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

500 kV Facilities Impact

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.

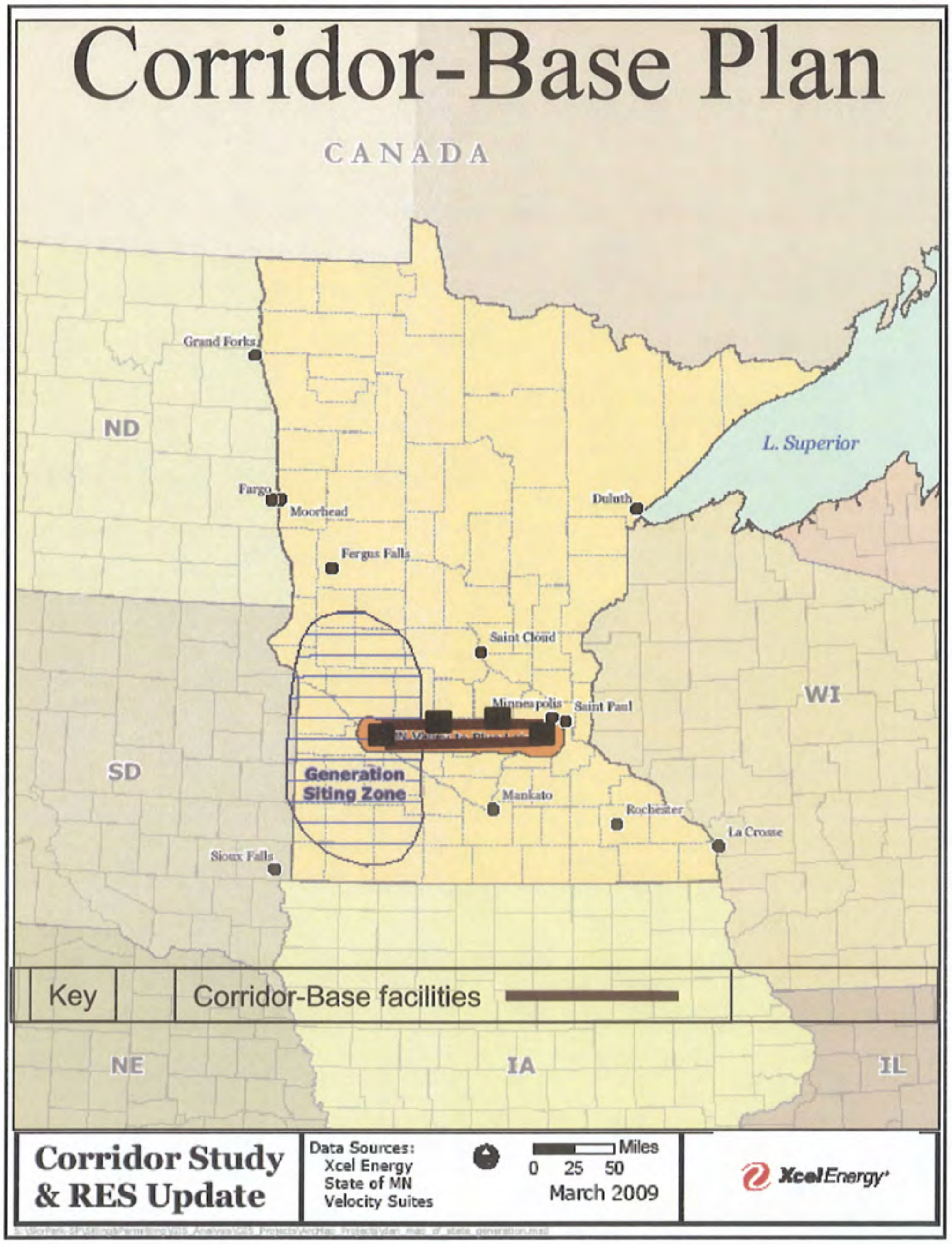
- The option called Corridor-Base ("Double-circuit 345 kV 1 express") consists of a Hazel Creek-Panther-McLeod-Blue Lake double circuit 345 kV line with one

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.

