Dispersed Renewable Generation Transmission Study Phase II

Volume I

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Prepared for:

Minnesota Office of Energy Security
Office of the Reliability Administrator

Prepared by:
The Minnesota Transmission Owners

September 15, 2009

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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
- Minnesota Power
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- Missouri River Energy Services
  (also representing Hutchinson Utilities Commission and Marshall Municipal Utilities)
- Northern States Power Company, a Minnesota Corporation (" Xcel Energy")
- Otter Tail Power Company
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Willmar Municipal Utilities

Note: The Minnesota Transmission Owners (MTO) are utilities that own or operate high voltage transmission lines within Minnesota. When this group was originally formed in 2001, Minnesota Statutes were revised to require each electric transmission owning utility in the state to file a biennial transmission planning report. Additional utilities have joined the MTO to collaborate on more recent transmission studies.

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September 15, 2009

Dear Energy Legislators, Commissioners, Staff and Colleagues:

In May of 2007, Governor Tim Pawlenty and the Minnesota Legislature charged the Reliability Administrator and his Office with conducting a two-phase statewide transmission study of the siting potential for dispersed renewable generation. This requirement was included in the legislation enacting the Governor's Next Generation Energy Initiative[1]. The report for Phase I of this study was filed on June 16, 2008. This report contains the analysis and results of the second phase of this study.

Two-Phased Study details. The focus of the entire study is to analyze, in two phases, the transmission impacts of siting 600 MW of dispersed renewable generation in each phase (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 potential locations studied were based on public input, regional availability of renewable resources, current dispersed generation in the Midwest Independent Transmission System Operator's (MISO) transmission interconnection request queue, and access to existing transmission. The priority for Phase I of the study was to first utilize the existing transmission system infrastructure by identifying non-constrained capacity sufficient to accommodate 10-40 MW of generation, then to develop system upgrades as needed to mitigate affected transmission facilities. Phase II of the study was to continue this work by identifying a second 600 MW.

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

Phase I

As stated before, the goal of Phase I of the study was to identify project sites that will minimize impacts to the transmission system. The findings of the Phase I study were issued in a June 2008 report. The Phase I study showed, through extensive analysis, that even dispersed generation can have substantial impacts on the electric grid. The Phase I Study concluded that, due to constrained transmission, the majority of the 600 MW could be sited at various locations in and around southeastern and southwestern Minnesota. Since the date of the Phase I report issuance, many sites have been "claimed" by requesting interconnection to MISO.

Phase II

The Phase II work initially identified that there were limited locations in the state that could accommodate 10-40 MW of generation without incurring some amount of transmission investment. As such, the study team went on to identify and include certain assumed transmission projects in the Phase II study then focused on locations that could potentially accommodate generation without incurring major transmission investments. It should be noted here that this study does not, nor does it intend to, address the allocation of or responsibility for any such transmission investments.

After adding the proposed transmission projects mentioned above, the Study identified locations in each of the study's five regions of the State (Northwest, Northeast, West-Central, Southwest, Southeast) but stated that siting 600 MW in these (or other locations) would depend, not only on "local" (close to the generation) transmission upgrades, but on larger, regional transmission construction as well. **The bottom line of the Phase II study is that, after rigorous expert engineering assessments, the lower and higher voltage transmission grid is essentially constrained in Minnesota when viewed in aggregate statewide.**

Study team. The two-Phase Dispersed Renewable Generation study benefited greatly from a stellar assembly of national, regional and state technical experts representing the national energy laboratories, MISO, wind and community energy advocates and Minnesota's utilities. This technical review committee (TRC) guided and reviewed the work of the Analytic Team. Seven full-day TRC meetings and dozens of conference calls were held throughout the course of the two Phases of the study to review and discuss each Phase's 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 in each Phase on the project sites to be studied, on the modeling approach, and on the key results and conclusions.

For both Phases of the study, the Technical Review Committee was chaired by Matt Schuerger, under contract with the Minnesota Office of the Reliability Administrator, and the analyses were completed by an Analytic Team led by Jared Alholinna and his colleagues at Great River Energy in collaboration with the Minnesota electric utilities. In addition, MISO participated and provided invaluable expertise and analysis in collaborating with the TRC and the Analytic Team. This group of transmission and engineering experts successfully completed an extensive amount of challenging and innovative work in each Phase, including development of the first state-wide models of the electrical system which include lower along with upper voltage transmission 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, neither Phase of the study could have achieved its goals.

In conclusion, when the Governor's Next Generation Energy Initiative was enacted, 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 increased energy conservation and efficiency, demand response, emerging efficiency technologies and dispersed renewable generation where it can be interconnected reliably, and
- Significantly increasing high-voltage transmission capacity in the state.

The Two-Phase Dispersed Generation study makes a major contribution to this fundamental State policy and these strategies.

Thank you to the Technical Review Committee and the Study Team for an extraordinary effort and a set of ground breaking studies.

Sincerely,

/s/ WILLIAM R. GLAHN

Acting Reliability Administrator
Minnesota Office of Energy Security

WRG/MW/sm

IMPORTANT NOTE: This study is a representative analysis. Parties interested in pursuing any of these potential dispersed renewable generation siting and transmission interconnection opportunities must work with their transmission provider, as these results do not, and are not meant to, constitute a full interconnection study. Potential individual generation developers desiring to site a project at any location identified in these studies must work with their transmission provider or utility to apply for interconnection to MISO and to complete required interconnection studies to determine specific transmission impacts and receive approval to interconnect. Also, please note that this study does not intend to, nor does, address the allocation of or responsibility for any costs provided in this report. DRG developers are encouraged to work with their transmission providers and the Midwest ISO to identify potential interconnection issues, needs and costs that specifically pertain to their proposed project.

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
September 15, 2009

DRG Study Phase II, Volume I

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I. Executive Summary

Synopsis

In May 2007 the Minnesota Legislature enacted (and the Governor signed into law) the Next Generation Energy Act of 2007 directing the Minnesota Office of Energy Security, Office of the Reliability Administrator (ORA) to manage a statewide transmission study of dispersed renewable electricity generation potential. The study was to be divided into two phases of 600 MW each with reports due June 16, 2008 and September 15, 2009. The Dispersed Renewable Generation (DRG) Phase I Study analyzed the impacts of the first 600 MW of renewable dispersed generation to be placed throughout Minnesota's five out-state transmission planning zones in a model representing the transmission system in the 2010 timeframe. The dispersed renewable generation projects are assumed to be 10 to 40 MW in nameplate capacity and interconnected on the lowest transmission voltage level that exists in the vicinity of the assumed generation sites.

The objective of the DRG Study Phase II, as reported here, was to analyze the impacts of installing an additional 600 MW of dispersed renewable electric generation in the five out-state zones in a model representing the 2013 timeframe. The year 2013 base case transmission model and generation dispatch assumptions utilized in this Phase II study were designed to closely mimic the way the generation and transmission system operates in the upper Midwest. In response to public comments and reflecting back upon the first phase, the DRG Phase II study team in consultation with the Technical Review Committee updated the assumptions and study process from DRG Phase I to DRG Phase II. These changes created a model closely representing expected operating conditions and along with other generation and transmission additions and as such, affected the study results.

DRG Phase II was not simply a continuation of the DRG Phase I study. Stakeholders assessed the process and results of the DRG Phase I study and made changes to assumptions and analytical methods using the latest data and methodologies to improve upon the study process. The methodologies and conclusions of this study are performed separately from DRG Phase I and other Minnesota dispersed studies. To the extent that these results differ, it is due to the employment of new, updated transmission and topology and more current study assumptions. Key improvements in Phase II assumptions compared to Phase I were:

- including both planned transmission upgrades and those queued new generation projects that have executed interconnection agreements;
- using the an economic dispatch over the entire Midwest ISO footprint to determine the generation sink;

- including a two-mile radius around an interconnection point for wind profile data.

This study was conducted with assumptions similar to Midwest ISO Network Resource Interconnection Service (NRIS) evaluations that result in full deliverability of project output which is less likely to result in curtailment. This study does not attempt to make a determination about any project's feasibility of accepting curtailment or conditional transmission service.

As a result of an initial site screening process, a final potential interconnection site list was determined. It included installing 120 MW each in all five outstate Minnesota transmission planning zones: Northwest, Northeast, West-Central, Southwest, and Southeast. Then the study team tested the system for issues.

From this potential site list, the study team conducted single site, zonal, and statewide analysis that enabled this 2013 base case to be tested with varying additional amounts of dispersed generation. **For the year 2013, even while assuming the addition of numerous and significant transmission improvements, the study found that there are very limited opportunities for DRG to connect without additional transmission upgrades and the associated costs**. **In fact, the statewide dispersion of 600 MW of additional DRG is not possible without encountering significant constraints or limitations that require material costs to resolve (what transmission engineers call "limiters"). The statewide aggregate analysis showed that up to 50 MW of DRG, far short of the objective of 600 MW, could possibly be added in Minnesota without encountering material transmission limiters.**

The DRG Phase II study group went beyond the legislated scope by looking at a DRG Sensitivity analysis and a Grid Expansion exercise. The DRG Sensitivity analysis examined what may happen to the DRG outlet capability should more generation already in the Midwest ISO queue be placed in service than was included in the base case models. The DRG Grid Expansion exercise looked at how adding certain planned and/or studied transmission grid improvements with in-service dates beyond 2013 impact the viability of DRG opportunities.

This study provides a representative analysis that identifies transmission upgrades necessary to interconnect varying amounts of generation at each potential DRG site. Results emphasize the high state of utilization of the transmission system, which does not allow for much increase in generation interconnection of any size without associated new transmission. When considering 40 "small" generation plants in terms of regional limiters, they appear as an aggregation and create one "big" generation plant and overload regional transmission facilities in the same manner.

As informative as this study is, it is neither intended to nor is it able to supplant any of the studies, tests or other processes required for interconnection to the existing transmission system. As such, Parties interested in pursuing any of these potential opportunities at the identified sites must work with their transmission provider to obtain interconnection and/or delivery service, as this representative analysis does not constitute a full and official interconnection study. The transmission provider's interconnection studies could determine transmission improvements that are different from those determined through this study. Potential generation projects must apply for interconnection service and complete required interconnection studies to determine specific transmission impacts and corresponding network upgrades at the time and location of their interconnection and receive necessary approvals to interconnect to the transmission system.

Background

Minnesota is a leader in renewable energy development with its Renewable Energy Standard (RES) generally requiring 25 percent of the electrical energy sold by the state's utilities to come from renewable sources by 2025. More specifically, Xcel Energy has been directed to supply 30 percent of its customers' electricity needs with renewable resources by 2020. The DRG Study Phase II is part of a greater effort to advance effective development of renewable energy and inform developers, policy makers, and utilities of the related opportunities and obstacles associated with the development of renewable energy sources.

This DRG Study Phase II is an inclusive examination of the dispersed renewable generation potential in the context of where the generation is placed on the power system and how it affects the greater interconnected electric system. This study is intended to provide a greater understanding of the impacts of the dispersed placement of renewable generation in Minnesota and thereby assist in meeting the state's renewable energy requirement with a specific focus on smaller scale generation development.

The DRG Phase II study team encountered many of the same challenges as other recent transmission study teams have found: the transmission system is stressed and the generation interconnection queue has an abundance of requests. The grid is at its design capacity which causes congestion. For the year 2013 model there are significant base case transmission facility overloads as a consequence of anticipated generation additions. These overloads may need to be addressed even without any additional generation, DRG or otherwise. As such, these constraints are not uniquely the result of new DRG possibilities, but rather **any generation additions of any size will add to the transmission overload concerns**. The Midwest ISO generator interconnection queue is flush with requests. As of May 2009, there were 360 active projects representing more than 65,000 MW of generation in the entire Midwest ISO footprint. Minnesota alone accounted for 156 of the 360 projects for over 21,000 MW.

Process

Work on the DRG Study began in July 2007 when the Minnesota Office of Energy Security, Office of the Reliability Administrator, 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. DRG Phase I study analysis took place between July 2007 and May 2008 with a report release date of June 16, 2008. DRG Phase II progressed through the significant work involved in each of the main study steps or milestones of substation data collection and modeling, substation site screening, short list site development, and finally, an analysis of the resulting final short list of potential DRG sites. The DRG Phase II team also conducted a queue analysis of the interaction between the DRG Phase I final potential sites and the prior Midwest ISO generation queue requests. An additional effort to look at DRG Sensitivity analysis and Grid Expansion exercises went beyond the legislated scope. The DRG Phase II commenced in September 2008 and concludes with this final report issued on September 15, 2009.

Findings

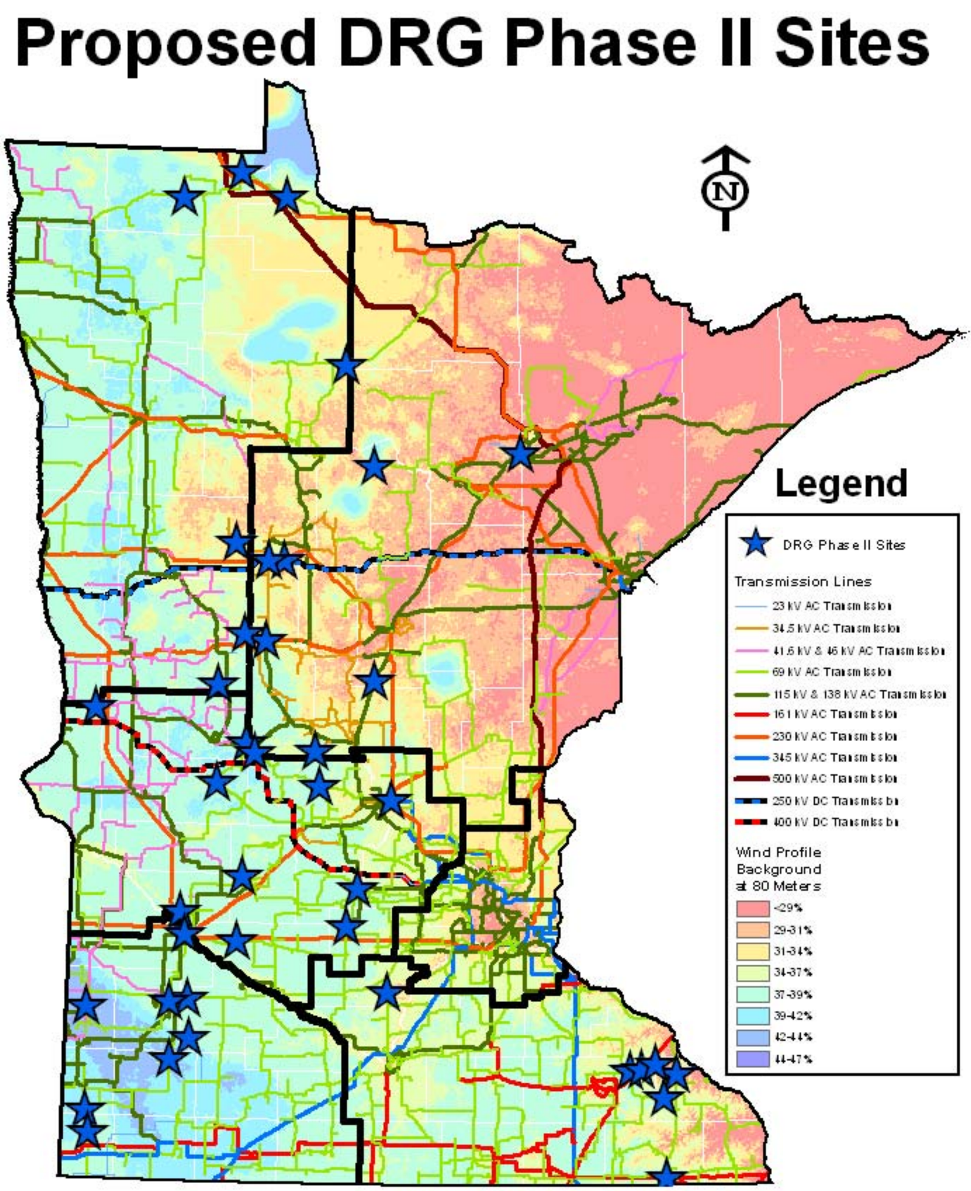
Midwest ISO queue analysis - The DRG Phase II study team conducted additional analysis of the DRG Phase I sites to examine any correlation between the final 20 DRG Phase I Study sites and the prior Midwest ISO generation interconnection queue requests made before the June 16, 2008 release of the study report. The method for this analysis was to examine the final 20 DRG sites to determine the number of Midwest ISO queue requests and total MW at various points – located at the exact electrical buses[2,] identified in Phase I or nearby those sites. This analysis showed a strong correlation between the locations of the final DRG Phase I sites and the Midwest ISO generation queue in terms of the number of project requests and their associated MW outputs. This suggests that the transmission system has limited opportunities for new DRG requests since the outlet capability identified in the first phase will likely be consumed by the prior queued generation requests.

The Midwest ISO queue received 14 generation queue requests in response to the issuance of the DRG Phase I results. This is significant because it shows that wind developers were aware of and followed the progress of the study. There were requests placed at more than half the DRG Phase I sites, with almost 800 MW in total in those 14 queue requests.

[2] A bus is 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.

Data collection and system modeling - The substation data collection and modeling process resulted in an initial data set of more than 2,600 Minnesota transmission substation buses, more than 2,200 of which were located in the five outstate zones. Since detailed analysis of each substation bus would require significant time and effort of a magnitude to prevent the TRC from meeting its legislative report deadline, the study team and the TRC decided to employ a multi-level screening process to develop a manageable number of DRG potential sites.

Figure 1 – Statewide Map of Final DRG Phase II Potential Short List Sites



Site Screening process - The site screening process employed strict analytical methods and processes to narrow the substation buses down to 492 potential locations. Experienced engineering judgment and specific transmission grid experience was used to review key substation characteristics further narrowing this list to the 40 geographically diverse potential sites most appropriate for DRG interconnection. These 40 sites will be referred to as the Potential Short List of DRG Phase II sites. The 40 generation sites are spread rather evenly throughout the five outstate transmission planning zones.

Table 1- Summary of DRG Phase II Substation Screening Process

	Site Screening Process - Number of Buses at each step		
Planning Zone	**All Buses in five zones**	**Buses After Eliminating those with any of the following attributes:** **–Unacceptable wind levels** **–Unsuitable voltage levels** **–In congested areas**	**Buses After Employing Engineering Judgement**
NW	424	28	8
NE	676	106	8
WC	477	271	9
SW	267	74	8
SE	400	16	7
TOTALS	**2244**	**495**	**40**

Analysis - The next study steps analyzed the impact of adding generation at the 40 potential sites on the greater transmission system. The study team ran a steady-state transmission system analysis program to determine how generation added at single sites, the zonal aggregation of the sites and the statewide aggregation of sites affected the reliability of the electrical grid. The computer program was run using two models: one with the DRG added at the 40 potential sites and then another base case 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 analysis showed that 16 of the sites could potentially achieve 40 MW with no limiters, the maximum zonal outlet was 50 MW with no limiters and there were 34 limiters with a dispersion of 600 MW.

Table 2 – DRG Phase II Generation Outlet Capability Summary (MW)

Generation Outlet Capability Summary (MW)							
Zone	Site Name	Single Site	Zonal Aggregation	Zone	Site Name	Single Site	Zonal Aggregation
NW	Compton	20	50	NE	Bena	25	40
	Moranville	10			Pine Lake	15	
	Nashua Tintah	15			Dewing	15	
	Osage	20			Hubbard	40	
	Parkers Prairie	20			National Taconite	15	
	Shooks	35			Palmer Lake	40	
	Stafford	10			Verndale	15	
	Williams	5			West Union	15	
WC	Albany	40	50				
	Benton	40					
	Big Swan	40				Statewide Aggregation	
	Crooks	35				**50**	
	Douglas County	40					
	Fiesta	40					
	Glenwood	40					
	Hutchinson Plant1	40					
	Willmar Muni	30					
SW	Granite Falls	40	40	SE	Altura	40	40
	Hardwick	40			Elgin	40	
	Holland	30			Harmony	40	
	Ivanhoe	40			Henderson	10	
	Lake Sarah Tap	5			St. Charles Tap	40	
	Lyon County	5			Wabaco	35	
	Milroy	0			Whitewater	15	
	Walnut Grove	5					

Conclusions

Upon the completion of the DRG Phase II study, the TRC concluded the following:

- The single site analysis reveals that 16 of the 40 sites have generation outlet capability of at least 40 MW. The remaining 24 sites have outlet capabilities between zero and 35 MW.

- The zonal analysis results show that the maximum zonal generation output is 50 MW as seen in both the Northwest and West-Central zones and with the remaining zones having generation output capabilities of 40 MW.

- The statewide analysis shows that it is not possible to site 600 MW of dispersed renewable generation without overloading numerous transmission facilities unless system upgrades are made. Rather than the 600 MW, the zonal analysis showed that there could only be up to 50 MW of DRG possible without transmission improvements.

- For the year 2013, there are very limited opportunities for DRG to connect without additional transmission upgrades and the associated costs.

- The study team started with a 2013 transmission model that was already at its design capacity due to the number and size of the generation projects existing and with signed generation interconnection agreements that are scheduled to be on-line by 2013. From this starting point, the task of identifying additional DRG opportunities becomes more difficult and much more analysis and testing is required to evaluate any site.

- While placing 600 MW in Minnesota, widespread regional transmission constraints and other limitations on the integrated grid (limiters) were found both inside and outside of Minnesota. Minnesota generation is dependent on regional solutions to enable the greater system to operate reliably and efficiently in the wider Midwest ISO market.

- The stability analysis of an additional 600 MW reveals the need for additional voltage and reactive power support facilities in eastern Minnesota and in northwestern Wisconsin.

- A criticism of the Phase I study was that the generation projects in the Midwest ISO generation interconnection queue were not included. As such, for the Phase II study, the generation projects slated for addition by the year 2013 were included in the Phase II study along with their associated transmission upgrades. These generation project additions created a stressed 2013 base case model before this study began due to a total of 7,000 MW of requested generation located both inside and outside of Minnesota being added to the model. Any transmission upgrades required under these generation interconnection agreements were also included in the model. A generation developer with a new project would have to enter the queue behind the projects that are already in the queue. Not all projects in the queue with on-line dates of 2013 were included in this model. It was assumed that those projects with signed interconnection agreements have the most likelihood of actually being constructed and were thus the projects that were included in the base model.

- The capacity identified through this study for DRG prospective sites reflects an analysis at a single point in time. The generation projects presently moving through the Midwest ISO generation interconnection queue and other (non-Midwest ISO) utility generation interconnection queues could occupy these sites or utilize the transmission capability of these sites.

DRG Phase II study assumptions are based on public comments and the combined input and knowledge of the TRC and study team. Changing any assumptions in turn impacts the study results. These findings collectively present a reasonable, knowledgeable study.

II. Introduction

The state of Minnesota has been one of the most ambitious states in the development and use of renewable electricity. The American Wind Energy Association reports that in 2008 Minnesota ranked first in the nation in the percentage of energy it gets from wind power. Legislative and regulatory requirements along with Minnesota utilities' collaborative efforts have produced real results. The Renewable Energy Standard (RES), requiring that 25 percent of the electricity consumed in Minnesota be generated by renewable resources by 2025 is the most publicized of this legislation. 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 Xcel Energy to supply 30 percent of its customers' electricity needs with renewable sources by 2020.

The RES legislation also directs transmission-owning utilities to analyze and identify specific transmission solutions for serving the renewable energy resources necessary to comply with the expanded and accelerated renewable energy objectives. These corresponding commitments to transmission planning and construction must be part of the greater plan to realize these challenging RES goals. One of the challenges the state of Minnesota and the Upper Midwest region faces is the question of how to advance renewable electric generation while maintaining the reliable, cost-effective electric power system people depend upon for the stability of our economy and the quality of their lives.

DRG Legislation

Minnesota's legislative and regulatory policies mandate substantial growth and use of renewable energy. The Next Generation Energy Act of 2007 is just one directive designed 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 http://ssl.csg.org/dockets/28cycle/28ES/0328ESC09mn.pdf.

This enabling legislation 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 second phase of the study participants must analyze the impacts of an additional total 600 megawatts of dispersed generation projects installed among the five transmission planning zones." The enabling legislation also directs "the utilities must employ an analysis similar to that used in the first phase of the study, and must use the most recent information available, including information developed in the first phase. The second phase of the study must use a generally accepted 2013 year transmission system model including all transmission facilities that are expected to be in service at that time." The phase II study report of the findings and recommendations must be complete by September 15, 2009.

One point to note is that the Minnesota renewable energy legislation includes certain renewable energy standard milestones which must be met before and after the 2013 date required for this DRG Phase II study. The study assumes that, for the purposes of this analysis, the prorated renewable energy goals will be met at 2013. The MTO Compliance Filing of September 11, 2008 specified 2012 and 2016 mandated RES values representing the additional renewable energy capacity over 2007 levels that need to be achieved to meet the greater Minnesota RES goals. The DRG Phase II study team interpolated those numbers to come to a 2013 mandated RES gap value of approximately 2,200 MW to be used for this study.

The legislation states that 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 Twin Cities transmission planning zone was excluded by statute from the DRG Study.

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.

The project methodology considered 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 of 2007 also mandated the consideration of wind resource, existing and contracted wind projects, and current dispersed generation in the Midwest ISO interconnection queue. The Midwest ISO generation interconnection queue is a list used in the process to obtain a generation interconnection agreement from the Midwest ISO 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 to new locations to reduce undesirable transmission system impacts."

MTO Sponsored Studies

The DRG Study Phase II is one of several coordinated efforts sponsored by the Minnesota Transmission Owners (MTO)[3] to support Minnesota's continued leadership in renewable electric generation development. The MTO group recognizes that careful, cooperative assessment of the transmission infrastructure is necessary to enable reliable electric system operation and this has driven the extensive study work. The MTO has sponsored a series of studies examining the planning steps necessary to meet the transmission needs of the expanded renewable energy standard objectives. These studies include the DRG Phase I Study, Corridor Study, RES Update Study, and the Capacity Validation Study (CVS).

The purpose of the MTO sponsored studies is to assess the transmission system in the upper Midwest for improvements necessary to develop a transmission system that i) allows the development of electric generation projects that satisfy all legal requirements, including the Minnesota Renewable Energy Standard Milestones, ii) continue to enable reliable, low cost energy for our region, and iii) continue to develop a robust and reliable transmission system that meets

[3]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 2001 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 Phase II Study.

customers needs. The Corridor Study examined the 230 kV transmission corridor from the Granite Falls, Minnesota area to the southwest corner of the Twin Cities for possible upgrade opportunities. The RES Update Study investigated and recommended future transmission alternatives to increase transmission delivery beyond that enabled by the proposed Corridor project. The Capacity Validation Study was a high level analysis to synthesize the various transmission studies being performed throughout the region and determine the approximate generation delivery capability created by various combinations of the projects being studied. (These study reports can be found at www.minnelectrans.com.)

MTO members have received feedback encouraging the study of dispersed renewable generation scenarios when conducting transmission system planning studies. In response to these inquiries, the MTO members plan to investigate DRG scenarios and the resulting implications when identifying transmission system improvements.

Electric Grid Overview

The North American electrical system is a complex interconnected grid in which power generators are interconnected through many thousands of 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 county roads delivering power within those regions. The focus of this DRG Phase II Study is to assess the impact of connecting new dispersed renewable generation to the Minnesota lower voltage transmission grid (the 'county roads') while maintaining the intricate balance between the generation and load on the transmission system.

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 classifications 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 Midwest Independent Transmission System Operator (Midwest ISO) 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:

> Distribution provider
> 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:

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

<u>Transmission</u>
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 34.5 kV, 23.9 kV, 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.

DRG Phase I Summary

While this report summarizes the DRG Phase II study, a review of DRG Phase I helps describe the progression from the initial study work to the most recent efforts. DRG Phase II is not simply a continuation of DRG Phase I. Lessons learned in Phase I drove modified assumptions and processes for Phase II.

The objective of the DRG Phase I study was to assess whether 600 MW of dispersed renewable generation could be placed throughout Minnesota with minimal impacts on the transmission grid. The DRG Phase I analysis successfully demonstrated just that – a DRG scenario where 600 MW of 10 to 40 MW dispersed projects 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.

For DRG Phase I, the study team evaluated the electric transmission system impacts, developed specific solutions and calculated 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 Phase I study team conducted analysis of potential DRG sites in the five non-Twin Cities transmission planning zones. 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 power flow model with the DRG project(s) producing energy and then a power flow model without the DRG sites included. 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 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 Phase I 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 Phase I 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. This issue reduced the potential site selection in these zones. The impact of the Dorsey transformers was less widely noticed in the DRG Phase II study in part because of the Midwest ISO market dispatch assumption, transmission system additions, and other updated assumptions. This led to system flows that mimicked those observed in the real-time on the grid – generally to the south and east. As a result, the flow through the Dorsey transformers was reduced.

The final potential site list included installing 300 MW in the Southeast transmission planning zone, 100 MW in the West-Central transmission planning zone, 40 MW in the Northeast transmission planning zone, zero MW in the

Northwest transmission planning zone and the remaining 160 MW in the Southwest transmission planning zone.

Figure 2 – Map of Minnesota Electric Transmission Planning Zones

The table below shows the single site and zonal distribution of the DRG that was used to locate the statewide 600 MW. As can be seen in this table as well as in Figure 3, several of the northern sites were unable to be used due to transmission congestion which is caused by the DRG at those sites.

