Twin Cities versus the need to make use of that line's corridor in a more efficient way by building a new line (the Corridor-Base option) on that corridor. That 230 kV line is an integral part of the delivery to load of the existing wind generation in southwest Minnesota. If that 230 kV line needs to be taken out of service for construction of a new line on the same corridor, risk of curtailment of wind generation will ensue, and curtailment of wind generally results in higher costs for Minnesota electric customers. This study has not attempted to quantify the amount of potential curtailment or the cost allocation that may apply to such curtailments.

An alternative to taking that 230 kV line out of service for construction would be to build the new facilities alongside that 230 kV line. This possibility has been investigated and seems feasible for part of the route of the Corridor-Base option. Since the System Alternative does not involve any changes to that 230 kV line, the System Alternative avoids this constructability issue.

7.2.2: Schedule

The primary schedule consideration is the need to meet the 2016 milestone of the Minnesota Renewable Energy Standard. Therefore, the base-project facilities need to be in service by the end of year 2015. If the base-project and the required underlying-system facilities are not installed by this time, there is risk the Minnesota load-serving entities will not all be able to meet their portion of the Renewable Energy Standard. Curtailment of wind energy would be likely; such curtailment has been demonstrated in production-cost model (PROMOD) analyses for this study.

The other effect of not having the recommended facilities in place by 2016 is the risk of increased production cost and load cost to meet the energy needs of Minnesota electric customers. As shown in section 6.1, there is a substantial penalty (~200 M$ present value over 40 years) from not having the recommended facilities installed.

The underlying system facilities required must also be installed by the end of year 2015, though the actual facilities installed as underlying facilities may change between the time of this report and year 2016. Were the electric system loads and generation and transmission to develop exactly as modeled, the underlying-system facilities required to be built would be exactly as described in this document. However, many developments of transmission system changes or load changes or generation additions or retirements could affect the list of underlying-system facilities required by year 2016. A simple example of such a change would be a new large industrial load being added at a substation slated in this study for a new capacitor. If that load were added in year 2011, the need for that capacitor may be advanced to 2011. By the time the Corridor Study facilities would be added, that capacitor would no longer be on the list of needed underlying-system facilities.

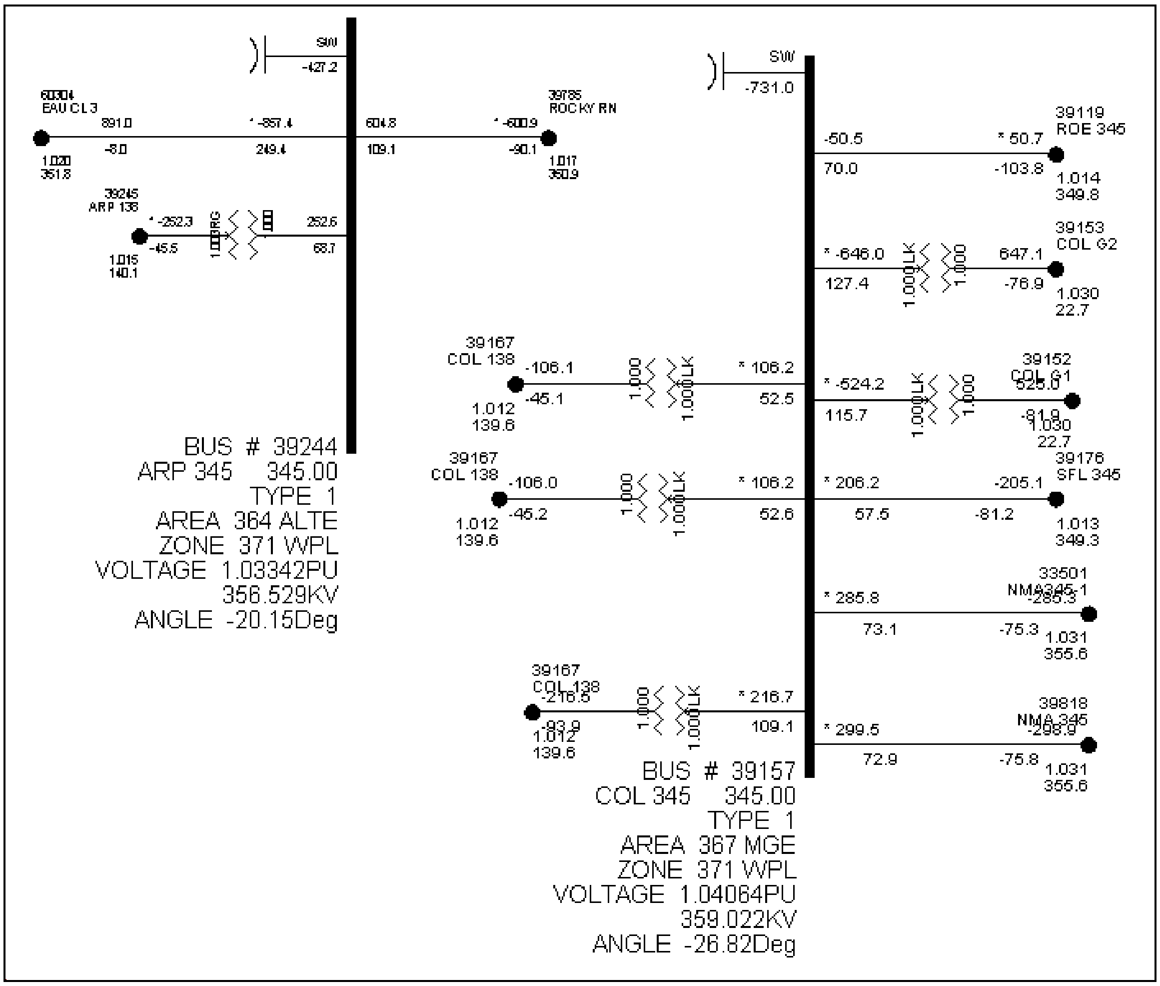
7.3: Facilities Assumed In Place

The modeling started out with the facilities noted in section 4 of this report modeled. As the study continued, those facilities were generally found to be sufficient to meet the needs they were designed to meet. However, with the Corridor-Base plan and 2000 MW of new generation sources, the Hazel Creek-Granite Falls 230 kV line (not yet built) loaded to over 500 MVA under contingency (loss of the Granite Falls-Willmar 230 kV line) and to over 450 MVA under system-intact conditions. Therefore, this line needs to be built for those loading levels. The cost of this is not included in the estimates in this report since this line has not yet been built, and the incremental cost over the present design should be small. Given the high system-intact loading, a large conductor such as 2312 kcm is recommended to minimize losses. Under the System Alternative, this line does not load as highly – 220 MVA under system-intact conditions and 480 MVA under contingency (loss of the Granite Falls-Minnesota Valley Tap 230 kV line).

