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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

IN THE MATTER OF THE REQUEST OF MINNESOTA POWER FOR A CERTIFICATE OF NEED FOR THE GREAT NORTHERN TRANSMISSION LINE PROJECT	MPUC Docket No. E015/CN-12-1163 OAH Docket No. 65-2500-31196

DIRECT TESTIMONY AND ATTACHMENTS OF SACHIN SHAH

ON BEHALF OF

THE DIVISION OF ENERGY RESOURCES OF
THE MINNESOTA DEPARTMENT OF COMMERCE

SEPTEMBER 19, 2014

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TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Sachin Shah. I am a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning (Department or DOC). My business address is 85 7th Place East, Suite 500, Saint Paul, Minnesota 55101.

Q. What is your educational and professional background?

A. A summary of my educational and professional background is presented in DOC Ex. ___ at (SS-1) (Shah Direct).

II. PURPOSE AND SCOPE

Q. What are your responsibilities in this proceeding?

A. My overall responsibility in this proceeding is to review the proposed need and address a subpart of Certificate of Need (CN) criteria established in Minnesota Rules part 7849.0120 in Minnesota Power, an operating division of ALLETE, Inc.'s (MP, Applicant, or the Company) Application for a Certificate of Need (Petition) to construct the Minnesota/Manitoba border—Blackberry 500 kV transmission line and associated facilities, referred to as the Great Northern Transmission Line (GNTL). 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. I note that my testimony focuses primarily on forecasting, whereas DOC Witness Dr. Steve Rakow discusses whether the Applicant has shown a need for the proposed facility under 7849.0120 A (2) through A (4).

Q. Do you address the overall summary and recommendations, analysis of alternatives, or the rest of the criteria established by Minnesota Statutes and Minnesota Rules, for example 7849.0120 A (2), in your testimony?

A. No. Department Witness Dr. Rakow presents the overall DOC recommendations regarding the overall summary and recommendations, analysis of alternatives, and the criteria established by Minnesota Statutes and Minnesota Rules.

Q. Did the Applicant request any exemptions to its filing requirements?

A. Yes. On November 20, 2012, prior to the filing of its initial application, the Applicant filed with the Minnesota Public Utilities Commission (Commission) a *Petition for Exemption from or Confirmation of Certain Filing Requirements – In the Matter of the Request by Minnesota Power for a Certificate of Need for the Great Northern Transmission Line*. MP requested these exemptions to assess whether the required data are necessarily applicable to MP's project. Instead, the Applicant proposed to provide data that are more relevant to the details associated with the proposed Project such as on the transfer capability requirements, data from its Advanced Forecast Report (AFR) on its industrial load growth, and on the analysis reviewed by the Commission when it approved MP's Power Purchase Agreement (PPA) with Manitoba Hydro (MH) for 250 MW in Docket No. E015-M-11-938 (11-938 Docket).

Q. What was the result of MP's petition for exemption from providing certain data?

A. On February 28, 2013, the Commission issued an *Order Approving Notice Plan, Granting Variance Request, and Approving Exemption Request* to certain filing requirements in Minnesota Rules. See February 28, 2013 Order at Pages 3 -5; included as MP Ex. ___ Appendix B (Initial Petition).

III. ASSESSMENT OF NEED

Q. According to MP, what need is to be addressed by the proposed GNTL?

A. On pages 2 and 3 of its Petition, MP stated the following:

> The Project will provide delivery and access to power generated by Manitoba Hydro's hydroelectric stations in Manitoba, Canada. The Project is required to facilitate delivery of 383 megawatts ("MW") of hydropower and wind storage energy products to serve Minnesota Power customers – including a 250 MW power purchase agreement ("PPA") and Energy Exchange Agreement ("EEA") (collectively the "250 MW Agreements"), approved by the Commission in 2012, along with a new agreement for an additional 133 MW Energy Sale Agreement and Energy Exchange Agreement (collectively, the "133 MW Renewable Optimization Agreements"). Combining the two agreements, Minnesota Power has procured a combined total of over 1.5 million megawatt hours ("MWh") annually, with the ability annually to store 1 million MWh of wind power in Manitoba Hydro's system.

Q. According to MP, what other needs are to be addressed by the proposed GNTL?

A. MP stated that Minnesota Power and Manitoba Hydro recently finalized a Term Sheet for the 133 MW Renewable Optimization Agreements (ROA). The ROA includes an additional 750,000 MWh of renewable energy storage, by June 1, 2020, included as MP Ex. ___ Appendix D (Initial Petition) (including both Public and Nonpublic versions). I note that the ROA has not been filed with the Commission, nor has it been analyzed, let alone approved. Thus, at this time it is not possible to conclude that the ROA is driving the need for the transmission line. In any event, MP's case regarding need is largely based upon the 250 MW PPA approved in the 11-938 Docket. Please see MP Ex. ___ at 3-5 (Petition).

Q. Does MP offer any other basis to conclude that the line might be needed?

A. Yes, in a general sense. On page 3 of its Petition, MP stated the following:

> Several other items also drive the need for a new transmission line to be built from Manitoba, Canada to Minnesota Power's Blackberry Substation, including the increasing demand for access to competitively priced, emission-free, renewable energy for Minnesota Power and the region, serving growing industrial load on the Iron Range, strengthening regional transmission reliability and taking advantage of the synergies of wind and hydroelectric power.

I note that Dr. Rakow discusses regional issues and generation capacity issues that have been developing in the Supply Adequacy Working Group (SAWG) of the Midcontinent Independent System Operator (MISO). Thus, I defer to his testimony on this issue.

Q. Please provide a brief description of the GNTL project.

A. According to MP, the Project represents the Minnesota portion of major new transmission facilities necessary to deliver the power called for under the Commission-approved 250 MW Agreements discussed above. In addition, on page 4 of its Petition, MP states in part the following:

> …The [11-]938 Docket completed a regulatory process of identifying Minnesota Power's resource needs and selecting the best means of meeting those needs. That process began with Minnesota Power's 2010 Integrated Resource Plan ("IRP" or "Plan") docket, MPUC Docket No. E- 015/RP-09-1088 ("1088 Docket"), where Minnesota Power included in its long-term action plan

> pursuing a "250 MW expansion of Manitoba Hydro generation and associated transmission in [the] 2020 time frame."[6] Subsequently, the Commission and Department affirmed that Minnesota Power had significant projected capacity and energy deficits over the period 2020-2035, and therefore the company "would need a significant additional amount of peaking capacity and energy to meet its future capacity and energy needs."[7]
>
> ---
>
> [6] MPUC Docket No. E-015/RP-09-1088, Order Accepting Resource Plan and Requiring Compliance Filings, May 6, 2011, p. 4.
>
> [7] Appendix C, Department Comments, p. 4.

Q. Were there any other Commission proceedings regarding MP's proposed GNTL?

A. Yes. As MP indicates above, on September 16, 2011 in Docket No. E015/M-11-938, MP petitioned the Commission for approval of the 250 MW System Power Sale Agreement (SPSA) and the Energy Exchange Agreement (EEA) between MP and MH (11-938 Docket). While MP may not have been required to obtain approval of the PPA, utilities often file with the Commission for approval of PPAs even when it is not required. Generally, they do so to reduce the risk that costs related to a PPA will be rejected by the Commission at a later date. In essence, it is better to seek approval in a PPA petition before spending money than to seek approval after spending money (in a rider or rate case) and not get reimbursed.

Q. Would you provide a very brief description of MP's agreements in the 11-938 Docket?

A. Yes. MP's petition in the 11-938 Docket described the two agreements as follows:

- the SPSA requires MP to purchase from Manitoba Hydro 250 MW of capacity and energy (250 MWh during 16 hours each day) from June 1, 2020 through May 31, 2035;
- the EEA allows MP to sell 250,000 MWh per year to Manitoba Hydro and later buy back that energy from June 1, 2020 through May 31, 2035.

Q. What were the main issues to be addressed by the Commission in reference to MP's agreements in the 11-938 Docket?

A. There were three main issues to be addressed by the Commission:

1) was there a need for the proposed capacity/energy?
2) if there was a need, what was the most appropriate type of resource to meet the need (baseload, peaking, wind, etc.)? and
3) was the PPA in the best interest of MP's ratepayers?

Q. How did the Commission decide these issues?

A. The Commission's February 1, 2012 Order approved MP's proposed SPSA and EEA.

Q. Based on your review of the Applicant's testimony what has the Applicant stated regarding the need for the Project?

A. The Applicant's witness Mr. Allan S. Rudeck, Jr. stated in his Direct Testimony:

> …Also in 2012, the Commission approved Minnesota Power's next long term base load power supply, a 250 MW Power Purchase Agreement ("PPA") and innovative Energy Exchange Agreement with Manitoba Hydro (collectively, the "250 MW Agreements") designed to optimize wind energy together with Manitoba Hydro hydroelectric generation, together bringing economic

> benefits to Minnesota Power customers. This additional, new source of carbon-free energy, and associated wind storage benefits, can only be realized by Minnesota Power, and provided by Manitoba Hydro, with the addition of a new, large transmission interconnect between the Province of Manitoba and the State of Minnesota.

