Dispersed Renewable Generation Transmission Study

Volume I

Docket Number E999/DI-08-649

Prepared for:

Minnesota Department of Commerce
Office of Energy Security

Prepared by:
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June 16, 2008

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June 16, 2008

In May of 2007, Governor Pawlenty and the Minnesota Legislature adopted a requirement for a statewide study of dispersed renewable generation potential, in the legislation enacting the Governor's Next Generation Energy Initiative[1]. This report contains the analysis and results of the first phase of this study.

Study details. The focus of the study is to analyze, in two phases, the transmission impacts of 600 MW of dispersed renewable generation (1200 MW total) distributed in the five out-state planning zones. For purposes of this study, dispersed renewable generation projects are Renewable Energy Standard eligible generation projects (including wind, biomass, and solar) that are between 10 and 40 MW each. The goal of the study is to identify project sites that will minimize impacts to the transmission system. The potential locations studied were based on public input, regional availability of renewable resources, current dispersed generation in the MISO queue, and access to existing transmission. The priority was to first utilize the existing transmission system infrastructure then develop system upgrades as needed to mitigate affected transmission facilities. A second phase will be completed by September 15, 2009.

Study team. The Phase I study benefited greatly from a stellar assembly of national, regional and state technical experts representing the national energy laboratories, the Midwest Independent System Operator (MISO), wind and community energy advocates and Minnesota's utilities. This technical review committee (TRC) guided and reviewed the work of the analytic team. Four TRC meetings, each a full day, and numerous conference calls were held throughout the course of the study to review and discuss the study methods and assumptions, potential project locations, model development, results, and conclusions. With excellent input from the utilities, MISO, wind interests, and national experts, the TRC achieved consensus on the project sites to be studied, on the modeling approach, and on the key results and conclusions.

[1] Laws of Minnesota 2007, Chapter 136, Article 4, Section 17

The study analysis itself was completed by an analytic team lead by Jared Alholinna and his colleagues at Great River Energy in collaboration with the Minnesota electric utilities and with MISO. This team successfully completed an extensive amount of challenging and innovative work including development of the first state-wide models of the electrical system which include lower voltage lines and the development of new methodologies to identify potential opportunities for dispersed renewable generation. Without the commitment and creativity of this group of talented transmission engineers, the Phase I study could not have achieved its goals.

Study findings. The objective of this study work was to assess the potential ability to install 600 MW of dispersed renewable generation throughout Minnesota with minimal impacts on the transmission system. A number of potential opportunities for new dispersed generation in Minnesota are identified in the results of the Phase I report of the Dispersed Renewable Generation Study. After working through significant technical challenges with numerous iterations of configurations of potential installations, the Phase I analysis successfully demonstrated a dispersed renewable generation potential scenario where 600 MW could be sited without significantly affecting any transmission infrastructure. At the same time, the study results clearly indicate that even dispersed generation projects, individually and in aggregate, can have substantial impacts on the transmission grid overall.

In enacting the Governor's Next Generation Energy Initiative, the 2007 legislature established nation-leading renewable electricity requirements and greenhouse gas emissions reduction goals. These targets must be met, and must be met in timely, reliable, and cost-effective ways. It is a fundamental policy of the Minnesota Office of Energy Security that, in order to do so, we must employ the dual strategy of:

- Using our existing transmission infrastructure more efficiently, through the installation of dispersed renewable generation and
- Significantly increasing high-voltage transmission capacity in the state.

This Phase I study confirms and underscores that fundamental policy.

IMPORTANT NOTE: This study is a representative analysis. Parties interested in pursuing any of these potential opportunities must work with their transmission provider, as these results do not constitute a full interconnection study. This will require individual potential generation projects to apply for interconnection and to complete required interconnection studies to determine specific transmission impacts and receive approval to interconnect.

Next steps. In order to encourage successful implementation of these study findings, the Office of the Reliability Administrator intends to convene and facilitate a technical working group in the second half of 2008 to look into actions necessary, in coordination with MISO and with the Minnesota utilities, to interconnect potential projects that may be sited at locations identified in this study report. Specifically, the group will focus on lower voltage locations that, due to a number of technical and operational aspects, could potentially be interconnected through the local utility in coordination with MISO. The group will identify and develop appropriate procedures to ensure coordination between MISO and the Minnesota electric utilities on lower voltage state-level interconnections[2].

The work for Phase II of the Statewide study of dispersed generation potential will begin in the fall of 2008, with a report due by September of 2009. As challenging as this Phase I study has been, I expect Phase II will be much more difficult. It took an incredible amount of creative and technical work to find the 600 MW of dispersed generation for Phase I. One of the critical issues for Phase II will be whether this initial 600 MW approaches the technical limits for dispersed generation in the state without significantly affecting transmission infrastructure, or whether the Phase II work will be as successful as Phase I has been.

Thank you to all of the study participants for an extraordinary effort and a ground breaking study.

Sincerely,

Edward A. Garvey
Acting Reliability Administrator
Minnesota Office of Energy Security

[2] See Office of Energy Security report on state interconnection jurisdiction, issued June 7, 2008; completed in response to Minnesota Session Laws Chapter 136, Article 4, Section 21.

I hereby certify that this plan, specification or report was prepared by me or under my direct supervision and that I am a duly Licensed Professional Engineer under the laws of the state of Minnesota.

Jared Alholinna

Registration Number 26459
June 16, 2008

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Minnesota Transmission Owners (MTO)

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

Note: The Minnesota Transmission Owners (MTO) are utilities that own or operate high voltage transmission lines. When originally formed this group was made up of those utilities subject to 2000 legislation requiring transmission owners to file a biennial transmission report. Additional utilities have joined the MTO to collaborate on transmission studies associated with the 2007 Renewable Energy Standard legislation and this includes work like the DRG Study.

Technical Review Committee (TRC)

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Gordon Pietsch	Great River Energy
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Larry Schedin	Minnesota Chamber of Commerce (LLS Resources)
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I. Executive Summary

Abstract

The objective of the Dispersed Renewable Generation (DRG) Study was to assess the potential ability to install 600 MW of dispersed renewable generation throughout Minnesota with minimal impacts on the transmission system. A number of potential opportunities for new dispersed generation in Minnesota are identified in the results of Phase I of the Dispersed Renewable Generation Study Report. The statewide aggregate analysis successfully demonstrated a dispersed renewable generation potential scenario where 600 MW could be sited without significantly affecting any transmission infrastructure. However, extensive study and analysis showed that even dispersed generation can have substantial impacts on the electric grid.

The final potential site list included installing 300 MW in the Southeast transmission planning zone, 160 MW in the Southwest transmission planning zone, 100 MW in the West-Central transmission planning zone, 40 MW in the Northeast transmission planning zone and 0 MW in the Northwest transmission planning zone. This is a representative analysis. Parties interested in pursuing any of these potential opportunities must work with their transmission provider, as these results do not constitute a full interconnection study. This will require individual potential generation projects to apply for interconnection and complete required interconnection studies to determine specific transmission impacts and to receive approval to interconnect.

Purpose

In May 2007 the Minnesota Legislature approved the Next Generation Energy Act of 2007 directing the Minnesota Department of Commerce Office of Energy Security to manage a statewide transmission study of dispersed renewable generation potential. The study is to be divided into two phases of 600 MW each with reports due June 2008 and September 2009, respectively. The DRG Transmission Study's first phase goal is to analyze the impacts on the transmission system of 600 MW of dispersed renewable generation to be placed throughout Minnesota's five out-state transmission planning zones in 2010. The renewable generation projects are to be 10 to 40 MW and interconnected on the lowest voltage level transmission that exists in the vicinity of the projected generation sites. The study group expanded the legislated scope of the project to include study of the sub-transmission system impacts, where possible.

Background

Minnesota is a leader in renewable energy development with its Renewable Energy Standard (RES) requiring 25 percent of the energy produced by the state's utilities to come from renewable sources by 2025. Xcel Energy has been directed to supply 30 percent of its customers' electricity needs with renewable sources by 2020. The DRG Study is part of a greater effort to advance effective development of renewable energy.

Previous renewable energy studies have taken a cursory look at the impacts that generation interconnection may place on the reliability and cost of a dispersed renewable generation project. This DRG Study is a more comprehensive examination of the renewable generation potential in the context of where the generation is placed in the system and how it affects the greater interconnected electric system. This study supersedes studies like the West -Central Community-Based Energy Development (CBED) Study, and it offers a greater understanding of the optimal placement of renewable generation in Minnesota to meet the state's requirement with a specific focus on smaller scale development.

Process

Work on the DRG Study began in July 2007 when the Minnesota Department of Commerce appointed a Technical Review Committee (TRC) to oversee both phases of the study to make recommendations to the Minnesota Transmission Owning (MTO) utilities regarding all aspects of the study's technical methods and assumptions. Between July 2007 and May 2008, the study team progressed through the study milestones of substation data collection and modeling, substation site screening, short list system analysis and lastly, an analysis of the resulting final list of potential DRG sites. Throughout the process the TRC, along with the appropriate utilities, held several sets of public meetings in each of the five out-state transmission planning zones to collect input from all interested parties.

Findings

The substation data collection and modeling process resulted in an initial data set of 2258 Minnesota transmission substation buses. Since detailed analysis of each substation bus requires significant time and effort, the study team and the TRC decided to employ a screening process to develop a manageable number of DRG potential sites.

A site screening process narrowed the substation buses down to more than 300 potential locations. Using engineering judgment to review key substation characteristics further narrowed this list to 42 geographically diverse potential sites most appropriate for DRG interconnection. This list of 42 will be referred to as the Potential Short List of DRG Sites. The 42 generation sites are spread rather evenly throughout the five outstate transmission planning zones. Of this short list, three sites are biomass generation and the rest are wind generation.

The next study steps analyzed the impact of the 42 potential sites on the greater transmission system. The study team ran a steady-state analysis program to determine how the individual sites, the zonal aggregation of sites and the statewide aggregation of sites affected the reliability of the electric grid. The computer program was run using a model with the DRG and then a model without the DRG. These two runs were then compared to determine the impact of the DRG on the transmission system. Results of the single site and zonal aggregation analysis found that for the Northeast transmission planning zone, the Northwest planning zone and the West –Central planning zone, the significantly affected facilities (or overloads) had a common limiting factor of either of the two 230/500 kilovolt (kV) transformers at the Dorsey substation near Winnipeg, Manitoba, Canada.

The Dorsey transformer issues proved to be a significant finding in the DRG Study. When any type of new generation, in this case DRG, is placed on the sub-transmission or transmission system, the generation output will seek the lowest impedance path to the loads. The DRG steady-state analysis found that for the individual, zonal and state aggregation in the Northwest, Northeast and West-Central zones, one of the significant low impedance paths is through the Dorsey substation transformers.

The high voltage transmission system in northern Minnesota and North Dakota is connected to Manitoba through three parallel 230 kV transmission lines that ultimately provide paths to the Dorsey substation near Winnipeg, Manitoba. At the Dorsey substation these two transformers step up or transform the voltage from 230 kV to 500 kV to provide an effective way to bring power from Manitoba to the Twin Cities area. These transformers are already fully loaded without the addition of DRG in Minnesota. The study's steady state analysis showed significant power flow from the new generation making its way to the 230 kV / 500 kV Dorsey transformers resulting in unacceptable overloads.

Data, maps and diagrams describing the Dorsey issue can be found in the body of this report. The report also addresses some possible mitigation approaches to solve the Dorsey issue.

The study team with TRC input explored many approaches to resolve the Dorsey transformer issue in the context of this DRG Study. The final consensus was to rerun the steady-state analysis shifting the DRG sites from northern zone sites to the zones in the south and east. The study team ran the individual, zonal and statewide analysis repeatedly each time shifting potential DRG sites to the south and east to avoid the Dorsey issue. The final list of potential DRG sites reflects that shift with the aggregated outlet capability in MW of DRG as follows:

- Northwest Transmission Zone, 0 MW;

- Northeast Transmission Zone, 40 MW;
- West-Central Transmission Zone, 100 MW;
- Southwest Transmission Zone, 160 MW;
- Southeast Transmission Zone, 300 MW.

The study objective of integrating 600 MW of statewide total potential DRG sites was achieved. But, the challenges in doing so should not be discounted. The study team and TRC dealt with some complicated technical concerns to reach this outcome.

Conclusions

The collaborative process of the study team with the TRC and public input provided a robust environment for rigorous analysis and creative problem solving.

The statewide aggregate analysis demonstrated a dispersed renewable generation scenario where a total of 600 MW of 10 to 40 MW new generation projects could potentially be sited without significantly affecting any transmission infrastructure. Significant impacts to the high voltage transmission system were found in the initial site distribution, as indicated by the Dorsey transformer issues, which limit the dispersed renewable generator outlet capability in aggregate and at many of the individual sites. Additionally, the single site analysis revealed that 19 of the 42 Potential Short List of DRG Sites had transmission limitations at levels below 40 MW. The transmission limitations were identified for these sites and specific system upgrades were formulated for each site.

The DRG Study team was tasked with identifying favorable project sites with minimal impact to the transmission system located throughout the five outstate Minnesota planning zones. Months of data collection, model building, site screening, steady-state analysis, loss analysis, and transient stability modeling have produced sound results. The study team, with stakeholders' input, has identified a number of promising sites to reach the study's statewide goal of analyzing the impact of 600 MW of DRG on the transmission system. However, there may be existing interconnection requests in a utility queue or MISO queue that might occupy these potential DRG sites.

Table 1 – Statewide Potential DRG Sites

Zone	Zone Total (MW)	DRG Site	DRG Site (MW)
NW	0		
NE	40	Cloquet	40
W-C	100	Glencoe Municipal	40

Zone	Zone Total (MW)	DRG Site	DRG Site (MW)
		Bird Island	40
		Atwater	20
SW	160	Sveadah	19
		Steen	21
		New Ulm	21
		Mountain Lake	21
		Morgan	21
		Magnolia	16
		Lakeside Ethanol	21
		Brookville	19
SE	300	Waseca	39
		Vasa	39
		New Prague	39
		Lafayette	29
		Goodhue	39
		French Lake	39
		Crystal Food	39
		Airtech	39

The team also identified several interesting opportunities for additional analysis that may be investigated in the DRG Phase II Study.

DRG developers need to contact the local utility to examine opportunities for DRG site selection and foster coordination for further study work and/or interconnection requirements.

This study report is the result of extensive examination of the statewide potential for DRG sites. The detailed assessment of any individual site's actual and specific DRG potential requires coordination with the local utility and a regional transmission provider such as MISO or MAPP to conduct interconnection studies and assess delivery possibilities. Most Minnesota utilities have documented interconnection guidelines available on their Web sites that help explain their processes and requirements. The US Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and the Midwest Reliability Organization (MRO) each have generation interconnection requirements as well.

This study report represents a snapshot in time. Due to the tremendous level of wind generation interconnection requests in Minnesota and the surrounding states, some – or possibly all – of this transmission capacity may be used by other resources or interconnection requests, with some due to loop flow issues.

This study should be understood as indicative only. The performance of specific projects will depend on actual system performance and assumptions.

In addition, the wind performance identified at specific locations is based on wind forecasting models and should be viewed as providing relative levels among sites. Generators should not rely on the specific capacity factors identified but rather on their own measurements of actual wind conditions at the sites.

II. Introduction

The state of Minnesota has made a significant commitment to increasing the development and use of renewable electricity through various legislative and regulatory requirements. The latest of these is the Renewable Energy Standard (RES), which requires that 25 percent of the electricity consumed in Minnesota be generated by renewable resources by 2025. This is one of the highest state renewable commitments in the United States and the Minnesota utilities have a vested interest in the collaborative process to help the state meet its legislated RES goals. Additionally, Minnesota's RES also holds Xcel Energy to a higher standard, requiring that utility to supply 30 percent of its customers' electricity needs with renewable sources by 2020.

Minnesota has made corresponding commitments to transmission planning and construction to support compliance with the RES. One of the challenges the state of Minnesota and the Upper Midwest region faces is how to advance renewable electric generation while maintaining the reliable, cost-effective electric power system we all depend on for the stability of our economy and the quality of our lives. As energy demand grows and the interconnected bulk electric transmission infrastructure is strained, careful analysis, planning and coordination is necessary to ensure the prudent and effective implementation of additional generation and electric transmission system upgrades.

The DRG Study is one of several coordinated efforts intended to support Minnesota's continued leadership in renewable electric generation development. The Minnesota Transmission Owners (MTO) sponsor four other studies: the Corridor Study, the 2016 Transmission Study, the 2025 Transmission Vision Study and the Generation and Transmission Optimization Study. The MTO is made up of utilities that own or operate high voltage transmission lines in the state of Minnesota. When originally formed this group consisted of those utilities subject to the 2000 legislation requiring transmission owners to prepare a biennial transmission report. Additional utilities have joined the MTO to further collaborate on transmission study work associated with the 2007 RES legislation including efforts like the DRG Study.