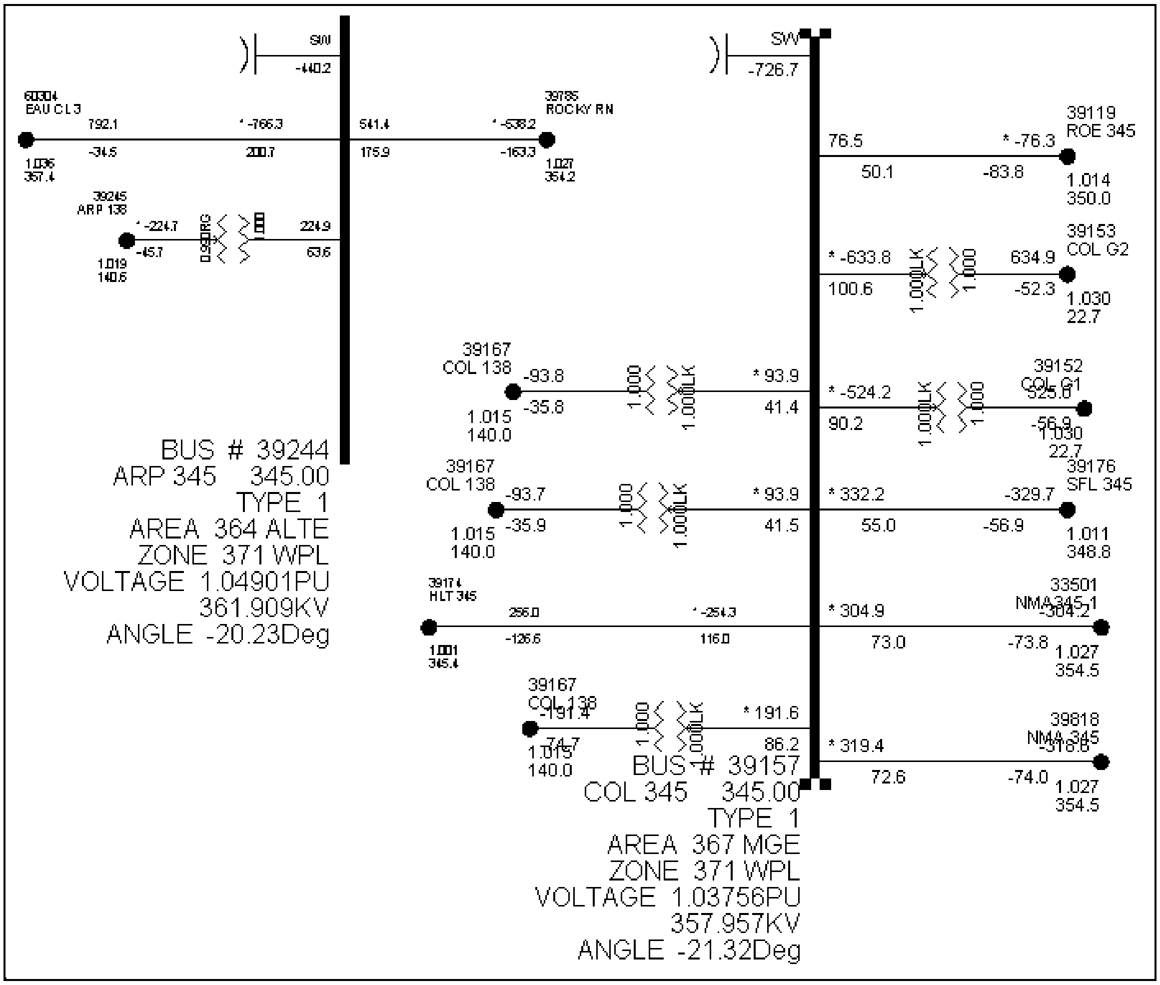
7.4: Underlying System Side Analyses

7.4.1: Side analysis of reactive requirements at Arpin

A small side analysis was performed to investigate the reactive requirements at Arpin and Columbia if a new La Crosse-Madison-area 345 kV line is added. The below diagram shows a Madison-area bus – Columbia 345 kV – and the Arpin 345 kV bus for the Corridor-Base option with 2000 MW new generation in southwest Minnesota and eastern South Dakota, off-peak loads, and MWEX at 1525 MW.

