BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

STATE OF MINNESOTA

In the Matter of the Request by Minnesota Power

For a Certificate of Need for the

Great Northern Transmission Line

OAH Docket No. 65-2500-31196

MPUC Docket No. E-015/CN-12-1163

Exhibit _______

MISO STUDIES

Direct Testimony and Exhibits of

SCOTT HOBERG

August 8, 2014

MR. SCOTT HOBERG

OAH Docket No. 65-2500-31196

MPUC Docket No. E-015/CN-12-1163

Contents

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Scott Hoberg and my business address at Minnesota Power is 30 West Superior Street, Duluth, Minnesota 55802.

Q. What is your current position with Minnesota Power?

A. I am the Supervising Engineer of the System Performance Department.

Q. How long have you been employed by the Company and when did you assume your current position?

A. I joined Minnesota Power in December of 2008 and assumed my current position in June of 2014.

Q. Please describe your educational and professional background.

A. I have a Bachelor of Science degree in Electrical Engineering, with an emphasis in power systems, from South Dakota State University. Prior to joining Minnesota Power I worked for Midcontinent Independent System Operator ("MISO") for eight years. While at MISO, I worked in the control room for the Western Region as an operations engineer, providing engineering support for short term planning and real-time operations. Since 2006 I have been a licensed professional engineer in the State of Minnesota.

Q. What are your present duties at Minnesota Power?

A. I am responsible for providing technical support to the Company, customers, and regional transmission organizations in order to ensure safe and reliable operation of the Bulk Electric System. I work with neighboring utility and reliability coordination engineers to develop real-time operating plans and procedures. I also perform detailed future looking analysis as well as review of external study work meant to document the impact of changes made to the electric system including generation interconnections and transmission lines.

Q. Can you also describe your ongoing interactions with MISO and your involvement in MISO studies?

A. As a part of my day to day job activities, I coordinate with the MISO Outage Coordination Department on transmission and generation outage scheduling studies to determine impacts or if corrective mitigation plans are required to facilitate outages. I also work as needed with the MISO real-time operations engineers to determine system operating limits and establish valid operating levels during forced system outages. Because of this work with the MISO operations personnel and my work on near-term and long-term regional planning, I have led the involvement from the Minnesota Power perspective in regional MISO studies. Recently these studies have included the Northern Area and Manitoba Hydro Wind Synergy Studies.

Q. What is the purpose of your testimony?

A. I discuss the MISO studies and Transmission Service Request ("TSR") Reports considered by Minnesota Power in the course of our work on the Great Northern Transmission Line (also "Project") and in our consideration of alternatives to the Project. I also discuss the Wind Injection Study (Appendix O of the Certificate of Need Application ("Application")) and the Great Northern Transmission Line Economic Impact Study performed by Ventyx and discussed in Section 6.3.3 of the Application.

Q. Do you sponsor certain sections and appendices of the Application?

A. Yes, I sponsor:

- Section 7.2 (MISO Studies Considered in Analysis);
- Appendix I (MISO Manitoba Hydro Wind Synergy Study Final Report, September 2013);
- Appendix M (MISO Northern Area Study, June 2013);
- Appendix N (Dorsey – Iron Range 500 kV Project Preliminary Stability Analysis, December 5, 2012);
- Appendix O (Manitoba – United States Transmission Development Wind Injection Study, March 1, 2013); and
- Appendix Q (MH – US TSR Sensitivity Analysis Draft Reports, July 2013).

Q. Do you also have Exhibits to your testimony?

A. Yes. I attach the following:

- Exhibit ___ (SH), Schedule 1 – Minnesota Power's Response to Department of Commerce ("Department") Information Request ("IR") 1, discussing Transmission Study Requests ("TSRs") and including attachments;
- Exhibit ___ (SH), Schedule 2 – Minnesota Power's Response to Department IR 3, attaching the GNTL Economic Impact Study conducted by Ventyx;
- Exhibit ___ (SH), Schedule 3 – Minnesota Power's Responses to Department IR 6, also discussing TSRs and studies and including attachments; and
- Exhibit ___ (SH), Schedule 4 – Minnesota Power's Response to RRANT IR 4, regarding MISO studies and other materials referencing the Project.

II. MISO STUDIES

Q. Have the Project and alternative new Manitoba – United States transmission interconnections been the subject of MISO studies, reports or other MISO efforts over the past several years?

A. Yes. Both a new interconnection to Minnesota Power's Blackberry substation and alternative new interconnections have been extensively studied by MISO and others for several years. For example, Ex. __ (SH), Schedule 4 provides a listing of MISO studies and presentations referencing the Project.

Most notable is the study from Appendix I (MISO Manitoba Hydro Wind Synergy Final Report, September 2013); where transmission plans including an Eastern Plan such as the Project were analyzed within phases three and four of the study. It was found that significant benefits can be realized from adding a 500 kV transmission line from Manitoba to MISO.

Q. Has Minnesota Power specifically considered some of these studies and other materials during the course of developing the Project and considering alternatives to the Project?

A. Yes. The Company has considered a number of MISO studies, including the Northern Area Study, the Manitoba Wind Synergy Study and Manitoba Hydro-United States Transmission Service Request ("TSR") analyses.

Q. Can you briefly describe the MISO Northern Area Study?

A. The Northern Area Study, Appendix M to the Application, was developed as an exploratory study to understand how the development of new potential Manitoba – MISO tie-lines, changing mining and industrial load levels, and the retirement of generating units drive transmission investment in MISO's footprint. The Northern Area Study originated because of multiple transmission proposals and reliability issues located in MISO's northern footprint. The objective of the Northern Area

Study was to: (1) identify the economic opportunity for transmission development in the area; (2) evaluate the reliability and economic effects of drivers on a regional, rather than local, perspective; (3) develop indicative transmission proposals to address study results with a regional perspective; and (4) identify the most valuable proposal(s) and screen them for robustness.

Q. Was the Northern Area Study designed to determine a "best" transmission project or a preferred new transmission interconnection between Manitoba and the United States?

A. No. The Northern Area Study provides no indication or comparison between various Manitoba to MISO tie-line options. Tie-lines and new hydro generation were inputs to the Northern Area Study to determine economic development opportunities after the tie-lines and generating units are built and in-service – essentially answering what (if any) build-out is required for MISO's entire northern footprint to realize the benefits of new Manitoba imports. Given the nature of the study, transmission solutions stemming from the Northern Area Study analysis were not intended to be recommended for MTEP Appendix A or B consideration. Rather, the Northern Area Study's results and findings were intended to determine and feed future studies.

Q. Can you also describe the impetus behind the MISO Manitoba Hydro Wind Synergy Study and that Study's results?

A. As discussed in the Application, the variable and non-peak nature of wind creates integration challenges within MISO. Manitoba Hydro, with its large and flexible system, offers potential solutions for meeting these challenges. At the prompting of Manitoba Hydro and the potential customers of output from their new hydroelectric dams, MISO conducted the Manitoba Hydro Wind Synergy Study, Appendix I to the Application, to evaluate whether the cost of expanding the transmission capacity between Manitoba and MISO would enable greater wind participation in the MISO market. At the time of the Application, MISO had 12 gigawatts ("GW") of wind online and 15 GW of active wind projects in the queue. Manitoba Hydro is looking to expand its hydro system significantly over the next several years, but its current firm export capacity to MISO is limited to 1,850 MW which is insufficient to meet the needs of future wind generation in MISO for synergy with hydropower. Thus, this study looked at expanding transmission capacity between MISO and Manitoba Hydro to facilitate an increase in the realization of these benefits.

The study found significant benefits can be realized from the addition of either an eastern 500 kV line between Winnipeg, Manitoba, and the Iron Range in northeastern Minnesota, or a western 500 kV line between Winnipeg, Manitoba, and Barnesville, Minnesota. Given the wide variety of benefit metrics along with the exploratory nature of the study, the specific allocation of benefits was not possible. This study simply showed that the total benefits in the MISO area are greater than the costs to build either line.

Wind synergy benefits from the expanded use of hydro resources from Manitoba Hydro are demonstrated in three ways: by wind curtailment reduction in MISO; by an inverse correlation between imports from Manitoba Hydro and MISO wind generation; and by a better utilization of both wind and hydro resources. Based on the analyses from the Manitoba Hydro Wind Synergy Study, MISO recommended both the eastern and western transmission projects for inclusion in MTEP13 Appendix B.

Q. You also indicated that Minnesota Power has considered MISO Manitoba Hydro – United States TSR Studies. Can you discuss the nature of those studies and their findings?

A. MISO continually processes generation interconnection requests and Transmission Service Requests ("TSRs") on the transmission system that they operate. One group of these TSRs involves an increase in the ability to transfer power from Manitoba into the United States. The original Manitoba Hydro TSRs requested delivery totaling 1,100 MW from Manitoba Hydro to four TSR customers in the United States (north to south), and 1,100 MW from utilities in the United States to

Manitoba Hydro (south to north). An initial System Impact Study ("SIS") was completed in July 2009 for Firm Transmission Service between Manitoba Hydro and the TSR customers. The two main transmission options considered in the SIS generally extended from the Winnipeg area into the United States via either northeastern Minnesota or the Red River Valley. A follow-up SIS completed in April 2010 evaluated the impact of a new 500 kV interconnection from the Winnipeg area to the planned CapX2020 Bison Substation near Fargo, North Dakota.

More recently, MISO conducted a series of sensitivities on the original option to evaluate alternative transmission scenarios for achieving 250 MW, 750 MW, or 1,100 MW of increased transfer capability from Manitoba to the United States. The MISO TSR Sensitivity Studies have included a "Western Plan" extending new 500 kV transmission to the Barnesville area in western Minnesota, an "Eastern Plan" extending new 500 kV transmission to the Iron Range in northeastern Minnesota, and a "230 kV Option" extending new 230 kV transmission to the Iron Range. While the two 500 kV options could facilitate increased transfers of 750 MW, 1,100 MW or more, the 230 kV Option would facilitate only Minnesota Power's 250 MW Agreements with Manitoba Hydro. The MISO TSR Sensitivity Studies have demonstrated that the alternative transmission options at their associated transfer levels do not result in negative impacts to the bulk electric system. At the time of the Application, MISO had not yet issued a final report for this series of studies so draft reports for the Eastern Plan and the Western Plan sensitivities were included in Appendix Q.

Q. Have those reports now been finalized?

A. No. The draft reports included as Appendix Q were never produced as final reports. This previous analysis was tabled in favor of revised model assumptions as well as new TSR requests. A revised TSR study was completed and MISO issued a final report on May 30, 2014. That report is attached as part of the Company's response to a DOC IR 6, Ex. __ (SH), Schedule 3.

Q. What are the key findings from that Report?

A. The Report found that, based on the conditions studied, south-bound TSRs from Manitoba to the United States could be granted by MISO to a maximum level of 883 MW provided that one facility be upgraded at an estimated cost of $250,000. It was also found that north-bound TSRs could be granted by MISO to a maximum level of 883 MW provided that three facilities are upgraded at an estimated cost of $48,180,000. However, the Report also notes that due to one facility upgrade costing $48 million, a partial north-bound TSR could be granted by MISO to the level of 698 MW contingent on an estimated $180,000 in upgrades to two facilities.

Q. How do these TSR studies and reports, together with the other MISO studies you have referenced, support Minnesota Power's decision to construct the Project?

A. From a transmission planning study perspective the studies, while similar in nature all have slightly different focuses, but the conclusions all show that under a wide range of assumptions the Project has clear benefits to the State and regional transmission system. It is also shown that the Project integrates into the bulk electric system without significant impacts to the existing system as well as with future planned transmission and generation facilities. These key findings support the decision to construct the Project as it will provide value based on a wide array of future outcomes.

III. VENTYX REPORT

Q. In addition to the MISO studies and efforts you have discussed, what other analysis of the potential transmission-related impacts of the Project did Minnesota Power pursue?

A. In order to assess the impact of the Project on costs for electric consumers in Minnesota, Minnesota Power hired an experienced consultant, Ventyx, to perform a PROMOD analysis to estimate the change in locational marginal prices ("LMPs") specific to Minnesota and the estimated change in adjusted production costs within Minnesota and MISO region. The PROMOD software and the results of the Ventyx analysis are discussed in Ex. __ (SH), Schedule 2.

Q. Can you briefly describe LMPs and "adjusted production costs" as discussed here, and why those issues merit attention in this proceeding?

A. LMPs and adjusted productions cost are metrics that can be used to analyze the impact of a particular change made to an economic forecasting model. Changes influencing these two metrics can be very diverse from the addition of a transmission line or generation facility to the assumed price of natural gas or addition of a carbon tax. Adjusted production cost is a measure of energy production when determining the cost to serve load. Stated differently, it is the cost of market purchases less revenues from market sales, modified by imports and exports from neighboring markets. LMPs represent a cost incurred to supply the last incremental amount of energy at a specific location on the transmission grid that respects the limitation of the bulk electric system.

These economic metrics merit attention in that they can be used to gauge the impact of the Project on the whole of MISO as well as Minnesota load.

Q. And what were the results of the Ventyx analysis?

A. As explained in Schedule 2 to this testimony, Ventyx determined that the Project can be expected to bring about a slight decrease in the LMPs in Minnesota and will not materially change the adjusted production cost in Minnesota or MISO.

Q. And what is the significance of those findings?

A. The findings show that, based on the assumptions included in the Ventyx report, the Project is not expected to negatively impact load sources within the State of Minnesota based on the LMP and adjusted production cost metrics. Further the Project is not expected to effect a significant change to adjusted production cost within the MISO boundary. A vertically-integrated utility with a balance between economic generation assets and demand would therefore see little change in its market settlement.

As such, the Ventyx study further demonstrates the value of the Project to the Company, its customers, the State and the region.

Q. Does this conclude your testimony?

A. Yes, it does.

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State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

Docket Number: E015/CN-12-1163 Date of Request:

Requested From: David Moeller
Minnesota Power

Response Due:

Analyst Requesting Information: Steve 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.	
1	Regarding any transmission serve request(s) (TSR) for the power purchase agreement with Manitoba Hydro included in Minnesota Power's resource plan, please provide the following data and supporting documents:

a. The current status of the TSR(s);
b. Findings from any studies that have been completed or are in draft form related to the TSR(s); and
c. The current schedule for the remainder of the TSR proceeding(s).

Response:

a. The TSR Minnesota Power requested is under study by MISO transmission planning engineers. Most recently Minnesota Power requested MISO study the optimal transmission solutions for transfers of 250MW, 750MW and 1100MW. Those studies are nearing completion with Minnesota Power and Manitoba Hydro collaborating on the correct modeling assumptions on both systems to provide the most accurate results. Preliminary study results are expected by the end of 2012, at that time Minnesota Power and Manitoba Hydro will have the opportunity to review MISO's determination and agree on the outcome before publication.

Response by: David R Moeller

List sources of information:

Title: Senior Attorney

Department: Legal Services

Telephone: 218-723-3963

b. In addition to the TSR study referenced above, Minnesota Power has commissioned power flow studies with Excel Engineering to analyze the impact of incremental wind power generation injection at both Fargo, ND and Brookings, SD. This study work quantifies the North Dakota export limit resulting from the congestion of wind injection and simultaneous imports of 1100 MW from Manitoba Hydro. This study work is nearing completion and the results will be forwarded to the Department as soon as they are available.

   Two large MISO sponsored studies are also underway. The MISO Manitoba Wind Synergy Study and the Northern Area Study, both of these studies continue to work their way through the MISO stakeholder process. Attached to this response are the latest updates from MISO to the stakeholder community for each of these studies. The results to date from both of these studies indicate that the Winnipeg to Iron Range to Duluth Project (Great Northern Transmission Line) has positive economic benefits to the MISO footprint.

c. Once final study results of the TSR study are completed by MISO and accepted by Minnesota Power and other interested TSR parties, the parties will develop and execute a Facilities Construction Agreement (FCA). The FCA will define the project, outline the ownership of the project, provide project milestones and address the allocation of transmission rights. Since the Great Northern Transmission Line will be participant funded and will not be eligible for MISO cost allocation, the execution of the FCA will conclude the TSR process and MISO will move this project into Appendix A of the MISO MTEP.

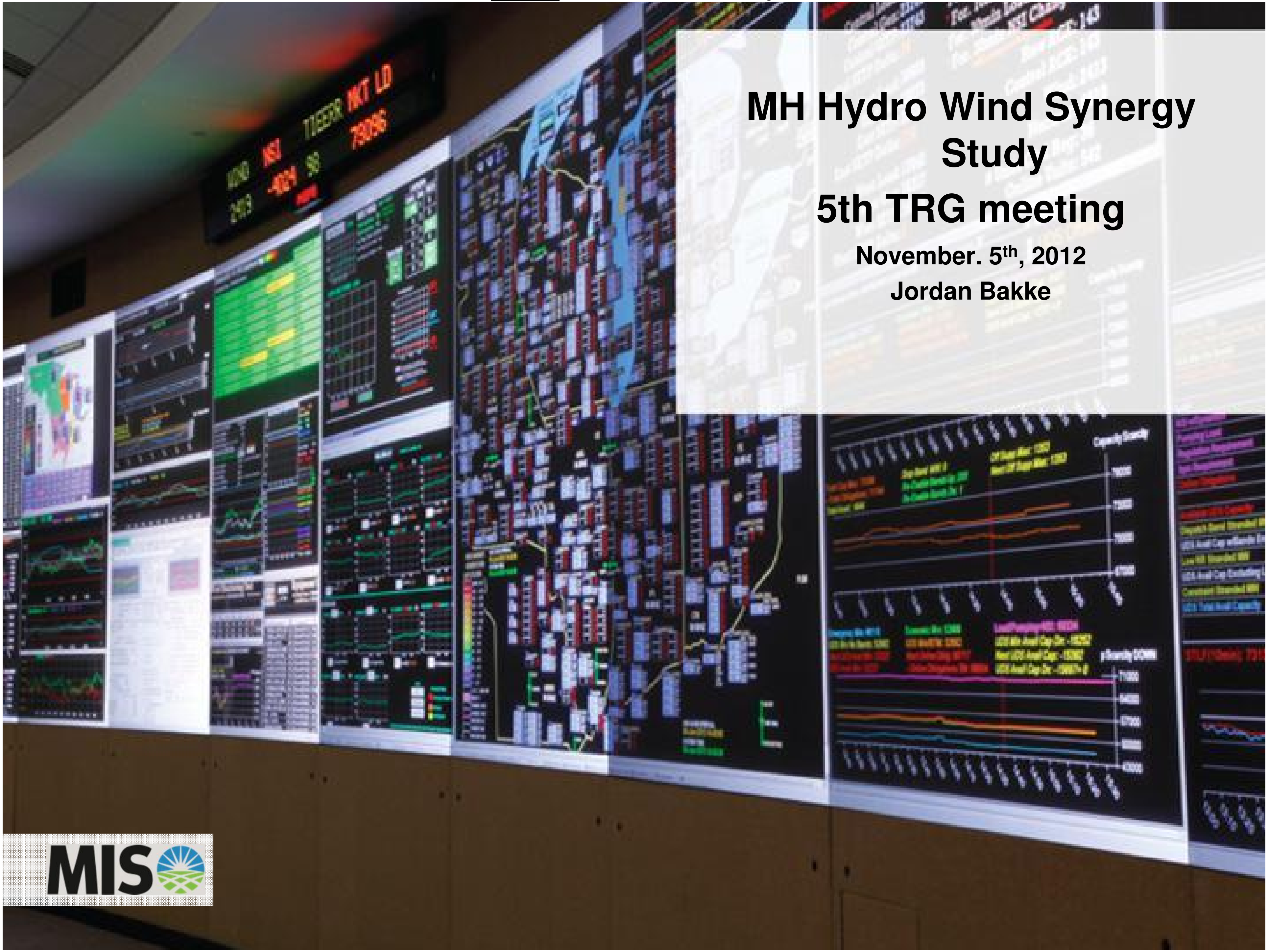
Response by: David R Moeller

Title: Senior Attorney

Department: Legal Services

Telephone: 218-723-3963

List sources of information:



MH Hydro Wind Synergy Study

5th TRG meeting

November. 5th, 2012

Jordan Bakke

MISO

Agenda

- Phase III Objective
- Phase III Base Model Overview
- Phase III Manitoba Hydro Expansion
- Transmission Plan Options
- Generation Differences
- Benefit Summary
- Conclusion
- Next Steps

Phase III Objective

To evaluate the costs and benefits of adding additional transmission between MISO and Manitoba Hydro

Phase III Base Model Review

- **Using 2027 MTEP12 BAU future**
- **Models were presented at the 8/9/2012 ESMUG meeting**
- **Uses Ventyx's 2012 annual PowerBase release with MISO-specific data updates**
- **Major Database Updates**
  - MISO & External Queued Generation Updates
  - Demand & Energy updates
  - Commercial Model Updates
  - Unit Retirement and Maintenance Schedule
  - Fuel Price & Escalation
  - Event File

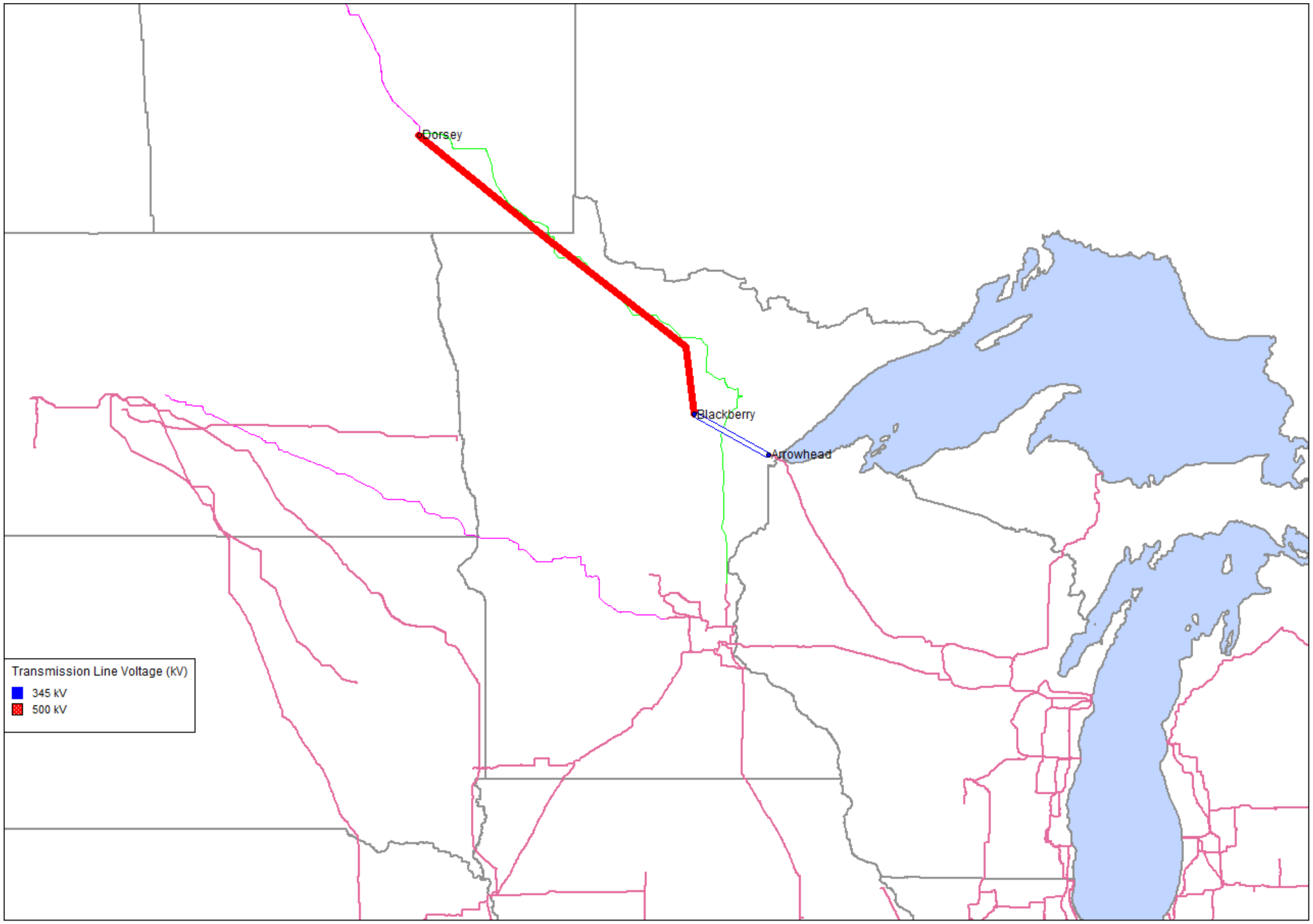
Phase III Manitoba Hydro Expansion

- Study is configured such that the base case corresponds to No New Tie-line to Manitoba.
- With New Tie-line to Manitoba cases include Keeyask (695 MW) and Conawapa (1485 MW), which is consistent with MH's Power Resource Plan
- The No New Tie-line to Manitoba case (base case) includes only Conawapa (1485 MW)

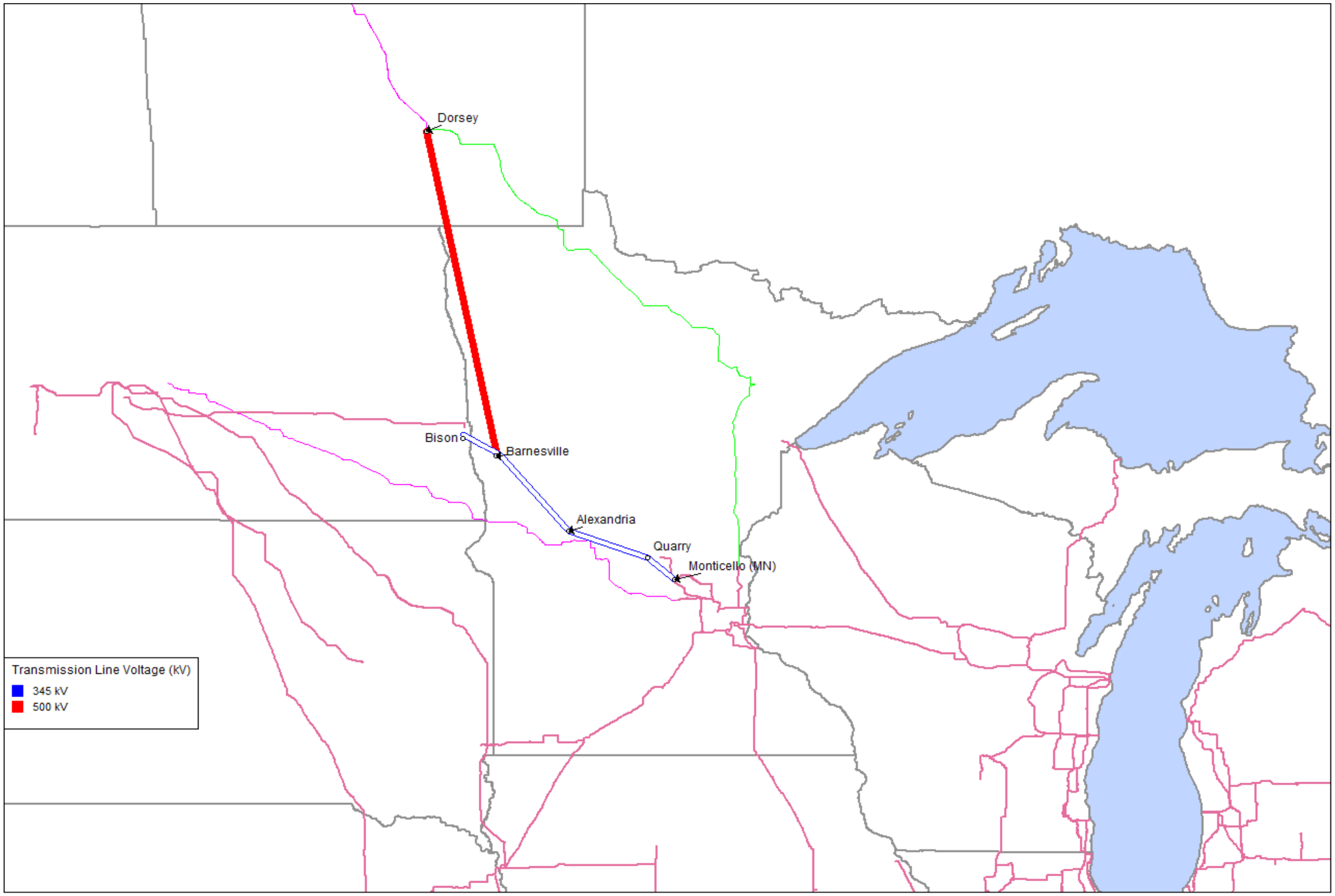
Transmission Plan Options

- **Three transmission options have been studied**
  - Dorsey to Fargo/Moorhead Area
    - 500kV line from Winnipeg to Fargo/Moorhead Area
    - 345kV line from Fargo to Monticello
  - Dorsey to Blackberry
    - 500kV line from Winnipeg to Grand Rapids
    - 345kV double circuit line from Grand Rapids to Duluth
  - Dorsey to T-Blackberry,Bison
    - 500kV line from Winnipeg to T-Tap
    - 500kV line from T-Tap to Grand Rapids
    - 345kV double circuit line from Grand Rapids to Duluth
    - 345kV double circuit line from T-Tap to Fargo

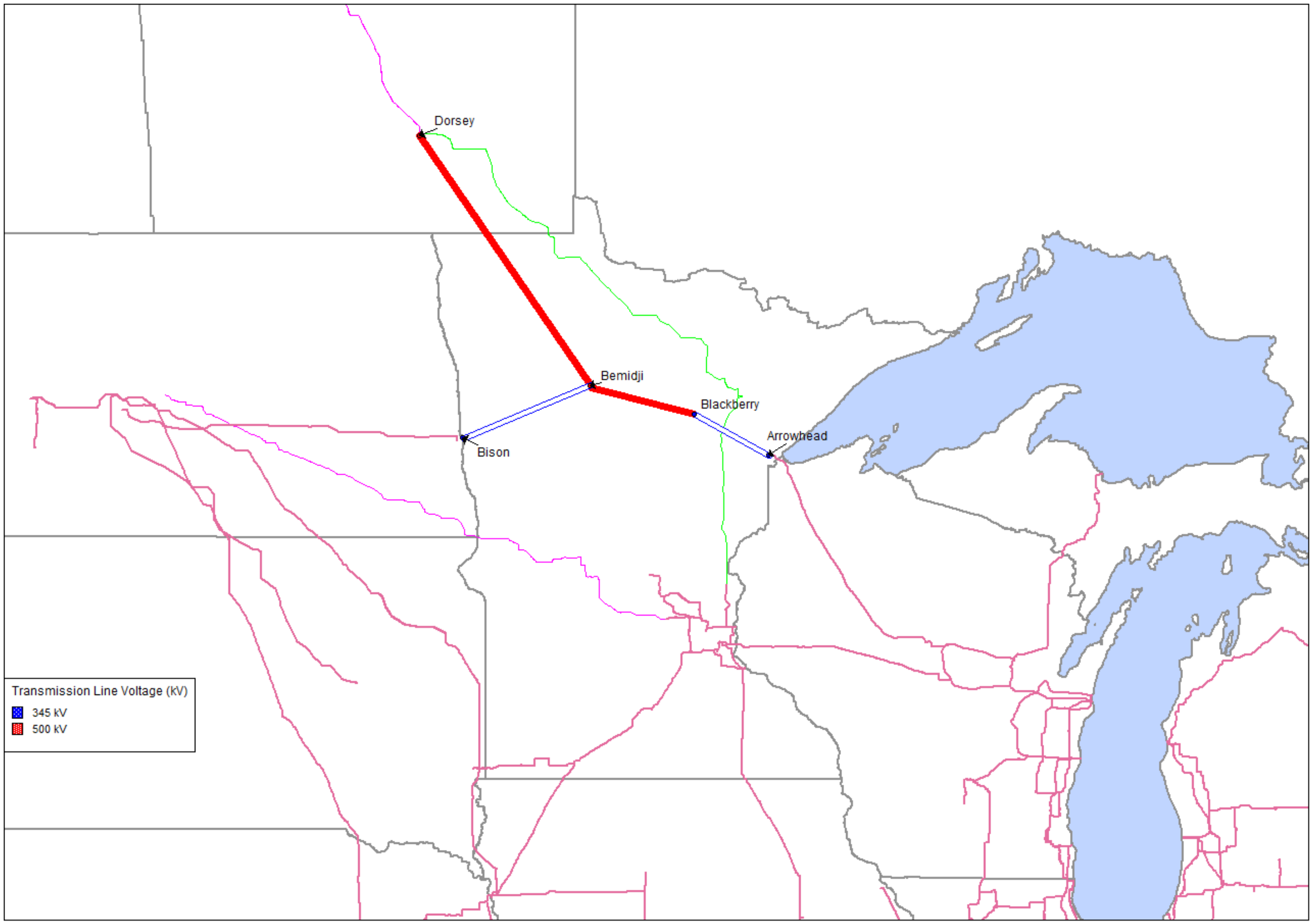
Transmission Option 1 – Dorsey to Blackberry