The Corridor Study examines the 230 kV transmission corridor between the city of Granite Falls and the southwest corner of the Twin Cities for possible upgrade opportunities. The 2016 Transmission Study looks at the RES resource gap and identifies transmission alternatives to meet the 2016 RES while supporting long-term transmission development. The 2025 Transmission Vision Study develops a transmission plan that addresses the RES, load growth and planning reserve requirements and is coordinated with the MISO transmission expansion planning process. The Generation and Transmission Optimization Study is intended to analyze the economic benefits of siting wind projects in high wind regions where additional transmission is needed for energy delivery versus more local marginal wind regions where less new transmission infrastructure will be needed. (Contact MTO members for more information).

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 transmission system with limited access points act like interstate highways, moving electric power long distances from region to region. The sub-transmission lines are more like neighborhood roads delivering power to retail customers. The focus of this DRG Study is to assess the impact of connecting new dispersed renewable generation to the Minnesota lower voltage transmission grid (the 'neighborhood roads') while maintaining the intricate balance between the generation and power transmission system. For the purposes of this study, dispersed renewable generation is defined as resources between 10 and 40 MW of peak capacity.

The term 'transmission' often is used generically for high voltage wires. This report also refers to the terms 'sub-transmission' and 'distribution'. The distinction between the three and their definitions are difficult to clearly and succinctly describe. There has been much debate and controversy on the three classifications of the electric system. There have been rulings by the Federal Energy Regulatory Commission (FERC) on determinations of jurisdiction by MISO and other Regional Transmission Organizations (RTOs). FERC and the National Electric Reliability Corporation (NERC) have published definitions on what constitutes distribution or distribution providers and transmission.

NERC offers the following definitions:

> <u>Distribution provider</u>
> Provides and operates the 'wires' between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the transmission owner also serves as the distribution provider. Thus, the distribution provider is not defined by a specific voltage but rather as performing the distribution function at any voltage.
>
> <u>Transmission</u>
> An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

From FERC's glossary:

Distribution
For electric - The act of distributing electric power using low voltage transmission lines that deliver power to retail customers.

Transmission
Moving bulk energy products from where they are produced or generated to distribution lines that carry the energy products to consumers.

The Minnesota Public Utilities Commission has determined that lines over 50 kV located in Minnesota are presumptively transmission, unless demonstrated to be distribution assets after applications of relevant factors, including FERC's 'seven-factor test'.

For the purposes of this study, and without setting precedent, the transmission system is defined as facilities with voltages greater than 50 kV; the sub-transmission system consists of facilities below 50 kV and above 15 kV; and distribution are facilities 15 kV and below.

The transmission voltages common in Minnesota are 500 kV, 345 kV, 230 kV, 161 kV, 115 kV and 69 kV. Sub-transmission voltages include 46 kV, 41.6 kV, 34.5 kV and 23 kV and the wide range of distribution voltages include 14.4 kV, 13.8 kV, 13.2 kV, 12.47 kV, 4.16 kV and 2.4 kV. There is some functional overlap at the 23 kV and 34.5 kV levels; in some areas these lines function as components of the sub-transmission system, whereas in other areas they are distribution circuits.

A. Summary of Study Scope

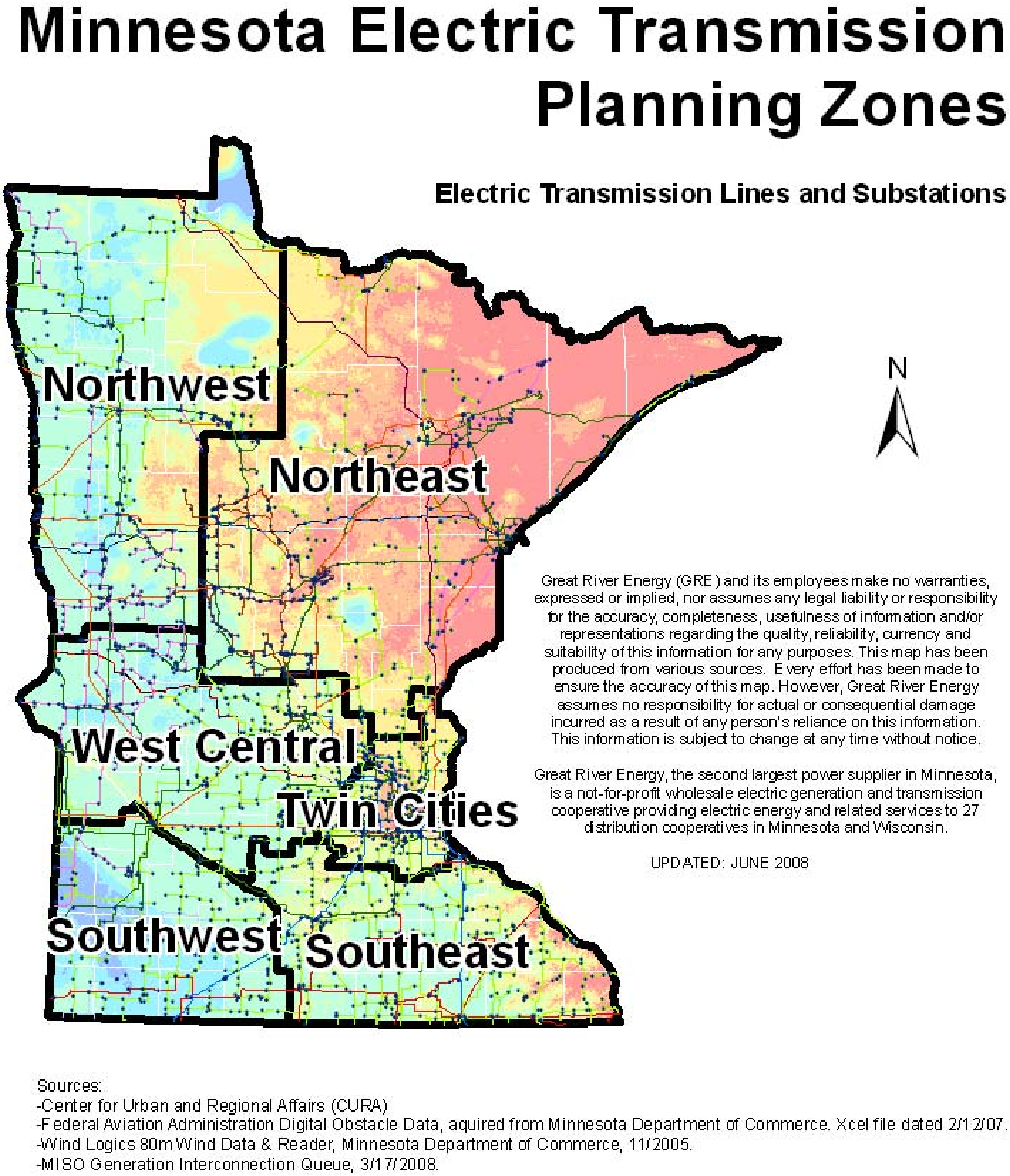
In May 2007 the Minnesota Legislature enacted significant energy legislation called the Next Generation Energy Act of 2007 that, among many other things, stipulated a statewide study of dispersed generation potential to be coordinated by the Minnesota Department of Commerce. This study is known as the Dispersed Renewable Generation (DRG) Transmission Study (or DRG Study). Its objective is to analyze the potential for the impacts of 600 MW of dispersed renewable generation assumed to be placed on the system in 2010. The study also assumes, as directed by the legislation, that the projects will be 10 to 40 MW each and will be interconnected to the electric transmission system.

The goal of the first phase of the study was to identify potential project sites that will minimize impacts to the transmission system. The priority was to first utilize the existing transmission system infrastructure then identify potential system upgrades necessary to mitigate the effects of additional DRG upon transmission facilities. The study team set out to evaluate the electric transmission system impacts, develop specific solutions and assign associated solution costs. Minnesota electric utilities collaborated to provide vital substation and transmission data that was then used in the DRG site selection and system modeling processes. The study team produced meaningful, broadly supported results through a technically rigorous study process.

The DRG Study considered the type of renewable generation to be studied. The study site screening criteria was designed to identify the highest quality renewable resource with proximity to available transmission capacity while also considering public input.

The renewable dispersed generation was to be distributed among the five out-state planning zones. The planning zones are described as Northeast, Northwest, West-Central, Southwest and Southeast. The Twin Cities transmission planning zone was excluded in the DRG Study as part of a statutory decision.

A map of the planning zones in Minnesota is shown below. More detailed maps of each zone can be found at http://www.minnelectrans.com/ and a list of the transmission planning zones is located in the upper left hand corner of the Web site homepage. After selecting a zone, a link is enabled in the top center of the page that directs you to a detailed map of the zone.



Map 1 – Minnesota Electric Transmission Planning Zone Map

The DRG Study analytical work was conducted by the Minnesota transmission owning utilities and Midwest Independent Transmission System Operator (MISO). While engineers at Great River Energy, MISO, and consultants hired by the Minnesota utilities did the majority of the analytical work, personnel at many of the Minnesota utilities collected and provided valuable electrical transmission and distribution systems data to allow the core study team to build a state-wide model of the generation and transmission grid.

The Minnesota Department of Commerce appointed a technical review committee (TRC) to review and guide the key assumptions, methods, and analysis and to review the preliminary and final results. TRC members are individuals with experience and expertise in electric transmission system engineering, renewable energy generation technology and dispersed generation. This team will regularly review both the first and second phases of the study.

B. DRG Legislation

One of the stated goals of the Next Generation Energy Act of 2007 is to bolster investment in the development of renewable generation. Section 17 of this legislation requires a Statewide Study of Dispersed Generation Potential (the DRG Study). The legislation breaks down the study requirements into two phases of 600 MW each with separate reports due June 2008 and September 2009. The full text of the Next Generation Energy act can be found at https://www.revisor.leg.state.mn.us/bin/bldbill.php?bill=S0145.2.html&session=ls85 .

The enabling legislation, the Next Generation Energy Act of 2007, states that "each electric utility subject to the Minnesota Renewable Energy Standard (RES) (Minnesota Statutes, section 216B. 1691, https://www.revisor.leg.state.mn.us/statutes/?id=216B.1691), must participate collaboratively in conducting a two-phase study of the potential for dispersed generation projects that can be developed in Minnesota."

An additional legislative requirement dictates that the Commissioner of Commerce appoint a Technical Review Committee (TRC) prior to the start of the first phase. The legislation calls for the team to be comprised of individuals with experience and expertise in electric transmission system engineering, renewable energy generation technology and dispersed generation. The TRC must oversee both phases of the study making recommendations to the utilities regarding the study's technical methods and assumptions. The legislation also stipulates that the TRC, with the appropriate utilities, hold public meetings prior to each phase of the study in each of the five out-state electric transmission planning zones. The mandate further requires establishing procedures for handling commercially sensitive information for all individuals who have access to the study data and results before they are publicly distributed.

According to the legislation, “in the first phase of the study participants must analyze the impacts of 600 MW of new dispersed renewable generation” distributed in the Northeast, Northwest, West-Central, Southwest and Southeast Minnesota electric transmission planning zones. The legislation defines dispersed generation as an electric generation project with generating capacity between 10 and 40 MW that utilizes an “eligible energy technology.” According to referenced legislation, eligible energy technology includes an energy technology that generates electricity from the following renewable energy sources: solar, wind, biomass, and hydroelectric with a capacity of less than 100 MW (https://www.revisor.leg.state.mn.us/statutes/?id=216B.1691).

The study must employ a “generally accepted 2010 transmission system model including all transmission facilities expected to be operating in 2010.” The project methodology must consider regional projected load growth, planned changes in the bulk transmission system network and long-range transmission plans being developed for the RES. The Next Generation Energy Act also mandated the consideration of wind resource, existing and contracted wind projects, and current dispersed generation in the MISO interconnection queue. The MISO generation interconnection queue is a list, currently first-come first-serve list used in the process to obtain an interconnection agreement from MISO to place new generation on the region’s electric transmission system.

The legislation orders the study to “analyze the impacts of individual projects and all projects in aggregate on the transmission system and identify specific modifications to the transmission system necessary to remedy any problems caused by the installation of dispersed generation projects, including cost estimates for the modifications. The study must analyze the additional dispersed generation projects connected at the lowest voltage level transmission that exists in the vicinity of the projected generation sites. A preliminary analysis to identify transmission system problems must be conducted with the projects installed at initially selected locations. The technical review committee may, after reviewing the locations selected for installation recommend moving the installation sites once to new locations to reduce undesirable transmission system impacts.”

C. 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 was handled correctly. 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, all TRC members completed a non-disclosure agreement allowing them access to the process and preliminary results. In conformance with FERC requirements, the report's final results and conclusions of the DRG Study were revealed at the same time to all interested parties.

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. Examples of standards relating to the DRG Study include the Transmission Planning Standards TPL 001-0, TPL 002-0, and TPL 003-0. These standards describe how reliable systems need to be developed to meet specific performance requirements under normal conditions (category A); following the loss of a single bulk electric system element (category B); and following the loss of two or more bulk electric system elements (category C). The DRG Study modeling and analysis followed each of the three referenced TPL standard requirements. Details on NERC standards can be found at http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

D. Schedule

The DRG Study began in earnest in July 2007 when the TRC was appointed by the Minnesota Department of Commerce, Office of Energy Security. The TRC provided review and guidance throughout the process. Four full-day TRC meetings and a number of conference calls were held. The first TRC conference call was held in August to initiate the process of goal setting, agree on the approach and set general guidelines. Additional TRC meetings and calls were held October 2, December 19, February 20, April 10, April 30, May 16, and May 30.

In September 2007 the utilities comprising the Minnesota Transmission Owners organized the project team with the core group of engineers who began the analytical work. The first major milestone was the substation data collection process which took place between October and December of 2007. The site screening analysis ran from December through February; the project team ran several programs for the AC analysis between February and May; assessing the results, drawing conclusions and writing the report ran from May through the deadline of June 15; and three sets of public meetings were held in September 2007, March/April 2008 and June/July 2008.

The project study team made adjustments to the analytical process based on the direction given by the TRC and the feedback from the public meetings.

Table 2 – Dispersed Renewable Generation Study Timeline

Dispersed Renewable Generation Study Timeline	
Jul 2007	Technical Review Committee (TRC) selected by Minnesota Department of Commerce.
Aug 15, 2007	**TRC teleconference to initiate group with structure, process and schedule. Preliminary study work and study plan were presented.**
Sept 2007	Minnesota Transmission Owning utilities choose engineers for study team, and they begin analytical work.
Sept 2007	First set of public meetings to gather input on site selection and comments.
Oct 2, 2007	**First TRC meeting to review public input, MISO queue status, system modeling and substation data collection process.**
Oct – Dec 2007	Substation data collection process.
Dec 19, 2007	**Second TRC meeting to assess site screening methodology, sub-transmission system modeling and biomass projects.**
Dec 2007 – Feb 2008	Site screening analysis.
Feb 20, 2008	**Third TRC meeting to discuss second set of public meetings, screening methodology, analytical studies and implementation of study results.**
Feb – April 2008	AC analysis.
Mar/Apr 2008	Second set of public meetings to provide DRG Study update.
Apr 10, 2008	**TRC teleconference to discuss enhanced screening methods, analytical steps and revised substation bus short list.**
Apr 30, 2008	**Fourth TRC meeting to review key results, findings and conclusions.**
May – Jun 2008	Assess results, draw conclusions and write report.
May 16, 2008	**TRC teleconference to review updated analysis.**
May 30, 2008	**TRC teleconference to review and discuss draft report.**
Jun 16, 2008	Publicly accessible webinar to review DRG Study report results.

E. Stakeholder Involvement

While the enabling legislation provided clear direction in many aspects of the DRG Study, key issues and questions were left to be resolved by the TRC and the project study team with input from other stakeholders. These key issues and questions included determining the mix of renewable generation to be studied, development of the system model and clarifying assumptions, the scope of the analysis and methodology, and the range of the solutions to be considered. It was important for the project team to consider how the study results might be used and to focus on providing a useful and practical study report.

In order to produce the most useful results, the project team made several efforts to seek stakeholder involvement. The MTO, an organization formed to collectively address transmission planning-related legislation, provided substation and other transmission system data to enable the project team to build an accurate model. The engineering expertise of MTO transmission planners was requested throughout the process to ensure assumptions, models and analytical methods were on track and accurately reflected the true nature and operations of the transmission system.

The TRC met regularly with the study team throughout the study process to provide review and guidance. The interaction at these meetings offered the committee of experts opportunities to assess the technical merits of the process and present additional information and strategies to ensure the best outcome. Some examples of key considerations put before the TRC included decisions regarding the scope of analysis and methodology; how to conduct the steady-state and stability studies; what are reasonable generation re-dispatch assumptions; what level of aggregation is appropriate – sub-zonal, zonal, statewide; and how to weight the analysis of individual projects versus the aggregation of projects.