Table 3 – DRG Phase I – Statewide Generation Outlet Capability

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	

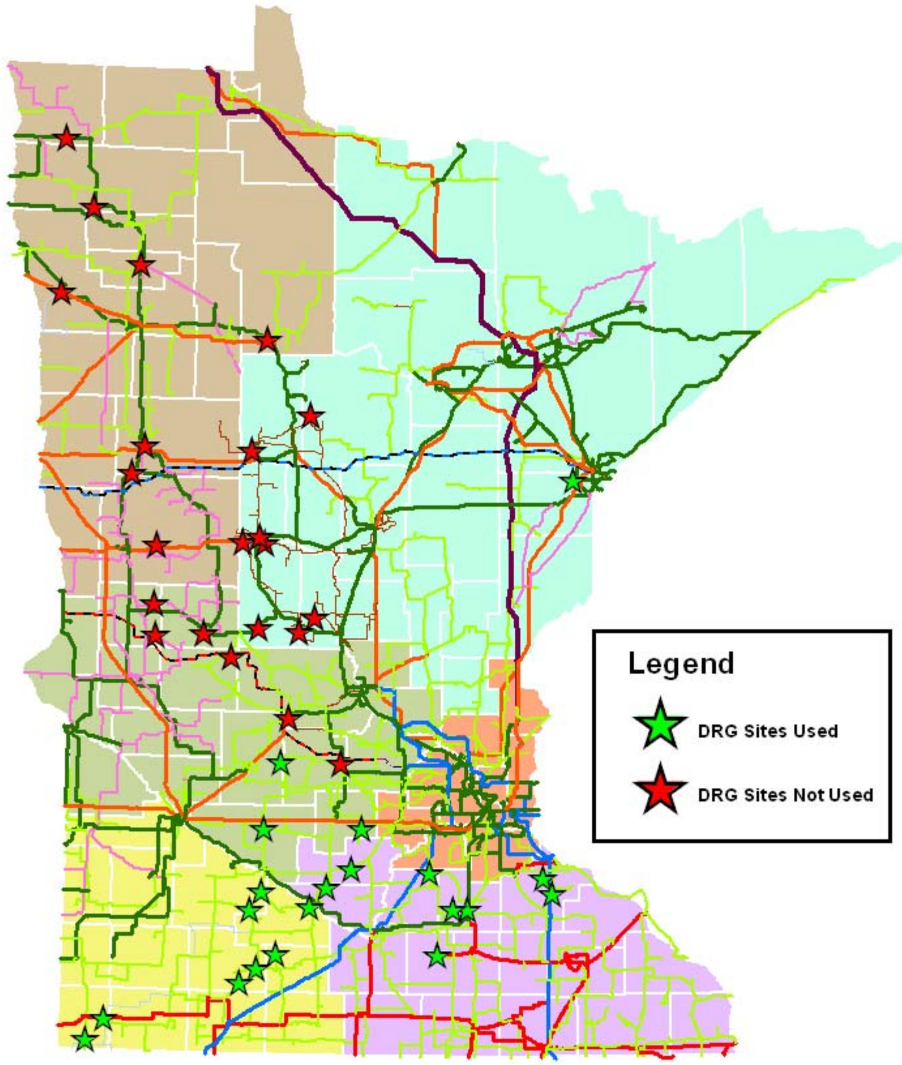
Zone	Name	Single Site (MW)	Zone (MW)
W-C	West Port	0	100
	Swan Lake	0	
	Paynesville	0	
	Hoffman	0	
	Glencoe Municipal	40	
	Erdahl	0	
	Birds Island	40	
	Atwater	20	
	Alexanderia	0	

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	

Figure 3 – Final DRG Phase I for Statewide Analysis



The DRG Phase I study report represented a snapshot in time and is only a representative of the results that may be discovered during more extensive analysis. DRG developers are always encouraged to contact the local utility to examine opportunities for DRG site selection and to foster coordination for further study work and/or interconnection requirements. There may be existing interconnection requests in a utility queue or Midwest ISO queue that might occupy these or nearby potential DRG sites or may utilize the transmission capacity assumed to be available to serve the DRG sites identified in Phase I.

DRG Phase I Midwest ISO Queue Analysis after Phase I Report Release

After the DRG Phase I report was released, the DRG Phase II Study team conducted additional analysis of DRG Phase I to examine any correlation between the final 20 DRG Phase I Study sites and the prior Midwest ISO generation queue requests made before the June 16, 2008 release of the study report. The method for this analysis was to examine the final 20 DRG sites to determine the number of Midwest ISO queue requests and total MW at the exact buses identified in Phase I or nearby those sites. This analysis showed a strong correlation between the locations of the final DRG Phase I sites and the Midwest ISO generation queue in terms of the number of project requests and their associated MW outputs.

In addition, the Midwest ISO queue received 14 queue requests in response to the issuance of the DRG Phase I results. This is significant because it shows that wind developers were aware of and followed the progress of the study. As soon as the report was complete, the developers were ready to leverage the information and act on the opportunity. The Midwest ISO had generation interconnection requests at more than half the DRG Phase I sites, with almost 800 MW in total in the 14 queue requests.

The DRG Phase I study report can be found at http://www.state.mn.us/portal/mn/jsp/content.do?subchannel=-536881736&programid=536916477&sc3=null&sc2=-536887792&id=-536881351&agency=Commerce.

Midwest ISO Queue Reform

DRG Phase I identified 20 potential sites for dispersed renewable generation development. Implementation of these opportunities is affected by the Midwest ISO's queue reform. The Midwest ISO assessed their interconnection process to transition from a 'first-in, first-served' to a 'first-ready, first-served' approach. On August 25, 2008, the Midwest ISO queue reform created a 'fast' track for study of generation projects in areas with relatively unconstrained transmission. The Midwest ISO generation interconnection process and fundamentally the availability of transmission capacity impact the rate of renewable energy development. Potential generation projects, which are sited at locations where existing transmission system outlet capacity is adequate to meet the requirements of the generation output, will be able to move quicker through the Midwest ISO queue analysis process than those generation projects sited in transmission constrained areas. More details on the Midwest ISO queue can be found in section VIII of this report.

DRG developers are encouraged to contact the local utility to examine opportunities for DRG site selection and to foster coordination for further study work and/or interconnection requirements. Most Minnesota transmission owning utilities have generation interconnection guidelines available on their web sites or by request. Also, whether Minnesota DRG installations are in Midwest ISO member locations or in other transmission providers' areas, the projects need to enter a queue or process where the interconnection requests move through a series of studies and tests to achieve interconnection rights.

III. Summary of DRG Phase II Study Scope

The Dispersed Renewable Generation (DRG) Transmission Study was ordered in May 2007 when the Minnesota Legislature enacted the Next Generation Energy Act of 2007. This legislation required a two-phase, statewide study of dispersed generation potential to be coordinated by the Minnesota Office of Energy Security, Office of the Reliability Administrator. The legislation instructed the Minnesota transmission owning utilities to conduct two phases of the study analyzing the potential for the impacts of two blocks of 600 MW of dispersed renewable generation to be placed on the transmission system in 2010 and 2013 timeframes respectively. The DRG Phase I Study was completed and the report was delivered to the Minnesota PUC on June 16, 2008.

The DRG study phase II objective is to analyze the potential for the impacts of an additional 600 MW of dispersed renewable generation assumed to be placed on the transmission system in a 2013 timeframe. The study also assumes, as directed by the legislation, that the generation projects will be 10 to 40 MW each and will be interconnected to the electric transmission system.

The goal of the second phase, like the first phase of the study, was to identify potential project sites and then analyze the impacts to the transmission system. The priority was to first utilize the capacity of the existing transmission system infrastructure then identify potential system upgrades necessary to mitigate the effects of additional DRG on the impacted transmission facilities. Using updated models, assumptions and methodologies, the study team evaluated the electric system impacts, developed specific solutions and assigned associated solution costs.

The DRG Study analytical work was conducted by the Minnesota transmission owning utilities and Midwest Independent Transmission System Operator (Midwest ISO). While engineers at Great River Energy, Missouri River Energy Services, Midwest ISO, and consultants hired by the Minnesota utilities performed the majority of the analytical work, personnel at many of the Minnesota utilities collected and provided valuable electrical transmission and generation systems data to allow the core study team to build a year 2013 state-wide model of the generation and transmission grid.

The dispersed renewable generation was spread out 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 from the DRG Study by statute. Minnesota transmission planners commonly refer to these zones when describing transmission project planning.

The Minnesota Office of Energy Security, Office of the Reliability Administrator appointed a technical review committee (TRC) to review and guide the key assumptions, methods, and analysis and to review the preliminary and final results for both DRG Phase I and Phase II. TRC members are individuals with experience and expertise in areas such as electric transmission system engineering, renewable energy generation technology and/or dispersed generation. This team regularly reviewed the results from the first and second phases of the study.

The DRG Phase II study team along with the TRC decided to expand the scope of the study by undertaking DRG Sensitivity and Grid Expansion exercises. The DRG Sensitivity analysis examined the interaction between DRG site generation outlet potential and prior queued generation. The Grid Expansion exercise looked at how adding certain planned and/or studied transmission grid improvements with in-service dates beyond 2013 impact the viability of DRG opportunities. For both of these evaluations, the study team included the 42 potential sites from DRG Phase I, the 40 DRG Phase II potential sites and ten additional sites in each planning zone for a total of 132 monitor points.

The DRG Phase II enabling legislation requires that the participants must analyze the impacts of an additional sum of 600 MW of dispersed generation projects installed among the five transmission planning zones, or a higher total capacity amount if agreed to by both the utilities and the technical review committee. The technical review committee and the study team decided the first priority was to examine the effects of the next DRG Phase II 600 MW first given the difficulty in locating the first 600 MW in DRG Phase I. The DRG Sensitivity and Grid Expansion exercises investigate the opportunity for additional DRG capacity, if possible.

One of many issues that the DRG Phase II study team and TRC contemplated was whether to examine the DRG Phase II sites during spring light load conditions. In the spring, the windy weather patterns and mild temperatures result in high wind generation production and light electric loads due to reduced heating and cooling demands. During this type of system condition, the transmission operators typically take less economical and natural gas generating plants off line and coal generating plants are backed down to accommodate the influx of wind power. The study team determined that this seasonal condition was more of an operational concern and not unique to DRG versus other wind generation. Another consideration was the fact that the Midwest ISO does not study a spring light load condition in their generation interconnection studies. Therefore, the TRC and study team decided this type of analysis was not a priority and would not be examined in DRG Phase II.

Another topic the DRG Phase II study team and the TRC pondered was whether it made sense to add PROMOD analysis to the DRG Phase II scope. PROMOD is an hourly production cost modeling analysis program that mimics the Midwest ISO's real-time generation market's least-cost generation dispatch. It can be used to model how a new transmission or generation project functions in the market environment from an economic perspective. After much discussion, the group decided that PROMOD analysis was outside the legislated guidelines for the DRG Phase II study. Another concern was that embarking on this analysis would tie up valuable engineering analysis time and talent, as PROMOD utilizes significant time in both computing resources and human resources to process the large volume of output the program creates

A. DRG Phase I and DRG Phase II Differences

During DRG Phase I, the study team along with the TRC kept a running list of ideas that might be pertinent opportunities for DRG Phase II analysis. Experience and knowledge gained during DRG Phase I also helped define better analytic practices and assumptions that were employed during DRG Phase II. These key issues and questions included development of the system model and clarifying assumptions, the scope of the analysis and methodology, and the range of the solutions to be considered. The DRG Phase II changes are important to understanding the Phase II study results.

Source/Sink Assumptions: For purposes of these studies, the DRG project buses were identified as the generation sources or the locations where generation was added to the system. DRG Phase I assumed the generation sinks were the natural gas generating units in the Twin Cities metro and surrounding areas. The generation sinks are the generation plants which have their outputs reduced in the analysis to accommodate the generation increases at the incremental generation sources under study. For DRG Phase II, the TRC and the study team decided to use the Midwest ISO market dispatch based on the security constrained economic dispatch of generation to determine the sink assumption since this set of sinks more closely models the way the system operates and the method used by the Midwest ISO to study generation interconnection requests. Merit order of generation dispatch is the operational methodology of turning down more expensive generation when the less expensive, generation is ramped up on the system. The Midwest ISO market dispatch represents a much larger geographic footprint than the Twin Cities metro area sink used in DRG Phase I. This view of the electrical system is a better reflection of the way the Midwest ISO manages the transactions on the electrical grid.

Two-Mile Radius for Wind Profile Data: For DRG Phase I the wind profile data assigned to each substation bus was the value measured at that specific point. A valuable contribution from public input was the suggestion that the wind profile at the exact substation may not represent the true wind potential that might be found in the vicinity of the transmission substation. Therefore, for DRG Phase II, the team decided to gather the wind data for points within a two-mile radius of the substations. One reality is that wind generation plants are not placed right at a substation. This will also allow for the possibility that a substation could be located in a valley where the wind resources are poor, yet the wind potential may be acceptable on a nearby ridge. This assumption change and its implication are discussed in more detail in the assumptions section of the report. In completing this analysis, lakes and rivers were excluded from being considered as potential sites.

Wind Output Level in the Study Models: It is recognized that wind output fluctuates during various times of the year and seasons. Wind typically blows more vigorously during the off-peak electric demand times and less during the highest electricity load, peak times. In DRG Phase I, the study team valued the wind output at 100% of its nameplate output rating during both summer peak and summer off-peak. The DRG Phase II study team and the TRC considered what would be the most appropriate level to set for the wind output assumption in the models. After discussion of probable real world operation (e.g. geographic diversity of the DRG sites) and the recent wind output levels assumed in other planning efforts, the DRG Phase II team chose to model all wind generators in the five-state region at 90% of nameplate capacity in the summer off-peak scenario and 20% of nameplate capacity in the summer peak scenario for wind output levels.

Distribution Factor: Distribution Factor (DF) is the term that defines the percentage of generated power that flows on a transmission facility during a particular system topology and is often expressed as a percentage of the generator power output. Distribution factor is one way to screen for a project's impact on an overloaded facility. During the substation bus screening process, the DRG Phase I study team eliminated substation buses with distribution factor ratings at 3% or greater on overloaded facilities. For DRG Phase II, the TRC recommended opening up this criteria to a 5% distribution factor. The reasoning was that this 5% threshold was consistent with some Midwest ISO studies and allowed more substation buses to move through to the AC analysis steps of the study.

Emergency Rating vs. Normal Rating: Transmission facilities may have more than one rating depending on the condition of the transmission system. Under typical ("System Intact") conditions where no outages exist on the system, a continuous (normal) seasonal rating is used. Under contingency situations where one or more transmission elements is out of service, an emergency rating is applied which is typically higher than the continuous rating, but can only be used for a limited amount of time. Utilities in the upper Midwest sometimes employ this rating for 30 minutes or less. In DRG Phase I, the continuous rating was used to screen for significantly affected facilities under both system intact and contingency conditions. For Phase II, the continuous rating was used to evaluate system intact conditions and the emergency rating was used to screen for significantly affected facilities in contingency situations.

Midwest ISO SCED Analysis: The Midwest ISO Security Constrained Economic Dispatch (SCED) is the method that determines how the generation resources participating in the Midwest ISO market will be dispatched in a least cost fashion while maintaining transmission reliability and security. The TRC recommended that the DRG Phase II employ this dispatch method since this will more closely mimic one step generators must take when going through the Midwest ISO interconnection process – the Midwest ISO Feasibility and System Impact Study. This dispatch was not part of the DRG Phase I study.

Substation Bus Inclusion: For DRG Phase I, the study team eliminated buses without load in the models during the screening process. The DRG Phase II study team chose to allow all buses to be examined and not just those with load. This increased the number of potential buses to be examined in the site screening process.

Generation Additions to the Base Model: DRG Phase II included significantly more additional generation in the representative 2013 year base model reflecting known generation additions and highly probable Midwest ISO queued generation which have already signed generation interconnection agreements. DRG Phase I ignored the Midwest ISO queue because at the time generation project status was difficult to determine. The reformed Midwest ISO queue provides more information on likely generation projects.

Contingency Identification: For phase II the team looked at contingencies in the five-state region (Minnesota, Wisconsin, Iowa, North Dakota, and South Dakota) and Manitoba area. During DRG Phase I the study team only monitored significant buses in or immediately adjacent to Minnesota.

Biomass: DRG Phase I assumed the fuel for two of the DRG short list sites was biomass. This phase I assumption was based upon public comments and leveraged a biomass study conducted by the University of Minnesota. DRG Phase II final site selection did not include additional biomass in the fuel mix since the biomass study had not been updated with additional sites to examine.

B. Regulatory Context

Electric generation and transmission service is a regulated industry. Care was taken during this study to follow all appropriate regulations. For example, commercially sensitive, non-public market information was handled correctly as related to U.S. Federal Energy Regulatory Commission (FERC) Order 2004 regulations concerning the separation of transmission and resource planning efforts. These standards of conduct are in place to prevent anticompetitive practices between electric transmission providers and their marketing affiliates. To ensure FERC regulations were enforced, 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 studies 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 in the United States. 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, TPL 002, and TPL 003. 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/page.php?cid=2|20.

C. Schedule

The DRG Study began July 2007 when the TRC was appointed by the Minnesota Office of Energy Security, Office of the Reliability Administrator. The TRC provided review and guidance throughout the entire process. For the DRG Phase II Study, three full-day TRC meetings and eight web-conference meetings were held to discuss assumptions, analytical processes, and results. Three public web-conferences were conducted to allow interested parties to contribute to the study. Adjustments were made to the study approach based on direction from the TRC and feedback from the public meetings.

Table 4 – Dispersed Renewable Generation Study Timeline

Dispersed Renewable Generation Study Timeline	
Jul 2007	Technical Review Committee (TRC) selected by Minnesota Office of Energy Security, Office of the Reliability Administrator for DRG Phase I and DRG Phase II.
June 16, 2008	DRG Phase I Study Report complete.
Sept 17, 2008	TRC web conference to review impact of DRG Phase I study, discuss DRG Phase II scope, process and schedule.
Oct 15, 2008	DRG webinar Public Presentation to review DRG Study requirements, DRG Phase I results, DRG Phase II public comments, initial scope and schedule.
Oct 29, 2008	TRC meeting to discuss DRG Study Phase I update and implementation, DRG Phase II scope concepts model building process and assumptions and study schedule.
Dec 4, 2008	TRC web conference to discuss final DRG Phase II scoping decisions, model building assumptions and

Dispersed Renewable Generation Study Timeline	
	screening process.
Jan 22, 2009	TRC web conference to review DRG Phase II progress update, DRG Sensitivity and Grid Expansion scoping, and schedule.
Feb 20, 2009	TRC web conference to seek input on DRG Sensitivity and Grid Expansion scoping.
Mar 26, 2009	TRC web conference to discuss generator additions and dispatch process.
Apr 21, 2009	TRC meeting to discuss model building changes and dispatch methods.
May 20, 2009	TRC web conference to discuss model building, dispatch and screening methods.
Jul 21, 2009	TRC meeting to discuss single site, zonal and statewide analysis results, conclusions, DRG Sensitivity and Grid Expansion, and next steps.
Aug 7, 2009	TRC web conference to review final results.
Aug 18, 2009	Public web conference to review study process.
Sept 2, 2009	TRC web conference to review draft study report.
Sept 15, 2009	DRG Phase II Study Report complete.
Sept 15, 2009	Public web conference to present DRG Phase II results and report.

D. Stakeholder Involvement

The study team sought input from stakeholders for both DRG Study Phase I and Phase II. The enabling legislation directed the group to employ an analysis method for DRG Phase II similar to that used in the first phase of the study. It also required the study team use information developed in the first phase of the study with the most recent information available. With these guidelines, the DRG Phase II study team used the feedback from the TRC and the public to help define the study scope, analytical approach and other key assumptions.

The study team provided many opportunities for the public to respond to DRG Study Phase I with ideas for DRG Study Phase II. Interested parties could submit comments and feedback after the June 16, 2008 DRG Phase I study report release. A public webinar on September 17, 2008 also invited public input to the process with an October 8, 2008 deadline for idea submission. The DRG Phase II study team reviewed the public input contributions and included these valuable ideas in the study process. A few examples of feedback that affected DRG Phase II include examining different sink assumptions, including non-load serving buses and expanding the wind net capacity factor to a wider area around the buses.

In order to produce the most useful results, the project team made several efforts to seek stakeholder involvement. The Midwest ISO was consulted to provide input to realistic system operating assumptions and data on the Midwest ISO queue impact. 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.

For example, the TRC was asked to help consider the approach for the transmission system modeling process, to help clarify the study sink assumptions, and to help determine which additional value-added analysis was most beneficial.

Several public webinar-based meetings were held to provide the opportunities for the public input to the process. The project team and the TRC carefully considered this feedback. The public webinars did not include a presentation of the 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.

IV. DRG Phase II Base Case Model Building Process

The DRG power flow model is a model used to conduct power flow analysis for the DRG study. The TRC and the study team took great care to define the study assumptions and the transmission and generation modeling process.

The DRG Phase I study team modeled the Minnesota integrated electrical system for the 2010 timeframe. This extensive effort resulted in the first known model to include all transmission lines in Minnesota. Details on the DRG Phase I model development follows. For Phase II, the study team started with the Phase I model and then made modifications to represent the anticipated 2013 Minnesota integrated electrical system.

The DRG Phase II study team set out to develop a representative model of the Minnesota transmission system for the 2013 timeframe. The entire integrated transmission system in Minnesota needed to be included in the model. This system is made up of 13 transmission system owning electric utilities, approximately 400 individual electrical generating units, more than 24,000 miles of transmission lines, and over 2,600 transmission substation buses supplying 15,000 plus MW of load (load calculated from the Midwest ISO Transmission Expansion Plan 2007 series summer 2013 peak model).

A. DRG Phase I, Transmission and Substation Data Collection and Mapping

For DRG Phase I, 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 mirrored the probable installation and operation of geographically dispersed 600 MW of wind generation in the 2010 timeframe.

Below is an overview of the discrete steps the study team performed to achieve the transmission and substation modeling effort for DRG Phase I.

MTEP 2013 Summer Peak and Off-Peak Models

During Phase I, the project team began substation data collection with data from the Midwest ISO Transmission Expansion Plan 2007 (MTEP07), 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 used the closest date to the desired 2010 model, the MTEP07 2013 model. The team utilized the summer 2013 summer peak (SUPK) and off-peak models (SUOP).

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 serve load closer to the generator's location. 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 load conditions. Under this summer off-peak scenario, electrical loads are lower than peak load (typically 70 percent of peak) and less economical peaking generation facilities, like natural gas-fired plants, are taken off-line. However, wind generation can be near its peak output during the summer off-peak times which can materially impact the locations and types of sinks during this period.

The electrical system must remain in balance, so that all power that is generated is used by a load somewhere on the system. The energy from any generator will flow to a load that is further away if there is not enough electrical demand close by to consume the power. With regards to DRG, the effect of this is to force more wind 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 system; 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 data from the Great River Energy Long Range Plan (GRE-LRP) and Otter Tail Power (OTP) power flow models allowed for more sub-transmission model detail to be included.

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.

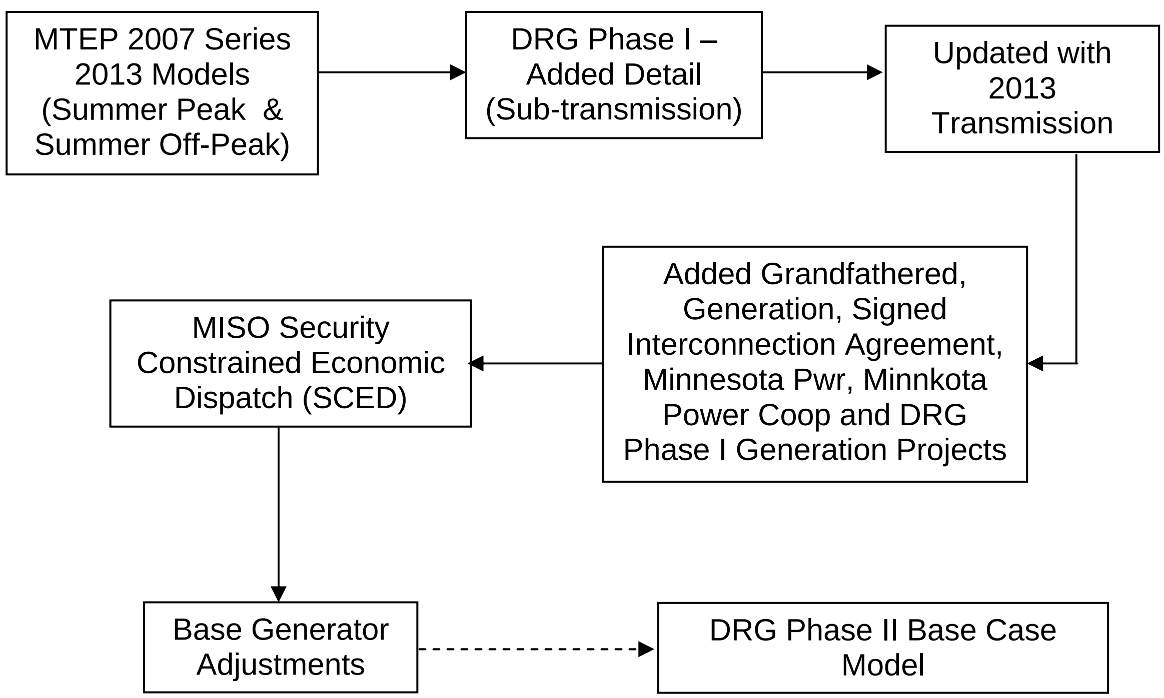
DRG Phase I Adjusted Topology to 2010

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.

B. DRG Phase II Model Development

The DRG Phase II study team began with the DRG Phase I model which is the Midwest ISO Transmission Expansion Plan 2007 (MTEP07) supplemented to include sub-transmission detail and a more complete representation of the statewide transmission model. (This is described in more detail above.) Using this existing model saved significant time allowing the study team to take on some additional DRG value-added analysis later in the study process.

Figure 4 – DRG Phase II Base Model Development Flow Chart



2013 Transmission and Sub-transmission System Additions

In order to bring the transmission system model topology up to the 2013 timeframe for DRG Phase II, the study team added numerous and significant transmission projects to the base model. These changes included adding all transmission facilities with in-service dates by 2013. The MTO compliance filing transmission projects[4] and the CapX2020[5] plan provided an outline as to which projects will be in-service by May 1, 2013. The study team also approached all participating generation and transmission owners in the region to submit any known upgrades with in-service dates before May 1, 2013. At the time of the model construction, these projects were expected to be in-service for 2013. The major projects that were added to the models are listed below:

Major 2013 Transmission Projects Added to Base Model

1. Segments of CapX2020 Group 1 transmission projects
   a. Brookings – Twin Cities 345 kV line project
   b. Monticello – St. Cloud 345 kV line
   c. North Rochester – La Crosse 345 kV line
2. RIGO (Regional Incremental Generation Outlet) transmission projects[6]
   a. Pleasant Valley – Byron 161 kV line
   b. Pleasant Valley – St. Bridget 161 kV line
   c. Byron – Westside 161 kV line
3. Wind projects
   a. Langdon – Hensel (ND) 115 kV line
   b. Pillsbury – Maple River (ND) 230 kV line
   c. Center – Prairie (ND) 345 kV line with Bison wind farm and others
4. Transmission substation additions
   a. Hampton
   b. North Rochester
   c. Fergus
   d. Lore
   e. Rose Hollow
   f. Rutland
   g. Pillsbury
   h. Rugby
5. Transmission system upgrades
   a. CapX2020 Group I underlying upgrades

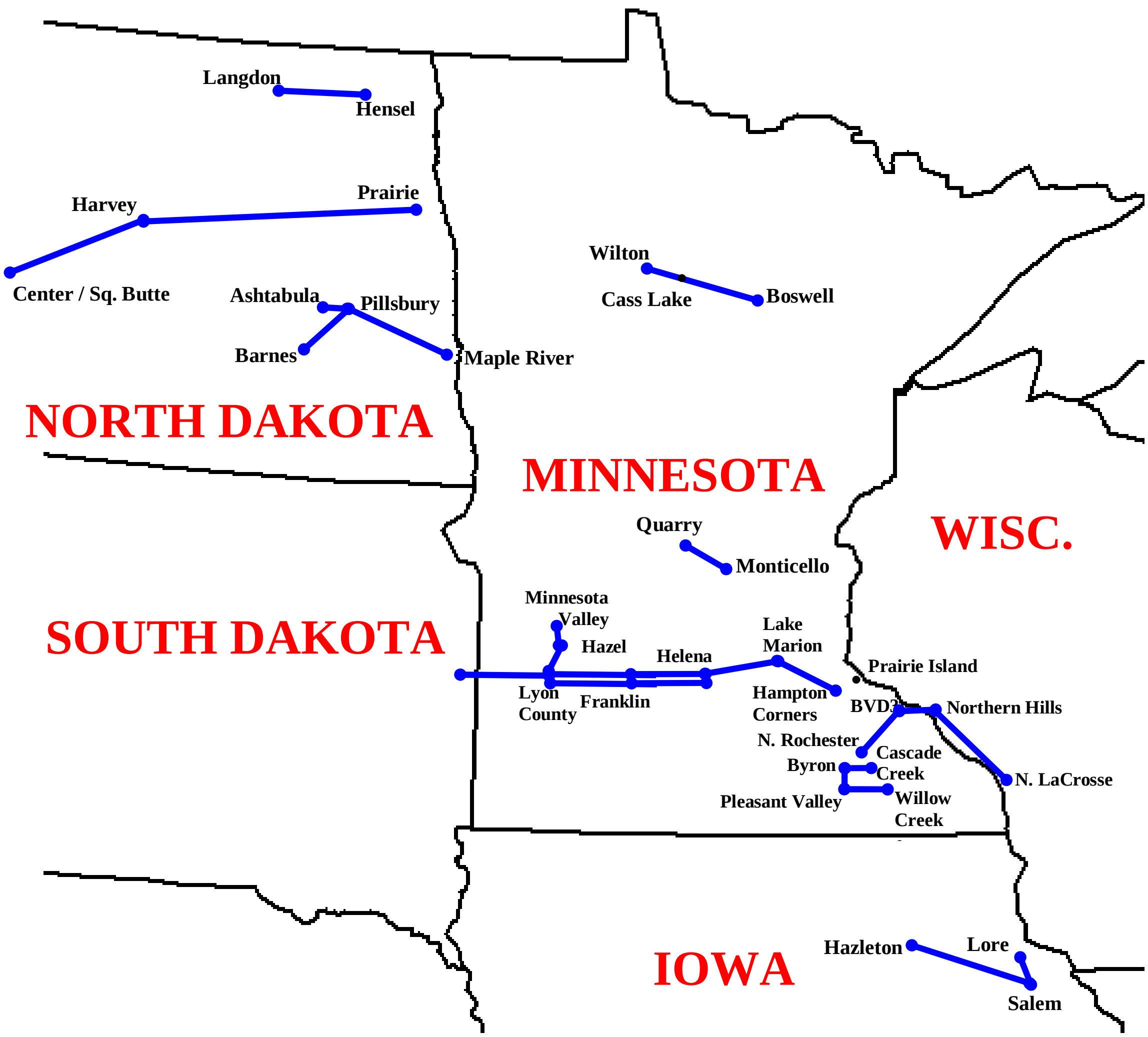
4 The MTO filed the 2007 Biennial Transmission Projects Report. A full version of the report can be found on the web at http://www.minnelectrans.com.

