BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE PETITION FOR CERTIFICATES OF NEED FOR THREE 345 kV TRANSMISSION LINE PROJECTS WITH ASSOCIATED SYSTEM CONNECTIONS

Docket No. ET2,E002 et al./CN-06-1115

DIRECT TESTIMONY AND EXHIBITS OF HWIKWON HAM

ON BEHALF

OF THE MINNESOTA OFFICE OF ENERGY SECURITY

MAY 23, 2008

DIRECT TESTIMONY OF HWIKSON HAM
IN THE MATTER OF APPLICATION FOR CERTIFICATES OF NEED FOR THREE 345 KV TRANSMISSION LINE PROJECTS WITH ASSOCIATED SYSTEM CONNECTIONS

DOCKET NO.ET2,E002, et al./CN-06-1115

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I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Hwikwon Ham. I am a Public Utilities Rates Analyst with the Office of Energy Security (OES).

Q. Please state your business address.

A. My business address is 85 7th Place East, Suite 500; St. Paul, Minnesota 55101.

Q. What is your educational and professional background?

A. A summary of my qualifications is included as OES Exhibit No. ___ (HKH-01).

II. PURPOSE AND STRUCTURE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. My testimony addresses two subparts of Certificate of Need (CoN) criteria established in Minnesota Rules part 7849.0120. Specifically, I consider:

- 7849.0120 A(1) the accuracy of the applicant's forecast of demand for the type of energy that would be supplied by the proposed facility; and
- 7849.0120 C(1) the relationship of the proposed facility, or a suitable modification thereof, to overall state energy needs.

Also, my testimony addresses Minnesota Statue Section 216B.243, Subd. 3 (9) with respect to a high-voltage transmission lines, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota.

Q. Please describe the structure of your testimony.

A. First, I note that OES witness Dr. Steve Rakow describes the background of this filing, including a description of the proposed project (Project) and the Applicants. I do not repeat that background information here. Second, my testimony addresses the above issues in two parts. The first part discusses the Project's expected overall impacts on the State of Minnesota's (State) energy and capacity needs (which I refer to as "energy need" in this testimony) and regional and local reliability. The second part discusses the reasonableness of Applicants' demand forecast used in engineering studies. Also, I discuss the reasonableness of generation interconnection need based on Applicants' energy and demand need forecast.

III. REGIONAL TRANSMISSION NEED AND PLANNING

Q. Does OES participate in discussions and policy matters concerning regional transmission planning?

A. Yes. The OES does so in various ways. First, OES is involved in the Midwest Independent System Operator (MISO)'s transmission planning process by following/participating in MISO's various workgroups such as Loss Of Load Expectation (LOLE) Working Group, MISO Transmission Expansion Planning (MTEP) workgroup, Joint Coordinated System Plan (JCSP) workgroup and Regional Generation Outlet Study (RGOS) and Narrowly Constrained Area Study (NCA) workgroups. Second, OES has begun holding meetings with the acting Reliability Administrator and stakeholders to discuss regional planning issues. Third, OES helped to create the MISO Quarterly Update Meeting that Minnesota utilities are required to host and participate in, to which

MISO and others are invited; OES actively comments on current topics in these meetings. Fourth, in all of the above forums, OES also discusses the effects of regional planning or lack of regional planning on energy costs and expected reliability in Minnesota.

Q. Please provide your role in OES's participation in regional transmission planning.

A. I am one of the OES staff members following the above-mentioned processes. Regarding the MISO, MTEP and JCSP workgroups, for example, as a participant I closely follow the topics covered in the workgroups, analyze the materials covered in the workgroup meetings, consider whether the issues covered in the materials are in Minnesota ratepayers' interest, and provide opinions to the workgroups to reflect Minnesota ratepayers' interest.

Q. Why does OES's participation in regional transmission planning provide a protection to Minnesota ratepayers' interest?

A. OES's participation in regional transmission planning positively influences Minnesota utilities to provide reliable and efficient electric service at reasonable prices to Minnesota ratepayers. While, to some extent, utilities have an incentive to provide such service, their incentives are not always fully aligned with ratepayers' interests or with neighboring utilities. Moreover, as the electrical system is regional in nature, the incentives of utilities in other states may not be fully aligned with Minnesota ratepayers' interests. OES has a role of helping ensure that Minnesota ratepayers' interests are represented.

Q. How does OES's participation in regional transmission planning positively influence Minnesota utilities to provide reliable, efficiently-delivered electricity at reasonable price to Minnesota ratepayers?

A. By maintaining appropriate interstate transmission capability, Minnesota utilities can provide reliable and reasonably priced energy to Minnesota ratepayers. Since 2005, all of Minnesota's four investor-owned utilities and many of Minnesota's municipal and cooperative utilities have been participating in MISO's energy market. Even though Minnesota ratepayers do not see the utilities' daily energy market activity and electricity price fluctuation, the daily electricity price in the MISO energy market eventually influences Minnesota ratepayers' electricity bills since most of Minnesota utilities trade electricity in the MISO energy market.[1] In fact, a big part of Minnesota ratepayers' monthly electricity bill can be heavily influenced by the MISO electricity market.

Further, the electricity market activity will be influenced by activity in the MISO's regional planning process. For example, if Minnesota has a shortage of transmission capability to import electricity from other states due to lack of long-term transmission projects such as CapX2020 and a shortage of generation capability, Minnesota utilities could pay high prices to buy electricity from the market. Therefore, in the long run, appropriate regional transmission planning and projects are crucial to ensuring reasonable electricity prices for Minnesota ratepayers. Thus, OES's participation in crucial regional planning, along with advocating on behalf of Minnesota ratepayers' interests in the planning process, will protect Minnesota ratepayers' interests.

[1] Minnesota utilities charge monthly energy related cost to their ratepayers through the automatic Fuel Clause Adjustment. Therefore, if a utility pays high prices to buy this month's electricity from the MISO energy market, ratepayers will pay the increased cost within one or two months.

I note that these are the roles the OES has had for years, and continues to have, as indicated by Minnesota Statutes 216A.085, which states:

> **216A.085 ENERGY ISSUES INTERVENTION OFFICE.** Subdivision 1. **Creation.** There is created within the Department of Commerce an Intervention Office to represent the interests of Minnesota residents, businesses, and governments before bodies and agencies outside the state that make, interpret, or implement national and international energy policy.
>
> Subd. 2. **Duties.** The Intervention Office shall determine those areas in which state intervention is most needed, most likely to have a positive impact, and most effective for the broad public interest of the state. The office shall seek recommendations from appropriate public and private sources before deciding which cases merit intervention.
>
> Subd. 3. **Staffing.** The Intervention Office shall be under the control and supervision of the commissioner of commerce. The commissioner may hire staff or contract for outside services as needed to carry out the purposes of this section. The attorney general shall act as counsel in all intervention proceedings.

Q. How does OES's participation in regional transmission planning further positively influence Minnesota utilities to provide reliable service to Minnesota ratepayers?

A. According to the U.S. Department of Energy, Energy Information Administration (EIA),[2] Minnesota imported 16 percent of its electricity through interstate transmission in 2006. The data shows that Minnesota has been, consistently, a net importer of electricity over the years (1990 to 2006) OES Exhibit No. ___ (HKH-02). Without these imports, Minnesota would be forced to build many new power plants in Minnesota which likely would result in higher prices for ratepayers. Conversely, if no further generation would be built, ratepayers would most likely pay higher prices dues to electricity shortages during high electricity usage time. OES's participation in regional transmission planning

[2] http://www.eia.doe.gov/cneaf/electricity/st_profiles/minnesota.html (Table 10. Supply and Disposition of Electricity, 1990 Through 2006 (Million Kilowatthours))

helps ensure that Minnesota utilities maintain adequate and reliable interstate transmission lines to provide reliable electric service.

Q. Was there a recent event showing the importance of interstate transmission lines?

A. Yes. On September 18, 2007, Minnesota's electrical system was almost separated from the rest of the electrical system due to transmission outages. OES Exhibit No. ___ (HKH-03) This "islanding" effect seriously jeopardize electricity reliability as the "islanded" area cannot be served by rest of the market. Unless "islanded" area has enough fast start units to meet the immediate energy need, utilities need to shed some or the entire existing loads in the area.

IV. RELIABILITY ANALYSIS

Q. Please define "reliability," "adequacy" and "security" as you refer to them in your testimony.

A. The planning standards of the North American Electric Reliability Council (NERC) define the reliability of the interconnected bulk electric systems using two terms, adequacy and security. NERC defines these two terms as follows:[3]

- **adequacy –** [H]aving sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. "Resources" refers to a combination of electricity generating and transmission facilities, which produce and deliver electricity; and "demand-response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand; and

[3] http://www.nerc.com/about/faq.html

- **security** – For decades, NERC and the bulk power industry defined system "security" as the ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Further, NERC defines the interconnected bulk electric systems as follows:

> There is no one definition, but NERC defines the bulk power system as the electric power generation facilities combined with the high-voltage transmission system, which together create and transport electricity around the continent. Put another way, the bulk power system is the continent's electricity system except for the local electricity facilities you see in your town or city. NERC does not deliver power directly to homes and businesses. That service usually is provided by a local utility of some kind. Local delivery is under the jurisdiction of state, provincial or local utility regulatory agencies.

Q. Please provide information about the ERO.

A. The NERC's website (http://www.nerc.com/about/) states that:

> Effective January 1, 2007, the North American Electric Reliability Council and the North American Electric Reliability Corporation merged, with NERC Corporation being the surviving entity. NERC Corporation was certified as the "electric reliability organization" by the Federal Energy Regulatory Commission on July 20, 2006.
>
> NERC's mission is to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization, NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

Q. Please provide information about the MRO.

A. The MRO's website (http://www.midwestreliability.org) states that:

> The Midwest Reliability Organization (MRO) is a voluntary association committed to safeguarding reliability of the bulk electric power system in the north central region of North America. In addition to being a member organization, the MRO is a Cross Border Regional Entity under the Energy Policy Act of 2005 (United States) and applicable jurisdiction in Canada.
>
> The essential purposes of the MRO are: (1) the development and implementation of regional reliability standards, (2) determining and enforcing compliance with those standards, including enforcement mechanisms, and (3) providing seasonal and long-term assessments of bulk electric system reliability. The MRO also provides other services consistent with its reliability charter.
>
> The MRO region includes more than forty organizations supplying approximately 280,000,000 megawatt-hours to more than twenty million people. The MRO membership includes municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO region spans nine states and two Canadian provinces covering roughly one million square miles.