MP Ex. ___ at 7-8 (Rudeck Direct).

At pages 9-10 in his Direct Testimony, Mr. Rudeck also stated the following:

> **Q. Along with working to diversify the Company's resource mix, has Minnesota Power identified the need for additional capacity and energy going forward?**
>
> A. Yes. Our Integrated Resource Plans ("IRP") and Advanced Forecasts consistently show the need for additional capacity and energy in the future. Beginning with Minnesota Power's 2010 Integrated Resource Plan ("IRP") docket, MPUC Docket No. E-015/RP-09-1088 ("1088 Docket"), Minnesota Power identified significant capacity and energy needs in the 2020 to 2035 time frame driven by customer load growth and diversification of its power supply. To address these load and supply changes, the Company included action in its 2010 IRP with the intent to pursue a 250 MW Power Purchase Agreement ("PPA") with Manitoba Hydro and associated new transmission to deliver that power, with power deliveries beginning in the 2020 timeframe. The inclusion of the Manitoba hydropower and new transmission, now the Great Northern Transmission Line, to deliver that power was part of the Company's least cost system-wide long term supply plan. The Minnesota Public Utilities Commission ("Commission") accepted the Company's 2010 IRP in 2011. Subsequently submitted Advanced Forecast Reports continue to support customer load growth outlook and the need for capacity and energy delivered by the Project.

MP Ex. ___ at 9-10 (Rudeck Direct).

Q. Based on the above, do you have any observations to offer?

A. Yes. As noted above, MP's PPA has already been addressed in the 11-938 Docket. In addition, I provide the Regional Energy Information System (REIS) data MP filed with the Department, under Minnesota Rules part 7610.0310, for reporting years 2009 through 2013. DOC Ex. ___ at (SS-2) (Shah Direct). Company Witness Mr. Rudeck included 2013 REIS data in his Direct Testimony. MP Ex. ___ (AJR), Schedule 1, page 102 of 106.

Q. What does your general observation in reference to the REIS data indicate?

A. As reported by MP, the REIS data indicates that MP generally has capacity deficits for both summer and winter for the period 2015 through 2019. Please see Figures 1 and 2 below. A negative figure indicates a deficit while a positive figure indicates a surplus.

Figure 1: Summer

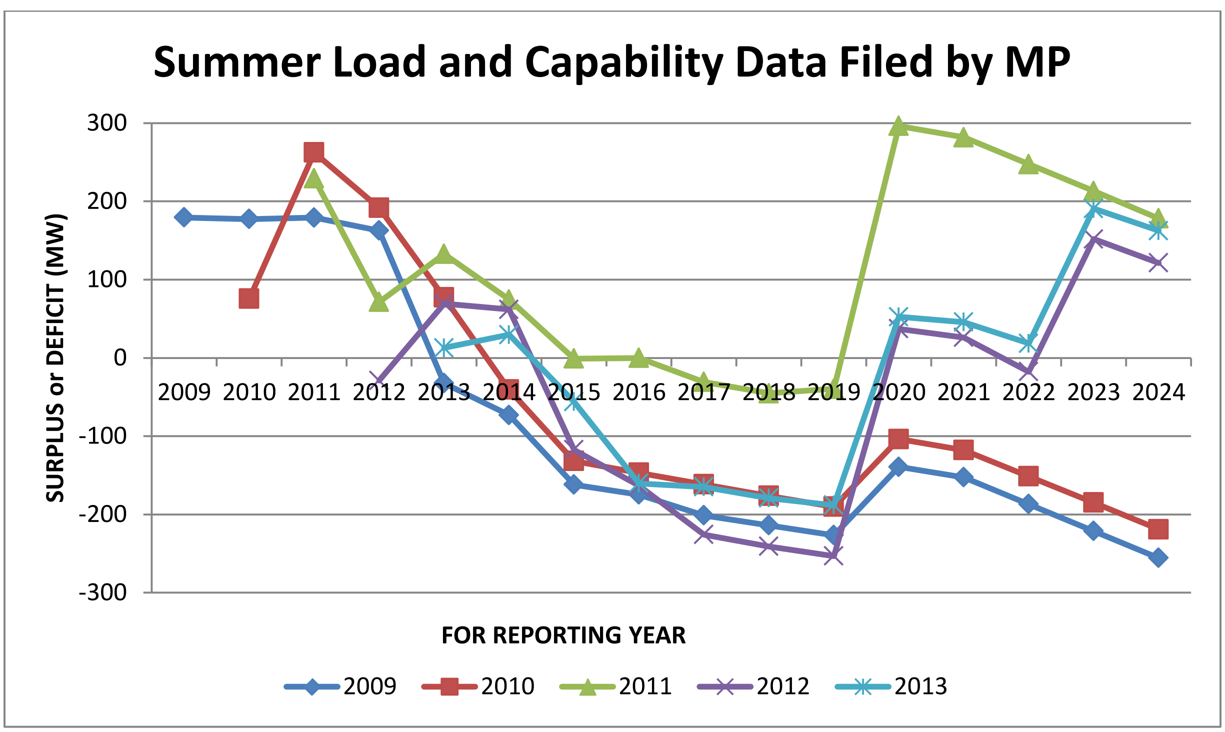
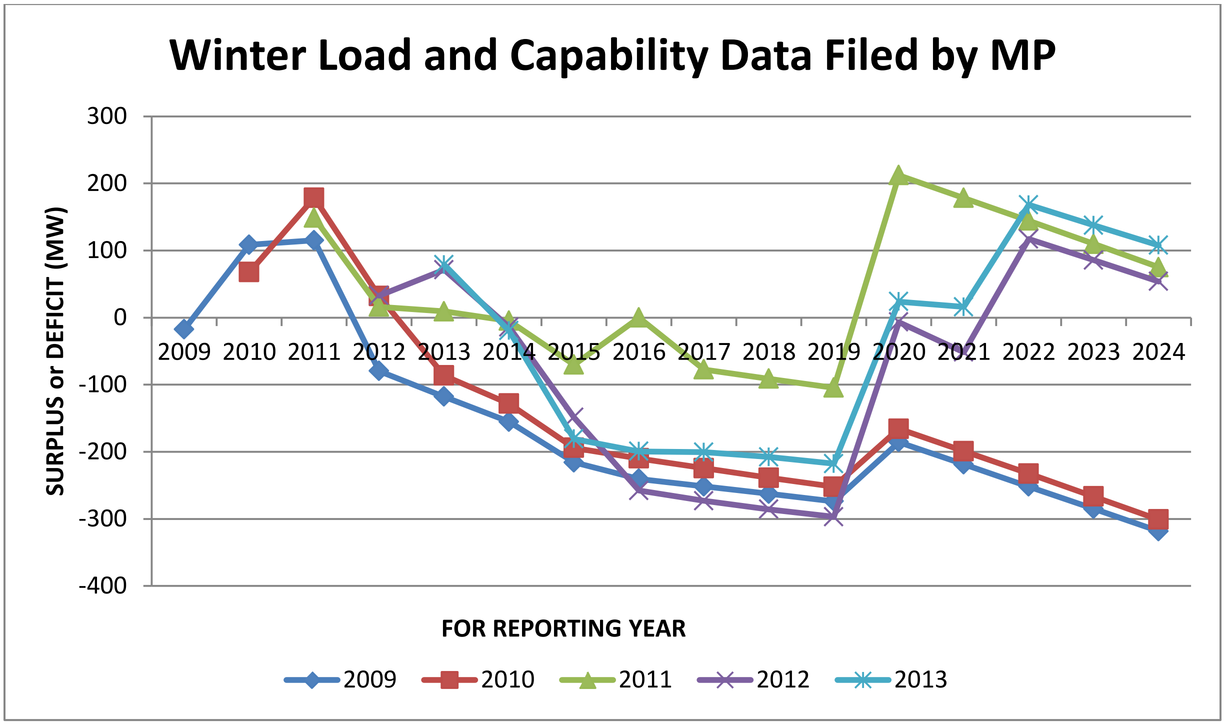


Figure 2: Winter



As shown above, MP's projected capacity deficits change to a surplus in the year 2020 once the MP-MH 250 MW contract begins.

Q. What additional information does the Company provide?

A. In the Company's most recent Integrated Resource Plan (IRP) filed with the Commission in Docket No. E015-RP-13-53 (13-53 Docket), included as MP Ex. ___ Appendix J (Initial Petition), on page 20 MP stated the following:

> Minnesota Power recognizes that not all projected growth in its industrial customer class will be forthcoming exactly on its proposed schedule. Through its econometric forecasting processes and by working closely with customers, Minnesota Power identified and included with its AFR2012 forecast submittal four scenarios for this growth potential and their impact to electric requirements in its service. For the 2013 Plan,

> the Wholesale Industrial Customer Addition scenario is utilized, recognizing 166 MW of overall industrial growth for this 15-year time period.