5 CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure reliable and affordable service. Capx2020 projects will be built in phases designed to meet the increasing demand for electricity and support renewable expansion. The CapX2020 Group 1 projects are the first projects in this plan.

6 The RIGO (Regional Incremental Generation Outlet Study) focused on increasing wind outlet capacity of the transmission system in areas outside the Buffalo Ridge area. This transmission study looked at west-central Minnesota and southeastern Minnesota 115 kV or 161 kV line improvements with an in-service goal of 2011.

b. Midwest ISO generation interconnection related transmission upgrades
c. Various capacitor additions and upgrades

Figure 5 – DRG Phase II Base Model Transmission Additions Map



The focus of the model development was the transmission system in Minnesota and neighboring states. The model was sent to each of the transmission planners on the TRC for review and verification of the model details including the transmission project in-service dates. They responded with suggested modeling changes. The study team then made the recommended modifications. Once the updates were complete, the study team compiled all of the layers (transmission lines, buses, wind profile, county, planning zone) into one map. This map can be found in Appendix A.

Specific transmission additions which have in-service dates after May 1, 2013 were not included in the base model; however some were examined as part of the Grid Expansion exercise described later in this report. One example is the addition of the Riel transmission substation in Manitoba that will help improve the Dorsey substation issues identified in the DRG Phase I study. Riel will be a 230/500 kV substation that will provide an additional connection between the 230 kV transmission system and 500 kV transmission line that runs from Dorsey substation northwest of Winnipeg to the Forbes Station in northeast Minnesota. This addition is anticipated to be in-service by 2014 and as such it was not included in the base model development for DRG Phase II. The Riel substation has been included in the Grid Expansion analysis discussed later in this report. The study team embarked on Grid Expansion analysis to assess how planned expansion of the core transmission capacity impacts DRG capability.

2013 Generation Additions

After identifying the known transmission system additions, the study team set out to determine which generation projects should be added to the model to represent the 2013 bulk electric system. The approach employed for DRG Phase II was to identify the Midwest ISO queued generation with probable installation before May 1, 2013 which included renewable generation necessary to meet the Minnesota RES.

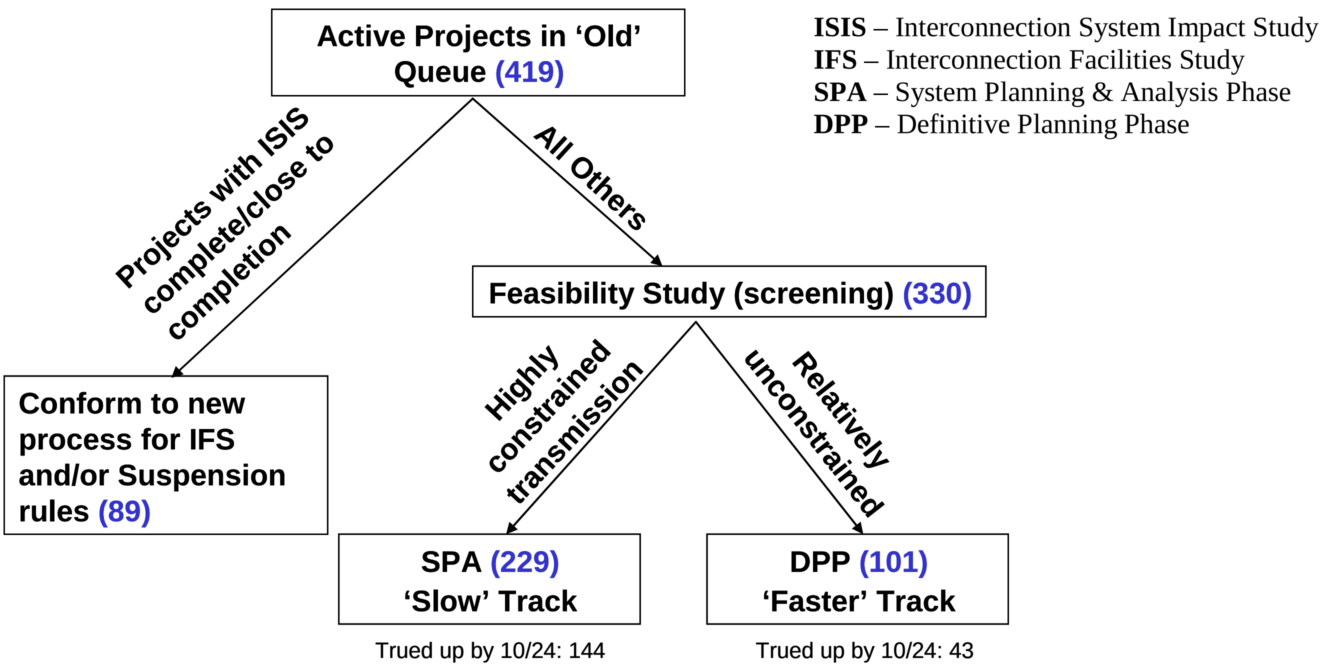
The DRG Phase II study team assessed the vast number of generation projects currently included in the Midwest ISO queue to determine the probability for a 2013 in-service date. Using the best information available at the time, the study established guidelines to judge which projects would most likely be developed. Given all the unknowns, there is the possibility that more generation projects might go forward and use up the available transmission capacity.

The study team looked for regional generation projects with signed generator interconnection agreements (GIA) due to be on-line by May 1, 2013. A GIA is a three-party agreement between the interconnection customer, the transmission owner where the proposed generator is planning to interconnect, and the Midwest ISO or other transmission provider. A generator with a signed GIA has successfully achieved the generator interconnection agreement with the Midwest ISO (or other transmission provider) and the interconnecting transmission owner as applicable.

The Midwest ISO generation interconnection queue grandfathered projects are generation interconnection projects which were in process before the Midwest ISO generation interconnection queue reform took effect and have advanced through the analysis proving to be highly probable by the 2013 in-service date. The following figure depicts the Midwest ISO process used to transfer generation interconnection projects from the old Midwest ISO queue process to the new reformed Midwest ISO queue. As part of the transition to the new process the Midwest ISO performed transition feasibility analyses on a majority of projects active in the queue to determine which path (System Planning & Analysis – slow or Definitive Planning Phase – faster) the projects would take under the new process.

Figure 6 – Old Midwest ISO Queue to Reformed Midwest ISO Queue

(number of projects are in parenthesis, current as of August 2008.)
Midwest ISO figure, used with permission from Midwest ISO.



* Midwest ISO figure used with permission from Midwest ISO.

The study team examined all generation projects with signed GIAs in the five-state area and reconciled this with generation additions already in the model to ensure the GIA projects were not double-counted. Of the 11,288 MW identified in the five state region, the study team found 4,740 MW of generation at the identified sites already in the model which left 6,548 MW was to be added to the model.

Table 5 – Generators with Signed Generator Interconnection Agreements

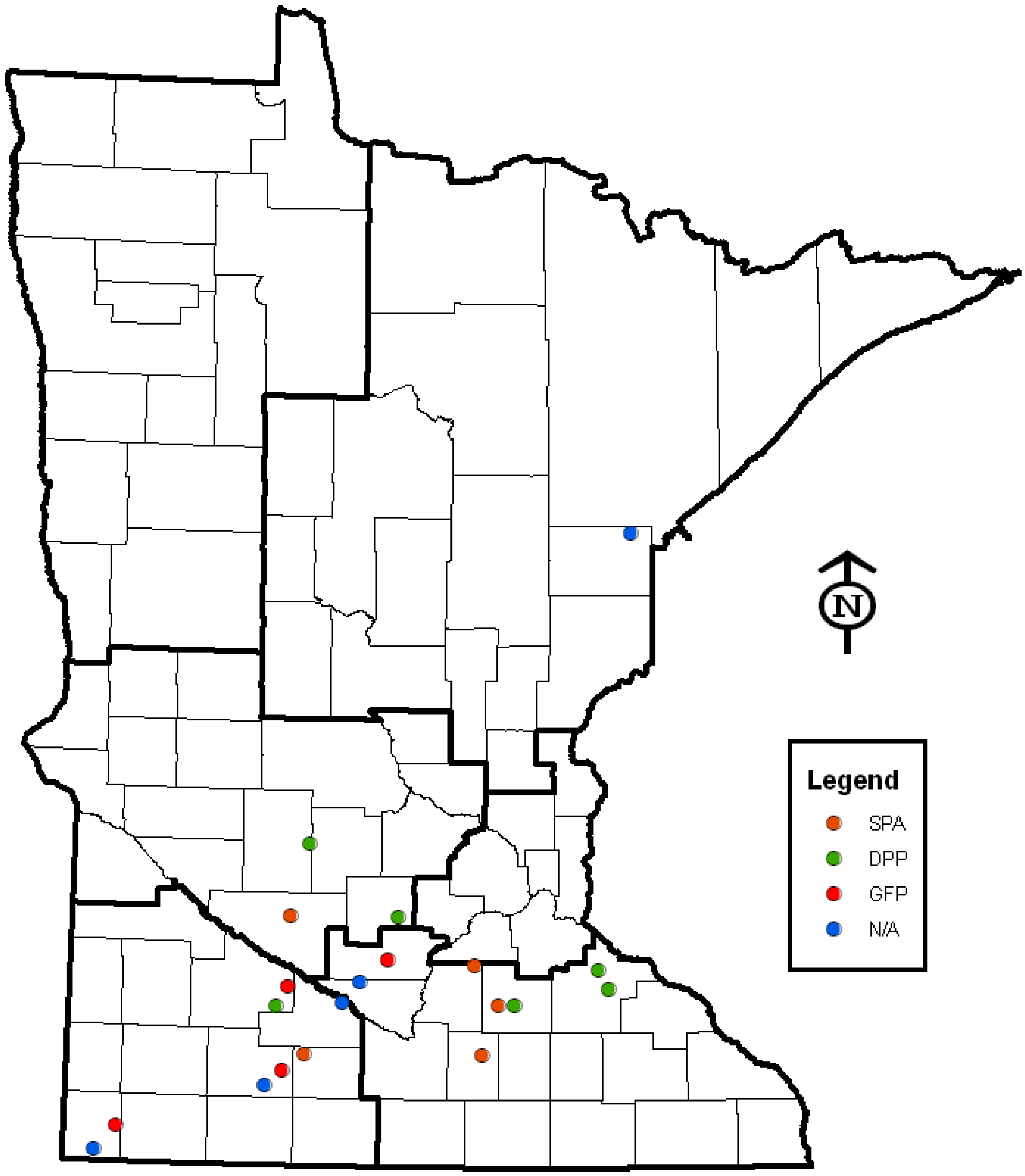
Signed IA's Summary Table		
STATE	MW	IN-SERVICE DATE RANGE
Minnesota	5,628	4/2/02 - 5/30/12
North Dakota	430	10/1/03 - 6/1/08
South Dakota	305	5/1/05 - 11/1/07
Wisconsin	3,837	6/1/01 - 6/1/11
Iowa	1,088	4/1/01 - 12/31/07
TOTAL	11,288	4/1/01 - 5/30/12

The Big Stone II and Mesaba Energy generation projects are not included in the base model since there are too many unknowns to be considered in place by 2013. The Big Stone II affiliated transmission projects were not included in the Phase II model since the generation and transmission projects are integral to each other. While the Big Stone II project has regulatory approval in the state of Minnesota, there is some uncertainty whether the transmission projects will be in service by the 2013 timeframe

The study team next needed to determine how much renewable energy will be required to meet the 2013 goal in accordance with the renewable energy standard (RES) milestones. The assumption was that the utilities would meet the RES milestones and that these related renewable generation sources would be included in the base model. The 2013 renewable generation nameplate value was found by interpolating between the 2012 and 2016 RES-mandated levels which were estimated in the MTO Compliance Filing of September 11, 2008. The interpolated 2013 wind generation needed to be added to 2007 modeled value is approximately 2,200 MW. Since there is no legislated RES goal for the exact year 2013, this wind generation number is to be used only for the purposes of this study. The 600 MW from DRG Phase I is assumed to be in-service by 2013 so 2,200 MW less 600 MW leaves a balance of 1,600 MW to be added to the models. The DRG Phase I projects are the 20 dispersed renewable generation projects totaling 600 MW placed in the model at the locations specified in DRG Phase I.

To identify which Midwest ISO generation queue projects would be chosen to represent the DRG Phase I, 600 MW of wind generation, the study team took generators from the categories of grandfathered (GFP), definitive planning phase (DPP) and system planning and analysis phase (SPA) and placed them in the model at the sites identified by DRG Phase I. A description of the Midwest ISO generation interconnection queue can be found in section VIII. The figure below shows these 20 generators which represent the DRG Phase I 600 MW. There were five sites where the study team could not find any project in the Midwest ISO queue within three buses of the site. These five generators are depicted as N/A and were filled with fictitious generators at the buses identified in Phase I.

Figure 7 – Generators to Fill DRG Phase I 600 MW



The next 1,600 MW of additional generation to represent the RES-mandated generation gap for the model came from Minnesota signed generation interconnection agreements that had in-service dates after 2007 and Midwest ISO queue grandfathered projects. The study team also sought geographic diversity for placing this generation by looking at all six Minnesota transmission planning zones, including the Twin Cities planning zone. To reflect the regional view of the grid, generation projects were identified from the five-state region of Minnesota, Iowa, North Dakota, South Dakota and Wisconsin as well as Manitoba, Canada. The team also included additional known North Dakota wind generation projects identified by Minnesota Power and one Minnkota Power Cooperative project. In addition, the study team did not include any information from the MidAmerican Energy Company queue, the Western Area Power Administration (WAPA) queue, the Dairyland Power Cooperative queue, or any other projects from the Minnkota Power Cooperative queue.

The make-up of this 2,200 MW in renewable generation expected to be in-service and representing the Minnesota RES-mandated goal is shown below.

Table 6 – Summary of Generators that Represent 2013 RES-Mandate Gap

Source	MW
Signed IA Projects	100
DRG Phase I Projects	600
Grandfathered Projects	768
DPP Cycle 1 Projects	0
Minnkota Queue Projects	358
MN Power (DC Line) Projects	374
TOTAL	**2200**

Given recognition that the DRG Phase II team chose to model the wind generators in the five-state region at 90% of nameplate for summer off-peak and 20% summer peak value for wind output levels, the wind generation projects were adjusted accordingly. Also, some of the Signed IA projects were upgrades to existing machines, and as such these existing generators were tracked along with the upgrades. The table below lists these two assumptions:

Table 7 – Generation Additions by Origin

SUMMARY TABLE	Generator Additions	
	SUOP (MW)	SUPK (MW)
SIGNED IA PROJECTS	7,925	7,012
DRG PHASE I PROJECTS	541	120
GRANDFATHERED PROJECT	691	154
MPC QUEUE PROJECTS	322	72
MP PROJECTS	336	75
TOTALS	**9,815**	**7,432**

The study team also needed to assess which proposed generation projects would NOT be included in the model. There is a great deal of wind generation projects in the Midwest ISO queue that are still in the early assessment phase of the reformed Midwest ISO queue. Projects in the following Midwest ISO queue phases were not included in the DRG Study Phase II model: the definitive planning phase (DPP), the system planning and analysis (SPA) phase, the system impact study phase (SIS) projects, and some of the grandfathered projects from the previous less likely to be in-service in 2013.

Table 8 – Generators Not Added to Models

WIND	IA	MN	ND	SD	WI	Totals
DPP	241	831	150	0	527	1,748
SPA	5,756	20,922	7,436	11,418	0	45,532
Grandfathered	760	335	0	216	749	2,060
Complete SIS; conform to new process starting with M3 milestone	0	0	150	0	99	249
Totals	6,757	22,088	7,736	11,634	1,374	**49,590**

DRG Phase II Wind Profile Information

After the DRG Phase II transmission system model had been adapted to more closely represent the projected 2013 transmission system scenario, the study team sought to add wind profile information to the model. The data for the wind profiles originated from research developed by WindLogics 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.

Throughout the DRG study process, the team has encouraged public input to the study methodology. One valuable contribution from public input was the suggestion that the wind profile at the exact bus may not represent the true wind potential that might be found in the vicinity of the transmission substation. The team decided to search for the highest wind net capacity factor (NCF) within a two-mile radius of each bus and then assign the highest NCF to that bus. One reality is that wind generation plants are not placed immediately adjacent to a substation. Expanding to a two-mile radius, allows for the possibility that a substation is located in a valley where the wind resources are poor, yet the wind potential may be acceptable on a nearby ridge. Using more advanced software tools, ESRI's ArcGIS Spatial analyst extension software, the exercise was automated to gather the wind profile data from the Wind Integration study and the results showed an increase in wind net capacity factor for most buses. Specifically, the software used a proximity tool to create a two-mile buffer around the transmission buses. This tool looked at the point value and created an entirely new layer in the mapping process with a radius of two miles around each bus.

The TRC recommended the study team filter out wind profile measurements made in water areas. This concern stemmed from the realization that off-shore wind projects tend to be larger than 40 MW and implementation of off-shore wind is quite expensive; also off-shore wind introduces a host of environmental and aesthetic issues. To map this, the study team overlaid the lakes layer onto the wind profile layer and zeroed out wind capacity values in the lake areas on the map that coincided.

Once the water areas' wind net capacity value was zeroed out from the dataset, the study team employed the software to search the two-mile radius to find the maximum value for wind net capacity value and assigned this value to the bus and the master potential site spreadsheet.

Since wind net capacity factor is one criterion used to screen potential bus locations, this DRG Phase II improvement to look at the wind capacity factor at a two-mile radius opened up a vast number of sites for possible DRG selection. The Northeast zone seemed to benefit most from the two-mile radius change, since this region has a hilly topology.

Table 9 – Wind Net Capacity Factor Summary by Zone

WIND NCF SUMMARY TABLE			
PLANNING ZONE	**NEW SITES > 35%**	**AVG. NCF @ BUS**	**AVG. NCF 2-MILE RADIUS**
NORTHWEST	35	37.3	38.2
NORTHEAST	46	30.5	32.0
WEST CENTRAL	59	36.5	37.4
SOUTHWEST	2	38.8	39.5
SOUTHEAST	61	34.9	36.3
TOTALS	**203**	**35.6**	**36.7**

C. DRG Phase II Assumptions

The TRC and study team evaluated the assumptions used in the DRG Phase I and determined which assumptions were most prudent for DRG Phase II model building and assessment. Changes made for DRG Phase II assumptions explain some of the study result differences between DRG Phase I and DRG Phase II.

Sink Assumptions

Establishing the generation source and sink assumptions was vital for a representative model of how the individual DRG projects would be studied by the Midwest ISO or other transmission provider and how the interconnected generation and transmission system would operate with the DRG additions. The models have generation units with power outputs that when combined exactly match the load in the model plus the system power losses (Generation = Load + 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 to accommodate the new generation. 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 'sources' are equal to the magnitude of the 'sinks' plus the change in losses in the electrical system.

For purposes of these studies, the proposed DRG project buses were identified as the generation sources. DRG Phase I assumed the generation sinks were the natural gas units in the Twin Cities metro and surrounding area. For DRG Phase II, the TRC and the study team decided to use the Midwest ISO market dispatch based on economic merit order of generation dispatch to determine the sink assumption since this sink more closely models the way the system is planned and operates. For generation interconnection studies, the economic merit order of generation is used where the operational methodology involves turning down more expensive generation on the system when the proposed generation is added to the system while considering potential transmission facility violations. The Midwest ISO market dispatch sink determination represents a much larger geographic footprint than the Twin Cities metro area sink used in DRG Phase I. This view of the electrical system reflects the real way system operators actually manage the transactions of the electrical grid. This sink assumption is more closely aligned with the Midwest ISO market operations and study procedures.

The areas defined in the model with corresponding participation percentages were chosen to replicate the Midwest ISO market dispatch during the summer peak and off-peak scenario. Tables 10 and 11 below show the most uneconomical generation and their corresponding participation levels (%) in the various Midwest ISO control areas that were turned down to accommodate the new DRG generation in the summer off-peak model. Figures 8 and 9 illustrate that the vast majority of the least economical generation is not located in Minnesota, but rather in the southern and eastern areas of the Midwest ISO.

Table 10 – Midwest ISO Market Sink Dispatch (summer off-peak)

Control Area		Sink %
AMIL	Ameren IL	9.0%
AMMO	Ameren MO	1.9%
CPGS	Cinergy Power Generation Services	4.2%
CE	Commonwealth - Edison	1.3%
CCS	Continental Cooperative Services	4.6%
FE	First Energy	6.6%
ITC	International Transmission Co	13.3%
IPL	Indianapolis Power & Light	6.9%
METC	Michigan Electric Transmission Co	5.5%
MP	Minnesota Power	5.9%
UPPC	Upper Peninsula Power Co	1.6%
WE	Wisconsin Energy	18.0%
WPS	Wisconsin Public Service	18.7%
XEL	Xcel Energy Inc	2.7%
		100.0%

Figure 8 – DRG Phase II Midwest ISO Dispatch Summer Off-Peak Generation Sink Map

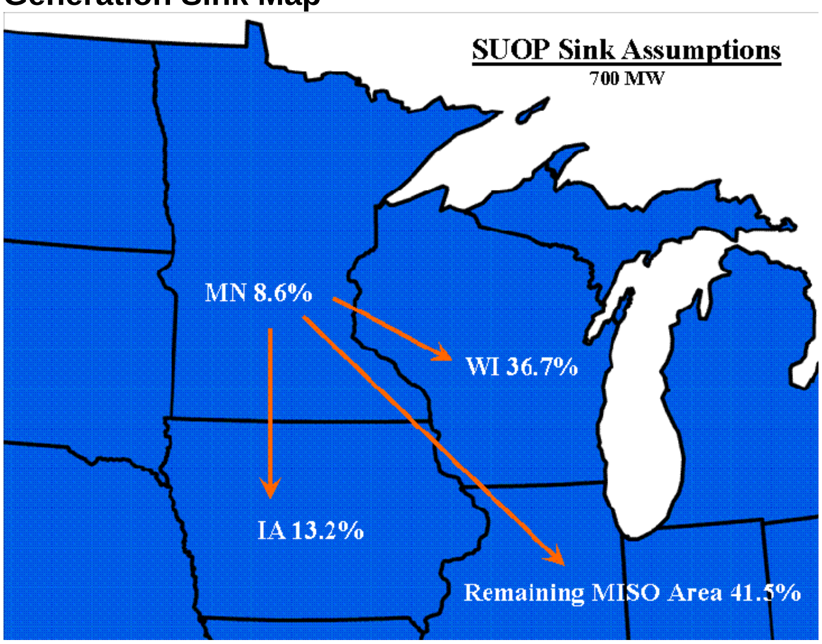
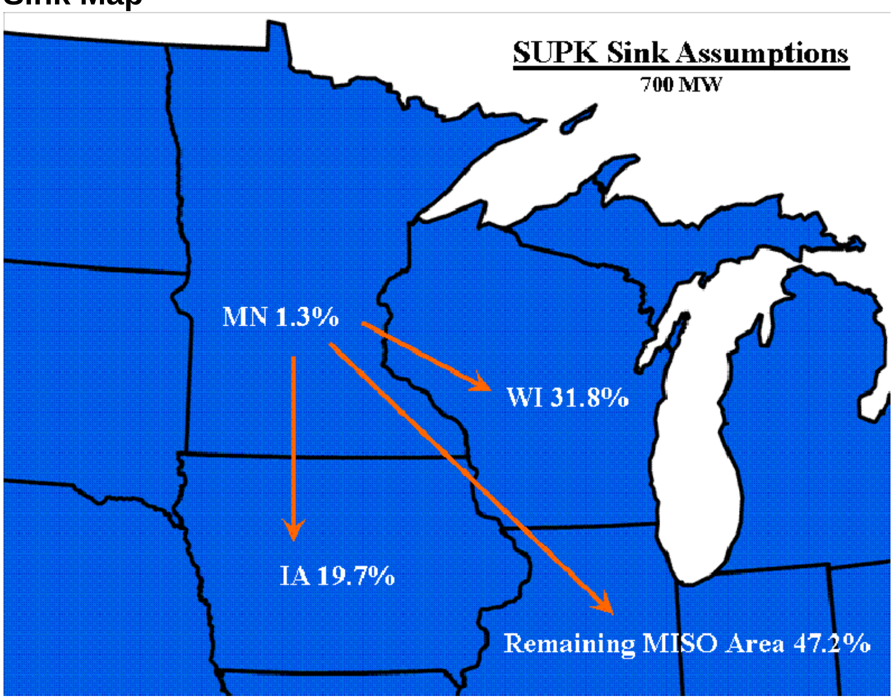


Table 11 – Midwest ISO Market Sink Dispatch (summer peak)

	Control Area	Sink %
ALTW	Alliant West	10.8%
AMIL	Ameren IL	0.7%
AMMO	Ameren MO	5.1%
CE	Commonwealth - Edison	0.4%
CCS	Continental Cooperative Services	0.2%
DE	Duke Energy	6.3%
FE	First Energy	14.5%
ITC	International Transmission Co.	8.9%
IPL	Indianapolis Power & Light	12.9%
MGE	Madison Gas & Light Co.	1.1%
METC	Michigan Electric Trans. Co.	1.4%
MP	Minnesota Power	1.3%
PJM	Pennsylvania - Jersey - Maryland	0.9%
UPPC	Upper Peninsula Power Co.	1.6%
WE	Wisconsin Energy	19.9%
WPL	Wisconsin Power & Light	7.9%
WOLVERIN	Wolverine Power Supply Co.	3.3%
XEL	Xcel Energy	3.0%
		100.0%

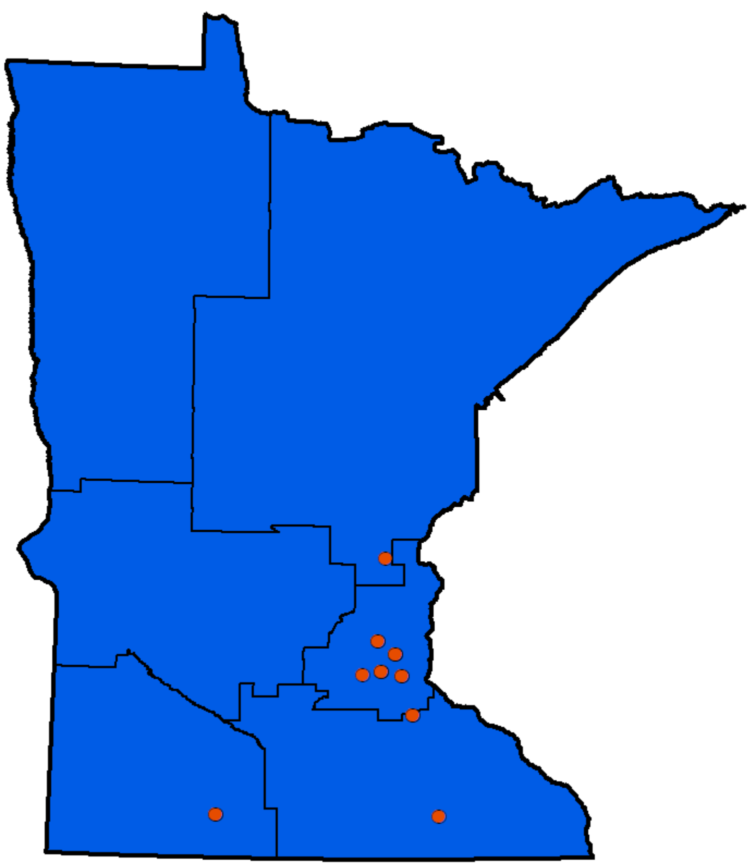
Figure 9 – DRG Phase II Midwest ISO Dispatch Summer Peak Generation Sink Map



As the previous maps depict, for the Midwest ISO footprint, the energy generally flows with a west to east and north to south bias. This is due to the reality that less expensive generation is found in the north and western portion of the Midwest ISO footprint and the electric load density is greater in the eastern portion of the Midwest ISO footprint. The other factor is that much of the Midwest ISO footprint's energy demand peak coincides with lower energy demand in Canada. Consequently, Manitoba Hydro typically exports a considerable amount of energy into the Midwest ISO during the summer months.

As a comparison, the following map illustrates the DRG Phase I sink assumption that the generation sinks were the natural gas generating units in the Twin Cities metro and surrounding areas. This DRG Phase I sink assumes that the generation sinks and sources are both located in Minnesota, but as has been described earlier in this report, this sink assumption is in contrast to both the study methodologies and market operations within the Midwest ISO.