Q. What is the Mid-Continent Area Power Pool (MAPP)?

A. Article 1 of the Restated Mid-Continent Area Power Pool Agreement[4] states:

> MAPP was established to operate as a regional reliability council and power pool to realize and further the reliability and other benefits of interconnected operations among a large number of entities engaged in the electric utility business in the MAPP Region. MAPP now functions to provide a reserve sharing pool and a regional transmission group. The regional transmission group provides for the comparable and efficient provision of transmission service on a consistent basis, to realize and further the benefits of coordinated regional transmission planning, and to resolve disputes over the provision of transmission services.

[4] http://www.mapp.org/assets/pdf/Restated%20Agreement%20Amendements/Restated%20Agreement%20(Oct%202006).pdf

Q. Please provide your general assessment of the State of Minnesota's energy and capacity needs.

A. The OES reviewed recently approved the Integrated Resource Plans (IRPs) from four investor-owned utilities (Northern States Power Company d/b/a Xcel Energy (Xcel)[5], Minnesota Power (MP)[6], Otter Tail Power Company (OTP)[7], and Interstate Power and Light Company (IPL)[8]) operating in the State. During the review the Department concluded that all of the utilities showed the likelihood of significant capacity and energy needs during the 2010 – 2015 timeframe. Also, Great River Energy filed its IRP[9] in 2005 and showed significant capacity and energy need during the same timeframe. Since the above five utilities serve the majority of customers in the State and all of them are likely to need capacity and energy during the 2010–2015 timeframe, I conclude that the State needs more capacity and energy during the 2010–2015 timeframe.

I further reviewed the *Mid-Continent Area Power Pool Load and Capability Report* (Report) issued on May 1, 2007[10] to confirm this conclusion with the most up-to-date information. The Report affirmed my conclusion on the general assessment of the State's energy needs during the 2010 –2015 timeframe.

Q. Why don't you provide specific numbers instead of a general assessment of the State of Minnesota's energy need?

A. There is information and numbers from the Report on capacity deficit/surplus in OES Exhibit No.___ (HKH-04). However, the type of energy needed (baseload, intermediate,

[5] Docket No. E002/RP-04-1752
[6] Docket No. E015/RP-04-865
[7] Docket No. E017/RP-05-968
[8] Docket No. E001/RP-05-2029

peaking) for each utility cannot be decided by simply checking the total energy need. Obtaining such specific numbers requires more complicated processes (involving, for example, cost minimizing generation expansion modeling) to evaluate the type of energy needed. Also, the evaluation of energy need is a utility-specific process since the analysis depends on a utility's existing generation fleet, purchase power contracts, fuel acquisition processes and procurement policies and processes to satisfy future needs. For utilities subject to the Commission's jurisdiction, this specific analysis occurs in integrated resource plans. My testimony references a number of relevant resource plan dockets above in which intensive analysis has been performed to test the utilities' statements regarding load and supply capacity. As such, I do not repeat that analysis here. Therefore, I confine my discussion in this testimony to the State's overall energy need in generic terms instead of identifying specific types of energy needed.

Q. What is your opinion on the impact of the Project on the general assessment of the State of Minnesota's energy need?

A. Based on my general assessment of the State's energy need, I conclude that the Project will have a positive impact in meeting the State's energy need by providing transmission to deliver and to import energy generated or purchased to meet the State's energy need.

Q. Pertaining to Minnesota Statute section 216B.243, Subd. 3 (9), please discuss the impact of the Project on regional reliability.

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[9] Docket No. ET2 /RP-05-1100
[10] http://www.mappcor.org/assets/pdf/2007%20MAPP%20LC%20Report%20FINAL.pdf

A. First, I need to define the word "region." Since all of the Applicants are physically located in the MRO's footprint and MISO's footprint, I use MRO and MISO as the "region."

Q. Please continue to discuss the impact of the Project on regional reliability.

A. The MRO-U.S. region is projected to have significant capacity deficits during the 2010–2015 timeframe. In page 9 of *MRO 2006 Ten-Year Reliability Assessment*[11], MRO states:

> Tables 5 shows the summer capacities in MW above the reserve targets for the MRO-U.S. subregion for the 2006-2015 time period. MRO-U.S. had a capacity surplus of 2,671 MW in 2006 summer. This capacity surplus is forecast to decrease to 630 MW in 2009 summer. A capacity deficit of 59 MW is shown as occurring in 2010 summer and reaching 5,625 MW in 2015 summer.
>
> (OES Exhibit No.___ (HKH-05)).

The capacity projected to be needed during 2010–2015 can be met by newly built generation or by importing electricity from other regions. Therefore, the proposed Project, if it is built, is expected to have positive impacts by facilitating mitigation of the capacity deficits mentioned above by providing extra generation outlets to the MRO-U.S. footprint.

Q. Pertaining to Minnesota Statute section 216B.243 Subd. 3 (9), do you think that the Project will improve reliability in the MISO footprint?

A. In page 9 of *MISO's Transmission Expansion Plan 2007 (MTEP07)*[12], MISO states:

[11] http://www.midwestreliability.org/03_reliability/assessments/2006_Ten-Year_Reliability_Assessment.pdf
[12] http://www.midwestmarket.org/publish/Document/5d42c1_1165e2e15f2_-7ba40a48324a/MTEP07_Report_10-04-07_Final.pdf

1.2.3 Other Significant Projects Pending Appendix A Recommendation

There are three projects referred to as the CAPX projects that the Midwest ISO is not seeking Board approval for at this time, but for which we expect to do so in the near future. These three projects represent significant bulk power 345 kV expansions of the Midwest ISO transmission system. The three projects add over 500 miles of new 345 kV lines, and several transformer installations to support loads over a wide area of the upper Midwest, and to deliver new renewable generation resources to reliably meet load projections in the region. The three projects are briefly described here and will be further discussed in stakeholder meetings in the next several months as the final cost allocations are determined for these projects.

Also, in page 9 to 11, MISO states:

<u>P286-P287 Fargo-Alexandria-St Cloud-Monticello 345kV line</u>

■ Justification
- Resolves NERC Standard issues in three areas along line route
  - Red River Valley at north end
  - Alexandria area to south
  - St. Cloud area near south end
- Multiple Category B events
- Multiple Category C events including voltage instability

<u>P1024 – Hampton Corners – Rochester – La Crosse 345 kV line</u>

■ Justification:
- Resolves NERC Standard issues in Rochester, MN and La Crosse, WI areas which are southeast of Minneapolis/St. Paul
  - Rochester area
  - La Crosse area
- Multiple Category B events
- Multiple Category C events

<u>P1203 Brookings, SD to Twin Cities 345 kV line</u>

■ Justification
- Provides for reliable delivery of generation to meet forecast load growth and support Renewable Portfolio Standard (RPS) requirements

Based on the above statements, I conclude that the Project is required in order to improve general regional transmission reliability. I note that MISO's conclusions that transmission facilities are needed are corroborated by such as the 2007 "islanding" event noted above and MISO's designation of part of Minnesota as "narrowly constrained area". A part of Minnesota and Iowa has been considered to be a "narrowly constrained area" meaning that there is insufficient transmission which typically results in higher congestion costs for which ratepayers are currently paying in their rates.

Q. Based on the above discussion, please provide the conclusions on this section of your testimony.

A. The Project is required to meet the State's energy need and to improve MISO/MRO reliability. Thus, the proposed project will have a positive impact on meeting the State's energy need and on improving the MISO/MRO reliability.

V. REVIEW OF REASONABLENESS OF APPLICANTS' NEED CLAIMS

Q. Please provide a brief summary of the structure of this section of your testimony.

A. In this section, I discuss the reasonableness of the claimed need forecasts. Specifically, I assess the claimed need with adjustments required by the newly enacted Minnesota Renewable Energy Standard (RES) and Conservation Statutes. OES witnesses Mr. Davis, Ms. Peirce and Mr. Shaw provide data to complete this task and I refer to their testimony for specific development of those factors. More specifically, Mr. Davis provides data reflecting a reduction of Peak Demand need due to Conservation Statutes. Ms. Peirce provides testimony regarding additional wind energy capacity to meet the RES Statute. Mr. Shaw reviews and provides data regarding utility supply-side resources.

Q. Did you modify any data provided by other OES witnesses?

A. No.

Q. Did you have a chance to discuss this approach with other parties in this proceeding?

A. Yes. On October 29, 2007, OES staff members and several parties[13] met in an OES conference room to present OES's method of incorporating the new DSM and RES requirements in its calculation of Minnesota utilities' generation interconnection need.

A. REASONABLENESS OF APPLICANTS' DEMAND FORECAST USED IN ENGINEERING STUDIES

Q. Please provide an overview of Applicants' peak demand forecast.

A. According to the Appendix A-1 of the application, the Applicants used 4,500MW to 6,300MW demand growth as the basis for the engineering studies. The Table 1 of the Appendix A-1 shows the detail of the projection. The table indicates that nine Minnesota control areas' demand will grow from 20,201 MW in 2009 to 26,488 MW in 2020. The Applicants used MAPP 2004 Series summer peak model and used predicted a growth rate to obtain 2020 summer peak demand.

Q. Based on your review, is the Applicants' peak demand forecast reasonable?

A. Yes.

Q. Did you independently verify the Applicants' peak demand forecast?

A. Yes, I did. I obtained the most recent data, MRO 2007 Series summer peak model (OES Exhibit No.___ (HKH-06)) to update the table. The updated table (OES Exhibit No.___ (HKH-07)) shows 22,228 MW peak demand in 2009. Then I used a growth rate based on most recently approved or accepted IRP from Minnesota utilities to obtain year 2020 summer peak demand. (OES Exhibit No.___ (HKH-08)) It shows that year 2020 peak demand is 27,060 MW which is about 572 MW more than Applicants' original forecast of 26,488 MW.

Q. Why didn't you reduce the 2020 peak demand with new DSM requirement?

A. That process is discussed in the next part of my testimony.

B. APPLICANTS' INTERCONNECTION NEED

Q. Please provide an overview of the Applicants' interconnection need claims.

A. Given the need claimed in their engineering studies, Applicants need to have both conventional non-renewable generation and renewable generation to meet the need.[14] As indicated in the testimony of OES Witness Susan Peirce, in addition to non-renewable generation, the Applicants need a significant amount of wind generation to meet the new RES Statute.

[13] Applicants, Wind on the Wires/MCEA, NAWO/ILSR, and Windustry participated in the meeting.
[14] Pages 1.2 to 1.4 of the Application briefly discuss the claims.

Q. Did you calculate the total wind generation interconnection need?

A. No. Ms. Peirce calculated and provided the number. Based on her calculation, Minnesota utilities need an additional 3,148 MW to 4,911 MW of wind generation to meet Minnesota's new RES Statute requirement.