Transmission Option 2 – Dorsey to Fargo/Moorhead Area

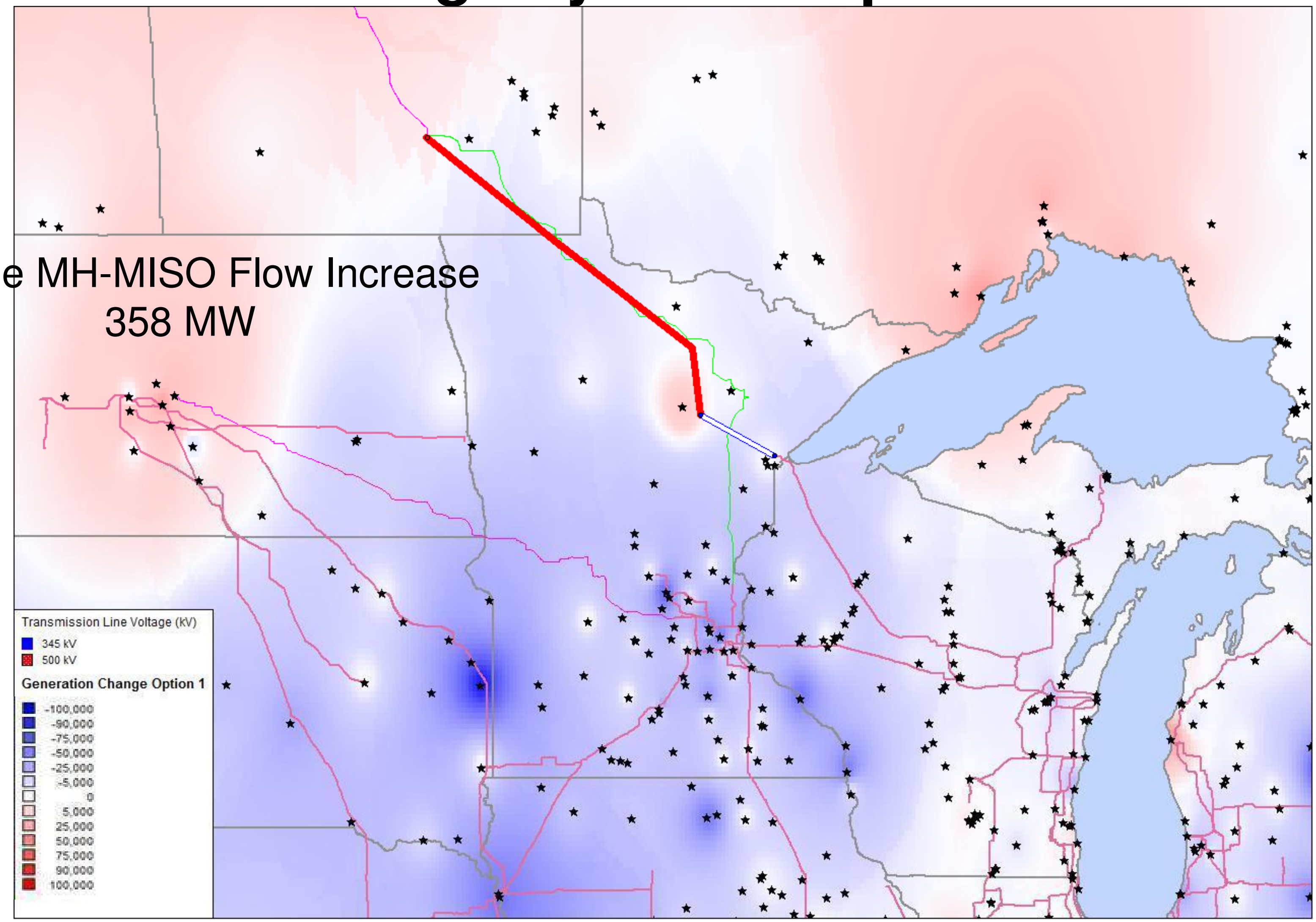


Transmission Option 3 – Dorsey to T-Tap Blackberry/Bison



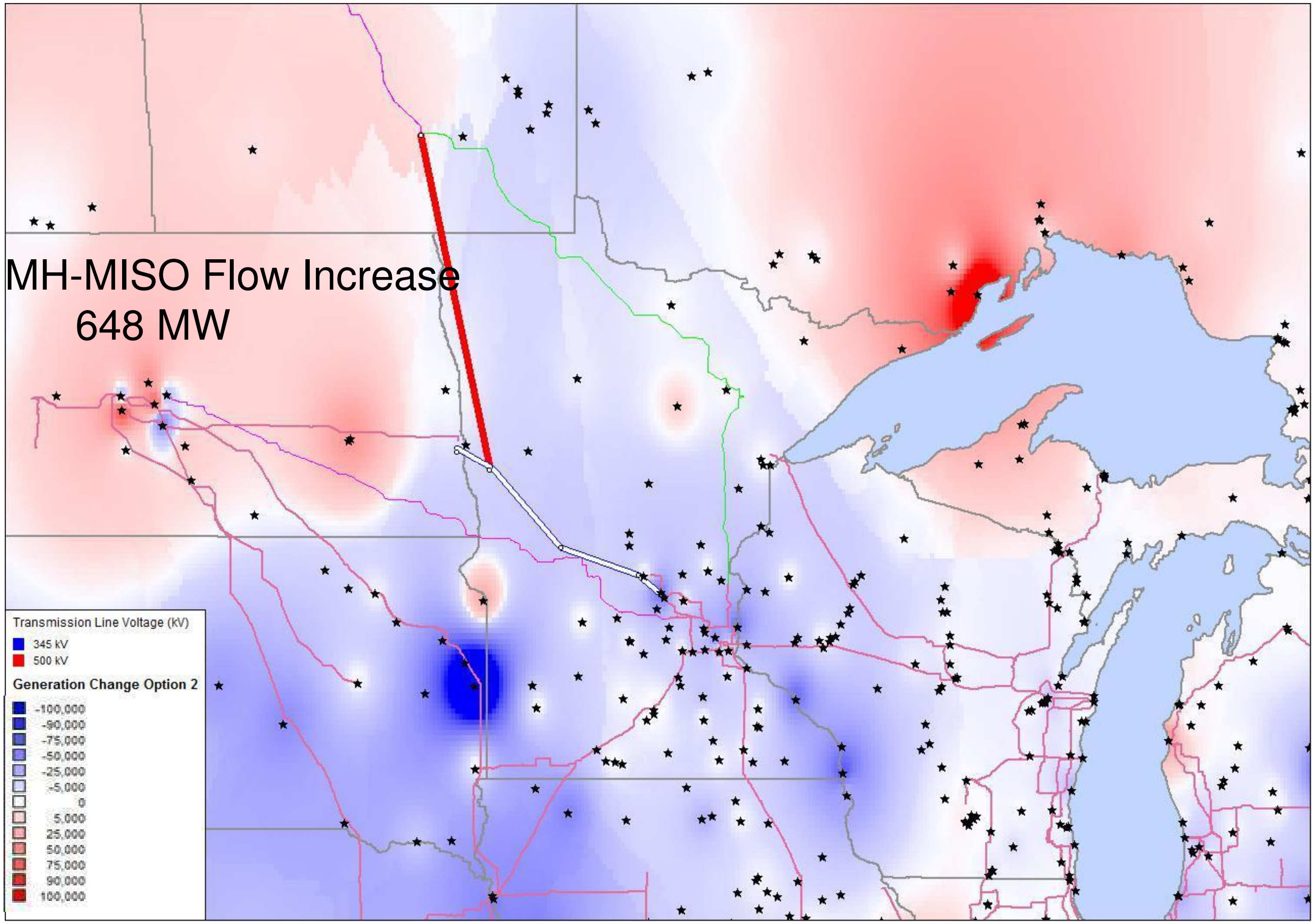
Generation Change by Unit – Option 1- East

Average MH-MISO Flow Increase
358 MW



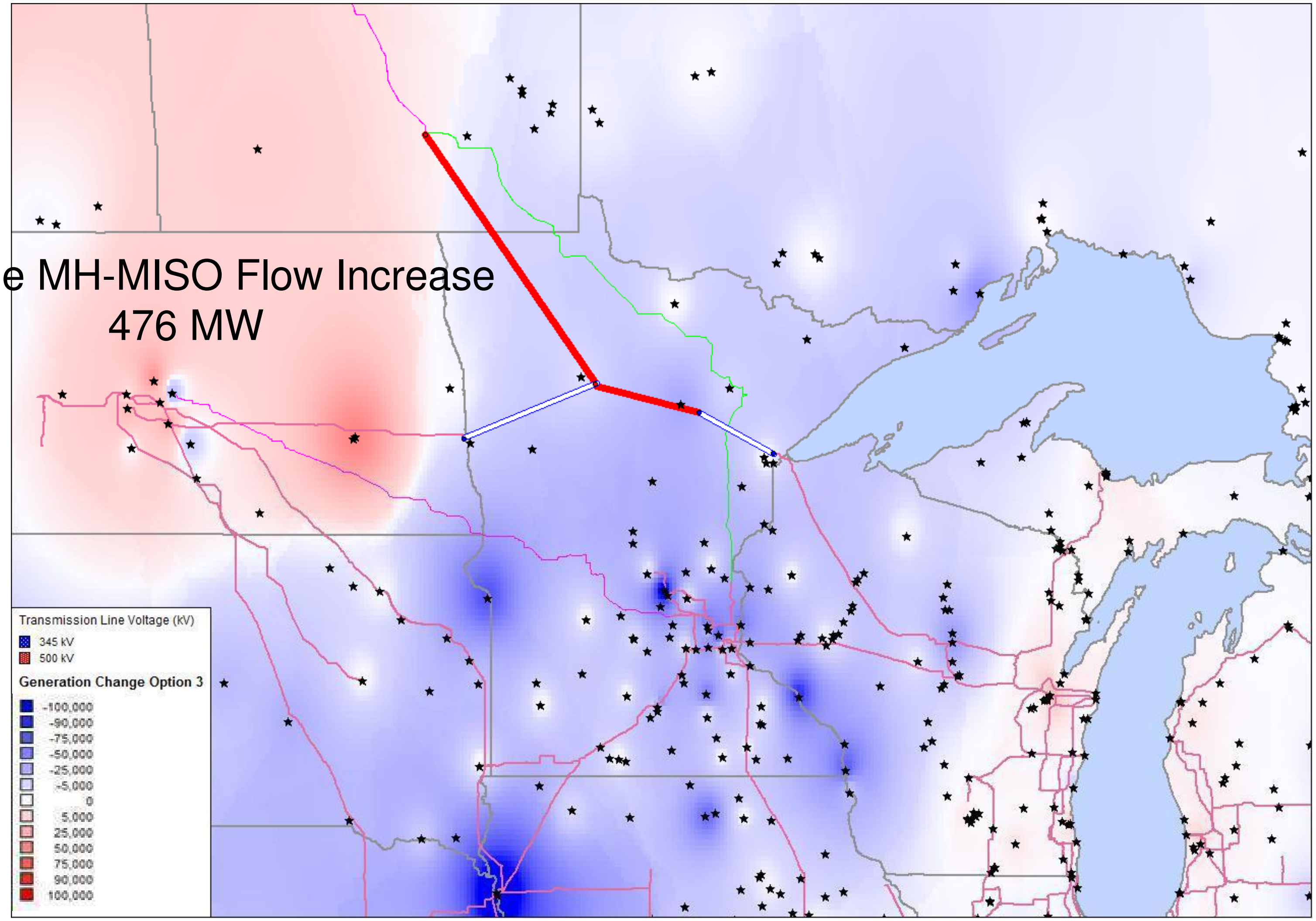
Generation Change by Unit – Option 2 - West

Average MH-MISO Flow Increase
648 MW

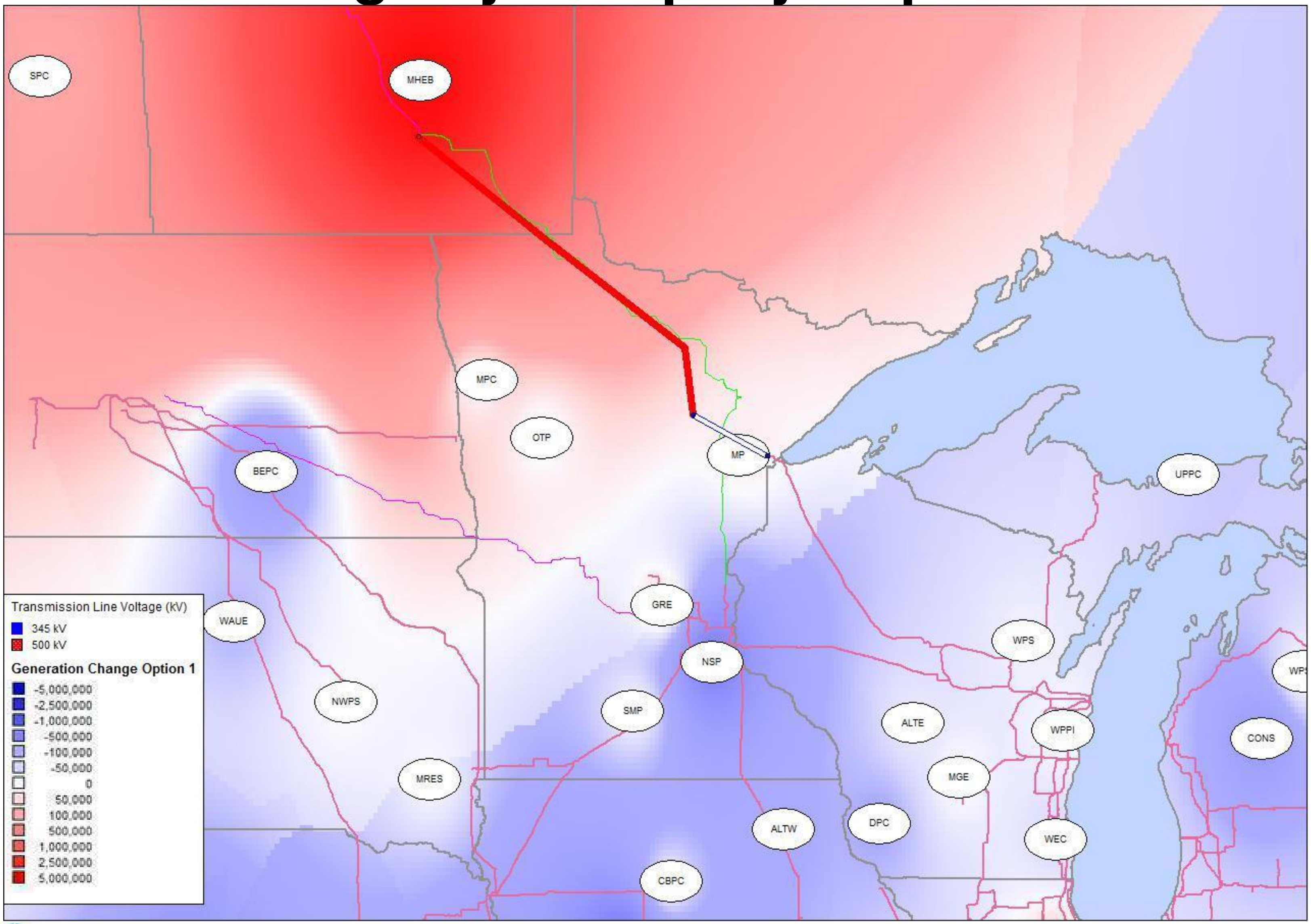


MISO

Generation Change by Unit – Option 3 – T-Tap

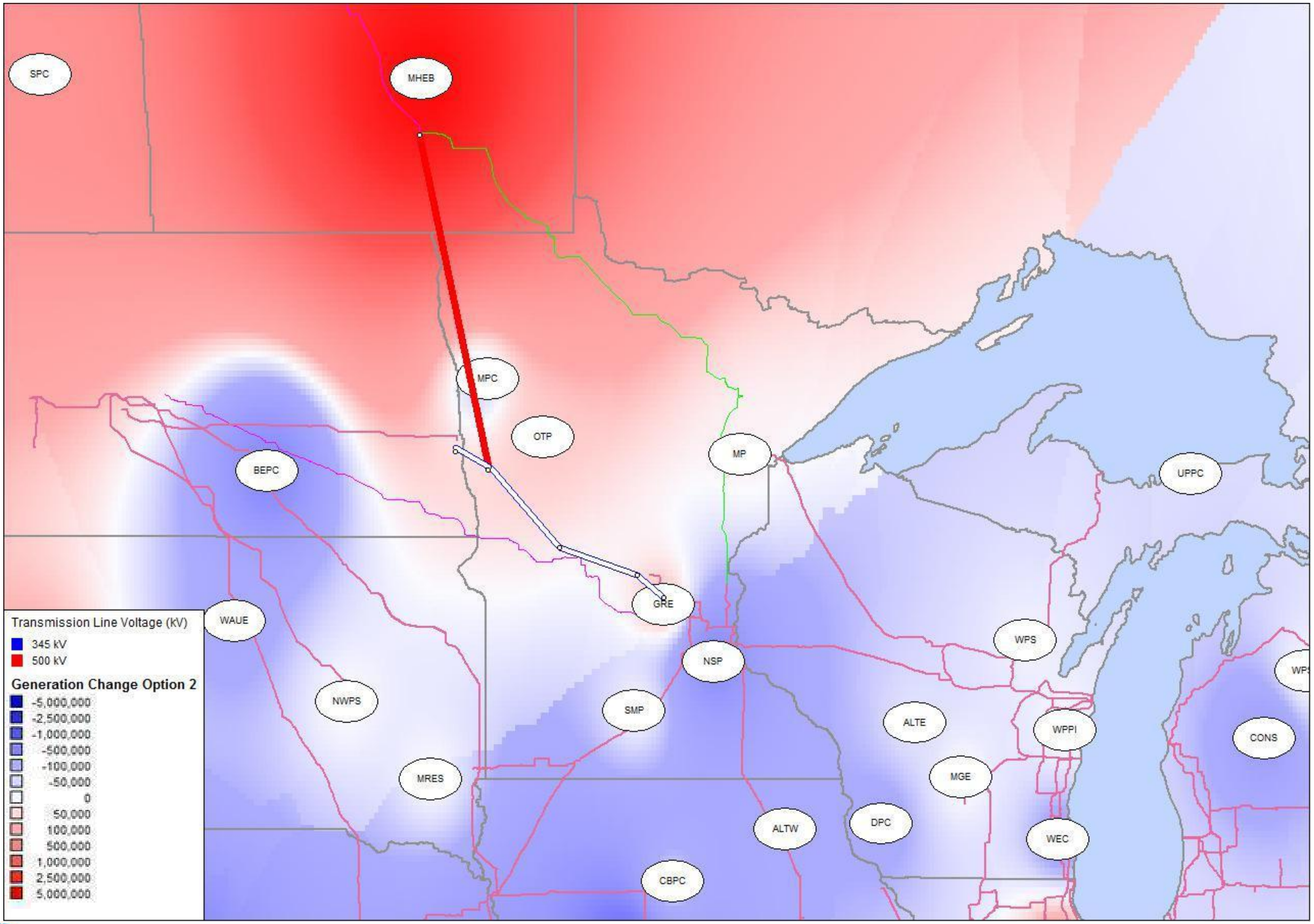


Generation Change by Company– Option 1



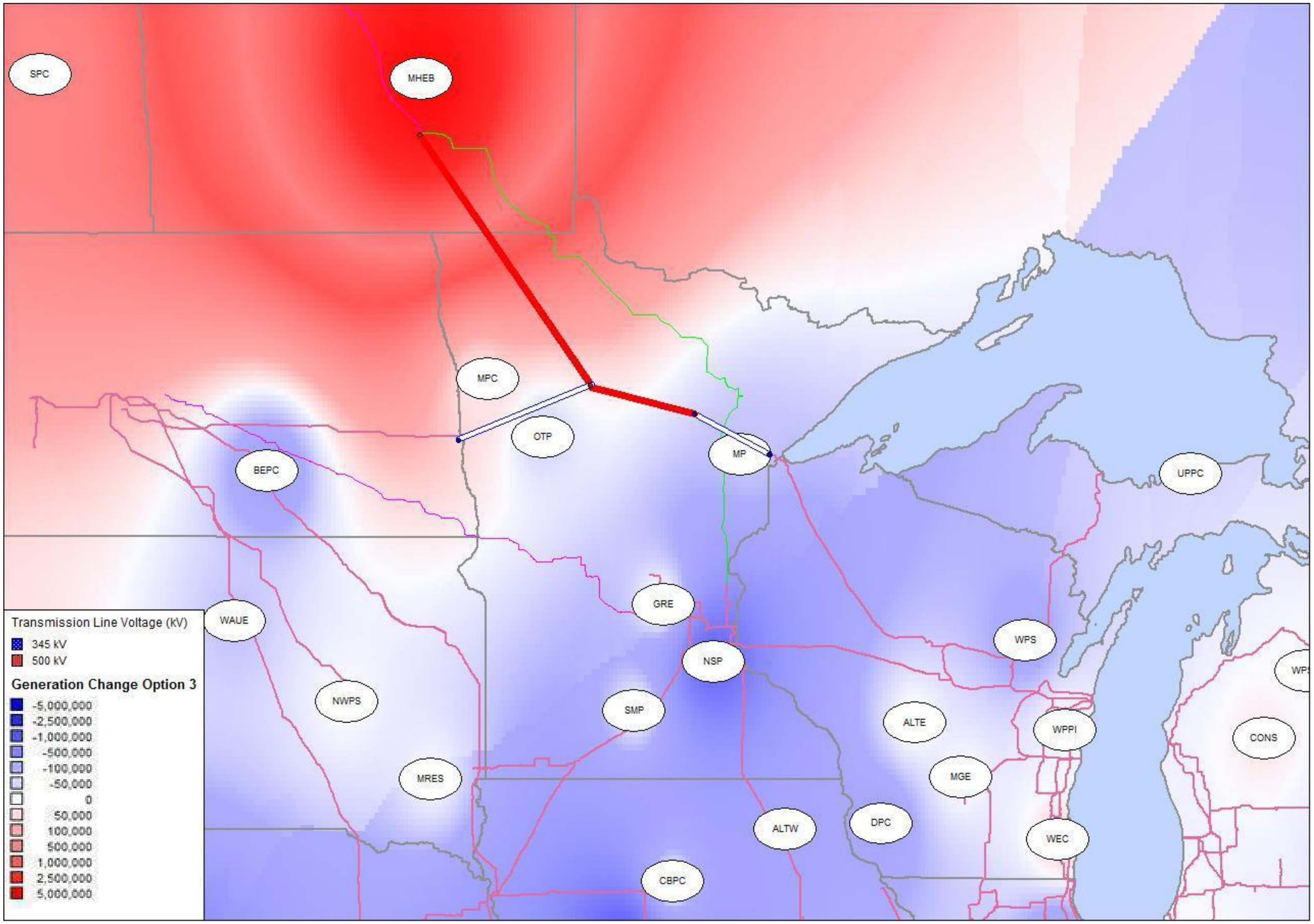
MISO

Generation Change by Company– Option 2



MISO

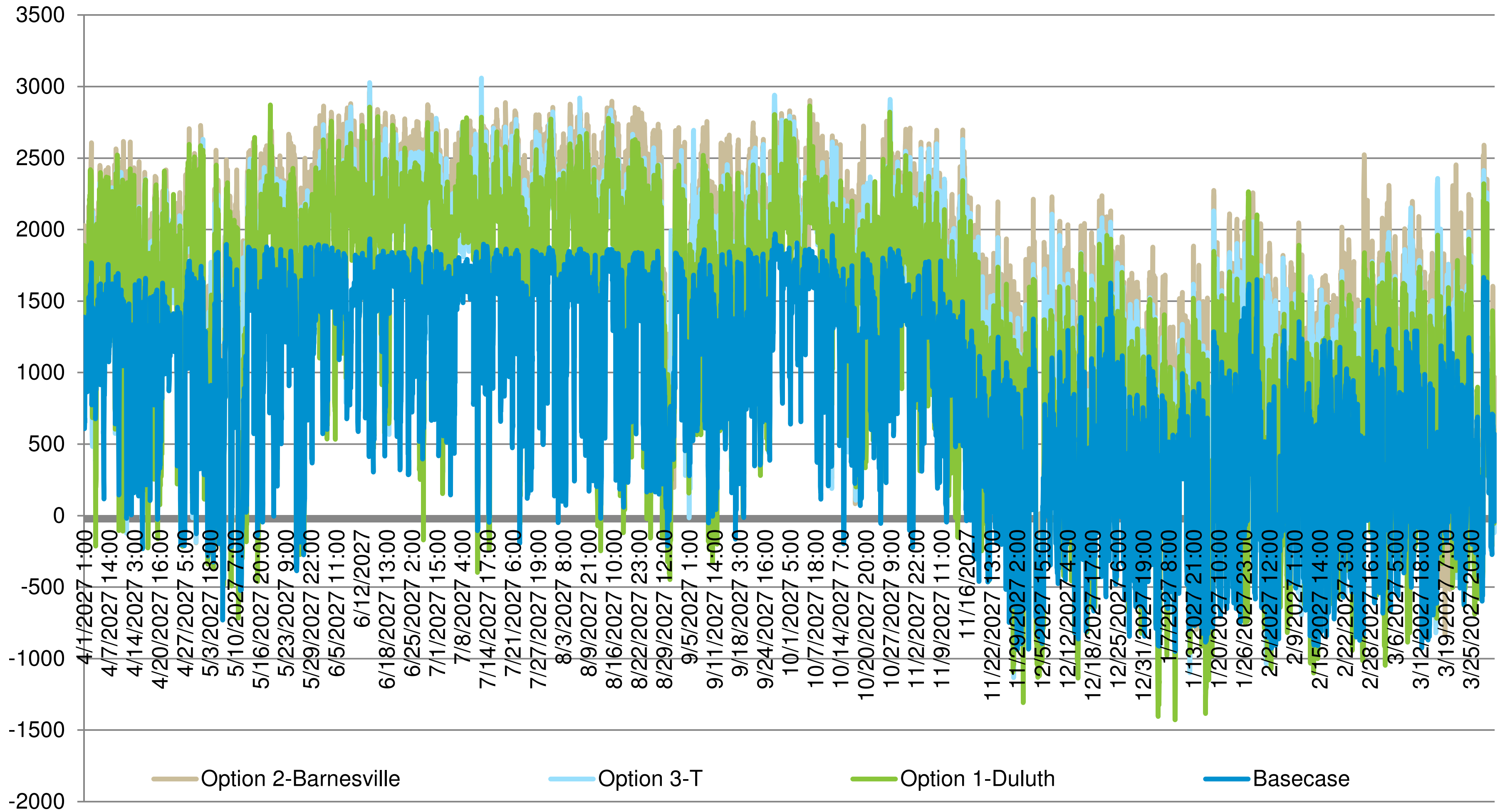
Generation Change by Company– Option 3



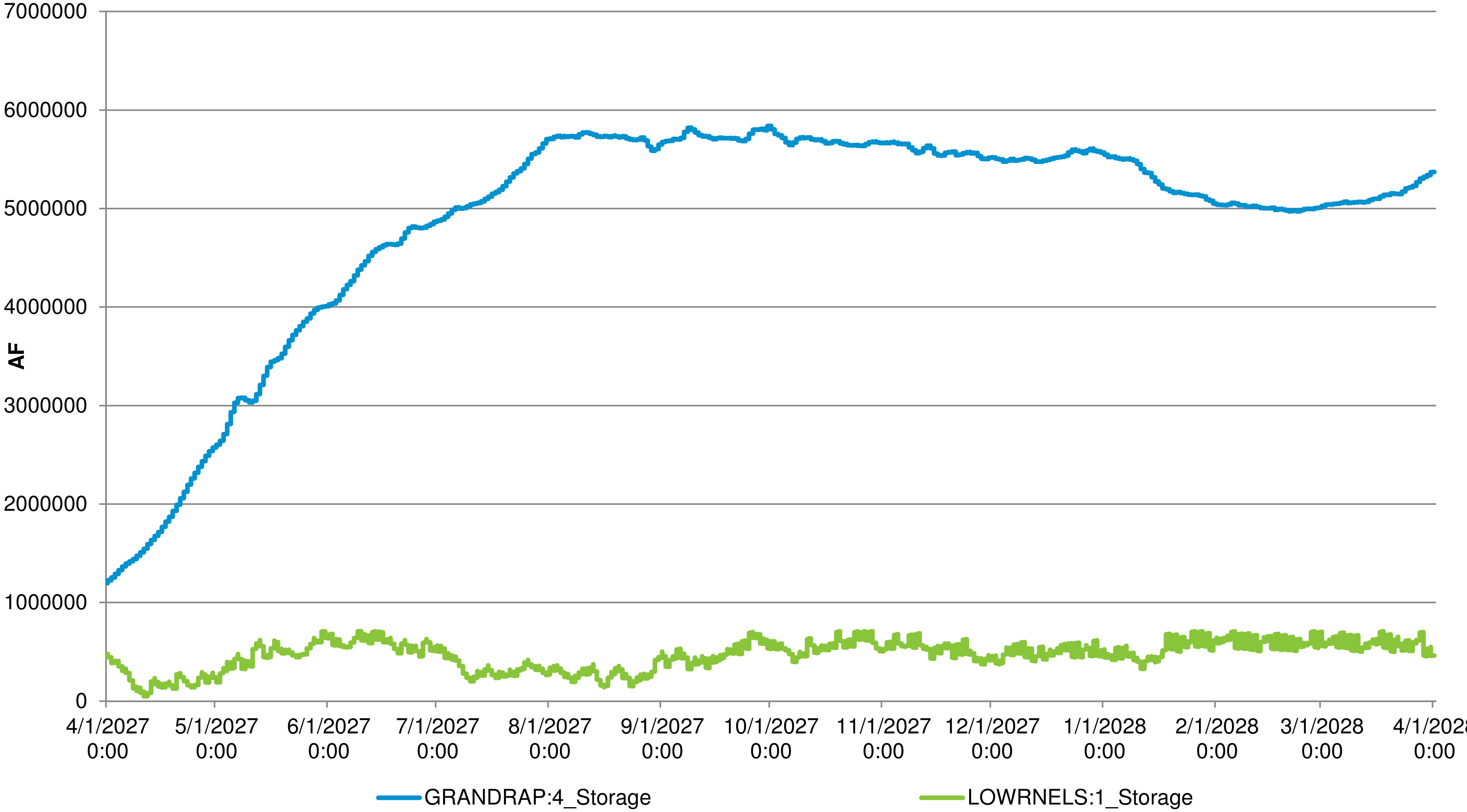
Summary of Generation Change Maps

- Manitoba Hydro has about the same generation in all of the change cases (Option 1-3)
- Interface flow differences are due to generation changes outside of MH
- Option 2 shows increased generation in IESO and decreased flow from MH to non MISO MAPP which causes the increased flow from MH to MISO
- All options show the same high level generation pattern changes (generation increases in the north and west and decreases in the east and south)
- With increased transmission, higher cost generation is reduced and lower cost generation is increased