Figure 10 – DRG Phase I Sink Assumption Twin Cities Area Gas Generating Units



Establishing Interface Power Transfer Levels

Another assumption the DRG Phase II study team made was to determine realistic levels of the power transfers over the significant regional interfaces. The performance of the transmission system is affected by the power transfers across these interfaces. For the state of Minnesota, the major transmission system interfaces are the North Dakota Export (NDEX), the Manitoba Hydro Export (MHEX), and the Minnesota-Wisconsin Export (MWEX). Each of these interfaces consists of a group of defined transmission lines which collectively define an electrical boundary. The sum of the real power (MW) carried across each these groups of lines constitute the flow across the respective interfaces. Each interface has a pre-determined maximum level of flow that serves as a proxy for adhering to transmission system limitations otherwise not as trivial to identify and observe, such as transient stability issues. Historically, the transmission planners have established power limits in MW to represent system operating limits for flows across these interfaces. The DRG Phase II study team set summer on-peak and summer off-peak levels for each of the three interfaces to the TRC recommended levels.

Energy Conservation Assumptions

The TRC and study team considered whether the model building process should include some load adjustments in response to the Minnesota energy conservation improvement goals. The Next Generation Energy Act directs utilities to meet annual energy savings goals of 1.5% of gross annual retail sales. This legislation takes effect in 2010. Historically, average utility conservation through the utilities' conservation improvement plan (CIP) has been about 0.7% annually. Since the 2013 model is based on historical consumption, it included any effects of compound energy savings from the existing CIP program. By 2013 the new CIP program will have been in place for only three years and at that point any compound effects from the new savings goal will not likely be significant in comparison with the effects of economic activity on electric load levels. Therefore, the TRC and study team concluded that it would not be necessary to adjust 2013 Minnesota electric load levels in response to the 1.5 % CIP goal.

Wind Output Modeling Assumption

The DRG Phase II study team and TRC considered what the most appropriate value would be to set for the wind output assumption. Wind output is commonly expressed as a percentage of nameplate rating. Various organizations choose to model the wind output differently to account for the variable input energy source of wind and fluctuating output of wind generation. Also, considering that the coincidence of all the wind generation being at full output at the same time is very low. In DRG Phase I, the study team set the wind output at 100% summer peak and 100% summer off-peak of their nameplate ratings. The Midwest Reliability

Organization instructs its entities to model the wind output at 20% of nameplate for summer peak and 35% for summer off-peak in the models. The Midwest ISO interconnection studies assume 20% of nameplate output for the summer peak and 100% output for the summer off-peak wind dispatch in the models. The DRG Phase II study team began with a 20% summer peak and 100% summer-off-peak wind dispatch. Later, after discussion of probable real world operation (e.g. geographic diversity of DRG sites), the DRG Phase II team chose to model all wind generators in the five-state region of Minnesota, North Dakota, South Dakota, Iowa and Wisconsin at 90% nameplate output level for summer off-peak and 20% nameplate output summer peak value for modeling purposes to help represent that not all plants will simultaneously be at peak output.

Distribution Factor Assumption

Distribution Factor (DF) is the term that defines the amount of generated power that flows on specific transmission facilities for a specific transmission topology relative to the generator power output and is often expressed in percent. Distribution factor is one way to screen for overloaded facilities. For DRG Phase II the TRC recommended, and the study team adopted, a five percent distribution factor rather than the three percent value used in DRG Phase I.

Emergency Rating vs. Normal Rating

Transmission planning engineers use performance standards developed by NERC and regional reliability organizations that describe how reliable systems need to be developed for specific performance requirements. These requirements are described in terms of 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). During DRG Phase I, the study team assumed transmission facilities could not be loaded above their continuous rating (rate A) under any situation. For DRG Phase II, the TRC recommended the study team employ the emergency rating (rate B) threshold for system contingencies when considering transmission facility overloads.

Network Resource Interconnection Service (NRIS)

The DRG Phase I and DRG Phase II study work was conducted with assumptions similar to the Midwest ISO Network Resource Interconnection Service (NRIS) evaluation that allows proposed generation to interconnect with the transmission system at a level comparable to existing designated network resource generators. This is a reasonable and a generally accepted approach for performing transmission capability analyses. A generator developer seeking the Energy Resource Interconnection Service (ERIS) option could be evaluated differently depending upon the evaluation procedures adopted by the local utility and/or the independent transmission system operator. While the ERIS evaluation criteria may be more relaxed than that used for NRIS, it carries with it increased risk of curtailment. This study does not attempt to make a determination about a project's ability to accept curtailment or obtain transmission service of any nature.

Generation in Congested Counties Assumption

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 transmission congestion in counties where many generation projects were already planned.

Screening Process Inclusion of Potential Substation Buses

In DRG Phase I, the screening process eliminated substation buses without load. During the substation site screening process the DRG Phase II study team decided to include all buses (with or without load) that were 161 kV or lower. This increased the number of potential buses for selection and for further study.

D. Midwest ISO Security Constrained Economic Dispatch (SCED)

The next step of the model building process was to run the model through the Midwest ISO Security Constrained Economic Dispatch (SCED) process to adjust the model such that it will mimic the actual Midwest ISO-wide market operation. This process was not used in the DRG Phase I study, but this step was added to DRG Phase II based on recommendations from the TRC. This SCED program adjusts the generators on an economic basis while avoiding transmission system violations. FERC defines SCED as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." DRG Phase II used this Midwest ISO market dispatch to balance the existing generation with the additional generation which was added to the model. The SCED determined which existing generation should be turned down to accommodate this new additional generation. This balancing was based on an economic and security merit order of generation this dispatch more closely models the way the system operates. Merit order of generation is the operational methodology of turning down more expensive generation when the new generation being studied is added to the system. This operational approach allows a constrained transmission grid to operate more efficiently.

The Midwest ISO agreed to run the DRG Phase II model through the SCED program with direction from the DRG Phase II study team. The study team guidelines included the following recommendations:

- do not re-adjust the MW value of the new wind generators added to the model;
- do not adjust the existing wind generators in the five-state region;
- do not adjust the nuclear generators; and

- maintain operation of must-run thermal units. Must-run thermal units are the fossil fuel-fired generation units that must be kept on line at a certain level to assure reliable system operation.

The study team chose to run the SCED to ensure that the base model didn't begin with extensive system overloads. The SCED analysis resulted in changes to the MHEX, MWEX and NDEX interface levels.

After assessing the changes made as a result of the SCED process, the DRG Phase II study team shifted some generation units to bring the interface flow levels back acceptable study levels. The table below shows how the various generation projects were adjusted during the SCED and Interface adjustment processes. The wind generation in all of the categories remains unchanged during all steps, however the natural gas, combined cycle & coal units were adjusted.

Table 12 – Generation Additions to Models

SUMMARY TABLE	Before SCED		After SCED		After NDEX Adjustment	
	SUOP (MW)	SUPK (MW)	SUOP (MW)	SUPK (MW)	SUOP (MW)	SUPK (MW)
SIGNED IA PROJECTS	7,925	7,012	5,394	7,026	5,207	7,026
DRG PHASE I PROJECTS	541	120	541	120	541	120
GRANDFATHERED PROJECTS	691	154	691	154	691	154
MPC QUEUE PROJECTS	322	72	322	72	322	72
MP PROJECTS	336	75	336	75	336	75
TOTALS	**9,815**	**7,432**	**7,284**	**7,446**	**7,097**	**7,446**

The table below shows all of the generation that was added to the model by fuel type in the five-state region of Minnesota, North Dakota, South Dakota, Iowa & Wisconsin. As it was described in the "2013 Generation Addition" section, some of the Signed IA projects were upgrades to existing machines or plant performance improvements, and as such these existing generators output levels were tracked along with the upgrades. Because of this tracking methodology, the table below shows 1,751 MW of nuclear generation additions, but it should be noted that there were only 76 MW of actual additional nuclear output in the model. Likewise, only 144 MW of actual coal generation additions were made to the model.

Table 13 – 2013 Base Model Generation Additions by Fuel Source

SIGNED IA PROJECTS	Base Model	
	SUOP (MW)	SUPK (MW)
BIOMASS	15	20
COAL	539	683
COMBINED CYCLE	600	2,448
DIESEL	0	0
GAS	1,091	1,854
HYDRO	46	46
NUCLEAR	1,751	1,751
WIND	1,164	225
TOTALS	**5,207**	**7,026**

The table below shows the three key regional flow interface levels after the SCED and NDEX adjustment process.

Table 14 – Interface Levels after NDEX Adjustments

Interface Flow Levels (MW)			
Model	SUOP Limit	SUOP Base Case	SUPK Base Case
NDEX	**2080**	2012	1015
MHEX	**2175**	1913	1838
MWEX	**1525**	1260	707

V. Substation Site Screening Process

The DRG Phase II study team began with a list of the 2,244 total Minnesota transmission buses organized by the five out-state planning zones. The team needed to narrow the list to a qualified, manageable number of buses. The most appropriate buses were first identified using five screening criteria in incremental steps. The measures were based on strict analytics. These steps were similar to the first screening steps employed in the DRG Phase I process. As these lists shortened, the sixth screening step employed engineering judgment of the study team along with the TRC to assess the best locations based on numerical results and knowledge of the electrical environment of the sites while trying to maintain geographical and electrical diversity of the final sites.

FCITC Analysis

Next the DRG study team ran the First Contingency Incremental Transfer Capability (FCITC) in the Power System Simulator for Engineering Managing and Utilizing System Transmission (PSS®MUST) software to calculate the impact of transactions on key transmission network elements during contingency conditions. FCITC is the quick, in this case DC/linear, analysis tool that provides the outlet capability of defined generators or groups of generators to defined sink points. This DC (linear) analysis was used to quickly and approximately calculate the generator outlet capacity of more than 2200+ buses in the five Minnesota planning zones for the summer peak and summer off-peak cases. This screening tool was used to help narrow down the potential substation buses. The more time-consuming and detailed AC (non-linear) analysis is used later in the screening process.

The first screening step evaluated the results of the FCITC analysis. The team identified the lowest FCITC value of either the summer off-peak or summer peak scenario. All buses with minimum FCITC values of less than zero were removed from the lists. This process reduced the number of potential sites from 2,244 sites to 906 potential sites. The assumption is that if a site showed no outlet capability with DC analysis, it would be less likely to result in positive capability after AC analysis which was conducted later in the process.

Bus Voltages

The next screening step was to eliminate buses with distribution level voltages and higher transmission level voltages. The team was able to identify buses with voltages below 23 kV and above 230 kV and remove these from the pool. The enabling legislation directed the DRG Phase II study team to work toward identifying transmission buses with lower transmission voltages. Buses below 23 kV are considered distribution facilities rather than transmission lines. It is unlikely that a developer would propose a 230 kV or higher voltage substation to accommodate a 10-40 MW wind project. Also these higher voltages do not fit in the spirit of working toward lower voltage interconnections. This step reduced the number of potential buses from 906 to 815 sites.

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. In DRG Phase II, the wind net annual capacity factor was identified as the highest value within a two-mile radius of the bus. This allowed for a wind profile value that took into account situations where the bus might be located in a valley, but the land in close proximity has a better wind profile. Wind profile values in water areas were zeroed out when assigning the wind profile value. 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 18.6 percent to 44.5 percent. This screening step brought the potential sites from 815 down to 548 buses.

Midwest ISO Queued Generation

The subsequent step in the site screening process was to consider the impact of Midwest ISO queued generation on substation buses. The study team totaled all generation projects in the Midwest ISO generation interconnection queue by county for the state. With guidance from the TRC, the study team then used these results to set aside all buses in counties where Midwest ISO queued generation exceeded 500 MW. 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 transmission congestion in counties where many generation projects were already planned. By eliminating potential sites in these congested counties, the potential site list was reduced to 492 buses. It should be noted that there may be other generator interconnection requests in Minnesota which are tracked by organizations other than the Midwest ISO. These additional generation requests were not considered when establishing counties with more than 500 MW of generation queue requests.

The screening began with the initial model of 2,244 potential sites. The first four screening steps methodically removed from consideration buses with low probability to host DRG to reach a total of 492 sites. The table below shows this progression in the five transmission zones.

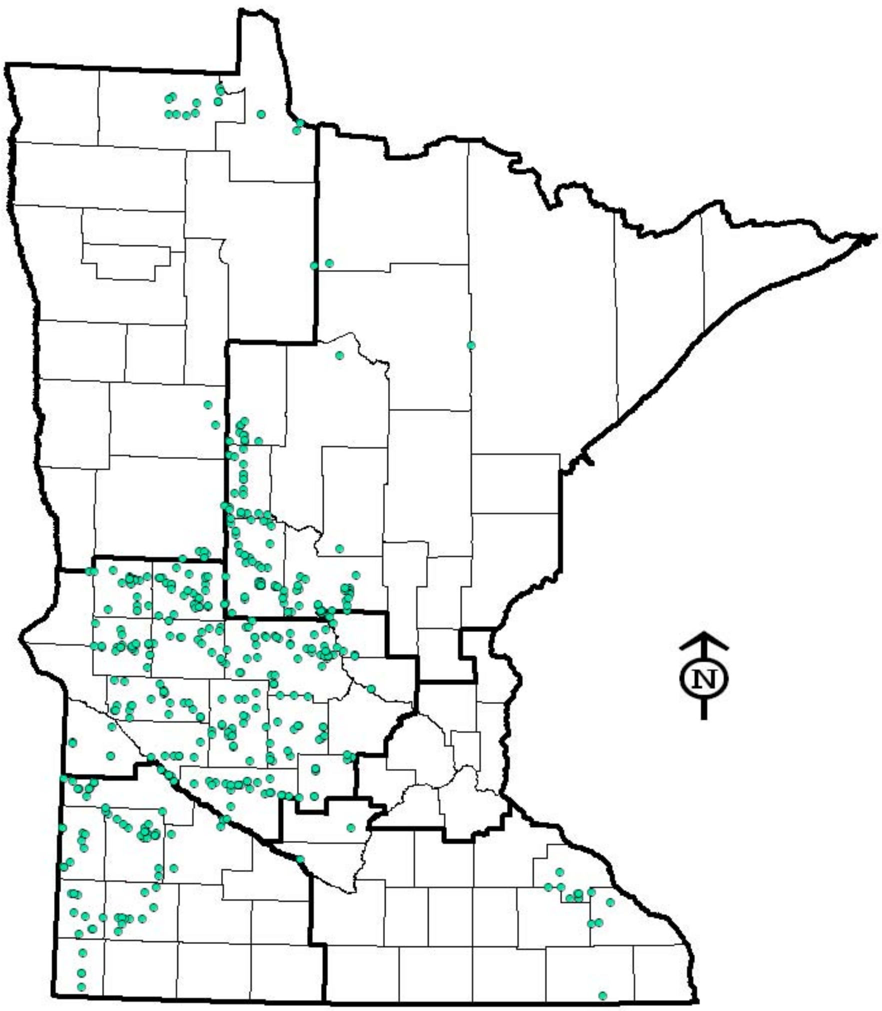
Table 15 – Screening Process in Five Outstate Zones

Planning Zone	Number of Buses				
	All Buses	2. After Eliminating Combined FCITC < 0	3. After Eliminating Buses Less than 23 kV and Greater than 230 kV	4. After Eliminating Buses w/ NCF < 35%	5. Buses After Eliminating Counties w/ MISO Queue Generation > 500 MW
NW	424	40	29	28	28
NE	676	424	368	108	106
WC	477	347	323	318	271
SW	267	74	74	74	74
SE	400	21	21	20	16
TOTALS	**2244**	**906**	**815**	**548**	**495**

The following map shows the available sites statewide after the initial screening steps. This map includes sites with:

- voltages lower than 200 kV and greater than 23 kV,
- minimum FCITC (summer off-peak and summer peak) greater than zero,
- wind net capacity factor greater than 35%, and
- less than 500 MW of Midwest ISO queue generation in the county.

Figure 11 – DRG Phase II Sites After Initial Screening.



Engineering Judgment

The previous steps screened to make sure all criteria was met, narrowing the original list of 2,244 substation buses down to more than 492 potential locations for DRG. However, there were still too many sites to conduct detailed analysis. The next few screening steps employed engineering judgment and specific transmission grid experience to evaluate the remaining buses for outlet capability and wind quality while striving for geographic diversity and transmission voltage variety. The TRC provided valuable information about buses with unique situations where technical issues might result in unforeseen complications.

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 at least half of the buses below 69 kV. The team also balanced the remaining sites for the FCITC values and their wind NCF's. Where two buses had FCITC values less than 60, the FCITC was the deciding factor. However, where two buses had FCITC values greater than 60, then the bus with the higher wind NCF was given the edge.

The TRC had specific recommendations for this part of the screening process based on their working knowledge of the regional transmission system. Their recommended modifications included avoiding the Sherburne County Generating Station site in the West-Central zone and replacing the Lyon County 69 kV site with the Lyon County 115 kV. The TRC also had recommended that the Fort Ridgley site in the Southeast Zone be avoided since the New Ulm generation was not in-service in the models. It was also decided to place only seven sites in the Southeast zone due to the limited number of viable sites that were all located in a tight area. Since the West-Central had numerous diverse sites, the TRC chose to add another site to the West-Central zone and thus the short list remained at 40 sites. The short list of the 40 sites are shown and followed with the sites in each of the zone maps.

Table 16 – DRG Phase II Short List

NW Planning Zone

Substation Name	kV	County	NCF	FCITC
Compton	34.5	Otter Tail	37	24
Osage	34.5	Becker	35	26
Nashua Tintah	41.6	Wilkin	38	18
Parkers Prairie	41.6	Otter Tail	39	21
Moranville	69	Roseau	39	28
Shooks	69	Beltrami	37	31
Stafford	69	Roseau	39	28
Williams	69	Lk of Woods	37	16

NE Planning Zone

Substation Name	kV	County	NCF	FCITC
Pine Lake	34.5	Morrison	38	34
Hubbard	34.5	Hubbard	36	45
Verndale	34.5	Wadena	38	59
Bena	69	Cass	37	29
West Union	69	Todd	39	42
Dewing	115	Crow Wing	36	35
National Taconite	115	St. Louis	35	191
Palmer Lake	115	Hubbard	35	110

WC Planning Zone

Substation Name	kV	County	NCF	FCITC
Albany	69	Stearns	38	89
Benton County	69	Benton	35	112
Big Swan	69	Meeker	39	58
Crooks	69	Renville	44	42
Douglas County	69	Douglas	39	59
Fiesta	69	Chippewa	37	52
Glenwood	69	Pope	40	49
Hutchinson Plant1 Tap	69	McLeod	37	68
Willmar Municipal	69	Kandiyohi	38	93

SW Planning Zone

Substation Name	kV	County	NCF	FCITC
Granite Falls	69	Ylw Medicine	38	57
Hardwick	69	Rock	41	60
Ivanhoe	69	Lincoln	43	56
Lake Sarah Tap	69	Murray	43	35
Lyon County	115	Lyon	38	107
Milroy	69	Redwood	37	30
Holland	69	Pipestone	41	42
Walnut Grove	69	Redwood	39	41

SE Planning Zone

Substation Name	kV	County	NCF	FCITC
Altura	69	Winona	36	89
Elgin	69	Wabasha	37	40
Harmony	69	Fillmore	44	73
Henderson	69	Sibley	43	26
St. Charles Tap	69	Winona	37	49
Whitewater	69	Winona	36	19
Wabaco	161	Wabasha	35	190