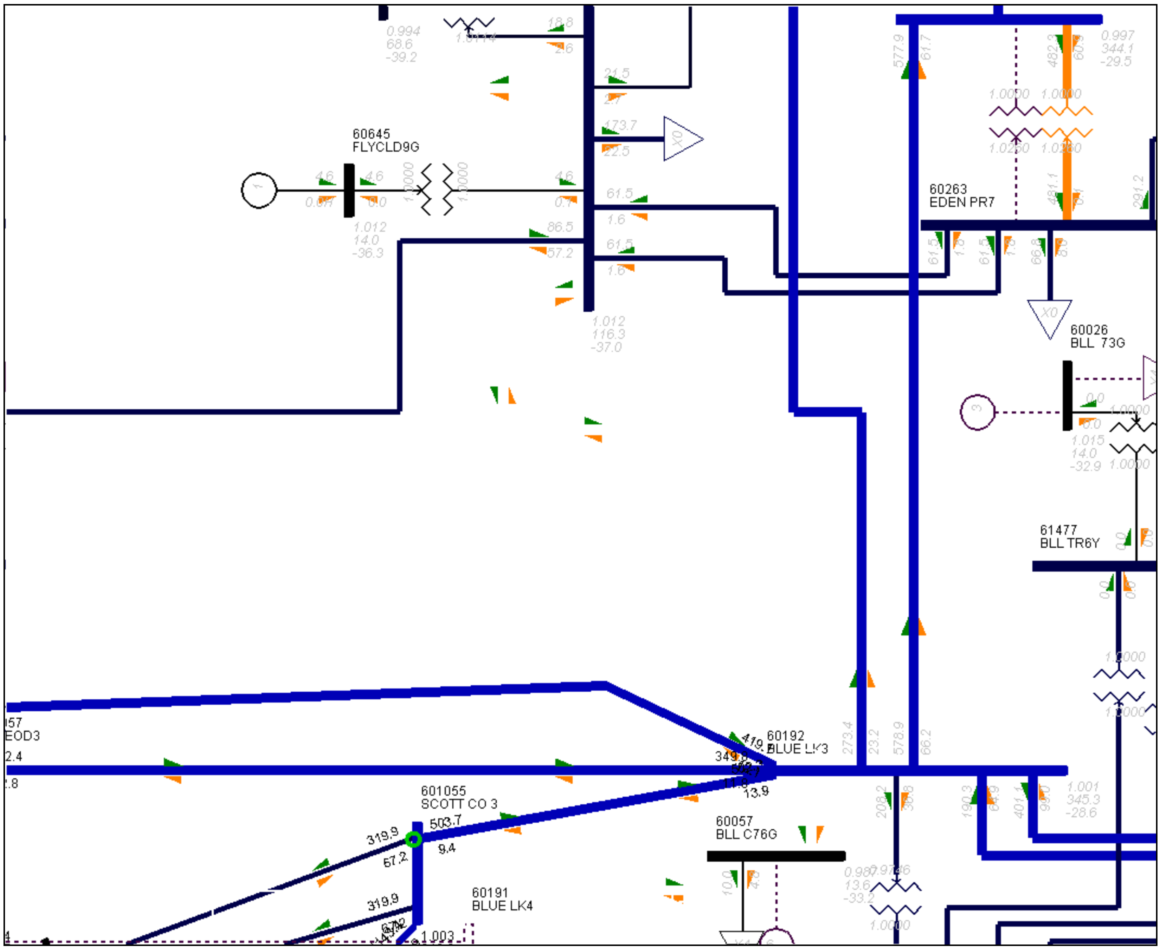


The following diagram shows the same conditions as the above diagram except with the North La Crosse-Columbia 345 kV line added. As can be seen, the reactive needs at Arpin and Columbia are not significantly reduced. This is due to the fact the flow on the 345 kV lines connecting at Arpin is not reduced much by adding the North La Crosse-Columbia 345 kV line.



7.4.2: Eden Prairie 345/115 transformers

To fix the issue of the Eden Prairie 345/115 transformers overloading for loss of each other, the option of adding 345/115 transformation at Scott County was tested; this would be a 345 kV tap on the Blue Lake-Helena line; however, with 2000 MW of wind, Eden Prairie transformer 10 still loaded to 109% for loss of the other bank. The below excerpt from a map shows this effect.



Therefore the best plan for the Eden Prairie transformers appears to be to replace them.

7.5: Dorsey Forbes 500 kV line

As in most studies of added generation west of the Twin Cities with a sink of the Twin Cities or east of the Twin Cities, the power flow on the Dorsey-Forbes 500 kV line was shown to increase in this study. However, the distribution factor of the increase was less than 3% under system-intact conditions. Under outage conditions, the 500 kV line was not shown to overload in any situation. This shows the Corridor-Base option and System Alternative do a good job of efficiently moving the study generation to the Twin Cities area with little impact on the 500 kV line.

Minnesota RES Update Study Report

Volume 1

Prepared for the Minnesota Transmission Owners

Principal Contributors: Michael Cronier and Daniel Kline

March 31, 2009

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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Listing of Tables and Figures