Q. What recommendations did the Department provide to the Commission in the Company's most recent IRP?

A. In the Department's *Comments* in the most recent IRP, on page 51[1] the Department stated the following:

> The Department recommends that the Commission require MP to:
>
> - initiate the process of retiring or selling Taconite Harbor unit 3 so that the unit is removed from MP's system by no later than the end of 2015;
> - switch the fuel of Laskin units 1 and 2 to natural gas by 2015;
> - add 100 to 200 MW of wind capacity in the 2014-2016 time frame as long as the resource is reasonably priced;
> - add about 200 MW of intermediate capacity in the 2015-2017 time frame as long as the resource is reasonably priced; and
> - procure energy savings equal to 1.87 percent of retail sales

Q. Based on the above, do you have any observations to offer?

A. Yes. With regards to the 2013 Advanced Forecast Report (AFR) and the most recent MP Integrated Resource Plan (IRP) filed with the Commission in Docket No. E015-RP-13-53 Docket, referenced above by Company Witness Mr. Rudeck and included as MP Ex. ____ Appendices H and J (Initial Petition), the specific analysis with regards to MP's 2013 AFR and the associated load and supply capacity has already been

[1] June 3rd, 2013 Comments of the Department in Docket No. E015/RP-13-53.

performed by the Department. I do not provide that analysis here and instead I confine my general observation in this testimony to the fact that MP's most recent IRP and the 2013 AFR has been approved by the Commission in its November 12, 2013 *Order Approving Resource Plan, Requiring Filings, and Setting Date for Next Resource Plan*. However, I note that, even after approval of the 250 MW PPA in 11-938, the Commission determined that MP needed to add capacity to its system in the subsequent IRP.

Q. Do any additional Company Witnesses' have statements regarding the need for the Project?

A. Yes. Company Witness David J. McMillan's Direct Testimony stated the following:

> **Q. Can you further describe the hydropower deliveries that the Project supports?**
>
> A. The Great Northern Transmission Line supports two sets of agreements between Minnesota Power and Manitoba Hydro. First, the Project supports the 2011 250 MW Power Purchase Agreement and Energy Exchange Agreement between Minnesota Power and Manitoba Hydro (collectively the "250 MW Agreements"), approved by the Minnesota Public Utilities Commission ("Commission") in 2012 in MPUC Docket No. E-015/M-11-938 ("[11-]938 Docket"). In addition to providing needed capacity and energy to Minnesota Power, the 250 MW Agreements contain innovative wind storage provisions that leverage the flexible and responsive nature of hydropower to enhance the value of Minnesota Power's significant wind energy investments.

MP Ex. ___ at 6-7 (McMillan Direct).

He further stated the following:

> …Moreover, the unique structure of the Manitoba Hydro Agreements means that the Project can meet Minnesota

> Power's needs, while protecting our ratepayers and also improving overall transmission system reliability and facilitating additional energy sales between Manitoba Hydro and other regional utilities – providing State and regional benefits.
>
> ...Not only will the Project meet Minnesota Power's needs by supporting the Manitoba Hydro Agreements, it will also benefit the State and region through increased reliability and capacity to import hydropower from Manitoba. Given Manitoba Hydro's current and pending agreements with other Minnesota and regional utilities,[3] Manitoba Hydro requires the transmission capacity available with a 500 kV line.
>
> ---
>
> 3 As discussed in the PUB's NFAT Report, Manitoba Hydro has current and future contracts totaling several hundred MW with Xcel Energy, Great River Energy and Wisconsin Public Service, in addition to its contracts with Minnesota Power.

MP Ex. ___ at 12; and 21 (McMillan Direct).

Q. Based on the above, do you have any observations to offer?

A. Yes. In MP's response to Department Information Request No. 6, MP provided additional information on MH's agreements with various utilities in Minnesota and a utility in Wisconsin. DOC Ex. ___ at (SS-3) (Shah Direct). That information indicates that there are various Transmission Service Requests (TSR's) between MISO and MH that involve MP and another utility in Wisconsin called Wisconsin Public Service (WPS) referenced above. I observe that the WPS TSRs indicate the potential need for more transmission capacity in addition to the capacity required for the MP agreements.

I note that Dr. Rakow discusses the issue of need for the 500 kV line in his direct testimony as to regional generation needs and externalities.

Q. Based on this information, what do you conclude?

A. At this time MP has filed a CN. In this proceeding, MP's claimed need is that a transmission line (at 230 kV or more) is needed to deliver the SPSA's energy and capacity. Thus, this proceeding doesn't involve a question of whether there is a need for the 250 MW energy and capacity or whether MH is the right resource—that has already been addressed in the 11-938 proceeding. As a result, I conclude that the accuracy of the forecast of demand has already been addressed as to the 250 MW of generation from MH. However, I note with the graphs above, based on recent information, that the 250 MW of generation continues to be needed to serve MP's customers reliably.

IV. CONCLUSION

Q. Please provide your conclusion at this time.

A. In this proceeding, I did not perform an analysis of the 2013 AFR or develop an alternative forecast to determine if MP has a need for energy and capacity as this has already been reviewed and approved by the Commission in the 13-53 Docket. More importantly, as described above the accuracy of the forecast of demand as to the determination of the claimed need for 250 MW and whether MH is the right resource was already addressed and approved in the 11-938 Docket. However, I note with the graphs above, based on recent information, that the 250 MW of generation continues to be needed to serve MP's customers reliably.

Q. Does this conclude your Direct Testimony?

A. Yes.

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Division of Energy Resources
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St. Paul, MN55101-2198

EDUCATION

- University of North Carolina-Charlotte, Master of Science, Economics, 1996.

- University of North Carolina-Charlotte, Bachelor of Arts, Major in Economics and Minor in Political Science, 1993

Prior to joining the Department of Commerce from January, 1998 till July, 1999, I worked at a CPA firm in St. Louis where I prepared tax returns and maintained clients' general ledger databases. After leaving the CPA firm I worked as Brokerage Service Associate with American Express Financial Advisors. I Assisted clients and financial advisors with their brokerage account service needs via telephone, provided basic financial market information and processed securities transactions and payment requests. Obtained Series 7 securities registration / license.

EXPERIENCE AT DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

I have been employed as a Rates Analyst with the Department of Commerce, Division of Energy Resources (DOC-DER) since February, 2000. During my time with the Department of Commerce, Division of Energy Resources I have been assigned a wide variety of filings dealing with a number of different issues. For example:

As a rates analyst for the Department of Commerce, Division of Energy Resources, my duties have included evaluating comments on different issues, such as investigating and filing testimony and comments for forecasting in:

- UtiliCorp United Inc.'s Request for an Increase in Rates in Docket No. G007,011 /GR-00-951;
- Great Plains Request for an Increase in Rates in Docket No. G004/GR-02-1682;
- Hutchinson Utilities Commission's Certificate of Need proceeding in Docket No. G252/CN-01-1826;
- Dakota Electric's Request for an Increase in Rates in Docket No. E111/GR-03-261;
- Interstate Power and Light Company's Request for an Increase in Electric Rates in Docket No. E001/GR-03-767;
- CenterPoint Energy Minnegasco, a Division of CenterPoint Resources Corp., Request for an Increase in Rates in Docket No. G008/GR-04-901;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-04-1511;
- Montana Dakota Utilities d/b/a Great Plains Request for an Increase in Rates in Docket No. G004/GR-04-1487;
- Alliant Energy d/b/a Interstate Power and Light Company's Resource Plan in Docket No. E001/RP-05-2029;
- Great River Energy's Resource Plan in Docket No. ET2/RP-08-784;
- Dakota Electric's Request for an Increase in Rates in Docket No. E111/GR-09-175;
- Northern States Power Company d/b/a Xcel Energy Request for an Increase in Rates in Docket No. G002/GR-09-1153;
- Interstate Power and Light Company's Request for an Increase in Electric Rates in Docket No. E001/GR-10-276;
- Alliant Energy d/b/a Interstate Power and Light Company's Resource Plan in Docket No. E001/RP-08-673;
- Minnesota Power and Great River Energy's Certificate of Need proceeding in Docket No. ET2, E015/CN-10-973;
- Xcel Energy's Certificate of Need proceeding in Docket No. E002/CN-11-332;
- Xcel Energy's Certificate of Need proceeding in Docket No. E002/CN-12-113;
- Minnesota Power's Resource Plan in Docket No. E015/RP-13-53;
- In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need in Docket No. E002/CN-12-1240; and
- Northern States Power Company d/b/a Xcel Energy Request for Authority to Increase Rates for Electric Service in Minnesota in Docket No. E002/GR-13-868.

My duties have also included reviewing miscellaneous rate and fuel procurement filings involving gas utilities, for example, evaluating Demand Entitlement and True-up filings. 1 was previously responsible for producing the Quarterly PGA summary, and producing and coordinating the publication of the DOC-DER's Annual Fuel Reports (Gas). I have also provided testimony on natural gas in The Matter of Application of Mankato Energy Center, LLC, A Wholly Owned Subsidiary of Calpine Corporation, for a Certificate of Need for A Large Electric Generating Facility in Docket No. IP6345/CN-03-1884.