Figure 12 – Map of Proposed DRG Sites in the Northwest Planning Zone

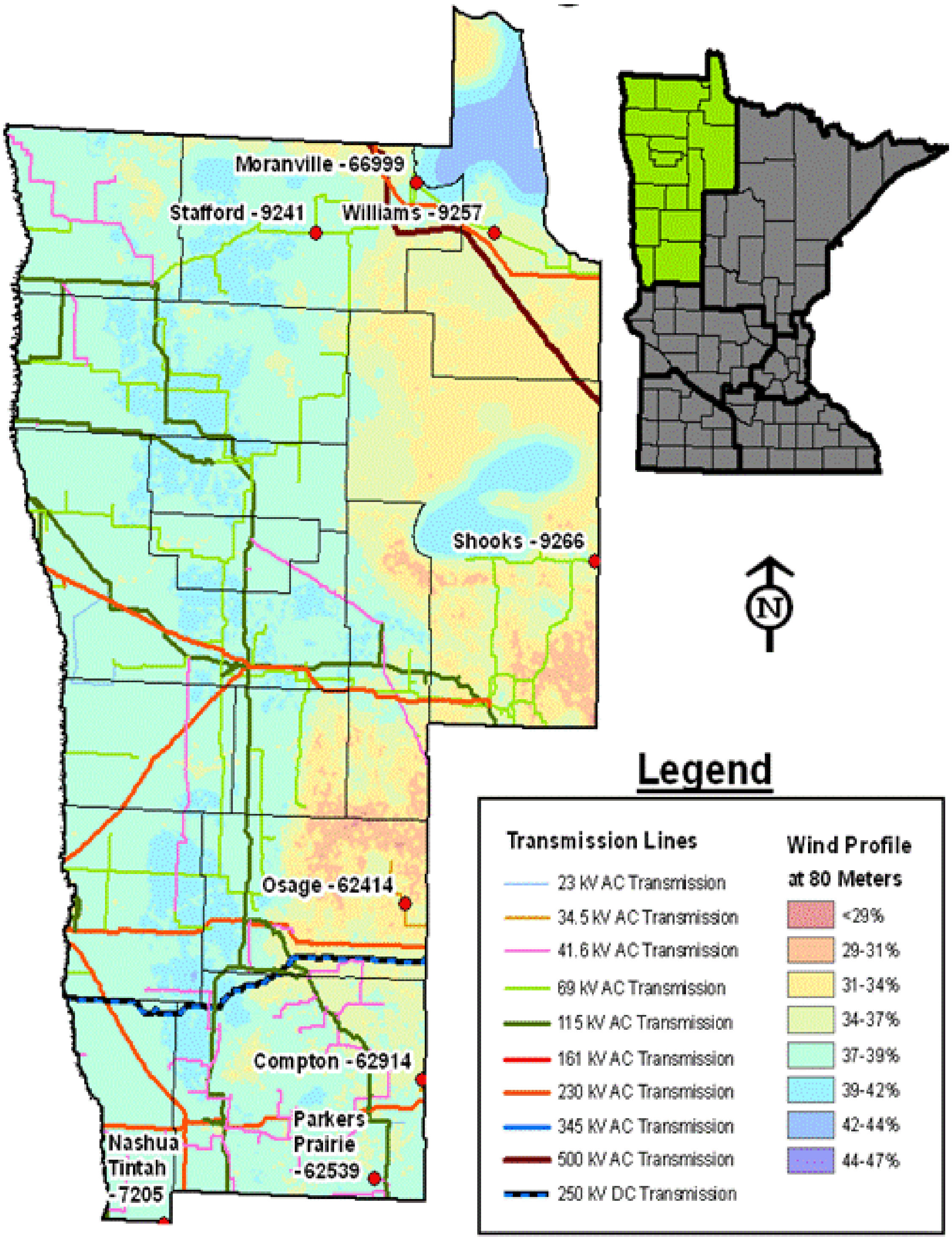


Figure 13– Map of Proposed DRG Sites in the Northeast Planning Zone

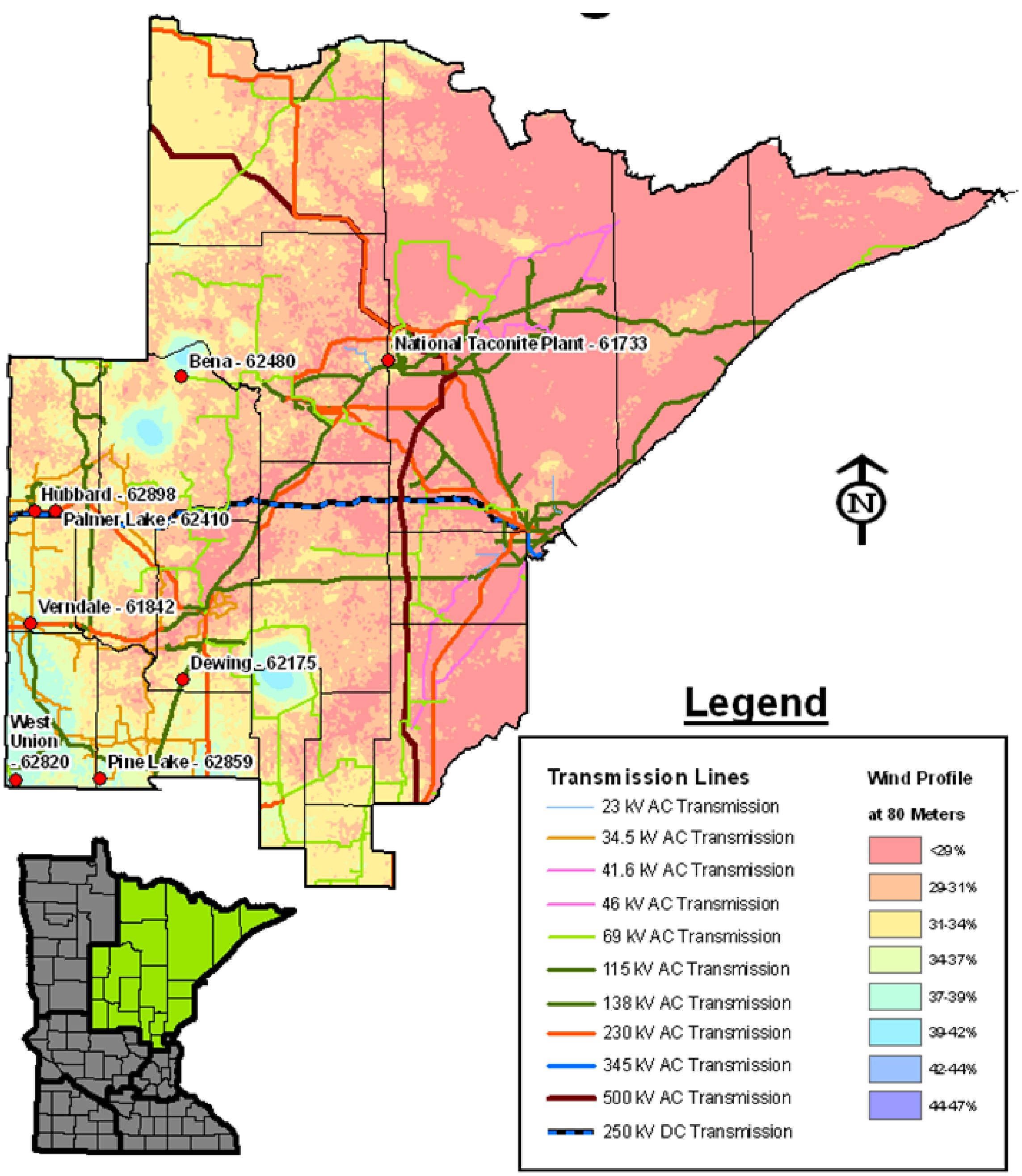


Figure 14 – Map of Proposed DRG Sites in the West-Central Planning Zone

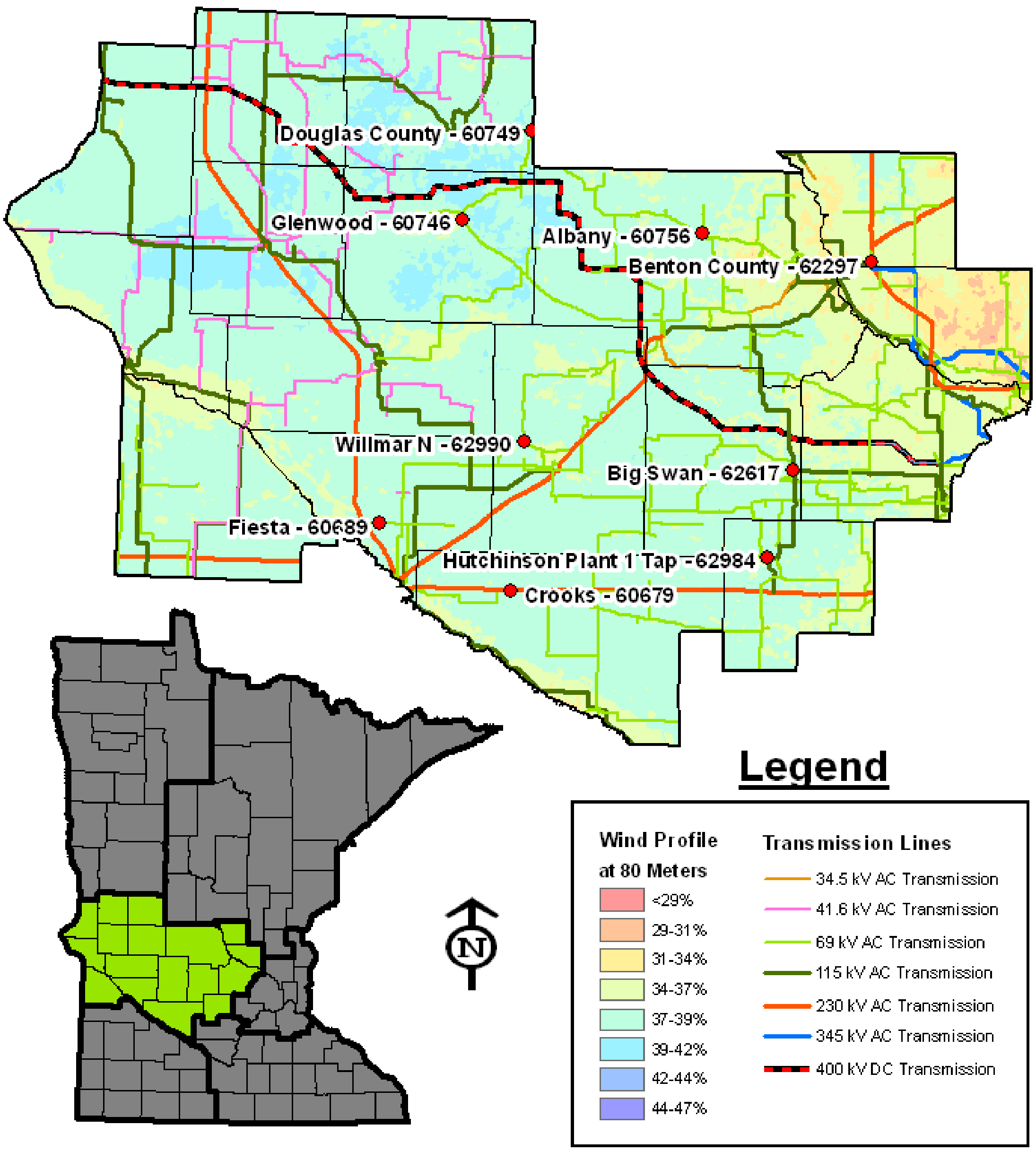


Figure 15 – Map of Proposed DRG Sites in the Southwest Planning Zone

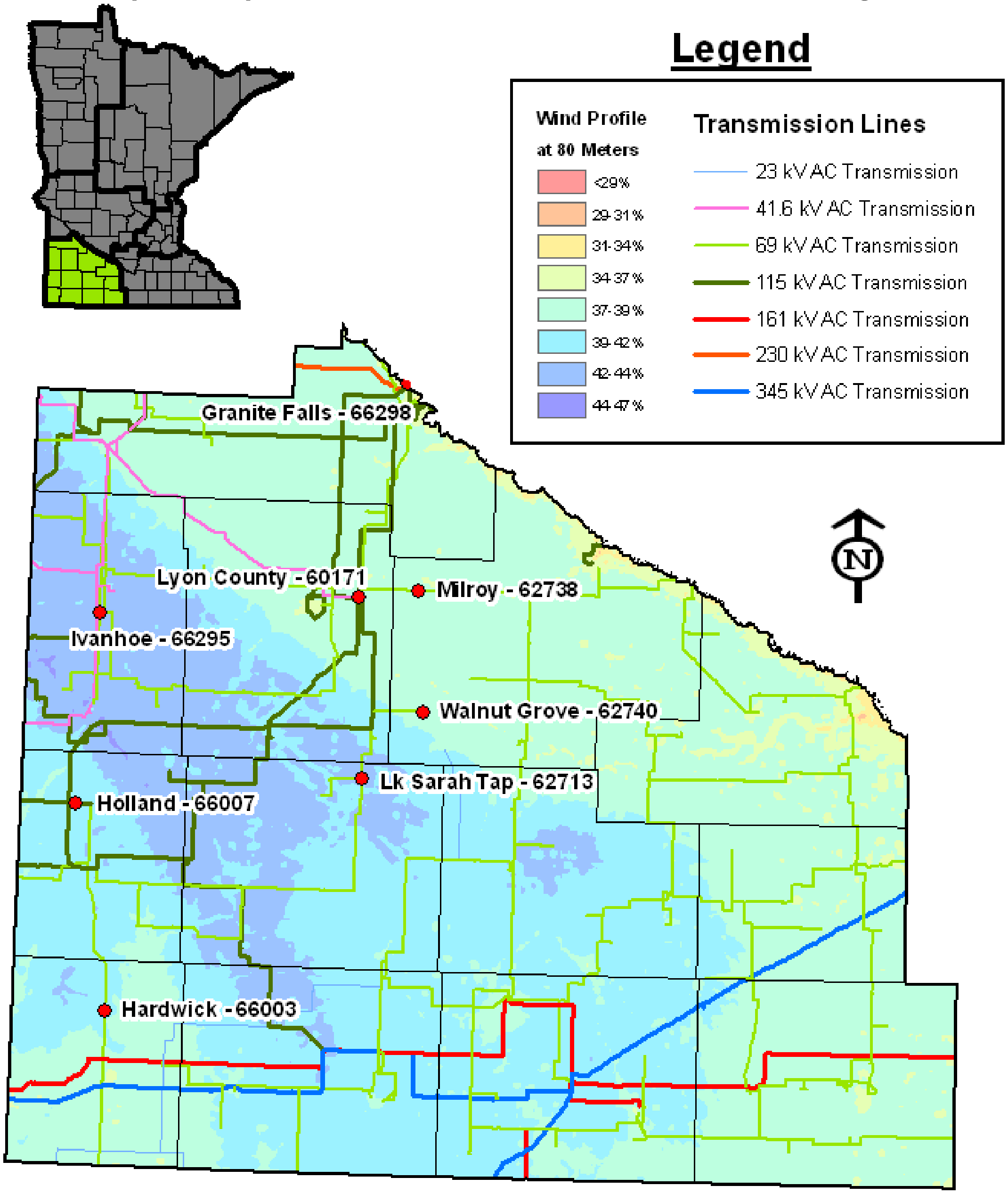


Figure 16 – Map of Proposed DRG Sites in the Southeast Planning Zone

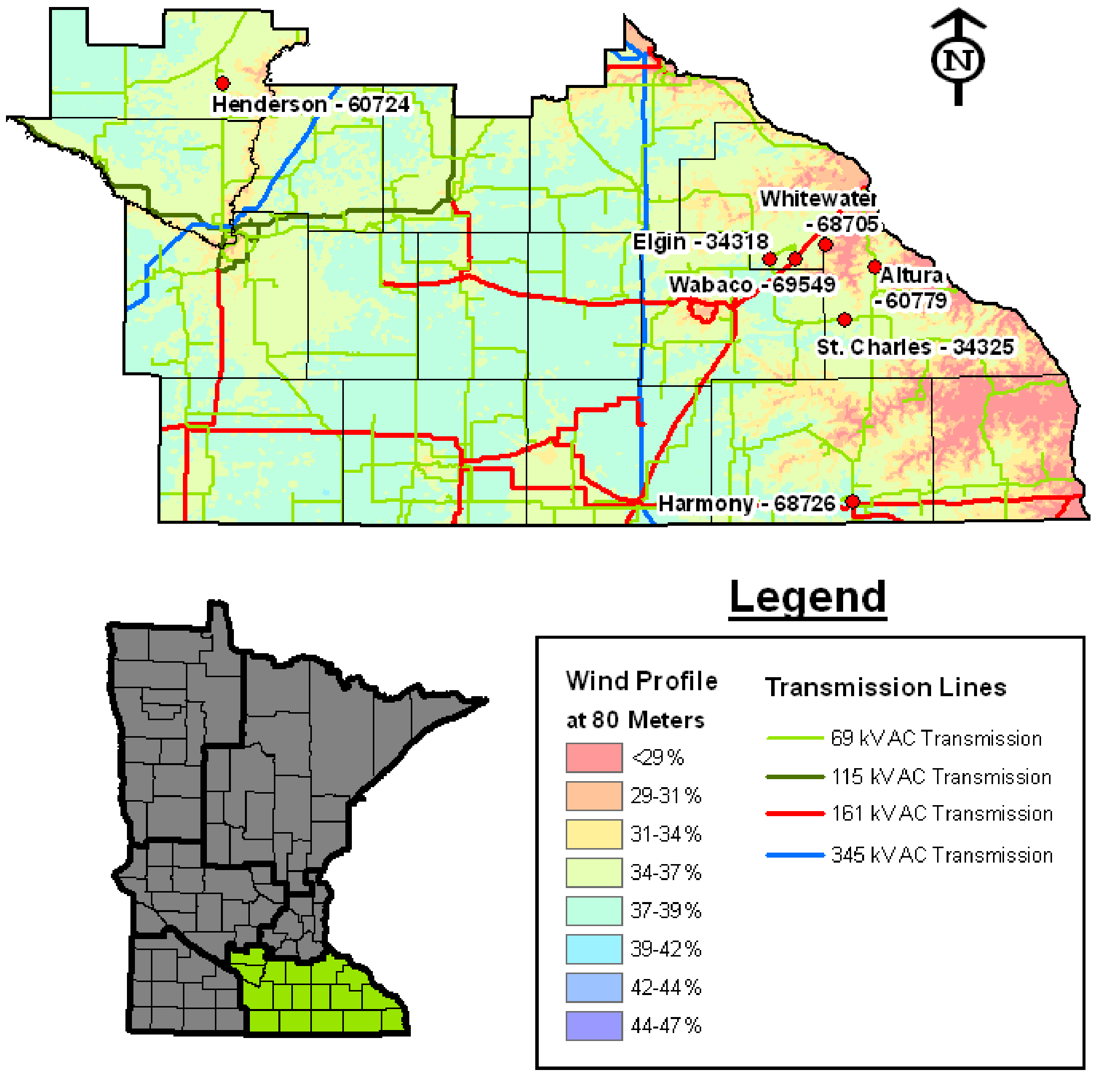


Table 17 – DRG Phase II Short List with Substation Ownership

Substation Name	Bus Owner	Bus Voltage	Planning Zone	County
Compton	GRE	34.5	NW	Otter Tail
Moranville	MPC	69	NW	Roseau
Nashua Tintah	OTP	41.6	NW	Wilkin
Osage	GRE	34.5	NW	Becker
Parkers Prairie	GRE	41.6	NW	Otter Tail
Shooks	MPC	69	NW	Beltrami
Stafford	MPC	69	NW	Roseau
Williams	MPC	69	NW	Lake of the Woods
Bena	GRE	69	NE	Cass
Dewing	GRE	115	NE	Crow Wing
Hubbard	GRE	34.5	NE	Hubbard
National Taconite	MP	115	NE	St. Louis
Palmer Lake	GRE	115	NE	Hubbard
Pine Lake	MP	34.5	NE	Morrison
Verndale	MP	34.5	NE	Wadena
West Union	GRE	69	NE	Todd
Albany	GRE	69	WC	Stearns
Benton County	GRE	69	WC	Benton
Big Swan	GRE	69	WC	Meeker
Crooks	XCEL/RSCPA	69	WC	Renville
Douglas County	XCEL	69	WC	Douglas
Fiesta	XCEL	69	WC	Chippewa
Glenwood	XCEL	69	WC	Pope
Hutchinson Plant1 Tap	GRE/HMU	69	WC	McLeod
Willmar North	GRE/WMU	69	WC	Kandiyohi
Granite Falls	WAPA	69	SW	Yellow Medicine
Hardwick	WAPA	69	SW	Rock
Holland	WAPA	69	SW	Pipestone
Ivanhoe	WAPA	69	SW	Lincoln
Lake Sarah Tap	GRE	69	SW	Murray
Lyon County	XCEL	69	SW	Lyon
Milroy	GRE	69	SW	Redwood
Walnut Grove	GRE	69	SW	Redwood
Altura	XCEL	69	SE	Winona
Elgin	ALTW	69	SE	Wabasha
Harmony	DPC	69	SE	Fillmore
Henderson	XCEL	69	SE	Sibley
St. Charles	DPC	69	SE	Winona
Wabaco	DPC	161	SE	Wabasha
Whitewater	DPC	69	SE	Winona

VI. Analysis

Steady-state analysis was conducted on individual sites, on each planning zone and statewide. Stability analysis was conducted on the 600 MW statewide scenario. The study team ran the AC analysis of the impact of the new generation on the transmission system using an AC solution algorithm while examining both system intact and contingency situations. The study team logged 2500 plus hours of computing time to run the ac and dc analysis.

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 performs systematic outages on a user-defined set of transmission components then outputs the results in a formatted in a Microsoft Excel spreadsheet. The spreadsheet then allows for the convenient comparison of results. It should be noted that this DRG Study did not undertake voltage analysis, such as those performed the Midwest ISO during actual generation interconnection studies and these voltage examinations may result in the need for additional voltage control equipment.

A. 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 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) > 5%. (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 for system-intact conditions and 100 percent of its emergency rating for contingency conditions. The Midwest utilities have varying methods of rating their facilities. For example, some utilities establish short-term emergency ratings for their transmission lines; typically this is 110% of the continuous rating, for a period of 30 minutes to four hours, depending on owner. Some utilities do not allow for any emergency rating on their facilities. System reconfiguration (switching) or generation re-dispatch must occur during the defined emergency period to reduce the line or transformer loadings to within the continuous ratings.

The DRG Phase II Study Team referred the NERC Transmission Planning Standards TPL 001-0.1, TPL 002-0, and TPL 003-0 to identify the appropriate criteria to measure the system performance. 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/page.php?cid=2|20.

The steady-state thermal 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.

B. 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 40 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 regional 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 analysis was re-run with the DRG output set to 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 is shown below and the detailed results are shown in Appendix D.

Table 18 – Single Site Analysis

DRG II - Single Site Contingency Results					
Zone	Site Name	Outlet MW	Zone	Site Name	Outlet MW
NW	Compton	20	NE	Bena	25
NW	Moranville	10	NE	Pine Lake	15
NW	Nashua Tintah	15	NE	Dewing	15
NW	Osage	20	NE	Hubbard	40
NW	Parkers Prairie	20	NE	National Taconite	15
NW	Shooks	35	NE	Palmer Lake	40
NW	Stafford	10	NE	Verndale	15
NW	Williams	5	NE	West Union	15
WC	Albany	40			
WC	Benton	40			
WC	Big Swan	40			
WC	Crooks	35			
WC	Douglas County	40			
WC	Fiesta	40			
WC	Glenwood	40			
WC	Hutchinson Plant 1 Tap	40			
WC	Willmar Municipal	30			
SW	Granite Falls	40	SE	Altura	40
SW	Hardwick	40	SE	Elgin	40
SW	Holland	30	SE	Harmony	40
SW	Ivanhoe	40	SE	Henderson	10
SW	Lake Sarah Tap	5	SE	St. Charles Tap	40
SW	Lyon County	5	SE	Wabaco	35
SW	Milroy	0	SE	Whitewater	15
SW	Walnut Grove	5			

C. Zonal Aggregation Analysis

The aggregation of the DRG within 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 individual planning zones. There were about eight DRG sites in each of the planning zones, each with an upper study limit of 40 MW and it was decided to begin with a zonal aggregation total of 200 MW. When studied on a zonal basis, the analysis is performed while assuming generation is added to only one planning zone in the state while all the other zones are held to 0 MW.

The zonal base and the changed zonal (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 regional limiting contingencies.

The DRG sites had a range of output capacities as determined in the single site DC analysis and these outlet capabilities established the starting point for the generation participation levels at each of the sites in the zonal aggregation. The intention for designating this participation methodology was to avoid those limiters seen at certain sites that were found in the single site analysis and thus the distribution of the DRG placement was optimized in an attempt to minimize transmission overloads or limiters. This zonal aggregation analysis was performed at 200 MW and the results of this case were then compared to the base case and any significantly affected facilities were recorded. In cases where 200 MW of DRG in a zone resulted in SAFs, the analysis was re-run at 150 MW of DRG output and then decreased in increments of 50 MW steps until a DRG output level was reached where no SAFs resulted. The participation of individual sites in the zonal generation is shown in the table below. The zonal aggregation analysis summary is shown below and the detailed analysis output is available in Appendix D.

Table 19 – Generation Distribution for Zonal Analysis

Zonal Contingency Analysis Summary Table							
Bus	Site Name	FCITC	Distribution of Zonal Generation				Zonal Outlet Capacity
			200 MW	150 MW	100 MW	50 MW	
NW Planning Zone							
62914	Compton	29	18	13	9	4	**50**
66999	Moranville	35	36	27	18	9	
7205	Nashua Tintah	35	13	10	7	3	
62414	Osage	45	22	17	11	6	
62539	Parkers Prairie	191	18	13	9	4	
9266	Shooks	110	36	27	18	9	
9241	Stafford	59	31	23	16	8	
9257	Williams	42	27	20	13	7	
NE Planning Zone							
62480	Bena	20	17	13	8	4	**40**
38854	Pine Lake	28	20	15	10	5	
62175	Dewing	18	27	20	14	7	
62898	Hubbard	26	27	20	14	7	
61733	National Taconite	21	27	20	14	7	
62410	Palmer Lake	31	27	20	14	7	
61842	Verndale	28	27	20	14	7	
62820	West Union	16	27	20	14	7	
WC Planning Zone							
60756	Albany	89	22	17	11	6	**50**
62297	Benton	112	22	17	11	6	
62617	Big Swan	58	22	17	11	6	
60679	Crooks	42	22	17	11	6	
60749	Douglas County	59	22	17	11	6	
60689	Fiesta	52	22	17	11	6	
60746	Glenwood	49	22	17	11	6	
62984	Hutchinson Plant1 Tap	68	22	17	11	6	
62990	Willmar Municipal	93	22	17	11	6	

Zonal Contingency Analysis Summary Table							
Bus	Site Name	FCITC	Distribution of Zonal Generation				Zonal Outlet Capacity
			200 MW	150 MW	100 MW	50 MW	
SW Planning Zone							
66298	Granite Falls	57	26	19	13	6	**40**
66003	Hardwick	60	26	19	13	6	
66008	Holland	42	19	15	10	5	
66295	Ivanhoe	56	26	19	13	6	
62713	Lake Sarah Tap	35	26	19	13	6	
60171	Lyon County	107	26	19	13	6	
62738	Milroy	30	26	19	13	6	
62740	Walnut Grove	41	26	19	13	6	
SE Planning Zone							
60779	Altura	89	31	24	16	8	**40**
34318	Elgin	40	31	24	16	8	
68726	Harmony	73	31	24	16	8	
60724	Henderson	26	31	24	16	8	
34325	St. Charles Tap	49	31	24	16	8	
69549	Wabaco	190	31	24	16	8	
68705	Whitewater	19	12	9	6	3	

In cases where the zonal analysis showed that 50 MW of zonal capability was not achievable without encountering a SAF, the highest single site capability of 40 MW was used as the zonal capability, as each zone should be able to achieve output as found in the single site analysis.

D. Statewide Aggregation Analysis

A primary goal of this DRG Study Phase II was to investigate the placement of an additional 600 MW of dispersed generation and analyze the impacts of this additional generation on the 2013 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 and regional limiting contingencies in Manitoba and the surrounding four-states.

The distribution of the 600 MW of statewide DRG also used the output capabilities from the single site analysis to establish the starting point for the participation factors for each of the sites in the statewide site analysis. The intention for designating this participation methodology was to avoid those limiters found in the single site analysis caused by specific sites and thus the distribution of the DRG placement was optimized in an attempt to minimize transmission overloads or limiters.

The statewide analysis shows that it is not possible to site 600 MW of dispersed renewable generation without overloading several transmission facilities. Rather than the 600MW, the zonal analysis showed that there could only be up to a total of 50 MW of DRG possible in the state of Minnesota. The participation of the statewide generation is shown in the table below.

Table 20 – Statewide Contingency Analysis

Statewide Contingency Analysis Summary Table				
Bus	**Site Name**	**FCITC**	**Generation Level for Statewide analysis**	**Statewide Outlet Capacity**
NW Planning Zone				**50**
62914	Compton	20	11	
66999	Moranville	28	21	
7205	Nashua Tintah	18	8	
62414	Osage	26	13	
62539	Parkers Prairie	21	11	
9266	Shooks	31	21	
9241	Stafford	28	19	
9257	Williams	16	16	
NE Planning Zone				
62480	Bena	29	11	
38854	Pine Lake	35	13	
62175	Dewing	35	16	
62898	Hubbard	45	16	
61733	National Taconite	191	16	
62410	Palmer Lake	110	16	
61842	Verndale	59	16	
62820	West Union	42	16	
WC Planning Zone				
60756	Albany	89	13	
62297	Benton	112	13	
62617	Big Swan	58	13	
60679	Crooks	42	13	
60749	Douglas County	59	13	
60689	Fiesta	52	14	
60746	Glenwood	49	14	
62984	Hutchinson Plant 1 Tap	68	14	
62990	Willmar Municipal	93	13	

Statewide Contingency Analysis Summary Table				
Bus	**Site Name**	**FCITC**	**Generation Level for Statewide analysis**	**Statewide Outlet Capacity**
SW Planning Zone				**50**
66298	Granite Falls	57	16	
66003	Hardwick	60	16	
66008	Holland	42	12	
66295	Ivanhoe	56	16	
62713	Lake Sarah Tap	35	15	
60171	Lyon County	107	15	
62738	Milroy	30	15	
62740	Walnut Grove	41	15	
SE Planning Zone				
60779	Altura	89	19	
34318	Elgin	40	19	
68726	Harmony	73	18	
60724	Henderson	26	19	
34325	St. Charles Tap	49	19	
69549	Wabac	190	19	
68705	Whitewater	19	7	

In cases where the analysis showed that 600 MW of statewide capability was not achievable without encountering a SAF, the highest zonal capability was used as the statewide capability, as the state should be able to achieve output from at least a single zone. The highest zonal outlet capability was 50 MW in both the Northwest and West-Central zones.

Table 21 – Limiter Summary by Zone

Limiter Summary - Number of limiters			
Zone	Site Name	Single Site- to achieve 40 MW	Zonal- to achieve 200 MW
NW	Compton	3	5
	Moranville	3	
	Nashua Tintah	16	
	Osage	4	
	Parkers Prairie	5	
	Shooks	1	
	Stafford	5	
	Williams	9	
WC	Albany	0	1
	Benton	0	
	Big Swan	0	
	Crooks	4	
	Douglas County	0	
	Fiesta	0	
	Glenwood	0	
	Hutchinson Plant1	0	
	Willmar Municipal	1	
SW	Granite Falls	0	12
	Hardwick	0	
	Holland	2	
	Ivanhoe	0	
	Lake Sarah Tap	9	
	Lyon County	3	
	Milroy	4	
	Walnut Grove	5	
NE	Bena	2	7
	Pine Lake	3	
	Dewing	1	
	Hubbard	0	
	National Taconite	3	
	Palmer Lake	1	
	Verndale	1	
	West Union	2	
SE	Altura	0	9
	Elgin	0	
	Harmony	0	
	Henderson	4	
	St. Charles Tap	0	
	Wabaco	1	
	Whitewater	4	

Statewide- to achieve 600 MW
34

E. Conclusions of AC Analysis

The Midwest ISO generator interconnection queue is flush with requests. As of May 2009, there were 360 active projects representing more than 65,000 MW of generation in the entire Midwest ISO footprint. Minnesota alone accounted for 156 of the 360 projects for over 21,000 MW.

For the year 2013, even with the addition of numerous and significant transmission improvements, there are very limited DRG opportunities to connect without additional transmission upgrades and the associated costs. The 2013 transmission model is already stressed or congested due to the number and size of the generation projects scheduled to be on-line by 2013. From this starting point, the task of identifying additional DRG opportunities becomes more difficult. Connecting new generation further reduces any outlet capacity available in the local area and causes more stress to the transmission system. The type of generation is not the critical factor when considering the difficulty of siting additional generation on a strained transmission system.

The results show very limited DRG opportunities without necessary transmission upgrades. In addition to numerous local injection related limiters each affecting one or two sites, there were widespread regional limiters affecting virtually every potential site.

In the single site analysis, 16 of the 40 sites had potential outlet capabilities of at least 40 MW on an individual basis. This analysis did not examine generation levels beyond 40 MW. The remaining 24 sites had generation outlet capabilities ranging from zero to 35 MW.

The zonal analysis found the maximum generation outlet capability to be 50 MW in both the Northwest and West -Central zones with the remaining zones having outlet capabilities of 40 MW.

The statewide dispersion of 600 MW of additional DRG is not possible without encountering significant limiters. In fact, there were 34 local and regional transmission facility limitations found in this scenario. The maximum statewide generation outlet capability without the need for facility upgrades was found to be 50 MW, which is the maximum generation outlet capability found in the zonal analysis. Note that achieving this outcome would require no additional generation projects to be pursued in the other four outstate zones.

DRG projects may not be responsible for some of the upgrades, but they may be asked to financially participate in those upgrades, such as those fixes which are required to solve the Zion-Pleasant Prairie overload.

It is very difficult to analyze and quantify the zonal and statewide impacts as projects are not evaluated by Midwest ISO in this manner. The Midwest ISO does not do aggregate studies of numerous generation projects dispersed in a wide region.

On a regional level, 40 “small” generation plants appear as an aggregation and create one “big” generation plant that overloads regional transmission facilities in the same manner.

Post-2013 Addition Analysis

Given the significant number of limiters found in the AC analysis, the study team and the TRC decided to run a sensitivity case with some future higher voltage transmission projects. The Post-2013 addition analysis looked at the impact of adding significant transmission additions. Some of these additions are scheduled to be in-service shortly after 2013 to relieve known system reliability issues. And one project that may be proposed is also included. These projects were a limited set of future potential projects and are shown below:

- Remaining CapX2020 Group 1 projects
  - Quarry (St. Cloud)-Alexandria-Fargo 345 kV line
  - Hampton-North Rochester 345 kV line
- LaCrosse to Madison 345 kV line project.

The results of the Post-2013 analysis are shown in the tables below. These transmission additions improve system performance and reduce the number of zonal and statewide limiters especially in the Northwest, West-Central and Southwest zones. There was no change in the number of limiters for the Northeast and Southeast zones.

Table 22 – Post-2013 Limiters Results by Zone

		Number of Limiters	
		SUOP	SUPK
Zone	Zonal MW Level	Post 2013 Limiter Diff	Post 2013 Limiter Diff
NE	50	0	-2
	100	2	-2
	150	0	0
	200	-2	-1
NW	50	1	0
	100	-3	-1
	150	-1	-1
	200	-2	0
SE	50	0	0
	100	0	1
	150	0	0
	200	0	1
SW	50	1	0
	100	-1	0
	150	-1	0
	200	-3	-1
WC	50	-1	0
	100	-1	0
	150	0	-1
	200	-1	-1

Table 23 – Post-2013 Limiters by Summer Peak and Summer Off-Peak

	Statewide MW Level	Number of Limiters		Post 2013 Limiter Diff
		Base Case	Post 2013	
SUOP	600	26	11	-15
SUPK	600	18	16	-2

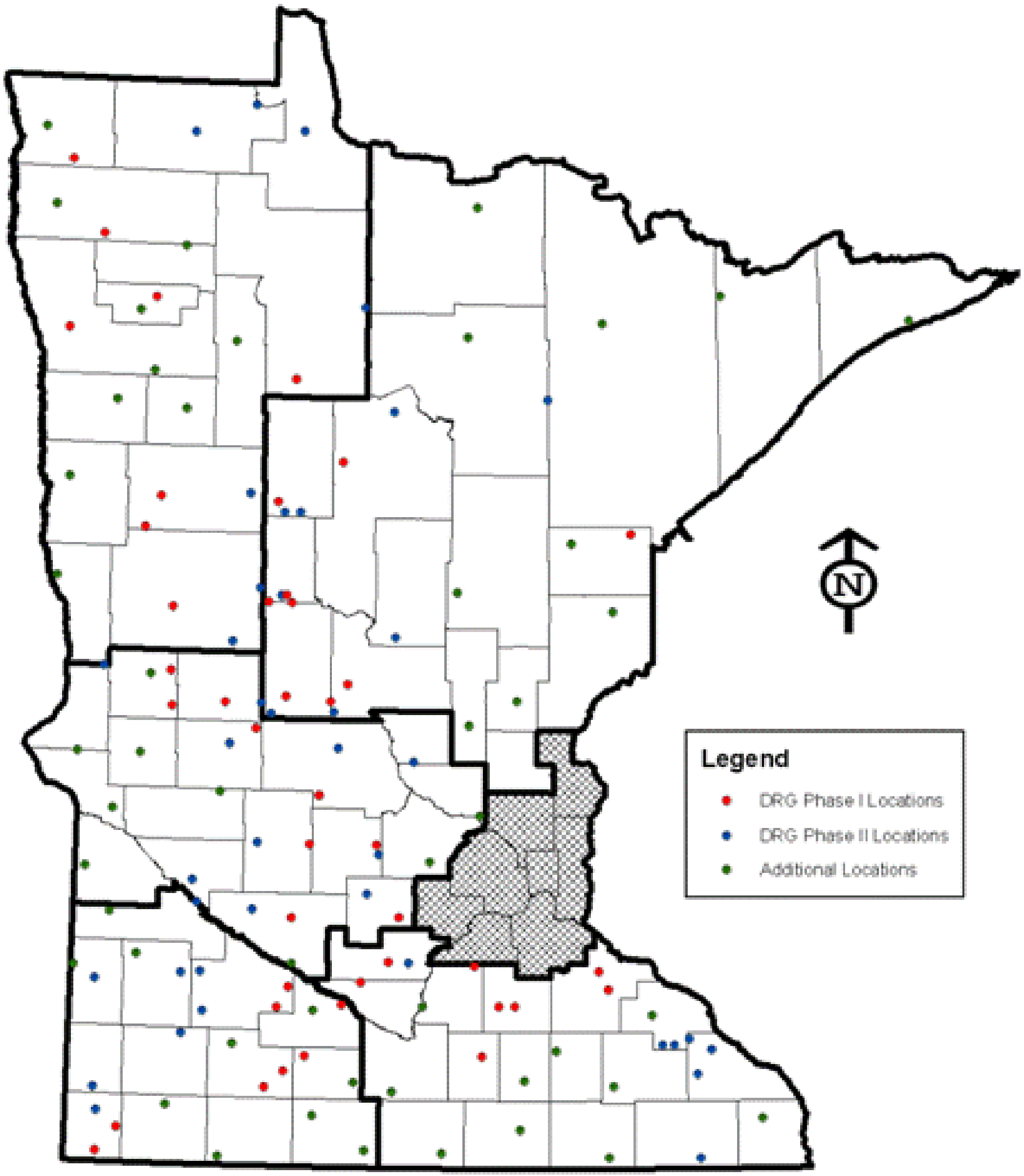
The cost of the Post-2013 transmission study projects is roughly $875 million. Considering only the case of the statewide output of 600 MW of DRG, the costs of the Post-2013 projects would be greater than fixing the individual DRG limiters. By their nature, high voltage projects are not designed to alleviate the lower voltage transmission limiters, so this is not a failing. Rather, it shows that dispersing the generation on the lower voltage transmission system is a strategy that requires upgrades to both the lower voltage system and the regional higher voltage network. The Post-2013 projects were designed to enable much greater capacity output than 600 MW. If the study team were to test DRG placements on the 115 kV and above sites, the study team would find significantly higher amounts of outlet capacity in many locations, after addition of the Post-2013 projects. This is due to these Post-2013 projects providing efficient paths to the Midwest ISO market, but they do not by themselves solve the lower voltage limiters to create the on-ramps to the higher voltage network.