Q. Did you verify the wind generation interconnection need in other way?

A. Yes. I have checked the MISO generation interconnection request queue to see if the interconnection need is realistic.[15] By checking the queue, I could check whether the electric industry is making progress meet the Minnesota statutory requirements. During September 2007 and October 2007, around the time of the Application filing, 25,032 MW of wind generation interconnection requests were filed at MISO. Most of the requested generator is located in the Minnesota, South Dakota, and North Dakota region. Further, many of the requested specific interconnection points are the substations along the proposed Project lines. OES Exhibit No.___ (HKH-09)

Q. Is 21,237 MW of wind generation need realistic?

A. Possibly. However, this amount is far more than the Minnesota needs. Further, it is very possible that some of those requests are duplicates to satisfy the same need. However, some of MISO's study shows about 13,000 MW to 60,000 MW of wind generation are needed in the region. OES Exhibit No.___ (HKH-10)

[15] Minnesota RES Statute allows utility to take off-ramp.

Q. Did you calculate the non-renewable generation interconnection need?

A. Yes. With Mr. Davis, Mr. Shaw and Ms. Peirce's help, I have calculated the interconnection need. First, I subtracted the DSM requirement from the new 2020 peak demand. Second, I calculated the state-wide capacity deficit in year 2020, using the new DSM adjusted 2020 peak demand forecast and Mr. Shaw's supply side resource number. Then, I subtracted accredited wind generation capacity based on wind interconnection needed to meet the RES Statute, provide by Ms. Peirce.

Q. What is the possible range of the non-renewable generation interconnection need?

A. As shown in OES Exhibit No.___ (HKH-11), Minnesota utilities need 2,233 MW to 3,057 MW of non-renewable generation to serve Minnesota ratepayers reliably in addition to the wind generation need by 2020 to meet the RES Statute.

Q. What is the overall generation interconnection need?

A. Based on the above calculation of interconnection need, I conclude that Minnesota needs 5,572 MW to 7,764 MW of generation by 2020 to serve Minnesota ratepayers reliably.

Q. Based on your verification of the 2020 peak demand forecast and calculation of generation interconnection need, what do you conclude?

A. Based on my verification of the 2020 peak demand forecast and calculation of generation interconnection need, I conclude that the Applicants' need inputs to their engineering studies were reasonable.

C. APPLICANTS' LOCAL COMMUNITY SERVICE RELIABILITY NEED CLAIM

Q. Please provide an overview of the Applicants' local reliability need claims.

A. The Applicants claimed that in the near future, Rochester, Minnesota, La Crosse, Wisconsin and Winona, Minnesota, St. Cloud, Minnesota, Alexandria, Minnesota and the Red River Valley areas of Minnesota and North Dakota will not be able to be served reliably with the existing transmission lines. Based on Applicants' claim, the St. Cloud area is already facing loss of load under critical contingency[16]. The Red River Valley area is not expected to be in a critical condition in the near future; however, it will face loss of load under critical contingency conditions starting in 2019.

Q. What do these critical conditions mean in the reliability standard, specifically Transmission Planning (TPL) section, newly instituted by the Electric Reliability Organization (ERO)?

A. These critical conditions will most likely violate TPL-001, TPL-002, TPL-003, or TPL-004 without proper planning to mitigate the conditions. OES Exhibit No.___ (HKH-13)[17] In other words, the transmission network, with very high probability, cannot be operated to supply projected customer demands and projected firm transmission services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B, C or D of Table I in TPL-001, TPL-002, TPL-003, or TPL-004.

[16] The Applicants stated that "The critical contingency in the St. Cloud area is the loss of the double circuit line between the Benton County Substation and the Granite City Substation during summer peak loading." (Page 4.31 of the application)
[17] Similar issue was discussed in my Direct Testimony (page 7-10) in Docket No. E002,ET3/CN-04-1176.

Q. Given the potential reliability standard violation, how did you evaluate the claimed need?

A. I have verified the Applicants' local peak demand forecasting by verifying each area's demographic information. OES Exhibit No.___ (HKH-12) Based on the population growth rate evaluation, the peak demand forecast for the area is reasonable.

Q. Based on your analysis, what do you conclude?

A. Based on my analysis, Applicants need to plan to mitigate the potential reliability standard. Further, I conclude that the proposed project can serve as one the mitigation option to the potential reliability standard.

VI. CONCLUSION

Q. Please state your conclusions regarding the reasonableness of the Applicants' forecasts used in their engineering studies.

A. Based on the above analysis, I conclude that the peak demand forecasts used in the engineering studies are reasonable.

Q. Please state your conclusions regarding the expected impact of the Project on the Minnesota's energy need and regional reliability.

A. Based on the above analysis, I conclude that the Project will likely have a significant positive effect on regional reliability and will have significant positive impacts on the reliability of the five local systems, Rochester, MN, La Crosse, WI and Winona, MN, St. Cloud, MN, Alexandria, MN and Red River Valley area of MN and ND.

Q. Does this conclude your testimony?

A. Yes.

HWIKWON HAM

Minnesota Department of Commerce
85 7th Place East, Suite 500
St. Paul, MN 55101-2145

Professional Background

Education

Degree	*Field*	*Institution*	*Year*
M.A.	Economics	University of Minnesota	1998
B.A.	Economics	University of Illinois at U-C (Summa Cum Laude and University Honors)	1988

Experience at Office of Energy Security

Professional Training:
Strategist (integrated resource planning model software) training Phase I (November 2007)
Strategist (integrated resource planning model software) training Phase II (February 2008)

Experience with Regional Planning and Reliability:

Participating OMS Resource Adequacy Working Group (Since 2005)

Participating MISO Supply Adequacy Working Group (Since 2005)

Participating MISO MTEP Stakeholder Workshop (Since 2006)

Participating MISO Joint Coordinated System Plan workshop (Since 2007)

Participating MISO Regional Generation Outlet Study & NCA Study Working Group (Since 2008)

Participating MISO Loss of Load Expectation (LOLE) Studies Working Group (Since 2008)

Participating and Voting Member of MRO Reliability Standards Process (Since 2006)

Dockets :

Docket No.	Company	Sections
IP6339/CN-03-1841	Trimont Wind I	Forecasting
E002/CN-04-76	Xcel Energy	Forecasting
E001/RP-03-2040	IPL	Forecasting
E015/RP-04-865	Minnesota Power	Forecasting
E002/RP-04-1752	Xcel Energy	Forecasting
ET2/CN-05-347	GRE	Forecasting
E002/CN-05-123	Xcel Energy	Forecasting
ET2/RP-05-1100	GRE	Forecasting
ET10/RP-05-1102	MRES	Forecasting
E017/RP-05-968	Otter Tail Power	Forecasting

E001/GR-05-748	IPL	Forecasting
E002/GR-05-1428	Xcel Energy	Forecasting
ET-2/CN-06-367	GRE	Forecasting & Reliability
E017 et al/CN-05-619	Otter Tail Power	Forecasting & Reliability
E002,ET3/CN-04-1176	Xcel Energy	Forecasting & Reliability

Work Experience
Research Associate
Hubert H. Humphrey Institute of Public Affairs, Dates Employed: 1999-2003
University of Minnesota

Responsible for management and analysis of micro economic data, technical writing and public presentation. Worked on impact of regulation (occupational licensing) on quality and price of the service.

Research Assistant
Department of Economics, Dates Employed: 1995-2003
University of Minnesota

Responsible for coordinating work among other assistant, data search, data management, and data analysis.

Teaching Assistant
Department of Economics, Dates Employed: 1990-1998
University of Minnesota

Responsible for teaching the courses, evaluating the classes, and supervising term paper writing. Microeconomics, Macroeconomics, Econometrics, advanced level Econometrics.

Academic Papers
"Regulating the Labor Market: The Role of Occupational Licensing" with Morris Kleiner, 2003 working paper.

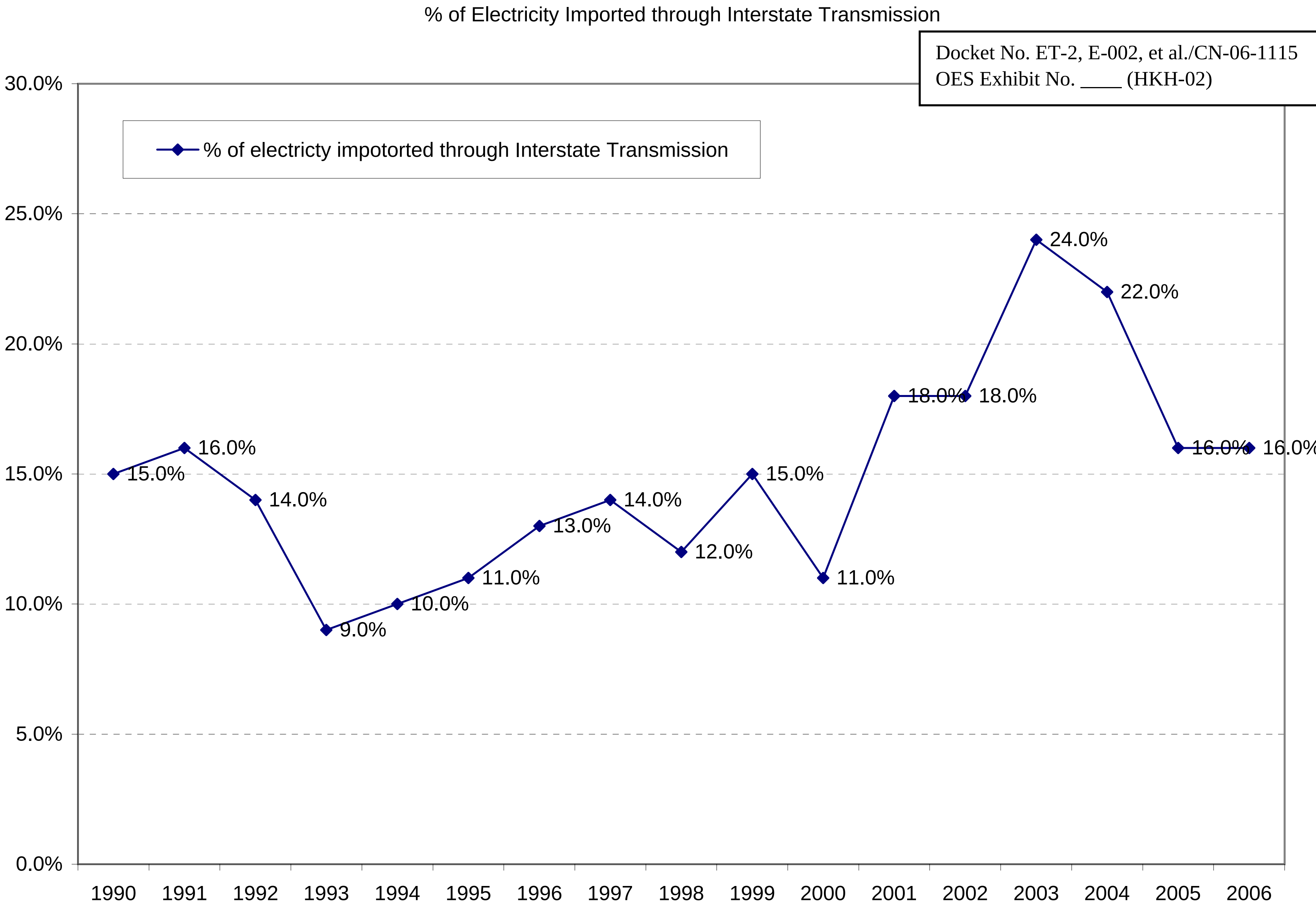
"The Effect of Different Industrial Relations Systems in the U.S. and the European Union on Foreign Direct Investment Flows" with Morris Kleiner, Multinational Companies and Global Human Resource Strategies Edited by William N. Cooke, Greenwood Publishing 2002.