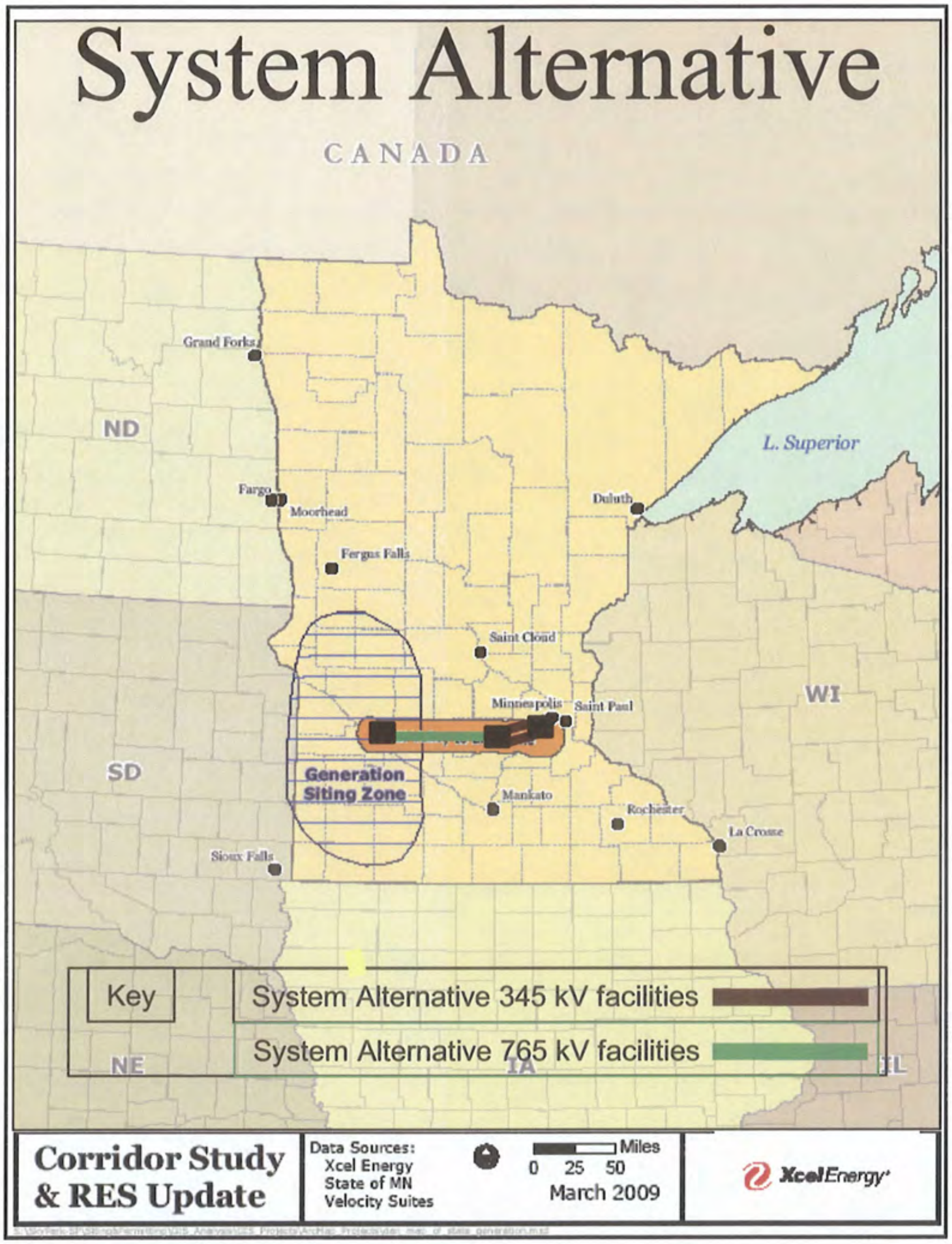
- The option called System Alternative ("765 kV New ROW") entails a 765 kV line from Hazel Creek to the West Waconia area with a double circuit 345 kV line from West Waconia to Blue Lake. This option has a great benefit if one of the recent proposals for such an area 765 kV development is successfully 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 *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. 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