F. Grid Expansion Sensitivity Analysis

The goal of the Grid Expansion exercise was to determine if expanding the transmission grid enables additional DRG opportunities and to examine the reliability impacts of Grid Expansion. The Post-2013 and the Grid Expansion exercises are somewhat duplicates of each other, but the Post-2013 was a focused sensitivity based upon the AC analysis results of 40 sites, whereas the Grid Expansion exercise is a DC analysis designed to offer widespread DRG outlet trends in relation to expansions of the high voltage grid.

In order to determine the effects of Grid Expansion, the outlet capability needed to be monitored at numerous diverse sites. The study team started with all 42 DRG Phase I sites and the 40 DRG Phase II sites. Next, the team added the 10 sites in each of the five Minnesota planning zones to help fill in the gaps created by the Phase I & II sites. These 132 sites (42+40+50) were monitored for changes in their respective outlet capabilities and are shown in the figure below.

Figure 17 – Grid Expansion Map



The same transmission system base case 2013 model was used as with the AC analysis. Next the team added the transmission system additions in logical steps and combinations of future projects. These are the projects with probable in-service dates through 2018.

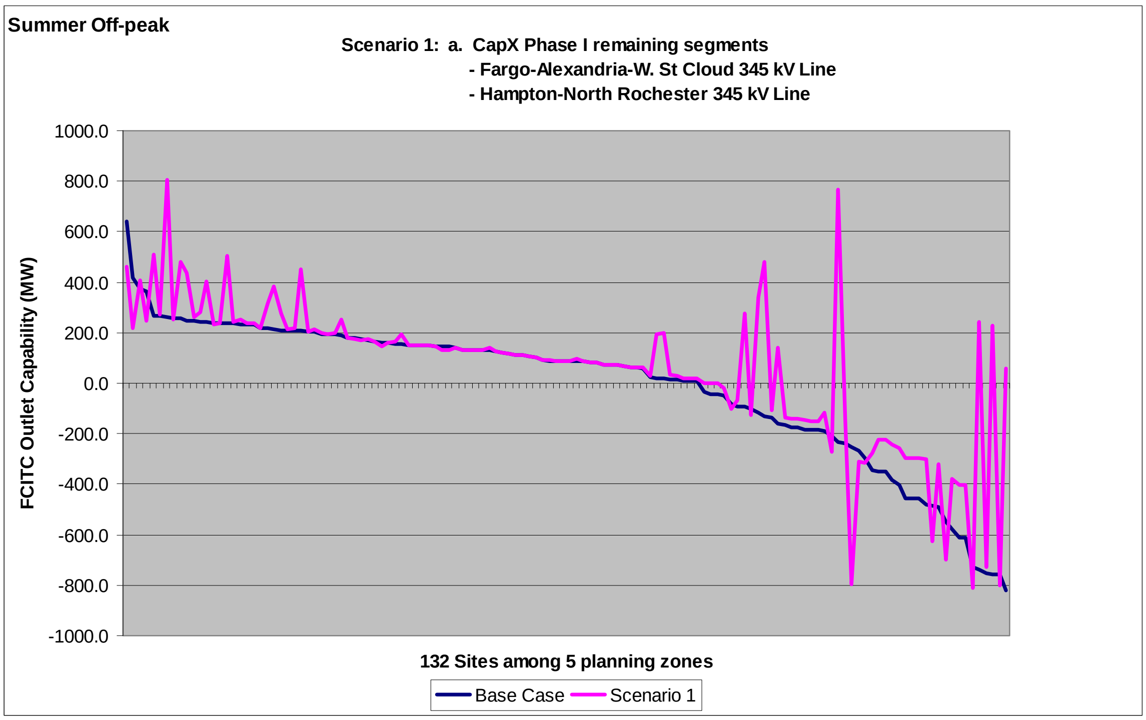
Examples of these transmission system additions include:

a) the CapX2020 Phase I remaining segments (Fargo (Maple River) – Alexandria – West St. Cloud (Quarry), Hampton – Rochester)
b) the CapX2020 Phase I upsized to double circuit option,
c) the Big Stone II 600 MW generation and transmission project,

d) the Minnesota Valley (Hazel) – Blue Lake Corridor Upgrade,
e) the Riel substation and 500 kV capacity upgrades,
f) the Lakefield Junction – Adams 345 kV line
g) the Manitoba Hydro TSR (Transmission Service Request) of 1000 MW and indicative 500 kV transmission project.

The study team evaluated the following scenarios which had different combinations of transmission system additions: 1-(a), 2-(a,b), 3-(a,c), 4-(a,d), 5-(a,e), 6-(a,d,e), 7-(a,d,e,f), 8-(a,d,e,g). Then, the team ran single site FCITC at the 132 sites and recorded the increase or decrease in outlet capability at each site.

Figure 18 – The Grid Expansion Scenario 1 Graph



The above figure shows the Base Case outlet capabilities among the 132 sites with a dark blue line. The Base Case outlet capabilities range from 642 MW at the best site to -818 MW at the worst site. With the addition of the remaining CapX Group I segments, the outlet capabilities for the 132 sites are shown with the purple line. In comparison to the Base Case, the Scenario 1 case shows increased outlet capabilities at 86 of the sites, decreased outlet capabilities at 31 of the sites and no change at 15 of the sites. The remaining seven scenario graphs are shown in Appendix H.

Table 24 – Summary of Eight Grid Expansion Scenarios

Grid Expansion - 115 kV and above Limiters								
Outlet Capability at 132 sites	Scenario Number							
	1	2	3	4	5	6	7	8
Increased	86	82	52	86	86	85	86	12
Decreased	31	35	70	31	32	33	30	119
No Change	15	15	10	15	14	14	16	1
Total	132	132	132	132	132	132	132	132

The bulk of the DRG sites in this analysis showed that the majority of the base case limiters are local outlet issues (transmission constraints close to the DRG sites). Most of the limiters that were identified through the AC analysis are 69 kV and lower voltage transmission constraints. Regional high voltage grid projects are not designed to alleviate those lower voltage constraints and thus regional projects are not showing a capability benefit for the sites with lower voltage limiters. These regional high voltage grid projects help correct constraints on the "highways" to the Midwest ISO market and are not intended to fix the "onramps" or "local roads". Both "local" and "highway" constraints must be corrected in order to successfully interconnect DRG projects.

The remaining CapX2020 Group 1 projects, Scenario 1, increase the generation outlet capability of several sites. For this particular study exercise, none of the other scenarios appear to add any more outlet to the system for DRG beyond the CapX2020 Group 1 remaining segments (Scenario 1) alone. An explanation for this is that the underlying projects associated with the projects in the other seven scenarios were not added to the models with their primary projects. Typical transmission line studies include an "underlying" set of upgrades where the transmission system is analyzed for any underlying facilities which become overloaded as a result of the transmission project addition itself. In other words, bigger regional high voltage transmission projects often require lower voltage transmission fixes along with the larger system addition. Some of the Grid Expansion projects have not evolved enough to reach the "underlying" analysis stage. As a result the underlying system fixes were not known and thus were not included in this analysis. Another explanation which is mentioned previously is that the limiters that were encountered were local limiters that are not intended to be fixed by the other more regional projects that were analyzed.

In scenarios 3 & 8, more sites experienced a decrease in outlet capability than those with increases. These two scenarios involved the addition of generation associated with the transmission Grid Expansion additions; Big Stone II with 600 MW and the Manitoba Hydro TSR with 1000 MW. These Grid Expansion projects associated with generation additions are sized using existing system margin or generator outlet capacity. Without the addition of their respective underlying system fixes, these transmission projects by themselves don't add back all the margin or generator outlet capability that is used by the generation.

G. 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 closer, direct path. 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 both summer peak and summer off-peak models, in the base case and in the statewide DRG scenario with 600 MW of dispersed generation with the transmission fixes as listed in Table 33 in Cost Analysis Section. The cases with the Post-2013 projects were also included. The results of the loss analysis are shown in Table 25.

Table 25 – Loss Analysis Summary

<table>
<tr><th colspan="2" rowspan="2">SUOP System Losses (MW)</th><th colspan="3">SUOP Loss Comparison (MW)</th></tr>
<tr><th>Basecase+600 MW
vs
Basecase</th><th>Basecase+Post 2013
vs
Basecase</th><th>Basecase+Post 2013+600 MW
vs
Basecase+600 MW</th></tr>
<tr><td>Basecase</td><td>15853</td><td rowspan="4">109</td><td rowspan="4">-76</td><td rowspan="4">-87</td></tr>
<tr><td>Basecase + 600 MW</td><td>15962</td></tr>
<tr><td>Basecase + Post 2013</td><td>15777</td></tr>
<tr><td>Basecase + Post 2013 + 600 MW</td><td>15875</td></tr>
<tr><th colspan="2" rowspan="2">SUPK System Losses (MW)</th><th colspan="3">SUPK Loss Comparison (MW)</th></tr>
<tr><th>Basecase+600 MW
vs
Basecase</th><th>Basecase+Post 2013
vs
Basecase</th><th>Basecase+Post 2013+600 MW
vs
Basecase+600 MW</th></tr>
<tr><td>Basecase</td><td>16923</td><td rowspan="4">30</td><td rowspan="4">-33</td><td rowspan="4">-27</td></tr>
<tr><td>Basecase + 600 MW</td><td>16953</td></tr>
<tr><td>Basecase + Post 2013</td><td>16890</td></tr>
<tr><td>Basecase + Post 2013 + 600 MW</td><td>16926</td></tr>
</table>

The results in the table above indicate that for the summer off-peak case, there is a 109 MW increase in losses for the 600 MW DRG scenario when compared to the base case. This means that 18% of the 600 MW is consumed by the transmission system prior to reaching customer load. These losses are the result of transporting the 600 MW of DRG in Minnesota to generation sinks in the wider Midwest ISO market. Introducing the Post-2013 projects reduces the system losses by 76 MW compared to the base case and by 87 MW compared to the 600 MW of DRG scenario. This reduction in losses is due to the additional high voltage paths for the power flow which leads to a reduction in overall system resistance and lower loading on existing lines. In a similar manner, adding more interstates to a transportation system reduces the density of traffic on the surrounding roadways which reduces the number of traffic jams and allows the vehicles to travel more efficiently.

For the summer on-peak condition, the system-wide losses for the 600 MW DRG scenario are 30 MW higher than the base case. The differences between the Base Case and the 600 MW case (30 MW) are lower in summer on-peak than the summer off-peak scenario (109 MW). In summer peak, more widespread and uneconomical 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. Adding the Post-2013 projects also lowers the summer peak losses in the Base Case and the 600 MW DRG case.

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

H. Transient Stability Monitoring and Study Assumptions

After the final 40 locations were chosen for potential Dispersed Renewable Generation (DRG) based on the DRG Phase II 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 Mid-Continent Area Power Pool (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 of the DRG II sites were represented as equivalent wind farms using the model shown in Figure 20 Connected to the POI is a typical wind farm substation transformer that steps down to 34.5 kV. Next is an equivalent branch representing the impedance (series and shunt) of the 34.5 kV collector system. After that is an equivalent GSU (generator step-up) transformer from 34.5 kV down to 0.575 kV. Finally, a single equivalent generator is connected to the 0.575 kV bus. The wind farm is sized based on the MW level determined in the AC power flow analysis.

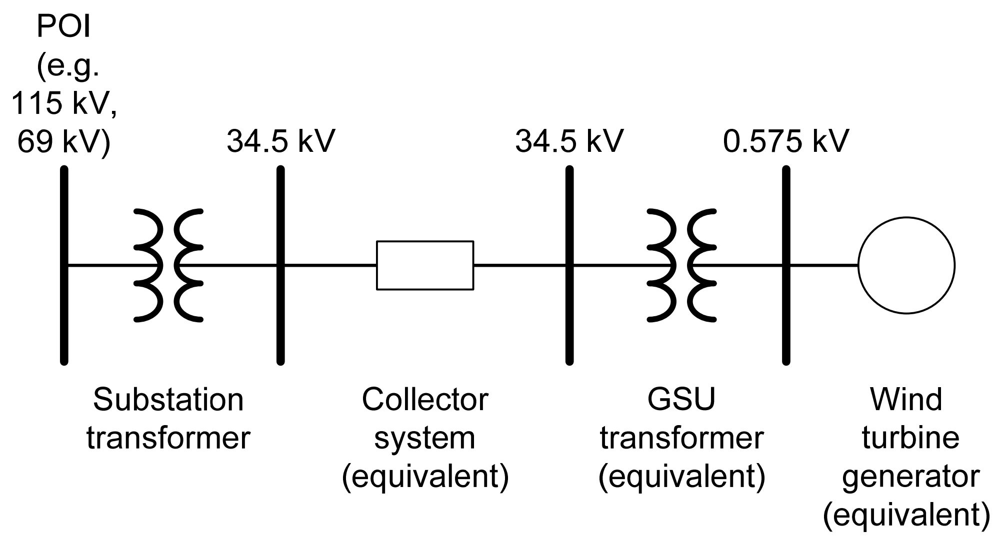


Figure 19 – DRG Wind Farm Model

For this study, the TRC decided that GE 1.5 MW wind turbines would be presumed to be used for all DRG wind farms, as was done in the DRG Phase I study. GE wind generators are of the DFIG (doubly-fed induction generator) type that is commonly installed today and is expected to be installed in the future as well. These generators have a reactive power capability from 0.90 leading (inductive) to 0.95 lagging (capacitive). They can dynamically supply the reactive power losses of their collector systems and regulate voltage at the point of interconnection. The GE wind turbine dynamic model did not include any inertial response or governor behavior, which was not a concern for this study.

System Stability Model

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

This 2015 summer off-peak case was reviewed and updated in order to match the high voltage transmission topology used in the AC analysis model. The following transmission projects were added to the model:

Table 26 – Projects Added to the Stability Model

Projects add to the stability model	
1. CapX Project	Brookings Co. - Hampton 345kV
	Monticello - Quarry 345kV
	North Rochester - North Lacrosse 345kV
2. RIGO Project	Pleasant Valley - Byron 161kV
	Pleasant Valley - Willow Creek 161kV
	Byron - Maple Leaf 161kV Circuit 2
	Maple Leaf - Cascade Creek 161kV Circuit 2

In addition, the original 2015 case had most existing wind farms in the region dispatched at 20% of their rated capacity. These wind farms were increased to 90% of their rated capacity to reflect off-peak conditions that are both realistic and stressful to the transmission grid.

Adding DRG to the Stability Model

A software program was written in the IPLAN language during the DRG Phase I study to add the DRG wind projects to the NMORWG model. IPLAN is a programming language used for interacting with and automating the PSS/E software. This program was used again in the DRG Phase II study. As before, 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 the sub-transmission system. 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 frequently rises, sometimes significantly if the bus is relatively weak. In cases where the voltage rose above 105% of nominal, the reactive power capability of the DRG units was used to limit the voltage at the POI to 105%. 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 reactive power would take place between the system and the DRG under these conditions.

The sink generators used in the steady-state study were also used in building the stability model. The sinks were chosen to represent a Midwest ISO market dispatch. The most expensive units were taken off-line first.

The DRG Phase I plants were added first and dispatched to the Midwest ISO market. This caused the Minnesota-Wisconsin (MWEX) interface flow to go well above its rating. The DRG Phase II plants were added next, which further increase MWEX flow.

The IPLAN program also creates the standard GE wind turbine dynamic model for each DRG location, assuming each wind farm is running at 100% of capability.

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. Faults were added near the Square Butte HVDC rectifier, the Arrowhead – Weston 345 kV line, the White – Split Rock 345 kV line, and the Nobles – Lakefield 345 kV line, and Sherburne County Unit 3.

In a normal interconnection impact study for a single generation plant, many faults around the POI are studied. However, with so many DRG locations and a tight deadline, this was not feasible for this study. In addition, 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-DRG1 case with coal generation at URGE levels
- Pre-DRG1 case with updated transmission, existing wind increased to 90%, and interface flows reset to rated values
- DRG1 case without resetting interface flows
- DRG1 case with the MWEX interface reset to its rated value
- DRG2 case without resetting interface flows
- DRG2 case with the MWEX interface reset to its rated value

The Pre-DRG1 cases showed no violations of MAPP stability criteria. This includes generator stability, transient voltage dip criteria, damping criteria, and wind farms not tripping. These cases have MHEX, NDEX, and MWEX flows at their maximum rated values.

Both DRG1 and DRG2 cases without interface resetting had transient low voltage violations in the Arrowhead area for a fault on the King – Eau Claire 345 kV line. This is because dispatching DRG to the Midwest ISO market increases MWEX flow well above its 1525 MW rating.

The critical disturbance is a single-phase fault on the King – Eau Claire 345 kV line near King, with one King breaker failing to open. The breaker failure results in tripping of the King-Chisago 345 kV line as well. One option for improving the stability response of this fault is to install two additional 345 kV breakers at King.

This will allow the King-Chisago line to stay in service following breaker failure on the King – Eau Claire line, reducing the severity of the disturbance. This solution was tested on the DRG2 case, and the number of buses with voltage violations was reduced from 18 to three. The three remaining violations were at the Wisconsin Minong, Stinson, and Dahlberg buses.

To address the remaining violations, a 60 MVAr fast-switching capacitor was added at the Stone Lake 161 kV bus, set to switch on eight cycles after the initial voltage drop. This cleared up the remaining violations.

The recommended solution to the stability violations is:

- Installation of two 345 kV breakers at A.S. King for an estimated cost of $2,000,000, and
- Installation of one 60 MVAr fast-switching capacitor at Stone Lake 161 kV station located in Wisconsin for an estimated cost of $5,000,000

A more detailed study of this solution will be needed to confirm its effectiveness at increasing the rating of the MWEX interface. The costs cited are indicative costs, based on previous projects of similar scope. These estimates were developed without benefit of detailed site-specific information and should therefore be considered very approximate.

A second possible solution is construction of a 345 kV transmission line from La Crosse, Wisconsin, to Madison, Wisconsin. This is a much more expensive option with a much longer lead time, and it was not tested in this study.

A final option to eliminate the PCS fault violation is to reduce the MWEX interface flow back to its rated value by dispatching the DRG to the Twin Cities zone of Minnesota. This was modeled by using the “setexports” program included with the NMORWG package. While this does eliminate the stability violations, this dispatch method does not align with Midwest ISO interconnection study practices. DRG would not be approved as a “Network Resource” with this dispatch option.

Outputs tables from the NMORWG package are given in Appendix H. The voluminous RPT reports and PDF plots are available upon request.

Stability Analysis Conclusions

In Phase I of the DRG study, DRG was dispatched to Twin Cities’ area gas turbines. No stability problems were found. In Phase II of the DRG study, another 600 MW of DRG was added in Minnesota, and all 1200 MW of DRG was dispatched to the greater Midwest ISO market.

The MWEX interface was already loaded to its limit in the base case used for this stability study. Adding DRG and dispatching it to the Midwest ISO market increased the loading of MWEX well above its capability, and low voltage violations were seen for the PCS fault.

The recommended solution is to install two breakers at A.S. King and a 60 MVAr fast-switched capacitor at Stone Lake. The total cost is estimated to be $7,000,000.

Another option is to construct a 345 kV line from La Crosse, Wisconsin, to Madison, Wisconsin, but this option has a much higher cost and lead time.

Dispatching DRG to the Twin Cities avoids stability violations, but this method does not follow Midwest ISO study procedures.

This study shows that new DRG in Minnesota may have a difficult time interconnecting without system upgrades. The Minnesota-Wisconsin interface is currently constrained to 1525 MW. The network upgrades described above are possible solutions to increasing the capability of the Minnesota-Wisconsin interface and allowing DRG to interconnect to the system.

Important note: The results of this study are applicable to the assumed conditions. Some of the significant assumptions are:

- Using an updated 2015 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 additional detrimental impact on stability that would need mitigation, with a wide range of possible cost and time implications.

I. System Upgrades/Cost Analysis

The single site, analysis identified that 16 of the 40 sites required no upgrades for an outlet capability of 40 MW. This analysis also showed a varying number of limiters for the remaining 24 DRG sites that had transmission limitations for generation output levels below 40 MW. The transmission limitations for these sites were tabulated and specific system upgrades were created for each site.

The tables below list the facility improvements 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.

Table 27 - Northwest Zone Single-Site Cost Analysis

Northwest Zone								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Estimated Cost
COMPTON								
38809 533-TIE 38810 WADENA 1	MP	5.9	34.5	336 ACSR	34.0	Line Rebuild	795 ACSR	$ 1,897,000
38810 WADENA 38811 CMPTN TP 1	MP	1.3	34.5	336 ACSR	34.0	Line Rebuild	796 ACSR	$ 419,000
38811 CMPTN TP 62914 COMPTON9 1	GRE	4.42	34.5	4/0 ACSR	22.7	Line Rebuild	795 ACSR	$ 1,423,000
								$ 3,739,000
MORANVILLE								
9269 BIRCHDAL 6 66801 LUND 8 1	MPC	20.9	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 5,757,000
9269 BIRCHDAL 6 9270 LOMAN 6 1	MPC	23.6	69	1/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 6,508,000
9270 LOMAN 6 67017 RUNNING8 1	MPC	9.8	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 2,699,000
								$ 14,964,000
NASHUA								
62548 PRPPRSW9 62773 MILTONA9 1	GRE	8.2	41.6	4/0 ACSR	27.4	Line Rebuild	336 ACSR	$ 2,252,000
62753 MILTONA7 62773 MILTONA9 1	GRE	XFMR	115/41.6	N/A	30.0	Transformer Upgrade	40 MVA	$ 1,217,000
63123 HOOT LK9 63223 HOOT LK7 1	OTP	XFMR	115/41.6	N/A	27.0	Transformer Upgrade	40 MVA	$ 1,217,000
7163 CASCJT 4 63123 HOOT LK9 1	OTP	2.3	41.6	266 ACSR	17.3	Line Rebuild	336 ACSR	$ 635,000
7163 CASCJT 4 7164 DALTON 4 1	OTP	5.4	41.6	266 ACSR	34.0	Line Rebuild	336 ACSR	$ 1,490,000
7164 DALTON 4 62538 TEN MIL9 1	OTP	5.8	41.6	266 ACSR	34.0	Line Rebuild	336 ACSR	$ 1,601,000
7198 CATSEYE 4 62538 TEN MIL9 1	OTP	6.0	41.6	266 ACSR	34.0	Line Rebuild	477 ACSR	$ 1,725,000
7198 CATSEYE 4 7199 WENDEL 4 1	OTP	5.5	41.6	2/0 ACSR	21.0	Line Rebuild	336 ACSR	$ 1,518,000
7198 CATSEYE 4 7200 ASHBYJT 4 1	OTP	4.0	41.6	266 ACSR	34.0	Line Rebuild	336 ACSR	$ 1,104,000
7199 WENDEL 4 7204 NASUAJCT 4 1	OTP	2.8	41.6	2/0 & 3/0 ACSR	21.0	Line Rebuild	336 ACSR	$ 773,000
7200 ASHBYJT 4 7201 ELBOWJ 4 1	OTP	1.0	41.6	266 ACSR	34.0	Line Rebuild	336 ACSR	$ 276,000
7204 NASUAJCT 4 7205 NASHUA 41 1	OTP	8.0	41.6	1/0 ACSR	18.0	Line Rebuild	477 ACSR	$ 2,300,000
7204 NASUAJCT 4 8786 WENDEL 4 1	OTP	4.0	41.6	3/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 1,150,000
7215 ELBOWLK 4 63220 ELBOWLK7 1	MRES	XFMR	115/41.6	N/A	33.6	Transformer Upgrade	40 MVA	$ 1,217,000
7449 HERMAN 4 8786 WENDEL 4 1	OTP	11.7	41.6	3/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 3,364,000
7935 CLEARBK 4 63241 CLEARBR7 1	OTP	XFMR	115/41.6	N/A	10.0	Transformer Upgrade	35 MVA	$ 1,189,000
								$ 23,028,000
OSAGE								
38781 LLCAPBNK 38783 OSAGE MP 1	MP	3.8	34.5	336 ACSR	34.0	Line Rebuild	477 ACSR	$ 1,078,000
38781 LLCAPBNK 62421 LONG LK9 1	MP	0.3	34.5	336 ACSR	34.0	Line Rebuild	477 ACSR	$ 72,000
38783 OSAGE MP 62414 OSAGE 9 1	MP	15.9	34.5	1/0 ACSR	18.1	Line Rebuild	477 ACSR	$ 4,563,000
61625 BLCKBRY4 61626 BOSWELL4 2	MP	18.4	230	1431 ACSR	438.0	Temperature Upgrade	SPS Op Guide	$ -
								$ 5,713,000
PARKERS PRAIRIE								
62539 PRKR PR9 62547 PRKPRTP9 1	OTP	2.0	41.6	3/0 ACSR	23.8	Line Rebuild	477 ACSR	$ 575,000
62548 PRPPRSW9 62773 MILTONA9 1	OTP	8.2	41.6	4/0 ACSR	27.4	Line Rebuild	336 ACSR	$ 2,252,000
62753 MILTONA7 62773 MILTONA9 1	GRE	XFMR	115/41.6	N/A	30.0	Transformer Upgrade	40 MVA	$ 1,189,000
7197 PARKERS 4 62547 PRKPRTP9 1	OTP	2.3	41.6	3/0 ACSR & 266 ACSR	24.0	Line Rebuild	477 ACSR	$ 661,000
7197 PARKERS 4 62548 PRPPRSW9 1	OTP	3.0	41.6	3/0 ACSR	24.0	Line Rebuild	336 ACSR	$ 828,000
								$ 5,505,000
SHOOKS								
9268 BIG FALS 6 67017 RUNNING8 1	MPC	17.0	69	1/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 4,684,000
								$ 4,684,000
STAFFORD								
9241 STAFFORD 6 9244 MALUNG 6 1	MPC	2.9	69	#2 CU	41.0	Line Rebuild	336 ACSR	$ 803,000
9269 BIRCHDAL 6 66801 LUND 8 1	MPC	20.9	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 5,757,000
9269 BIRCHDAL 6 9270 LOMAN 6 1	MPC	23.6	69	1/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 6,508,000
9270 LOMAN 6 67017 RUNNING8 1	MPC	9.8	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 2,699,000
9483 SALOLTAP 6 9484 SALOL 8 6 1	MPC	0.1	69	4/0 ACSR	40.6	Line Rebuild	266 ACSR	$ 28,000
								$ 15,795,000
WILLIAMS								
63223 HOOT LK7 69413 EFERGUS7 1	OTP	1.6	41.6	266 ACSR	88.0	Line Rebuild	795 ACSS	$ 439,000
66773 ULRICH 9 66781 ULRICH T 1	OTP	XFMR	115/41.6	N/A	15.0	Transformer Upgrade	35 MVA	$ 1,189,000
9256 WILLMS T 6 66999 MORANVI8 1	MPC	20.5	69	2 FCU & 4/0 ACSR	41.8	Line Rebuild	336 ACSR	$ 5,644,000
9256 WILLMS T 6 9257 WILLIAMS 6 1	MPC	1.0	69	1/0 ACSR	40.0	Line Rebuild	336 ACSR	$ 287,000
9256 WILLMS T 6 9258 PITT 6 1	MPC	11.2	69	2 FCU & 4/0 ACSR	39.0	Line Rebuild	336 ACSR	$ 3,088,000
9258 PITT 6 66801 LUND 8 1	MPC	3.5	69	1/0 ACSR	40.0	Line Rebuild	336 ACSR	$ 972,000
9269 BIRCHDAL 6 66801 LUND 8 1	MPC	20.9	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	336 ACSR	$ 5,757,000
9269 BIRCHDAL 6 9270 LOMAN 6 1	MPC	23.6	69	1/0 ACSR	40.0	Line Rebuild	336 ACSR	$ 6,508,000
9270 LOMAN 6 67017 RUNNING8 1	MPC	9.8	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	336 ACSR	$ 2,699,000
								$ 26,583,000

Table 28 – Northeast Zone Single-Site Cost Analysis

Northeast Zone								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Estimated Cost
BENA								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
62480 BENA 8 62483 BENA TP8 1	GRE	14.9	69	2/0 ACSR	27.7	Line Rebuild	336 ACSR	$ 4,112,000
								$ 22,112,000
PINE LAKE								
38854 BERTRAM 61836 SWANVIL9 1	MP	1.61	34.5	336 ACSR	34.1	Line Rebuild	795 ACSR	$ 519,000
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
61636 SWANVIL7 61836 SWANVIL9 1	MP	XFMR	115/34.5	N/A	39.2	Transformer Upgrade	50 MVA	$ 1,020,000
								$ 19,539,000
DEWING								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
								$ 18,000,000
HUBBARD								
								$ -
NATIONAL								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
61653 RIVERTN7 62448 HILLCTY7 1	MP	42.3	115	336 ACSR	58.3	Temperature Upgrade	336 ACSR	$ 846,000
61740 GR RPDS7 62448 HILLCTY7 1	MP	25.4	115	336 ACSR / 4/0 CU	58.3	Temperature Upgrade	336 ACSR	$ 508,000
								$ 19,354,000
PALMER LAKE								
61625 BLCKBRY4 61626 BOSWELL4 2	MP	18.4	230	1431 ACSR&1590 ACSR	438.0	Temperature Upgrade	SPS Op Guide	$ -
								$ -
VERNDALE								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
								$ 18,000,000
WEST UNION								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
60751 SAUKCMU8 62820 W UNION8 1	XCEL	9.0	69	336A 2/0A 4/0A 3/6CU	39.6	Line Rebuild	477 ACSR	$ 2,588,000
								$ 20,588,000