MH-MISO Interface Flow (MW)

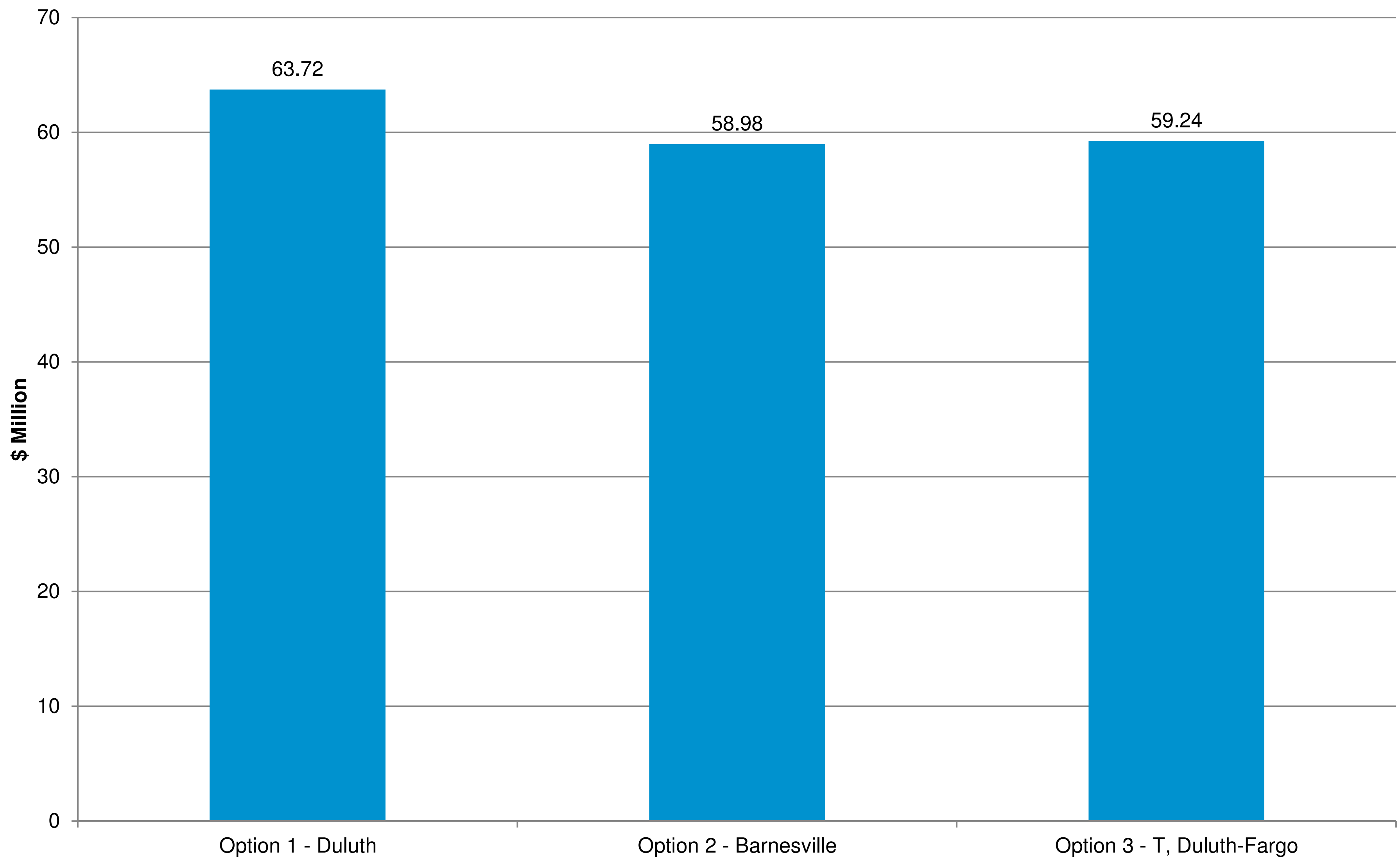


Storage Usage for MH Hydro Generators



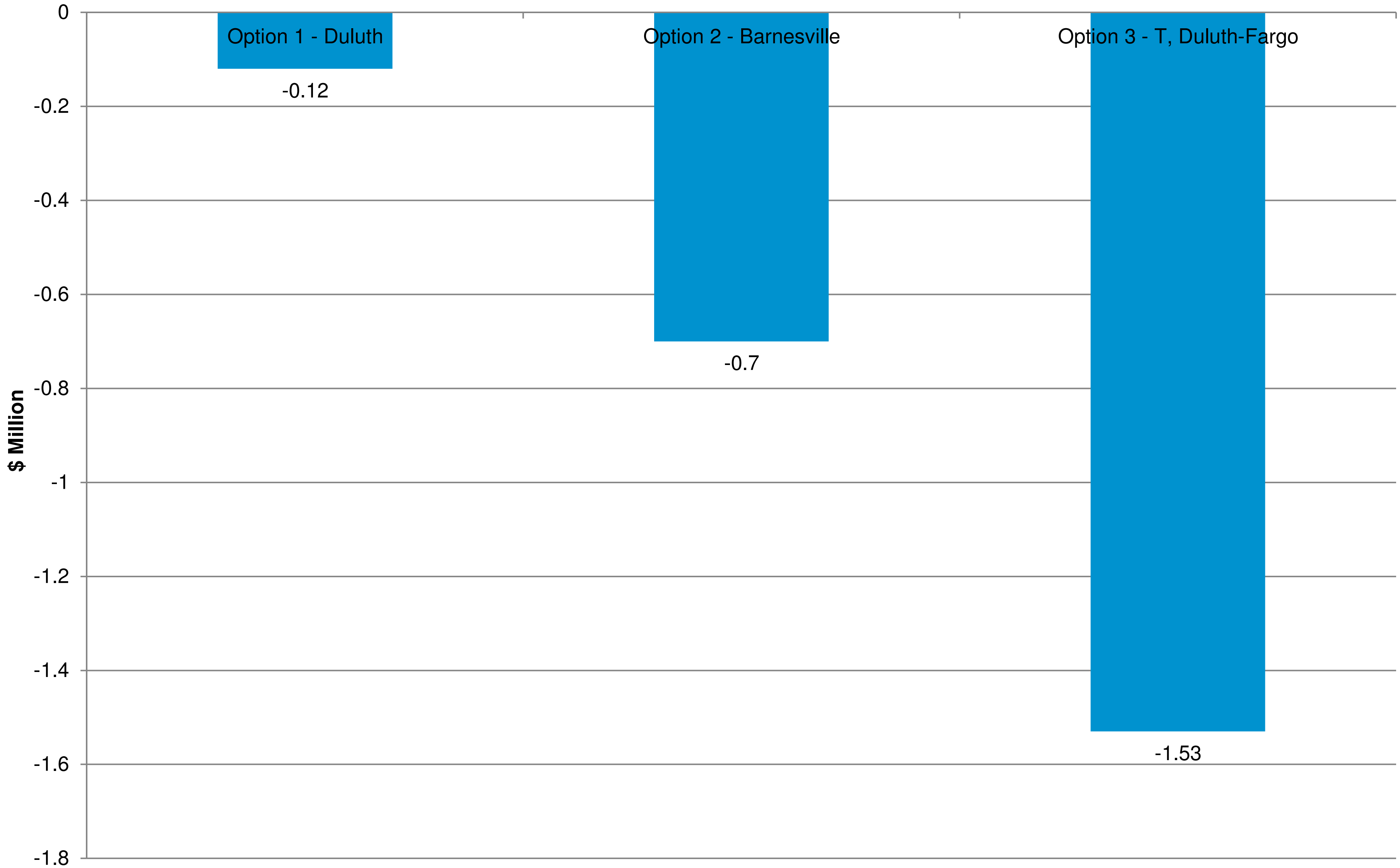
MISO

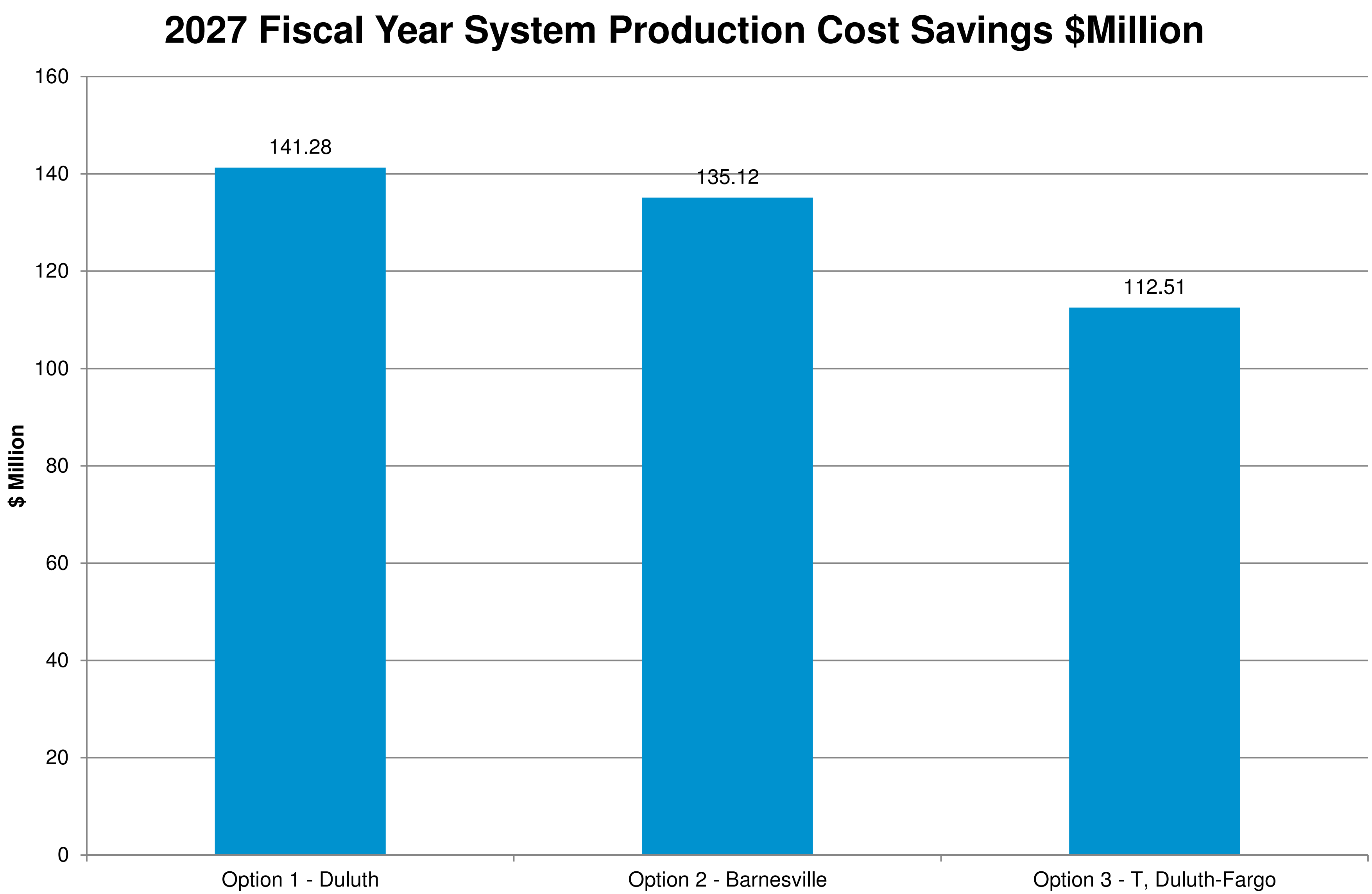
2027 Fiscal Year MISO Production Cost Savings $Million



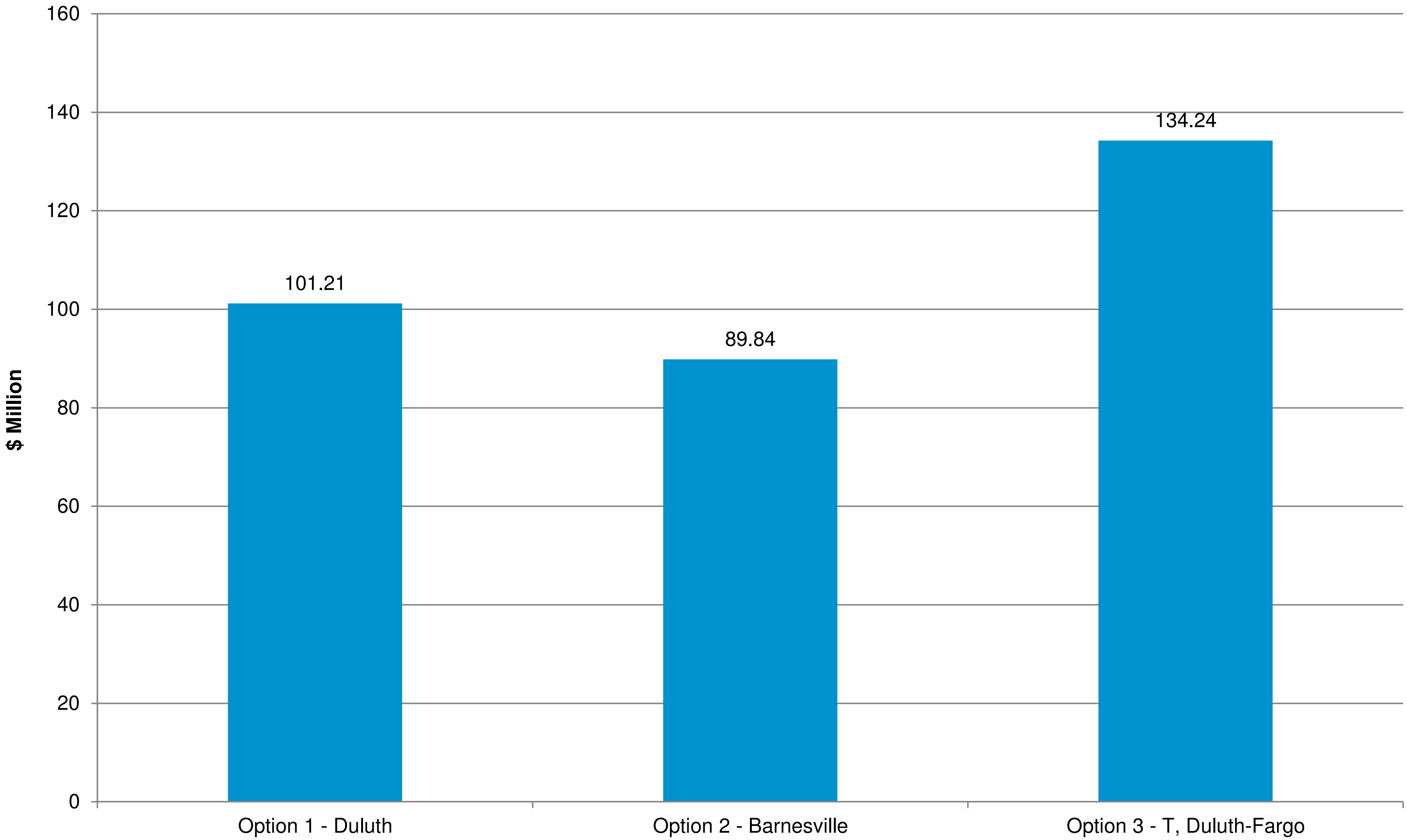
MISO

2027 Fiscal Year MH Production Cost Savings $Million

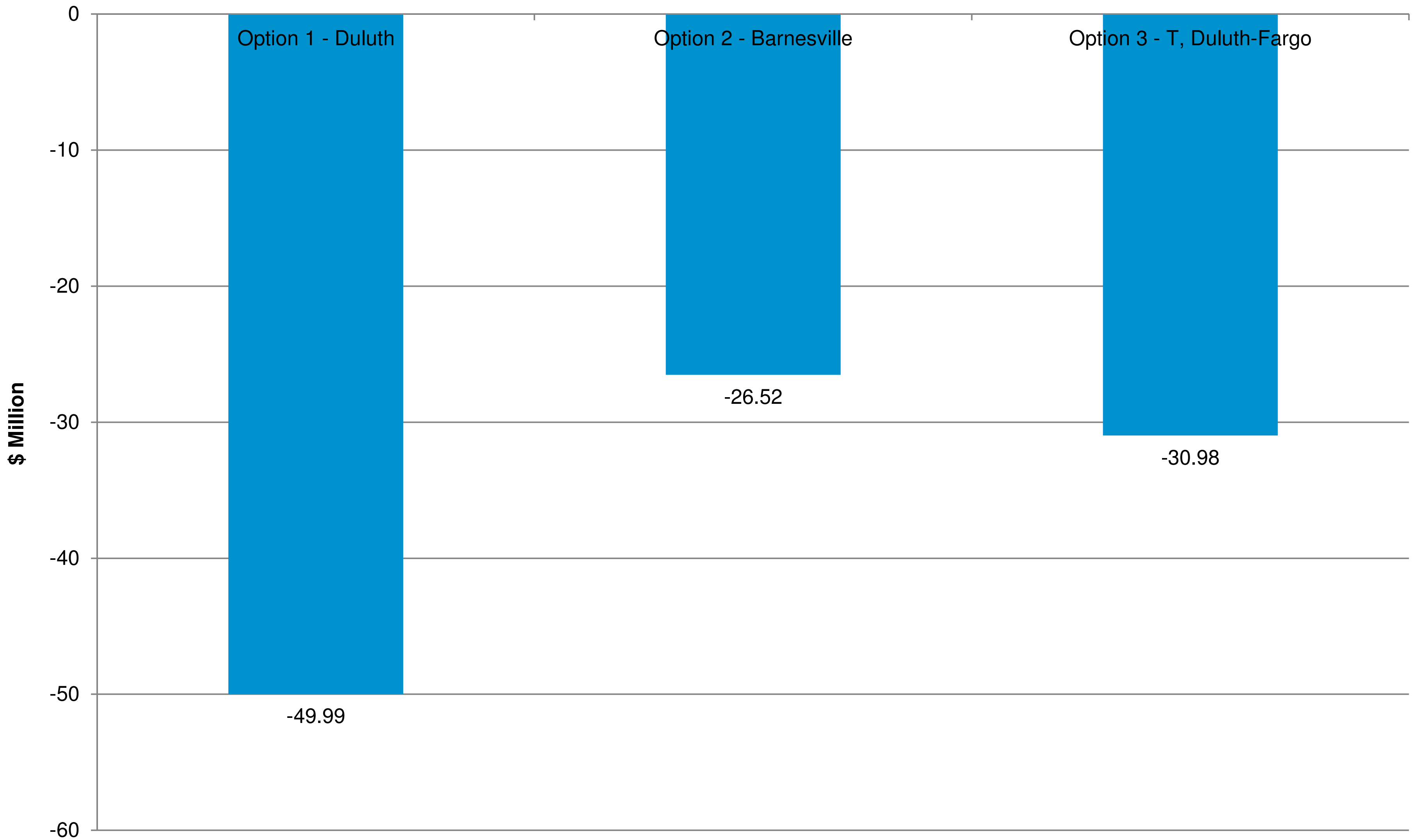



2027 Fiscal Year System Production Cost Savings $Million
$ Million
160
140
120
100
80
60
40
20
0
141.28
135.12
112.51
Option 1 - Duluth
Option 2 - Barnesville
Option 3 - T, Duluth-Fargo

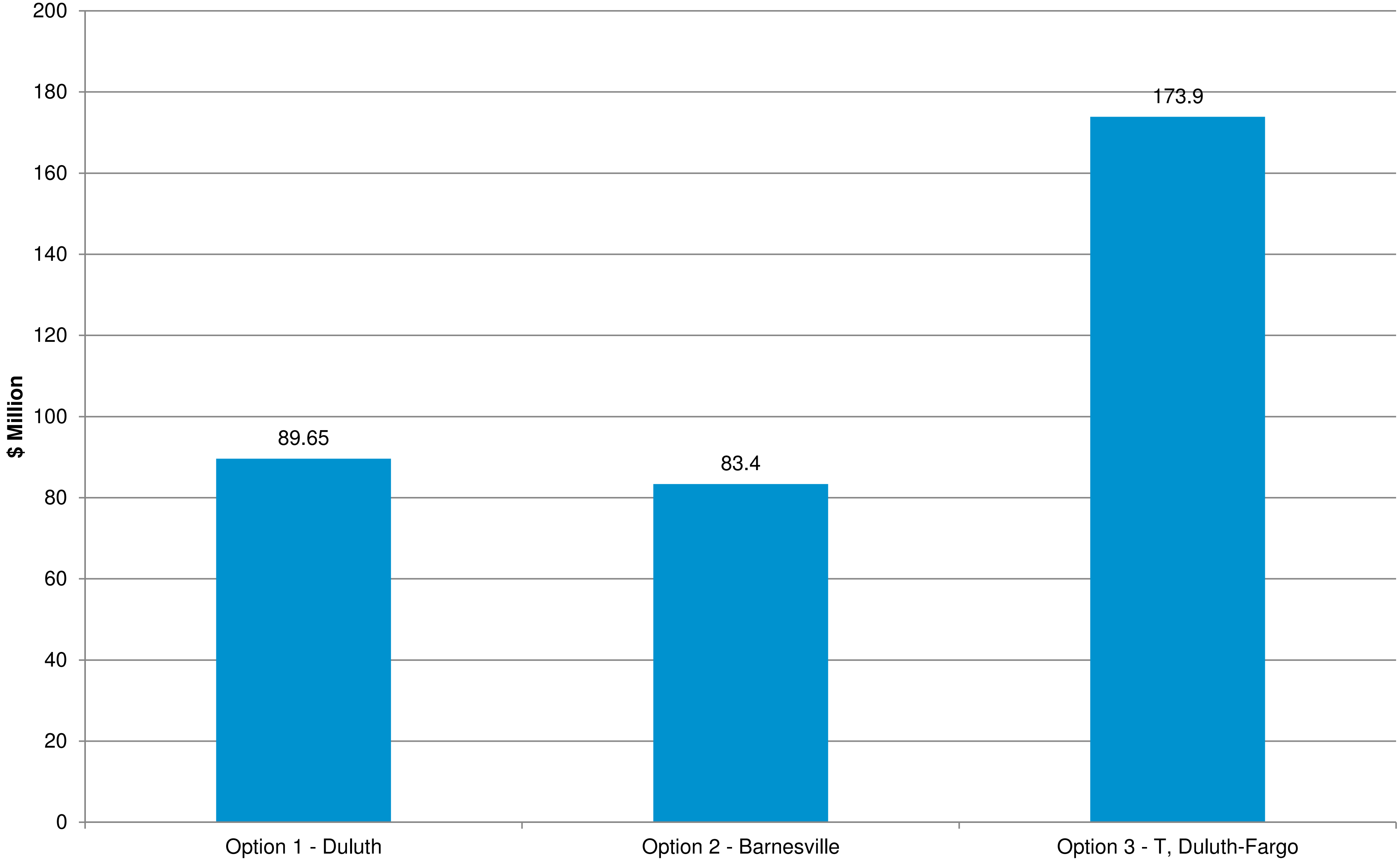
2027 Fiscal Year MISO Load Cost Savings $Million



2027 Fiscal Year MH Load Cost Savings $Million

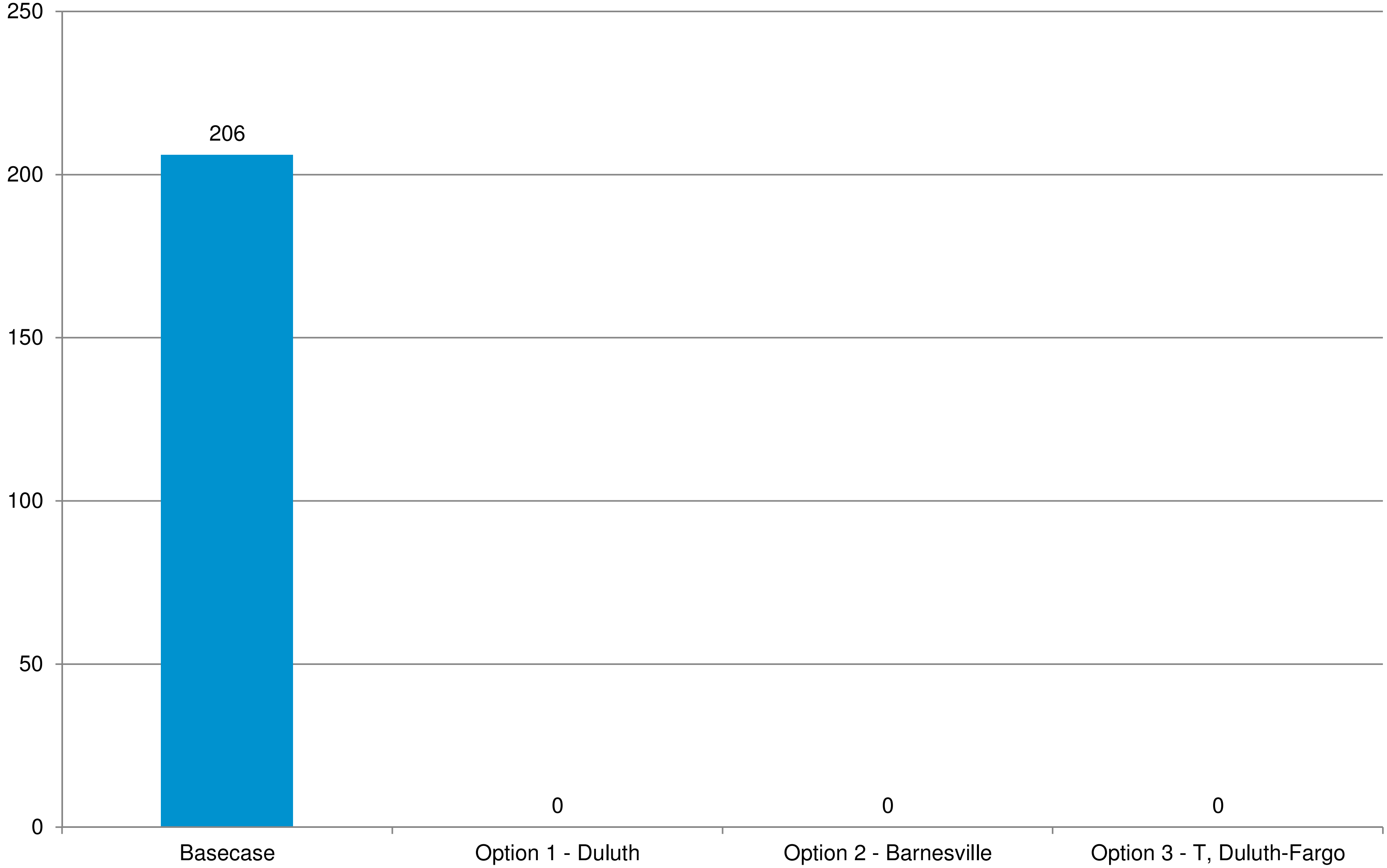


2027 Fiscal Year System Load Cost Savings $Million



MISO

2027 Fiscal Year Binding Hours MHEX_S 12



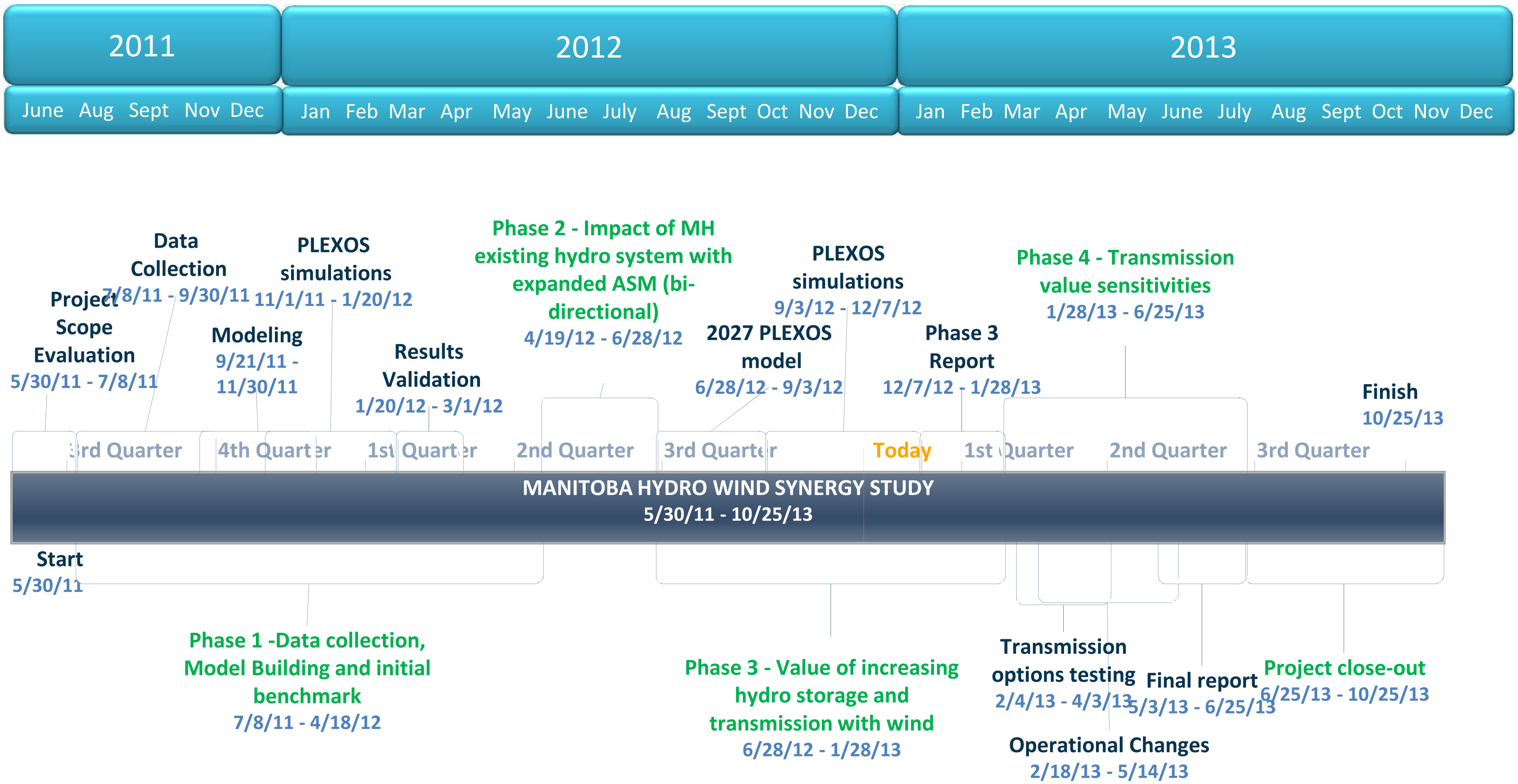
Other Findings

- Wind curtailment changes little because only the day ahead simulation was run, preceding this TRG, which includes a perfect wind forecast and no RT dispatch.
- Wind-synergy is present between MISO and MH, but doesn't change significantly with additional transmission and generation.
- Interleave runs should produce increased benefit because of the flexibility of the hydro generation and will be presented at the next TRG.