SEMINARS

National Association of Regulatory Utility- Commissioners' 42ntI Annual Regulatory Studies Program, Institute of Public Utilities, Michigan State University, 2000

MINNESOTA POWER
2009 ADVANCE FORECAST REPORT

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0310 Item G. LOAD AND GENERATION CAPACI (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2009	Summer	1,350	82	1,268	1,452	0	175	1,443	1,627	1,871	284	350	1,805	183	1,626	179
		Winter	1,545	93	1,452	1,452	0	175	1,627	1,627	1,895	472	550	1,817	207	1,834	-17
Present Year	2010	Summer	1,735	174	1,561	1,625	0	0	1,561	1,625	1,853	322	250	1,925	186	1,747	177
		Winter	1,779	154	1,625	1,625	0	0	1,625	1,625	1,856	222	150	1,928	194	1,819	108
1st Forecast Year	2011	Summer	1,722	100	1,622	1,686	0	0	1,622	1,686	1,910	184	100	1,994	194	1,815	179
		Winter	1,786	100	1,686	1,686	0	0	1,686	1,686	1,918	184	100	2,002	201	1,887	115
2nd Forecast Year	2012	Summer	1,743	100	1,643	1,697	0	0	1,643	1,697	1,918	184	100	2,002	196	1,839	163
		Winter	1,797	100	1,697	1,697	0	0	1,697	1,697	1,835	84	100	1,819	203	1,899	-80
3rd Forecast Year	2013	Summer	1,754	100	1,654	1,707	0	0	1,654	1,707	1,835	84	100	1,819	198	1,852	-32
		Winter	1,807	100	1,707	1,707	0	0	1,707	1,707	1,809	84	100	1,793	204	1,911	-118
4th Forecast Year	2014	Summer	1,767	100	1,667	1,716	0	0	1,667	1,716	1,809	84	100	1,793	199	1,866	-73
		Winter	1,816	100	1,716	1,716	0	0	1,716	1,716	1,782	84	100	1,766	205	1,921	-155
5th Forecast Year	2015	Summer	1,778	100	1,678	1,726	0	0	1,678	1,726	1,782	34	100	1,716	200	1,878	-162
		Winter	1,826	100	1,726	1,726	0	0	1,726	1,726	1,782	34	100	1,716	206	1,932	-216
6th Forecast Year	2016	Summer	1,789	100	1,689	1,736	0	0	1,689	1,736	1,782	34	100	1,716	202	1,891	-175
		Winter	1,836	100	1,736	1,736	0	0	1,736	1,736	1,782	20	100	1,702	207	1,943	-240
7th Forecast Year	2017	Summer	1,801	100	1,701	1,745	0	0	1,701	1,745	1,782	20	100	1,702	203	1,904	-201
		Winter	1,845	100	1,745	1,745	0	0	1,745	1,745	1,782	20	100	1,702	208	1,954	-252
8th Forecast Year	2018	Summer	1,812	100	1,712	1,755	0	0	1,712	1,755	1,782	20	100	1,702	204	1,916	-214
		Winter	1,855	100	1,755	1,755	0	0	1,755	1,755	1,782	20	100	1,702	210	1,965	-263
9th Forecast Year	2019	Summer	1,823	100	1,723	1,765	0	0	1,723	1,765	1,782	20	100	1,702	206	1,929	-227
		Winter	1,865	100	1,765	1,765	0	0	1,765	1,765	1,782	20	100	1,702	211	1,976	-274
10th Forecast Year	2020	Summer	1,835	100	1,735	1,776	0	0	1,735	1,776	1,782	20	0	1,802	207	1,942	-139
		Winter	1,876	100	1,776	1,776	0	0	1,776	1,776	1,782	20	0	1,802	212	1,988	-186
11th Forecast Year	2021	Summer	1,846	100	1,746	1,786	0	0	1,746	1,786	1,782	20	0	1,802	209	1,955	-153
		Winter	1,886	100	1,786	1,786	0	0	1,786	1,786	1,761	20	0	1,781	213	2,000	-219
12th Forecast Year	2022	Summer	1,858	100	1,758	1,797	0	0	1,758	1,797	1,761	20	0	1,781	210	1,968	-187
		Winter	1,897	100	1,797	1,797	0	0	1,797	1,797	1,739	20	0	1,760	215	2,012	-252
13th Forecast Year	2023	Summer	1,870	100	1,770	1,808	0	0	1,770	1,808	1,739	20	0	1,760	211	1,981	-221
		Winter	1,908	100	1,808	1,808	0	0	1,808	1,808	1,718	20	0	1,738	216	2,023	-285
14th Forecast Year	2024	Summer	1,881	100	1,781	1,818	0	0	1,781	1,818	1,718	20	0	1,738	213	1,994	-256
		Winter	1,918	100	1,818	1,818	0	0	1,818	1,818	1,697	20	0	1,717	217	2,035	-318

COMMENTS

7610.0310 Item G. LOAD AND GENERATION (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULEL PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2010	Summer	1,737	174	1,563	1,662	0	0	1,563	1,662	1,853	322	350	1,825	187	1,749	76
		Winter	1,789	127	1,662	1,662	0	0	1,662	1,662	1,856	222	150	1,928	198	1,860	68
Present Yea	2011	Summer	1,720	127	1,593	1,674	0	0	1,593	1,674	1,964	184	100	2,048	192	1,786	262
		Winter	1,774	100	1,674	1,674	0	0	1,674	1,674	1,970	184	100	2,055	202	1,876	179
1st Forecast	2012	Summer	1,727	100	1,627	1,680	0	0	1,627	1,680	1,930	184	100	2,014	196	1,823	192
		Winter	1,780	100	1,680	1,680	0	0	1,680	1,680	1,930	84	100	1,914	203	1,882	32
2nd Forecast	2013	Summer	1,739	100	1,639	1,695	0	0	1,639	1,695	1,930	84	100	1,914	198	1,837	77
		Winter	1,795	100	1,695	1,695	0	0	1,695	1,695	1,829	84	100	1,813	204	1,899	-86
3rd Forecast	2014	Summer	1,754	100	1,654	1,710	0	0	1,654	1,710	1,829	84	100	1,813	199	1,854	-41
		Winter	1,810	100	1,710	1,710	0	0	1,710	1,710	1,804	84	100	1,788	206	1,917	-128
4th Forecast	2015	Summer	1,769	100	1,669	1,724	0	0	1,669	1,724	1,804	34	100	1,738	201	1,870	-132
		Winter	1,824	100	1,724	1,724	0	0	1,724	1,724	1,804	34	100	1,738	208	1,932	-194
5th Forecast	2016	Summer	1,782	100	1,682	1,738	0	0	1,682	1,738	1,804	34	100	1,738	203	1,885	-147
		Winter	1,838	100	1,738	1,738	0	0	1,738	1,738	1,804	34	100	1,738	210	1,948	-210
6th Forecast	2017	Summer	1,795	100	1,695	1,751	0	0	1,695	1,751	1,804	34	100	1,738	204	1,900	-161
		Winter	1,851	100	1,751	1,751	0	0	1,751	1,751	1,804	34	100	1,738	211	1,963	-224
7th Forecast	2018	Summer	1,808	100	1,708	1,764	0	0	1,708	1,764	1,804	34	100	1,738	206	1,914	-176
		Winter	1,864	100	1,764	1,764	0	0	1,764	1,764	1,804	34	100	1,738	213	1,977	-239
8th Forecast	2019	Summer	1,821	100	1,721	1,776	0	0	1,721	1,776	1,804	34	100	1,738	208	1,928	-190
		Winter	1,876	100	1,776	1,776	0	0	1,776	1,776	1,804	34	100	1,738	214	1,990	-252
9th Forecast	2020	Summer	1,833	100	1,733	1,788	0	0	1,733	1,788	1,804	34	0	1,838	209	1,942	-104
		Winter	1,888	100	1,788	1,788	0	0	1,788	1,788	1,804	34	0	1,838	216	2,004	-166
10th Forecast	2021	Summer	1,845	100	1,745	1,800	0	0	1,745	1,800	1,804	34	0	1,838	210	1,956	-118
		Winter	1,900	100	1,800	1,800	0	0	1,800	1,800	1,784	34	0	1,818	217	2,018	-199
11th Forecast	2022	Summer	1,858	100	1,758	1,813	0	0	1,758	1,813	1,784	34	0	1,818	212	1,970	-151
		Winter	1,913	100	1,813	1,813	0	0	1,813	1,813	1,764	34	0	1,799	219	2,031	-233
12th Forecast	2023	Summer	1,870	100	1,770	1,825	0	0	1,770	1,825	1,764	34	0	1,799	213	1,983	-185
		Winter	1,925	100	1,825	1,825	0	0	1,825	1,825	1,745	34	0	1,779	220	2,045	-267
13th Forecast	2024	Summer	1,883	100	1,783	1,838	0	0	1,783	1,838	1,745	34	0	1,779	215	1,998	-219
		Winter	1,938	100	1,838	1,838	0	0	1,838	1,838	1,725	34	0	1,759	222	2,060	-301
14th Forecast	2025	Summer	1,896	100	1,796	1,850	0	0	1,796	1,850	1,725	34	0	1,759	217	2,012	-253
		Winter	1,950	100	1,850	1,850	0	0	1,850	1,850	1,705	34	0	1,739	223	2,074	-334