"Do Industrial Relations Institutions Influence Foreign Direct Investment? Evidence from OECD Nations" with Morris Kleiner, Industrial Relations 46 (2), 305–328.

Public Presentation
"Do Industrial Relations Affect Economic Efficiency?: International and U.S. State-level Evidence ", Universities Research Conference :Labor in the Global Economy, NBER May 2001

"Do Industrial Relations Institutions Impact Foreign Direct Investment?: Evidence from OECD Nations", Governing the Global Workplace: An International Symposium, University of Minnesota April 2005

Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. _____ (HKH-02)



☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Hwikwon Ham, MN Department of Commerce — Information Request No. 62
Date Received: April 8, 2008

Question:

Please provide full description of transmission related incident(s) which caused State of Minnesota (or a utility) in isolation or near isolation from rest of the electric grid system if there is such incident(s) over last two years.

- Please provide a copy of news paper article, MISO news release, utility news release, or any information provided to general public regarding the incident(s).
- Please provide finding(s) or report(s) regarding the incident(s).

Response:

The only known transmission-related incident that caused a condition of isolation or near isolation in the last two years happened on September 18, 2007. During this event, a 345 kV transmission line owned by Northern States Power Company, a Minnesota corporation ("NSPM" or "Xcel Energy"), tripped offline at 5:14 a.m. CDT as a result of a conductor failure, which was followed closely by the trip of a second 345 kV transmission line. Other transmission lines in the region were also out of service at the time of the incident for routine maintenance. A series of other transmission line trips on several utility systems caused portions of the NSPM system and utilities to the west and north of NSPM to "island" (*i.e.*, become isolated or disconnected) from the rest of the Eastern Interconnection for approximately nine minutes. The islanded portions of the NSPM system reconnected to the Eastern Interconnection at 5:29 a.m. CDT.

Due to the load/generation balance in the island that formed, the only significant loss of load occurred in Saskatchewan, as indicated in the news articles attached to this response. NSPM did not experience any retail customer outages; approximately 6,000 retail customers of our affiliate NSP (Wisconsin) lost service. Because the islanding event occurred so early in the morning, and concluded after only a few minutes, there were no communications to the general public.

This event is the subject of an active event analysis being led by the Midwest Reliability Organization ("MRO"), the North American Electric Reliability Corporation ("NERC") Regional Entity for the state of Minnesota. Separately, a compliance analysis is also being conducted to ensure utilities acted in accordance with all applicable NERC reliability standards. No final reports have been issued. When the final reports are issued, NSPM will make the reports available to the Department of Commerce, Office of Energy Security if NERC and MRO confidentiality rules allow disclosure.

Attached are copies of the following documents:

- A public version of the Form OE-417 report submitted by Xcel Energy to the U.S. Department of Energy ("DOE") after the September 18, 2007 event. The Form OE-417 is comprised of two parts, a Schedule 1, which provides general information about the event and Schedule 2, which is a detailed narrative of the event. Schedule 2 is considered confidential critical energy infrastructure information by DOE. Schedule 1 is not confidential, but lines 4-9 which relate to the identity of the NSPM official who filed the report are confidential. Lines 4-9 of Schedule 1 and Schedule 2 have been redacted accordingly (CapX2020 0000107-0000111).

- A notice of the event posted on the MRO website: http://www.midwestreliability.org/06_news/releases/Bulk_Power_System_Alert_09-18-07.pdf (CapX2020 0000112).

- Two newspaper clippings from Canadian media describing the outage in Saskatchewan (CapX2020 0000113-0000116).

Response By:	Daniel Kline
Title:	Transmission Planning Engineer
Department:	Transmission Reliability & Assessment
Company:	Northern States Power Company
Telephone:	612-330-7547
Date:	April 25, 2008

SEASONAL
LOAD AND CAPABILITY DATA

SEASONAL LOAD AND CAPABILITY

Summer 2007 through Winter 2016-17

Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. ____ (HKH-04)
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Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. ____ (HKH-04)
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FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP US - Total

		SUM 2007	WIN 2007	SUM 2008	WIN 2008	SUM 2009	WIN 2009	SUM 2010	WIN 2010	SUM 2011	WIN 2011
01	Internal Demand	32123	26531	33010	27312	34114	28174	34923	28763	35665	29295
02	**Standby Demand**	4	4	4	4	4	4	4	4	4	4
03	Total Internal Demand (01+02)	32128	26536	33015	27316	34119	28179	34927	28768	35669	29299
04	**Direct Control Load Management**	80	80	81	80	82	80	83	80	84	80
05	**Interruptible Demand**	495	212	495	212	495	212	399	116	399	116
06	Net Internal Demand (03-04-05)	31552	26244	32440	27023	33543	27886	34446	28572	35186	29103
07	**Total Net Operable Capacity**	35110	34774	35545	35182	36415	36068	36495	36249	36693	36518
07a	**Uncommitted Capacity**	0	0	0	0	0	0	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**	0	0	0	0	0	0	0	0	0	0
07b2	**Reliability Derating Group Subtotal**	0	0	0	0	0	0	0	0	0	0
07c	**Other Generation**	0	0	0	0	0	0	0	0	0	0
07d	Subtotal Committed Capacity (7-7a-7b1-7b2-7c)	35110	34774	35545	35182	36415	36068	36495	36249	36693	36518
08	Generator Capacity, <1MW (8a+8b)	50	50	49	51	52	53	53	54	55	56
08a	**Distributed Generator Capacity < 1 MW**	8	8	8	9	11	11	12	12	14	14
08b	**Other Capacity < 1 MW**	42	42	41	42	41	42	41	42	41	42
09	Total Net Generator Capacity (7d+8)	35158	34823	35593	35232	36466	36119	36547	36303	36746	36573
9b	**Distributed Generator Capacity >= 1 MW**	21	19	21	19	21	19	21	19	21	19
10	Total Capacity Purchases	6025	4156	5178	4139	5105	4015	4602	3700	4352	3624
11	Total Firm Purchases	1781	1222	1764	1177	1764	1177	1589	1000	1581	999
12	Total Participation Purchases	4244	2933	3414	2961	3341	2837	3013	2699	2771	2624
13	Total Capacity Sales	3317	3445	2943	3080	3124	3157	2509	2737	2252	2587
14	Total Firm Sales	1357	1771	1192	1606	1192	1606	1017	1429	1010	1429
15	Total Participation Sales	1961	1675	1752	1475	1932	1551	1492	1308	1242	1158
16	Net Capacity Resources (9+10-13)	37866	35531	37826	36288	38447	36977	38640	37264	38847	37609
17	**Schedule L Purchases**	50	260	50	265	50	270	51	275	51	281
18	Adjusted Net Capability (9+12-15)	37442	36082	37256	36719	37876	37408	38069	37696	38276	38041
19	**Annual System Demand**	31749	31915	32581	32761	33663	33785	34485	34586	35187	35268
20	Monthly Adjusted Net Demand (6-17-11+14)	31078	26536	31820	27190	32923	28048	33825	28729	34566	29255
21	Annual Adjusted Net Demand (19-11+14)	31326	32466	32012	33191	33094	34215	33916	35016	34619	35701
22	Net Reserve Capacity Obligation (21 x 15%)	4609	4772	4711	4883	4872	5038	4998	5160	5105	5261
23	Total Firm Capacity Obligation (20+22)	35686	31306	36530	32070	37793	33083	38824	33886	39670	34513
24	Surplus or Deficit(-) Capacity (18-23)	1754	4774	725	4652	82	4327	-751	3809	-1392	3529

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. ____ (HKH-04)
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FORECASTED SEASONAL LOAD & CAPABILITY
MEGAWATTS

MAPP US - Total

		SUM 2012	WIN 2012	SUM 2013	WIN 2013	SUM 2014	WIN 2014	SUM 2015	WIN 2015	SUM 2016	WIN 2016
01	Internal Demand	36380	29798	37033	30260	37671	30723	38317	31212	39031	31686
02	**Standby Demand**	4	4	4	4	4	4	4	4	4	4
03	Total Internal Demand (01+02)	36385	29802	37037	30264	37675	30728	38322	31216	39035	31691
04	**Direct Control Load Management**	85	80	85	80	86	80	87	80	88	80
05	**Interruptible Demand**	399	116	399	116	399	116	399	116	399	116
06	Net Internal Demand (03-04-05)	35902	29606	36553	30068	37191	30532	37836	31020	38549	31495
07	**Total Net Operable Capacity**	37116	36846	37313	37003	37349	37048	37348	37049	38009	37709
07a	**Uncommitted Capacity**	0	0	0	0	0	0	0	0	0	0
07b1	**Reliability Derating Unit Spec. Subtotal**	0	0	0	0	0	0	0	0	0	0
07b2	**Reliability Derating Group Subtotal**	0	0	0	0	0	0	0	0	0	0
07c	**Other Generation**	0	0	0	0	0	0	0	0	0	0
07d	Subtotal Committed Capacity (7-7a-7b1-7b2-7c)	37116	36846	37313	37003	37349	37048	37348	37049	38009	37709
08	Generator Capacity, <1MW (8a+8b)	57	58	58	59	60	60	60	61	62	63
08a	**Distributed Generator Capacity < 1 MW**	16	16	17	17	19	19	20	20	22	22
08b	**Other Capacity < 1 MW**	41	42	41	42	41	41	40	41	40	41
09	Total Net Generator Capacity (7d+8)	37171	36903	37370	37061	37407	37107	37407	37109	38069	37771
9b	**Distributed Generator Capacity >= 1 MW**	21	19	21	19	21	19	21	19	21	19
10	Total Capacity Purchases	4276	3572	4230	3527	4140	3444	3312	2851	2863	2818
11	Total Firm Purchases	1581	979	1561	979	1561	979	1261	979	1061	979
12	Total Participation Purchases	2695	2592	2669	2547	2579	2464	2051	1871	1802	1837
13	Total Capacity Sales	2252	2587	2232	2447	2032	2367	2031	2436	2231	2566
14	Total Firm Sales	1010	1429	1010	1429	1010	1429	1010	1529	1010	1329
15	Total Participation Sales	1242	1158	1222	1018	1022	938	1021	907	1221	1237
16	Net Capacity Resources (9+10-13)	39196	37887	39368	38141	39516	38182	38689	37523	38702	38021
17	**Schedule L Purchases**	52	286	52	291	53	297	53	302	53	307
18	Adjusted Net Capability (9+12-15)	38625	38339	38818	38592	38965	38634	38439	38074	38652	38372
19	**Annual System Demand**	35865	35940	36493	36534	37105	37122	37726	37719	38412	38315
20	Monthly Adjusted Net Demand (6-17-11+14)	35279	29773	35950	30229	36589	30687	37533	31271	38446	31541
21	Annual Adjusted Net Demand (19-11+14)	35296	36391	35944	36987	36557	37574	37477	38272	38363	38666
22	Net Reserve Capacity Obligation (21 x 15%)	5202	5362	5301	5453	5394	5539	5532	5648	5666	5707
23	Total Firm Capacity Obligation (20+22)	40481	35133	41251	35681	41982	36224	43063	36917	44107	37241
24	Surplus or Deficit(-) Capacity (18-23)	-1855	3208	-2436	2909	-3019	2406	-4625	1159	-5455	1132