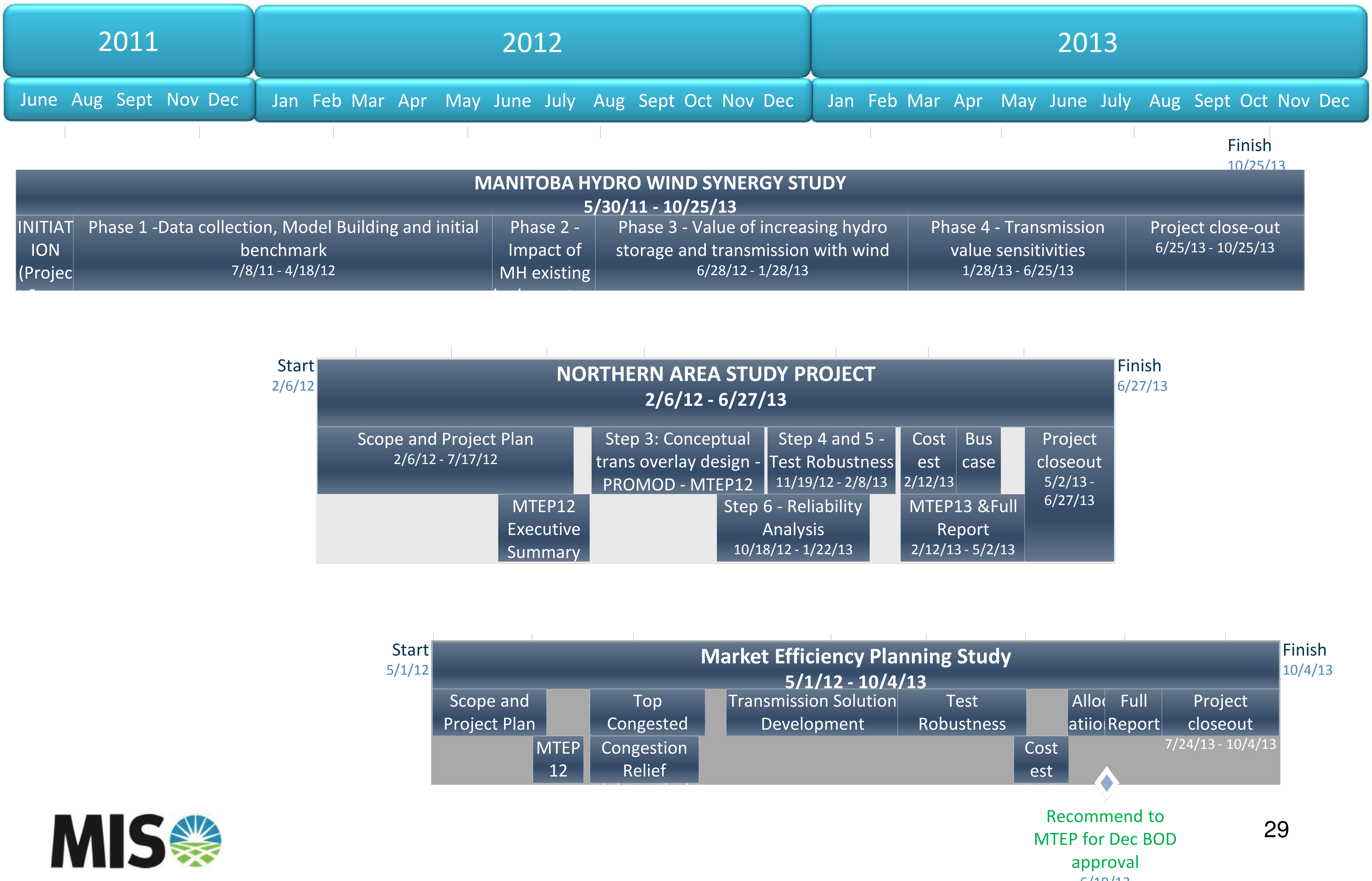
Conclusion

- **All three options show strong benefits**
- **Phase III is progressing on schedule**
- **The next TRG will be in mid January in St. Paul to present final Phase III results**

Manitoba Hydro Wind Synergy Study Timeline



MH Wind Synergy- NAS - MEPS Timelines



MISO

Coordination with Northern Area Study

- MH Wind Synergy Study (MHWSS) compares the 3 transmission options along with additional hydro generation.
- The results from MHWSS may lead to the project recommendation in MTEP13 Appendix B
- Northern Area Study is designing and testing transmission lines starting where the MHWSS options leave off
- Due to the studies timing, the Northern Area Study is using each of the 3 transmission options as input variables (separate sensitivities)
- The Northern Area Study is using the MHWSS developed hydro resource dispatch/outputs as an input

Next Steps

- Refine VWS curves with the help of MH in order to more accurately reflect hydro generators
- Get cost estimates from Duluth and T options
- We will be performing the Day Ahead (DA) and Real Time (RT) interleave runs to explore the production cost savings, wind curtailment, load cost reduction, etc. from the RT market caused by the divergence between forecasted and actual wind and load
- Continue to refine the benefit metrics of the three transmission option

Contact Info

- **Executive Sponsor**
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- **Project Consultant**
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- **Project Manager**
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  - Ryan Pulkrabek rpulkrabek@misoenergy.org
- **PLEXOS Study Engineer**
  - Jordan Bakke jbakke@misoenergy.org
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Northern Area Study
Technical Review Group (TRG)
4th Meeting
Presentation: November 2, 2012
Slides Updated: November 13, 2012
MISO

Agenda

- Welcome, Roll Call, and Review Agenda 9:00 AM
- Recap September 21st Meeting 9:05 AM
- Related Study Status Report 9:30 AM
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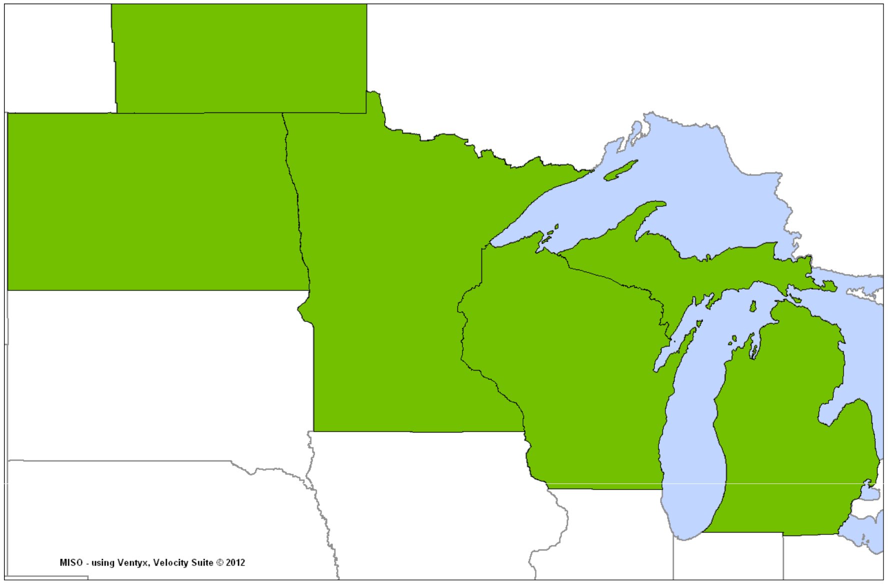
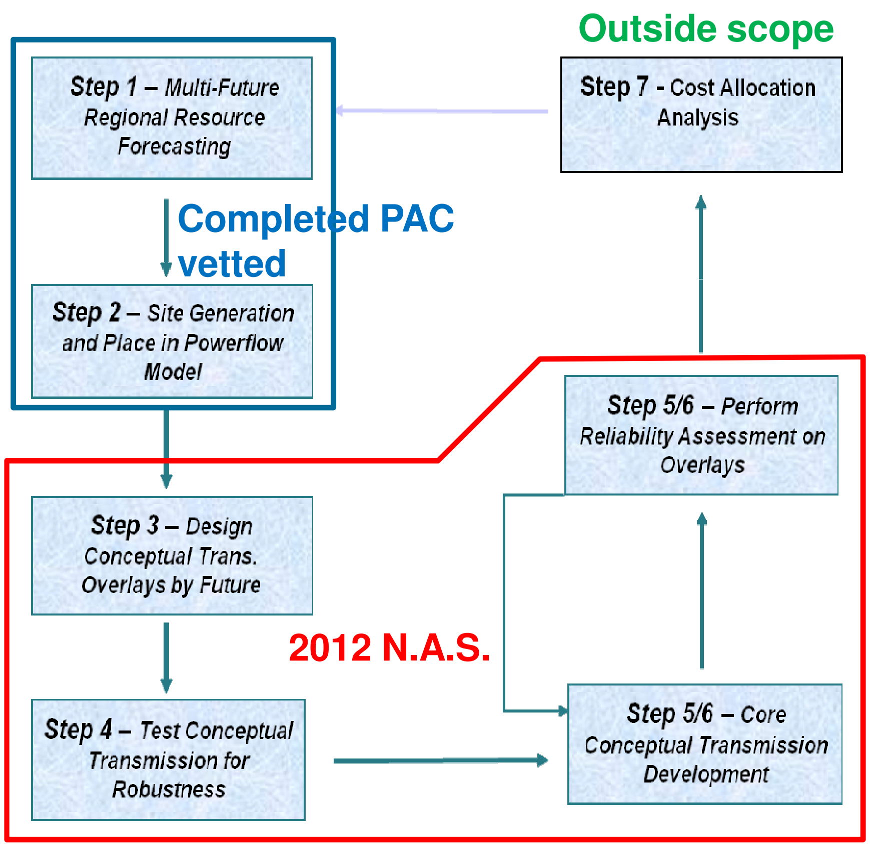
Study Recap



- **Driver: Multiple proposals by stakeholders & reliability issues located in MISO's northern footprint**
- **Objective is to conduct a comprehensive study to:**
  - Identify the economic opportunity for transmission development in the area
  - Evaluate the reliability & economic effects of drivers on a regional, rather than local, perspective
  - Develop indicative transmission proposals to address study results with a regional perspective
  - Identify the most valuable proposal(s) & screen for robustness
- **2012 analysis will provide guidance for next steps**

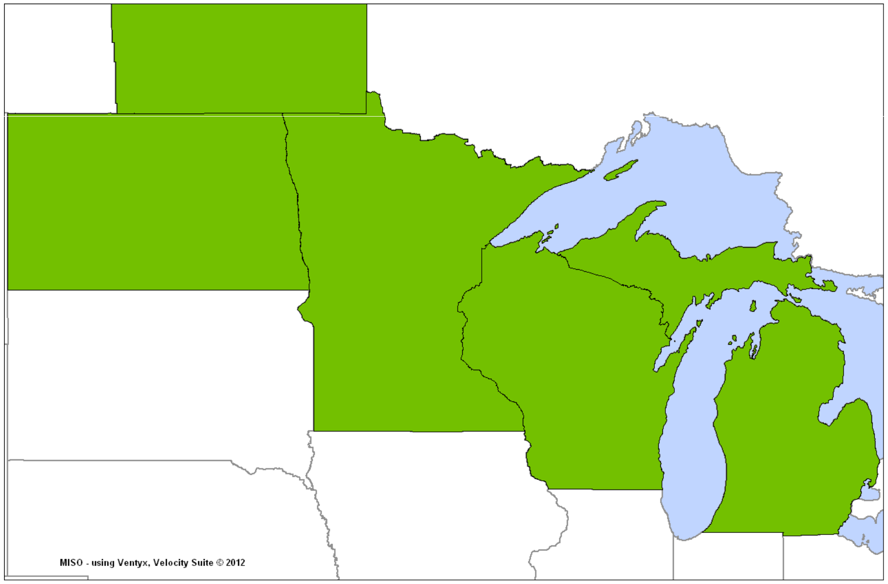
Study Progress

- **Northern Area Study is following the MISO 7 Step Planning Process that has been used for many of MISO's studies, including MTEP**
  - Currently, in Step 3 conceptual transmission overlay design and beginning Step 4 test conceptual transmission
  - Northern Area Study is using MTEP12 models as the base with specific updates to:
    - Load Levels
    - Imports from Manitoba Hydro
    - Presque Isle Unit Retirement
  - Assumptions finalized at July 11th TRG meeting



Sept 21st TRG Recap
Economic Potential

- Provides the magnitude of economic benefits that are available and how best to capture them
- Potential calculated by comparing constrained and unconstrained cases – what we have vs. what we want
- Unconstrained case relaxes all transmission constraints in the green area (infinite ratings)
- Optimal generation dispatch – doesn't care how it gets there

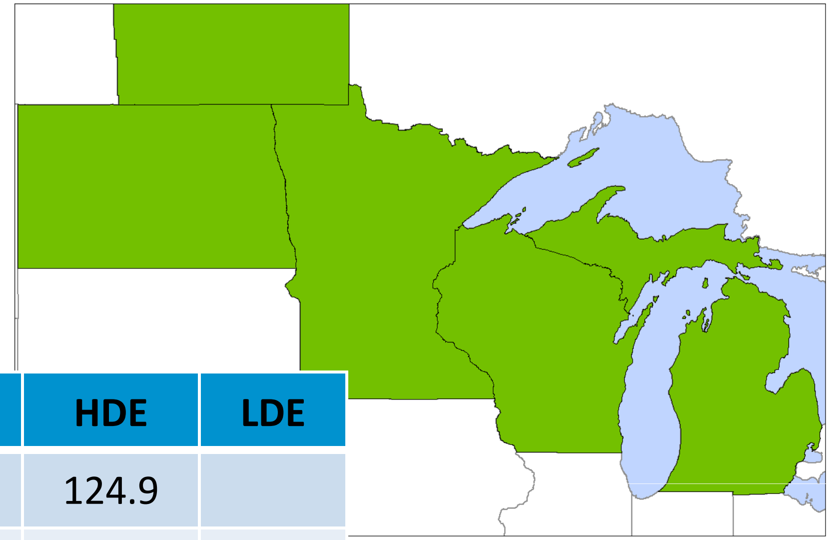


Sept 21st TRG Recap

Maximum Economic Potential

2027 MISO APC Savings ($M-2027)

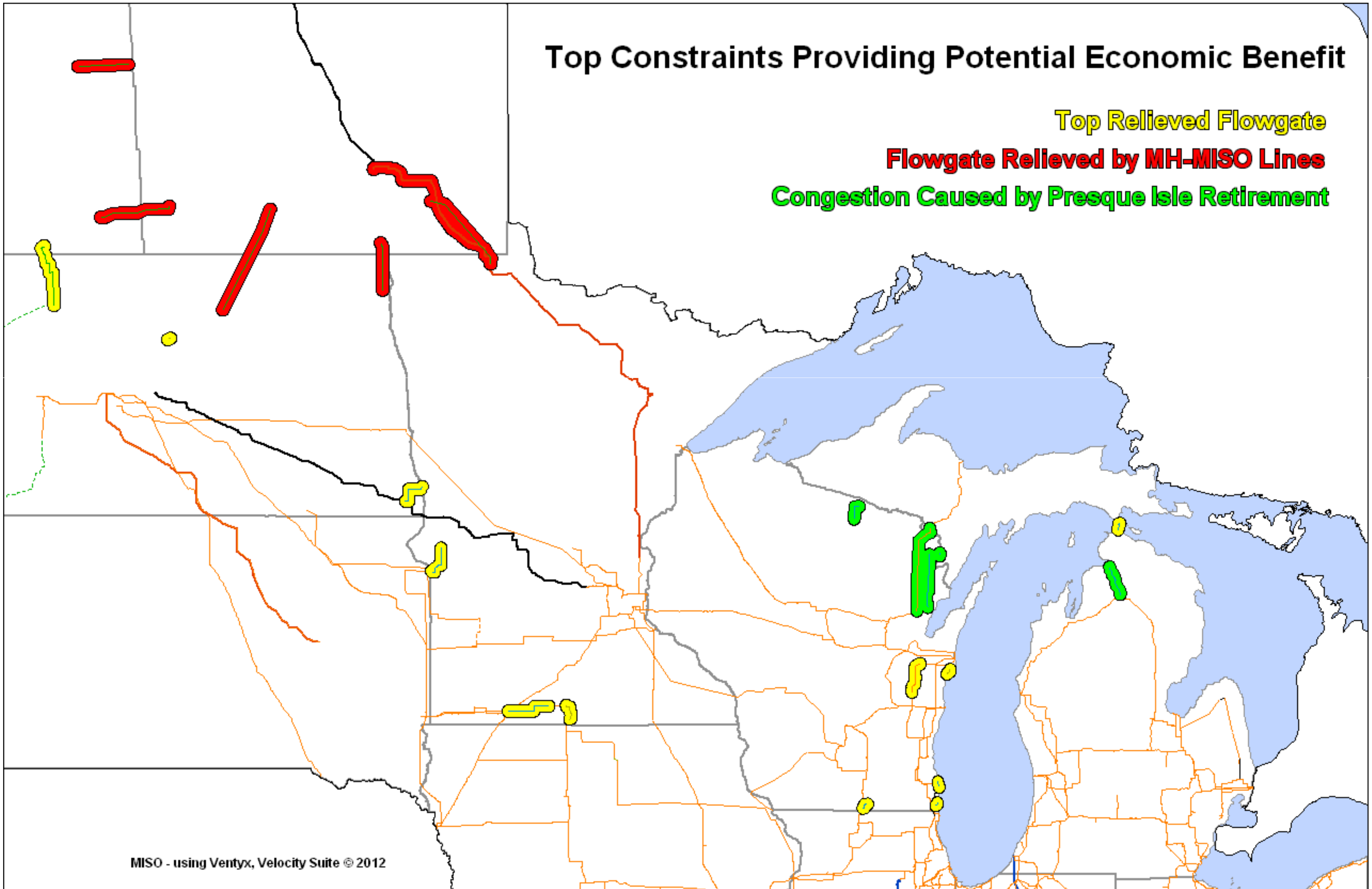
Total MISO benefit from relaxing all constraints in NAS footprint



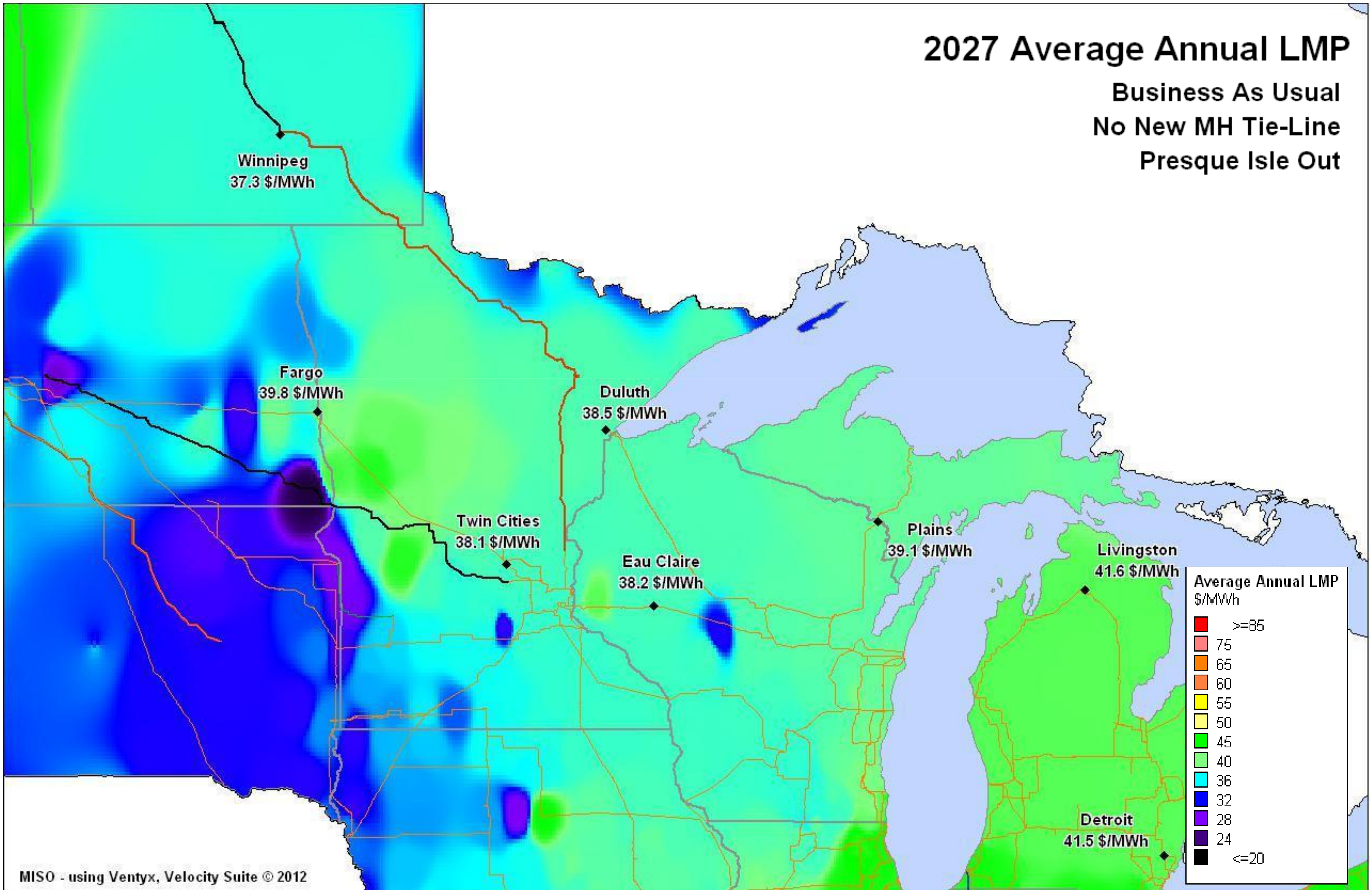
Scenario	BAU	HDE	LDE
No new MH tie-line, Presque Isle In	31.5	124.9	
No new MH tie-line, Presque Isle Out	30.1	126.8	5.5
MH - Duluth 500kV tie-line, Presque Isle In	20.9	113.0	4.7
MH - Duluth 500kV tie-line, Presque Isle Out	22.6	113.7	5.0
MH - Fargo 500kV tie-line, Presque Isle In	30.8	107.1	13.2
MH - Fargo 500kV tie-line, Presque Isle Out	29.9	110.7	12.8
MH - "T" 500kV tie-line, Presque Isle In	24.4	111.8	4.6
MH - "T" 500kV tie-line, Presque Isle Out	24.1	117.3	4.1

$100M in maximum economic potential could justify a $300M project with a 1.25 B/C ratio

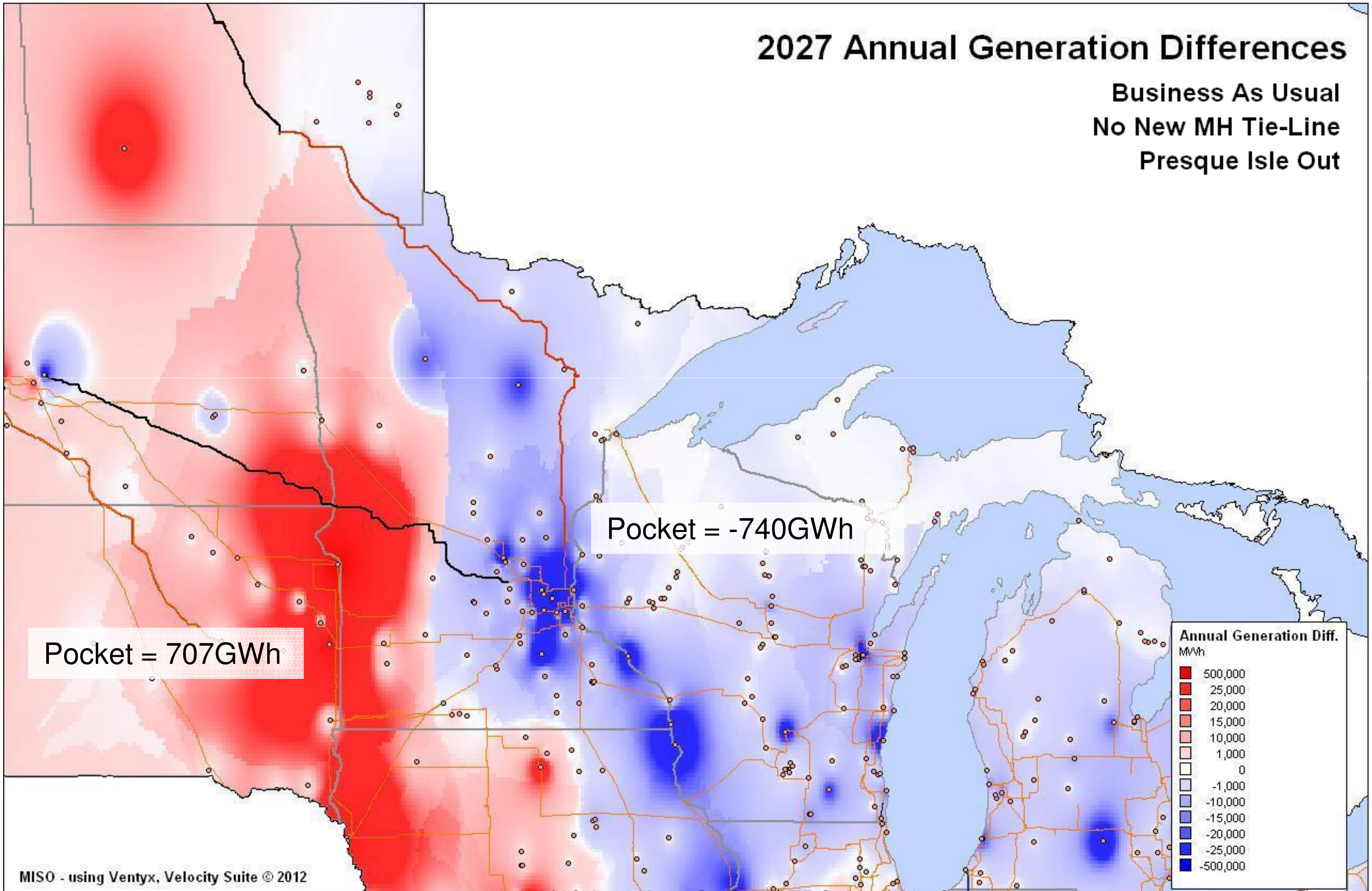
Sept 21st TRG Recap
Congestion Report



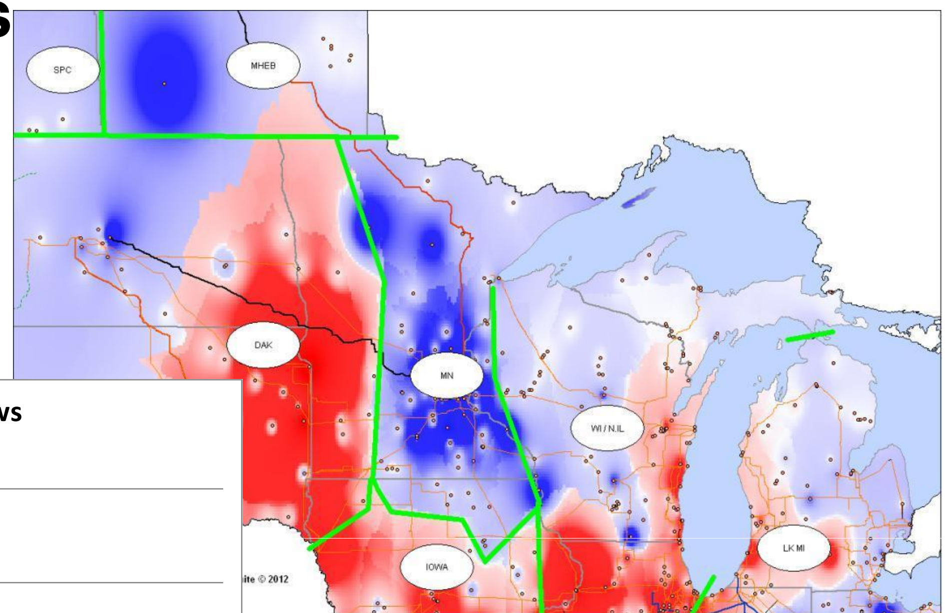
Sept 21st TRG Recap
Average Annual LMP

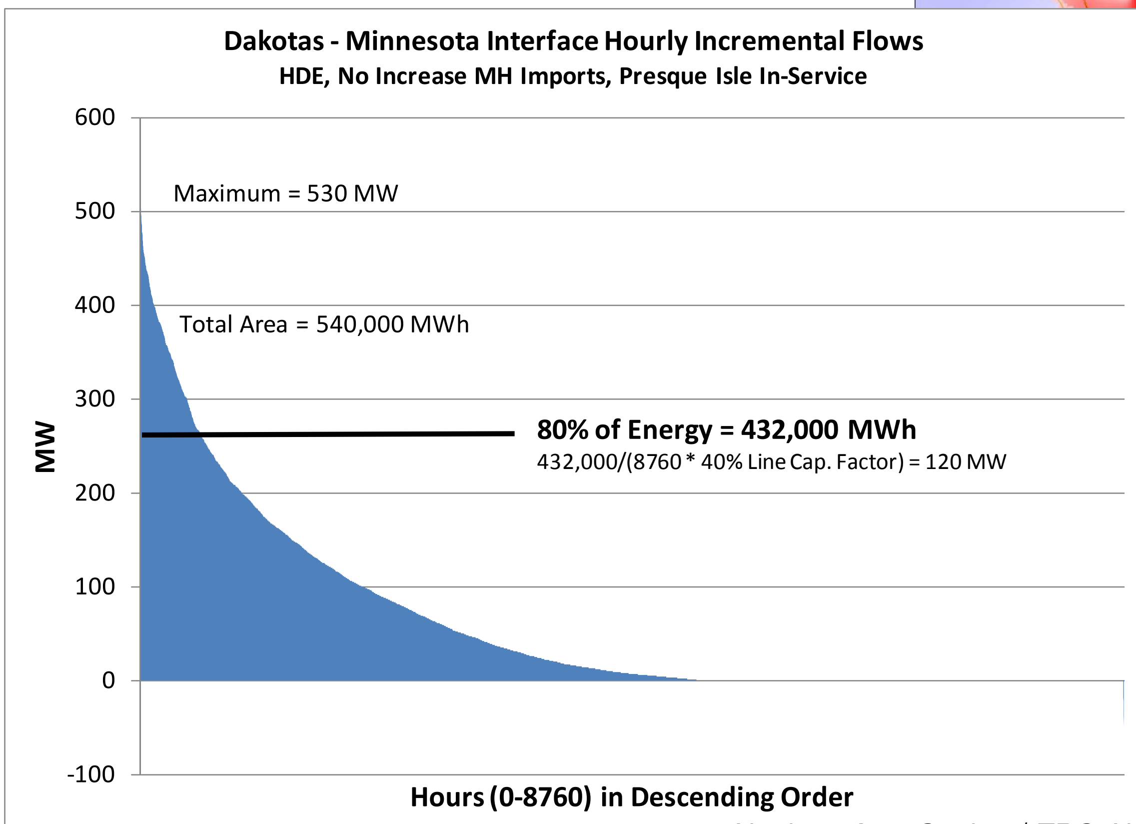


Sept 21st TRG Recap
Sources and Sinks



Sept 21st TRG Recap
Incremental Interface Flows





Sept 21st TRG Meeting Follow-Ups

- Posted full economic potential results package
- PROMOD models posted to the FTP site
- Asked TRG to review economic potential results and send in transmission plans