Two sets of public meetings were held to provide the opportunities for the public input to the process. A publicly accessible webinar will be held June 16, 2008, to present the results. Each set of meetings was held in each of the five out-state transmission planning zones. These meetings were held in conjunction with the Southwest Initiative Foundation and their introduction of the Rural Energy Development Initiative (REDI) program.

The Southwest Initiative Foundation is a regional community foundation selected to manage and implement a Minnesota statewide program designed to provide organizing and technical support to rural entities seeking to develop wind energy electric generation projects. This program is sponsored by the state of Minnesota and was established by the Minnesota State Legislature in 2007.

The first set of public meetings held in September 2007 allowed input on site suggestions and project size. Attendees could fill out surveys to submit site suggestions and present concerns and ideas. The project team listened carefully to key public input comments and themes. The meetings were held in Cloquet (Northeast planning zone), Thief River Falls (Northwest planning zone), Morris (West-Central planning zone) Owatonna (Southeast planning zone) and Marshall (Southwest planning zone).These meetings attracted nearly 500 interested citizens.

To determine which renewable generation should be studied, project team members looked at the quality of the renewable resource and its proximity to available transmission. The team also sought public input at the first set of public meetings in each of the five transmission planning zones. Based on feedback received at four out of five of the public meetings, the TRC decided to include some biomass sites. This information, combined with a biomass study conducted by the University of Minnesota ("Integrating Biomass to Produce Heat and Power at Ethanol Plants"), provided data for electric generation from potential biomass cogeneration at existing and planned ethanol plants in various locations in Minnesota. The assumption in the University of Minnesota study is that the waste heat will be used to meet process needs.

The second set of public meetings was held in March and April 2008. These meetings provided a general update of the DRG Study process, status and schedule. Over 200 people attended these meetings, which were held in Owatonna (Southeast planning zone), Marshall (Southwest planning zone), St. Cloud (West-Central planning zone), Grand Rapids (Northeast planning zone) and Mahnomen (Northwest planning zone). Speakers at the public meetings included representatives from the Minnesota Department of Commerce and the MTO.

The meetings did not include a presentation of the interim study results due to the commercially sensitive nature of the data. The confidentiality requirements spelled out in the legislation recognized the importance of retaining the preliminary data within the TRC and the study team until the final report was completed and made public.

The third set of public meetings will be held in late June through July 2008 after the report is released.

Key issues brought to the study team and TRC through the public meeting process include:

- Concerns about the aggressive timeline and its effect on study results;
- The project development barriers of transmission constraints and line siting;
- Frustrations with the MISO interconnection queue process and costs;
- The desire for more transmission interconnection options;
- The need to focus on conservation and energy efficiency to meet energy needs;
- The potential increased costs of dispersed renewable energy on ratepayers;
- Whether the 10 MW minimum site limit was too high for small communities who may be interested in smaller projects; and
- The public felt the team should keep in mind interactions with existing wholesale transmission contracts and policies and their impact on local distribution system operations.

The project team and the TRC carefully considered this feedback.

III. Models and Assumptions

The TRC and the study team spent a significant amount of time and effort in defining the study assumptions and the transmission modeling process because it was vital to begin with an accurate representation of the Minnesota transmission system, including the impacts of the greater integrated grid. The Minnesota integrated electrical system includes 13 transmission owning electric utilities, approximately 400 individual electrical generating units, more than 23,000 miles of transmission lines, and over 2,600 transmission substation buses supplying 12,000 plus MW of load (load calculated from the Midwest ISO Transmission Expansion Plan 2007 summer 2013 peak model).

Modeling the system to the detail needed to evaluate the transmission impact of the dispersed generation on the sub-transmission system was a complicated and time consuming task. The team determined generation type and location and load assumptions; the extent to which sub-transmission systems would be modeled and how to handle radial sub-transmission lines; and which wind turbine technology to model for these new dispersed generation sites. The goal of the model was a set of assumptions that reasonably mirror the probable installation and operation of geographically dispersed 600 MW of wind generation in the 2010 timeframe.

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 substation modeling effort.

MTEP 2013 Summer Peak and Off-Peak Models

To begin the process of the substation data collection, the project team started with data from the Midwest ISO Transmission Expansion Plan 2007 (MTEP07), which is a model of the entire Midwest region's transmission system as well as future transmission expansion plans. From this widely accepted data source, the team found that the closest date to the desired 2010 model was the MTEP07 2013 model. Given the study time constraints, the team determined that, since the MTEP07 did not have a2010 data model, this off-the-shelf model would provide the best initial model set. The team utilized the summer 2013 summer peak and off-peak models.

Planning studies are typically done with at least two different models: summer peak and summer off-peak. The summer peak condition is a model of the peak load condition in the summer. While by definition the summer peak occurs only once per summer, the utilities still have an obligation to have the transmission infrastructure necessary to support this peak load. During summer peak load, it is typical to have a wide range of generation on-line, including less economical generation. Due to the elevated load levels and an increased number of generators running, the generated power has a tendency to stay local and serve load nearby. The summer peak condition during the peak load, also places the most stress on the lower voltage transmission or sub-transmission systems, and the study of this condition is vital for the continued reliability of the transmission system.

It is also vital to examine the summer off-peak condition since it is generally more taxing to the higher voltage transmission system than peak conditions. Under this summer off-peak scenario, electrical loads are lower than peak load (typically 70 percent of peak) and less economical peaking generation is taken off-line. Less economical generation plants are those generators that have higher production costs, like natural gas-fired peaking plants. Often wind generation is near its peak during the summer off-peak times.

The electrical system must remain in balance, so the power that is generated must be used by a load somewhere. The energy from the wind generator will flow to a load that is further away if there is not enough electrical demand close by to consume the power. The effect of this is to force more of the generation on to the high voltage transmission grid for consumption by distant loads. This additional electrical power flow changes the power flow pattern and could increase the stress on the high voltage transmission line; this can create overloads that can cause congestion on the higher voltage grid.

Integrated GRE-LRP/OTP Transmission Model Detail

Several information sources were integrated into this MTEP07 2013 model to develop an accurate statewide transmission model. Supplementing the MTEP07 data with the Great River Energy Long Range Plan (GRE-LRP) Transmission and Ottertail Power (OTP) models allowed for more sub-transmission model detail. The other major change to the MTEP07 model was the renumbering of several bus numbers that conflicted with the GRE-LRP model.

Additional Detail Gathered from Minnesota Utilities

The project team gathered additional transmission system detail information from Minnesota utilities, such as historical minimum and maximum load data, transformer ratings and geographical locations. Additional detail of the lower voltage system, including 23 kV, 34.5 kV, 41.6 kV, and 46 kV sub-transmission lines, was provided by each utility. Steps were taken to ensure that load was not duplicated when this detail was added.

The study team compared the GRE's/United Service Group (USG) Geographic Information System (GIS) database with utility one-line diagrams to geographically locate transmission substations in the model. The GIS data was linked with an Access database to allow for the easy display of data. Maps of this data can be found in Appendix A.

The additional transmission detail was added to the summer peak and summer off-peak models through a series of automation files. The models were then compared to utility one-line diagrams to ensure continuity. This was an iterative process since the data was being brought together from many different sources.

Once the detailed model matched the utility one-line diagrams, the study team compared the GRE/USG's Geographic Information System (GIS) database with the complete models. The goal was to visually represent the new models in map format.

The GIS data was linked with an Access database by importing spreadsheets and using queries to format the data. All of the supplied information was keyed off of the substation bus number. Having this unique identifier for each bus allowed for the linking of the data acquired to a geographic point on the map.

Adjusted Topology to 2010

Next the team made a topology adjustment to remove all bulk electric system additions, like transmission and generation upgrades, reflected in the MTEP07 2013 model that would come into operation between 2010 and 2013. The major projects that were removed from the models are listed below and more detailed descriptions of the projects are listed in Appendix B:

1. Four CapX2020 Group I Projects
2. Big Stone II generation plant and the associated transmission projects
3. Hazelton 345/161 kV transformer upgrade
4. Fairfax 2nd transformer
5. Beverely substation
6. Mill Road/Lannon transformer and lines
7. Riverton-Swatra-Boswell 230 kV line
8. Reid-AB Brown-Gibson 345 kV line

Wind Profile Information

Finally, once the transmission system model had been adapted to more closely represent the projected 2010 transmission system scenario, the study team superimposed the model to the wind profile developed for the 2006 Minnesota Wind Integration Study. WindLogics utilized a sophisticated science-based atmospheric model developed over a three year period which was validated with historical data. This model took into account wind speed, air density, power density and energy production over sections 500 meter squared for the state. Capacity factors were then calculated at 80 meters based on a 1.65 MW turbine with production discounted 15 percent to represent real world conditions. This data was used to accurately represent long-term (40 year) wind speeds over the state. The source of the wind profile can be found at http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881736&programid=536905849&sc3=null&sc2=-536887792&id=-536881351&agency=Commerce.

MISO Queue Information

The Midwest ISO (MISO) Generator Interconnection Queue was reviewed as a resource for information related to potential additional generation projects proposed in the region. It was established under the Midwest ISO Open Access Transmission Tariff (OATT) and contains all active generation interconnection requests on the systems of Midwest ISO transmission owners. The MISO Generation Interconnection Queue was created by merging the pre-existing queues of MISO transmission owners. New requests for interconnection are added sequentially and processed in accordance with MISO procedures. The queue can be found at http://www.midwestiso.org/page/Generator+Interconnection.

The study team used GIS tools to compare the transmission planning zone boundaries with the county boundaries in the state. Doing this allowed the team to easily compile lists of the counties in each zone.

The team then sorted the MISO Queue projects by state and then by county, allowing for the easy summation of projects for each of the planning zones. The results of the calculations are given in the Table 3 below.

Table 3 – Summary of Substation Information

Summary of Substation Information					
Planning Zone	Number of Substation Buses	Summer Peak Load (MW)	Summer Off-Peak Load (MW)	MISO Queued (11/26/07) Generation (MW)	MISO Queued (11/26/07) Dispersed Generation (MW) (# of projects)
NE	677	2455	1790	1614	30 (1)
NW	457	1093	712	1443	20 (1)
W-C	470	2033	1376	8825	337 (16)
SW	265	660	497	5399	367 (15)

Summary of Substation Information					
Planning Zone	Number of Substation Buses	Summer Peak Load (MW)	Summer Off-Peak Load (MW)	MISO Queued (11/26/07) Generation (MW)	MISO Queued (11/26/07) Dispersed Generation (MW) (# of projects)
SE	400	2003	1564	9617	58 (3)

B. Substation Site Screening Process

Once the collection of the substation load and transformer data, and transmission line characteristics was completed, a database of the compiled information was created. The study team then began the substation site screening process. With guidance from the TRC, the study team considered many different approaches.

The initial strategy included using the engineering judgment of the Minnesota utilities transmission planning engineers to develop a DRG short list but upon further discussion, ideas were suggested to come up with a more thorough approach to site screening. It was determined that a concrete routine including analytic methods, engineering judgment, and public and TRC input would be required to judge each bus location equally. TRC discussions led the project team to a rigorous and well supported process. The substation bus screening process to refine the list of 2258 transmission substation buses in the five out-state transmission planning zones (Twin Cities not included) to those most appropriate for the study took several months.

The following is the process that led to the substation site short list.

MUST FCITC Calculation

The transmission substation screening process began by utilizing the Power System Simulator for Engineering Managing and Using System Transmission First Contingency Incremental Transfer Capability (PSS™E MUST FCITC) function. The purpose of the MUST FCITC function is to efficiently calculate the impact of transactions on key network elements during contingency conditions.

Using DC (linear) analysis, the tool quickly and approximately calculates generation outlet capacity for all 2258 buses for the summer peak and summer off-peak cases. The primary advantage of using the DC analysis is its efficiency and the relative ease with which an initial estimation can be attained. By comparison, AC analysis, by comparison, is much more time-consuming. Limiting the scope of the AC analysis made it possible to provide a much more robust finished product.

The lesser of the two FCITC ratings (peak or off-peak) was then assigned to the substation bus. The first screening eliminated all substation buses with MUST FCITC ratings that were less than zero as it was expected that if a site showed no outlet capability with DC analysis, it would be less likely to result in positive capability after AC analysis. Later, the short list buses were analyzed with more thorough AC (nonlinear) analysis techniques.

Model Off-peak Load and Distribution Transformer Rating

The study team sorted the remaining substation buses by the model off-peak load and distribution transformer ratings. The substation buses without model off-peak load or distribution transformer ratings were eliminated. It may be possible to add generation without going through a MISO interconnection process to buses that supply distribution load as long as the new generation does not exceed the minimum bus load.

This may not apply to non-MISO locations. For example, MAPP interconnections require approval from the MAPP Design Review Subcommittee (DRS). Because of this, the desire was to use the screening process to eliminate higher voltage buses and transmission tap points within the transmission system while retaining distribution substation buses. This step of the screening process identified distribution substation buses with modeled load or a distribution transformer.

Wind Profile

The study team used the wind profile as the next screening tool. Wind net annual capacity factor 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.

While the group understood the need to use the wind profile for site screening, there was much discussion regarding when this site characteristic should be examined. The TRC determined that the wind resource criteria should not be included directly in the first round of site ranking because there is a wide range of wind resource sites that can be economically developed with present wind turbine technology. In other words, this information would not help narrow down the site selection enough to help the process. There was support among the TRC for a wind resource floor to be used as the fourth step in the screening process.

The study team sorted the remaining substation buses by the superimposed wind profile value and removed sites with a wind net annual capacity factor lower than 35 percent. The general net capacity factors in the state of Minnesota at the transmission substation sites range from 17 percent to 44 percent.

MISO Queued Generation

The subsequent step in the site screening process was the impact of MISO queued generation on substation buses. The study team totaled all generation projects in the MISO generation interconnection queue by county for the state. With guidance from the TRC, the study team then used these results to eliminate all buses in counties where MISO queued generation exceeded 500 MW except where dispersed generation was already in the queue. It was not considered desirable to try and place additional DRG in areas that had many generation projects already planned. The concern was that the smaller projects characteristic to this study would encounter massive congestion in counties where many generation projects were already planned.

Engineering Judgment

The previous steps screened to make sure all criteria was met, narrowing the original list of 2258 substation buses down to more than 300 potential locations for DRG. However, there were still too many sites to conduct detailed analysis. The next few screening steps employed engineering judgment to evaluate the remaining buses and strive for geographic diversity and transmission voltage variety.

To ensure geographic diversity, the next screening step was to limit each transmission planning zone to eight substation buses per zone and where possible, to one substation bus per county. These factors were weighed while attempting to have an equal number of lower voltage buses (those below 69 kV) as higher voltage buses (69 kV and 115 kV). The team also looked at the FCITC of the remaining buses and chose those with FCITC ratings less than 60 MW. For buses with FCITC less than 60 MW, the team used the highest wind net capacity factor for selection. Finally, a few buses were added with selected biomass (ethanol plant) locations that showed a positive FCITC.

The University of Minnesota Biomass Study conducted in 2007 showed the potential for Biomass generation at the sites shown in the Table 4.

Table 4 - University of Minnesota Biomass Study Input

City	County	Transmission Planning Zone	Biomass Generation Potential
Janesville	Waseca	SE	20 - 40 MW
Heron Lake	Jackson	SW	20 - 40 MW
Welcome	Martin	SW	20 - 40 MW
Fairmont	Martin	SW	20 - 40 MW
Fergus Falls	Ottertail	NW	20 - 40 MW

City	County	Transmission Planning Zone	Biomass Generation Potential
Note : Estimated potential for electrical generation from biomass at planned ethanol plants assuming waste heat is used to meet process needs. (The range is for steam extraction turbine or integrated gasification combined cycle.)			
Reference: De Kam, M.J., R.V. Morey, and D.G. Tiffany. 2007. Integrating biomass to produce heat and power at ethanol plants. ASABE Paper No. 076232. St. Joseph, Mich.: ASABE			

After a couple of months of systematic analysis and rigorous screening, the study team was able to take the list of 2258 transmission substation buses and come up with a short list of 42. Following the step-by-step process developed by the study team and supported by the TRC, this list featured the desired geographic diversity and technical merit. It is important to note that these substation buses had passed the first set of tests designated by the study team and TRC.

However, this was not the final DRG site list. The demanding analysis stages with steady-state modeling, loss analysis, and transient stability followed the siting process.