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

7610.0310 Item G. LOAD AND GENERATION CAPACI (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2011	Summer	1,746		1,746	1,779	-	-	1,746	1,779	2,086	184	100	2,170	195	1,941	229
		Winter	1,779		1,779	1,779	-	-	1,779	1,779	2,093	184	150	2,127	199	1,978	149
Present Year	2012	Summer	1,722		1,722	1,776	-	-	1,722	1,776	2,071	183	280	1,974	181	1,903	71
		Winter	1,776		1,776	1,776	-	-	1,776	1,776	1,999	83	100	1,982	190	1,966	16
1st Forecast Year	2013	Summer	1,728		1,728	1,774	-	-	1,728	1,774	2,061	83	100	2,044	184	1,912	133
		Winter	1,774		1,774	1,774	-	-	1,774	1,774	1,988	83	100	1,971	188	1,962	9
2nd Forecast Year	2014	Summer	1,724		1,724	1,787	-	-	1,724	1,787	1,999	83	100	1,982	184	1,908	75
		Winter	1,787		1,787	1,787	-	-	1,787	1,787	1,988	83	100	1,971	189	1,976	-5
3rd Forecast Year	2015	Summer	1,738		1,738	1,800	-	-	1,738	1,800	1,988	33	100	1,921	184	1,922	-1
		Winter	1,800		1,800	1,800	-	-	1,800	1,800	1,988	33	100	1,921	191	1,991	-70
4th Forecast Year	2016	Summer	1,752		1,752	1,813	-	-	1,752	1,813	1,988	33	100	1,921	185	1,938	-16
		Winter	1,813		1,813	1,813	-	-	1,813	1,813	1,988	33	100	1,921	192	2,005	-84
5th Forecast Year	2017	Summer	1,765		1,765	1,825	-	-	1,765	1,825	1,988	33	100	1,921	187	1,952	-31
		Winter	1,825		1,825	1,825	-	-	1,825	1,825	2,008	33	100	1,941	194	2,019	-77
6th Forecast Year	2018	Summer	1,778		1,778	1,838	-	-	1,778	1,838	1,988	33	100	1,921	188	1,967	-45
		Winter	1,838		1,838	1,838	-	-	1,838	1,838	2,008	33	100	1,941	195	2,033	-91
7th Forecast Year	2019	Summer	1,791		1,791	1,849	-	-	1,791	1,849	2,008	33	100	1,941	190	1,981	-40
		Winter	1,849		1,849	1,849	-	-	1,849	1,849	2,008	33	100	1,941	196	2,046	-104
8th Forecast Year	2020	Summer	1,804		1,804	1,862	-	-	1,804	1,862	2,008	283	-	2,291	191	1,995	296
		Winter	1,862		1,862	1,862	-	-	1,862	1,862	1,988	283	-	2,271	198	2,059	212
9th Forecast Year	2021	Summer	1,817		1,817	1,874	-	-	1,817	1,874	2,008	283	-	2,291	193	2,010	282
		Winter	1,874		1,874	1,874	-	-	1,874	1,874	1,968	283	-	2,251	199	2,073	178
10th Forecast Year	2022	Summer	1,830		1,830	1,886	-	-	1,830	1,886	1,988	283	-	2,271	194	2,024	247
		Winter	1,886		1,886	1,886	-	-	1,886	1,886	1,948	283	-	2,231	201	2,087	144
11th Forecast Year	2023	Summer	1,843		1,843	1,899	-	-	1,843	1,899	1,968	283	-	2,251	196	2,038	213
		Winter	1,899		1,899	1,899	-	-	1,899	1,899	1,928	283	-	2,211	202	2,101	110
12th Forecast Year	2024	Summer	1,856		1,856	1,913	-	-	1,856	1,913	1,948	283	-	2,231	197	2,053	178
		Winter	1,913		1,913	1,913	-	-	1,913	1,913	1,908	283	-	2,191	204	2,116	75
13th Forecast Year	2025	Summer	1,870		1,870	1,927	-	-	1,870	1,927	1,928	283	-	2,211	199	2,069	142
		Winter	1,927		1,927	1,927	-	-	1,927	1,927	1,908	283	-	2,191	205	2,132	60
14th Forecast Year	2026	Summer	1,884		1,884	1,941	-	-	1,884	1,941	1,908	283	-	2,191	200	2,085	107
		Winter	1,941		1,941	1,941	-	-	1,941	1,941	1,908	283	-	2,191	207	2,147	44

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION (Express in MW)

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15
			SEASONAL MAXIMUM DEMAND	SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	SEASONAL SYSTEM DEMAND	ANNUAL SYSTEM DEMAND	SEASONAL FIRM PURCHASES (TOTAL)	SEASONAL FIRM SALES (TOTAL)	SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	NET GENERATING CAPABILITY	PARTICIPATION PURCHASES (TOTAL)	PARTICIPATION SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2012	Summer	1790		1790	1790			1790	1790	2070	184	305	1949	188	1978	-29
		Winter	1774		1774	1790			1774	1790	2013	84	100	1997	190	1964	33
Present Year	2013	Summer	1731		1731	1757			1731	1757	2051	84	150	1985	185	1916	69
		Winter	1757		1757	1757			1757	1757	1983	134	100	2017	188	1946	71
1st Forecast	2014	Summer	1766		1766	1848			1766	1848	1983	134	100	2017	189	1955	62
		Winter	1848		1848	1848			1848	1848	1999	134	100	2032	198	2046	-14
2nd Forecast	2015	Summer	1832		1832	1874			1832	1874	1927	84	100	1911	196	2028	-117
		Winter	1874		1874	1874			1874	1874	1941	84	100	1925	200	2073	-149
3rd Forecast	2016	Summer	1887		1887	1972			1887	1972	1941	84	100	1925	201	2088	-163
		Winter	1972		1972	1972			1972	1972	1941	84	100	1925	211	2182	-258
4th Forecast	2017	Summer	1943		1943	1985			1943	1985	1941	84	100	1925	207	2150	-226
		Winter	1985		1985	1985			1985	1985	1941	84	100	1925	212	2198	-273
5th Forecast	2018	Summer	1956		1956	1997			1956	1997	1941	84	100	1925	209	2165	-241
		Winter	1997		1997	1997			1997	1997	1941	84	100	1925	214	2210	-286
6th Forecast	2019	Summer	1967		1967	2007			1967	2007	1941	84	100	1925	210	2178	-253
		Winter	2007		2007	2007			2007	2007	1941	84	100	1925	215	2222	-297
7th Forecast	2020	Summer	1976		1976	2016			1976	2016	1941	284	0	2225	211	2188	37
		Winter	2016		2016	2016			2016	2016	1941	284	0	2225	216	2231	-7
8th Forecast	2021	Summer	1986		1986	2026			1986	2026	1941	284	0	2225	212	2199	26
		Winter	2026		2026	2026			2026	2026	1921	270	0	2191	217	2243	-52
9th Forecast	2022	Summer	1996		1996	2036			1996	2036	1921	270	0	2191	213	2209	-18
		Winter	2036		2036	2036			2036	2036	2101	270	0	2371	218	2254	117
10th Forecast	2023	Summer	2005		2005	2047			2005	2047	2101	270	0	2371	215	2220	152
		Winter	2047		2047	2047			2047	2047	2081	270	0	2351	219	2266	86
11th Forecast	2024	Summer	2015		2015	2057			2015	2057	2081	270	0	2351	216	2230	121
		Winter	2057		2057	2057			2057	2057	2061	270	0	2331	220	2278	54
12th Forecast	2025	Summer	2024		2024	2068			2024	2068	2061	270	0	2331	217	2240	91
		Winter	2068		2068	2068			2068	2068	2041	270	0	2311	222	2290	21
13th Forecast	2026	Summer	2033		2033	2079			2033	2079	2041	270	0	2311	218	2251	61
		Winter	2079		2079	2079			2079	2079	2041	270	0	2311	223	2302	10
14th Forecast	2027	Summer	2042		2042	2089			2042	2089	2041	270	0	2311	219	2261	50
		Winter	2089		2089	2089			2089	2089	2041	270	0	2311	224	2313	-2

COMMENTS

The deficit of 29 MW for the 2012 Summer period does not reflect non-compliance with MISO Resource Adequacy requirements. Minnesota Power was resource adequate for this historical timeframe. Per MISO rules, Minnesota Power submitted a peak demand estimate to MISO of 1729 MW based on a 50/50 forecast methodology (pg. 42 of AFR 2011 Forecast Methodology). Minnesota Power had sufficient capacity resources to meet the projected peak demand plus the planning reserve margin.

The actual peak demand for the 2012 summer timeframe was 1790 MW, which results in an apparent deficit of 29 MW. Based on the peak demand forecast submitted to MISO for Resource Adequacy compliance Minnesota Power was surplus capacity for the summer period by 32 MW. The difference between the peak demand forecast and actual peak was 61 MW. When the 61 MW change in the peak demand value is netted from the 32 MW surplus in capacity, the result is a 29 MW apparent deficiency in capacity (32 MW – 61 MW = -29 MW deficit).