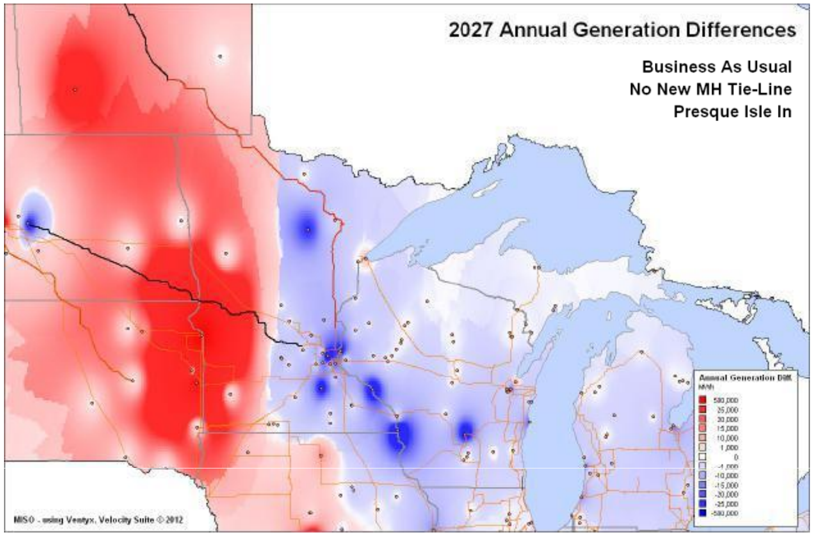
Models Updated With TRG Feedback

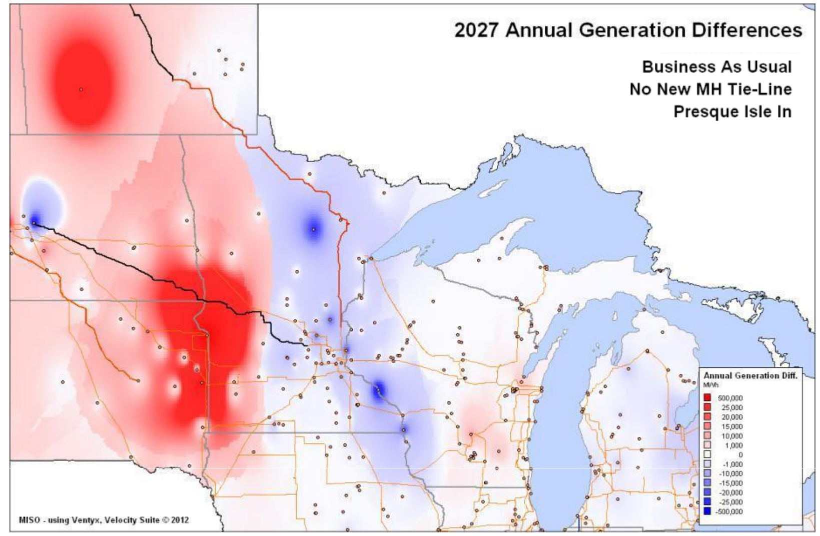
- **Noteworthy Updates:**
  - Manitoba Hydro units updated
    - Run-of-river hydro units modeled as hourly schedules to be consistent with Manitoba Hydro Wind Synergy Study
    - MH generation changed from Keeyask to Conawapa in the *No New Tie-line to MH* scenario. The *With New Tie-line* scenarios includes both Keeyask and Conawapa, which is unchanged and consistent with MH's power resource plan
  - Ontario and SaskPower generating units updated
  - Transmission projects in Wisconsin corrected
  - New Manitoba – Fargo option modeled
- **Updated PROMOD models posted to the MISO FTP site (NDA and PROMOD license required)**

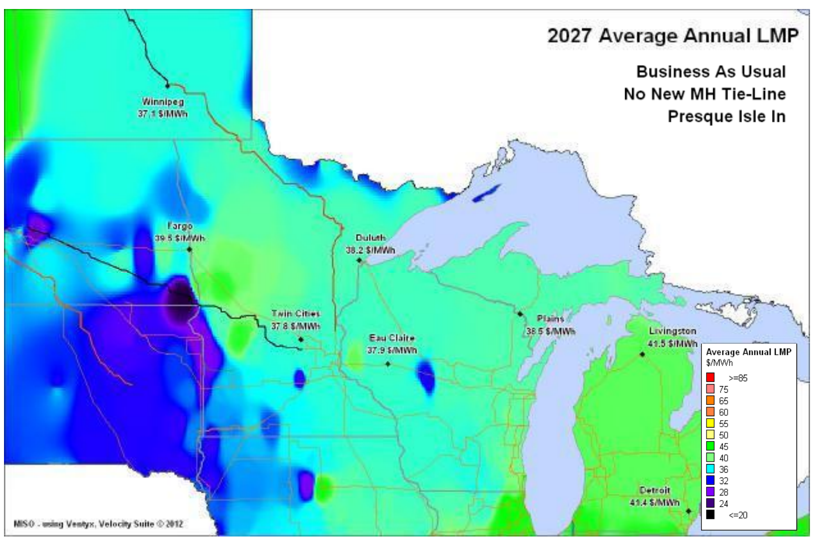
  ftp://ftpstp.midwestiso.org/pub/promodug/Northern_Area_Study_11022012/

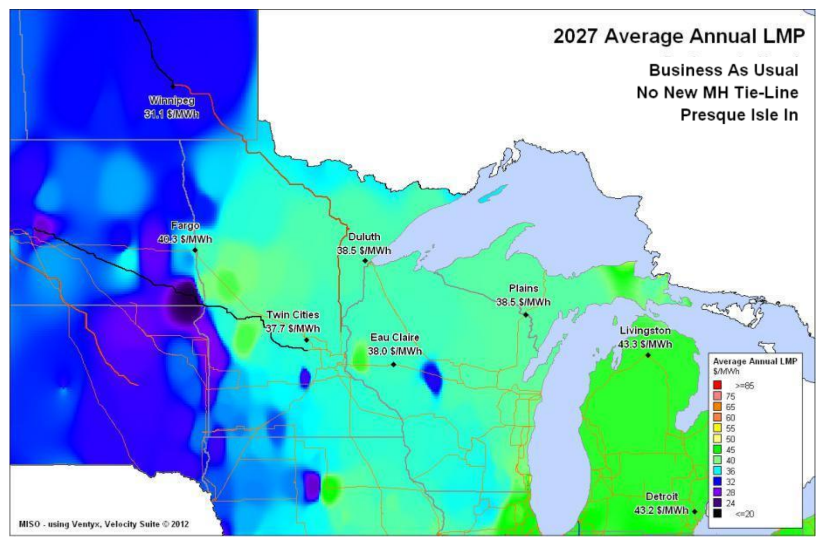
Model Updates Don't Significantly Affect Trends

9/21 | **Updated**



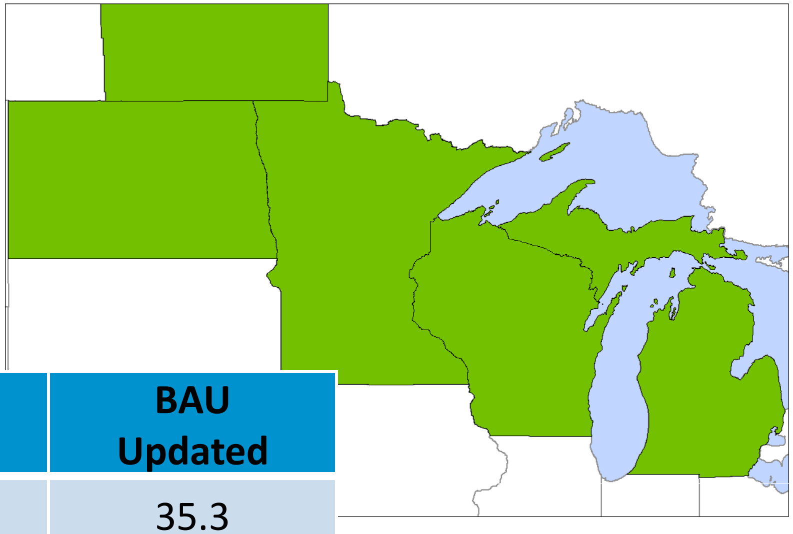






Model Updates Provide Similar Potential Benefits

2027 MISO APC Savings ($M-2027)



Total MISO benefit from relaxing all constraints in NAS footprint

Scenario	BAU 9/21	BAU Updated
No new MH tie-line, Presque Isle In	31.5	35.3
No new MH tie-line, Presque Isle Out	30.1	36.5
MH - Duluth 500kV tie-line, Presque Isle In	20.9	34.0
MH - Duluth 500kV tie-line, Presque Isle Out	22.6	34.2
MH - Fargo 500kV tie-line, Presque Isle In	30.8	28.9
MH - Fargo 500kV tie-line, Presque Isle Out	29.9	29.0
MH - "T" 500kV tie-line, Presque Isle In	24.4	33.6
MH - "T" 500kV tie-line, Presque Isle Out	24.1	33.4

HDE and LDE have similar trends

Kewaunee Nuclear Plant Retirement

- **On October 22, Dominion Resources announced they would retire the Kewaunee Nuclear Plant by mid-2013**
- **Maximum capacity of 556 MW**
- **Located in Carlton, Wisconsin (southeast of Green Bay)**
- **How to account in NAS?**
- **Attachment Y upgrades are not known**
- **Planning reserve margins must be maintained**
- **Proposal 1: Retire Kewanee in all cases all scenarios**
  - Updated EGEAS expansion shows no change to 2027, in-service date moves up for select RRF units (will change earlier year cases)
  - Attachment Y upgrades not included
- **Proposal 2: Leave unit as is and wait for more clarity**
- **Once line testing begins we can't change model assumptions**
- **TRG thoughts?**

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Manitoba Hydro Wind Synergy Study Update

- **Phase 1 and 2 are finished**
  - Established PLEXOS model with both electric system and hydraulic system included
  - Evaluated the potential benefit of bi-directional RT participation of MHEB hydro resources through external asynchronous resource (EAR)
- **Phase 3 study work is under way**
  - 3 transmission options received
  - First iteration of simulation is done
  - Preliminary results to be presented in Nov. 5th TRG meeting

Manitoba Hydro Long-Term TSRs

TSRs currently queued

- **Group study 4 TSRs totaling 1,100 MW**
- **Facility study completed $1.5 Billion in upgrades required.**
- **Customers have not indicated a willingness to commit to upgrades to date.**

Minnesota Power has requested that MISO perform a sensitivity study for their portion of the group study plus two additional options.

- **Three transfer options currently under study.**
  - 250 MW, 750 MW and 1,100 MW

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Presque Isle Retirement Sensitivity Analysis

- **It is public knowledge that retirement is being *considered* for the Presque Isle plant**
- **A MTEP sensitivity analysis is recommended because of potentially significant upgrades may be required to be planned and constructed in constrained time period**
- **Therefore, developing a potential mitigation plan in open stakeholder process is reasonable and prudent MTEP sensitivity analysis**
  - We need to determine what is necessary to allow Presque Isle to retire
  - We should also consider alternatives that may enable a long-term economic solution which are under study in NAS

Presque Isle Retirement Sensitivity Analysis

- **Presque Isle plant in Marquette, MI is the only base load plant in the Upper Peninsula**
  - 5 units: 2x55 + 3x78 MW = 344 MW total
  - Except for when on peak, at least one unit is always on maintenance outage
- **Base models: MTEP12 2017 Phase 2 series**
  - Peak
  - Off-peak with UPMI scalable loads to 80%
- **Generation dispatch**
  - Apply any topology adjustments
  - Outage plant and SCED for the “off” cases
  - Return plant to service and scale down ATC thermal fleet for the “on” cases

Presque Isle Retirement Sensitivity Analysis

- **Assumptions**
  - Straits VSC
    - Peak: 0 MW
    - Off-peak: 40 MW North-South
  - Load growth in the study area can be neglected. 2016 ≈ 2017
- **Topologies**
  - 2016
    - Escanaba Steam repowered as biomass
  - 2017
    - Green Bay-Morgan 345 kV line in service
    - Chalk Hills-18th Road 138 kV line in service

Presque Isle Retirement Sensitivity Analysis

- **Options to mitigate retirement-driven constraints**
  - Morgan-Plains-National 345 kV
  - Gardner Park-Venus-National 345 kV
  - Arrowhead-National 345 kV line
  - National-Livingston 345 kV line
  - Eau Claire-Park Falls-Cranberry-Plains 345 kV line
  - A generic "3rd 138 kV line" to the load pocket
  - Any new ideas?

Presque Isle Retirement Sensitivity Analysis

- **Steady State AC contingency screening**
  - Peak: Category A, B, C
  - Off-peak: Category A, B, C

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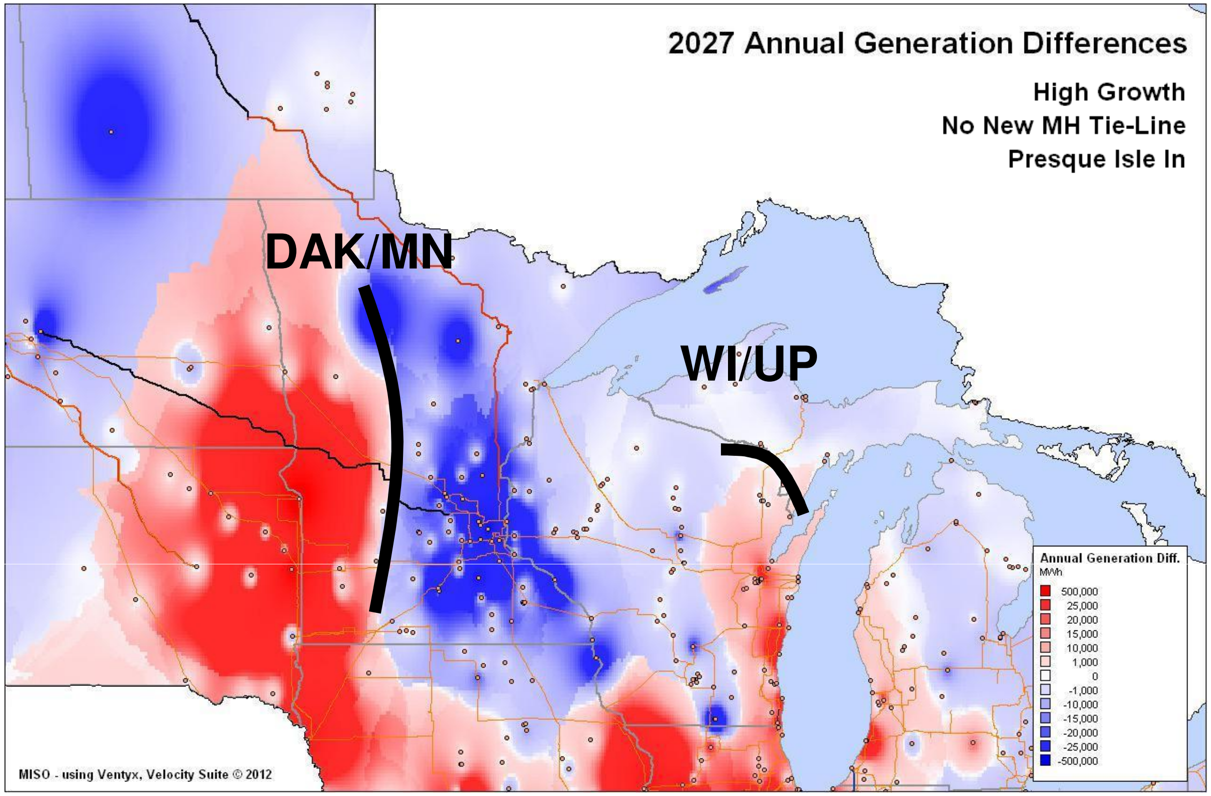
Northern Area Study Transmission Solutions

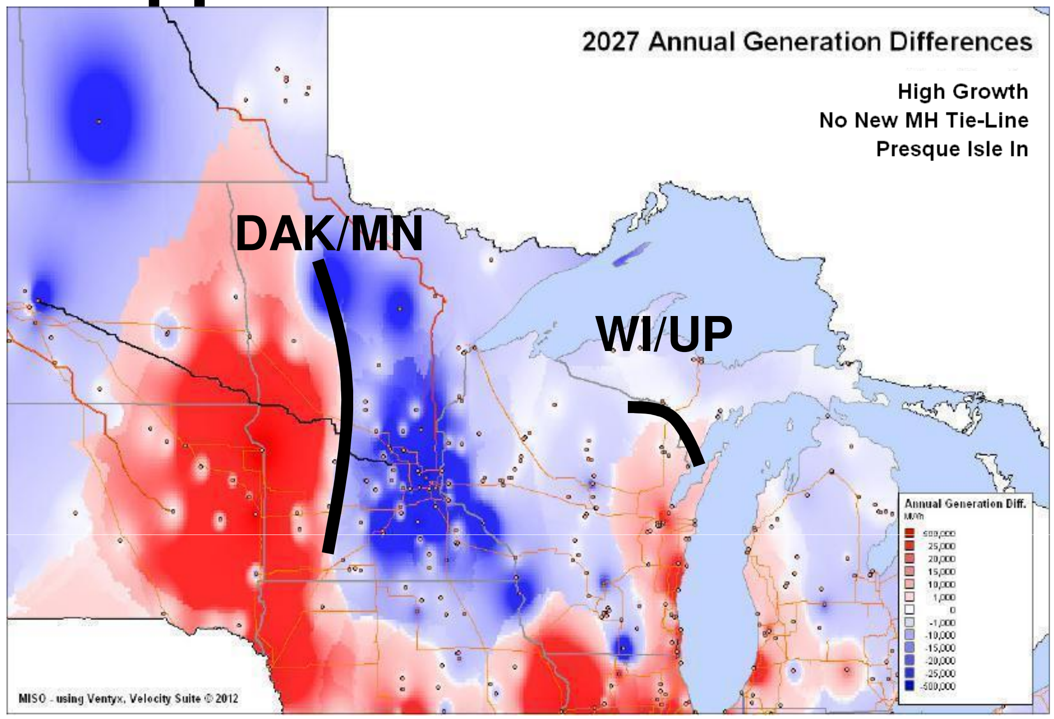
- **Goal: Present transmission solutions in an open and transparent setting**
- **Discuss proposed transmission solutions and how they exploit economic potential – are there other plans that may work better or aren't included?**
- **Additional transmission plans will be accepted through Friday November 9 – complete list of plans will be emailed to TRG**
- **Ultimate goal is to test, refine, and combine plans into optimal "if" solutions**
  - "If" this were to happen then this transmission project may be a good fit
- **Transmission design is an iterative process – "fix" something then see what happens**

Economic Potential Data Trends



- **Generally, all 24 sensitivities had similar trends**
- **Two primary "pockets" or interfaces for potential benefit**
  - Dakotas – Minnesota border
  - Wisconsin/Upper Michigan

Dakotas – Minnesota Opportunities



- **Congestion from wind**
- **Seen in all cases; MH-MISO plans all lessen congestion**
- **Presque Isle retirement has little to no effect on this area**
- **Primary Binding Constraints**
  - Hankinson – Wahpeton 230kV
  - Ortonville – Johnson Jct. - Morris 115kV
- **Interface Flow**
  - BAU: 550 GWh (600 MW max,130 MW at 80% duration and 40% CF)
  - HDE: 1,400 GWh (800 MW max, 320 MW at 80% duration and 40% CF)

TRG Supplied Plans (Dakotas – MN)

Upgrade Hankinson – Wahpeton 230kV and Big Stone – Morris 115kV

Lines are for illustrative purposes only, actual line routing may differ

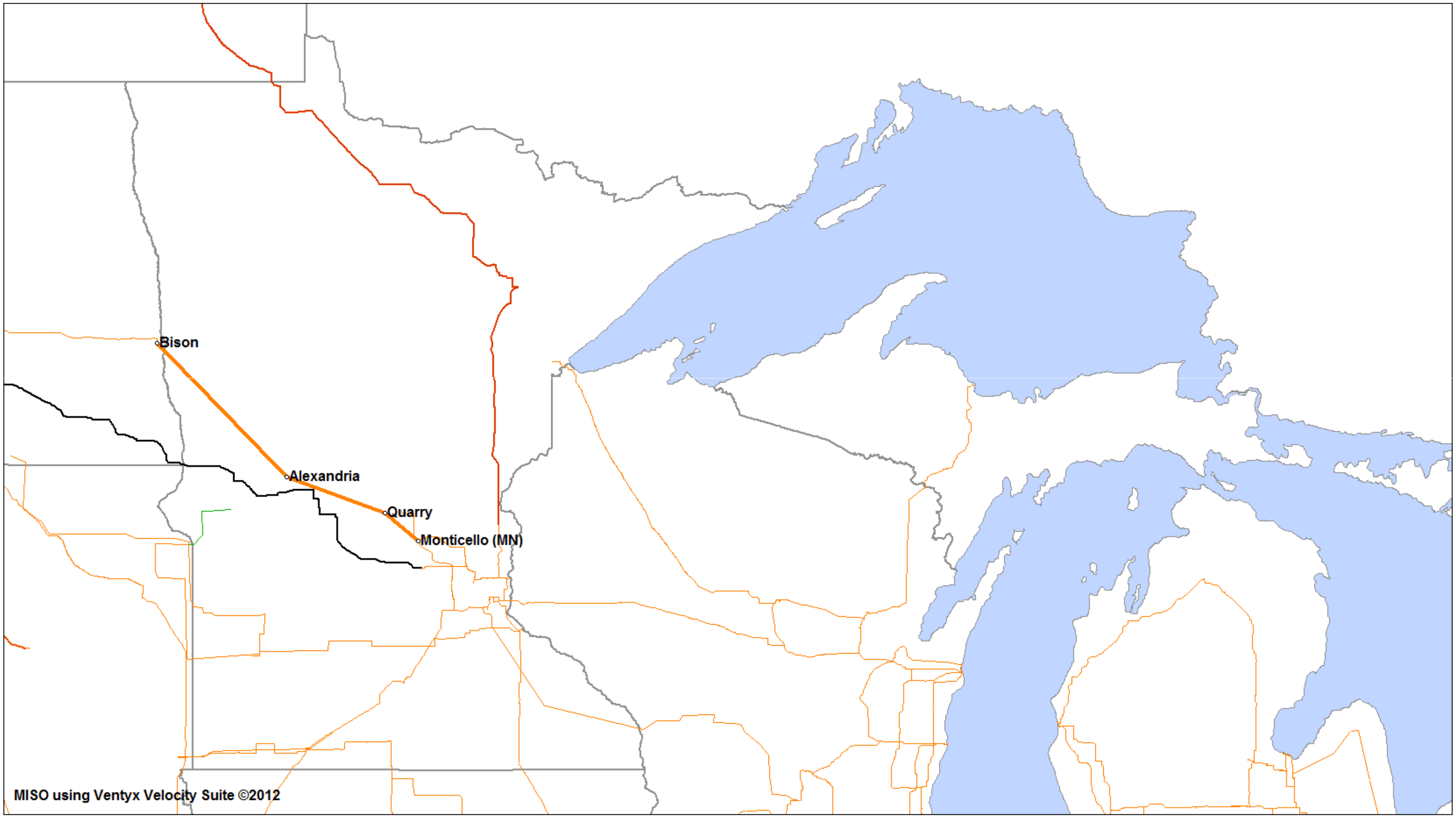
TRG Supplied Plans (Dakotas – MN)
Big Stone – Hazel 345kV

Lines are for illustrative purposes only, actual line routing may differ

TRG Supplied Plans (Dakotas – MN)
Brookings – Hampton 345kV

Lines are for illustrative purposes only, actual line routing may differ

TRG Supplied Plans (Dakotas – MN)
Fargo – Monticello 345kV



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MISO

TRG Supplied Plans (Dakotas – MN)
Corridor Project: Convert MN Valley/Hazel – Blue Lk 230kV to 345kVx2

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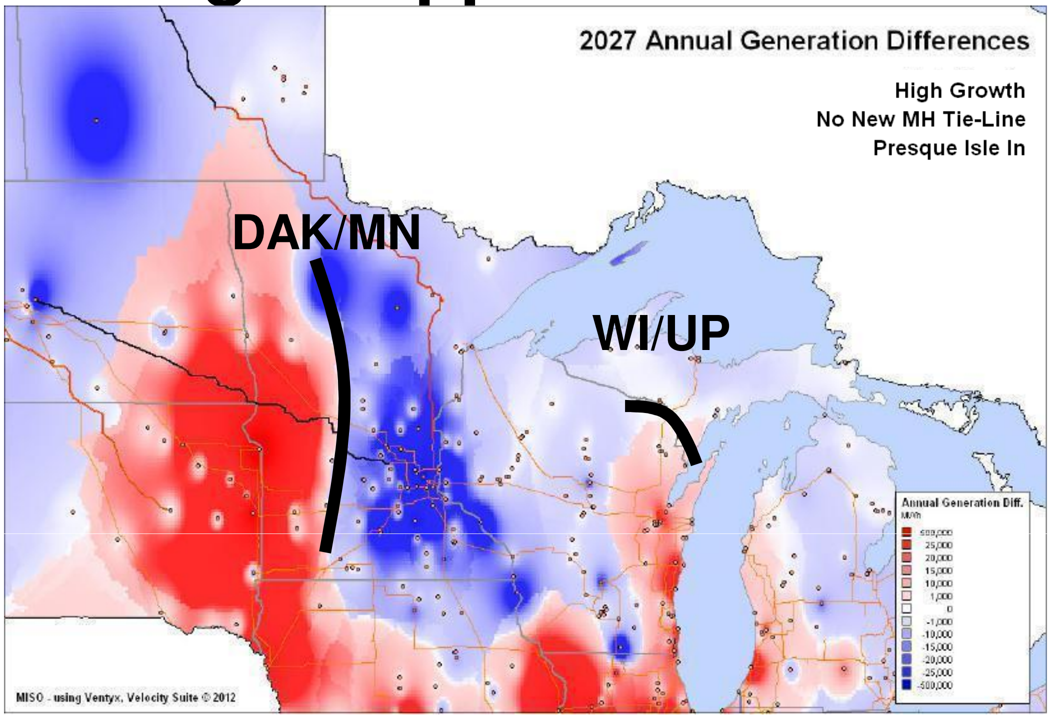
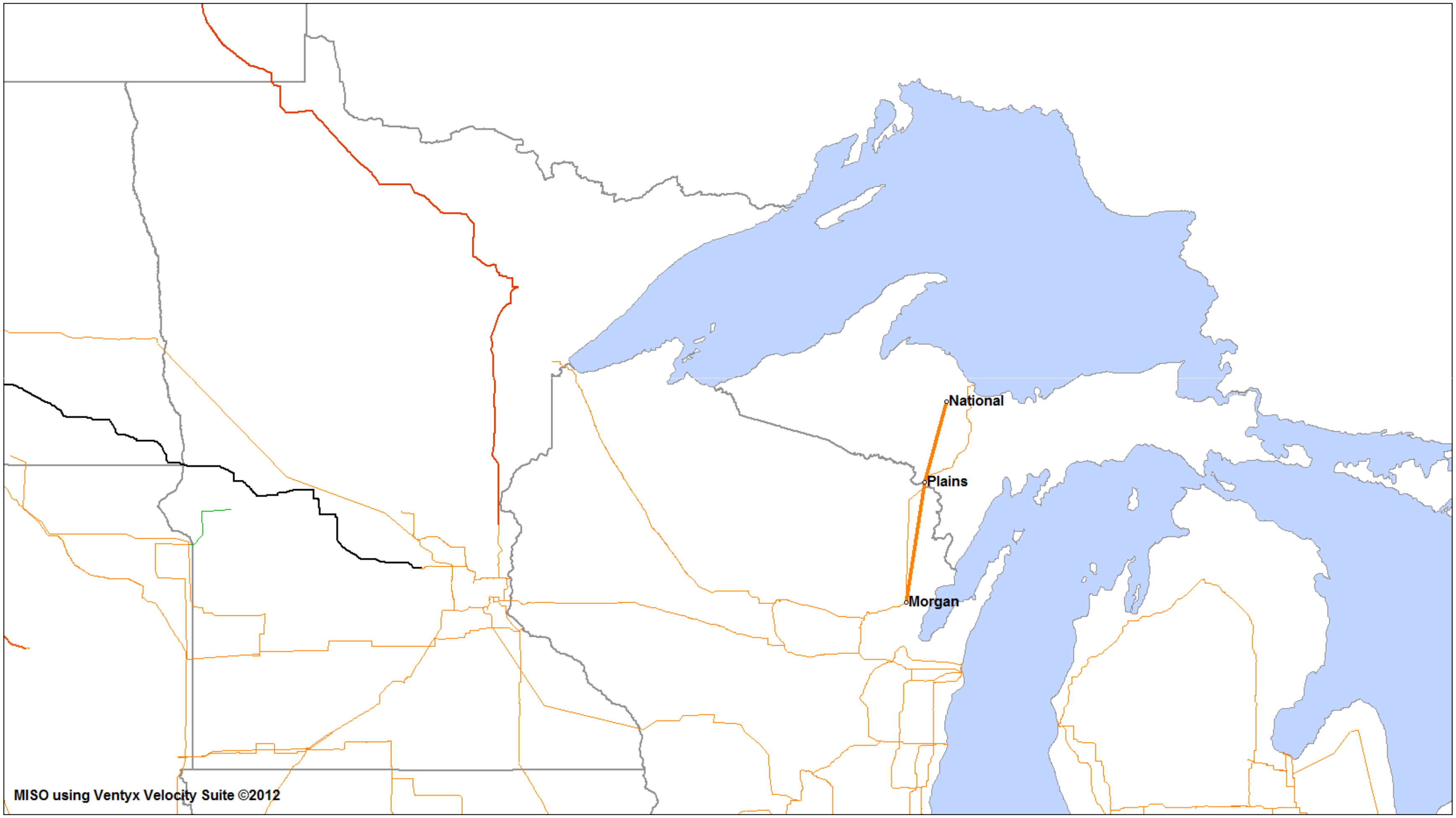
Wisconsin – Upper Michigan Opportunities