Table 5 – Potential Short List of DRG Sites after Screening Process

Northwest Transmission Planning Zone				
Substation Name	**kV**	**County**	**FCITC**	**Wind Net Capacity Factor**
Viking	115	Marshall	94	39.8
Cormorant	115	Becker	110	39.4
Halma	115	Kittson	88	38.8
Plummer	115	Red Lake	69	38.8
Audubon	41.6	Becker	74	38.7
Crookston Sugar	41.6	Polk	37	37.4
Osage	41.6	Otter Tail	34	37.6
Airport	41.6	Beltrami	25	35.0

Northeast Transmission Planning Zone				
Substation Name	**kV**	**County**	**FCITC**	**Wind Net Capacity Factor**
Little Sauk	115	Todd	109	37.6
RDO	115	Hubbard	122	35.5
Aldrich (Verndale)	115	Wadena	110	37.1
Bertram	34.5	Morrison	35	35.2
Walker	34.5	Cass	24	35.1
Hewitt	34.5	Wadena	37	37.9
Aldrich	34.5	Todd	35	36.4

Northeast Transmission Planning Zone				
Substation Name	**kV**	**County**	**FCITC**	**Wind Net Capacity Factor**
Flensburg	34.5	Morrison	18	35.8
Cloquet	115	Carlton	>35	Biomass

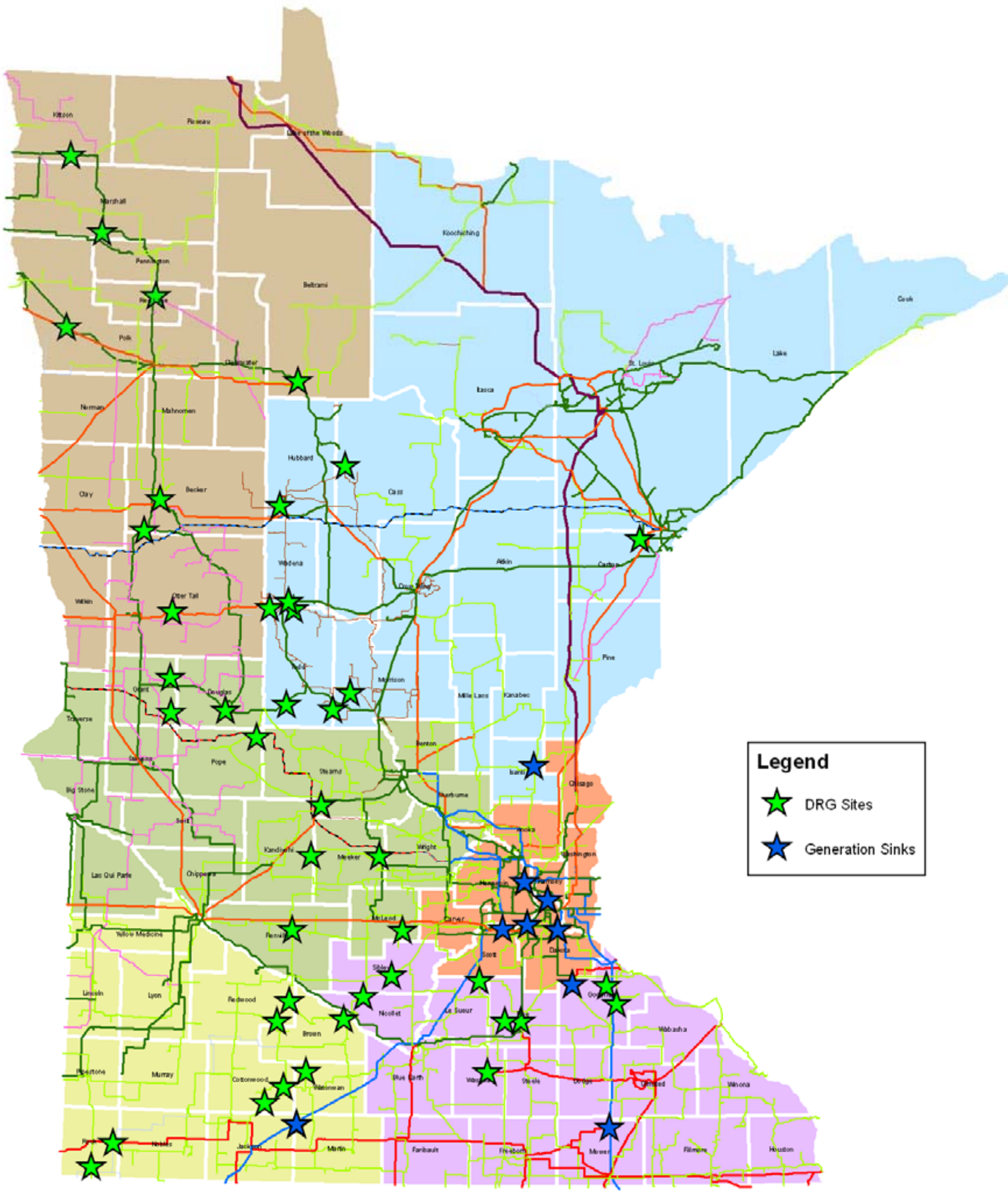
West-Central Transmission Planning Zone				
Substation Name	**kV**	**County**	**FCITC**	**Wind Net Capacity Factor**
Alexandria SW	115	Douglas	136	38.4
Bird Island	69	Renville	83	37.0
Swan Lake	115	Meeker	142	36.4
Glencoe Muni	115	McLeod	239	36.0
Erdahl	41.6	Grant	29	39.4
Westport	69	Pope	36	37.8
Paynesville	34.5	Stearns	28	38.8
Hoffman	41.6	Grant	25	36.5
Atwater	69	Kandiyohi	50	37.7 – Biomass

Southwest Transmission Planning Zone				
Substation Name	**kV**	**County**	**FCITC**	**Wind Net Capacity Factor**
Mountain Lake	69	Cottonwood	63	39.6
New Ulm	69	Brown	92	35.8
Lakeside Ethanol	69	Cottonwood	55	40.2 - Biomass
Morgan	69	Redwood	42	37.6
Magnolia	69	Rock	20	38.2
Sveadahl	69	Watonwan	40	38.2
Steen	69	Rock	30	37.5
Brookville	69	Redwood	35	37.0

Southeast Transmission Planning Zone				
Substation Name	kV	County	FCITC	**Wind Net Capacity Factor**
Waseca	69	Waseca	72	35.6
Airtech Park	115	Rice	79	35.0
New Prague	69	Le Sueur	60	36.6
Crystal Foods	69	Sibley	57	36.1
Vasa	69	Goodhue	47	36.1
Lafayette	69	Nicollet	39	36.1
French Lake	69	Rice	29	36.6
Goodhue	69	Goodhue	47	37.3

Map 2 shows the result of the screening process. These sites were selected to undergo further analysis to determine final DRG sites.

Map 2 – Substation Short List Map



IV. Analysis

Steady-state analysis was conducted on individual sites, on each planning zone and statewide. Stability analysis was conducted in aggregate, utilizing existing stability modeling. The study team ran the AC analysis which is the analysis of the power injection or generation capability of the new generation. This analysis was run on the transmission substation high side buses. The AC contingency analysis is an analysis of the generation capability of a dispersed generation scenario on an N-1 basis.

There is a strong correlation between summer peak and summer off-peak results. As sites are progressively aggregated from single site analysis to zonal analysis and then to statewide analysis, the total generation capability is less than the sum of its parts. The goal is 600 MW of generation state-wide; each zonal analysis was run in steps up to 225 MW.

Known common tower system contingencies were performed. This was done to take into consideration all the double circuit lines on the same towers or structures in Minnesota that are longer than one mile in length on an N -1 basis if both lines are taken out.

Tools

AC steady-state analysis is often referred to as thermal analysis in that it is a study of the thermal limits of the transmission equipment. Thermal analysis was conducted using the Siemens Power Technology Inc. Power System Simulator for Engineering (PSS™E) (Rev. 30.3) power flow program, which is an integrated, interactive, digital computer program for simulating, analyzing and optimizing power system performance. PSS™E was used in conjunction with GRE's automated contingency program. This contingency program can perform systematic outages on a user-defined set of transmission components and the program output is formatted in a Microsoft Excel spreadsheet. The spreadsheet then allows for the convenient comparison of results.

DRG Sinks

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.

These two study conditions are referred to, respectively, as Gen-to-Load and Gen-to-Gen methods. Typically, the Gen-to-Load method is utilized in long range transmission planning scenarios because generation must be added for the purpose of satisfying load growth, whereas the Gen-to-Gen method is more generally used in generation planning or generation interconnection studies. The Gen-to-Gen method best fits the purpose of this DRG Study.

In the Gen-to-Gen case, 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 the system balanced is the 'sink'. The magnitude of the 'source' is equal to that of the 'sink'.

The sources for this study were the 42 DRG sites. The study team, along with the TRC, considered which generators should be turned down when the DRG was placed into the models. This was the exercise of determining the sinks.

It was decided that it was prudent to use a fairly well established practice of sinking the DRG source generation to natural gas-fired generation plants. This practice is grounded in the operational methodology of turning down less economical generation when the renewable generation is ramped up on the system.

Natural gas generation units (peaking units) form the bulk of the less economical generation operating on the electric grid and, as such, they are usually ramped down before the more economical baseload generation. Additionally, the natural gas peaking units have the ability to ramp up or ramp down their power outputs rapidly which is conducive to the variable nature of wind generated power. Given the economics and their operational natures, natural gas generation plants are often matched with wind generation plants.

Since this was a study involving the examination of DRG in the state of Minnesota, it was decided that the sinks also should be within the state boundaries. The largest natural gas units in Minnesota are generally located in and around the Twin Cities metro area with a few in the outlying regions. The study team proposed a list of natural gas units to utilize as the sinks, which was approved following a discussion with the TRC. It was further decided that the amount of generation to be sunk at each natural gas unit should be based on a pro rata basis according to the output level of each natural gas unit in the model.

The sinks and their respective pro rata sink levels are shown in the table below. The summer peak sinks consisted of 10 natural gas peaking plants, whereas the summer off-peak sinks consisted of five peaking plants. In the summer off-peak model, half of the original sink units were off-line and producing no power so it was not possible to use them as sinks.

Table 6 – DRG Study Sinks

Bus Name	Summer Peak		Summer Off-Peak	
	Base Case Gen (MW)	Pro Rata Allocation	Base Case Gen (MW)	Pro Rata Allocation
Elk River	178.0	11%	0.0	0%
Cambridge	122.0	7%	95.7	8%
Riverside	203.0	12%	140.4	12%
Inver Hills	122.5	7%	0.0	0%
Blue Lake	160.0	9%	0.0	0%
Black Dog	200.0	12%	382.5	31%
High Bridge	210.0	12%	357.8	29%
Pleasant Valley	151.4	9%	0.0	0%
Cannon Falls	178.5	11%	244.4	20%
Lakefield	164.9	10%	0.0	0%
Totals	**1690.3**	**100%**	**1220.8**	**100%**

Steady State Analysis Methodology

To determine the effects of generation at each site on the transmission system, the changed model with the DRG had to be compared with a base case model that had no DRG. Performing an evaluation on the base case model determines the power flow levels and existing transmission system deficiencies, setting a baseline from which the changed case can be compared. A comparison of the changed case against the base case determines significantly affected facilities (SAF) as caused by new generation.

Significantly affected facilities are those facilities that 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%. (Note: See Definition of Terms at the end of this report for explanation of PTDF & OTDF.)

For the purposes of this study, the criteria for an overloaded transmission facility were 100 percent of its continuous rating limit for both system intact and N-1 contingency conditions. The Midwest utilities have varying methods of determining overloaded facilities. For example, some utilities consider their transmission lines to be overloaded in an N-1 condition when the power flow reaches 110 percent of the continuous rating. The extra 10 percent is known as an emergency rating and is intended for short-term use only (four hours or less). Some utilities do not allow for any emergency rating on their facilities while others utilities allow an overload for only 30 minutes during system switching. Given the range of definitions of an overloaded facility, it was decided to standardize to the minimum limit for the purposes of this study.

The steady-state analysis was performed on both summer peak and summer off-peak models. In situations where the generation outlet capability results between the peak and off-peak cases varied, the lesser of the two generation capabilities was tabulated.

Single Site Analysis

There was a need to consider the outlet capability of each DRG site individually. When studied on an individual basis, the analysis is performed while assuming generation is added to only one DRG site in the state while all the other DRG sites are held to 0 MW. In addition to the base case, a minimum of 42 single site analysis cases were examined. The base case and the changed case were analyzed by taking all outages within and just beyond the respective planning zone where each DRG site was located. Select contingencies also were analyzed for each site.

The generation output at each DRG site was initially set to 40 MW before system intact and contingency analysis was performed. The results of the 40 MW case was then compared to the base case, and any significantly affected facilities were recorded. In cases where 40 MW of DRG resulted in SAFs, the case was re-run at 35 MW and decremented in 5 MW steps until a DRG output level was reached where no SAFs resulted. A summary of single site analysis results are shown in Table 7, and the detailed results are shown in Appendix E. It was observed that the limiting factor for many of the northern and west-central DRG sites was a contingency overload of either of the 230/500 kV transformers at the Dorsey Substation near Winnipeg, Manitoba, Canada.

Table 7 – Single Site Analysis Results

Planning Zone	Bus Name	Generation Outlet Capability (MW)	Planning Zone	Bus Name	Generation Outlet Capability (MW)
		Single Site			Single Site
NW	Viking	<10*	NE	Little Sauk	35*
	Silver Lake	20*		RDO	25*
	Plummer	<10*		Aldrich (Verndale)	35*
	Halma	<10*		Bertram	30*
	Cormorant	15*		Walker	20*
	Crookston	<10*		Hewitt	35*
	Audubon	15*		Aldrich	20*
	Bemidji Airport	10*		Flensberg	15*
W-C	West Port	25*		Cloquet	40*
	Swan Lake	15*	SE	Waseca	40
	Paynesville	35*		Vasa	40
	Hoffman	25*		New Prague	40
	Glencoe	25		Lafayette	30
	Erdahl	20*		Goodhue	40
	Birds Island	40		French Lake	40
	Atwater	40		Crystal Foods	40
	Alexanderia	25*		Airtech	40
SW	Sveadah	35			
	Steen	25			
	New Ulm	40			
	Mountain Lake	40			
	Morgan	35			
	Magnolia	25			
	Lakeside Ethanol	40			
	Brookville	35			

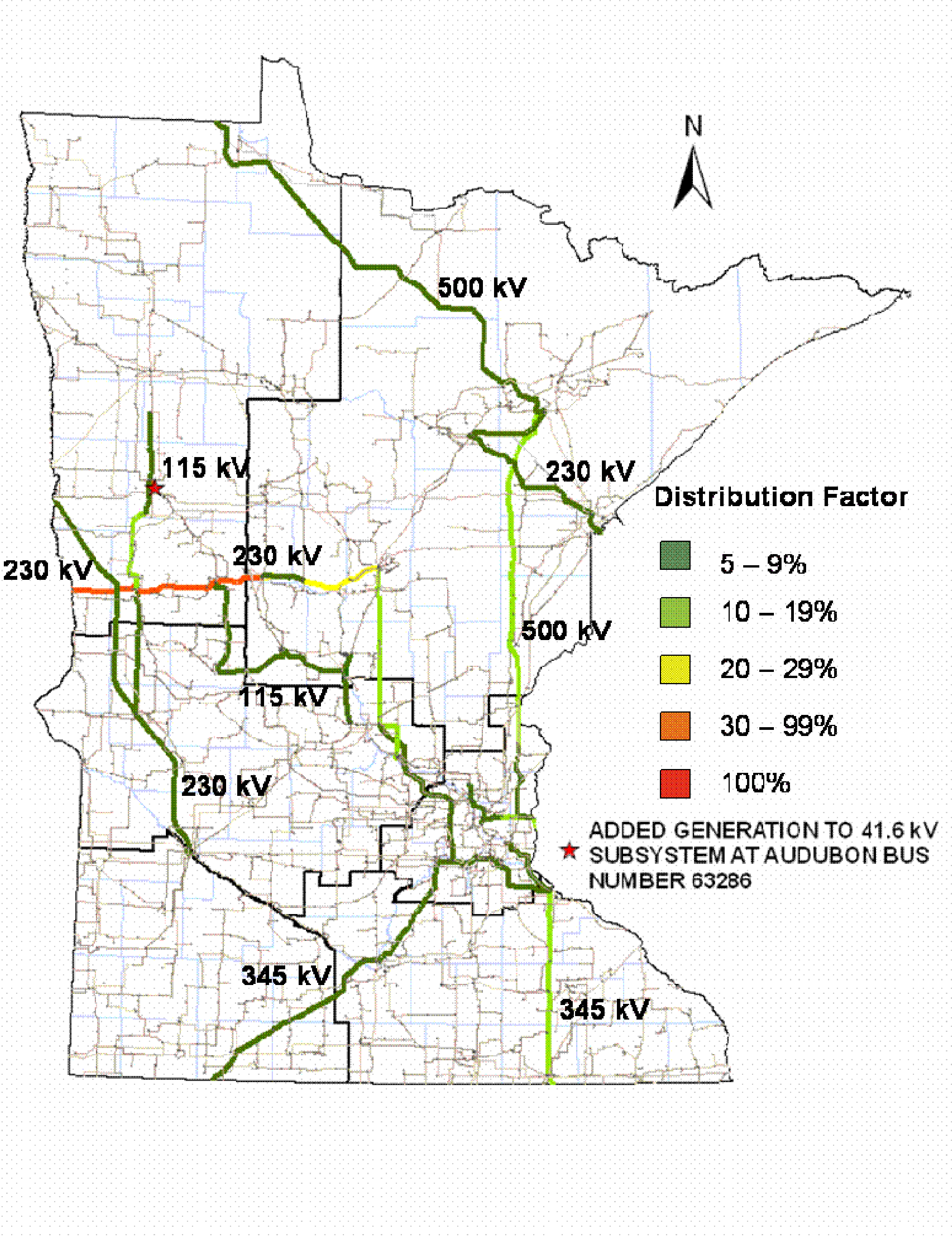
*** Denotes a limitation due to the Dorsey Transformer Overloads**

Dorsey Transformer Issues

The power from the DRG sites, even when placed on the sub-transmission system, utilizes the high voltage transmission grid in the path to the sinks. The portion of the DRG power making its way onto the high voltage grid is measurable and can be substantial. Distribution Factor (DF) is the term that defines the percentage of generated power that flows on the transmission facilities and is often expressed as a percentage of the generator power output. DF is further described in the **Definition of Terms** at the end of this report.