Table 29 – West Central Zone Single-Site Cost Analysis

West Central								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Estimated Cost
ALBANY								
								$ -
BENTON								
								$ -
BIG SWAN								
								$ -
CROOKS								
60679 CROOKS 8 60680 EMMET R8 1	XCEL	2.0	69	2/0 ACSR	40.7	Line Rebuild	477 ACSR	$ 552,000
60680 EMMET R8 60694 RENVILL8 1	XCEL	0.8	69	2/0 ACSR	40.7	Line Rebuild	477 ACSR	$ 221,000
60679 CROOKS 8 60695 DANUBE 8 1	XCEL	4.8	69	2/0 & 4/0 ACSR	40.7	Line Rebuild	477 ACSR	$ 1,380,000
60680 EMMET R8 60694 RENVILL8 1	XCEL	2.3	69	2/0 ACSR	40.7	Line Rebuild	477 ACSR	$ 661,000
								$ 2,814,000
DOUGLAS COUNTY								
								$ -
FIESTA								
								$ -
GLENWOOD								
								$ -
HUTCHINSON								
								$ -
WILLMAR								
60767 WLMSTAP8 62009 LKJOHNA8 1	GRE	4.5	69	4/0 ACSR	38.6	Line Rebuild	266 ACSR	$ 1,849,000
								$ 1,849,000

Table 30 – Southwest Zone Single-Site Cost Analysis

Southwest								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Estimated Cost
GRANITE FALLS								
								$ -
HARDWICK								
								$ -
HOLLAND								
66006 H TAP 66008 HOLLAND 1	L & O	7.5	69		45.4	Line Rebuild	336 ACSR	$ 2,070,000
66007 HOLLAND 66008 HOLLAND 1	L & O	XFMR	115/69	N/A	52.0	Transformer Upgrade	65 MVA	$ 1,368,000
								$ 3,438,000
IVANHOE								
								$ -
LAKE SARAH								
60392 WRIDGE 8 60859 ROCKTAP8 1	XCEL	2.7	69	2/0 CU	51.7	Line Rebuild	336 ACSR	$ 745,000
60392 WRIDGE 8 66005 PIPETAP 1	XCEL	7.5	69	2/0 CU & 4/0 ACSR	51.7	Line Rebuild	336 ACSR	$ 2,070,000
60395 ERIDGE 8 60835 CHNDLRT8 1	GRE	3.3	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 916,000
60395 ERIDGE 8 62710 CHANDLR8 1	GRE	4.6	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 1,270,000
60683 MINNVAL8 60684 YELWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 CU	34.0	Line Rebuild	477 ACSR	$ 4,571,000
60728 FRANKLN8 60771 RDWDFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 4,600,000
60855 TRACYSW8 62713 LKSRHTP8 1	XCEL	6.0	69	2/0 CU	51.7	Line Rebuild	336 ACSR	$ 1,656,000
60855 TRACYSW8 62741 WLNTGTP8 1	XCEL	1.0	69	4/0 ACSR	51.7	Line Rebuild	795 ACSS	$ 150,000
62713 LKSRHTP8 62714 CURRIE 8 1	GRE/ XCEL	8.5	69	2/0 CU & 4/0 ACSR	47.0	Line Rebuild	266 ACSR	$ 2,346,000
								$ 18,324,000
LYON COUNTY								
60171 LYON 60903 LYON CO8 1	XCEL	XFMR	115/69	N/A	80.5	Transformer Upgrade	95 MVA	$ 1,573,000
60683 MINNVAL8 60684 YELWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 CU	34.0	Line Rebuild	477 ACSR	$ 4,571,000
60728 FRANKLN8 60771 RDWDFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 4,600,000
								$ 10,744,000
MILROY								
60683 MINNVAL8 60684 YELWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 CU	34.0	Line Rebuild	477 ACSR	$ 4,571,000
60728 FRANKLN8 60771 RDWDFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 4,600,000
60771 RDWDFLTG 62735 REDWOOD8 1	GRE	1.1	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 295,000
62735 REDWOOD8 62737 SHRDNTP8 1	GRE	8.0	69	1/0 ACSR	31.6	Line Rebuild	266 ACSR	$ 2,214,000
								$ 11,680,000
WALNUT GROVE								
60392 WRIDGE 8 66005 PIPETAP 1	XCEL	7.5	69	2/0 CU & 4/0 ACSR	51.7	Line Rebuild	336 ACSR	$ 2,070,000
60395 ERIDGE 8 60835 CHNDLRT8 1	GRE	4.8	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 1,325,000
60395 ERIDGE 8 62710 CHANDLR8 1	GRE	4.6	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 1,270,000
60683 MINNVAL8 60684 YELWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 CU	34.0	Line Rebuild	477 ACSR	$ 4,571,000
60728 FRANKLN8 60771 RDWDFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Temperature Upgrade	477 ACSR	$ 4,600,000
								$ 13,836,000

Table 31 – Southeast Zone Single-Site Cost Analysis

Southeast								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Estimated Cost
ALTURA								
								$ -
ELGIN								
								$ -
HARMONY								
								$ -
HENDERSON								
34008 FOX LK 5 34012 FOXLAKE8 1	ALTW	XFMR	161/69	N/A	74.7	Transformer Upgrade	85 MVA	$ 1,938,000
60724 HENDRSN8 62674 JSNLDTP8 1	XCEL	3.0	69	2/0 CU	34.0	Line Rebuild	336 ACSR	$ 828,000
60730 ARLNGTN8 60731 GRENISL8 1	XCEL	5.8	69	2/0 CU	34.0	Line Rebuild	336 ACSR	$ 1,601,000
60730 ARLNGTN8 62674 JSNLDTP8 1	XCEL	2.5	69	2/0 CU	34.0	Line Rebuild	477 ACSR	$ 719,000
								$ 5,086,000
ST. CHARLES								
								$ -
WABACO								
34000 NIW 5 34015 LIME CK5 1	ITC	16.3	161	477 - 26/7 ACSR	202	Line Rebuild	795 ACSR	$ 5,443,000
								$ 5,443,000
WHITEWATER								
68703 PLAINVIE 68705 WHITEWAT 1	Peoples	3.8	69	1/0 ACSR	19.0	Line Rebuild	266 ACSR	$ 1,035,000
68703 PLAINVIE 69158 T PLV 8 1	DPC/ Peoples	3.2	69	1/0 ACSR	19.0	Line Rebuild	266 ACSR	$ 883,000
68706 T WHWATR 69158 T PLV 8 1	DPC/ Peoples	8.0	69	1/0 ACSR	19.0	Line Rebuild	266 ACSR	$ 2,208,000
68707 T ZUM 68711 WEST ALB 1	Peoples	8.5	69	1/0 ACSR	19.0	Line Rebuild	266 ACSR	$ 2,346,000
								$ 6,472,000

The zonal analysis identified the transmission limitations in each zone which are necessary for generation output levels of 200 MW. The transmission limitations for these sites were tabulated and specific system upgrades were created for each zone.

The table shown below lists the facility improvements identified as necessary to achieve outlet capability for up to 200 MW of DRG in each zone.

Table 32 – Zonal Cost Analysis

Zonal Cost Analysis								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Est. Cost
NW								
61625 BLCKBRY4 61626 BOSWELL4 2	MP	18.4	230	1431 ACSR	438.0	SPS Operating Guide	N/A	$ -
67327 ELLENDL7 67401 ABDNJCT7 1	NEW	-	115	-	88.0	Upgrade CT/Relays @ Ellendale	125 MVA	$ 125,000
9269 BIRCHDAL 6 66801 LUND 8 1	MPC	20.9	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 5,757,000
9269 BIRCHDAL 6 9270 LOMAN 6 1	MPC	23.6	69	1/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 6,508,000
9270 LOMAN 6 67017 RUNNING8 1	MPC	9.8	69	1/0 ACSR & 4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 2,699,000
							TOTAL	**$ 15,089,000**
NE								
36421 ZION ; R 38849 PLS PR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
37384 ZION ; 39362 LAKEVIEW 1	"	"	"	"	"	"	"	"
39345 KENOSH45 39362 LAKEVIEW 1	"	"	"	"	"	"	"	"
39033 DAR 138 39036 NOM 138 1	ATC	25.6	138	266.8 ACSR 26/7	105	Line Rebuild	477 ACSR	$ 10,599,000
61625 BLCKBRY4 61626 BOSWELL4 2	MP	18.4	230	1431 ACSR	438.0	SPS Operating Guide	"	$ -
60751 SAUKCMU8 62820 W UNION8 1	XCEL	9.0	69	336A 2/0A 4/0A 3/6CU	39.6	Line Rebuild	266 ACSR	$ 2,484,000
62646 WILSONL8 62647 SPRTLKS8 1	GRE	1.1	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 295,000
							TOTAL	**$ 31,378,000**
WC								
34137 TRIBOJI5 66563 SPENCER5 1	ITC	18.8	161	636 ACSR	195	Temperature Upgrade	636 ACSR	$ 376,000
							TOTAL	**$ 376,000**
SW								
60392 WRIDGE 8 60859 ROCKTAP8 1	XCEL	2.7	69	2/0 CU	51.7	Line Rebuild	266 ACSR	$ 745,000
34000 NIW 5 34015 LIME CK5 1	ITC	16.3	161	477 - ACSR	202	Line Rebuild	795 ACSR	$ 5,443,000
34008 FOX LK 5 34012 FOXLAKE8 1	ALTW	XFMR	161/69	N/A	74.7	Transformer Upgrade	85 MVA	$ 1,938,000
34137 TRIBOJI5 66563 SPENCER5 1	ITC	18.8	161	636 ACSR	195	Temperature Upgrade	636 ACSR	$ 376,000
60392 WRIDGE 8 66005 PIPETAP 1	XCEL	7.5	69	2/0 CU & 4/0 ACSR	51.7	Line Rebuild	266 ACSR	$ 2,070,000
60395 ERIDGE 8 60835 CHNDLRT8 1	GRE	3.3	69	2/0 ACSR	34.8	Line Rebuild	477 ACSR	$ 1,380,000
60395 ERIDGE 8 62710 CHANDLR8 1	GRE	4.6	69	2/0 ACSR	34.8	Line Rebuild	477 ACSR	$ 1,323,000
60683 MINNVAL8 60684 YELWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 ACSR	34.0	Temperature Upgrade	4/0 ACSR	$ 318,000
60684 YELWMED8 62739 MLRY TP8 1	XCEL	11.4	69	2/0 CU	51.7	Line Rebuild	336 ACSR	$ 4,116,000
60728 FRANKLN8 60771 RDWDFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Line Rebuild	477 ACSR	$ 4,600,000
60771 RDWDFLTG 62735 REDWOOD8 1	GRE	1.1	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 295,000
62735 REDWOOD8 62737 SHRDNTP8 1	GRE	8.0	69	1/0 ACSR	31.6	Line Rebuild	266 ACSR	$ 2,214,000
							TOTAL	**$ 24,818,000**
SE								
34000 NIW 5 34015 LIME CK5 1	ITC	16.3	161	477 - ACSR	202	Line Rebuild	795 ACSR	$ 5,443,000
34008 FOX LK 5 34012 FOXLAKE8 1	ALTW	XFMR	161/69	N/A	74.7	Transformer Upgrade	85 MVA	$ 1,938,000
34137 TRIBOJI5 66563 SPENCER5 1	ITC	18.8	161	636 ACSR	195	Temperature Upgrade	636 ACSR	$ 376,000
34325 ST.CHRT8 68713 ST CHARL 1	DPC	1.0	69	4/0 ACSR	47	Line Rebuild	336 ACSR	$ 361,000
68713 ST CHARL 68774 UTICA 1	ITC	5.09	69	4/0 ACSR	47	Line Rebuild	336 ACSR	$ 1,837,000
39033 DAR 138 39036 NOM 138 1	ATC	25.6	138	266.8 ACSR 26/7	105	Line Rebuild	477 ACSR	$ 10,599,000
60184 APACHET7 60185 ARDNHLS7 1	XCEL	5.4	115	477 ACSR & 2312 AL	210	4.1M of 477 to 2312	2312 ACSR	$ 2,279,000
60730 ARLNGTN8 60731 GRENISL8 1	XCEL	5.8	69	2/0 CU	34.0	Line Rebuild	336 ACSR	$ 1,601,000
60730 ARLNGTN8 62674 JSNLDTP8 1	XCEL	2.5	69	2/0 CU	34.0	Line Rebuild	477 ACSR	$ 719,000
							TOTAL	**$ 25,153,000**

The costs for various outlet amounts from each zone are summarized in the table below.

Table 33 – Zonal Cost Summary

Zone	Zonal Costs for:			
	50 MW	100 MW	150 MW	200 MW
NW	$ -	$ 12,265,000	$ 14,964,000	$ 15,089,000
NE	$ 18,000,000	$ 18,000,000	$ 28,894,000	$ 31,378,000
WC	$ -	$ 376,000	$ 376,000	$ 376,000
SW	$ 7,970,000	$ 16,749,000	$ 21,507,000	$ 24,818,000
SE	$ 5,443,000	$ 20,298,000	$ 21,017,000	$ 25,153,000

The statewide AC analysis identified the 34 transmission limitations as well as two facility additions as identified in the stability analysis that are necessary for a statewide DRG level of 600 MW. The two specific stability system upgrades were identified and are listed in the table below.

Table 34 – Cost Analysis – Statewide Aggregation

Statewide Cost Analysis								
Facility Name	Owner	Length	Voltage	Existing Cond Size	Rate B (MVA)	System Upgrade	Upgrade Size	Est. Cost
34008 FOX LK 5 34012 FOXLAKE8 1	ALTW	XFMR	161/69	N/A	74.7	Transformer Upgrade	85 MVA	$ 1,938,000
60771 REDWOODFLTG 62735 REDWOOD8	GRE	1.1	69	2/0 ACSR	34.8	Line Rebuild	266 ACSR	$ 295,000
34000 NIW 5 34015 LIME CREEK5 1	ITC	16.3	161	477 - 26/7 ACSR	202	Line Rebuild	795 ACSR	$ 5,443,000
61625 BLACKBERRY4 61626 BOSWELL4 2	MP	18.4	230	1431 ACSR	438.0	Temperature Upgrade	1431 ACSR	$ 368,000
9269 BIRCHDAL 6 66801 LUND 8 1	MPC	20.9	69	1/0 ACSR &4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 5,757,000
9269 BIRCHDAL 6 9270 LOMAN 6 1	MPC	23.6	69	1/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 6,508,000
9270 LOMAN 6 67017 RUNNING8 1	MPC	9.8	69	1/0 ACSR &4/0 ACSR	40.0	Line Rebuild	266 ACSR	$ 2,699,000
60683 MINNVAL8 60684 YELLOWMED8 1	XCEL	15.9	69	4/0 ACSR & 2/0 CU	34.0	Line Rebuild	266 ACSR	$ 4,388,000
60728 FRANKLN8 60771 REDWOODFLTG 1	XCEL	16.0	69	2/0 ACSR	24.0	Temperature Upgrade	2/0 ACSR	$ 320,000
60730 ARLINGTON8 60731 GREENISLE8 1	XCEL	5.8	69	2/0 CU	34.0	Line Rebuild	336 ACSR	$ 1,601,000
60751 SAUKCMU8 62820 WEST UNION8 1	XCEL	9.9	69	3/6CU 2/0ACSR 4/0ACSR	39.6	Line Rebuild	266 ACSR	$ 4,042,000
34137 TRIBOJI5 66563 SPENCER5 1	ITC	18.8	161	636 ACSR	195	Temperature Upgrade	636 ACSR	$ 376,000
34423 MONONA_8 68748 POST 1	ITC	5.77	69	4/0 ACSR	28	Temperature Upgrade	4/0 ACSR	$ 115,000
34671 KLEMME 8 63727 HANCOCK8 1	ITC	6.3	69	266 ACSR	36	Line Rebuild	336 ACSR	$ 2,274,000
36242 SHEFFLD8 63731 HAMPTON8 2	ITC	14.14	69	3/0 ACSR	41	Line Rebuild	336 ACSR	$ 3,903,000
36242 SHEFFLD8 63774 SHEFFLD5 1	ITC	XFMR	161/69	N/A	84	Transformer Upgrade	90 MVA	$ 1,984,000
36421 ZION ; R 38849 PLEASANT PRAIR2 1	ATC		345	N/A	2000	New Bain-Zion 345 kV (6 miles)	2-954 ACSS	$ 18,000,000
37384 ZION ; 39362 LAKEVIEW 1	"	"	"	"	"	"	"	"
38141 NST 69 38142 STM 69 1	"	"	"	"	"	"	"	"
38364 SGL 69 39242 SGL 138 1	ATC	XFMR	138/69	N/A	70	Transformer Upgrade	75 MVA	$ 1,665,000
38590 SHOTO 39641 SHOTO 1	ATC	XFMR	138/69	N/A	72	Transformer Upgrade	75 MVA	$ 1,665,000
39033 DAR 138 39036 NOM 138 1	ATC	25.6	138	266.8 ACSR 26/7	105	Line Rebuild	477 ACSR	$ 10,599,000
39328 GRANVL 6 91318 GRANVL3 1	ATC	XFMR	345/138	N/A	478	2nd 478 MVA Transformer	478 MVA	$ 23,236,000
39345 KENOSH45 39362 LAKEVIEW 1	ATC	5.0	138	477 ACSR	288	Line Reconductor	477 ACSS	$ 860,000
39901 COC DPC 68843 T TC 1	DPC	3.79	69	795ACSR &4/0ACSR	47	Line Rebuild	795 ACSR	$ 802,000
58190 HOPE MD8 63719 HOPE 5 1	ITC	XFMR	161/69	N/A	84	Transformer Upgrade	90MVA	$ 1,984,000
58190 HOPE MD8 63720 HOPE 8 1	"	"	"	"	"	"	"	"
60104 CANNONFLS7 60801 CANFLSTR8 1	XCEL	XFMR	115/69	N/A	112	Transformer Upgrade	115 MVA	$ 1,727,000
60104 CANNONFLS7 60801 CNFLSTR8 2	XCEL	XFMR	115/69	N/A	112	Transformer Upgrade	115 MVA	$ 1,727,000
60184 APACHET7 60185 ARDENHILLS7 1	XCEL	5.4	115	477 ACSR &2312 AL	210	4.1M of 477 to 2312	2312 AL	$ 3,001,000
60190 BLACK DOG7 60258 WILSON 7 1	XCEL	4.5	115	795 ACSR	239	Line Rebuild	795 ACSS	$ 2,403,000
60307 JACKSON5 60966 JACKCO 8 1	XCEL	XFMR	161/69	N/A	47	Transformer Upgrade	50 MVA	$ 1,275,000
60321 HYDROLN7 61006 WISSOTAG 1	XCEL	XFMR	115/69	N/A	48	Transformer Upgrade	50 MVA	$ 1,275,000
60823 REDWING8 62387 SPRINGCREEK8 2	XCEL	4.6	69	477 ACSR &1250 AL	92.4	Line Rebuild	795 ACSR	$ 1,845,000
STONE LAKE, 60 MVAr Fast Swi Capacitor	XCEL	N/A	345	N/A	N/A	Capacitor Addition	N/A	$ 5,000,000
A.S. KING - Two 345 kV Breakers	XCEL	N/A	345	N/A	N/A	Breaker Addition	N/A	$ 2,000,000
								$ 121,075,000

Table 35 – DRG Phase II Cost Analysis Summary

DRG II - Cost Analysis Summary

Zone	Site Name	Single Site-Cost to achieve 40 MW	Zonal-Cost to achieve 200 MW
NW	Compton	$ 3,739,000	$ 15,089,000
	Moranville	$ 14,964,000	
	Nashua Tintah	$ 23,028,000	
	Osage	$ 5,713,000	
	Parkers Prairie	$ 5,505,000	
	Shooks	$ 4,684,000	
	Stafford	$ 15,795,000	
	Williams	$ 26,583,000	
NE	Bena	$ 22,112,000	$ 31,378,000
	Pine Lake	$ 19,539,000	
	Dewing	$ 18,000,000	
	Hubbard	$ -	
	National	$ 19,354,000	
	Palmer Lake	$ -	
	Verndale	$ 18,000,000	
	West Union	$ 20,588,000	
WC	Albany	$ -	$ 376,000
	Benton	$ -	
	Big Swan	$ -	
	Crooks	$ 2,814,000	
	Douglas County	$ -	
	Fiesta	$ -	
	Glenwood	$ -	
	Hutchinson Plant1	$ -	
	Willmar Muni	$ 1,849,000	
SW	Granite Falls	$ -	$ 24,818,000
	Hardwick	$ -	
	Holland	$ 3,438,000	
	Ivanhoe	$ -	
	Lake Sarah Tap	$ 18,324,000	
	Lyon County	$ 10,744,000	
	Milroy	$ 11,680,000	
	Walnut Grove	$ 13,836,000	
SE	Altura	$ -	$ 25,153,000
	Elgin	$ -	
	Harmony	$ -	
	Henderson	$ 5,086,000	
	St. Charles Tap	$ -	
	Wabaco	$ 5,443,000	
	Whitewater	$ 6,472,000	

Statewide-Cost to achieve 600 MW
$ 121,075,000

In the single site, zonal and statewide analyses, the DRG caused overloads in the eastern Wisconsin transmission system. According to Midwest ISO study procedures these overloads met the criteria which would require mitigation before the interconnection of the generation. Specifically, the major overload was the 345 KV transmission line that runs from Zion, Illinois to Pleasant Prairie, Wisconsin and the solution, as identified by the transmission owner, is a new Bain – Zion 6 mile transmission line of the 345 kV class which is estimated to cost $18 million. The study team found that this project had to be included in the underlying case in order for the model to identify potential zonal and single sites.

Even though this study was charged by the statute to identify transmission costs required to facilitate the 600 MW of DRG locations, this study makes no attempt to address the allocation of or responsibility for such costs. These costs may or may not be allocated to the generation developers. There may be multiple drivers for the transmission improvement projects listed above including reliability, load serving, other generator projects. Each generation developer contemplating a DRG project at any location should first work with the local transmission provider and the Midwest ISO to discuss potential transmission cost impacts for developer's project.

All the projects assumed to be in the base case would need to be in-service in addition to those listed in this cost analysis section.

The unit cost estimates for the various system fixes and upgrades are also shown in Appendix F.

J. DRG Sensitivity Analysis

The study team attempted to conduct a sensitivity analysis in order to gain insight as to what may happen to the DRG outlet capability should more generation already in the Midwest ISO queue be placed in service than was included in the study models. The study team conducted a DC FCITC analysis similar to the grid expansion sensitivity by looking at the outlet potential of 132 DRG sites both with and without more prior queued generation added to the system. The results did not show a consistent pattern of increased or decreased outlet capability which made it impossible to draw a useful conclusion to the analysis. Part of the problem with the analysis was that if more prior queued generation were added to the system, more than likely transmission upgrades would be needed that are not known at this time. Therefore, the TRC decided to abandon this sensitivity and focus on other more useful analysis. Therefore, no results from this analysis are included in this report.

VII. DRG Integration Issues

As stated before, DRG developers are encouraged 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 websites 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 Midwest ISO members must be approved by Midwest ISO 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 Midwest ISO's Contingency Reserve Sharing Group (CRSG) must demonstrate reliable generating capacity capability. This is accomplished through the applicable generation accreditation processes. The GRSP handbook is located at: http://www.mapp.org/DesktopDefault.aspx?Params=454b040717565c79401a0c0b7b61564300000003c3 Producers adding generation will most likely be responsible for the cost of all study work performed by the utility required to obtain these approvals. The details on the MAPP requirements can be found in the MAPP Policies and Procedures manual at the same link as shown above and the Midwest Reliability Organization requirements can be found at http://www.midwestreliability.org and the Midwest ISO requirements can be found at http://www.midwestiso.org/page/Generator+Interconnection.

Utilities in Minnesota that are members of Midwest ISO are governed by the Midwest ISO Open Access Transmission Tariffs (OATT) while utilities that are not Midwest ISO 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, Midwest ISO, NERC and FERC to ensure that the most up-to-date procedures are used in the project design, operation and maintenance requirements.

Voltage analysis was not done as a part of the DRG Phase II study but voltage analysis would be a part of any interconnection study, whether it was performed by the Midwest ISO, any other independent transmission system operator or an individual utility. A voltage study might identify the need to add voltage or reactive support devices to address interconnection issues.

Although this study makes no attempt to address allocations of or responsibility for transmission costs, the following are offered strictly for information to show examples of interconnection costs that may (or may not) be borne by the power producer (this is not an all inclusive list):

- Study analyses, including stability and short circuit, 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 (facility studies).
- 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 interconnection facilities for which the producer will be responsible.
- 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.

VIII. Midwest ISO Interconnection Process

DRG projects that connect to the transmission system may still need to enter the Midwest ISO generation 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. There may also need to be 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
(prepared by Durgesh Manjure, Midwest ISO)

A. INTRODUCTION

In the report documenting the findings of the Phase I analyses of the DRG study, a brief description of the Midwest ISO Generator Interconnection Queue process was provided. At the time (Summer 2008), the Midwest ISO was preparing to file the Tariff language for reforming the Interconnection Queue Process at FERC, and the write-up included a brief background of the queue situation and a comparison of the then existing (under FERC Order 2003) interconnection process and the proposed, reformed queue process, intended to bring forth the salient differences in the two paradigms.

The primary driver for the queue reform was the growing backlog and the need to identify solutions to reduce cycle time and increase certainty through the generator interconnection process.

It was hypothesized that the following high-level factors were contributing to the queue logjam:

- 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
- 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

Fig. 1 below graphically depicts the interconnection requests (MW) in the Midwest ISO queue by year and fuel type. It is interesting to overlap this graph with the Queue reform/transition timeline. FERC approved the queue reform proposal in August of 2008, and there was a 60-day transition period before the new procedures were made effective.

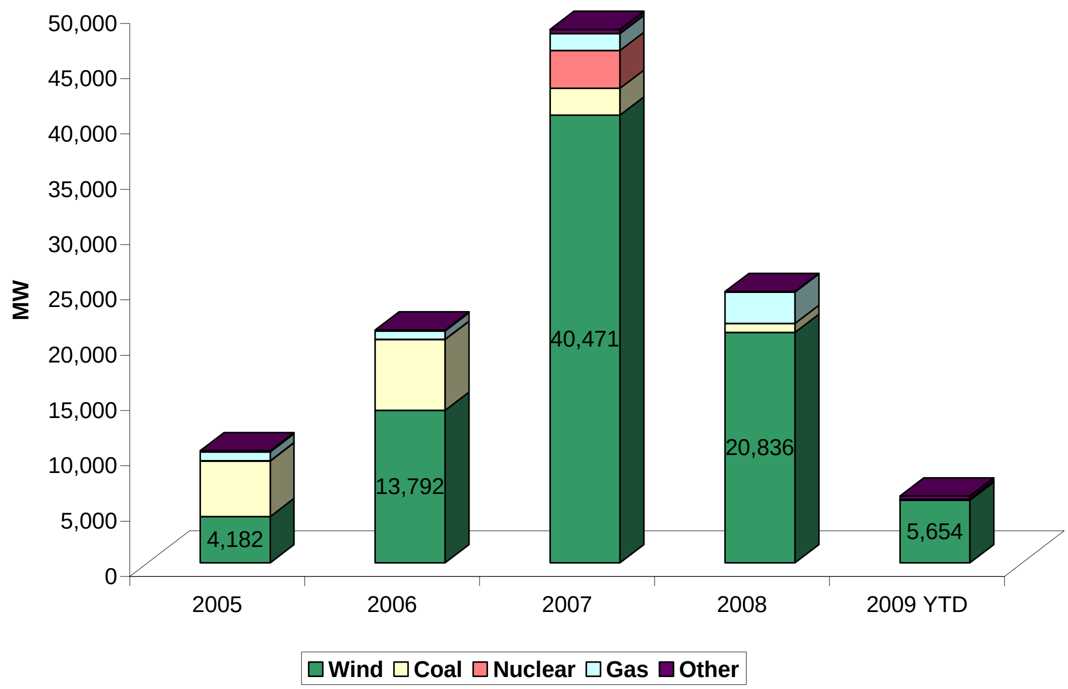


Fig.1. Midwest ISO interconnection queue MW statistics by Year and Fuel type (Wind MWs are noted).

In response, the Midwest ISO initiated the queue reform effort through the Interconnection Process Task Force (IPTF), and filed the resulting Tariff language at FERC in June 2008. The reformed generation interconnection procedures were accepted by FERC in August 2008.