- **Congestion from energy trying to get to UP loads and high prices**
- **Highest in HDE futures and Presque Isle retirement**
- **Current topology, MH imports only slightly increase congestion**
- **Primary Binding Constraints**
  - ATC Flow South Interface
  - South Lake Michigan/ComEd
  - McGulpin Interface
- **Interface Flow Across Lake MI (Difficult to Estimate)**
  - BAU: 5,000 GWh (3,330 MW Max; 1,200 MW at 80% duration and 40% CF)
  - HDE: 12,000 GWh (5,000 Max; 2,700 MW at 80% duration and 40% CF)

TRG Supplied Plans (WI/UP)
Morgan – Plains – National 345kV



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TRG Supplied Plans (WI/UP)
Gardener Park - Venus - National 345kV

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TRG Supplied Plans (WI/UP) Arnold – Livingston 345kV

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TRG Supplied Plans (WI/UP)
National – Livingston 345kV

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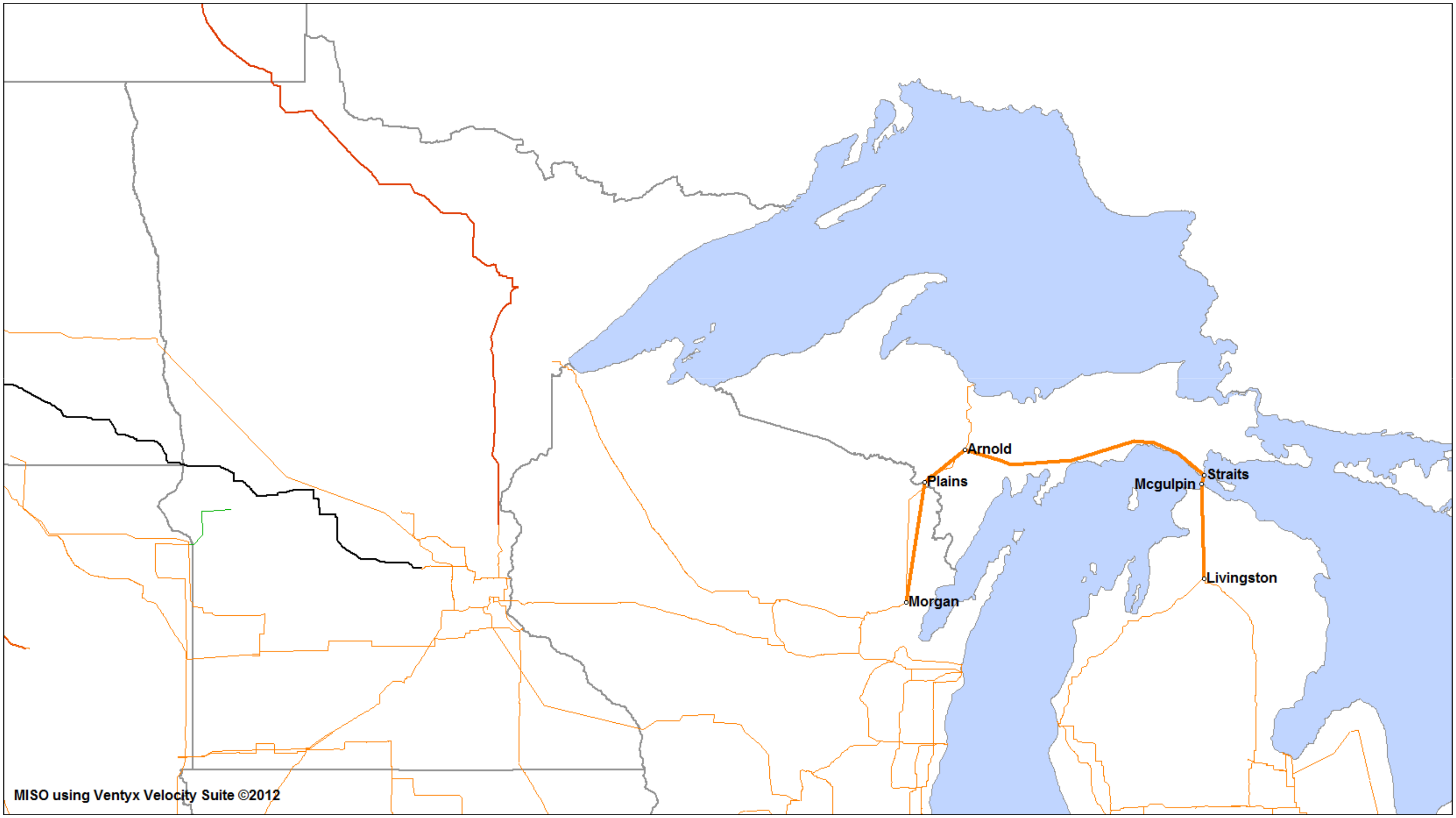
TRG Supplied Plans (WI/UP)
Morgan – Plains – Arnold – Livingston 345kV



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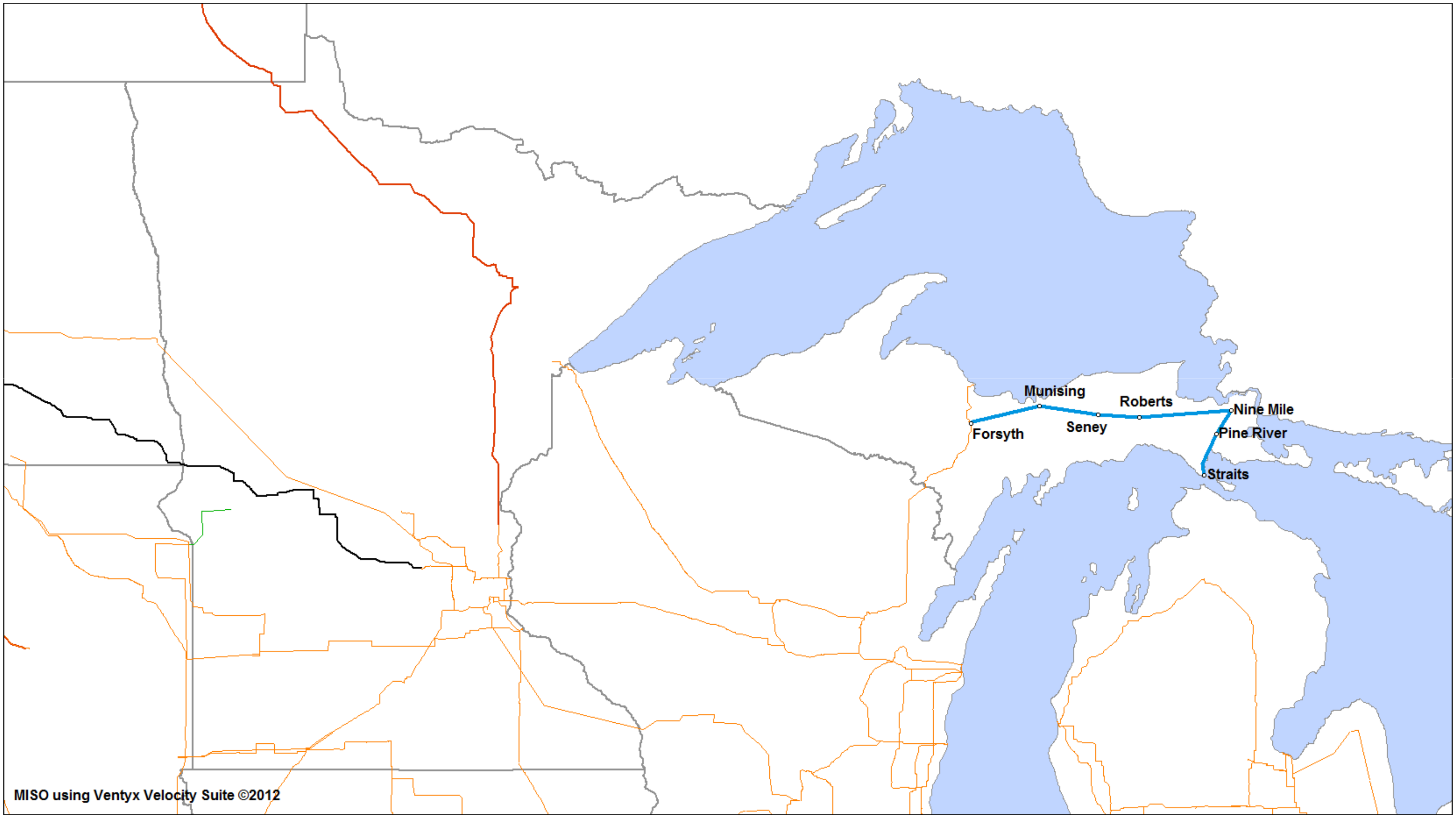
TRG Supplied Plans (WI/UP)
Marquette County - Mackinac County 138kV



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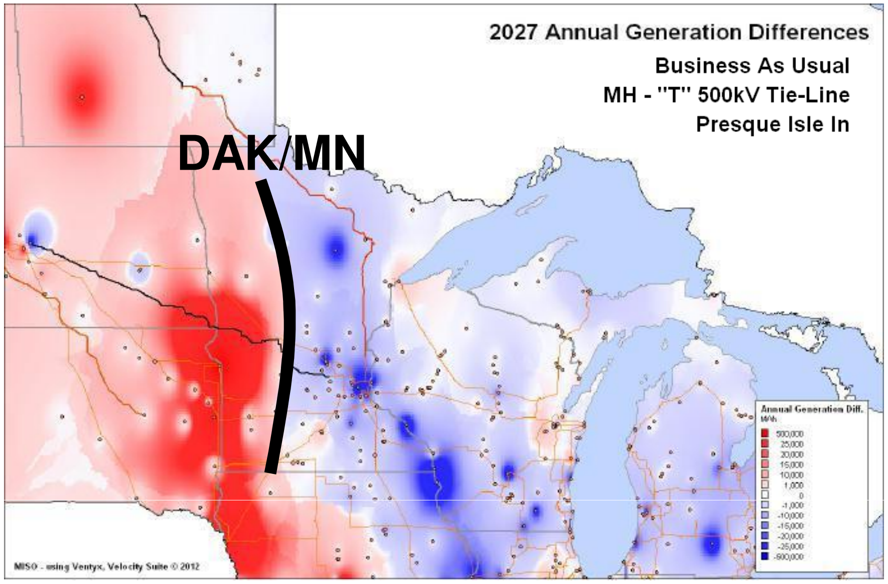
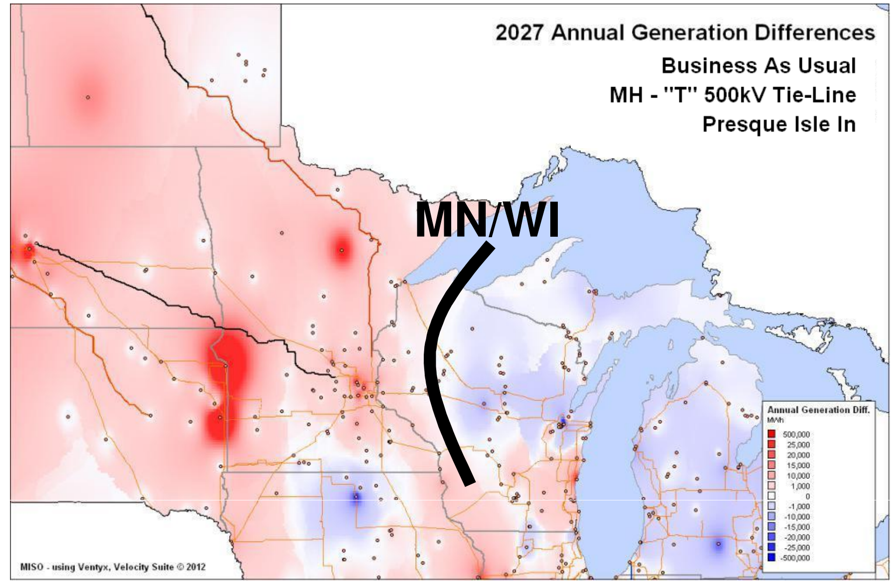
Holistic Plans



Before Mitigating DAK/MN



After Mitigating DAK/MN

- **Next iteration in the process - after mitigating DAK/MN new "interface" is the Minnesota to Wisconsin border**
- **Transport new imports to load and high prices**
- **New primary binding constraints after mitigating DAK/MN**
  - Arrowhead – Stone Lake 345kV; Stinson Phase Shifter
  - South Lake Michigan/ComEd/McGulpin Interface
- **New MN/WI BAU inc. Interface flow: 830 GWh (1,040 MW Max, 200 MW "80%")**

TRG Supplied Plans (Holistic)
Arrowhead – National 345kV

Lines are for illustrative purposes only, actual line routing may differ

TRG Supplied Plans (Holistic)
Arrowhead – Arnold – Livingston 345kV

Lines are for illustrative purposes only, actual line routing may differ

MISO

TRG Supplied Plans (Holistic)
Eau Claire – Arnold – Livingston 345kV

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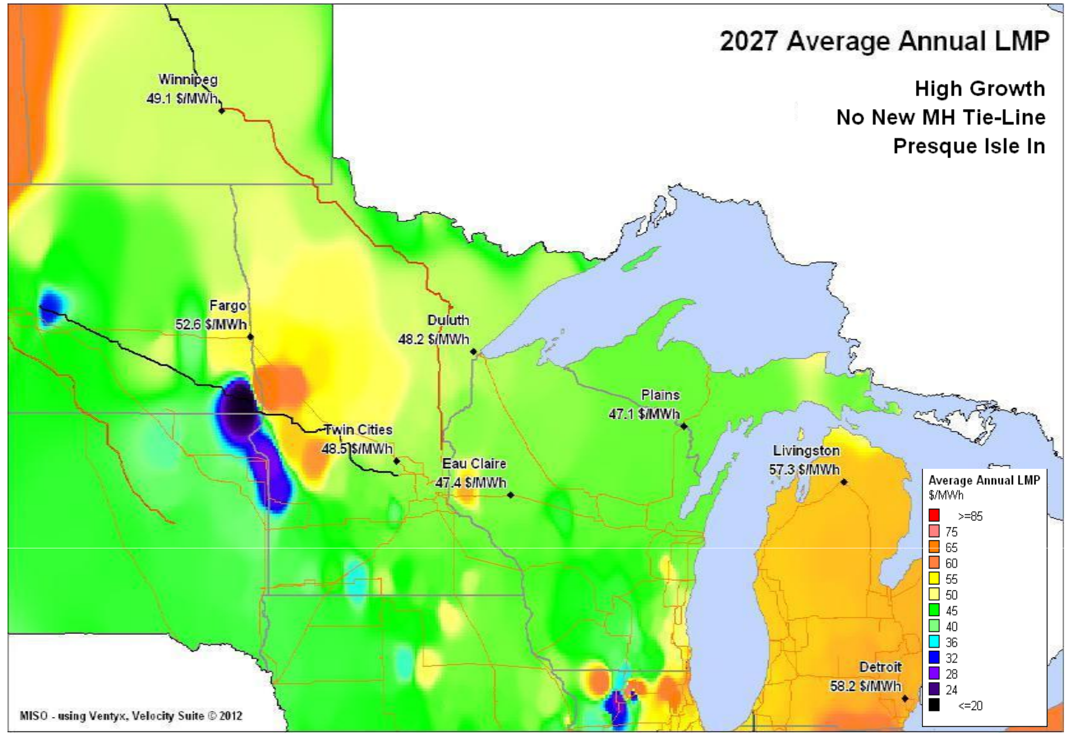
DC Opportunities?

- No DC options submitted by TRG; however, multiple parties expressed interest in exploring opportunities
- In all scenarios highest prices in Michigan
- DC responds to LMP differences and acts on market signals



- AC responds to power angle differences and has a complex flow through the AC system
- DC could help with potential Lake Michigan loop flows
- Should we include DC in analysis? TRG thoughts?
- Subsequent "proposed" lines sized based on Lake Michigan interface flows (HDE: 12,000 GWh)

"Proposed?" Plans (DC)
Blackberry – Livingston/Tittabawassee 500kV DC

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"Proposed?" Plans (DC)
Blackberry – Plains 500kV DC

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"Proposed?" Plans (DC)
Blackberry – Plains – Livingston/Tittab. 500kV DC

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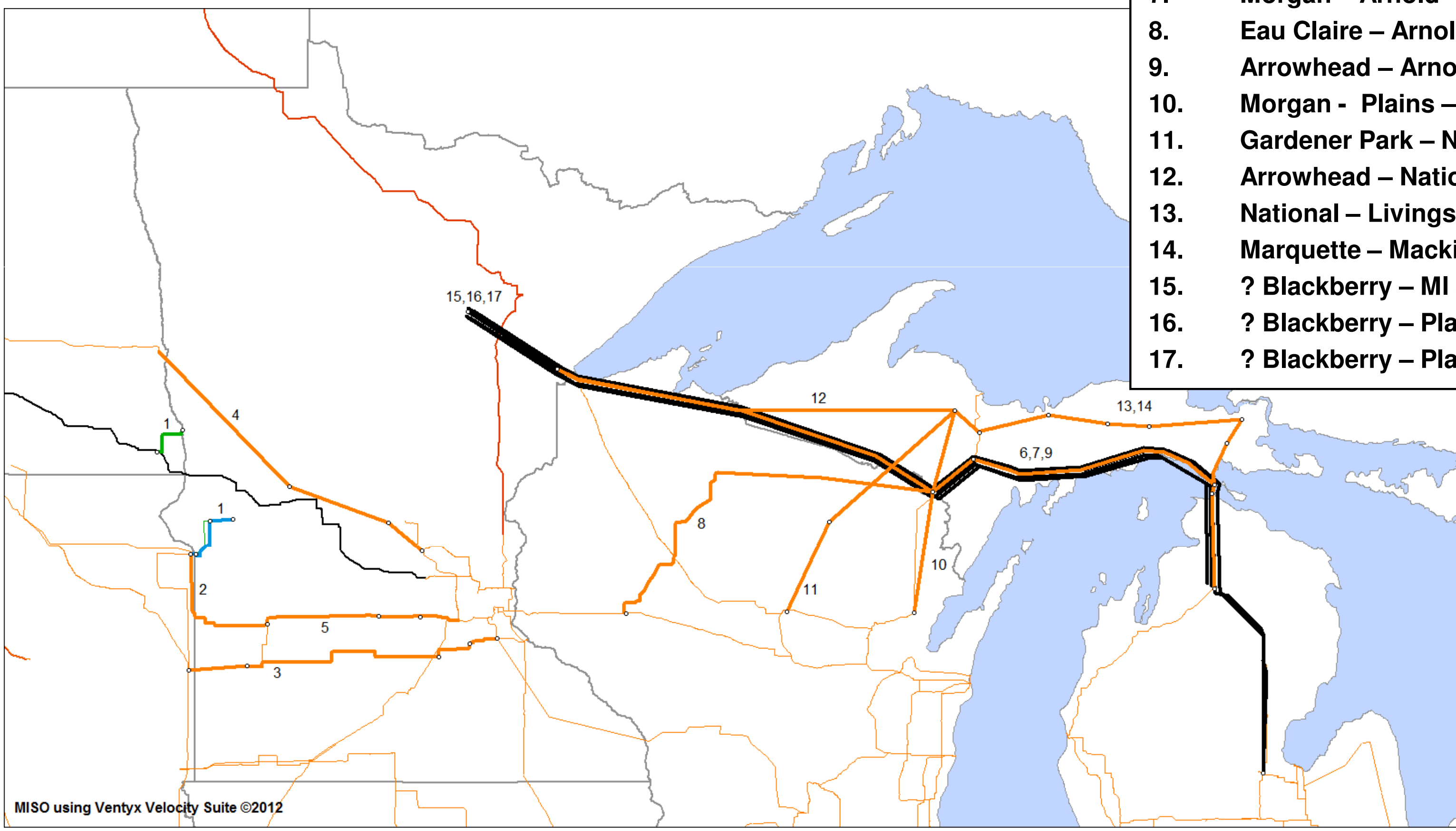
Northern Area Study Options Summary (As of Oct 31, 2012)

1. Upgrade Hankinson- Wahepton 230 kV and Big Stone – Morris 115kV
2. Big Stone – Hazel 345kV
3. Brookings – Hampton 345kV
4. Fargo – Monticello 345kV
5. Convert: Hazel – Blue Lake 345kV
6. Arnold – Livingston 345kV
7. Morgan – Arnold – Livingston 345kV
8. Eau Claire – Arnold – Livingston 345
9. Arrowhead – Arnold – Livingston 345
10. Morgan - Plains – National 345kV
11. Gardener Park – National 345kV
12. Arrowhead – National 345kV
13. National – Livingston 345kV
14. Marquette – Mackinac Cnty 138kV
15. ? Blackberry – MI 500kV DC
16. ? Blackberry – Plains 500kV DC
17. ? Blackberry – Plains – MI 500kV DC



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Work Plan

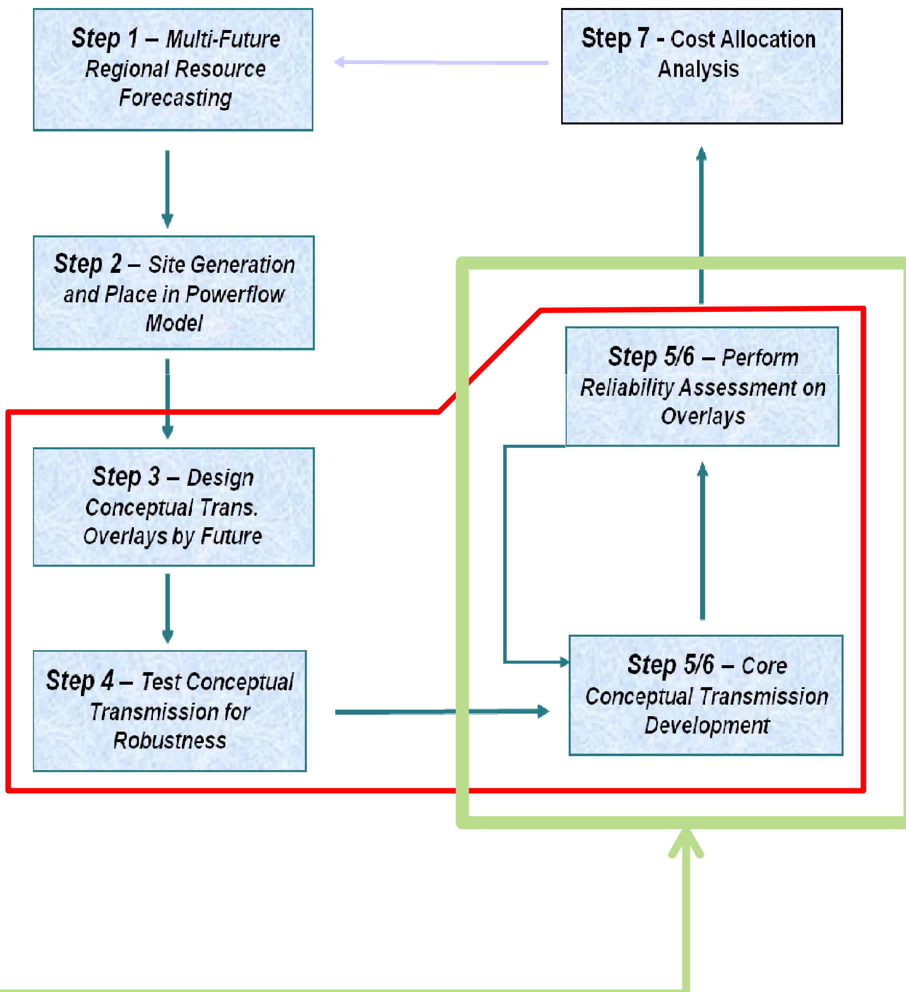
- All submitted plans will be evaluated for study year 2027 economic benefits under selected scenarios
- Plans will be refined, or combined into portfolios – goal is to narrow down the number of options
- Plans further analyzed for economic benefits for study years 2017 and 2022
- Best-fit refined plans/portfolios will be evaluated for reliability
- Iterative refinement between reliability and economics
- Dec 7th meeting will fall amidst refinement and testing process
- All results will be posted and communicated to the entire TRG via email

Reliability Analysis

- **Reliability No Harm Tests**
  - No degradation of system reliability with addition of transmission plans
  - Analyze underbuild requirements
  - Identify any additional reliability improvements
- **Steady State (Thermal) Study**
  - Looking for overloads and voltage violations under contingency
- **Voltage Stability Study**
  - Identify voltage collapse conditions under high transfer
- **Transient Stability Study**
  - Looking for issues in seconds after disturbance

Reliability Next Steps

- Refined plans from economic analysis will be added to powerflow models
- No Harm tests will be performed
- Transmission plan additions/improvements will be fed back to economics



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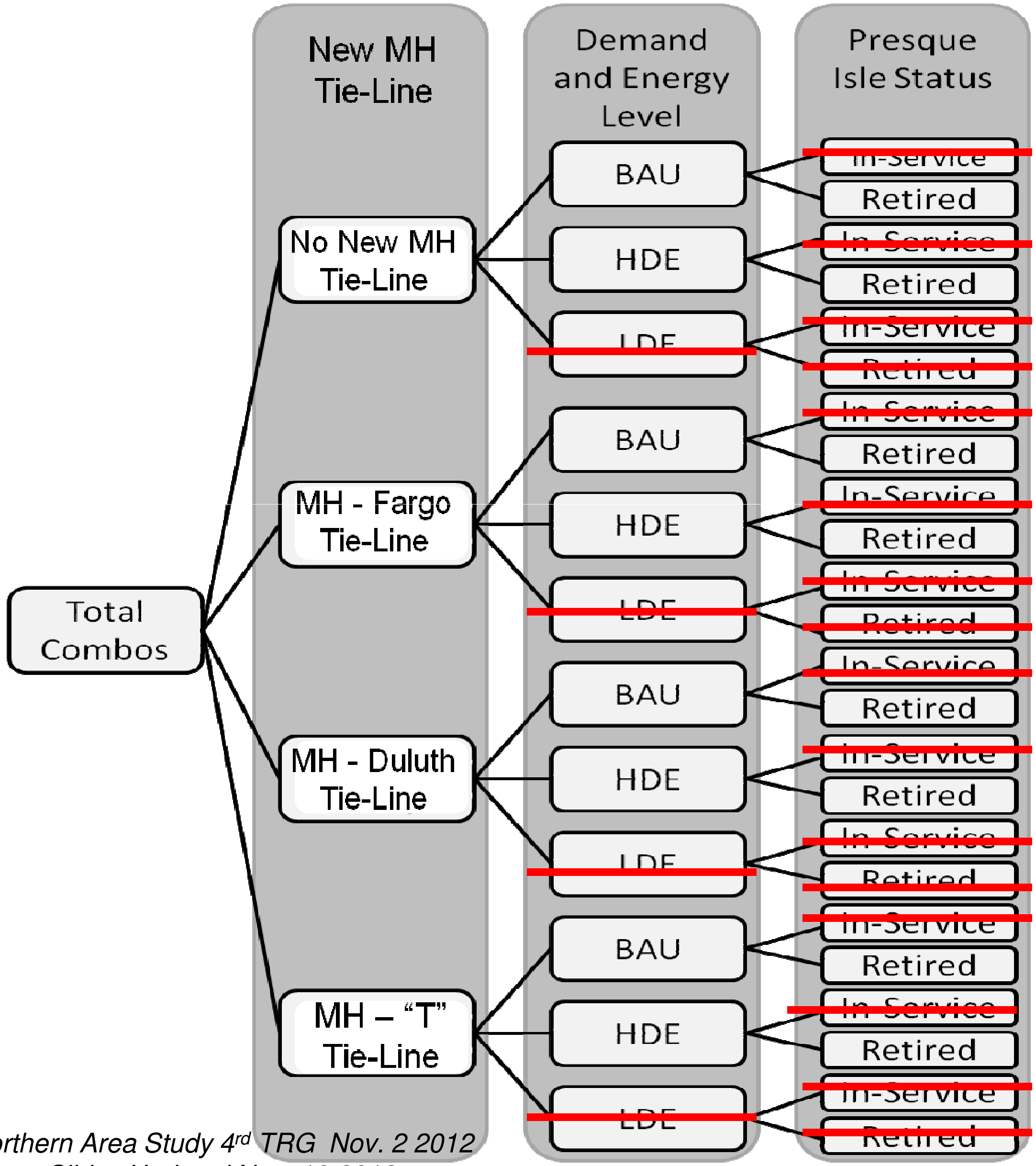
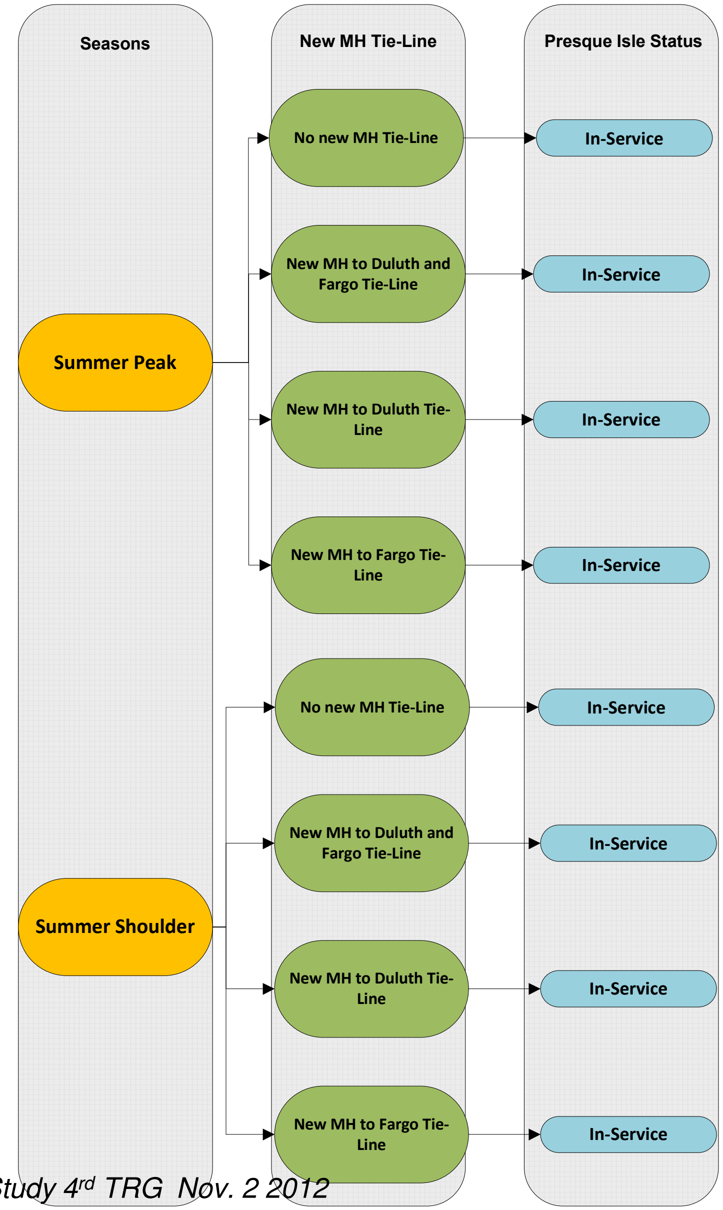
Economic Scenarios Selection