The map below shows an example of the percentage (DF) of the power generated at a dispersed site that utilizes the higher voltage transmission grid. Related to the Dorsey issue, the map shows that between 5-9 percent of the power generated at the Audobon site utilizes the northern portion of the 500 kV line and between 10-19 percent of the power shows up on the southern portion of the 500 kV line.

Map 3 - Distribution Factor Map



The Dorsey substation is located near Winnipeg, Manitoba and is an interconnection point between:

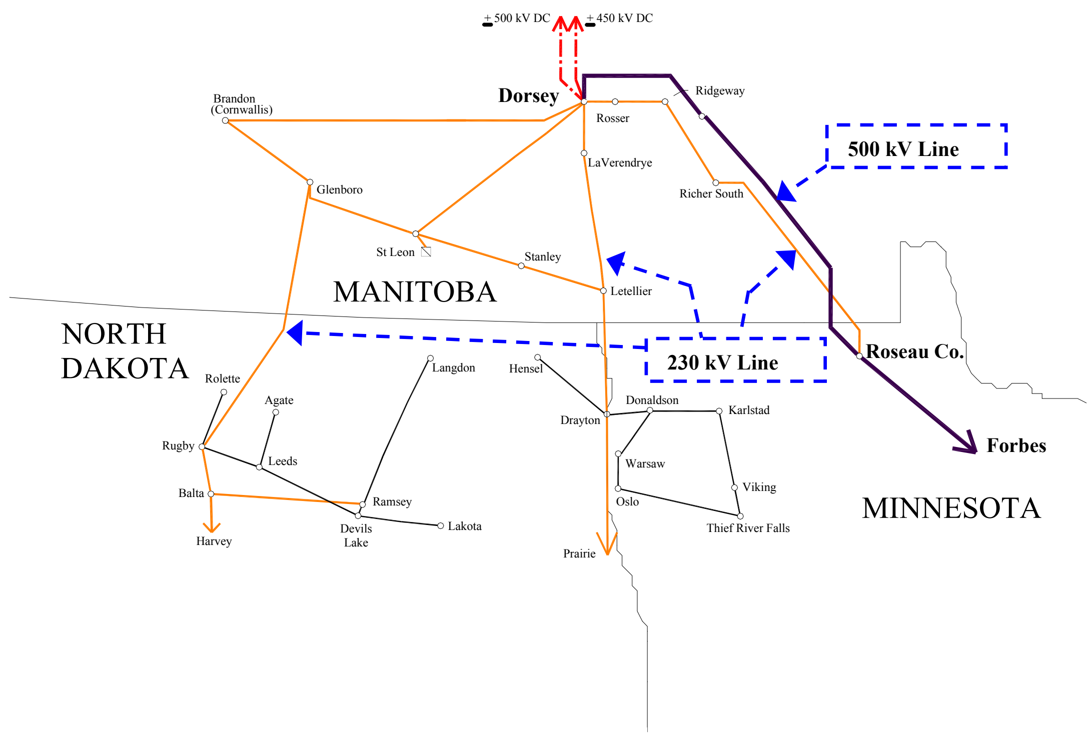
1. Two DC line systems that transport power from the two hydro electric dams further north in Manitoba.

2. An extensive 230 kV system that provides connections from Manitoba to Minnesota, North Dakota, Ontario and Saskatchewan.

3. A 500 kV line that provides an extremely strong connection between Dorsey and the Chisago substation just north of the Twin Cities area.

The 230 kV system has three lines that form paths from northern Minnesota and North Dakota to the Dorsey substation in Manitoba. These lines are the Rugby-Glenboro, Drayton-Letellier, and the Roseau-Richer South 230 kV lines. Two 230/500 kV transformers at the Dorsey substation transform or step the voltage from 230 kV to 500 kV. These transformers provide a strong connection between the 230 kV and 500 kV systems. A transmission map of the area is shown below:

Map 4 - Transmission Map Illustrating the Dorsey 230/500 kV System.



The 500 kV line runs from Dorsey to Roseau County to Forbes and then to Chisago. This line is the largest line in the area and it has been further enhanced by the installation of series capacitors. These series capacitors placed on the strong transmission line have the effect of creating a super-highway from Manitoba to the Twin Cities. Because of this, power, which takes the path of least resistance, has a strong tendency to utilize this 500 kV path when traveling from a source to a sink. This creates a situation where power generated in northern Minnesota flows north on the 230 kV system to the Dorsey substation, where the power passes through the transformers to the 500 kV system and then travels down the 500 kV line to the sinks in the Twin Cities area.

The table below shows the portion of power in each planning zone that travels through the 230/500 kV transformers in the power flow models.

Table 8 – Distribution Factors on Dorsey Transformers

	PTDF		OTDF: Removing 2nd Xfmr
	DF 1 st Xfmr	DF 2 nd Xfmr	DF 1st Xfmr
Summer Peak			
Base Case	x	x	x
NE	2.9%	3.3%	4.5%
NW	10.3%	11.9%	21.5%
SE	0.7%	0.9%	0.7%
SW	1.9%	2.2%	3.3%
W-C	2.3%	2.7%	4.4%
State	3.3%	3.8%	7.0%
Summer Off-Peak			
Base Case	x	x	x
NE	3.5%	4.1%	5.2%
NW	10.7%	12.4%	19.9%
SE	1.0%	1.2%	-0.1%
SW	2.4%	2.9%	2.8%
W-C	2.9%	3.3%	3.7%
State	2.9%	3.4%	5.8%

Each 230/500 kV transformer is loaded to nearly 100 percent in the base case during an outage of the other transformer. Thus adding more generation of any size or type in northern Minnesota causes additional loading on the transformers during contingency conditions which in most cases, causes the transformers to overload. This overloading is what is limiting the DRG outlet capability of many of the sites in the northern half of the state. This is an inadvertent (loop) flow situation and the overloaded transformers are unintended consequences.

Despite the unintentional nature of these consequences, a new generation project that causes this overload could be charged with the cost of mitigating the overload. The added cost of mitigating these overloads on the 500 kV system is prohibitively expensive, this is what facilitated the shift in generation sites to the southern portion of the state.

Zonal Aggregation Analysis

The aggregation of the DRG in each of the five planning zones was studied, and this examination provides a good measure of the transmission capacity available for generation in each of the planning zones. There were about eight DRG sites in each of the planning zones, each with an upper limit of 40 MW and it was decided to begin with a zonal aggregation total of 225 MW.

The DRG sites had a range of output capacities as determined in the single site analysis and these outlet capabilities established the starting point for the participation factors for each of the sites in the zonal aggregation. The zonal base and the changed (aggregate) cases were analyzed by taking all outages within and just beyond their respective planning zone as well as all the contingencies in adjacent planning zones and selected known limiting contingencies.

This zonal aggregation analysis was performed at 225 MW and the results of this 225 MW case were then compared to the base case and any significantly affected facilities were recorded. In cases where 225 MW of DRG in a zone resulted in SAFs, the case was re-run at 200 MW and then decreased in increments of 25 MW steps until a DRG level was reached where no SAFs were observed. Through this iterative process, the participation of the individual DRG sites was adjusted to determine an optimum pattern of generation among the sites in order to find the maximum aggregate output of each zone. The zonal aggregation analysis summary is shown in Table 9 and the detailed analysis output is available in Appendix E.

A contingency overload of either 230/500 kV transformer at the Dorsey substation near Winnipeg, Manitoba, Canada was observed, which is an extremely limiting factor for the Northwest, Northeast and West-Central zones.

Table 9 – Zonal Aggregation Analysis Results

Planning Zone	Generation Outlet Capability (MW))
	Zonal Aggregation
NW	20*
NE	35*
W-C	40*
SW	50
SE	300
* Denotes a limitation due to the Dorsey Transformer Overloads	

Statewide Aggregation Analysis

A primary goal of this DRG Study was to investigate the placement of 600 MW of dispersed generation with minimal impacts to the transmission system. For this statewide aggregation contingency analysis, all of the statewide facility outages were considered as well as those of facilities immediately adjoining Minnesota.

The starting point for the zonal participation was derived from the results of the zonal analysis. The participation pattern was substantially shifted south due to the limitations on the northern and west-central zones and after extensive discussion with the TRC. The examination of the statewide aggregation analysis output and the resulting overloading of the Dorsey transformers led to a process of the continual southward shift of the DRG level. The final participation levels on a site and zonal basis are shown in Table 10.

Table 10 - 600 MW Statewide Aggregation - DRG Participation Levels

Zone	Name	Single Site (MW)	Zone (MW)
NW	Viking	0	0
	Silver Lake	0	
	Plummer	0	
	Halma	0	
	Cormorant	0	
	Crookston	0	
	Audubon	0	
	Bemidji Airport	0	

Zone	Name	Single Site (MW)	Zone (MW)
NE	Little Sauk	0	40
	RDO	0	
	Aldrich (Verndale)	0	
	Bertram	0	
	Walker	0	
	Hewitt	0	
	Aldrich	0	
	Flensberg	0	
	Cloquet	40	

Zone	Name	Single Site (MW)	Zone (MW)
W-C	West Port	0	100
	Swan Lake	0	
	Paynesville	0	
	Hoffman	0	
	Glencoe Municipal	40	
	Erdahl	0	
	Birds Island	40	
	Atwater	20	
	Alexanderia	0	

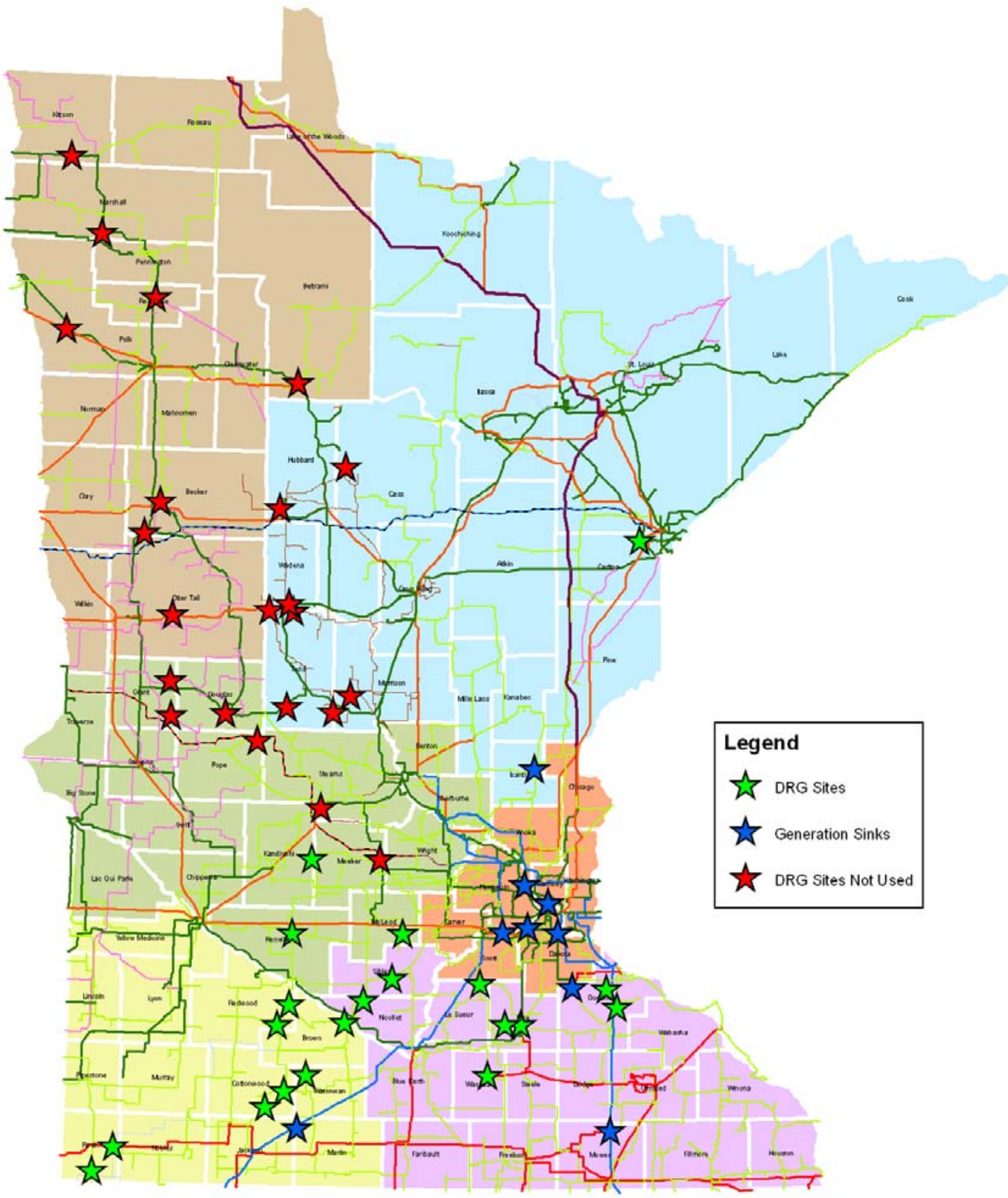
Statewide Total	600 MW

Zone	Name	Single Site (MW)	Zone (MW)
SW	Sveadah	19	160
	Steen	21	
	New Ulm	21	
	Mountain Lake	21	
	Morgan	21	
	Magnolia	16	
	Lakeside Ethanol	21	
	Brookville	19	

Zone	Name	Single Site (MW)	Zone (MW)
SE	Waseca	39	300
	Vasa	39	
	New Prague	39	
	Lafayette	29	
	Goodhue	39	
	French Lake	39	
	Crystal Food	39	
	Airtech	39	

A map illustrating the locations of the final DRG sites that comprise the 600 MW of dispersed generation is shown below. Included are some of the original locations of sites that were not considered for the final DRG sites.

Map 5 – Final DRG Site Map



Conclusions of AC Analysis

The single site analysis results generally showed local and lower voltage limiting elements while the zonal and statewide aggregate analysis results generally identified regional and higher voltage limiting elements. On a single site basis, the Northwest and Northeast were found to be the most limited planning zones with respect to siting DRG. These zones were severely limited by higher voltage facility overloads in Manitoba.

The results of the zonal aggregation analysis showed that the DRG zonal capabilities in the Northeast, West Central and Southwest were 35 MW, 40 MW and 50 MW respectively. Whereas the DRG participation of the Northeast, West-Central and Southwest zones in the statewide DRG pattern were 40 MW, 100 MW, and 160 MW respectively. Thus, these three zones showed a generation output capability increase when studied on a statewide aggregate basis.

The 2010 transmission can support 600 MW of aggregate DRG. The TRC defined sink pattern is a likely scenario, but a change in the generation sink could change the results of this study. The study results reflect the assumption of, in essence, a power delivery to the natural gas generation (generation sinks) located in a wide area around the Twin Cities (for which natural gas served as a proxy). If each of the DRG sites were studied individually and if the assumed generation sink was located very near that particular DRG site, then those individual study results could vary from the individual and aggregate results seen in this study.

It must be further stressed that these results, particularly those in the Southwest zone, are based on the assumption that large amounts of prior-queued generation are not in the model. The base assumption for these studies assumed installation of the Buffalo Ridge Incremental Generation Outlet (BRIGO) facilities and the associated generation. This brought the amount of generation in Southwest Minnesota to 1,175 MW and the additional Southwest zone generation was based on having only those 1,175 MW of generation in service.

Interconnection studies assume all prior queued generation impacted by the installation of new generation is in service. In Southwest Minnesota, this generation totals several thousand megawatts.

All renewable generation developers should work closely with the local transmission owner and operator to determine the specific single site generation impacts on the local distribution, sub-transmission and transmission system. Interested parties also may benefit from working with independent consultants well-versed in the transmission system in a particular area. The assumptions chosen for the DRG Study are the best engineering judgment for a study of this scope. Local transmission owners and operators, however, have additional knowledge of unique operating characteristics of their system and they may identify other local generation sinks that could change the outcome of an interconnection study.