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item G. LOAD AND GENERATION (Express in MW)

			Column 1 SEASONAL MAXIMUM DEMAND	Column 2 SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND	Column 3 SEASONAL SYSTEM DEMAND	Column 4 ANNUAL SYSTEM DEMAND	Column 5 SEASONAL FIRM PURCHASES (TOTAL)	Column 6 SEASONAL FIRM SALES (TOTAL)	Column 7 SEASONAL ADJUSTED NET DEMAND (3 - 5 + 6)	Column 8 ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)	Column 9 NET GENERATIN G CAPABILITY	Column 10 PARTICIPATIO N PURCHASES (TOTAL)	Column 11 PARTICIPATI ON SALES (TOTAL)	Column 12 ADJUSTED NET CAPABILITY (9 + 10 - 11)	Column 13 NET RESERVE CAPACITY OBLIGATION	Column 14 TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	Column 15 SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)
Past Year	2013	Summer	1782		1782	1782			1782	1782	2058	77	150	1985	191	1972	13
		Winter	1751		1751	1782			1751	1782	1990	127	100	2017	187	1938	79
Present Yea	2014	Summer	1727		1727	1772			1727	1772	1885	157	100	1942	185	1912	30
		Winter	1772		1772	1772			1772	1772	1885	157	100	1942	190	1961	-20
1st Forecast	2015	Summer	1807		1807	1931			1807	1931	1918	127	100	1945	194	2001	-56
		Winter	1931		1931	1931			1931	1931	1930	127	100	1957	208	2138	-181
2nd Forecast	2016	Summer	1923		1923	1958			1923	1958	1942	127	100	1969	207	2129	-160
		Winter	1958		1958	1958			1958	1958	1942	127	100	1969	211	2168	-199
3rd Forecast	2017	Summer	1941		1941	1973			1941	1973	1956	127	100	1983	207	2148	-165
		Winter	1973		1973	1973			1973	1973	1956	127	100	1983	211	2184	-201
4th Forecast	2018	Summer	1954		1954	1979			1954	1979	1956	127	100	1983	209	2162	-179
		Winter	1979		1979	1979			1979	1979	1956	127	100	1983	212	2191	-208
5th Forecast	2019	Summer	1962		1962	1988			1962	1988	1956	127	100	1983	210	2171	-188
		Winter	1988		1988	1988			1988	1988	1956	127	100	1983	213	2201	-218
6th Forecast	2020	Summer	1970		1970	1996			1970	1996	1956	277	0	2233	211	2181	53
		Winter	1996		1996	1996			1996	1996	1956	277	0	2233	214	2209	24
7th Forecast	2021	Summer	1976		1976	2003			1976	2003	1956	277	0	2233	211	2187	46
		Winter	2003		2003	2003			2003	2003	1956	277	0	2233	214	2217	16
8th Forecast	2022	Summer	1982		1982	2010			1982	2010	1936	277	0	2213	212	2195	19
		Winter	2010		2010	2010			2010	2010	2116	277	0	2393	215	2225	168
9th Forecast	2023	Summer	1990		1990	2019			1990	2019	2116	277	0	2393	213	2202	191
		Winter	2019		2019	2019			2019	2019	2096	277	0	2373	216	2235	137
10th Forecast	2024	Summer	1997		1997	2028			1997	2028	2096	277	0	2373	214	2210	162
		Winter	2028		2028	2028			2028	2028	2076	277	0	2353	217	2245	108
11th Forecast	2025	Summer	2004		2004	2035			2004	2035	2076	277	0	2353	214	2218	134
		Winter	2035		2035	2035			2035	2035	2056	277	0	2333	218	2253	79
12th Forecast	2026	Summer	2011		2011	2044			2011	2044	2056	277	0	2333	215	2227	106
		Winter	2044		2044	2044			2044	2044	2056	277	0	2333	219	2263	70
13th Forecast	2027	Summer	2019		2019	2053			2019	2053	2056	277	0	2333	216	2235	97
		Winter	2053		2053	2053			2053	2053	2056	277	0	2333	220	2273	59
14th Forecast	2028	Summer	2027		2027	2063			2027	2063	2056	277	0	2333	217	2244	89
		Winter	2063		2063	2063			2063	2063	2056	277	0	2333	221	2284	49

COMMENTS

Minnesota Power utilizes MISO's ICAP Reserve Capacity calculation and reserve margin assumption of 11.32%

Method for calculating Reserve Capacity Obligation:
[(Peak Demand - Demand Resource) x (1+11.32%)] - Peak Demand + Demand Resource = Net Reserve Capacity Obligation

Net Generating Capability values (column 9) are taken from MISO PY 2014-2015. Available Demand Resource MW is included in Net Generating Capability to balance Load and Capability.

Note: The above table reflects the most current econometric forecast and customer assumptions. Minnesota Power's MISO Peak Demand Submittal for summer of 2014 was based on a non-coincident peak of 1735 MW. The winter peak forecast was 1783 MW. 2013 peak demand values are actuals. Thus, the surplus/ deficit shown in the above table will vary from what was entered in MISO Module E in November 2013.

As shown in Minnesota Power's most recent Integrated Resource Plan, Minnesota Power is in the process of executing a bilateral bridging strategy to address the deficits identified in the 2016-2019 timeframe

YEAR	MN Rule 7610.0310 Item G -- SUMMER SURPLUS (+) OR DEFICIT (-) CAPACITY -- --- BY REPORTING YEAR				
	2009	2010	2011	2012	2013
2009	179				
2010	177	76			
2011	179	262	229		
2012	163	192	71	-29	
2013	-32	77	133	69	13
2014	-73	-41	75	62	30
2015	-162	-132	-1	-117	-56
2016	-175	-147	0	-163	-160
2017	-201	-161	-31	-226	-165
2018	-214	-176	-45	-241	-179
2019	-227	-190	-40	-253	-188
2020	-139	-104	296	37	53
2021	-153	-118	282	26	46
2022	-187	-151	247	-18	19
2023	-221	-185	213	152	191
2024	-256	-219	178	121	162

YEAR	MN Rule 7610.0310 Item G -- WINTER SURPLUS (+) OR DEFICIT (-) CAPACITY -- --- BY REPORTING YEAR				
	2009	2010	2011	2012	2013
2009	-17				
2010	108	68			
2011	115	179	149		
2012	-80	32	16	33	
2013	-118	-86	9	71	79
2014	-155	-128	-5	-14	-20
2015	-216	-194	-70	-149	-181
2016	-240	-210	0	-258	-199
2017	-252	-224	-77	-273	-201
2018	-263	-239	-91	-286	-208
2019	-274	-252	-104	-297	-218
2020	-186	-166	212	-7	24
2021	-219	-199	178	-52	16
2022	-252	-233	144	117	168
2023	-285	-267	110	86	137
2024	-318	-301	75	54	108

*Highlighted part indicates actual for that year

minnesota power
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July 16, 2014

VIA EMAIL

Mr. Alexius Hofschulte
MN Office of Energy Security
85 7th Place East
Suite 500
St. Paul, MN 55101-2198

RE: Department of Commerce Information Requests
Docket No. E015/CN-12-1163

Dear Mr. Hofschulte:

Attached please find Minnesota Power's response to the Department of Commerce Information Requests Nos. 4 through 12 and 15 through 20, in the above-referenced Docket, including attachments. As I discussed with Mr. Rakow, responses to Information Requests Nos. 13 and 14 will be provided by July 25, 2014.

Please contact me at the number above should you have any questions related to this matter.

Yours truly,

David R. Moeller

Attachments
c: Carol Overland
Andrew Moratzka

9298073v1

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request:July 7, 2014

Requested From: David R. Moeller, Senior Attorney Response Due:July 17, 2014

Analyst Requesting Information: Stephen Rakow

Type of Inquiry:	[ ] Financial	[ ] Rate of Return	[ ] Rate Design
	[ ] Engineering	[ ] Forecasting	[ ] Conservation
	[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
6	Please provide the final reports related to Appendix Q (see page 69 of the Petition) or indicate that MP will provide the final reports in direct testimony.

Response:

The TSR reports referenced on page 69 of the Petition were never produced as final reports. Attached are the last revisions that were issued by MISO on July 3rd, 2013, (MH-MP_AC_Thermal_Sensitivity_Analysis-Western_Plan-Draft_Report-01-07-13.pdf) and (MH-MP_AC_Thermal_Sensitivity_Analysis-Eastern_Plan-Draft_Report-01-07-13.pdf). This previous analysis was tabled in favor of revised model assumptions as well as new TSRs requests. This revised TSR study was completed and issued in a final report by MISO on May 30th, 2014 (SISR_A627_A628_A629_A630_Report_FINAL.pdf).

Response by: Scott Hoberg________________ List Sources of Information:

Title: Engineer Senior______________ ________________________________

Department: System Performance & Transmission Planning _______________________

Telephone: 218-355-2618 _______________ ________________________________

MH-US TSR Sensitivity Analysis

System Impact Study

OASIS Reference #: 76703672, 79258361, 79258364, 79258450, 79258492, 79258646, 79258668, 79429002

MISO Project: A383, A627, A628, A629, A630

Final Report

May 30, 2014

MISO
720 City Center Drive
Carmel
Indiana - 46032
http://www.MISOenergy.org

Contents

MISO

1. Introduction
The purpose of this study was to perform sensitivity analysis on the new transmission for the MH-US south- (summer) and US-MH north- (winter) bound TSRs.