The following are the highlights of the new generator interconnection process:

I. Formalized the Pre-Queue Process

II. Paradigm shift

- Creation of a *"fast-lane"* for projects that are in areas with relatively less constrained transmission
- Transition from a *"first-in, first-served"* approach to *"first-ready, first-served"* as demonstrated through the achievement of specific milestones

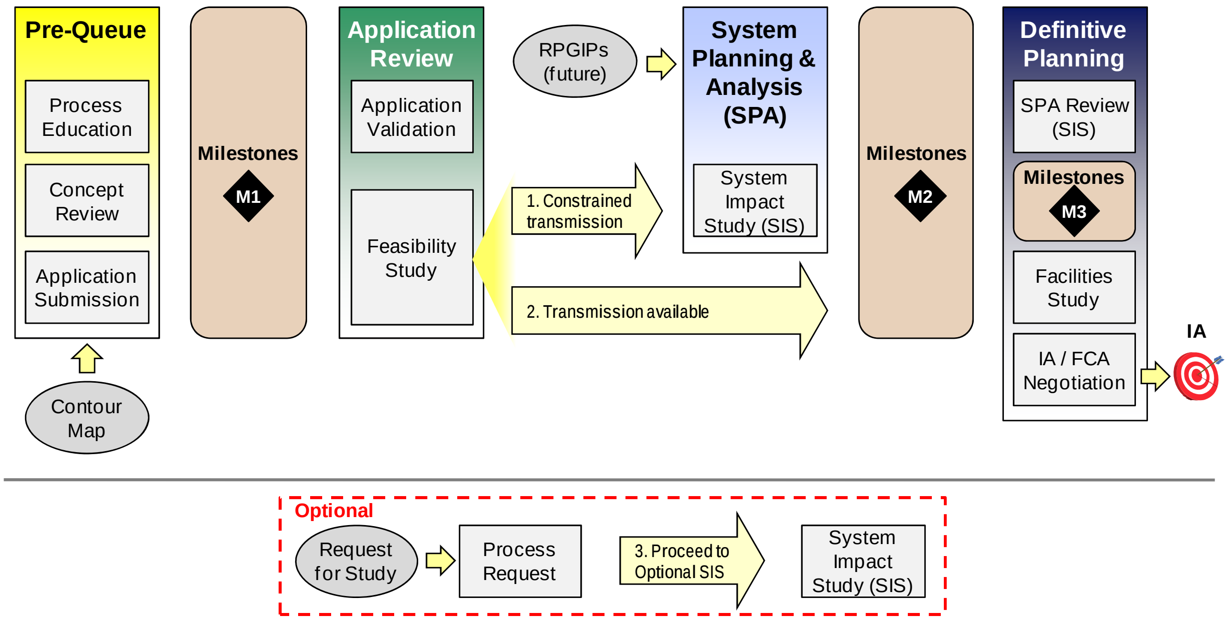
III. Up-front deposit for all studies based on the project size

IV. Elimination of the ability to suspend projects for economic reasons

The subsequent sections provide a high-level summary of the new queue process and some queue statistics, intended to broadly show the impact of the queue reform on the queue itself, and provide some information about projects in the queue that would qualify as Dispersed Renewable Generation (DRG).

1 THE NEW GENERATOR INTERCONNECTION PROCESS

The new Generator Interconnection process has many steps that are similar to the current queue process. In particular, the actual reliability studies performed under the new process are the same, and are performed in a similar manner (from a technical perspective). 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 aforementioned addition of a “fast lane.” The new process is graphically depicted ahead in Fig. 2.

Fig.2. The new Midwest ISO Generator Interconnection Process

As shown above, the new Generator Interconnection Process is divided into four phases:

– Pre-Queue Phase
– Application Review Phase
– System Planning & Analysis Phase
– Definitive Planning Phase

The **Pre-Queue Phase** is designed to facilitate dialogue between the Midwest ISO and potential Interconnection Customers in order to have customers be as prepared as possible when entering the queue.

The **Application Review Phase** is where the interconnection application is validated and the Feasibility Study is performed. The Feasibility study is no longer optional (as it used to be in the old process), and is much more significant, as the results of this study determine the path the request takes (slower lane (SPA) or the faster lane (DPP)) through the interconnection process.

System Planning & Analysis (SPA) is where analyses similar to the System Impact Study are performed. Projects that are likely to require major transmission improvements have to go through the SPA phase.

The **Definitive Planning Phase** (DPP) involves performing full system impact studies for projects that directly enter this phase (fast lane) or performing a review of the SPA study. Depending upon the extent of changes in the SPA study while entering the DPP, the SPA review could either be a quick review with no study work, or could potentially entail a complete SIS rerun. In addition, the Facilities studies are also performed under the DPP. The Generator Interconnection Agreement & Facilities Construction Agreement negotiation work is included in the DPP as well.

2. INTERCONNECTION QUEUE STATISTICS

Post-transition

As part of the transition to the new process, Midwest ISO performed transition feasibility analyses on a majority of projects active in the queue to determine which path (SPA or direct DPP) the projects would take under the new process. Projects that were beyond the system impact studies completion stage at the time of transition were excluded from these analyses. Fig. 3 below shows the split up of the queue post-transition, based on the study status and feasibility analysis results.

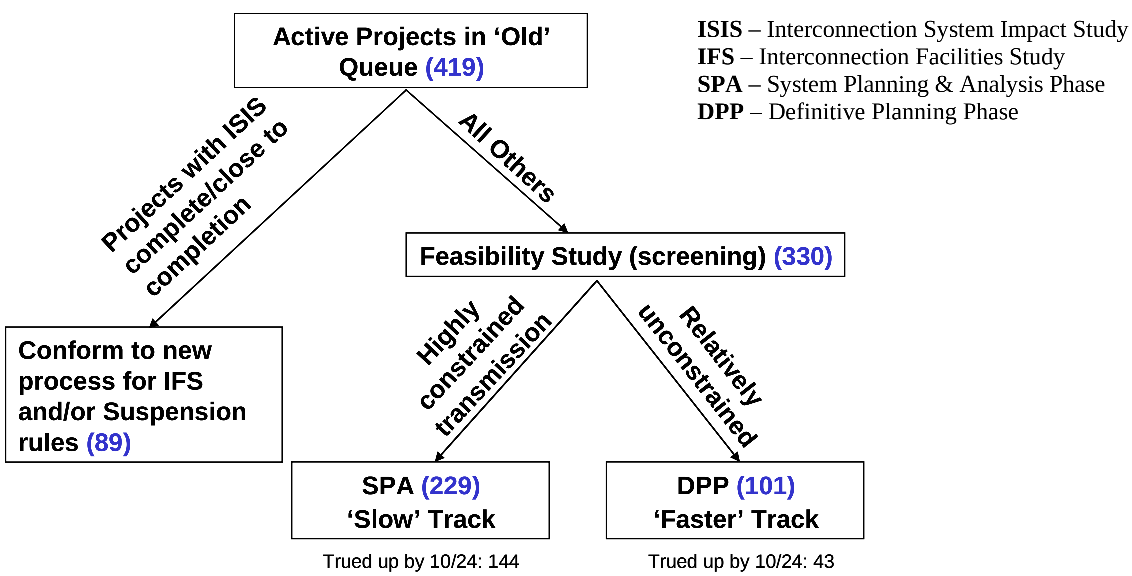


Fig.3. Queue break-up after transition feasibility analyses (number of projects are in parenthesis)

Fig.4. below shows the trend in the queue since August 2008, when the FERC Order on the new process was received. It is interesting to note that since then, almost 19,000 MW worth of requests have dropped out of the queue!

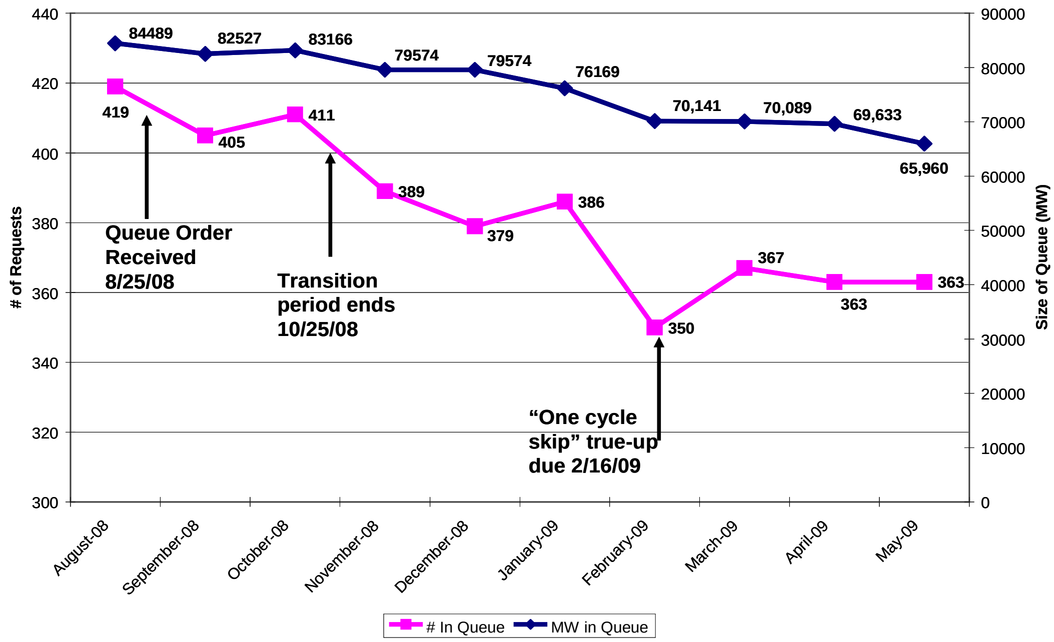


Fig.4. Queue progression since acceptance of new procedures

Figs. 5 & 6 further qualify the trend shown above in Fig. 4 and show the projects that have entered and withdrawn from the queue respectively (cumulative MW by state and fuel type) since August 2008. All numbers from hereon are current as of early July 2009.

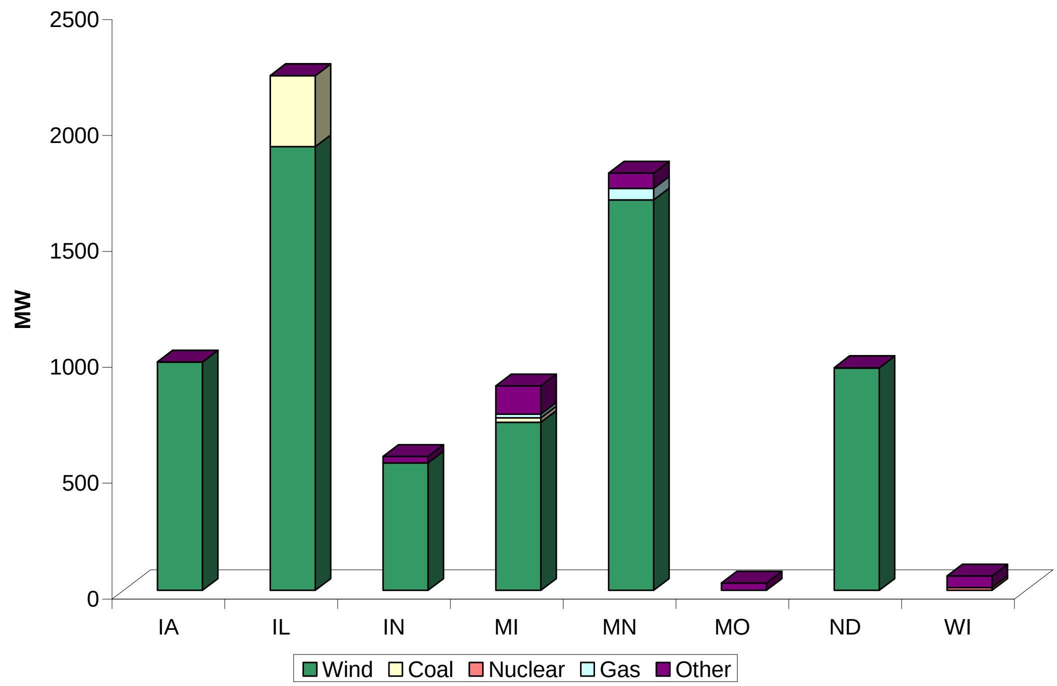


Fig.5. Projects that entered the queue since the new process was approved

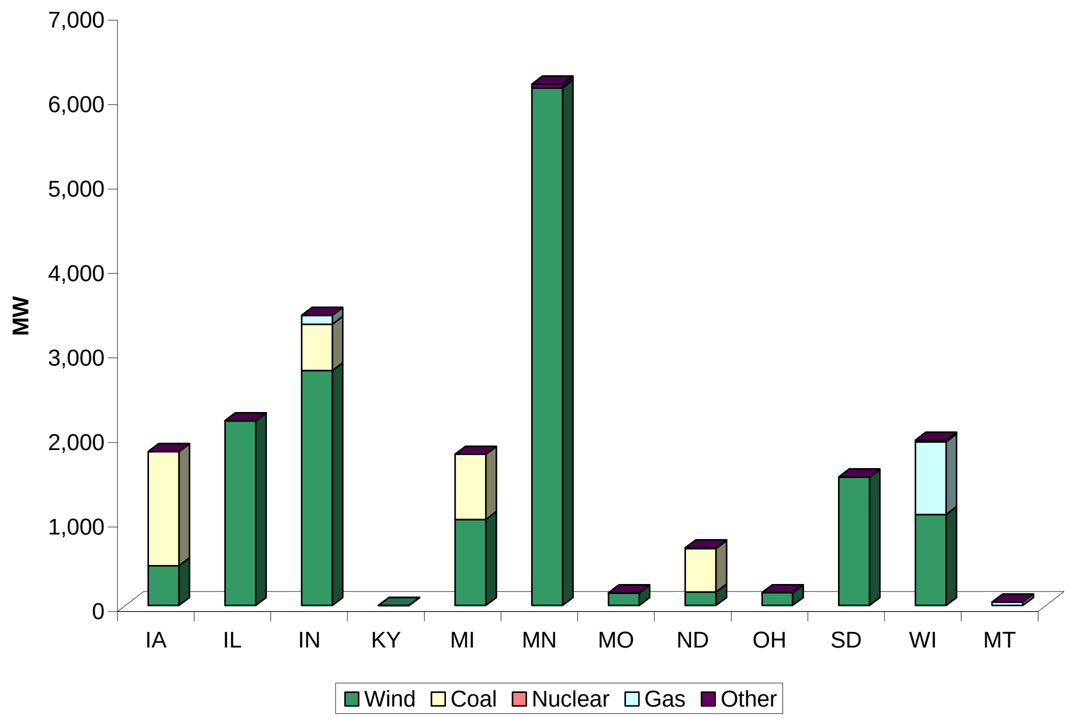


Fig.6. Projects withdrawn from the queue since the new process was approved

Finally, Fig. 7 ahead shows the active projects (cumulative MW) in the queue by state and fuel type. As a testimony to the tremendous wind resource in the

Midwestern US, it is observed that requests for proposed wind generation exceedingly dominate the queue composition.

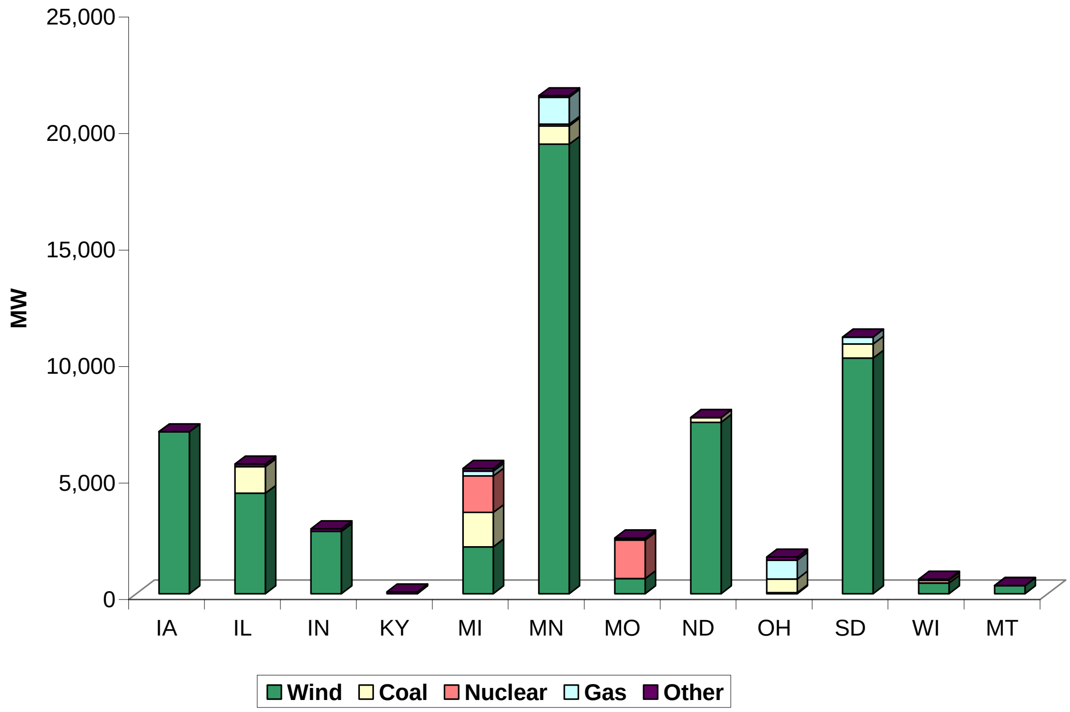


Fig.7. Cumulative MWs currently active in queue, by state and fuel type

2. Requests in Queue eligible to qualify as Dispersed Renewable Generation

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 Midwest ISO interconnection queue was filtered using this guideline, to get a feel for how many projects qualifying as DRG are already being studied through the MISO GI process. Figs.8-9 graphically represent these projects. Fig.8. shows the break-up of the requests (by cumulative MW), classifying the projects according to the stage where they are at in the study process. Fig.9 shows the geographic location of these projects. The various categories referred to in Fig. 8 are as follows:

1. **SPA**: These projects are in the System Planning & Analysis phase of the GI process and system impact studies to determine required transmission improvements are not yet completed.
2. **DPP – SIS**: These projects are at the SPA review stage in the Definitive Planning Phase of the GI process and planning analyses to determine required transmission improvements are not yet completed.
3. **DPP – FaS**: These projects are under the Facilities study stage in the DPP. Planning analyses have been completed and detailed

engineering work on the required transmission improvements is ongoing

4. **Done**: This category indicates that the project has completed the study process and has successfully achieved a generator interconnection agreement (GIA).

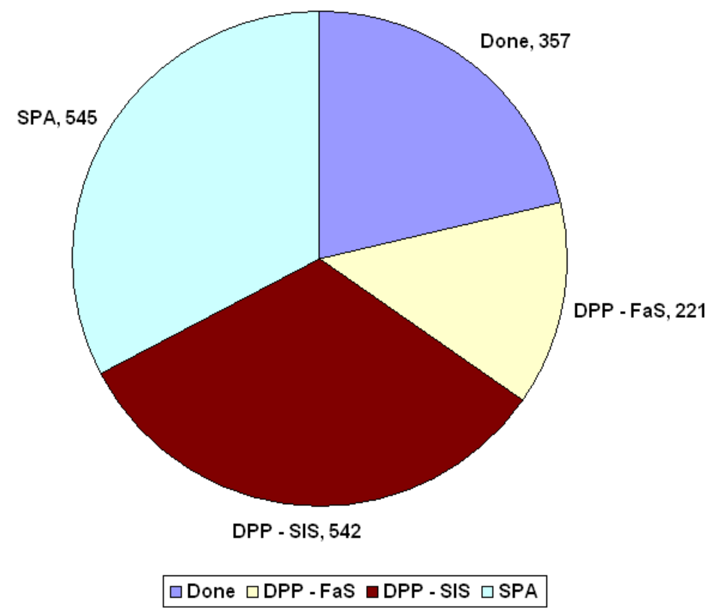


Fig.8. Breakup of MN Renewable Energy Standard eligible generation projects (wind, biomass, solar) in the queue between 10 and 40 MW, by study status (cumulative MW)

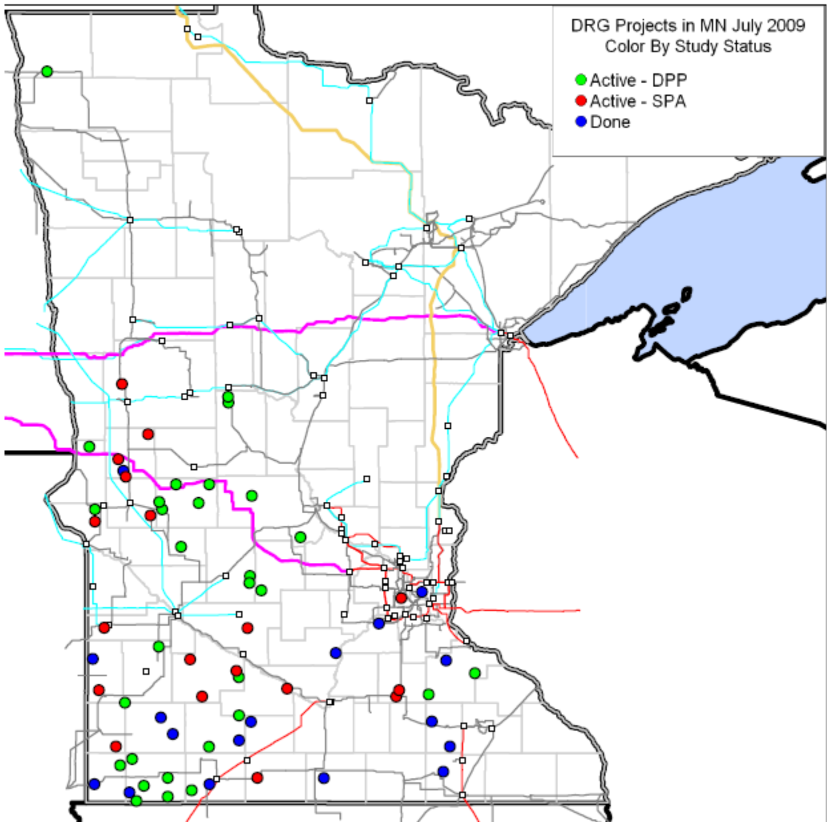


Fig.9. Location of MN Renewable Energy Standard eligible generation projects (wind, biomass, solar) in the queue between 10 and 40 MW as of July 2009

References:

[1] Midwest ISO Transmission and Energy Market Tariff Attachment X – Generator Interconnection Procedures, [Online] Midwest ISO Website, http://www.midwestmarket.org/publish/Document/25f0a7_11c1022c619_-7d600a48324a

[2] Business Practices Manual for Generator Interconnection Procedures [Online] Midwest ISO Website, http://www.midwestmarket.org/publish/Document/45e84c_11cdc615aa1_-7e010a48324a

[3] Generator Interconnection Study & Agreement Jurisdiction Within the Midwest ISO Footprint, [Online] Midwest ISO Website, http://www.midwestmarket.org/publish/Folder/3b0cc0_10d1878f98a_-7e1c0a48324a

[4] Midwest ISO Generator Interconnection Interactive Queue, [Online] Midwest ISO Website, http://www.midwestmarket.org/page/Generator+Interconnection+Queue

[5] Midwest ISO Generator Interconnection Planning page, [Online] Midwest ISO Website, http://www.midwestmarket.org/page/Generator+Interconnection

IX. DRG Phase II Study Conclusions

The DRG Phase II study team analyzed the process and findings from DRG Phase I, built upon that foundation, and updated the assumptions and methods to conduct the DRG Phase II study. Public input, TRC guidance, and DRG study team findings and experience influenced the DRG Phase II decisions regarding assumptions and methodology. This collaboration resulted in a thorough, high quality study. The changes from DRG Phase I to DRG Phase II influence the study findings.

For the year 2013, even after adding these additional numerous and significant transmission improvements, the model still provides very limited opportunities for DRG to connect without additional transmission upgrades and the associated costs. One significant finding was that while placing 600 MW of DRG in Minnesota, widespread regional transmission limiters were found both inside and outside of the state. Minnesota generation is dependent on regional solutions to enable the greater system to operate reliably and efficiently in the wider Midwest ISO market. Examples of these regional limiters include high voltage transmission lines in Wisconsin, Illinois and Minnesota.

As stated above, the study shows that the statewide dispersion of 600 MW of additional DRG is not possible without encountering significant limiters unless the system is upgraded. In fact, there were 34 local and regional transmission facility limitations found in this scenario as well as two facility additions as identified in the stability analysis that are necessary for a statewide DRG level of 600 MW. In the single site analysis, 16 of the 40 sites had potential outlet capabilities of at least 40 MW. This single site analysis did not attempt to examine generation levels beyond 40 MW. The remaining 24 sites had generation outlet capabilities ranging from zero to 35 MW. The zonal analysis found the maximum generation outlet capability to be 50 MW in both the Northwest and West-Central zones with the remaining zones having outlet capabilities of 40 MW. The maximum statewide generation outlet capability without additional facility upgrades was determined to be 50 MW, which is the maximum generation outlet capability found in the zonal analysis.

The study team identified the necessary system upgrades and associated costs to remedy the limiters. The statewide total to implement all the system upgrades necessary to achieve 600 MW of DRG in Minnesota is just over $121 million. This project cost total includes a new 345 kV transmission line from Bain substation, Wisconsin to the Zion Energy Center, Illinois. The impact of this new transmission line is $18 million of the total $121 million estimated cost for all the system upgrades.

Even though this study was charged by the statute to identify transmission costs required to facilitate the 600 MW of DRG locations, this study makes no attempt to address the allocation of or responsibility for such costs. These costs may or may not be allocated to the generation developers. There may be multiple drivers for the transmission improvement projects listed above including reliability, load serving, other generator projects. Each generation developer contemplating a DRG project at any location should first work with the local transmission provider and the Midwest ISO to discuss potential transmission cost impacts for developer's project.

The 2013 transmission model for this Phase II study found that the State's transmission system is already at its design capacity due to the number and size of the generation projects scheduled to be on-line by 2013. In response to stakeholder comments provided in Phase I, 7,000 MW of already queued generation was added to the DRG Phase II base case transmission and generation models to provide a more realistic representation of new generation that may come on line by 2013 and use existing transmission capacity. **Any generation developer seeking to site a new generator at any of the identified sites within this study would have to submit a request behind the projects that are already in the interconnection queue.**

Given the congested nature of the 2013 base case model, some transmission upgrades may be needed to address overall transmission system limiters in the base case, prior to adding any new generation. From this starting point, the task of identifying additional DRG opportunities becomes more difficult. Connecting new generation of any type further reduces any outlet capacity available in the local area where the generation is placed and causes more stress to the transmission system. The type of generation is not a critical factor when considering the difficulty of siting additional generation on a strained transmission system.

The stability analysis of an additional 600 MW of DRG under the Phase II assumptions reveals the need for additional voltage and reactive power support facilities in eastern Minnesota and northwestern Wisconsin. DRG projects may not be entirely responsible for these voltage and reactive additions, but they may be asked to participate financially in those upgrades.

One difference between the DRG Phase I results and DRG Phase II results is the absence of the Dorsey Transformer issue in DRG Phase II. The DRG Phase II study team and the TRC modified some of the assumptions and analysis methods used in DRG Phase I. One change was opening up some of the criteria like using the emergency rating (rate B) in Phase II rather than the normal rating (rate A) in Phase I to identify constraints. Another threshold that was loosened was changing the distribution factor cutoff from 3% in DRG Phase I to a 5% cutoff in DRG Phase II which had affected the Dorsey transformer. The requirement for adding several assumed transmission lines also created transmission flow changes that reduced the load on the Dorsey transformer. These transmission lines include the Twin Cities to Brookings County, South Dakota line and the Bemidji to Grand Rapids, Minnesota line and the St. Cloud to

Monticello line. Use of Midwest ISO market sink increases flow south and east of Minnesota and thereby not causing as much loop flow on the Dorsey line. Operating assumptions also changed during the time between DRG Phase I and DRG Phase II study work. Also, after the DRG Phase I report was released and the public provided feedback, one comment the DRG study team received was the recommendation to ignore the Dorsey Substation Issue.

The capacity identified through this study for DRG prospective sites reflect an analysis at a point in time. The generation projects presently moving through the Midwest ISO generation interconnection queue and other utility generation interconnection queues could (and likely will) occupy these sites and use the identified outlet capacity. This study represents a high level analysis and does not exactly replicate a site-specific interconnection study and facility study such as those performed by the Midwest ISO. As a result, differences in a site-specific interconnection assumptions and analysis may be found.

DRG Phase II study assumptions are based on public comments and the combined input and knowledge of the TRC and study team. Changing any assumptions impacts the study results. This collaborative process resulted in these findings which collectively present a reasonable, knowledgeable study. The generation projects presently moving through the Midwest ISO generation interconnection queue and other (non-Midwest ISO) utility generation interconnection queues could occupy these sites or utilize the transmission capability of these sites.

Definition of Terms

Alternating Current (AC): An electric current that reverses direction in a circuit at regular intervals.

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.

Direct Current (DC): An electric current that flows in one direction.

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 during a particular system topology. 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."

Generation Interconnection Agreement (GIA): A GIA is a three-party agreement between the interconnection customer, the transmission owner where the proposed generator is planning to interconnect and the Midwest ISO. A generator with a signed GIA would mean that the generator has successfully achieved the generator interconnection agreement with the Midwest ISO and the interconnecting transmission owner.

Impedance: A measure of opposition to a sinusoidal alternating current (AC). Electrical impedance continues the idea of resistance to AC circuits, describing not only the relative amplitudes of the voltage and current, but also the relative phases. When the circuit is driven with direct current (DC) there is no distinction between impedance and resistance.

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

Midwest ISO Generation Interconnection Queue: The Midwest ISO generation interconnection queue is the process to get a generation interconnection agreement from Midwest ISO to put power on the region's electric transmission system.

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

NDEX: The North Dakota Export (NDEX) interface flow the NDEX is the sum of the MW 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) > 5%.

Sink: The generation sink is the existing power generation in a system that is assumed to be turned down when new source generation is put on line. To keep an electrical system balance the magnitude of the 'source' is equal to that of the 'sink' plus the losses in the electrical system.

Source: The generation sink is the new electrical generation added to the system.

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.