The DRG Study relied on the experience and knowledge of the study team and the TRC. The study team diligently investigated the best data, tools and leading approaches to assure a sound outcome. The TRC meetings offered an open exchange to challenge engineering judgment and discuss strategy. The study team responded to feedback adding additional research runs, adjusting assumptions and scrutinizing output. The end result of this iterative process is a thorough study report providing more information than is required by legislation.

As with any study, new methods and information may come to light that may be proposed for the DRG Phase II Study. The TRC and the study team conclude that the DRG Phase I results are the best results based on the collective expertise and judgment and the substantial, though limited, resources applied to this study.

Loss Analysis

An analysis of the system wide electrical losses was performed. The loss analysis is typically performed across the entire Eastern Interconnection rather than just on a local system in order to take into consideration the inadvertent power flows (loop flows) and the corresponding changes in losses which they cause. The inadvertent flows are those power flows that travel out from a generation point or source on the transmission grid in a wide circle or circuitous loop to the load or sink rather than in a more nearly direct path. For example, a measurable portion of the power generated in the southwest part of the state can travel as far north as Manitoba or as far south as Nebraska before looping back to serve load in the Twin Cities metro area. These inadvertent flows incrementally contribute to system losses and it is prudent to account for them in a loss analysis.

The loss analysis was performed with the use of the PSS™E (Rev. 30.3) load flow program on both summer peak and summer off-peak models, in the base case and in the statewide DRG scenario with 600 MW of dispersed generation. The results of the loss analysis are shown in Table 11.

Table 11 – Loss Analysis Results

Loss Analysis		
Model	**SUMP MW**	**SUOP MW**
Base Model	17291.5	15829.8
DRG Model with 600 MW	17282.0	15837.1
Loss Reduction with DRG	9.5	-7.3

The results in the table above indicate that for the summer on-peak condition, the system-wide losses in a 600 MW DRG scenario are 9.5 MW lower than the base case where the generation is concentrated in a wide area around the Twin Cities. In summer peak conditions, more generation is on-line to serve the increased load levels and the generation has a tendency to stay local and be consumed in the nearby area. With a DRG scenario, the generation is matched with larger local load levels, and the generation is consumed by that local load.

The summer off-peak, however, shows a 7.3 MW loss increase in the DRG scenario when compared to the base case. There are a few explanations for the net differences in the summer peak and summer off-peak results. In a summer off-peak case where the load levels are lower, uneconomical generation is typically turned off in favor of more economical and renewable generation. In this condition where fewer generators are on-line, the generation must travel further before being consumed by the load. For this reason, having the generation dispersed is most beneficial in higher load level conditions when considering the system losses.

In either case (9.5 MW loss decrease or 7.3 MW loss increase), the incremental loss impact is relatively minor, being less than ±1.6 percent of the 600 MW generation increment.

The full output of the loss analysis is available in Appendix F.

System Upgrades

There were no system upgrades required in the final generation pattern which constituted the 600 MW of DRG as shown in the **AC Analysis** section. However, there was a realization that this DRG scenario was heavily biased toward the southern portions of the state as result of the contingency overload violations on the Dorsey 230/500 kV transformers and related 500 kV facilities. The large portion of Minnesota that is negatively affected by the transfer limitations caused by these contingency loaded transformers necessitates discussion about the possible mitigation options. The following four solutions were discussed with the TRC.

1. **Install a third 1200 MVA, 230/500 kV transformer at Dorsey**

This transformer would be placed in parallel with the two existing 1200 MVA, 230/500 kV transformers at the Dorsey substation or another new substation on the 500 kV line between Dorsey and Roseau. This third transformer would likely cause a reduction in the impedance path from the 230 kV Dorsey bus to the 500 kV Dorsey bus to Roseau, which could lead to increased flow on the line, causing a cascade problem where the Roseau series capacitors could become overloaded in a system intact condition. With the additional system intact loading, it is likely that additional shunt capacitors would be required at the Forbes substation. Additionally, given a likely lead time of about 18 months for the manufacture and delivery of a new transformer, it is unlikely that this would be a possible solution to meet the 2010 timeframe. An estimated cost for this transformer solution would be approximately $30 million plus $6 million to upgrade the Roseau series capacitors and $5 million for Forbes shunt capacitors for a final total of approximately $41 million.

2. **Install phase shifters on three northern 230 kV lines**

The Rugby-Glenboro, Drayton-Letellier, and the Roseau-Richer South 230 kV lines form the primary paths from northern Minnesota to the 230 kV bus at Dorsey. Installing phase shifting transformers on the three 230 kV lines would permit the control of flow on, and, in essence, create one-way valves on those 230 kV transmission lines. This would limit the loop flow from Minnesota to Manitoba through the 230/500 kV transformers, which would mitigate the transformer overloading caused by Minnesota generation.

The exact lead time for installing three phase shifters is unknown, but it is likely that the manufacture time would extend the project beyond the 2010 timeframe. Also, the installation of phase shifters would change the operating nature and would degrade the dynamic stability performance of the existing transmission grid requiring extensive amounts of study to determine the post-project behavior of the transmission system.

The estimated cost per phase shifter project is about $20 million or about $60 million for all three phase shifter projects. However, there are also system intact loading considerations regarding the 500 kV system; these could result in generation reductions during a considerable number of hours per year.

3. **Install a Special Protection Scheme to curtail Minnesota generation**

A Special Protection Scheme (SPS) would trip Minnesota generation in the case of a 230/500 kV transformer outage and curtail the Minnesota generation that could cause the remaining 230/500 kV transformer to overload. The research, development and design of an SPS is a very involved process requiring coordination with and approval of regional reliability authorities, and the equipment and installation costs vary widely. It is likely that each DRG site would need a separate SPS that would require the approval of Manitoba Hydro. However, it is a potential solution that could be examined further.

4. **Communicate and coordinate a resolution with Manitoba Hydro**

Manitoba Hydro has an existing DC runback scheme where they can reduce the power output of their hydro dams and the flow on their DC lines, which in turn, will reduce the loading on the 230/500 kV transformers. However, Manitoba Hydro has firm transmission rights for their hydro power export and performing this runback action lowers their exports and the resulting revenues. Communicating with Manitoba Hydro and engaging in a possible agreement may result in an approval for generation interconnection with regard to the Dorsey overload issues. It should be noted that this type of coordination is the responsibility of the generation developer.

The statewide aggregate AC analysis results showed a DRG scenario where 600 MW could be sited without significantly affecting any transmission infrastructure. The statewide DRG site placement pattern for 600 MW was dictated by limitations found in the single site and zonal aggregation analysis as well as those found in the statewide aggregation analysis.

In addition to the Dorsey transformer issues limiting the generator outlet capability at many of the sites, the single site analysis also revealed that 19 of the 42 DRG sites had other transmission limitations for generation output levels below 40 MW, although these limitations did not affect the ability to achieve 600 MW of DRG statewide. The transmission limitations for these sites were identified and specific system upgrades were created for each site.

Table 12 lists the facility improvements (beyond the Dorsey Transformer Issues) identified as necessary to achieve outlet capability for up to 40 MW of DRG on a single site basis. These improvements are only indicative of the actual corrections that may be undertaken after detailed engineering study.

Tables 12 – Cost of Site Upgrades in the Five Planning Zones

Northwest Zone								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate A (MVA)	System Upgrade	Upgrade Size	Estimated Cost
BEMIDJII AIRPORT								
7909 AIRPORT JCT - 7910 AIRPORT	OTP	0.3	41.6	1/0 ACSR	19.1	Line Rebuild	336 ACSR	$ 52,000
							Total	**$ 52,000**
CROOKSTON								
7972 CROOKSTON - 7974 SIMPLOT	OTP	2.9	41.6	266&1/0&3/0 ACSR	26.8	Line Rebuild	336 ACSR	$ 580,000
7972 CROOKSTON - 7982 CROOKSTON SUGAR	OTP	1.3	41.6	266 ACSR	39.6	Line Rebuild	336 ACSR	$ 273,000
7980 CROOKSTON - 7982 CROOKSTON SUGAR	OTP	0.6	41.6	266 ACSR	40.2	Line Rebuild	336 ACSR	$ 144,000
7975 CROOKSTON PLANT - 7980 CROOKSTON JCT	OTP	0.3	41.6	266 ACSR	40.2	Line Rebuild	336 ACSR	$ 69,000
66776 WILTON TAP - 66968 WILTON	MPC	XFMR	115/69	N/A	88.4	Xfmr Upgrade	112 MVA	$ 1,703,000
							Total	**$ 2,769,000**
PLUMMER								
7966 BROOKS - 7967 PLUMMER SW	OTP	6.2	41.6	3/0 ACSR	17.4	Line Rebuild	336 ACSR	$ 1,240,000
7967 PLUMMER SW - 63252 PLUMMER	OTP	XFMR	115/41.6	N/A	33.6	Xfmr Upgrade	48 MVA	$ 1,264,000
							Total	**$ 2,504,000**
SILVER LAKE								
63166 SILVER LAKE - 63366 SILVER LAKE	OTP/GRE	XFMR	230/41.6	N/A	27.0	Xfmr Upgrade	48 MVA	$ 1,897,000
							Total	**$ 1,897,000**

Northeast Zone

Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate A (MVA)	System Upgrade	Upgrade Size	Estimated Cost
ALDRICH 34.5								
38701 ALDRICH - 62905 STAPLES	MP	6.3	34.5	336 ACSR	25.1	Line Rebuild	477 ACSR	$ 1,323,000
7211 ULRICH - 66773 ULRICH	OTP	0.3	41.6	266 ACSR	31.4	Line Rebuild	336 ACSR	$ 50,000
66717 ULRICH - 66781 ULRICH TAP	OTP/MPC	XFMR	115/41.6	N/A	33.2	Xfmr Upgrade	48 MVA	$ 1,264,000
66773 ULRICH - 66781 ULRICH TAP	OTP/MPC	XFMR	115/41.6	N/A	32.1	Xfmr Upgrade	48 MVA	$ 1,264,000
							Total	**$ 3,901,000**
BERTRAM								
38854 BERTRAM - 61836 SWANVILLE	MP	3.2	34.5	336 ACSR	34.2	Line Rebuild	447 ACSR	$ 677,000
							Total	**$ 677,000**
FLENSBERG								
38885 508-27T7 - 62854 FLENSBERG	MP	8.9	34.5	3/0 CU	18.8	Line Rebuild	336 ACSR	$ 1,780,000
62852 GRE FLENSBERG - 62854 FLENSBERG	MP	0.7	34.5	3/0 CU	19.1	Line Rebuild	336 ACSR	$ 132,000
							Total	**$ 1,912,000**
HEWITT								
38801 HEWITT - 38802 501-533H	MP	2.5	34.5	336 ACSR	37.3	Line Rebuild	795 ACSR	$ 600,000
38801 HEWITT - 62899 HEWITT	MP	1.6	34.5	3/8 CU	37.8	Line Rebuild	336 ACSR	$ 320,000
38802 501-533H - 38803 BERTHA	MP	4.5	34.5	336 ACSR	36.5	Line Rebuild	795 ACSR	$ 1,080,000
38802 501-533H - 38812 501-533W	MP	8.8	34.5	336 ACSR	37.3	Line Rebuild	795 ACSR	$ 2,104,800
38803 BERTHA - 62900 EAGLE BEND	MP	4.4	34.5	336 ACSR	34.8	Line Rebuild	795 ACSR	$ 1,058,400
38810 WADENA - 38811 COMPTON TAP	MP	1.3	34.5	3/8 CU	35.8	Line Rebuild	795 ACSR	$ 312,000
38811 COMPTON TAP - 62899 HEWITT	MP	3.5	34.5	336 ACSR	38.4	Line Rebuild	795 ACSR	$ 840,000
38812 501-533W - 61842 VERNDALE	MP	0.1	34.5	336 ACSR	37.3	Line Rebuild	795 ACSR	$ 26,400
							Total	**$ 6,341,600**
WALKER								
38741 BADOURA TAP - 38742 AKELEY	MP	0.7	34.5	2/0 CU	20.8	Line Rebuild	336 ACSR	$ 140,000
38741 BADOURA TAP - 61838 AKELEY	MP	0.2	34.5	2/0 CU	20.8	Line Rebuild	336 ACSR	$ 147,000
38742 AKELEY - 38743 WALKER	MP	8.4	34.5	2/0 CU	21.5	Line Rebuild	336 ACSR	$ 168,000
							Total	**$ 455,000**

West - Central

Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate A (MVA)	System Upgrade	Upgrade Size	Estimated Cost
ERDAHL								
7202 POMME DE TERRE - 62762 SANFORD TAP	OTP	1.5	41.6	3/0 A	24.3	Line Rebuild	336	$ 300,000
7202 POMME DE TERRE - 7203 ERDAHL JCT	OTP	5.0	41.6	3/0 A	24.5	Line Rebuild	336	$ 1,000,000
7203 ERDAHL JCT - 62761 AMOCO TAP	OTP	6.0	41.6	3/0 A	24.6	Line Rebuild	336	$ 1,200,000
							Total	**$ 2,500,000**
GLENCOE MUNICIPAL								
62985 HUTCHINSON PARK - 62986 HUTCHINSON	HUC	0.2	69	336 ACSR	47.7	Line Rebuild	477 ACSR	$ 42,000
							Total	**$ 42,000**
HOFFMAN								
7215 ELBOW LAKE - 7446 BARRET	OTP	4.8	41.6	266 ACSR	26.8	Line Rebuild	336 ASCR	$ 960,000
							Total	**$ 960,000**
WEST PORT								
60748 WESTPORT - 60749 DOUGLAS COUNTY	Xcel	10.3	69	2/0 A	38.2	Line Rebuild	336 ASCR	$ 2,060,000
							Total	**$ 2,060,000**

Southwest									
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate A (MVA)	System Upgrade	Upgrade Size	Estimated Cost	
BROOKVILLE									
34274 JOHNSONVILLE TAP - 62731 WANDA	Alliant W	3.0	69	2/0 A	38.2	Line Rebuild	336 ACSR	$	600,000
62731 WANDA - 62732 SUNDOWN	Alliant W	7.0	69	2/0 A	39.2	Line Rebuild	336 ACSR	$	1,400,000
							Total	**$**	**2,000,000**
MAGNOLIA									
34215 MAGNOLIA - 34269 ADRIAN TAP	Alliant W	1.0	69	2/0 A	39.1	Line Rebuild	336 ACSR	$	200,000
							Total	**$**	**200,000**
MORGAN									
62072 SLEEPY EYE - 62080 HOME TAP	Xcel	4.0	69	2/0 ACSR	27.7	Line Rebuild	336 ACSR	$	808,000
							Total	**$**	**808,000**
SVEADAHL									
34231 MOUNTAIN LAKE - 60935 BUTTERFIELD	Xcel/Alliant	8.4	69	4/0 A	37.9	Line Rebuild	336 ACSR	$	1,680,000
							Total	**$**	**1,680,000**

Southeast									
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate A (MVA)	System Upgrade	Upgrade Size	Estimated Cost	
FRENCH LAKE									
34299 WASECA JCT - 62876 FRENCH LAKE TAP	Alliant W	1.0	69	3/0 A	41.0	Line Rebuild	336 ACSR		$200,000
34300 MONTGOMERY - 34301 NEW PRAGUE	Alliant W	1.0	69	4/0 A & 2/0 A	36.0	Line Rebuild	336 ACSR		$200,000
34301 NEW PRAGUE - 60936 NEW PRAGUE TAP	Alliant W	0.4	69	4/0 A	35.0	Line Rebuild	336 ACSR	$	80,000
							Total	**$**	**480,000**
LAFAYETTE									
60719 LAFAYETTE - 60725 WINTHROP	Xcel	7.8	69	2/0A/336ACSR	37.0	Line Rebuild	336 ACSR	$	1,560,000
60719 LAFAYETTE - 62079 LAFAYETTE	Xcel	1.0	69	2/0 A	37.0	Line Rebuild	336 ACSR	$	200,000
62077 SCHILLING TAP - 62079 LAFAYETTE	Xcel	1.0	69	2/0 A	37.0	Line Rebuild	336 ACSR	$	200,000
61250 JAMESTOWN - 62351 JAMESTOWN TAP	Xcel	2.8	69	4/0 ACSR	37.3	Line Rebuild	336 ACSR	$	560,000
							Total	**$**	**2,520,000**

The Unit Cost Estimates used on the cost analysis are shown in Appendix G.

E. Transient Stability Modeling and Study Assumptions

After the final 20 locations were chosen for potential DRG based on power flow studies, the sites were tested for stability. Each potential DRG plant was modeled in the Northern MAPP Operating Review Working Group (NWORWG) stability package with a typical generation plant model. The stability analysis tested the critical regional faults for the state of Minnesota and the interconnected MAPP system to determine if adding 600 MW of DRG would affect regional system stability. Local stability near the DRG points of interconnection (POIs) was not assessed.