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

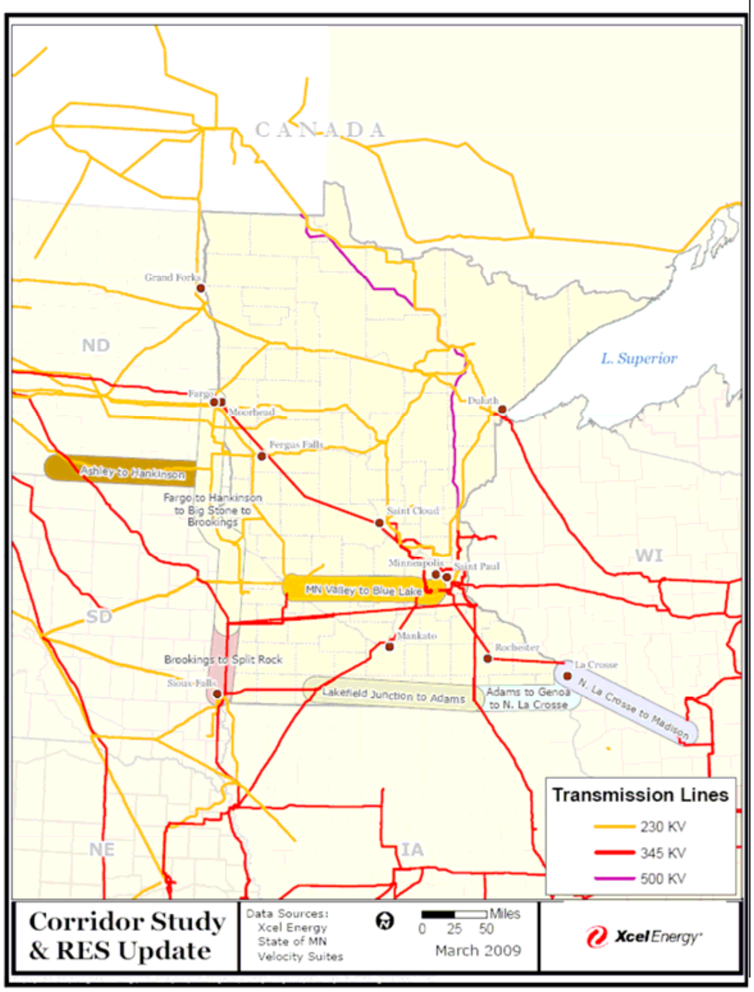
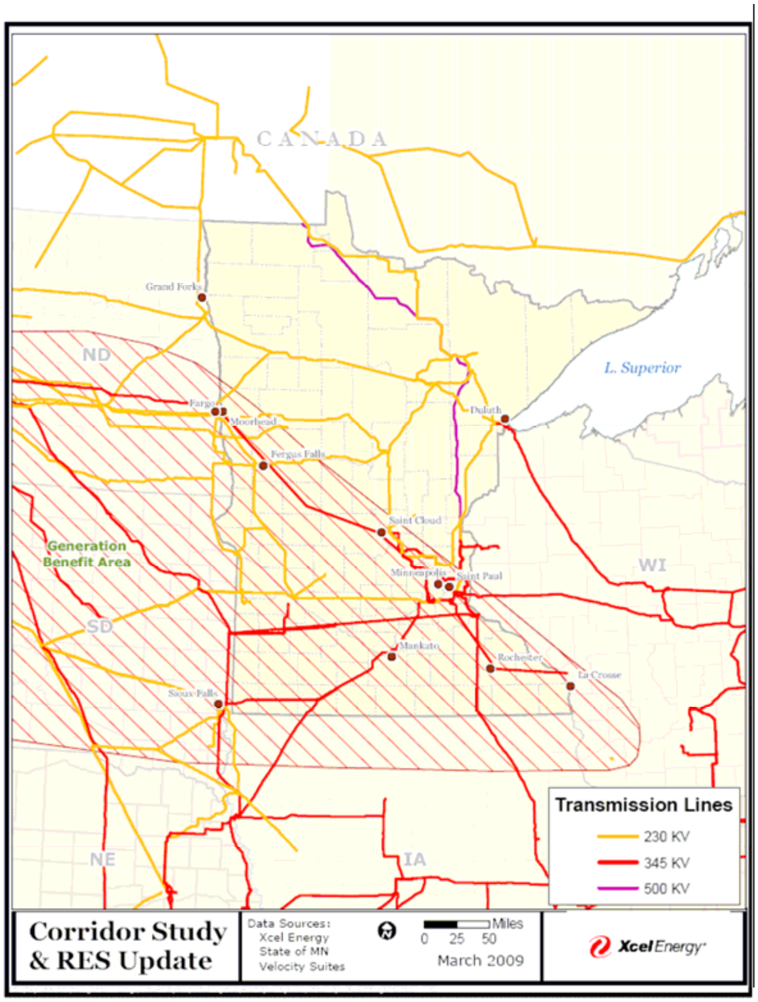


Figure 2.0.B – RES Generation Benefit Area



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

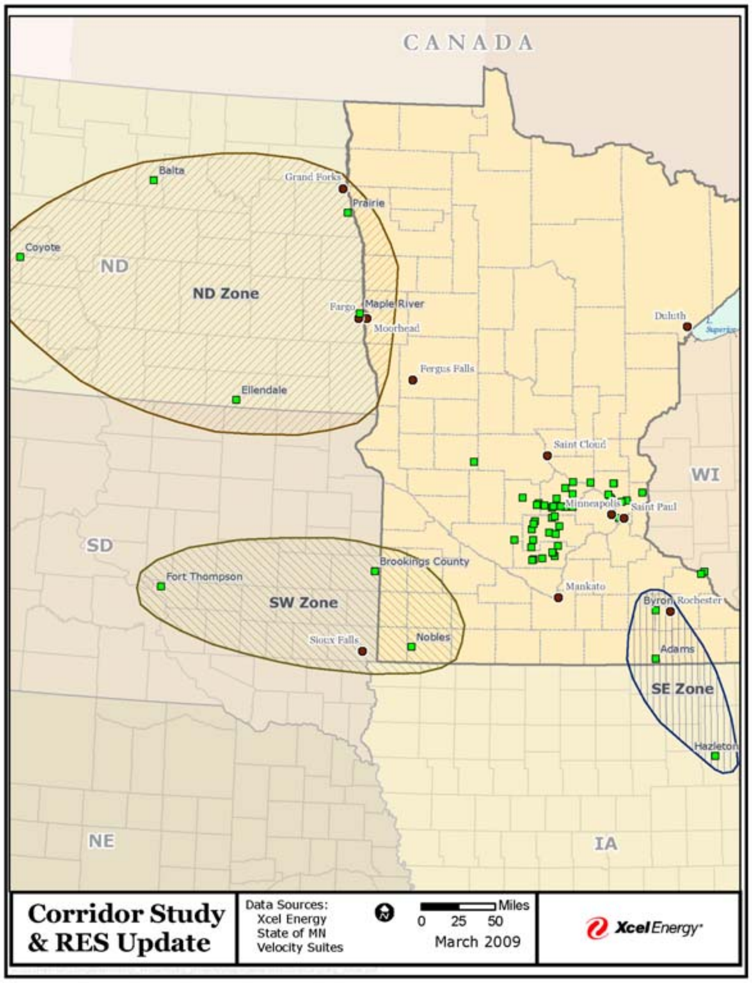


Table 4.3.1.F – SE Zone Sources

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:

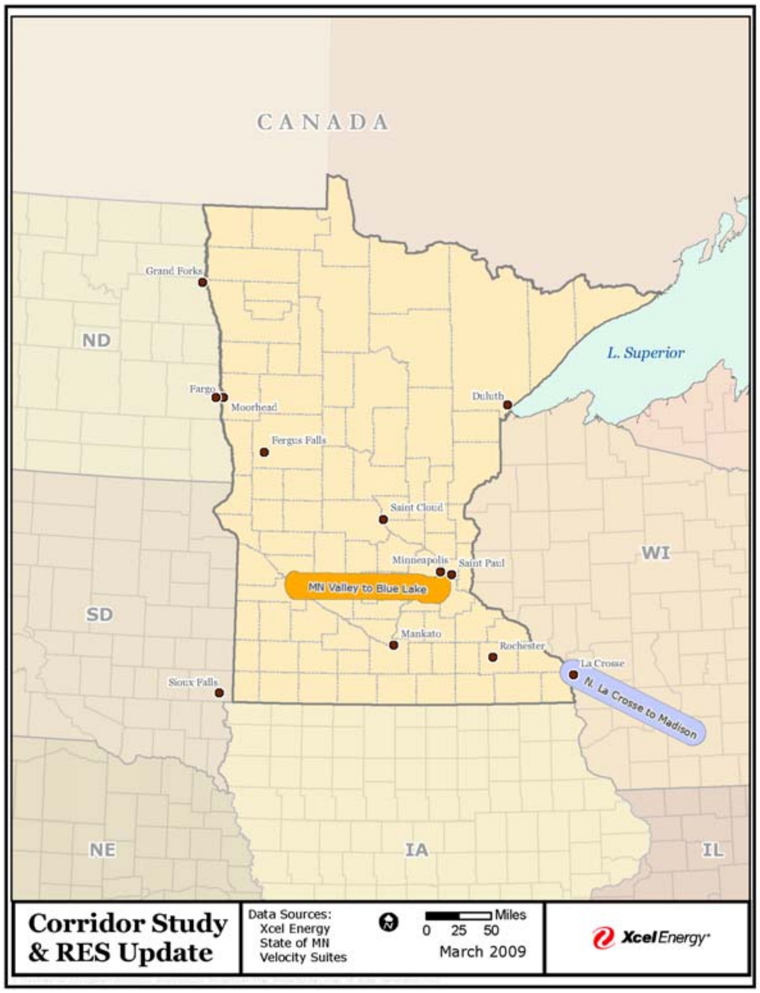
4.5.1: La Crosse - Madison Project

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



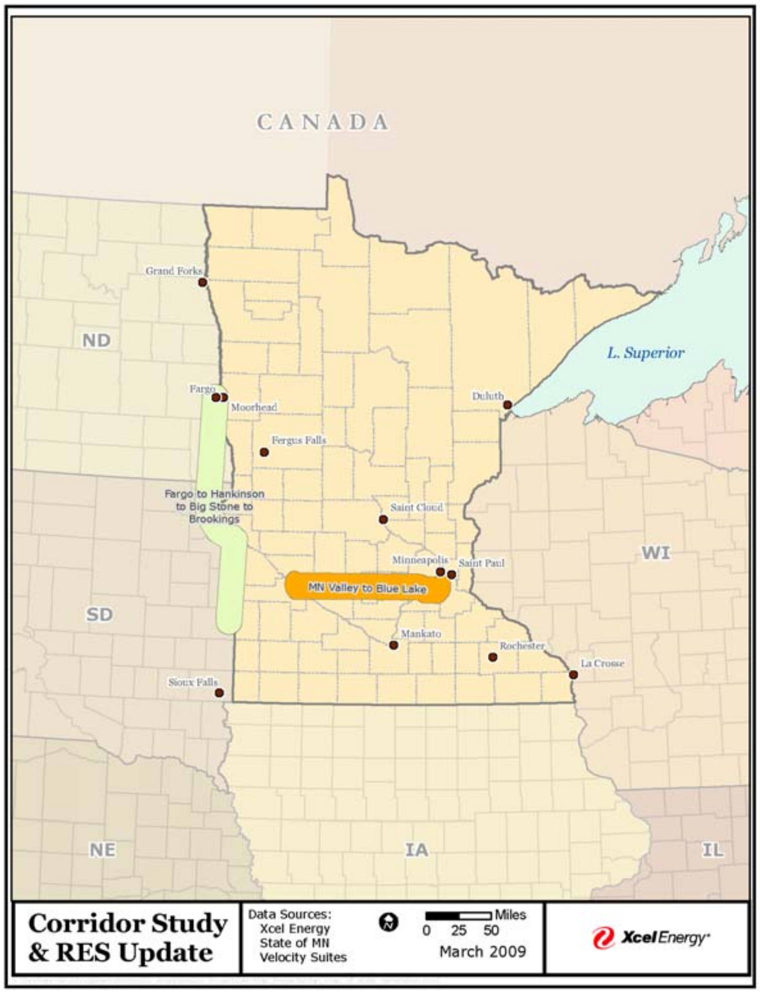
4.5.2: Fargo-Brookings County Project

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

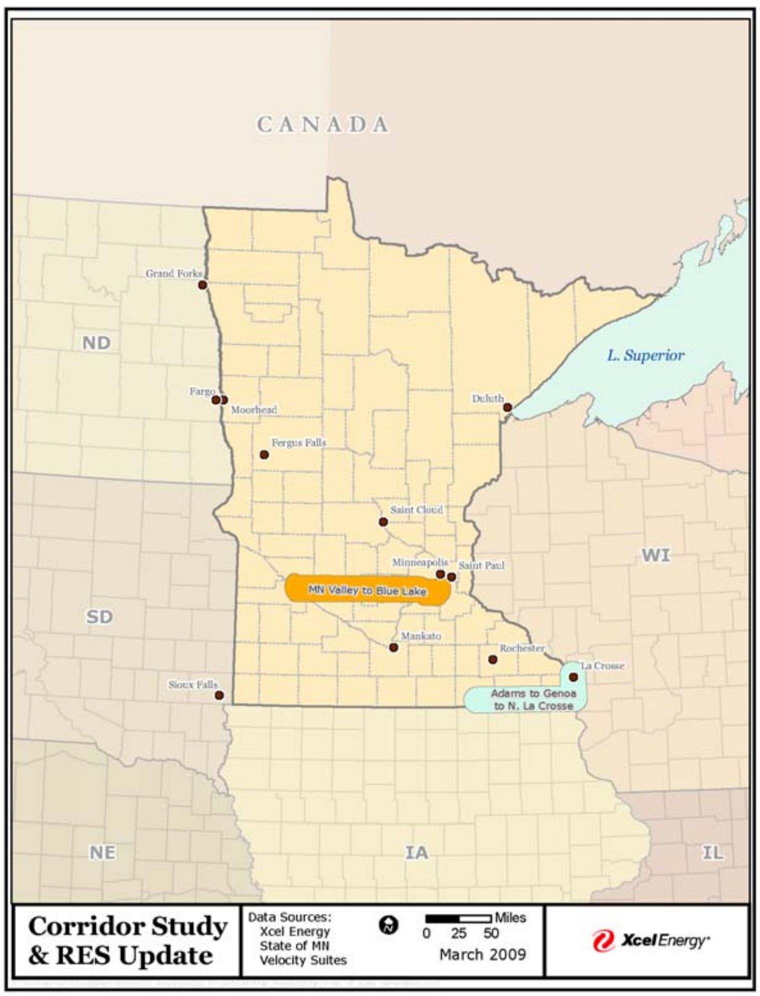
4.5.6: Adams-La Crosse Project

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.

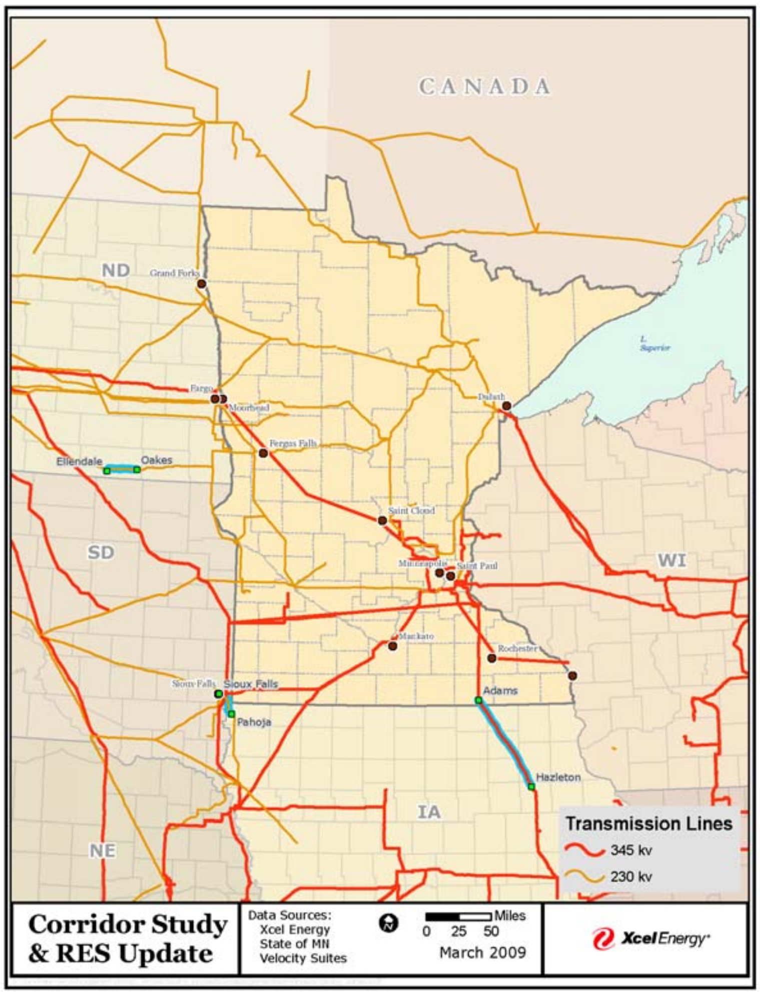
5.0: Results

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.

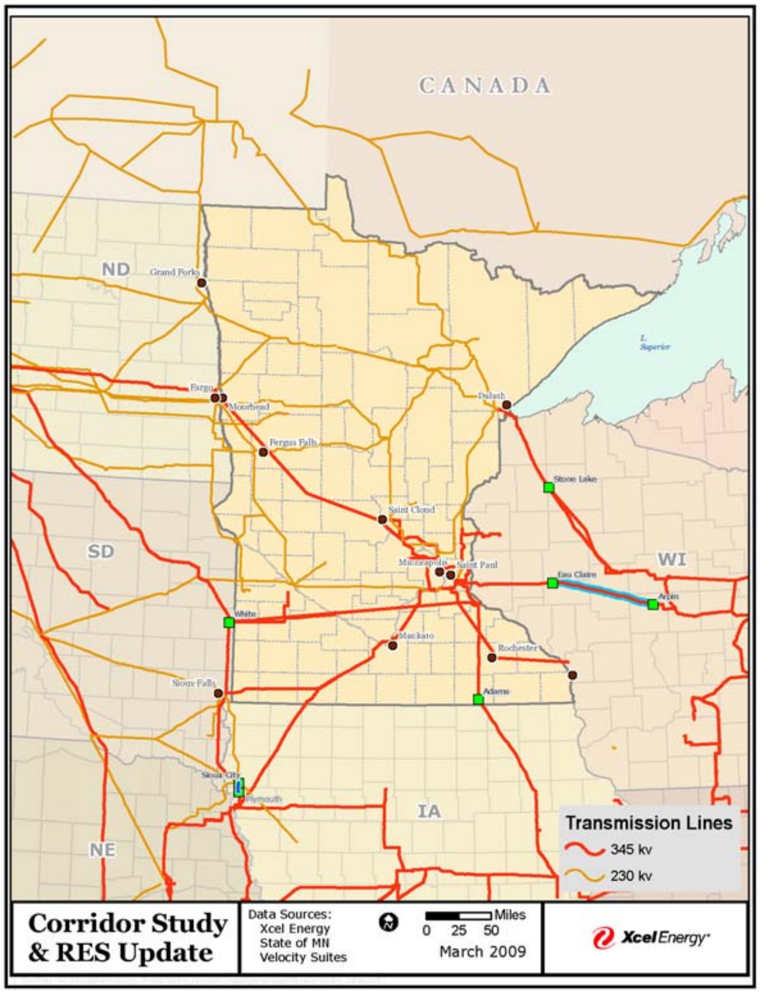
- Stone Lake 345/161 kV Transformer – this transformer is located along the recently completed Arrowhead – Gardner Park 345 kV line. The overload generally shows up for contingencies that involve loss of the Stone Lake – Gardner Park. In addition, a 345 kV breaker failure contingency that causes loss 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 Ashley & Broadland Lines Lakefield Jct. – Madison	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 Ashley & Broadland Lines Lakefield Jct. – Madison	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 Ashley & Broadland Lines Lakefield Jct. – Madison	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 Ashley & Broadland Lines Lakefield Jct. - Madison	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 & Broadland Lines Lakefield Jct. – Madison	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 & Broadland Lines Lakefield Jct. – Madison	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. – Madison	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. – Madison	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 CapX2020 Group I projects. Under a Midwest ISO market dispatch scenario, it was concluded that using DRG projects to meet the 2016 RES milestone was not 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 Midwest ISO market 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 methods by which the Midwest ISO studies and thus approves generation interconnection requests. In addition, this is not indicative of how power is dispatched in the real-time Midwest ISO market. Thus, this wider Twin Cities dispatch simply assumes that 2000 MW of DRG capacity will replace 2000 MW of existing Minnesota capacity under the real-time market dispatch. It is debatable whether adding this amount of new generation without additional bulk transmission and utilizing the unusual dispatch scenario described is realistically feasible. This scenario would result in significant existing generation in Minnesota that could not operate.