SUMMER: MAY 1 - OCT 31; WINTER: NOV 1 - APR 30

Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. ____ (HKH-05)

MRO

2006 TEN-YEAR RELIABILITY ASSESSMENT

Compiled by

Midwest Reliability Organization

RELIABILITY ASSESSMENT COMMITTEE

October 2006

Table 3

MRO-U.S. Predominantly Hydroelectric System Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer	75.2%	75.2%	75.2%	58.5%	58.5%	59.1%	59.1%	59.1%	59.1%	59.1%
Winter	41.4%	41.4%	41.4%	41.5%	41.5%	41.5%	41.5%	41.5%	41.5%	41.5%

MRO-U.S. Resource Adequacy

Table 4 shows the reserve margins for the 2006-2015 time period for the combined predominantly thermal and hydroelectric systems of MRO-U.S. The subregion is expected to continue to be a summer-peaking subregion. Its summer reserve margin is forecast to decrease from 21.0% in 2006 summer to 2.4% in 2015 summer. The subregion's winter reserve margin varies from 31.1% in 2006 winter to 14.7% in 2015 winter. Because of the different levels of reserve targets for the predominantly thermal (15 percent) and hydroelectric (10 percent) systems, Table 4 does not show whether or not the resources available in MRO-U.S. would adequately meet the assumed reserve targets. This is assessed in Tables 5 and 6.

Table 4

MRO-U.S. Combined Generation Reserve Margins

(Percent of Annual Demand Adjusted for Sales and Purchases)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer	21.0%	19.5%	18.7%	15.8%	14.2%	12.6%	11.9%	8.6%	6.8%	2.4%
Winter	31.1%	30.4%	29.4%	30.5%	29.1%	25.4%	23.4%	20.4%	17.4%	14.7%

Tables 5 shows the summer capacities in MW above the reserve targets for the MRO-U.S. subregion for the 2006-2015 time period. MRO-U.S. had a capacity surplus of 2,671 MW in 2006 summer. This capacity surplus is forecast to decrease to 630 MW in 2009 summer. A capacity deficit of 59 MW is shown as occurring in 2010 summer and reaching 5,625 MW in 2015 summer.

Table 5

MRO-U.S. Summer Capacity in MW above the Reserve Targets

	2006	2007	2008	2009	2010	2011	2012	2013	2014	*2015*
Available Reserve	8,261	7,782	7,633	6,601	6,024	5,451	5,236	3,856	3,088	1,103
Reserve above Reserve Targets	2,671	2,062	1,791	630	-59	-725	-1,061	-2,560	-3,458	-5,625

Table 6 shows the winter reserve capacities in MW above the reserve targets for the MRO-U.S. subregion for the 2006-2015 time period. MRO-U.S. had a capacity surplus of 6,902 MW in 2005-06 winter. This capacity surplus is forecast to decrease to 1,777 MW in 2015-16 winter. Thus, the subregion will have adequate winter generating capacity through 2015-16 winter.

Table 6

MRO-U.S. Winter Capacity in MW above the Reserve Targets

	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	*2015-16*
Available Reserve	12,714	12,657	12,471	12,702	12,354	10,692	10,054	8,928	7,785	6,702
Reserve above Reserve Targets	6,902	6,707	6,419	6,800	6,356	6,209	5,467	4,251	2,992	1,777

MRO-CANADA ASSESSMENT

Expected Reserves for the Predominantly Thermal System

Table 7 shows the reserve margins for the 2006-2015 time period for the predominantly thermal system of MRO-Canada. As seen in this table, the summer reserve margin for the MRO-Canada predominantly thermal system decreases from 25.4% in 2006 summer to 14.1% in 2015 summer. The winter reserve margin varies from 19.1% in 2006 winter to 7.3% in 2015 winter.

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OES Exhibit No. ____ (HKH-06)

2007 SERIES, MRO/MBS BASE CASE LIBRARY
2009 SUMMER PEAK CASE, JULY 6, FINAL

331 – ALT (West)

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
4077.4	3861.2	0.0	0.0	150.0

600 – Xcel Energy (North)

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
11182.2	9710.9	0.0	0.0	0.0

608 - MP

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS	MOTORS
1818.2	2204.7	0.0	0.0	145.2	-214.3

613 – SMMPA/RPU

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
433.5	224.7	0.0	0.0	0.0

618 - GRE

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
1743.8	2431.4	0.0	0.0	502.5

626 – OTP/MPC

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
1999.7	1428.0	0.0	0.0	140.4

680 - DPC

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
972.8	1058.6	0.0	0.0	0.0

Data from 2004 MAPP Series Model and 2007 MRO Series Model

		Load Level (MW)	
Control Area	Control Area Reference Number	2004 MAPP SERIES FINAL 2009 SUMMER PEAK	2007 MRO SERIES FINAL 2009 Summer Peak
ALT(West)	331	3265.3	4077.4
Xcel Energy (North)	600	9632.6	11182.2
MP	608	1507.3	1818.2
SMMPA/RPU	613	330	433.5
GRE	618	2837.7*	1743.8
OTP/MPC	626	1685.2	1999.7
DPC	680	954.7	972.8
Total		20212.8	22227.6

*In Table 1 in Appendix A-1 of the Certificate of Need Application, the 2009 load level (2004 MAPP Series) for GRE is listed as 2,833.50 MW. This is a typographical error and should instead reflect 2,837.7 MW as provided here.

```
 2004 MAPP SERIES FINAL 2009 SUMMER PEAK
 F-09SUPK.SAV /BUSES = 21866 BRANCHES = 33100/ 100% OF PEAK

331 – ALT(West)

  LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
   3265.3     3412.1        0.0        0.0      188.1

600 – Xcel Energy (North)

  LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
   9632.6     9026.5        0.0        0.0        0.0

608 -  MP

  LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS     MOTORS
   1507.3     1990.5        0.0        0.0      139.8     -214.3

613 – SMMPA/RPU

  LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
    330.0      185.3        0.0        0.0        0.0

618 - GRE

  LOAD-MW GENERATION   SHUNT-MW   REACTORS CAPACITORS
   2837.7     2401.1        0.0        0.0      502.5

626 – OTP/MPC
```

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
1685.2	1282.2	0.0	0.0	140.2

680 - DPC

LOAD-MW	GENERATION	SHUNT-MW	REACTORS	CAPACITORS
954.7	1173.5	0.0	0.0	0.0

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OES Exhibit No. ____ (HKH-07)
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Docket No. ET-2, E-002, et al./CN-06-1115
OES Exhibit No. ____ (HKH-08)

Demand forecasts from most recently approved/accepted MN IRP proceeding

Year	System MW Demand	System MW Demand	System MW Demand	System MW Demand	System MW Demand	System MW Demand	System MW Demand	System MW Demand	System MW Demand	
	Dairyland	Minnkota	GRE	Xcel	MRES	IPL	MP	OTP	SMMPA	Total
2009	943	898	2,878	10679	811	3006	1773	739	569	22297
2010	957	922	2,966	10874	824	3050	1797	757	577	22724
2011	971	944	3,061	11058	838	3102	1829	770	586	23160
2012	986	968	3,150	11266	853	3154	1855	783	595	23609
2013	998	992	3,241	11425	867	3207	1875	803	604	24012
2014	1010	1017	3,339	11601	881	3260	1895	821	612	24436
2015	1023	1042	3,433	11818	894	3316	1912	835	622	24895
2016	1037	1067	3,528	12050	907	3372	1928	849	631	25369
2017	1049	1092	3,629	12239	920	3429	1944	864	640	25805
2018	1061	1119	3,725	12435	932	3487	1955	878	649	26240
2019	1075	1145	3,826	12638	943	3546	1971	893	658	26694
2020	1088	1173	3,924	12838	955	3606	1984	908	667	27144
Growth Rate	1.31%	2.46%	2.86%	1.69%	1.50%	1.67%	1.03%	1.89%	1.46%	1.80%

Based on Applicants Response to OES Information Request 46 (E)