DRG Plant Models

All but three of the DRG sites were represented as equivalent wind farms using the equivalent wind farm model shown in Figure 1 for these plants. The TRC decided which technology wind turbine to use for modeling purposes. Their first choice was the Type 2 wind turbine, which is a wound rotor induction generator with variable rotor resistance, but the modeling software did not support this type of wind turbine. Next the TRC and project team chose Type 3 (doubly fed induction generator) wind turbines as the assumed generator in the transient stability analysis model. The biomass model for the transient stability modeling was replicated from the existing Fibrominn biomass generator.

Using this model, a typical wind farm substation transformer is connected to the point of interconnection stepping down the voltage to 34.5 kV. Next , an equivalent branch is attached representing the impedance (series and shunt) of the 34.5 kV collector system. This is followed by an equivalent generator step-up (GSU) transformer from 34.5 kV down to 0.575 kV. Finally, a single equivalent generator is connected to the 0.575 kV bus.

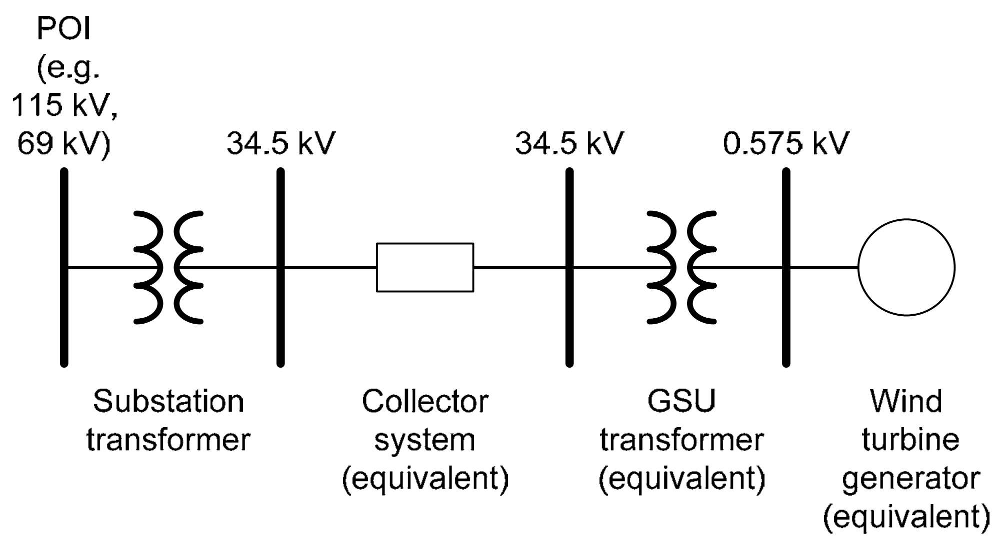


Figure 1 – DRG Wind Farm Model

For this study, GE 1.5 MW wind turbines were assumed for all DRG wind farms. GE wind generators are of the doubly-fed induction generator (DFIG) type that is commonly installed today and is expected to be used in the future as well. These generators have a reactive power capability from 0.90 leading to 0.95 lagging, and can dynamically supply the reactive power losses of their collector systems and regulate voltage.

For the three biomass locations, the model of Figure 2 was used. The model and data were copied from the existing FibroMinn biomass generator.

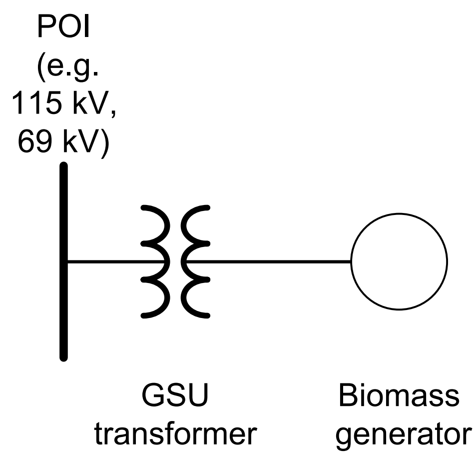


Figure 2 – DRG Biomass Model

System Stability Model

The software package used for stability studies in Minnesota is the Northern MAPP Operating Review Working Group (NMORWG) package. This package includes a set of programs built on top of the commercially available simulation program Power Systems Simulator for Engineering (PSS/E). The NMORWG package automates the application of many faults, special controls, and operating procedures used in the MAPP region.

Adding DRG to the Stability Model

A software program was written in the IPLAN language to add the DRG projects to the NMORWG model. A few of the buses chosen in the steady-state analysis do not exist in the NMORWG model due to its slightly less detailed representation of sub-transmission. For these buses, the nearest bus that is represented in the NMORWG model was chosen as a replacement.

When injecting the desired power levels into the chosen buses, voltage will frequently rise, sometimes significantly if the bus is relatively weak. In cases where the voltage rose above 105 percent of nominal, the reactive power capability of the DRG (GE wind turbine generators and biomass synchronous generators) was used to limit the voltage at the POI to 105 percent. At buses where overvoltage was not an issue, the voltage schedules were set to achieve a nominal power factor of 1.0 at the POI. In other words, approximately zero exchange of megavolt ampere reactive (MVAr) between the system and the DRG.

The sink generators used in the DRG steady-state analysis were also used in building the stability model.

The most significant interface flow change resulting from adding DRG is a decrease of 29 MW in the Minnesota-Wisconsin EXporting (MWEX) interface flow mainly due to the sinks chosen in the Twin Cities area. The MWEX is the sum of the flows on the Arrowhead-Stone Lake and the King Eau Claire 345 kV lines. The Manitoba Hydro EXporting (MHEX) interface flow increased by only 5 MW, but the 500 kV line flow at Dorsey increased by 17 MW due to loop flow up the 230 kV ties and back down the 500 kV line. The MHEX is the sum of the flows on the three 230 kVand the 500 kV tie lines that cross the Manitoba and the Minnesota and North Dakota borders. The North Dakota EXporting (NDEX) interface flow increased by 3 MW. The NDEX is the sum of the flows on the 18 lines that make up the “North Dakota Export” Boundary.

The DRG IPLAN program was also written to generate the standard GE wind turbine dynamic model for each DRG location, assuming each wind farm is running at 100 percent of capability. This is a relatively realistic assumption for an off-peak model and aligns with MISO practices.

Regional Faults

Only regionally significant faults were tested in this stability analysis. This includes all of the faults listed in Appendix K of the MAPP Reliability Criteria and Study Procedures Manual. A few faults were added near the Square Butte HVDC rectifier and one fault was added for the new Arrowhead-Weston 345 kV line.

In a normal interconnection impact study for a single generation plant, many faults around the POI are studied. However, with many DRG locations and a tight deadline, this was not feasible for this study. Additionally, these chosen sites are simply representative of possible sites for DRG, and the overall regional impact is more relevant to the goals of the DRG Study. When an individual generation project requests interconnection, detailed local faults will be studied at that time.

Stability Study Results

The regional faults were simulated on the following previously described cases:

- Pre-DRG case with coal generation at URGE levels
- Post-DRG case without resetting the NDEX, MHEX, and MWSI interfaces to their maximum allowable levels
- Post-DRG case with the NDEX, MHEX, and MWSI interfaces reset to their maximum allowable levels

No violations of MAPP stability criteria were found across all three power flow cases and all 18 faults. This includes generator stability, transient voltage dip criteria, damping criteria and wind farms not tripping.

Outputs from the simulations are given in the appendices, including the TBL tables. The RPT reports are available in Appendix H and the PDF plots are available upon request.

These results seem to indicate that if the 600 MW of DRG plants are spread around Minnesota in an appropriate pattern, the impact on regional stability could be minimal.

Important note: These results are for the assumed conditions. Some of the significant assumptions are:

- Using a 2008 off-peak power flow case. For a specific DRG interconnection impact study, a model would be built to represent the in-service year for the requested plant and would include all prior-queued generation.
- Only regional faults were simulated. For a specific DRG interconnection impact study, faults in the local area around the POI would be tested.

For a specific DRG interconnection impact study, it is possible that there could be a detrimental impact on stability that would need mitigation with a wide range of possible cost and time implications.

V. DRG Integration Issues

DRG developers need to contact the local utility to examine opportunities for DRG site selection and foster coordination for further study work and/or interconnection requirements.

Each dispersed renewable generation project will need to be integrated into the existing electric utility transmission system. Care must be taken to ensure that every entity that connects to this highly interconnected network follows the regulations set by Federal Energy Regulation Commission (FERC), the North American Electric Reliability Corporation (NERC), the Midwest Reliability Organization (MRO), and the guidelines set forth by each utility.

Most Minnesota transmission owning utilities have generation interconnection guidelines available on their Web sites or by request. One purpose of interconnection guidelines is to assure the safety of electric utility personnel and the general public. Another reason the guidelines are imperative is to minimize degradation of the reliability and service for all users of the electricity grid and to provide a uniform process for all parties interested in interconnecting generators to a utility's transmission grid. Adherence to the guidelines also reduces the chance for property damage for the utilities, the public and the generator owner.

FERC Orders 2003 and 2006 final rules require FERC-jurisdictional electric utilities to use standardized generation interconnection procedures and agreements for all pending or new requests to interconnect a generator at transmission voltage. FERC has established a pro forma generation interconnection procedure and a pro forma generation interconnection agreement. FERC breaks down these procedures and agreements by greater than 20 megawatts (large generators) and less than 20 megawatts (small generators). The FERC final rules also allow for each utility to account for regional differences in their own procedures and agreements where the detailed technical requirements for interconnection are documented. There also may be specific technical requirements unique to an individual state or regional reliability organization. The details on the FERC procedures and agreements can be found at http://www.ferc.gov/industries/electric/indus-act/gi.asp.

All generation projects in the MRO region must meet all applicable NERC and MRO standards. Interconnections to MISO members must be approved by MISO and the MAPP Design Review Subcommittee must approve interconnections to MAPP members. In addition, producers intending to supply generation capacity to members of the MAPP Generation Reserve Sharing Pool (GRSP) or MISO's Contingency Reserve Sharing Group (CRSG) must demonstrate reliable generating capacity capability. This is accomplished through the applicable generation accreditation processes. Producers adding generation will most likely be responsible for the cost of all study work performed by the utility required to obtain these acceptances. The details on the MAPP requirements can be found at http://www. Mapp.org and the Midwest ISO requirements can be found at http://www.midwestreliability.org.

Utilities in Minnesota that are members of MISO are governed by the MISO Open Access Transmission Tariffs (OATT) while utilities that are not MISO members are governed by their own OATT. Each OATT has stipulations regarding generation interconnection procedures as required by FERC.

Persons seeking to interconnect to the transmission system must review the generation interconnection procedures set forth by the electric utility, MAPP, MISO, NERC and FERC to ensure that the most up-to-date procedures are used in the project design, operation and maintenance requirements.

The following are examples of interconnection costs that may be borne by the power producer (this is not a complete list):

- Study analyses and related expenses to determine: feasibility to interconnect, transmission facilities required for interconnection, system upgrades required for interconnection, construction and project schedules, cost estimates and other related information.
- Preparation and presentation of study results to appropriate regional oversight committees or planning groups.
- Land and rights-of-way, including any required licensing or permitting.
- The producer's interconnection facilities.
- Meter installation, testing, and maintenance, including all parts and other related labor.
- Meter reading and scheduling.
- Telemetry installation, testing, and maintenance, including all parts and other related labor.
- Operating expenses, including communication circuits.
- The utility's protective device installation, testing, equipment cost, and related labor.
- The producer's protective device and interlock review of design, inspection, and test witnessing.
- Programming costs to incorporate generation data into the utility's energy management system.

Each electric utility may have unique technical requirements for generation interconnection. The configuration requirements of the interconnection also will depend on where the physical interconnection is to occur and the performance of the system with the proposed interconnection. Each utility may have various substation designs that will affect interconnection requirements. The specific requirements for each installation will be determined in the required interconnection and facility studies.

While the utility studies will cite the specific technical requirements for interconnection to the utility transmission system, the generator developer should consult an expert in the field of system protection to help with the nuances and complexities involved in designing their own protection scheme in consideration of the site-specific conditions.

VI. MISO Interconnection Process

DRG projects that connect to the transmission system may still need to enter the Midwest Independent Transmission System Operator (MISO) interconnection queue or another utility generation interconnection queue and complete a System Impact Study. Dispersed distribution connected projects that largely (but not entirely) serve local load must undergo a coordinated study between the local utility and the Midwest ISO. An operating agreement. It is also important to understand that receipt of approval for a generation interconnection does not grant any transmission service, nor ensure availability of transmission service for delivery of the generation output to any purchaser.

MIDWEST ISO GENERATOR INTERCONNECTION PROCESS – CURRENT AND PROPOSED
(prepared by Durgesh Manjure, MISO)

A. BACKGROUND

The level of requests for generator interconnection in the Midwest ISO system has exploded in recent years, driven, in large part, by renewable mandates. The Midwest ISO received over 200 generator interconnection requests in 2007, which represents an increase of more than 60% over the number of requests received in 2006, and more than double the level of requests received in each of the years from 2002–2005.

The current backlog of queued interconnection requests and high level of stakeholder frustration with the process indicate that the good intentions of Federal Electric Regulatory Commission (FERC) Order No. 2003 have resulted in a number of unintended consequences. The process is working as designed, but the design is not working in the current public policy and energy market environment. Specifically it appears that the current process, which places value in a queue position, rather than an interconnection agreement, with a relatively lower cost of queue entry, and with no cost for suspension at the end of the process, has effectively incented stakeholders to enter the queue early and often. When an earlier queued project suspends or drops out of the queue, customers who have the remaining queued projects face high levels of rework/restudy and frustrating delays. The problem is compounded by the fact that many of these requests submitted to the Midwest ISO are being proposed in areas where little or no transmission capability exists and significant network upgrades are required to support generator interconnection.

In the face of a growing backlog of generator interconnection requests, the Midwest ISO initiated an effort to address the issues raised by stakeholders, with the goal of identifying improvements to the FERC Order No. 2003 generator interconnection process. Stakeholders have been actively involved in the identification and development of solutions. This effort is ongoing through a Midwest ISO stakeholder committee, known as the Interconnection Process Task Force (IPTF) which reports to the Planning Advisory Committee. This group consists of a broad range of stakeholders, including generation developers, transmission owners, load serving entities and state regulatory staff, and has been working since September 2007 to identify solutions to reduce cycle time and increase certainty through the generator interconnection process.

A high-level summary of the current and the proposed Generator Interconnection Process is provided ahead. It is important to note that the information contained in this section is current as of May 2008. The proposed process is yet to be filed at the FERC and is **subject to change** depending upon the FERC order that will be received. Detailed information is available in the reference documents cited at the end of the section.

B. CURRENT GENERATOR INTERCONNECTION PROCESS OVERVIEW

Currently, Midwest ISO processes interconnection requests per the rules established in Attachments X and R of the Midwest ISO Transmission and Energy Markets Tariff. Attachment X details the Large Generator interconnection procedure and applies to generating resources larger than 20 MWs. Attachment R pertains to smaller generators – 20 MWs or lesser in size. Per these processes, the Midwest ISO offers Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). In order to grant interconnection service, Feasibility Studies, System Impact Studies and a Facilities Studies are performed. Details about the study procedures can be obtained from the existing interconnection tariff. Successful completion of these studies (along with meeting the tariff requirements) results in an interconnection agreement, which is typically a three-party agreement - between the interconnection customer, the transmission owner and the transmission provider (Midwest ISO). The document is mostly pro-forma, and is filed at FERC if it deviates from the pro-forma.

The interconnection study and agreement jurisdiction within the Midwest ISO footprint is outlined in a flowchart posted to the Midwest ISO web-site (Generator Interconnection Planning page – see reference). As indicated in the flowchart, if the point of interconnection for a DRG project is on the transmission system under Midwest ISO's jurisdiction, they would need to enter the Midwest ISO generator interconnection queue to obtain interconnection service. Otherwise, the DRG project would need to work with the local distribution company to which they are proposing to interconnect. The interconnection study in such cases may need to be coordinated with the Midwest ISO, depending upon the impacts to the transmission system.