- **Current problem: Too many scenarios for testing all transmission plans**
- **Maximum scenarios for economic testing is 8**
- **Proposal:**
  - Eliminate LDE Scenario?
    - Report will clearly say that under LDE future the was little to no economic benefits
  - Only test one Presque Isle in-service status?
    - Which status?
    - Final plans will be evaluated under both scenarios
- **Please provide feedback by Nov. 9th**



Reliability Scenario Selection

- **Thermal Study**
  - All the proposed Scenarios
  - Looking for your input to reduce the number of scenarios
- **Voltage Stability Study**
  - “Worst case scenario” will be studied
  - Looking for your input to pick the worst case scenario
- **Transient Stability Study**
  - “Worst case scenario" will be studied



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• Presque Isle Retirement Sensitivity Analysis	9:45 AM
• NAS Transmission Solutions and Work Plan	10:15 AM
• Scenario Selection	11:15 AM
• Transmission Line Costs	11:30 AM
• Schedule Update	11:40 AM
• Open Discussion and Next Steps	11:50 AM
• Adjourn and Lunch	12:00 PM

Refresh Generic Transmission Line Costs

- Updates provided by TRG. Thank you.
- Additional updates for other states?
- Used to calculate benefit to cost ratios for conceptual plans – allows comparison between options
- TRG supplied project costs will be used in NAS if available

Updated Transmission Line Estimates ($M/mile)

TRG supplied based on actual and estimations CapX Group 1 permitting and construction

kV	WI	MN	DAK
115	$1.10	$1.00	$0.75
161	$1.30	$1.25	$0.90
230	$1.70	$1.60	$1.25
345	$2.90	$2.70	$2.30
345-2	$3.50	$3.25	$3.00
500	$3.40	$3.20	$2.80
765	$4.50	$4.00	$3.50

Agenda

• Welcome, Roll Call, and Review Agenda	9:00 AM
• Recap September 21st Meeting	9:05 AM
• Related Study Status Report	9:30 AM
– Manitoba Hydro Wind Synergy Study	
– TSR Update	
• Presque Isle Retirement Sensitivity Analysis	9:45 AM
• NAS Transmission Solutions and Work Plan	10:15 AM
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• Schedule Update	11:40 AM
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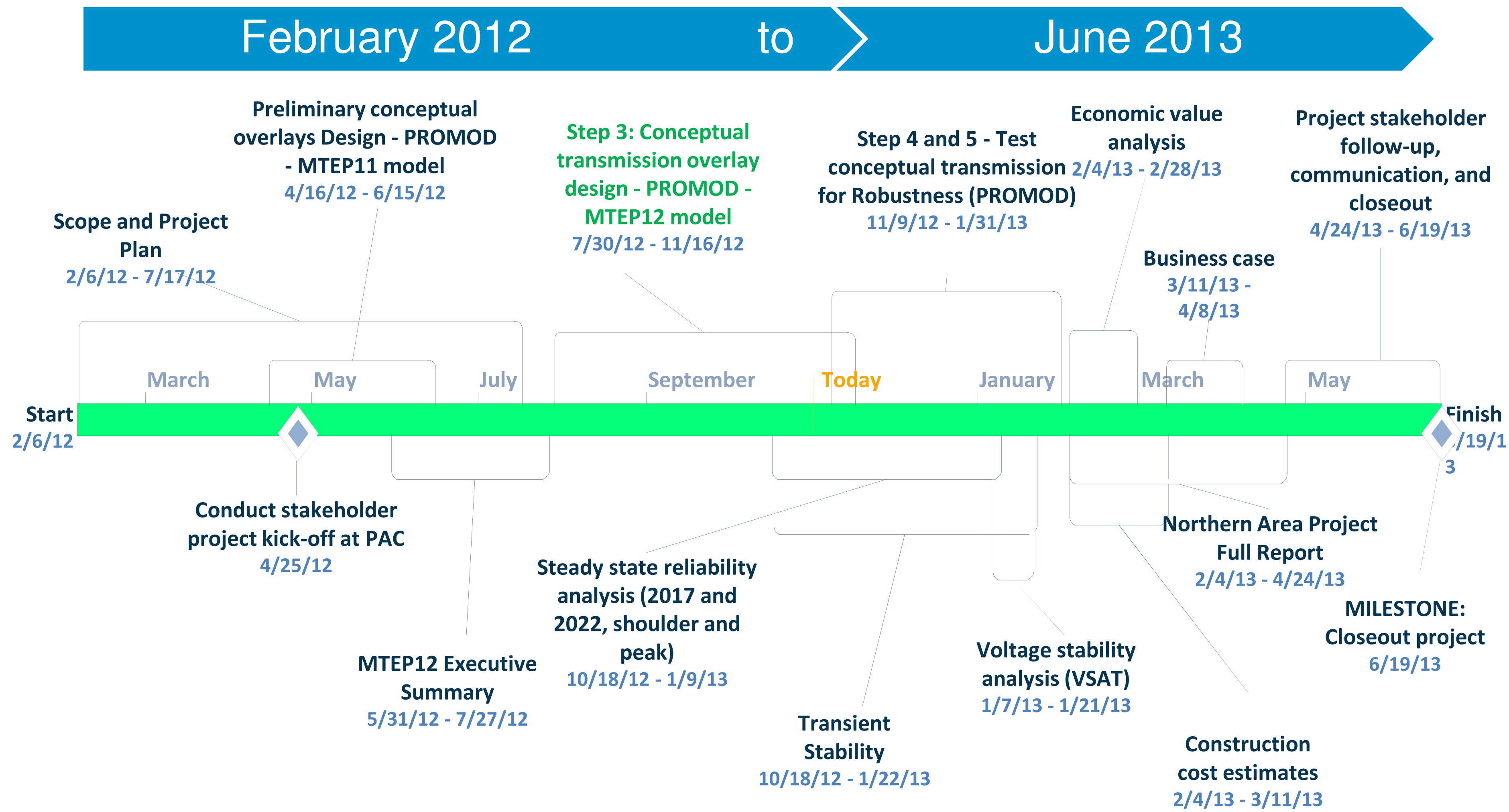
• Adjourn and Lunch	12:00 PM

Northern Area Study Project Plan

Task Name	Start	Finish
NORTHERN AREA STUDY PROJECT	2/6/12	7/3/13
☑ Scope Development	2/6/12	7/17/12
☑ Preliminary conceptual overlays Design - PROMOD - MTEP11 (POC)	4/16/12	6/15/12
Step 3: Conceptual transmission overlay design - PROMOD - MTEP12	7/30/12	11/16/12
Step 4 & 5 - Test conceptual transmission for Robustness (PROMOD)	11/9/12	1/31/13
Step 6 – Reliability Analysis	10/18/12	1/22/13
Steady State Reliability Analysis (2017 and 2022, shoulder & peak)	10/18/12	1/9/13
Transient Stability Screening	10/18/12	1/22/13
Voltage stability analysis (VSAT)	1/7/13	1/21/13
Step 5 - Consolidate and Sequence	1/31/13	2/4/13
Economic value analysis (final production cost calculation)	2/4/13	2/28/13
Construction cost estimates	2/4/13	3/11/13
Business case analysis	3/11/13	4/8/13
☑ MTEP 12 Executive Summary	5/31/12	7/27/12
Northern Area Project Full Report	2/4/13	4/24/13
Project stakeholder follow-up, communication, and closeout	4/24/13	6/19/13

Northern Area Study Timeline



MISO

Agenda

• Welcome, Roll Call, and Review Agenda	9:00 AM
• Recap September 21st Meeting	9:05 AM
• Related Study Status Report	9:30 AM
– Manitoba Hydro Wind Synergy Study	
– TSR Update	
• Presque Isle Retirement Sensitivity Analysis	9:45 AM
• NAS Transmission Solutions and Work Plan	10:15 AM
• Scenario Selection	11:15 AM
• Transmission Line Costs	11:30 AM
• Schedule Update	11:40 AM
• Open Discussion and Next Steps	11:50 AM
• Adjourn and Lunch	12:00 PM

What's Next?

- MISO
  - Send TRG full list of transmission options and selected scenarios (after November 9th)
  - Provide TRG results as they become available
- TRG
  - Supply additional transmission plans by November 9th
  - Supply scenario selection feedback by November 9th
  - Supply feedback on Kewaunee retirement by November 9th
  - Provide additional updates to generic $/mi transmission costs

- Next meeting tentatively scheduled for December 7th

Contact Information

- **Northern Area Study Project Management**
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- **Northern Area Study Reliability Analysis**
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- **Presque Isle Retirement Sensitivity Analysis**
  - Tyler Giles
    tgiles@misoenergy.org 651.632.8430

State of Minnesota

DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Utility Information Request

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

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

Analyst Requesting Information: Steve 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.	
3	Please provide an estimate of the impact of the proposed project on locational marginal prices (LMPs).

Response:

Based on the analysis completed by Ventyx and summarized in the report *"Economic Analysis of the Great Northern Transmission Line 2022 and 2027"* the Project will slightly decrease the locational marginal price (LMP) within the state of Minnesota across both scenarios (Business as Usual and High Growth) and both timeframes (2022 and 2027) as shown in table 4.1 of the report.

Response by: Scott Hoberg

List sources of Information: Ventyx GNTL Economic Analysis

Title: Engineer Senior

Department: System Performance & Transmission Planning

Telephone: 218-355-2618

Economic Analysis of the Great Northern Transmission Line 2022 & 2027

Prepared for:
Minnesota Power

Ventyx project no.: US-V00001330A
Final Report

Date:

4/9/2014

Prepared by:
Ventyx, an ABB company

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AN ABB COMPANY

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Table of Contents

1 Introduction

1.1 Executive Summary

Minnesota Power retained Ventyx, an ABB company (Ventyx) to perform detailed hourly nodal market simulation and forecasts to examine the benefits of constructing a new 500 kV transmission line from Manitoba to Minnesota.

The primary goal of this analysis was to quantify changes, caused by interconnecting this new line, in:

1. the estimated cost to serve demand for market participants in MISO and in Minnesota
2. the Locational Marginal Price (LMP) within the State of Minnesota

The metric "Adjusted Production Cost" (APC) as defined by the Midcontinent ISO (MISO) was used to estimate cost.

Based on the analysis it has been shown that for the two years studied (2022 and 2027) and two future scenarios (Business-As-Usual and High Growth) analyzed the impact of the Great Northern Transmission Line (GNTL) caused a decrease in LMPs within Minnesota. Also it is shown that the new transmission line causes no material change in the calculated Adjusted Production Cost based on MISO's APC methodology.

1.2 Scope

In early 2013, MISO performed its Northern Area Study (NAS), assessing the potential benefits of a variety of transmission projects – including the GNTL - that have been proposed to address the needs of MISO's northern tier of states, including Minnesota. That study was performed using the PROMOD IV market simulation model, analyzing the economic impacts in the years 2022 and 2027, and using MISO's MTEP 2012 database.

For this GNTL study, Ventyx considered using MISO's MTEP 2013 database for PROMOD IV. However, that database was still under revision by MISO at the time Ventyx undertook the GNTL study. Consequently, Ventyx obtained from MISO the NAS database, which was based on the MTEP 2012 data assumptions.

Ventyx compared the key assumptions, such as gas price forecasts, load growth, generator retirements, and new generation expansion, between the NAS data and the work-in-progress MTEP 2013 database. These data assumptions were reviewed with Minnesota Power staff, and they – along with Ventyx – agreed that the differences in key assumptions between MTEP 2012 and MTEP 2013 were minor, and that the GNTL study would proceed using the NAS database.

For this GNTL study, two futures were analyzed. The first was MISO's **Business-As-Usual** (BAU) future, representing mid-range economic assumptions. The second was MISO's **High Growth** (HG) future, representing assumptions of higher economic growth, including higher demand growth and higher gas prices.

Taking full advantage of the NAS database, Ventyx simulated the years 2022 and 2027 to capture the impact of additional generation resource development by Manitoba Hydro.

The generation schedules from hydro plants in Manitoba are as represented in MISO's NAS analysis, which was in turn derived by MISO and Manitoba Hydro as part of their joint "Manitoba Hydro Wind Synergy Study".

Note that these hydro generation schedules are assumed to be static between the pre-GNTL and post-GNTL cases. Consequently, the analysis presented here will not capture possible benefits deriving from modifications to Manitoba Hydro's generation scheduling practices that might be implemented when GNTL is in service. These simulations dispatch hydropower hourly schedules at a very low offer price, so that the energy will generally be taken by the market unless transmission limitations constrain its delivery. Except when it is curtailed by such congestion, this Manitoba Hydro export energy is a "price-taker", bought by the market at the local LMP.

1.3 About PROMOD IV software

PROMOD IV provides valuable information on the dynamics of the marketplace through its ability to determine the effects of transmission congestion on key system flowgates. PROMOD IV captures the constraints and limitations inherent in electric power transmission using a DC load flow algorithm. All major transmission equipment is modeled, including transformers, phase-angle regulators, DC ties, generation buses, load buses, and transmission lines with reactance and resistance inputs.

Transmission system modeling is fully integrated with the commitment and dispatch algorithm so that generators are scheduled, started, and cycled while enforcing transmission flow constraints.

PROMOD IV simultaneously optimizes transmission, generation, and ancillary service requirements for all 8760 hours to provide a robust security-constrained unit commitment and economic dispatch solution with bus-level LMP reporting. This study employed PROMOD IV, version 10.1.3.

2 Input Assumptions

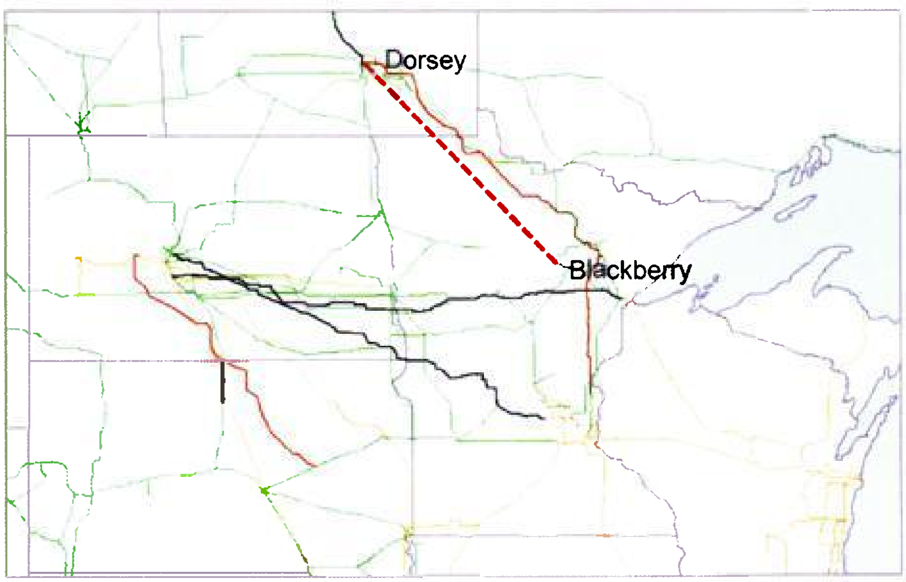
The majority of input assumptions were defined by Midcontinent ISO for their Northern Area Study.

2.1 Project Description

Minnesota Power, in partnership with Manitoba Hydro, proposes to construct a 500 kV transmission line from the International border that would terminate at the Blackberry substation in Itasca County (spanning an estimated 235 to 270 miles). The GNTL itself was modeled using MISO's data from NAS which was originally submitted by Minnesota Power. The project comprises the 500 kV branch from the Dorsey substation in Manitoba to the Blackberry substation in northwestern Minnesota, rated at 1732 MVA, plus additional system changes and upgrades at the Blackberry substation to feed these flows into the 230kV transmission system. Figure 1 below shows the general geographic arrangement of the project and is not representative of the project's actual route.

MISO's NAS analysis included as part of the project a 345kV extension from the Blackberry substation to the Arrowhead bus. This extension to the Arrowhead bus has not been represented in this Ventyx study.

Figure 1 -- Great Northern Transmission Line Path



2.2 Transmission Network

The scope of this database includes the entire Eastern Interconnect electric grid, excluding New England, Florida, Hydro-Quebec and the Canadian Maritime Provinces. These exclusions are sufficiently remote from Minnesota that they may be adequately represented by scaling their generation to meet their load and holding their net import or export constant.

The same network model is used for both 2022 and 2027. Therefore the only transmission difference examined is the presence or absence of the GNTL.

Two modifications were made to the MISO NAS data. First, the MISO ISO footprint was expanded to include the companies in the Entergy transmission region, which were to become integrated into the MISO market in December 2013. Second, the two futures were modified to include two conceptual transmission projects that were identified in the NAS study as significantly surpassing MISO's benefit/cost criterion:

- Hankinson – Wahpeton 230 kV upgrade
- Big Stone – Morris 115 kV upgrade

These two potential upgrades were determined by MISO to substantially increase the deliverability of wind generation from the Dakotas into Minnesota.

2.3 Generation

Table 2.1 presents the installed capacity of generation by fuel and type in MISO and in the companies that serve Minnesota load. Note the increase from 2022 to 2027 in wind, combined-cycle and combustion turbine capacity. These figures represent generic expansion and not specific proposals. There is no difference in the generation capacity mix between the Business As Usual and High Growth futures.

The schedule of hydropower from Manitoba was modeled per agreement between MISO and Manitoba Hydro for the Northern Area Study. Hydro energy is mostly represented as scheduled for peak-shaving (concentrated in higher-demand hours each day) with some flexibility to respond to market prices. This model mimics profit-maximizing bidding behavior without requiring that an offer price be assigned to the energy.

In the MISO NAS data, the hydro energy is offered to the MISO market at 0 $/MWh, shifting the supply curve to the right, with the expected effect of slightly lowering market clearing prices by displacing higher-cost generation in the receiving market. (Results of this study support this conjecture. Refer to Table 4.1.) However, the hydro energy is not free of charge; it is paid for at market clearing price. This study does not include the contract price for the energy, but it is supposed that the contract price is tied somehow to the market prices.

Table 2.1 – MISO and MN Generation Mix by Technology, 2022 and 2027

MISO - High Growth and Business As Usual				
Fuel	Technology	MW Capacity, 2022	MW Capacity, 2027	Change, 2022 to 2027
COAL	ST -Coal	60,496	60,496	-
	IGCC	1,077	1,077	-
GAS	CC	28,021	35,221	7,200
	CT -Gas	35,705	41,105	5,400
	ST Gas	16,788	16,780	(8)
	ICE -Gas	109	109	-
OIL	CT -Oil	4,486	4,486	-
	ST -Oil	158	158	-
	ICE Oil	381	381	-
	CT -Kerosene	67	67	-
RENEWABLES	CT -Renewable	36	36	-
	ST -Renewable	844	844	-
	ICE-Renewable	215	215	-
	ST -Other	167	167	-
WATER	Hydro	1,527	1,400	(127)
	Pumped-Storage	2,518	2,518	-
URANIUM	Nuclear	14,796	14,796	-
WIND	Wind	13,053	31,053	18,000
SUN	Solar PV	1,041	1,481	440
DEMAND RESPONSE	Interruptible Loads	9,169	9,169	-

Minnesota - High Growth and Business As Usual				
Fuel	Technology	MW Capacity, 2022	MW Capacity, 2027	Change, 2022 to 2027
COAL	ST -Coal	9,032	9,032	-
	IGCC	-	-	-
GAS	CC	2,897	4,097	1,200
	CT -Gas	7,315	7,315	-
	ST -Gas	267	259	(8)
	ICE -Gas	15	15	-
OIL	CT -Oil	1,690	1,690	-
	ST -Oil	-	-	-
	ICE -Oil	188	188	-
	CT -Kerosene	47	47	-
RENEWABLES	CT -Renewable	-	-	-
	ST -Renewable	452	452	-
	ICE-Renewable	26	26	-
	ST -Other	51	51	-
WATER	Hydro	375	350	(25)
	Pumped-Storage	-	-	-
URANIUM	Nuclear	2,366	2,366	-
WIND	Wind	6,583	11,286	4,703
SUN	Solar PV	220	320	100
DEMAND RESPONSE	Interruptible Loads	2,259	2,259	-

2.4 Demand

Demand in each area follows a synthetic hourly schedule which has been determined from load data for the years 2003-2009. This schedule is scaled so as to match the peak and annual energy figures assumed as in the table below.

Table 2.2 presents demand figures, described by annual peak and energy for MISO and for the companies that serve Minnesota load. The latter account for about 10 percent of MISO demand.

Table 2.2 – MISO and MN (weighted by sales) Demand, 2022 and 2027

		2022 BAU	2027 BAU	Growth Rate	2022 HG	2027 HG	Growth Rate
MISO	Peak MW	132,079	140,247	1.2%	141,857	156,279	2.0%
	Energy GWh	736,160	796,278	1.6%	802,554	907,110	2.5%
Minnesota Companies	Peak MW	13,923	15,019	1.5%	14,990	16,804	2.3%
	Energy GWh	80,695	86,895	1.5%	87,964	99,021	2.4%

2.5 Fuel Prices

Table 2.3 presents fuel prices for the Business as Usual and High Growth futures. Note that fuel prices are generally about 10% higher in the High Growth future.

Table 2.3 – Fuel Prices (nominal $/MBtu)

Business as Usual		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas (Henry Hub)	2022	$ 4.95	$ 4.93	$ 4.87	$ 4.66	$ 4.65	$ 4.67	$ 4.71	$ 4.74	$ 4.75	$ 4.79	$ 4.89	$ 5.05
	2027	$ 5.40	$ 5.38	$ 5.32	$ 5.09	$ 5.08	$ 5.11	$ 5.15	$ 5.18	$ 5.19	$ 5.24	$ 5.34	$ 5.51
Oil #6	2022	$ 13.30	$ 12.96	$ 12.99	$ 13.27	$ 13.64	$ 13.93	$ 14.21	$ 14.35	$ 14.37	$ 14.26	$ 13.99	$ 13.62
	2027	$ 14.50	$ 14.13	$ 14.16	$ 14.47	$ 14.87	$ 15.19	$ 15.49	$ 15.65	$ 15.66	$ 15.54	$ 15.25	$ 14.85
Oil #2	2022	$ 20.00	$ 19.76	$ 19.58	$ 19.50	$ 19.44	$ 19.42	$ 19.63	$ 20.28	$ 21.04	$ 21.23	$ 20.88	$ 20.36
	2027	$ 21.81	$ 21.54	$ 21.35	$ 21.26	$ 21.19	$ 21.17	$ 21.39	$ 22.11	$ 22.93	$ 23.14	$ 22.76	$ 22.19
Kerosene	2022	$ 21.17	$ 21.03	$ 21.02	$ 21.09	$ 21.17	$ 21.39	$ 21.70	$ 22.29	$ 22.91	$ 22.89	$ 22.34	$ 21.51
	2027	$ 23.08	$ 22.93	$ 22.91	$ 22.98	$ 23.08	$ 23.32	$ 23.65	$ 24.29	$ 24.97	$ 24.95	$ 24.35	$ 23.45

Business as Usual		Average	Min	Max
Coal (MN units)	2022	$ 2.31	$ 1.48	$ 3.48
	2027	$ 2.52	$ 1.61	$ 3.79

High Growth		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Gas (Henry Hub)	2022	$ 5.55	$ 5.53	$ 5.46	$ 5.22	$ 5.21	$ 5.24	$ 5.28	$ 5.31	$ 5.32	$ 5.38	$ 5.48	$ 5.66
	2027	$ 6.41	$ 6.38	$ 6.31	$ 6.04	$ 6.03	$ 6.07	$ 6.11	$ 6.15	$ 6.16	$ 6.22	$ 6.33	$ 6.54
Oil #6	2022	$ 14.91	$ 14.53	$ 14.56	$ 14.88	$ 15.30	$ 15.62	$ 15.93	$ 16.09	$ 16.11	$ 15.99	$ 15.68	$ 15.27
	2027	$ 17.21	$ 16.77	$ 16.81	$ 17.17	$ 17.66	$ 18.03	$ 18.39	$ 18.58	$ 18.59	$ 18.45	$ 18.10	$ 17.62
Oil #2	2022	$ 22.43	$ 22.16	$ 21.95	$ 21.86	$ 21.80	$ 21.77	$ 22.00	$ 22.74	$ 23.59	$ 23.80	$ 23.40	$ 22.82
	2027	$ 25.89	$ 25.57	$ 25.34	$ 25.24	$ 25.16	$ 25.13	$ 25.40	$ 26.24	$ 27.22	$ 27.47	$ 27.01	$ 26.34
Kerosene	2022	$ 23.74	$ 23.58	$ 23.57	$ 23.64	$ 23.74	$ 23.98	$ 24.33	$ 24.99	$ 25.68	$ 25.66	$ 25.04	$ 24.12
	2027	$ 27.40	$ 27.22	$ 27.20	$ 27.28	$ 27.40	$ 27.68	$ 28.08	$ 28.84	$ 29.65	$ 29.62	$ 28.90	$ 27.83

High Growth		Average	Min	Max
Coal (MN units)	2022	$ 2.59	$ 1.66	$ 3.90
	2027	$ 2.99	$ 1.91	$ 4.50

2.6 Emissions Prices

All emissions (SO_2, NO_X, CO_2) were assigned zero cost in 2022 and 2027.

3 Methodology

This analysis of the GNTL looks at the benefits to MISO and Minnesota in two ways:

1. Savings due to reduced Adjusted Production Costs (APC)
2. Changes in locational marginal prices (LMPs)

3.1 Adjusted Production Cost

APC is a common measure of energy production costs, used by the various ISOs to represent the net effect of market settlements when determining the cost to serve load. It is basically the cost of market purchases less revenues from market sales, modified by imports from and exports to neighboring markets.

Since it is impractical to try to capture the details of an ISO settlement statement, given uncertainty in the allocation of hedges, in the net impacts of market uplift charges, and in any particular market participant's bidding and scheduling policies, APC looks at the ISO settlement statement from the perspective of a vertically integrated utility (the predominant corporate structure of major market participants in MISO). In this view, the ISO market settlement simply represents a pricing mechanism for net purchases from, or sales to, the market.

In PROMOD IV simulations, a market participant ("company") will buy or sell among the other companies within its local market ("pool", such as MISO or PJM), depending on the state of the security-constrained dispatch each hour. The APC is calculated using the results of the PROMOD IV simulations, assuming that each company's net production is applied first to meet its own demand. Any surplus (or deficit) is sold to (or purchased from) other companies participating in the pool/market at the hourly rate.

According to MISO's APC definition, the hourly rate for sales to the pool is a blended marginal price for "net supply" by that company. It is the average of the LMPs at the company's own generator nodes, weighted by MWh production at each node. The hourly rate for energy purchased from the pool is a blend of the "net supply" prices for all companies that happen to be selling energy in the hour.

A company can also be allocated a share of economic purchases and sales that PROMOD IV schedules between pools, limited by economic hurdle rates defined between each pair of pools, and limited by the ability of the transmission system to carry these transfers. In MISO's NAS database, Manitoba Hydro is considered to be its own pool, as is the group of MRO companies that are currently neither in MISO nor in SPP[1].

MISO's definition of APC sets the price for any such inter-pool purchases and sales at the pool-wide generation-weighted LMP. Because this GNTL analysis focuses on the market interaction between Manitoba and Minnesota, Ventyx believes that it is more appropriate to price any such allocated inter-pool purchases and sales at the individual company generation-weighted LMP, and has used that pricing methodology in this analysis.

---

[1] The economic hurdle between MISO and Manitoba Hydro is set to zero.

This report summarizes the APC benefits of the GNTL on a MISO-wide basis and on a State of Minnesota basis. The latter Minnesota results are calculated by first multiplying the APC value for each company by the fraction of its load that is within Minnesota and then summing the result for all companies. The load fractions have been extracted from a prior study performed by Analysis Group (*"LMP Impacts of Proposed Minnesota-Iowa 345 kV Transmission Project: Supplemental Analysis"*, April 2013, Table 2, page 8).

3.2 LMP in Minnesota

An additional measure of the benefit of the GNTL is its impact on wholesale prices. PROMOD IV calculates from its nodal results the load-weighted zone LMP for each of the companies. These zone-level values are then weighted together, using load multiplied by the same factors from the Analysis Group report, to obtain a Minnesota load-weighted LMP. The company values are also averaged to obtain a MISO-wide load-weighted LMP. The change in these LMPs attributed to the GNTL being in service provides a measure of the benefits in terms of unhedged demand costs.

PROMOD IV calculates LMP including all three components: marginal energy, marginal congestion and marginal loss. It performs a Security-Constrained Unit Commitment (SCUC) and Economic Dispatch (SCED), such that the resulting output from all generators not only respects all generation operational constraints, including planned and forced outages, but also ensures that power flows on transmission facilities do not overload any facility for which a capacity limit has been provided, either in "system intact" (n-0) conditions or under the hypothetical loss of one facility (n-1). The transmission constraints are consistent with those used in the MISO NAS study.

4 Discussion of Results

Results are summarized below and interpreted.

4.1 Locational Marginal Price (LMP) in Minnesota

Table 4.1 presents the forecast change in LMP for Minnesota load, for the years 2022 and 2027 in the two future scenarios. The LMPs are load-weighted averages, expressed in nominal $/MWh.

In general, the wholesale prices show a decrease when GNTL is in service, as expected. In both scenarios, the relatively larger LMP decrease in 2027 is explained by the availability in that year of greater quantities of hydro-electric energy due to the commissioning of additional generating resources in Manitoba.

The comparatively lesser LMP decrease in the High Growth future is explained by observing that Manitoba Hydro's internal demand is forecast higher in the High Growth future, reducing the amount of energy that Manitoba Hydro has available for export, compared to the Business As Usual future.

Table 4.1 -- Change in Load-Weighted LMPs Related to GNTL

			LMP for Minnesota Load (Weighted-Average)					
			Average LMP ($/MWh)			Change due to 500 kV GNTL line (in - out, $/MWh)		
	Scenario	GNTL status	On-peak	Off-peak	All hours	On-peak	Off-peak	All hours
2022	BAU	out	$ 38.35	$ 25.91	$ 31.82	-0.08	0.00	-0.04
		in	$ 38.28	$ 25.91	$ 31.79			
	HG	out	$ 50.05	$ 34.65	$ 41.97	-0.01	0.00	-0.01
		in	$ 50.04	$ 34.65	$ 41.96			
2027	BAU	out	$ 42.29	$ 28.70	$ 35.18	-1.35	-0.26	-0.78
		in	$ 40.95	$ 28.44	$ 34.40			
	HG	out	$ 52.85	$ 39.13	$ 45.67	-0.53	-0.09	-0.30
		in	$ 52.32	$ 39.04	$ 45.37			

The change in LMP is the difference of the LMP with the GNTL in service minus the LMP without the GNTL in service, rounded to the nearest penny.

4.2 Adjusted Production Cost

Table 4.2 presents the forecast change in Adjusted Production Cost for MISO as a whole and for Minnesota only, in nominal dollars (2022$ and 2027$).