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. Due to the new transmission facilities in the model being fully subscribed and 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 capacity. 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). No attempt was made to evaluate the availability of appropriate terrain or availability of un-restricted land at these sites. In addition, 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 that capacity factor will have on the number of wind projects that must be installed to meet the 2016 RES milestone. 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 located in the Twin Cities area are producing less of the time and more turbines would be required to produce an equivalent amount of energy as those in more favorable wind areas. This is important because the investment cost of wind

[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 focused on safety, land values, and noise concerns among other issues. The GRE wind turbine was approved, while the Woodbury wind turbine was not.

turbines is much greater than the investment cost of transmission on a cost per MW basis.[5]

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 that are larger than 672 MVA, increasing the size of the transformers 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 fault current levels are nearing 63 kA – the interrupting limit of the 115 kV circuit breakers at Terminal.

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.

Considering all of these qualifications and while using all of the assumptions noted in this section, the DRG analysis showed that approximately 2000 MW of generation could be modeled using a Twin Cities dispatch.

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

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.

[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 energy at 25% capacity factor, approximately 2400 MW of wind turbines would be necessary. Information from Windustry for wind generation projects in 2007 indicates installed costs can range from $1.2 million to $2.6 million per MW. At those costs, this extra 400 MW results in an additional cost of $480 million to $1.04 billion.

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.