2. Summary
A No-Harm test has been performed to study the impact of the proposed Dorsey-Iron Range 500kV transmission line on the existing transmission system.

Yearly Firm transmission service has been requested under the MISO's Open Access Transmission and Energy Markets Tariff.

The combined transmission service requests seeks to reserve up to 883 MW of yearly, firm, network service from MISO to Manitoba Hydro during Winter and from Manitoba Hydro to MISO during Summer.

Table 1 MISO System Impact Study A383, A627, A628, A629, A630

OAIS TSR #	Start Time	Stop Time	Point of Receipt	Point of Delivery	Capacity Requested
MISO 79258668	6/1/2020	6/1/2025	WPS	MHEB-MISO	300
MISO 79258646	6/1/2020	6/1/2036	WPS	MHEB-MISO	200
MISO 79258492	6/1/2020	6/1/2040	MP	MHEB-MISO	133
MISO 79258450	6/1/2015	6/1/2020	MHEB-MISO	WPS	300
MISO 79258364	6/1/2020	6/1/2036	MHEB-MISO	WPS	200
MISO 79258361	6/1/2020	6/1/2040	MHEB-MISO	MP	133
MISO 79429002	6/1/2017	6/1/2037	MP	MHEB-MISO	250
MISO 76703672	6/1/2017	6/1/2037	MHEB-MISO	MP	250

Analysis has been performed for the outer year conditions to assess the impact of the proposed transfer on the transmission system. . The service can be granted in varying amounts pursuant to the mitigation of the transmission constraints as identified in Section 6 of the report.

3. Study Objectives

The objectives of this study are to:
- Identify MISO system constraints newly created or aggravated by the requested service.

- Identify non-MISO system constraints newly created or aggravated by the requested service, especially constraints on impacted systems that are not on the contract path.
- Identify potential system upgrades to mitigate any identified MISO-system constraints.

The study procedure includes:

- Use of Network Analysis to identify steady-state thermal and voltage violations on transmission facilities and flowgate violations.
- The relevant MISO, Reliability Region, and Control Area reliability criteria are used to identify such violations.
- The network analysis includes determining the availability of rollover rights.
- Use of Flow based Analysis to determine negative AFC on constrained Facilities.

The eight transmission service requests were divided into two groups according to the direction of the transfer. This is done to study the impact of the requests on the system.

The south bound transmission service requests (during Summer months) seek to reserve a total of 883 MW of transmission service from Manitoba Hydro to several sinks in the northern Midwest United States(Table 2).

Table 2: MH-US South Bound Requests

TSR #	Start Time	Stop Time	Point of Receipt	Point of Delivery	Capacity Requested
MISO 79258450	6/1/2015	6/1/2020	MHEB-MISO	WPS	300
MISO 79258364	6/1/2020	6/1/2036	MHEB-MISO	WPS	200
MISO 79258361	6/1/2020	6/1/2040	MHEB-MISO	MP	133
MISO 76703672	6/1/2017	6/1/2037	MHEB-MISO	MP	250

The north bound transmission service requests (during Winter months) seeks to reserve a total of 883 MW of transmission service from northern Midwest United States to Manitoba Hydro (Table 3).

Table 3 US-MH North Bound Requests

TSR #	Start Time	Stop Time	Point of Receipt	Point of Delivery	Capacity Requested
MISO 79258668	6/1/2020	6/1/2025	WPS	MHEB-MISO	300
MISO 79258646	6/1/2020	6/1/2036	WPS	MHEB-MISO	200
MISO 79258492	6/1/2020	6/1/2040	MP	MHEB-MISO	133
MISO 79429002	6/1/2017	6/1/2037	MP	MHEB-MISO	250

4. Models, Criteria, Methodology, and Assumptions

4.1 Models

4.1.1. Summer

MTEP 2013 power flow model representing a 2023 Summer Peak case was utilized. Modeling of TSRs and GIPs was based on "MHEB Group TSR System Impact Study Transmission Options W.1 and W.2" with revision date April 19, 2010. Flow on the MHEX is 1850 MW (south) in the summer peak benchmark case.

The three HVDC bipoles are set at 3874.6 MW in the benchmark case as follows:

- Bipole 1 = 1228.3 MW
- Bipole 2 = 1325.1 MW
- Bipole 3 = 1321.2 MW

The bipole inverters were used to source the south bound requests as shown below. The three HVDC poles were set at 4773.5 MW

- Bipole 1 = 1513.2 MW
- Bipole 2 = 1632.5 MW
- Bipole 3 = 1627.8 MW

4.1.2. Winter

MTEP 2013 power flow model representing a 2018 Winter Peak case was utilized. Modeling of TSRs and GIPs was based on "MHEB Group TSR System Impact Study Transmission Options W.1 and W.2" with revision date April 19, 2010. Flow on the MHEX is 700 MW (north) in the winter peak benchmark case.

The three HVDC bipoles are set at 1738.8 MW in the benchmark case as follows:

- Bipole 1 = 551.2 MW
- Bipole 2 = 594.7 MW
- Bipole 3 = 592.9 MW

The bipole inverters were used to source the north bound requests as shown below. The three HVDC poles were set at 853.2 MW

- Bipole 1 = 270.5 MW
- Bipole 2 = 291.8 MW
- Bipole 3 = 290.9 MW

4.2 Criteria

The following system conditions were considered for the steady-state analysis.

- NERC Category A with system intact (no contingencies)
- NERC Category B contingencies
- NERC Category C contingencies (only for the no harm test part.)
- Outage of single element 100 kV or higher (B.2 and B.3) associated with single contingency event in the following areas: ATCLLC (WEC, ALTE, WPS, MGE, UPPC), DPC, GRE, ITC Midwest, MH, MP, OTP, SMMPA, WAPA, XEL
- Outage of multiple-elements 100 kV or higher (B.2 and B.3) associated with single contingency events in the Dakotas, Manitoba, Minnesota, Wisconsin

The Manitoba HVDC power order reduction scheme was simulated for this sensitivity analysis. This was performed by reducing the flow on HVDC line by the MW pre-contingency flow on the contingent element. Thermal limits were identified using AC solve methods. Voltage and stability considerations were not included in the sensitivities.

4.3 Methodology

Complete sensitivity analysis is comprised of two parts. First part of the analysis studied impact of the transfer only. Both pre and post cases prepared for this part have the transmission plan modeled in them, only difference being the amount of MH-US Transfer. This part of the analysis was performed for all scenarios listed in the Table 2 above.

Second part of the analysis is a no harm test which studied the impact of both transfer and the transmission plan put together. Pre case for this study didn’t have transmission plan or the transfer modeled in it, whereas post case included both transfer and the transmission plan in it.

5. Results

PSS®E version 32 and PSS®MUST version 11.1 were used to perform the sensitivity study. Post transfer cases were screened at 100%.

5.1 Summer: 883 MW South-Bound Transfer, 500 kV Transmission

Table 4: MH – US Transfer

Monitored Element	Contingent Element	LBA	Rating	Post Transfer, Post Cont MVA	Pre Transfer, Post Cont MVA	Impact MVA	DF	FCITC
667501 RIEL 2 500 601012 ROSEAUN2 500 1	601062 MIDCOMP-S 500 608635 BLCKBRY2 500 1	MH/XEL	1905.3	2053.1	1391.8	661.3	74.8 9	685.65
608625 BLCKBRY4 230 608612 RIVERTN4 230 1	601016 CHIS CO2 500 601017 CHIS-N 2 500 1	MP	365	411.8	296	115.8	13.1 1	526.14
667224 RAD_K1_6 138 667231 RADSNDC6 138 1	667001 HENDAY 4 230 667002 LIMEST54 230 5	MH	125	270	56.8	213.2	24.1	282.46
699211 PT BCH3 345 699630 KEWAUNEE 345 1	694022 FOXRIVER B1 345 699359 N APPLETON 345 1	WEC/WPS	1006	1029.6	992.7	36.9	4.17	318.27
608625 BLCKBRY4 230 608624 FORBES 4 230 1	601012 ROSEAUN2 500 667501 RIEL 2 500 1 667500 DORSEY2 500 667501 RIEL 2 500 1	MP	287	487.2	356.6	130.6	14.7 9	- 470.57

5.2 Winter: 883 MW North-Bound Transfer, 500 kV Transmission

Table 5: US – MH Transfer

Monitored Element	Contingent Element	LBA	Rating	Post Transfer, Post Cont MVA	Pre Transfer, Post Cont MVA	Impact MVA	DF (%)	FCITC
620325 BROWNSV4 230 620327 HANKSON4 230 1	601001 FORBES 2 500 601017 CHIS-N 2 500 1	OTP	351	353.9	317.4	36.5	4.13	812.84
608601 CENTRDC4 230 657756 SQBUTTE4 230 1	601001 FORBES 2 500 601017 CHIS-N 2 500 1	MP/OTP	526	470.5	467.6	2.8	0.32	18385.32
615319 GRE-BENTON 4 230 608617 MUDLAKE4 230 1	601001 FORBES 2 500 601017 CHIS-N 2 500 1	XEL/MP	478	527.5	458.1	69.4	7.86	253.19
615460 GRE-RUSH CY4 230 602037 ROCKCR 4 230 1	601016 CHIS CO2 500 601017 CHIS-N 2 500 1	XEL	398.3	352.1	302.4	49.7	5.62	1703.82
652519 OAHE 4 230 652521 SULLYBT4 230 1	601016 CHIS CO2 500 601017 CHIS-N 2 500 1	WAPA	264	266.8	239.9	26.9	3.04	791.08