The results in Table 4.2 are given to four decimals to show clearly that the GNTL causes no material change, either increase or decrease, to the cost to serve load as computed by MISO's APC methodology.

The Adjusted Production Cost does not change despite the reduction in LMP that is enabled by the GNTL. This is because, although the cost of energy purchases may decrease for entities that are net purchasers, so too may the revenues (profits) decrease for entities that are net sellers of energy. The profits of the net sellers are further reduced because the additional energy purchased from Manitoba Hydro reduces the volume of energy that those net sellers would otherwise have produced and sold.

A vertically-integrated utility with a good balance between economic generation assets and demand would therefore see little change in its market settlement as average LMPs shift up or down.

Table 4.2 -- Change in Adjusted Production Costs Related to GNTL

			Adjusted Production Cost ($Billion)		Change due to GNTL (in - out, $Billion)	
	Scenario	GNTL status	MISO	Minnesota	MISO	Minnesota
2022	BAU	out	18.8001	1.6275	-0.0004	0.0002
		in	18.7996	1.6277		
	HG	out	24.0776	2.1563	0.0004	0.0030
		in	24.0780	2.1593		
2027	BAU	out	21.9331	1.9494	0.0022	-0.0033
		in	21.9354	1.9460		
	HG	out	31.5224	2.8627	0.0114	-0.0016
		in	31.5338	2.8610		

The change in cost is the difference of the adjusted production cost with the GNTL in service minus the adjusted production cost without the GNTL in service.

5 Carbon Sensitivity

As a simple sensitivity, Ventyx repeated the simulations of the Business As Usual scenarios with the assumption of the following CO2 regulation costs (in Nominal $/ton): $23.95 in 2022 and $26.70 in 2027 (Minnesota Power supplied these figures, citing the Minnesota Public Utilities Commission's Carbon Valuation Docket *(MPUC Docket Nos. E-999/CI-13-796 and E-999/CI-07-1199*).

Penalizing CO2 production raises the marginal cost of production for gas and coal-fired power plants, approximately as shown in Table 5.1 below. The given penalties are large enough to invert the economic merit order of coal and combined-cycle units and would raise LMP correspondingly when such a generator is the marginal unit (setting the price):

Table 5.1 – Illustrative Generator Marginal Cost with and without CO2 Penalty

		With no CO2 penalty				With CO2 penalty = $23.95		
		Fuel, $/MBtu	Heat Rate (MBtu / MWh)	Variable O&M, $/MWh	**Marginal Cost, $/MWh**	lb CO2 emitted per MBtu of heat	CO2 penalty, $/MWh	**Marginal Cost, $/MWh**
Coal	Steam Turbine	3	10.5	3	**$ 35**	209	$ 26	**$ 61**
Gas	Combined Cycle	5	8	2	**$ 42**	119	$ 11	**$ 53**
	Combustion Turbine	5	12	3	**$ 63**	119	$ 17	**$ 80**

The installed capacity of Combined-cycle generation being about half that of coal-fired generation (see Table 2.1) and insufficient by itself to meet the higher levels of demand, coal would be expected either to be on the margin or be displaced by less expensive imported energy in higher-demand hours in the "carbon tax" sensitivity.

Based on the "typical" figures from Table 5.1, the marginal energy component of LMP (neglecting transmission congestion and loss pricing) in peak hours would be expected to rise by at least $11-18 relative to the case with no carbon penalty, from $35-42 (coal or gas CC on the margin) to $53 or more (gas CC or imports on the margin). The results of this study support this conjecture. (Refer to the "on-peak average LMP" column of Table 5.2, below.)

Table 5.2 presents the change in Minnesota LMP in the carbon sensitivity case and compares it with the Business As Usual scenario. Table 5.3 presents the change in Adjusted Production Cost.

Table 5.2 – Locational Marginal Prices with and without CO2 Penalty

			LMP for Minnesota Load (Weighted-Average)					
			Average LMP ($/MWh)			Change due to 500 kV GNTL line (in - out, $ / MWh)		
	Scenario	GNTL status	On-peak	Off-peak	All hours	On-peak	Off-peak	All hours
2022	BAU	out	$ 38.35	$ 25.91	$ 31.82	-0.08	0.00	-0.04
		in	$ 38.28	$ 25.91	$ 31.79			
	Carbon	out	$ 54 85	$ 45.94	$ 50.17	-0.03	0.00	-0.01
		in	$ 54.82	$ 45.95	$ 50.16			
2027	BAU	out	$ 42.29	$ 28.70	$ 35.18	-1.35	-0.26	-0.78
		in	$ 40.95	$ 28.44	$ 34.40			
	Carbon	out	$ 60.62	$ 49.62	$ 54.87	-1.04	-0.04	-0.52
		in	$ 59.57	$ 49.58	$ 54.35			

Adding the carbon penalty to the BAU scenario reduced the simulated impact that GNTL would have on LMP in Minnesota. LMPs are flatter across load levels, presumably because gas is on the margin more frequently. This reduces the opportunity for the hydro energy delivered by GNTL to moderate high prices that drive up average prices.

Table 5.3 – Adjusted Production Cost with and without CO2 Penalty

			Adjusted Production Cost ($Billion)		Change due to GNTL (in - out, $Billion)	
	Scenario	GNTL status	MISO	Minnesota	MISO	Minnesota
2022	BAU	out	18.8001	1.6275	-0 0004	0.0002
		in	18.7996	1.6277		
	Carbon	out	31.1953	2.8776	0.0010	0.0006
		in	31.1963	2.8782		
2027	BAU	out	21.9331	1.9494	0.0022	-0.0033
		in	21.9354	1.9460		
	Carbon	out	35.5899	3.3205	0.0049	-0.0015
		in	35.5949	3.3190		

Adjusted Production Cost does not change materially with the addition of a carbon penalty.

6 Conclusion

PROMOD LMP simulations were performed for 2022 and 2027, using input assumptions consistent with the 2013 MISO Northern Area Study. Significant amounts of wind, combined-cycle and even solar PV generation were modeled in MISO in the 2027 cases that were not present in the 2022 cases.

Input assumptions were established for two separate future scenarios (Business as Usual and High Growth) and 8,760-hour chronological simulations were performed for each scenario with the GNTL in service and without, as the only input change.

The salient result from this study is that interconnection of the 500 kV GNTL brings about:

1. decreased Locational Marginal Prices (LMPs) within Minnesota
2. no material change to the cost to serve load in MISO or Minnesota

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 Draft Report (Western Plan)

July 3, 2013

Prepared By:

MISO Transmission Access Planning

Midwest Independent Transmission System Operator, Inc. P.O. Box 4202 Carmel, Indiana 46082-4202 1125 Energy Park Drive St. Paul, Minnesota 55108 317.249.5400 www.misoenergy.org

Contents

Introduction

The purpose of this study was to perform sensitivity analysis on alternative transmission options for the MH-US south bound TSRs. The sensitivity included iterations of the MH-US transfer.

Executive Summary

Results from this study show that the impact of the proposed Dorsey to Barnesville 500 kV Line and Barnesville to Monticello 345 kV double circuit line (250, 750 or 1100MW) transmission options do not impact the existing transmission system in an adverse way. The facilities that are impacted have mitigations that are outlined in the report. The estimated costs associated with these mitigations are relatively small. The status of G519 (Excelsior 600MW) has been confirmed as withdrawn, and hence it is not modeled for this study. Mitigation costs are shown below.

Scenario	Mitigation Costs (millions)
Dorsey – Barnesville 500 kV and Barnesville - Monticello 345 kV (250MW)	0
Dorsey – Barnesville 500 kV and Barnesville - Monticello 345 kV (750MW)	4
Dorsey – Barnesville 500 kV and Barnesville - Monticello 345 kV (1100MW)	4

Description of Request

The south bound requests reserve a total of 1100 MW of transmission service from Manitoba Hydro to several sinks in the northern Midwest United States (Table 1).

Table 1: MH-US South Bound Requests

\Oasis Ref No	Service Type	Start time	Stop Time	POR	POD	Requested Capacity	Queue Date	Study Number
76703536	Network	Nov-2014	Nov-2024	MHEB-MISO	GRE	200	12/7/2006	A388
76703671	Network	Jun-2017	Jun-2027	MHEB-MISO	WPS	500	6/12/2007	A380
76703672	Network	Jun-2017	Jun-2037	MHEB-MISO	MP	250	7/6/2007	A383
76703686	Network	Jun-2017	Jun-2027	MHEB-MISO	NSP	50	4/17/2008	A416
76703687	Network	Jun-2017	Jun-2027	MHEB-MISO	WEC	100	4/17/2008	A417

The proposed sensitivity options are described in Table 2.

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Table 2 Sensitivity Options

Option	Description
Y500 kV + A/B - 250	• MH-MP TSR only (250 MW) • One Dorsey – Barnesville 500 kV circuit • Two 345 kV circuits from Barnesville – Monticello • Two 500/345 kV transformers at Barnesville
Y500 kV + A/B - 750	• MH-MP TSR + MH-WPS TSR (750 MW) • One Dorsey – Barnesville 500 kV circuit • Two 345 kV circuits from Barnesville – Monticello • Two 500/345 kV transformers at Barnesville
Y500 kV + A/B - 1100	• All TSRs (1100 MW) • One Dorsey – Barnesville 500 kV circuit • Two 345 kV circuits from Barnesville – Monticello • Two 500/345 kV transformers at Barnesville

Criteria, Methodology, and Assumptions

Models

MTEP 2012 power flow model representing a 2022 Summer Peak condition 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 3670 MW in the benchmark case as follows:

- Bipole 1 = 958 MW
- Bipole 2 = 1032 MW
- Bipole 3 = 1680 MW

The bipole inverters were used to source the south bound requestsas shown in Table 3.

Table 3 MH-US TSR Sources

250 MW Injection	750 MW Injection	1100 MW Injection
• Bipole 1 = 1243.8 MW • Bipole 2 = 1341.9 MW • Bipole 3 = 1338.0 MW	• Bipole 1 = 1404.2 MW • Bipole 2 = 1515.0 MW • Bipole 3 = 1510.6 MW	• Bipole 1 = 1516.8 MW • Bipole 2 = 1636.5 MW • Bipole 3 = 1631.7 MW

Study TSRs were sunk to the generators in Table 4.

Table 4 MH-US TSR Sinks

Bus #	Generator Name	MW
WPS (A380)		
699993	Skygen Unit #1	172
699661	West Marinette Unit #3	75.0
699597	Pulliam Unit #31	74.0
698925	AP_PPRGT Unit	42.3

Bus #	Generator Name	MW
699591	Pulliam Unit #5	51.0
699679	Weston Unit #1	62.0
699595	Pulliam Unit #6	23.7
GRE (A388)		
615031	Pleasant Valley Unit #1	29.0
615041	Lakefield Unit #1	84.9
615045	LakefieldUnit #5	86.1
MP (A383)		
608667	Potlatch	24
608676	Hibbard Unit #3	20
608676	Hibbard Unit #4	15
608776	Boswell Unit #1	54
608777	Boswell Unit #2	54
608665	Thomson	36
608702	Laskin Unit #1	25
608702	Laskin Unit #2	22
Xcel Energy (A416)		
600073	River Falls	20
605308	Hatfield	6
600035	Wheaton Unit #4	24
WEC (A417)		
699322	Germantown Unit #5	83
699507	Valley Unit #2	17

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 associated with single contingency events in the Dakotas, Manitoba, Minnesota, Wisconsin

The Manitoba HVDC power order reduction scheme was not simulated for this sensitivity. Overloads that would be properly mitigated by a Manitoba HVDC runback were not included in the results of this study report. Thermal limits were identified using AC solve methods. Voltage and stability considerations were not included in the sensitivities.

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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. This part of the analysis was performed only for the 'Y500 kV + A/B - 1100' option as listed in the Table 2 above.

Analysis Results

PSS®E version 32 and PSS®MUST version 10.2 were used to perform the sensitivities.
Post transfer cases were screened at 100%.

250 MW Transfer, 500 kV + 345 kV A/B Transmission

Table 5: 250 MW Transfer, 230 kV Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
608696 TAC HBR6 138 608699 DUNKARD6 138 1	131.7	139.3	81.3	89	156.5	608696 TAC HBR6 138 608698 HOYT LK6 138 1	7.6	3.04
There is an existing SPS monitoring the flow on the transmission lines out of Tac Harbor, an overload would be mitigated by the SPS.								
608696 TAC HBR6 138 608698 HOYT LK6 138 1	131.4	139	80.5	89	156.2	608696 TAC HBR6 138 608699 DUNKARD6 138 1	7.6	3.04
There is an existing SPS monitoring the flow on the transmission lines out of Tac Harbor, an overload would be mitigated by the SPS.								
608696 TAC HBR6 138 608698 HOYT LK6 138 1	125.4	133	80.5	89	149.5	608698 HOYT LK6 138 608699 DUNKARD6 138 1	7.6	3.04
There is an existing SPS monitoring the flow on the transmission lines out of Tac Harbor, an overload would be mitigated by the SPS.								
608698 HOYT LK6 138 608699 DUNKARD6 138 1	124	131.5	73.2	89	147.8	608696 TAC HBR6 138 608698 HOYT LK6 138 1	7.5	3
There is an existing SPS monitoring the flow on the transmission lines out of Tac Harbor, an overload would be mitigated by the SPS.								

750 MW Transfer, 500 kV + 345 kV A/B Transmission

Table 6: 750 MW Transfer, 500 kV Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
657754 MAPLE R4 230 B$0371 345/230 1.00 1	405.8	460.6	261.6	420	109.7	3Wnd: OPEN B$0375 345/230 2	54.8	7.306667
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000								
620361 MAPLE R3 345 B$0371 345/230 1.00 1	416.1	469.9	264.7	420	111.9	3Wnd: OPEN B$0375 345/230 2	53.8	7.173333
Same transformer as above.								
657754 MAPLE R4 230 B$0375 345/230 1.00 2	406.4	461.1	263.1	420	109.8	3Wnd: OPEN B$0371 345/230 1	54.7	7.293333
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000								
620361 MAPLE R3 345 B$0375 345/230 1.00 2	416.7	470.6	266.3	420	112	3Wnd: OPEN B$0371 345/230 1	53.9	7.186667
Same transformer as above.								

1100 MW Transfer, 500 kV + 345 kV A/B Transmission

Table 7: 1100 MW Transfer, 500 kV + 345 kV A/B Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
657754 MAPLE R4 230 B$0371 345/230 1.00 1	405.8	460.6	261.6	420	109.7	3Wnd: OPEN B$0375 345/230 2	54.8	7.306667
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000								
620361 MAPLE R3 345 B$0371 345/230 1.00 1	416.1	469.9	264.7	420	111.9	3Wnd: OPEN B$0375 345/230 2	53.8	7.173333
Same transformer as above.								
657754 MAPLE R4 230 B$0375 345/230 1.00 2	406.4	461.1	263.1	420	109.8	3Wnd: OPEN B$0371 345/230 1	54.7	7.293333
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000								
620361 MAPLE R3 345 B$0375 345/230 1.00 2	416.7	470.6	266.3	420	112	3Wnd: OPEN B$0371 345/230 1	53.9	7.186667
Same transformer as above.								

No Harm Test Results, 500 kV + 345 kV A/B Transmission

Table 8: No Harm test results, 500 kV + 345 kV A/B Transmission

Monitored Element	Max Post Case Loading	Max Pre Case Loading	Rating	Contingency Description
657754 MAPLE R4 230 B$0371 345/230 1.00 1	116	46.78571429	TRUE	3Wnd: OPEN B$0375 345/230 2
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000				
620361 MAPLE R3 345 B$0371 345/230 1.00 1	118.1	47.47619048	TRUE	3Wnd: OPEN B$0375 345/230 2
Same transformer as above.				
657754 MAPLE R4 230 B$0375 345/230 1.00 2	116.2	46.83333333	TRUE	3Wnd: OPEN B$0371 345/230 1
Needs to be upgraded to 448 MVA. Estimated cost of upgrade is $ 4,000,000				
620361 MAPLE R3 345 B$0375 345/230 1.00 2	118.3	47.52380952	TRUE	3Wnd: OPEN B$0371 345/230 1
Same transformer as above.				

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Summary

In this study AC contingency analysis is performed for following three transfer levels made from Manitoba Hydro to US: 250MW, 750 MW and 1100MW. Transfer level are simulated by adjusting MW flows at the DC bipoles in Manitoba Hydro and sinking them to generation in MP, WPS, WEC, Xcel Energy and GRE. Table 3 and Table 4 of this report gives information on adjusted MW flows on DC bipoles and the study sinks respectively.

Details on study assumptions are given in the Table 2 of this report. Result tables given in this report are made 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 as preliminary estimates. Result summaries of the individual transmission options are described below.

- **250MW transfer**
  The 750MW transfer option showed violations on transmission lines coming out from Tac-Harbor substation. There is an existing SPS monitoring the flow on the transmission lines out of Tac-Harbor, and an overload would be mitigated by the SPS.
- **750MW transfer**
  The 750MW transfer option showed loading violations on the two Maple River 3 Winding transformers. Both of these will be mitigated by increasing the thermal ratings to 448 MVA. It is estimated to cost 8 million to upgrade Maple River transformers (4 million each).
- **1100MW transfer**
  The 1100MW transfer option showed loading violations on the two Maple River 3 Winding transformers. Both of these will be mitigated by increasing the thermal ratings to 448 MVA. It is estimated to cost 8 million to upgrade Maple River transformers (4 million each).
- **No Harm Test, Dorsey-Blackberry 500kV, 345kV Blackberry-Arrowhead 345kV double circuit**
  The no harm test also showed loading violations on the two Maple River 3 Winding transformers. Both of these will be mitigated by increasing the thermal ratings to 448 MVA. It is estimated to cost 8 million to upgrade Maple River transformers (4 million each).

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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 ContMW: This is the amount of MW flow on the limiting element in the model without the transfer modeled.

Post ContMW: This is the amount of MW flow on the limiting element in the model having study transfers modeled.

Base Flow: This is the MW 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: This value is calculated as difference between the **Pre ContMW** and **Post ContMW** 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)

MH-US TSR Sensitivity Analysis

Draft Report (Eastern Plan)

July 3, 2013

Prepared By:

MISO Transmission Access Planning

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Introduction

The purpose of this study was to perform sensitivity analysis on alternative transmission options for the MH-US south bound TSRs. The sensitivity included iterations of the MH-US transfer.

Executive Summary

Results from this study show that the impact of the proposed Riel-Shannon 230kV or Dorsey-Iron Range 500kV (750 or 1100MW) transmission options do not impact the existing transmission system in an adverse way. The facilities that are impacted have mitigations that are outlined in the report. The estimated costs associated with these mitigations are relatively small. The status of G519 (Excelsior 600MW) has been confirmed as withdrawn, and hence it is not modeled for this study. Mitigation costs are shown below.

Scenario	Mitigation Costs (millions)
Riel-Shannon 230kV (250MW transfer)	0
Dorsey-Iron Range 500kV (750MW transfer)	2.16
Dorsey-Iron Range 500kV (1100MW transfer)	0

Description of Request

The south bound requests reserve a total of 1100 MW of transmission service from Manitoba Hydro to several sinks in the northern Midwest United States (Table 1).

Table 1: MH-US South Bound Requests

\Oasis Ref No	Service Type	Start time	Stop Time	POR	POD	Requested Capacity	Queue Date	Study Number
76703536	Network	Nov-2014	Nov-2024	MHEB-MISO	GRE	200	12/7/2006	A388
76703671	Network	Jun-2017	Jun-2027	MHEB-MISO	WPS	500	6/12/2007	A380
76703672	Network	Jun-2017	Jun-2037	MHEB-MISO	MP	250	7/6/2007	A383
76703686	Network	Jun-2017	Jun-2027	MHEB-MISO	NSP	50	4/17/2008	A416
76703687	Network	Jun-2017	Jun-2027	MHEB-MISO	WEC	100	4/17/2008	A417

The proposed sensitivity options are described in Table 2.

Table 2 Sensitivity Options

Option	Description
230 kV	• MH-MP TSR only (250 MW) • Riel – Shannon 230 kV (294.15 miles) ○ Line data based on R50M
Y500 kV	• MH-MP TSR + MH-WPS TSR (750 MW) • Dorsey – Blackberry 500 kV (271.12 miles) ○ Line data based on Dorsey – Bison 500 kV option • Arrowhead PST = 0 • One 500/230 kV transformer at Blackberry (based on Forbes 500/230 kV)
Y500 kV + A/B	• All TSRs (1100 MW) • One Dorsey – Blackberry 500 kV circuit (271.12 miles) ○ Line data based on Dorsey – Bison 500 kV option • Two 345 kV circuits from Blackberry – Arrowhead (71.15 miles) • Arrowhead PST = 0 • Two 500/345 kV transformers at Blackberry (based on Maple River 500/345 kV) • One 500/230 kV transformer at Blackberry (based on Forbes 500/230 kV)

Criteria, Methodology, and Assumptions

Models

MTEP 2012 power flow model representing a 2022 Summer Peak condition 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 3670 MW in the benchmark case as follows:

- Bipole 1 = 958 MW
- Bipole 2 = 1032 MW
- Bipole 3 = 1680 MW

The bipole inverters were used to source the south bound requestsas shown in Table 3.

Table 3 MH-US TSR Sources

250 MW Injection	750 MW Injection	1100 MW Injection
• Bipole 1 = 1241.4 MW • Bipole 2 = 1339.3 MW • Bipole 3 = 1335.4 MW	• Bipole 1 = 1405.7 MW • Bipole 2 = 1516.5 MW • Bipole 3 = 1512.1 MW	• Bipole 1 = 1519.6 MW • Bipole 2 = 1639.5 MW • Bipole 3 = 1634.7 MW

Study TSRs were sunk to the generators in Table 4.

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Table 4 MH-US TSR Sinks

Bus #	Generator Name	MW
WPS (A380)		
699993	Skygen Unit #1	172
699661	West Marinette Unit #3	75.0
699597	Pulliam Unit #31	74.0
698925	AP_PPRGT Unit	42.3
699591	Pulliam Unit #5	51.0
699679	Weston Unit #1	62.0
699595	Pulliam Unit #6	23.7
GRE (A388)		
615031	Pleasant Valley Unit #1	29.0
615041	Lakefield Unit #1	84.9
615045	LakefieldUnit #5	86.1
MP (A383)		
608667	Potlatch	24
608676	Hibbard Unit #3	20
608676	Hibbard Unit #4	15
608776	Boswell Unit #1	54
608777	Boswell Unit #2	54
608665	Thomson	36
608702	Laskin Unit #1	25
608702	Laskin Unit #2	22
Xcel Energy (A416)		
600073	River Falls	20
605308	Hatfield	6
600035	Wheaton Unit #4	24
WEC (A417)		
699322	Germantown Unit #5	83
699507	Valley Unit #2	17

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 not simulated for this sensitivity. Overloads that would be properly mitigated by a Manitoba HVDC runback were not included in the results of this study report. Thermal limits were identified using AC solve methods. Voltage and stability considerations were not included in the sensitivities.

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. This part of the analysis was performed only for the 'Y500 kV + A/B' option as listed in the Table 2 above.

Analysis Results

PSS®E version 32 and PSS®MUST version 10.2 were used to perform the sensitivities.
Post transfer cases were screened at 100%.

MISO

250 MW Transfer, 230 kV Transmission

Table 5: 250 MW Transfer, 230 kV Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

750 MW Transfer, 500 kV Transmission

Table 6: 750 MW Transfer, 500 kV Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
608625 BLCKBRY4 230 B$0490 BANK 3 1.00 3	572.4	816.5	816.5	800	102.1	** Base Case **	244.1	32.54667
Blackberry 500/230KV transformer loading not a concern as actual size can still be changed to fit need.								
B$0490 BANK 3 1.00 608635 BLCKBRY2 500 3	573.3	816.5	816.5	800	102.1	** Base Case **	243.2	32.42667
Blackberry 500/230KV transformer loading not a concern as actual size can still be changed to fit need.								
608737 NASHWAK7 115 608739 BLCKBRY7 115 2	126.7	164	106	158	103.8	20L	37.3	4.973333
Line can be upgraded to increase thermal rating above post-contingent levels. Estimated cost is $2.16 million.								
608737 NASHWAK7 115 608739 BLCKBRY7 115 2	126.7	163.9	106	158	103.7	608739 BLCKBRY7 115 608781 20L TAP7 115 1	37.2	4.96
Same line section as above, Line can be upgraded to increase thermal rating above post-contingent levels. Estimated cost is $2.16 million.								

1100 MW Transfer, 500 kV + 345 kV A/B Transmission

Table 7: 1100 MW Transfer, 500 kV + 345 kV A/B Transmission

Monitored Element	Pre ContMW	Post ContMW	Base Flow	Rating	Cont. Ld%	Contingency Description	Impact	DF
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

No Harm Test Results, 500 kV + 345 kV A/B Transmission

Table 8: No Harm test results, 500 kV + 345 kV A/B Transmission

Monitored Element	Max Post Case Loading	Max Pre Case Loading	Rating	Contingency Description
N/A	N/A	N/A	N/A	N/A

MISO

Summary

In this study AC contingency analysis is performed for following three transfer levels made from Manitoba Hydro to US: 250MW, 750 MW and 1100MW. Transfer level are simulated by adjusting MW flows at the DC bipoles in Manitoba Hydro and sinking them to generation in MP, WPS, WEC, Xcel Energy and GRE. Table 3 and Table 4 of this report gives information on adjusted MW flows on DC bipoles and the study sinks respectively.

Details on study assumptions are given in the Table 2 of this report. Result tables given in this report are made 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 as preliminary estimates. Result summaries of the individual transmission options are described below.

- **250MW transfer, Riel-Shannon 230kV**
  No valid constraints were found for 250 MW transfer.
- **750MW transfer, Dorsey-Blackberry 500kV**
  The 750MW transfer option showed violations on two MP facilities. These would both be mitigated by increasing the thermal line ratings. Blackberry 500/230 kV Transformer is not a concern as actual size can still be changed to fit the need. It is estimated to cost 2.16 million to upgrade Blackberry-Nashwauk 115kV.
- **1100MW transfer, Dorsey-Blackberry 500kV, 345kV Blackberry-Arrowhead 345kV double circuit**
  No valid constraints were found for 1100 MW transfer.
- **No Harm Test, Dorsey-Blackberry 500kV, 345kV Blackberry-Arrowhead 345kV double circuit**
  No valid constraints were found for 1100 MW transfer.

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.

MISO

Pre ContMW: This is the amount of MW flow on the limiting element in the model without the transfer modeled.

Post ContMW: This is the amount of MW flow on the limiting element in the model having study transfers modeled.

Base Flow: This is the MW 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: This value is calculated as difference between the **Pre ContMW** and **Post ContMW** 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)

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
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MISO

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.

MISO

- 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

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

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Great Northern Transmission Project - Information Request #4

Docket Number: PUC Docket No.: E-015/CN-12-1163 Request Date: February 24, 2014
OAH Docket No.: 60-2500-30782

Requested From: Eric Swanson, attorney for MP; David Moeller, MP/Allete

Party Requesting Information: Carol A. Overland for RRANT

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

Request No.	
4.	With the exception of the MISO Northern Area Study, June 2013, Application Appendix M, please provide a copy and an active working link for any and all MISO scopes and studies, committee presentations, agendas and meeting minutes referencing all or part of the project known as Great Northern Transmission Study. **Response:** Please see attached list with links of all applicable MISO scopes and studies, committee presentations, agendas and meeting minutes referencing all or part of the project known as Great Northern Transmission Study.

These requests are continuing, and if new or additional information is discovered, please supplement your responses as soon as possible.

For all but Applications, electronic format preferred, via email or CD.

Response by: Cindy Hammarlund
Title: Transmission Marketing Manager
Department: Strategy & Planning
Telephone: 218-341-0391

List sources of information: OATI webOASIS – MISO

System Impact Study (SIS) reports and meeting presentations

Draft SIS Report Prior Outage & Injection Analysis	7/9/2010	Draft SIS Report Prior Outage & Injection Analysis
Draft SIS Report - TO Option	4/26/2010	Draft SIS Report - TO Option
Additional Impact Analysis Draft Report	4/20/2010	Additional Impact Analysis Draft Report
Executive Summary (Final Report)	7/20/2009	Executive Summary (Final Report)
Final SIS Report Summer Peak analysis	7/20/2009	Final SIS Report Summer Peak analysis
Final SIS Report Winter Peak analysis	7/20/2009	Final SIS Report Winter Peak analysis
Final SIS Report Stability analysis	7/20/2009	Final SIS Report Stability analysis
Updated Draft Stability SIS Report analysis	6/29/2009	Updated Draft Stability SIS Report analysis
Updated Draft SIS Report- Winter Peak analysis	6/29/2009	Updated Draft SIS Report- Winter Peak analysis
Updated Draft SIS Report- Summer Peak analysis	6/29/2009	Updated Draft SIS Report- Summer Peak analysis
Draft Stability analysis	4/30/2009	Draft Stability analysis
Draft SIS Report- Winter Peak analysis	3/20/2009	Draft SIS Report- Winter Peak analysis

System Impact Study (SIS) reports and meeting presentations – *Continued*

Draft SIS Report- Summer Peak analysis 3/11/2009 Draft SIS Report- Summer Peak analysis

Draft SIS Report 1/13/2009 Draft SIS Report

Preliminary Draft SIS Report 12/16/2008 Preliminary Draft SIS Report

LT MH Study Screening results 1/21/2009 LT MH Study Screening results

MH_TSR_Group Study_Transmission Options 1/21/2009 MH_TSR_Group Study_Transmission Options

Facilities Study Reports and meeting presentations

MH-MP_AC_Thermal_Sensitivity_Analysis-Eastern_Plan-Draft_Report-01-07-13.pdf 7/3/2013 MH-MP_AC_Thermal_Sensitivity_Analysis-Eastern_Plan-Draft_Report-01-07-13.pdf

MH-MP_AC_Thermal_Sensitivity_Analysis-Western_Plan-Draft_Report-01-07-13.pdf 7/3/2013 MH-MP_AC_Thermal_Sensitivity_Analysis-Western_Plan-Draft_Report-01-07-13.pdf

MH-MP TSR meeting Feb 2013 3/6/2013 MH-MP TSR meeting Feb 2013

MH-MP TSR meeting Jan 2013_EPL 1/8/2013 MH-MP TSR meeting Jan 2013_EPL

MH-MP AC Thermal Sensitivity Analysis - Draft Report - 01-03-2013 1/8/2013 MH-MP AC Thermal Sensitivity Analysis - Draft Report - 01-03-2013

Dorsey - Iron Range 500 kV Project Preliminary Stability Analysis - Draft Report - 12-5-2012 1/8/2013 Dorsey - Iron Range 500 kV Project Preliminary Stability Analysis - Draft Report - 12-5-2012

Facilities Study Reports and meeting presentations – *Continued*

MH Group Study Option 1 FS	6/1/2010	MH Group Study Option 1 FS
MH Group Study CapX - TO presentation	11/4/2009	MH Group Study CapX - TO presentation
CapX FS proposal presentation	11/4/2009	CapX FS proposal presentation
Additional Analysis Scope document	11/4/2009	Additional Analysis Scope document
Final FS Report (GRE)	1/19/2010	Final FS