MISO Queue Num	State	Max Summer Output (MW)	Point of Inter-connection	Fuel Type	In Service Date
39329-01	MN	38	POI is the Xcel Black Oak Switching Station on County Road 186 in Section 6 of Grove Township	Wind	1-Nov-10
39331-03	ND	600	Alberta Twp, Section 24 N/2 NW/4, SE/4 NW/4 and SE/4	Wind	15-Oct-12
39335-01	MI	150	Pere Marquette-Stonach 138kV line	Wind	31-Dec-11
39336-01	MN	200	Hayward 161 kV substation	Wind	1-Dec-09
39336-03	MN	400	345 kV Adams substation	Wind	1-Dec-09
39339-01	MN	600	Maple River 345 kV	Wind	1-Sep-14
39339-02	ND	1,500	Milton Young	Wind	1-Oct-13
39339-03	ND	1,500	near Bismarck ND	Wind	1-Oct-12
39343-03	IN	201	Reynolds Sub	Wind	1-Dec-09
39343-04	IN	201	Goodland Sub	Wind	1-Dec-09
39346-01	OH	50	Coldwater-rossburg 69 kV	Wind	31-Dec-10
39346-02	OH	50	Coldwater-Rossburg 69 kV	Wind	1-Oct-10
39353-01	NE	250	FT-GI 345 KV / Holt	Wind	31-Dec-09
39356-01	IA	200	161 kV line Decorah-Lansing	Wind	1-Oct-11
39357-01	MN	201	Alliant Energy's Hayward Substation	Wind	1-Sep-09
39357-02	MN	201	Alliant Energy's Hayward Substation	Wind	1-Sep-09
39358-01	MN	201	Moorhead-Morris 230 kV / Wilkin	Wind	30-Dec-11
39364-03	MN	80	R49WT159N, SE 1/4 of Sec 35	Wind	31-Dec-10
39364-06	SD	150	Xcel Grant 115 kV substation	Wind	1-Oct-10
39366-01	MN	1,500	Proposed N. Rochester 345 kV substtion	Wind	1-Apr-11
39366-02	MN	1,500	Proposed Hampton Corner 345 kV substation	Wind	1-Nov-11
39366-03	SD	1,500	Monticello substation in Wright Co. MN	Wind	1-Oct-12
39371-01	ND	200	Proposed Peak Wind substation 115 kV line	Wind	1-Dec-10
39371-03	IN	20	Watseka to Goodland 138 kV line	Wind	28-Feb-08
39371-04	IN	50	Watseka to Goodland 138 kV	Wind	15-May-08
39373-01	MI	59	Cosmo Tap (Bad Axe-Arrowhead) 120kV	Wind	31-Dec-08
39373-03	MN	80	Split Rock-Magnolia 161 kV	Wind	1-Sep-10
39374-01	MN	200	161 kV Alliant Line from Lansing to Harmony	Wind	15-Jun-10
39378-01	MN	1,500	Scott Junction 345/115 kV substation	Wind	1-Dec-10
39378-02	MN	1,500	New Scott Junction 345 kV/115 kV substation	Wind	1-Dec-10
39378-03	MN	1,500	Benton County 345 kV Substation	Wind	1-Dec-11
39378-04	MN	1,500	Benton County 345 kV substation	Wind	1-Dec-11
39378-05	MN	1,000	Monticello 345 kv substation	Wind	1-Dec-10
39378-06	MN	1,000	Monticello 345 kV substation	Wind	1-Dec-12
39378-07	IL	1,500	New Paddtown Substation tapping Paddock-Wempleton 345 kV line	Wind	1-Dec-10
39378-08	IL	1,500	New Paddtown Substation tapping Paddock-Wempleton 345 kV line	Wind	1-Dec-10
39379-01	MN	50	GRE 41.7 kV line or OTP 115 kV line	Wind	1-Dec-10
39384-01	IL	100	Caledonia	Wind	1-Jan-10
39386-01	MN	2,000	NSP's Crow River substation	Wind	31-Dec-11

State	MW
IA	200
IL	3,100
IN	472
MI	209
MN	15,251
ND	3,800
NE	250
OH	100
SD	1,650
Total	25,032

Midwest ISO
Energizing the Heartland

MTEP 2009 & JCSP 2008 Preliminary Siting Final Review

Jason Schmidt

651-632-8420

jschmidt@midwestiso.org

March 18, 2008

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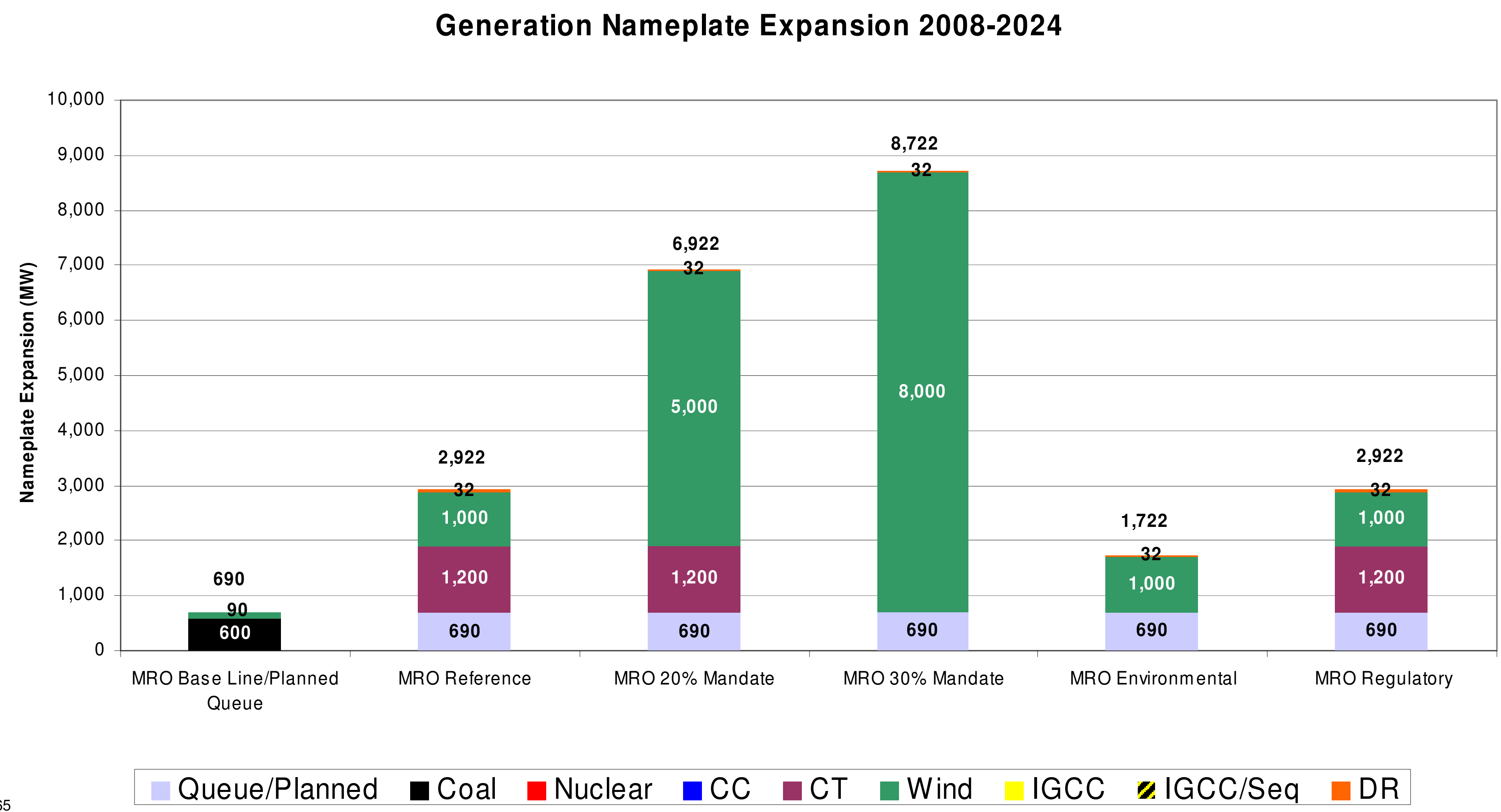
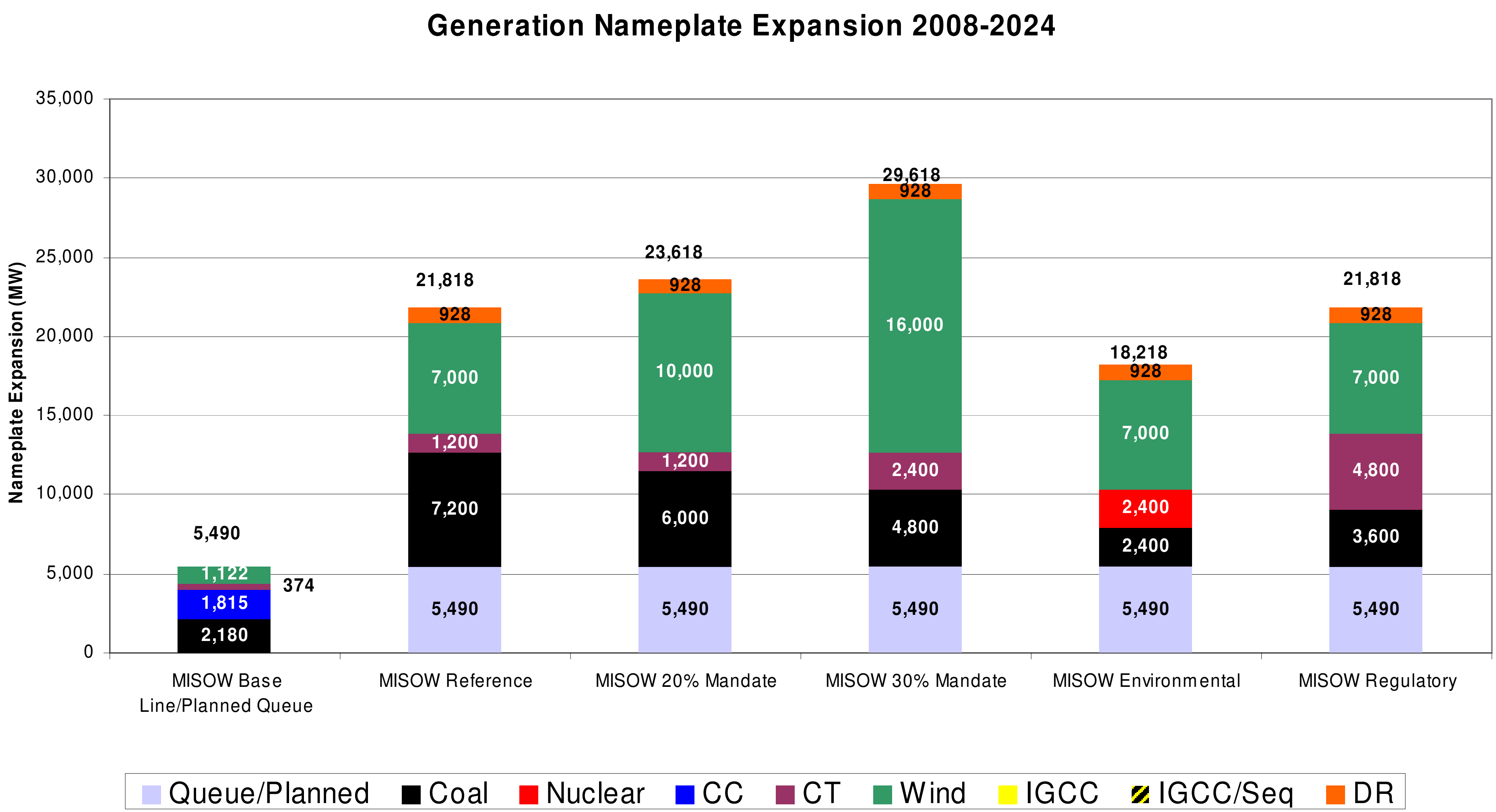
MRO Region