5.3 No Harm Test Results Dorsey-Iron Range 500 kV

Table 6: No Harm test results, 500 kV Transmission Line

Monitored Element	Contingent Element	LBA	Rating	Post Transfer, Post Cont MVA	Pre Transfer, Post Cont MVA	Impact MVA	DF (%)	FCITC
NONE	NONE							883

6. Conclusion

In this study, AC contingency analysis is performed for transfer from Manitoba Hydro to US for 883 MW during summer months and US to Manitoba Hydro for winter months. Transfer level is simulated by adjusting MW flows at the DC bipoles in Manitoba Hydro and sinking them to generation in MP and WPS. Section 4.1.1 and 4.1.2 of this report gives information on adjusted MW flows on DC bipoles.

Result tables (South-bound: Table 4; North-bound: Table 5) given in this report are compiled by comparing the AC analysis results of post and pre transfer scenarios. Since this was not a facility study, cost of various upgrades suggested by the study remain are preliminary estimates. Result summaries of the individual transmission options are described below.

- **883 MW transfer, Dorsey-Blackberry 500kV**
  Analysis has been performed for the near term and outer year conditions to assess the impact of the proposed transfer on the transmission system. The service can be granted if the following transmission constraints are mitigated. Some high level cost estimates are listed in the Table 7 (South-bound TSRs) and Table 8 (North-bound TSRs).

Table 7 Cost estimate to mitigate the constraint (South-bound TSRs)

Monitored Element	LBA	Rating (Normal/Contingency)	Minimum required rating for full transfer (Normal/Contingency)	Estimate upgrade cost
667501 RIEL 2 500 601012 ROSEAUN2 500 1	MH/XEL	1732.1/1905.3	1732.1/2054	Contingency will trigger Manitoba Hydro DC runback mechanism to reduce the flows on the DC line. Transmission Element is not overloaded after the flows on the DC tie and associated interface flows are reduced by the specified amount.
608625 BLCKBRY4 230 608612 RIVERTN4 230 1	MP	365/365	365/412	Contingency will trigger Manitoba Hydro DC runback mechanism to reduce the flows on the DC line. Transmission Element is not overloaded after the flows on the DC tie and associated interface flows are reduced by the specified amount.

667224 RAD_K1_6 138 667231 RADSNDC6 138 1	MH	125/125		The underlying unit is at the swing BUS to the area. Line is being overloaded due to unit generating more than the Pmax. Bringing the unit back to rating resolved the constraint.
699211 PT BCH3 345 699630 KEWAUNEE 345 1	WEC/WPS	960/960	960/1030	$250,000.00
608625 BLCKBRY4 230 608624 FORBES 4 230 1	MP	287/287	287/488	Contingency will trigger Manitoba Hydro DC runback mechanism to reduce the flows on the DC line. Transmission Element is not overloaded after the flows on the DC tie and associated interface flows are reduced by the specified amount.

Table 8 Cost estimate to mitigate the constraints (North-bound TSRs)

Monitored Element	LBA	Rating (Normal/Contingency)	Minimum required rating for full transfer (Normal/Contingency)	Estimate upgrade cost
620325 BROWNSV4 230 620327 HANKSON4 230 1	OTP	319/351	319/354	An investment of $50,000.00 towards the terminal line equipment at OTP's Hankinson substation will increase the rating to 401/442 MVA (normal/contingency)...
608601 CENTRDC4 230 657756 SQBUTTE4 230 1	OTP	478/526		Young#2 unit was over Pmax. Bringing the unit back to rating resolves the constraint.
615319 GRE-BENTON 4 230 608617 MUDLAKE4 230 1	XEL/MP	478/478	478/528	An investment of $130,000.00 towards the terminal line equipment will increase the rating to 513 MVA. This will increase the FCITC to 698 MW. To increase the rating further, a complete rebuild of the line will be required. Initial cost estimates are around $48 million for the 54 mile long 230 kV line.
615460 GRE-RUSH CY4 230 602037 ROCKCR 4 230 1	XEL	398.3/398.3		Transmission Line is not constrained with revised higher rating.
652519 OAHE 4 230 652521 SULLYBT4 230 1	WAPA	240/264	240/269	Note*1

- Note 1: The estimate is not available at the time of report posting. It will be updated during the following facility study stage.

1. South-bound TSRs: 883 MW of summer flow from Manitoba Hydro to US can be granted with the following upgrades:
    a. base case upgrades consisting of following facilities,
        i. Manitoba facilities
            1. Winnipeg (Dorsey) to US border 500 kV line,
            2. Riel 500/230 kV 1200 MVA transformer,
            3. Dorsey/Riel shunt compensation (line reactor and capacitors),
            4. Glenboro 250 MVA phase shifting transformer
        ii. US facilities:
            1. US border to Iron Range (Blackberry) 500 kV line,
            2. 60% series compensation,
            3. Blackberry 500/230 kV 1200 MVA transformer,
            4. Blackberry shunt compensation (line reactor and capacitors)
    b. Point Beach – Kewaunee line upgrade: about $250,000

2. North-bound TSRs:
   698 MW of winter flow from US to Manitoba Hydro can be granted with following network upgrades:
    a. base case upgrades consisting of following facilities,
        i. Manitoba facilities
            1. Winnipeg (Dorsey) to US border 500 kV line,
            2. Riel 500/230 kV 1200 MVA transformer,
            3. Dorsey/Riel shunt compensation (line reactor and capacitors),
            4. Glenboro 250 MVA phase shifting transformer
        ii. US facilities:
            1. US border to Iron Range (Blackberry) 500 kV line,
            2. 60% series compensation,
            3. Blackberry 500/230 kV 1200 MVA transformer,
            4. Blackberry shunt compensation (line reactor and capacitors)
    b. terminal equipment upgrade at Otter Tail Power's Hankinson substation: $50,000.00
    c. terminal equipment upgrade at both Xcel Energy' Benton substation and Minnesota Power's Mudlake substation: $130,000.00

   883 MW of winter flow from US to Manitoba Hydro can be granted by reducing the flows over Glenboro Phase Shifter to mitigate the overloading on Oahe – Sully Bt 230 kV transmission line and with the following network upgrades:
    a. base case upgrades consisting of following facilities,
        i. Manitoba facilities

MISO

1. Winnipeg (Dorsey) to US border 500 kV line,
2. Riel 500/230 kV 1200 MVA transformer,
3. Dorsey/Riel shunt compensation (line reactor and capacitors),
4. Glenboro 250 MVA phase shifting transformer

ii. US facilities:
1. US border to Iron Range (Blackberry) 500 kV line,
2. 60% series compensation,
3. Blackberry 500/230 kV 1200 MVA transformer,
4. Blackberry shunt compensation (line reactor and capacitors)

b. terminal equipment upgrade at Otter Tail Power's Hankinson substation: $50,000.00
c. reconductor the transmission line between Xcel Energy' Benton substation and Minnesota Power's Mudlake substation: $48 million

- **No Harm Test, Dorsey-Blackberry 500kV,**
  No constraints were found for the addition of the new 500 kV transmission line.

7. Definition of Terms

In order to make it easier for the reader to interpret the results, definitions of various columns used in the result tables are provided below:

Monitored Element: This is the limiting element. Description of the limiting element does not represent the actual name of the network elements. These are the names used in the PSSE models and include PSSE bus numbers.

Pre Transfer, Post Cont MVA: This is the amount of MVA flow on the limiting element in the model without the transfer modeled.

Post Transfer, Post Cont MVA: This is the amount of MVA flow on the limiting element in the model having study transfers modeled.

Base Flow: This is the MVA flow on the limiting element in the base case having study transfers implemented.

Rating: This is the rating of the limiting element.

Cont. Ld%: This is the post-contingency percentage loading on the limiting element in the model having study transfers modeled.

Contingency Description: This is the contingent element. Description of the contingent element does not represent the actual name of the network element. These are the names used in the PSSE models and include PSSE bus numbers.

Impact MVA: This value is calculated as difference between the **Pre Transfer, Post Cont MVA** and **Post Transfer, Post Cont MVA**values defined above.

DF: Distribution factor is the Impact calculated as percentage of the MW transfer level being studied. For this study all post –contingent overloads with greater than 100 Cont LD% and a DF of 3.0% were included.
DF = ((Impact/MW transfer Level)*100)

FCITC: First Contingency Incremental transfer Capability is the incremental available capacity on a given transmission element for a given contingency
FCITC = (Contingency Limit – Pre-Shift Continegcny Flow)/DF