1. Factors Contributing to Interconnection Queue Backlog

The Midwest ISO hypothesizes that under the current process the following broad factors have contributed to the current backlog in the interconnection queue:

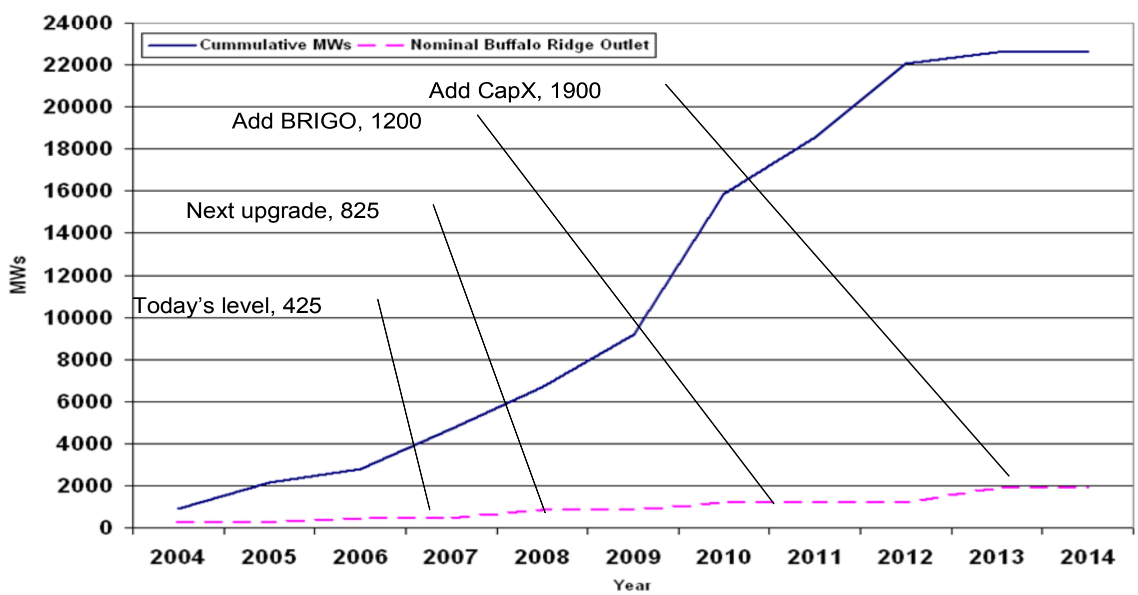
– Queue position being significantly valuable

– Having a relatively lower cost of entry into the queue

– Inordinately high amount (MW and number) of interconnection requests against a highly constrained transmission system (for example, in the Buffalo Ridge area, there are approximately 23,000 MW of wind generation requests for interconnection by 2014, with only 1,900 MW of outlet capacity planned for the region by that same date, as shown in Figure 1 below)

– High attrition driven primarily by the apparent oversupply of requests, and resultant rework, delays and uncertainty for subsequently queued projects

– No cost/penalty for suspension, resulting in large number (& MW) of projects being suspended which adversely impact timelines and uncertainty for later queued generators dependent on the transmission upgrades of the suspended generators (a suspension trend observed is the increasing level of projects suspending shortly following execution of the Interconnection



Agreement, supporting the theory that the current process incents projects to enter the queue, although they may not be ready to interconnect, and wait in suspension)

Figure 3: Generator Interconnection Requests in the Buffalo Ridge Area as of November 30, 2007

C. PROPOSED GENERATOR INTERCONNECTION PROCESS OVERVIEW

An overarching solution to the current logjam in the generator interconnection queue is switching the queue process from a first-in, first-out method to one that is milestones based. Doing so will allow projects to progress based on readiness, rather than solely on queue order.

In areas where transmission is unavailable, it is **not** expected that changes to the Generator Interconnection process in and of itself will significantly affect process time, because the limiting factor in those areas is a physical problem, not a process problem.

The proposed Generator Interconnection Process (GIP or GI process) is divided into four phases:

– Pre-Queue (represented by yellow in the diagram)
– Application Review (green)
– System Planning & Analysis (light blue)
– Definitive Planning (dark blue)

An overview of the proposed process is shown ahead in Figure 4.

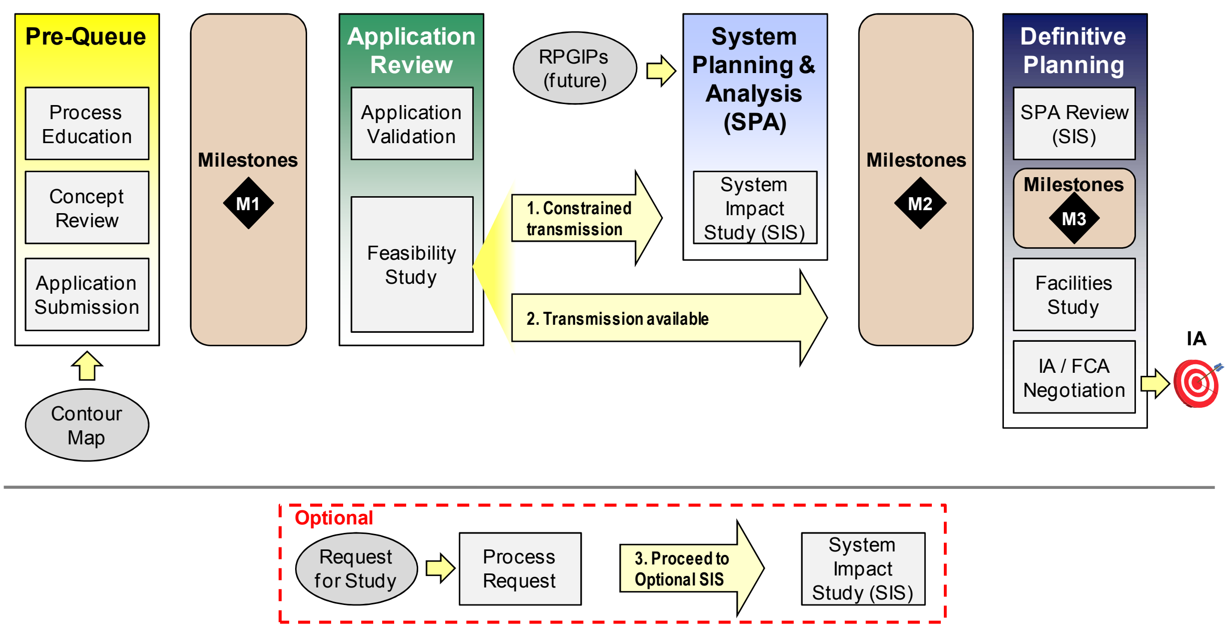


Figure 4: Proposed Generator Interconnection Process

The process incorporates increased interaction between customers and the Midwest ISO and uses milestone achievement as a method of moving Interconnection Requests (IRs) through the queue. Milestones (represented by black diamonds in the diagram) serve as control checkpoints where the Midwest ISO assesses IRs based on pre-defined criteria. Milestone achievement is a key determinant in how an IR is progressing through the process (the other key determinant is transmission availability). Milestones may be technical (such as a stability model) or business-related (such as proof of site control).

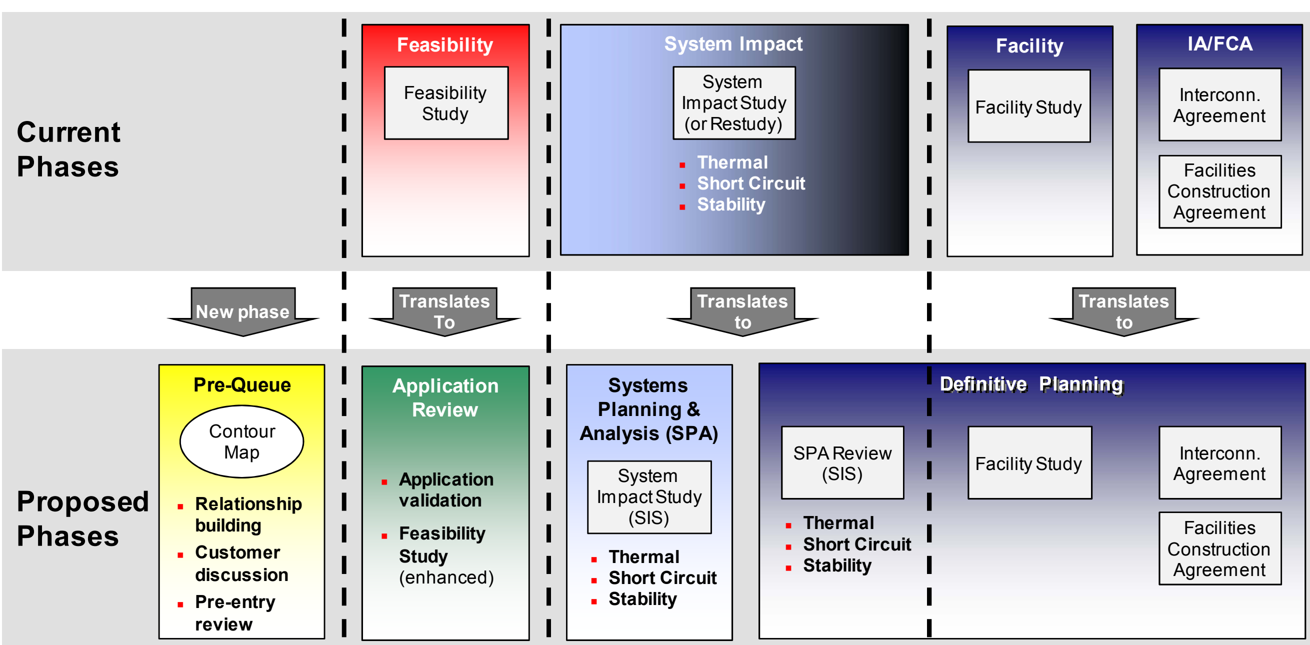
At the bottom of the four-phase process, there is an Optional Study process, indicated by the red dashed lines. Optional Study is for customers who wish to have their projects studied without entering the queue. Optional Studies are available today, but are rarely utilized. This is not expected to change.

In addition to implementing a milestone-based queue, the proposed process places limitations on Suspension, in order to reduce the level of uncertainty experienced by projects that follow suspending projects. It is expected that with the proposed milestone-based progression and changes to Suspension rules, IRs will move through the process quicker and with more certainty.

The IPTF is currently working toward a second quarter 2008 Tariff filing at the FERC to further progress towards implementation of these solutions.

D. COMPARISON OF MILESTONE-BASED QUEUE PROCESS TO CURRENT QUEUE PROCESS

The proposed Generator Interconnection (GI) process will have many steps that are similar to the current queue process. In particular, the actual study processes will have the same basic study structure as currently utilized. The main differences occur in how projects meet milestones, deposit amounts, and the different paths a project can take through the GI process – including the addition of a "fast lane." Figure 5 illustrates how the proposed study process compares to the current study processes.



** This graphic illustrates comparison of studies procedural differences; differences in milestones, deposits, and paths through the phases are not shown.*

Figure 5: Diagram Comparing Proposed GI Process to Current Process

The **Pre-Queue Phase** in the proposed GI process is completely new and is not comparable to any phase of the current GI process. This phase is designed to facilitate dialogue between the Midwest ISO and potential Interconnection Customers in order to have customers as prepared as possible when entering the queue.

The **Application Review Phase**, where the Application is validated and the Feasibility Study is performed, modifies and expands upon the Feasibility Study Phase in the current GI process.

System Planning & Analysis (SPA) is similar to the current System Impact Study Phase, but with a few very important distinctions:

- Queue position has lesser value; order of position in the System Planning & Analysis Phase does not translate to the same order of position through the entire process. That is, downstream position order may change in the Definitive Planning Phase, based on the achievement of milestones.
- Projects located where significant transmission constraints exist are not holding up projects that could otherwise move ahead.

In the **Definitive Planning Phase** (DPP), the two studies that will be performed are similar to current study procedures. If, during the review of previous System Impact Studies (SPA Review), a restudy is determined to be necessary, the restudy will be similar to the current System Impact Study. GI requests proposing to interconnect in areas with less-constrained transmission system and meeting their M2 milestones will proceed to the system impact study directly (fast lane). These studies would be performed under the DPP as well. The Interconnection Agreement/Facilities Construction Agreement (IA/FCA) agreement in the proposed GI process will differ from the current agreement process mainly by modifying the Suspension provisions to support a cost for Suspension and restrict the ability to suspend to Force Majeure conditions only.

References:

[1] Midwest ISO Transmission and Energy Market Tariff Attachment X – Large Generator Interconnection Process – FERC Order 2003, [Online] Midwest ISO Website, http://www.midwestmarket.org/publish/Folder/3e2d0_106c60936d4_-76630a48324a

[2] Business Practices Manual for Generator Interconnection under FERC Order 2003, [Online] Midwest ISO Website, http://www.midwestmarket.org/publish/Document/3b0cc0_10d1878f98a_-7d230a48324a

[3] Proposed Generator Interconnection Process Whitepaper, [Online] Midwest ISO Website,

http://www.midwestmarket.org/publish/Document/77a68f_119522dab5e_-7f690a48324a?

[4] Draft Tariff and Business Practices Manual for Proposed Generator interconnection Process, [Online], http://www.midwestmarket.org/publish/Folder/1e1401_118199304fa_-7dcd0a48324a?

VII. DRG Phase II

The DRG enabling legislation directs the study group to produce a second report due September 2009. In the second phase of the study, participants will analyze the impacts of an additional total of 600 MW of dispersed generation projects installed among the five out-state transmission planning zones. The utilities will employ an analysis similar to that used in the first phase of the study, and will use the most recent information available, including information developed in the first phase. The second phase of the study will use a generally accepted 2013 year transmission system model with all transmission facilities that are expected to be in service at that time. The team will coordinate with recent and current regional power system study work including long-range transmission plans developed for the Renewable Energy Standard (RES). The Commissioner of Commerce must submit a report containing the findings and recommendations of the second phase of the study to the commission by September 2009.

During discussions between the study team and the TRC on the strategy and technical details of the DRG Phase I Study, several potential Phase II Study opportunities surfaced and will be examined when the group reconvenes for the next phase. As with any study, new methods and information may come to light that may be proposed for use in the DRG Phase II Study.

VIII. Conclusions

The collaborative process of the study team with the TRC and public input provided a robust environment for rigorous analysis and creative problem solving.

The statewide aggregate analysis demonstrated a dispersed renewable generation scenario where a total of 600 MW of 10 to 40 MW new generation projects could potentially be sited without significantly affecting any transmission infrastructure. Significant impacts to the high voltage transmission system were found in the initial site distribution, as indicated by the Dorsey transformer issues, which limit the dispersed renewable generator outlet capability in aggregate and at many of the individual sites. Additionally, the single site analysis revealed that 19 of the 42 Potential Short List of DRG Sites had transmission limitations at levels below 40 MW. The transmission limitations were identified for these sites and specific system upgrades were formulated for each site.

The DRG Study team was tasked with identifying favorable project sites with minimal impact to the transmission system located throughout the five outstate Minnesota planning zones. Months of data collection, model building, site screening, steady-state analysis, loss analysis, and transient stability modeling have produced sound results. The study team, with stakeholders' input, has identified a number of promising sites to reach the study's statewide goal of analyzing the impact of 600 MW of DRG on the transmission system. However, there may be existing interconnection requests in a utility queue or MISO queue that might occupy these potential DRG sites.

Table 1 – Statewide Potential DRG Sites

Zone	Zone Total (MW)	DRG Site	DRG Site (MW)
NW	0		
NE	40	Cloquet	40
W-C	100	Glencoe Municipal	40
		Bird Island	40
		Atwater	20
SW	160	Sveadah	19
		Steen	21
		New Ulm	21
		Mountain Lake	21
		Morgan	21
		Magnolia	16
		Lakeside Ethanol	21

Zone	Zone Total (MW)	DRG Site	DRG Site (MW)
		Brookville	19
SE	300	**Waseca**	39
		Vasa	39
		New Prague	39
		Lafayette	29
		Goodhue	39
		French Lake	39
		Crystal Food	39
		Airtech	39

The team also identified several interesting opportunities for additional analysis that may be investigated in the DRG Phase II Study.

DRG developers need to contact the local utility to examine opportunities for DRG site selection and foster coordination for further study work and/or interconnection requirements.

This study report is the result of extensive examination of the statewide potential for DRG sites. The detailed assessment of any individual site's actual and specific DRG potential requires coordination with the local utility and a regional transmission provider such as MISO or MAPP to conduct interconnection studies and assess delivery possibilities. Most Minnesota utilities have documented interconnection guidelines available on their Web sites that help explain their processes and requirements. The US Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and the Midwest Reliability Organization (MRO) each have generation interconnection requirements as well.

This study report represents a snapshot in time. Due to the tremendous level of wind generation interconnection requests in Minnesota and the surrounding states, some – or possibly all – of this transmission capacity may be used by other resources or interconnection requests, with some due to loop flow issues. This study should be understood as indicative only. The performance of specific projects will depend on actual system performance and assumptions.

In addition, the wind performance identified at specific locations is based on wind forecasting models and should be viewed as providing relative levels among sites. Generators should not rely on the specific capacity factors identified but rather on their own measurements of actual wind conditions at the sites.

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.

Dispersed Generation (as defined in Minnesota Legislation): An electric generation project with a generating capacity between 10 and 40 MW.

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.

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."

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.

MISO Queue: The MISO interconnection queue is the process to get an interconnection agreement from MISO to put power on the region's electric transmission system.

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

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

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.

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.

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%.

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.