Midwest ISO West Region



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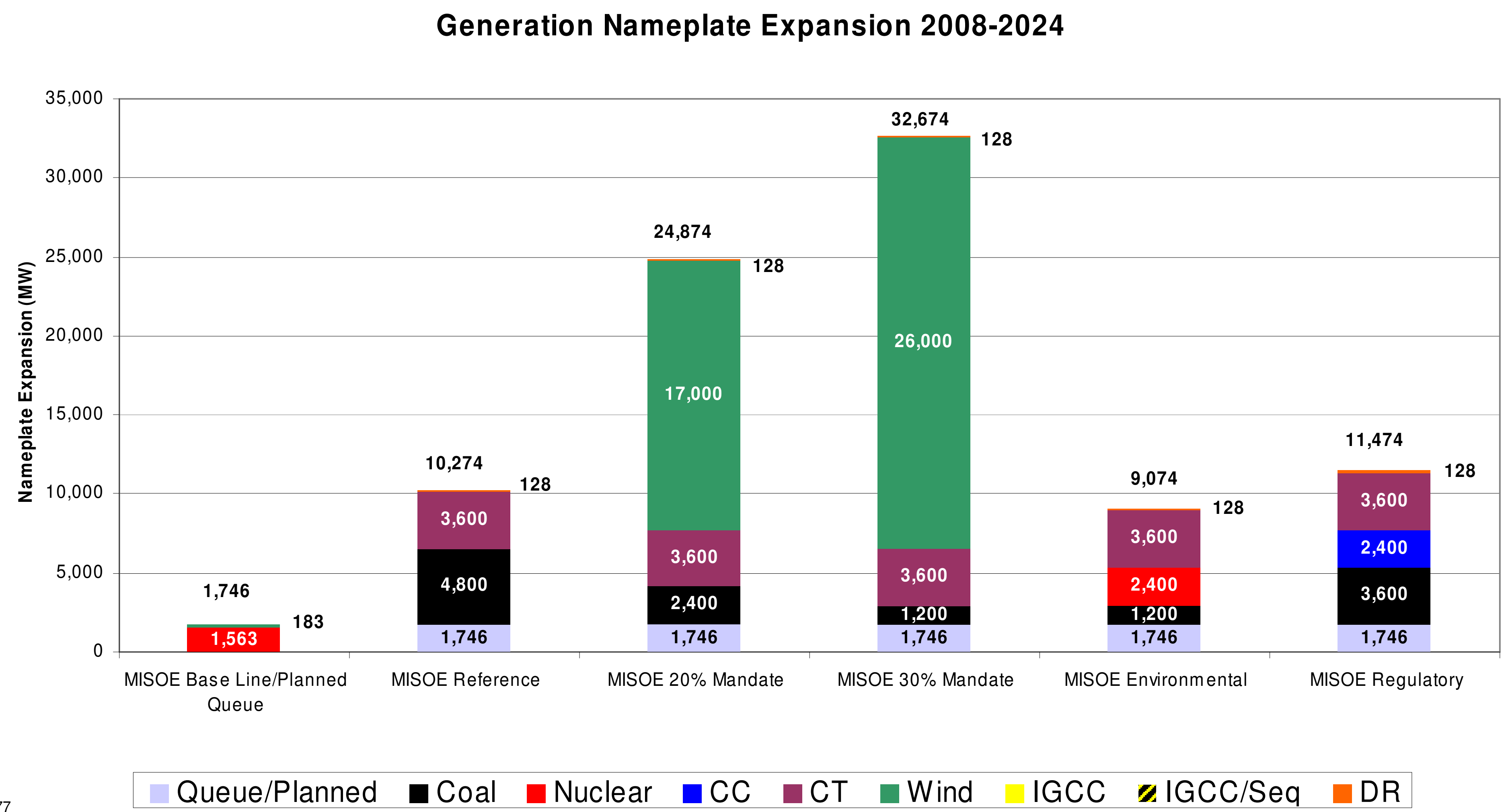
Midwest ISO East Region



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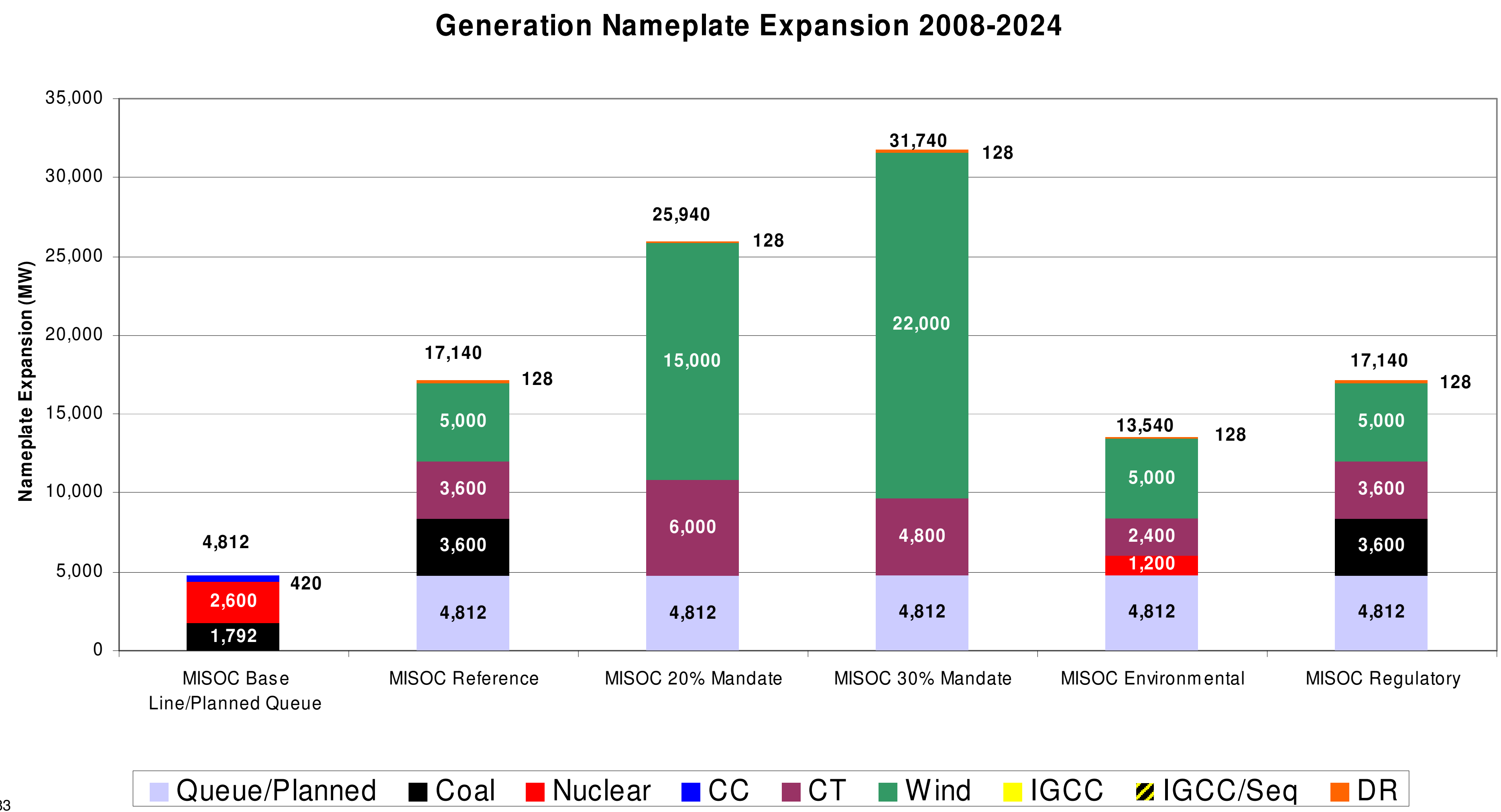
Midwest ISO Central Region



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Minnesota Renewable Interconnection Need

Scenarios			2020 (MW)
1% DSM	30%cf	REO Nameplate Capacity Need (MW)	4911
		REO Accredited Capacity Need (MW)	663
1.5% DSM		REO Nameplate Capacity Need (MW)	4563
		REO Accredited Capacity Need (MW)	616
1% DSM	40%cf	REO Nameplate Capacity Need (MW)	3404
		REO Accredited Capacity Need (MW)	460
1.5% DSM		REO Nameplate Capacity Need (MW)	3148
		REO Accredited Capacity Need (MW)	425

Minnesota Non-Renewable Interconnection Need

Scenarios		2020 (MW)
1% DSM	30%cf	**2853**
1.5% DSM		**2233**
1% DSM	40%cf	**3057**
1.5% DSM		**2424**

Minnesota Total Interconnection Need

Scenarios		2020 (MW)
1% DSM	30%cf	**7764**
1.5% DSM		**6796**
1% DSM	40%cf	**6461**
1.5% DSM		**5572**

Projected Minnesota Total Population by County, Region, and Metropolitan Area, 2005 to 2035
Minnesota State Demographic Center, April 2007
Sources: 2005 estimates from U.S. Census Bureau, modified by State Demographic Center.

Area	**2010 Projection**	**2020 Projection**	**% Change 2010-2020**
Douglas (County) : Alexandria	37,890	42,750	12.8%
Houston (County) : Winona-La Crosse	20,350	21,270	4.5%
Fargo, ND-MN	57,100	63,000	10.3%
Grand Forks, ND-MN	31,900	33,400	4.7%
Rochester, MN	192,700	217,900	13.1%
St. Cloud, MN	198,000	225,000	13.6%
Fargo, ND-MN + Grand Forks, ND-MN	89,000	96,400	8.3%

January 2007 Final Population Estimates, Percent Change Since Census 2000, Municipalities