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

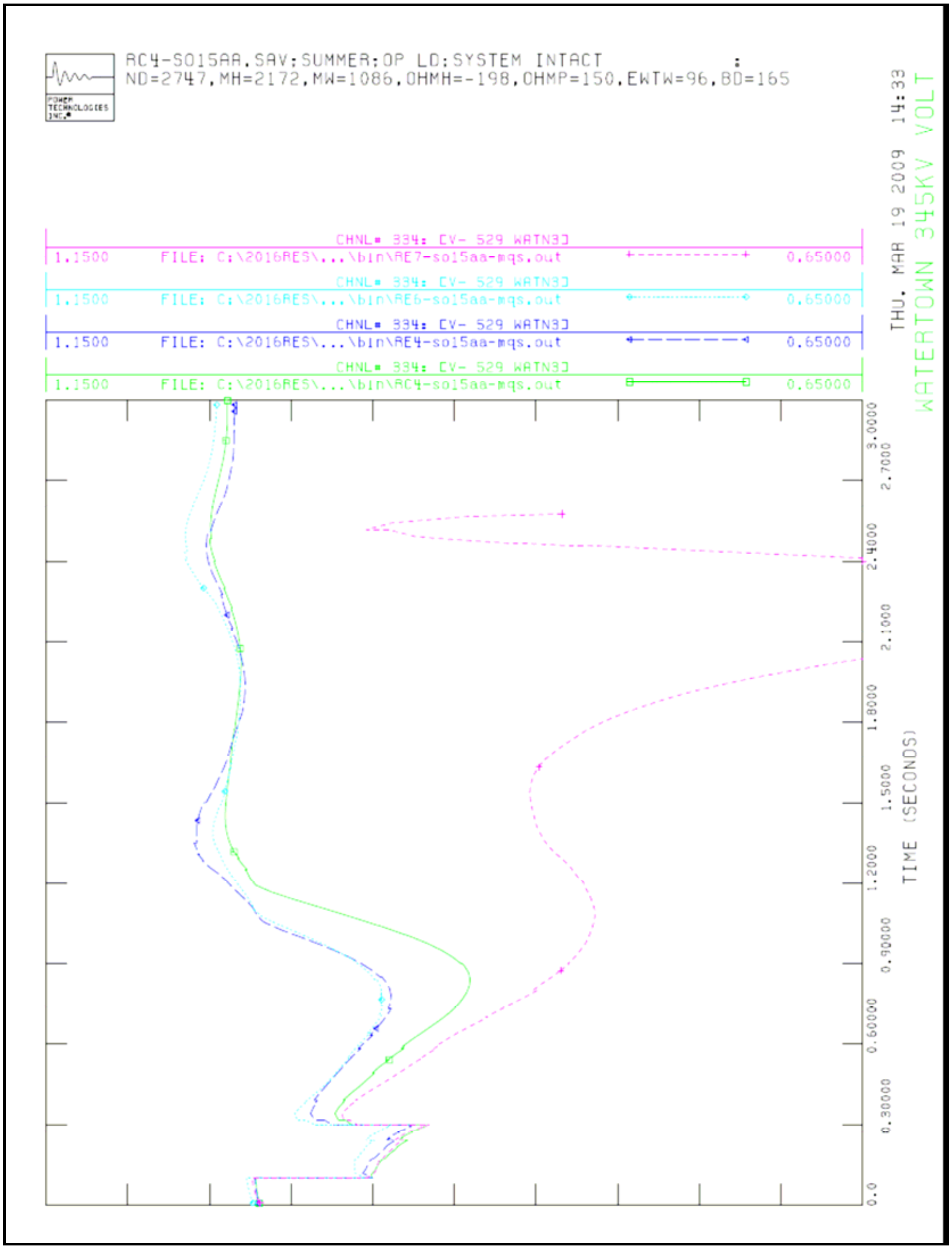
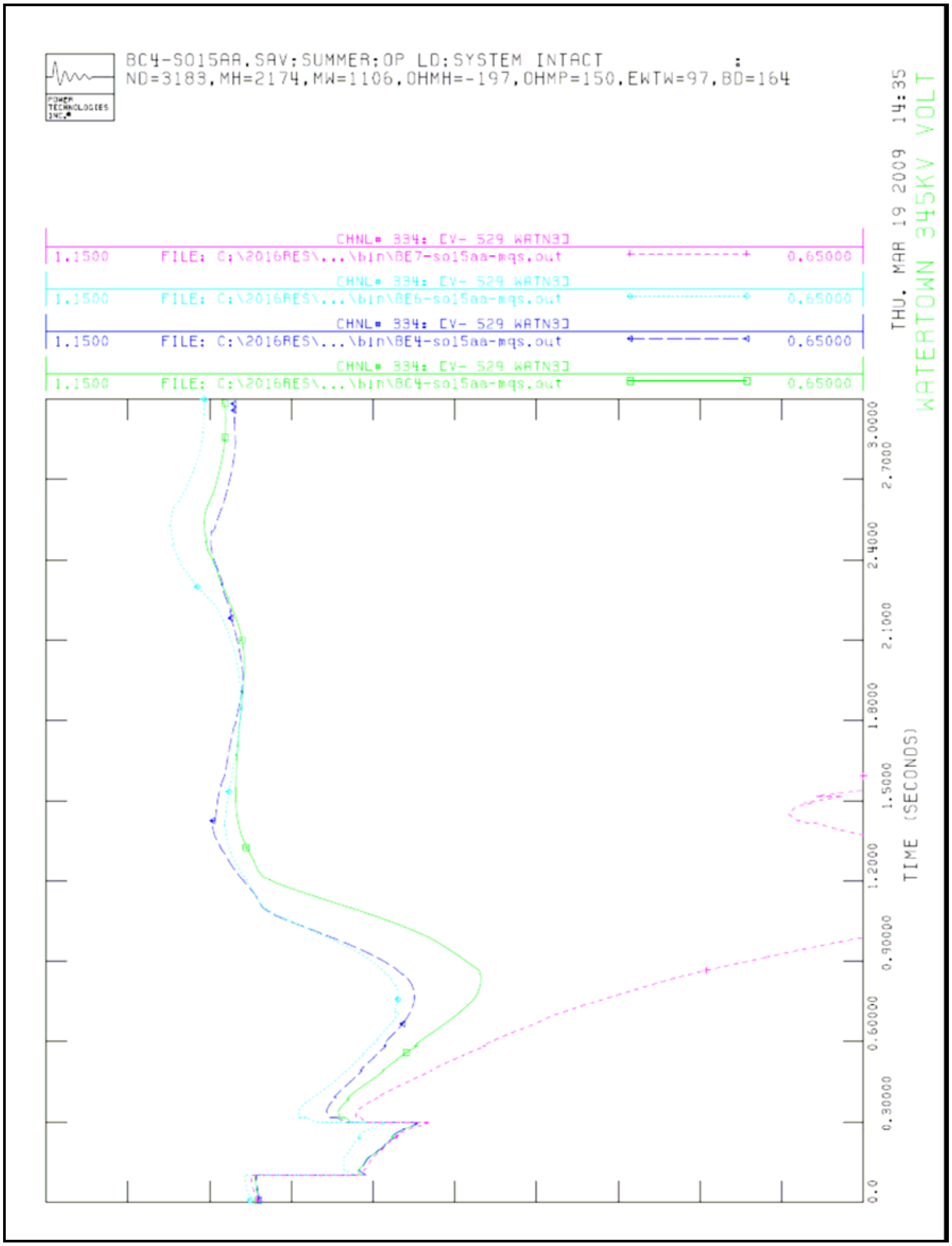


Figure 5.2.1.B – Watertown 345 kV Voltage with Big Stone II



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

Facilities	Generation	Source	Transmission Only			With Generation		
			Loss Without Facilities	Loss Without Facilities	Delta	Loss Without Facilities	Loss Without Facilities	Delta
	MW		MW	MW	MW	MW	MW	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 La Crosse-Madison	1581	ND / Cord	17500.5	17465.2	-35.3	17694.5	17652.8	-41.7
La Crosse-Madison	3600	ND / Cord	17500.5	17474.3	-26.2	18115.6	18072.2	-43.4
Adams-La Crosse La Crosse-Madison	3600	SE / Cord	17500.5	17468.3	-32.2	18115.6	18061.4	-54.2
Lakefield-Adams Adams-La Crosse La Crosse-Madison	3600	SE / Cord	17500.5	17460.3	-40.2	18115.6	18042.5	-73.1
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock La Crosse-Madison	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-La Crosse La Crosse-Madison	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 La Crosse-Madison	41.7	128,000,000
La Crosse-Madison	43.4	134,000,000
Adams-La Crosse La Crosse-Madison	54.2	167,000,000
Lakefield-Adams Adams-La Crosse La Crosse-Columbia	73.1	225,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock La Crosse-Madison	60.1	184,000,000
Maple River-Brookings Ashley-Hankinson Brookings-Split Rock Lakefield-Adams Adams-La Crosse La Crosse-Madison	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