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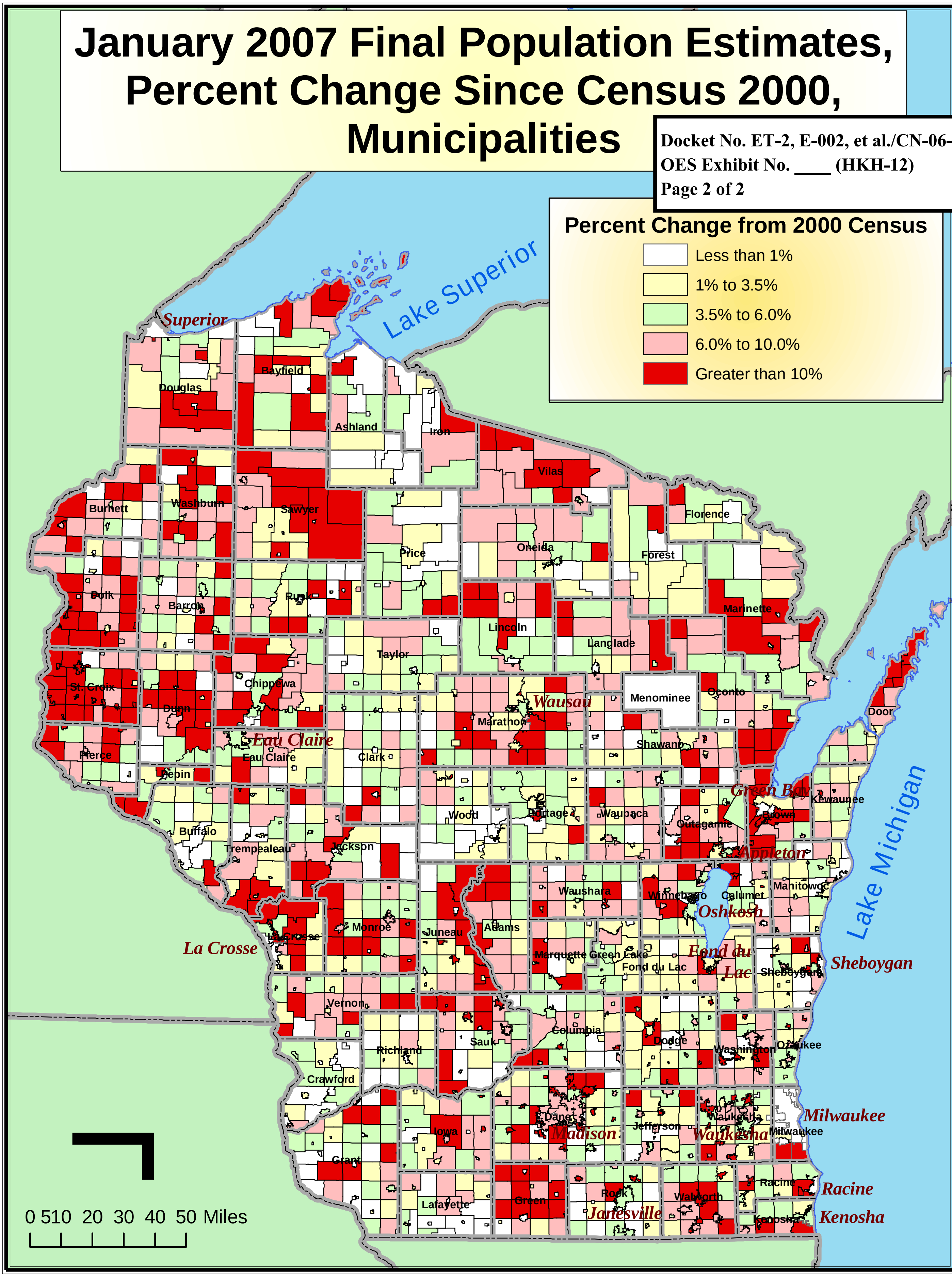

October 2007

prepared by Demographic Services Center
Wisconsin Dept. of Administration

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** TPL-001-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Transmission Planner.

5. **Effective Date:** June 4, 2007

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B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall: *[Violation Risk Factor: High]*

R1.1. Be made annually. *[Violation Risk Factor: Medium]*

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons. *[Violation Risk Factor: Medium]*

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s). *[Violation Risk Factor: Medium]*

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study. *[Violation Risk Factor: Medium]*

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses. *[Violation Risk Factor: Medium]*

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions. *[Violation Risk Factor: Medium]*

R1.3.4. Have established normal (pre-contingency) operating procedures in place. *[Violation Risk Factor: Medium]*

R1.3.5. Have all projected firm transfers modeled. *[Violation Risk Factor: Medium]*

R1.3.6. Be performed for selected demand levels over the range of forecast system demands. *[Violation Risk Factor: Medium]*

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies). *[Violation Risk Factor: Medium]*

R1.3.8. Include existing and planned facilities. *[Violation Risk Factor: Medium]*

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance. *[Violation Risk Factor: Medium]*

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A. *[Violation Risk Factor: Medium]*

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each: *[Violation Risk Factor: Medium]*

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon. *[Violation Risk Factor: Medium]*

R2.1.1. Including a schedule for implementation. *[Violation Risk Factor: Medium]*

R2.1.2. Including a discussion of expected required in-service dates of facilities. *[Violation Risk Factor: Medium]*

R2.1.3. Consider lead times necessary to implement plans. *[Violation Risk Factor: Medium]*

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed. *[Violation Risk Factor: Lower]*

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization. *[Violation Risk Factor: Lower]*

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R2.1 and TPL-001-0_R2.2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

None identified.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	April 4, 2007	Regulatory Approval — Effective Date	New

Table I — Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	 Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c]	 No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**

2. **Number:** TPL-002-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Transmission Planner.

5. **Effective Date:** June 4, 2007

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall: *[Violation Risk Factor: Medium]*

R1.1. Be made annually. *[Violation Risk Factor: Medium]*

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons. *[Violation Risk Factor: Medium]*

R1.3. Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). *[Violation Risk Factor: Medium]*

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. *[Violation Risk Factor: Medium]*

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. *[Violation Risk Factor: Medium]*

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R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses. *[Violation Risk Factor: Medium]*

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions. *[Violation Risk Factor: Medium]*

R1.3.5. Have all projected firm transfers modeled. *[Violation Risk Factor: Medium]*

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands. *[Violation Risk Factor: Medium]*

R1.3.7. Demonstrate that system performance meets Category B contingencies. *[Violation Risk Factor: Medium]*

R1.3.8. Include existing and planned facilities. *[Violation Risk Factor: Medium]*

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance. *[Violation Risk Factor: Medium]*

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems. *[Violation Risk Factor: Medium]*

R1.3.11. Include the effects of existing and planned control devices. *[Violation Risk Factor: Medium]*

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. *[Violation Risk Factor: Medium]*

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I. *[Violation Risk Factor: Medium]*

R1.5. Consider all contingencies applicable to Category B. *[Violation Risk Factor: Medium]*

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each: *[Violation Risk Factor: Medium]*

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon: *[Violation Risk Factor: Medium]*

R2.1.1. Including a schedule for implementation. *[Violation Risk Factor: Medium]*

R2.1.2. Including a discussion of expected required in-service dates of facilities. *[Violation Risk Factor: Medium]*

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R2.1.3. Consider lead times necessary to implement plans. *[Violation Risk Factor: Medium]*

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed. *[Violation Risk Factor: Medium]*

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization. *[Violation Risk Factor: Lower]*

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

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E. Regional Differences

None identified.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 4, 2007	Regulatory Approval — Effective Date	New

Table I — Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	 No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - 6. Loss of tower line with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**

2. **Number:** TPL-003-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Transmission Planner.

5. **Effective Date:** June 4, 2007

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall: *[Violation Risk Factor: High]*

R1.1. Be made annually. *[Violation Risk Factor: Medium]*

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons. *[Violation Risk Factor: Medium]*

R1.3. Be supported by a current or past study and/or system simulation testing that address each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). *[Violation Risk Factor: Medium]*

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. *[Violation Risk Factor: Medium]*

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R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. *[Violation Risk Factor: Medium]*

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses. *[Violation Risk Factor: Medium]*

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions. *[Violation Risk Factor: Medium]*

R1.3.5. Have all projected firm transfers modeled. *[Violation Risk Factor: Medium]*

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands. *[Violation Risk Factor: Medium]*

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies. *[Violation Risk Factor: Medium]*

R1.3.8. Include existing and planned facilities. *[Violation Risk Factor: Medium]*

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance. *[Violation Risk Factor: Medium]*

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems. *[Violation Risk Factor: Medium]*

R1.3.11. Include the effects of existing and planned control devices. *[Violation Risk Factor: Medium]*

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed. *[Violation Risk Factor: Medium]*

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C. *[Violation Risk Factor: Medium]*

R1.5. Consider all contingencies applicable to Category C. *[Violation Risk Factor: Medium]*

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each: *[Violation Risk Factor: Medium]*

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon: *[Violation Risk Factor: Medium]*

R2.1.1. Including a schedule for implementation. *[Violation Risk Factor: Medium]*

R2.1.2. Including a discussion of expected required in-service dates of facilities. *[Violation Risk Factor: Medium]*

R2.1.3. Consider lead times necessary to implement plans. *[Violation Risk Factor: Medium]*

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed. *[Violation Risk Factor: Lower]*

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization. *[Violation Risk Factor: Lower]*

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

None identified.

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F. Associated Documents

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Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata
0	April 4, 2007	Regulatory Approval — Effective Date	New

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Table I —Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of tower line with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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A. Introduction

1. **Title:** **System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)**

2. **Number:** TPL-004-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.

4. **Applicability:**

   4.1. Planning Authority.

   4.2. Transmission Planner.

5. **Effective Date:** June 4, 2007

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. To be valid, the Planning Authority's and Transmission Planner's assessment shall: *[Violation Risk Factor: Medium]*

R1.1. Be made annually. *[Violation Risk Factor: Medium]*

R1.2. Be conducted for near-term (years one through five). *[Violation Risk Factor: Medium]*

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category D contingencies of Table I. The specific elements selected (from within each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s). *[Violation Risk Factor: Medium]*

R1.3.1. Be performed and evaluated only for those Category D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information. *[Violation Risk Factor: Medium]*

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity. *[Violation Risk Factor: Medium]*

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses. *[Violation Risk Factor: Medium]*

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R1.3.4. Have all projected firm transfers modeled. *[Violation Risk Factor: Medium]*

R1.3.5. Include existing and planned facilities. *[Violation Risk Factor: Medium]*

R1.3.6. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance. *[Violation Risk Factor: Medium]*

R1.3.7. Include the effects of existing and planned protection systems, including any backup or redundant systems. *[Violation Risk Factor: Medium]*

R1.3.8. Include the effects of existing and planned control devices. *[Violation Risk Factor: Medium]*

R1.3.9. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed. *[Violation Risk Factor: Medium]*

R1.4. Consider all contingencies applicable to Category D. *[Violation Risk Factor: Medium]*

R2. The Planning Authority and Transmission Planner shall each document the results of its reliability assessments and shall annually provide the results to its entities' respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization. *[Violation Risk Factor: Lower]*

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment for its system responses as specified in Reliability Standard TPL-004-0_R1.

M2. The Planning Authority and Transmission Planner shall provide evidence to its Compliance Monitor that it reported documentation of results of its reliability assessments per Reliability Standard TPL-004-0_R1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Time Frame

Annually.

1.3. Data Retention

None specified.

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1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: A valid assessment, as defined above, for the near-term planning horizon is not available.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: Not applicable.

E. Regional Differences

None identified.

F. Associated Documents

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 4, 2007	Regulatory Approval — Effective Date	New

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Table I — Transmission System Standards — Normal and Emergency Conditions

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A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

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D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of tower line with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or System Voltage Limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

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