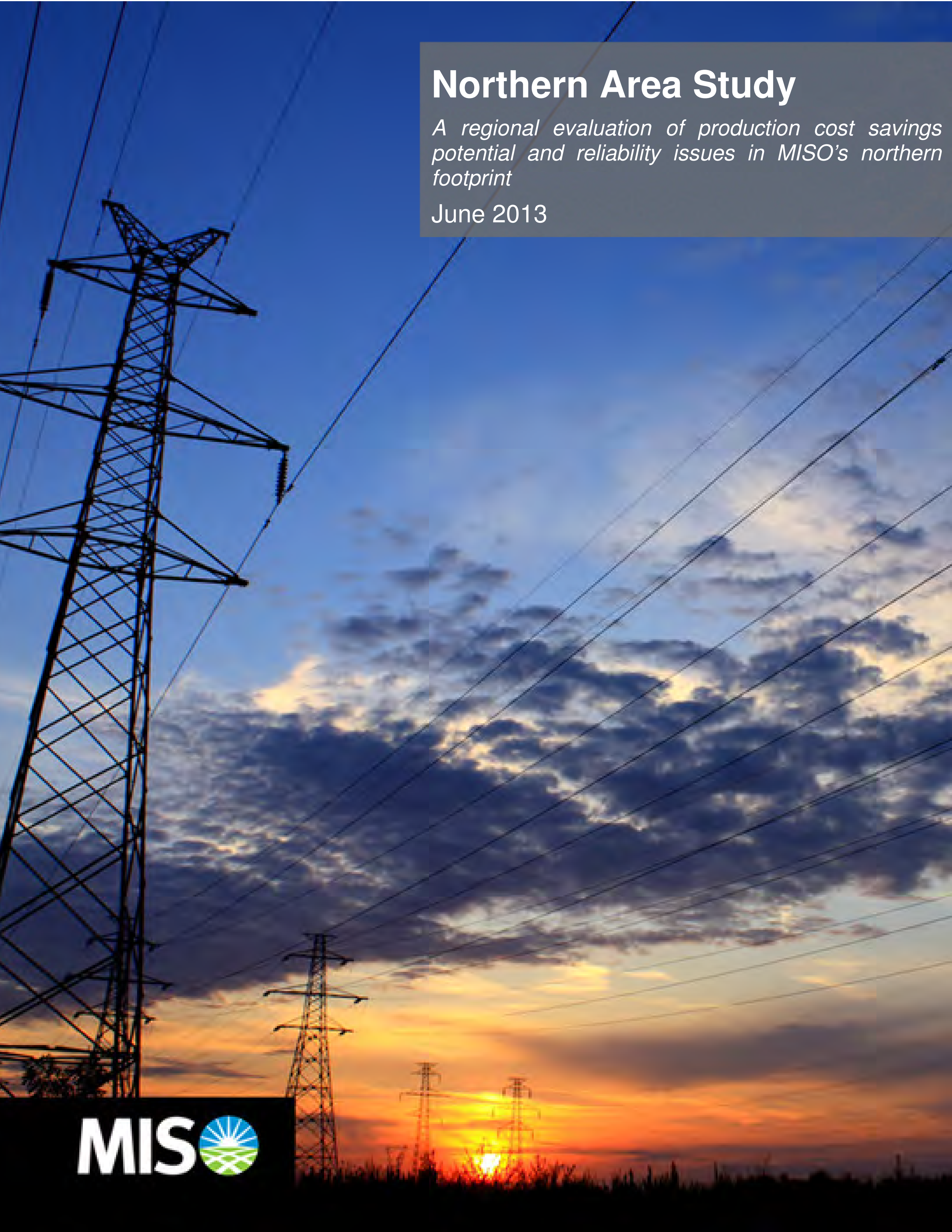
Northern Area Study

A regional evaluation of production cost savings potential and reliability issues in MISO's northern footprint

June 2013



MISO

Contents

Executive Summary – Northern Area Study

The Northern Area Study found that large-scale regional transmission expansion in MISO's northern footprint (North Dakota, Minnesota, Northern Wisconsin, Michigan Upper Peninsula, and Michigan) is not cost-effective based on production cost savings, under current business as usual conditions. Economic benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission investment. The Northern Area Study identified *Hankinson – Wahpeton 230 kV* & *Big Stone – Morris 115 kV* upgrade as a cost-effective option to mitigate the remaining out-year congestion from wind on the Dakotas – Minnesota border (B/C ratio 3.46 – 14.74 depending on scenario assumption). The *Hankinson – Wahpeton 230 kV* & *Big Stone – Morris 115 kV* option is being further analyzed in the Market Efficiency Planning Study. The Northern Area Study makes no conclusions regarding the broader multi-value benefits that might be achieved, or the need for future localized reliability upgrades.

> Large-scale regional transmission expansion in MISO's northern footprint is not cost-effective based solely on production cost savings, under the Northern Area Study current business as usual conditions

> Economic benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission investment beyond the tie-lines.

With Presque Isle Power Plant staying online, the production cost saving potential for new Upper Peninsula (UP) transmission lines is decreased. Even under the scenarios which grew UP mining load levels by an incremental 300 MW, Upper Peninsula transmission options' benefit to cost ratios peaked at 0.4 in the tested conditions. The Northern Area Study results show there are economic benefits of equalizing Michigan locational marginal prices with the rest of the footprint; however, options' production cost benefits do not exceed project costs. Northern Area Study HVDC options require significant additional upgrades to uphold reliability, but were most effective at mitigating Lake Michigan congestion. New high-voltage Upper Peninsula transmission lines could potentially change operating schemes and may require additional operations studies.

The Northern Area Study was a first-take exploratory study to understand the reliability and economic effects of drivers and the magnitude of transmission build-out opportunities. The Northern Area Study originated because of multiple transmission proposals and reliability issues located in the northern area of MISO Midwest. The objective of the Northern Area Study was 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

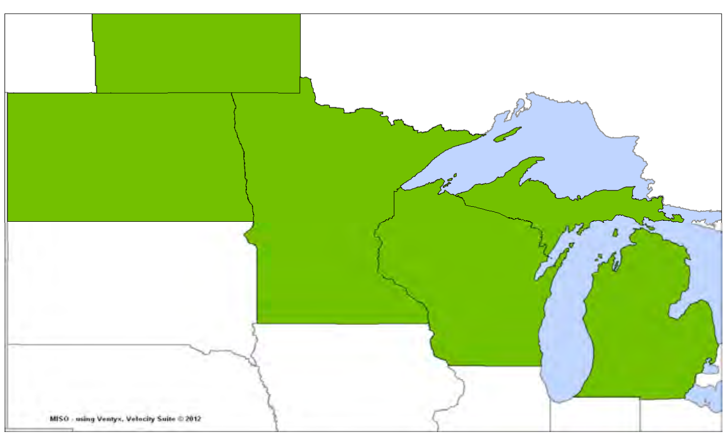


Figure E-1: Northern Area Study Footprint

The Northern Area Study was a regional evaluation of the production cost savings potential and reliability issues in the northern part of MISO's market footprint. Developed as an exploratory study to understand how various drivers dictate transmission investment, the Northern Area Study's results and findings will determine and feed future studies. Given the hypothetical nature of the study drivers, transmission solutions stemming from the Northern Area Study analysis were excluded from MISO Transmission Expansion Plan (MTEP) Appendix A or B consideration. The Northern Area Study followed MISO's 7-Step Planning Process and was performed in an open and transparent manner.

> With Presque Isle staying online, the production cost savings potential for new UP transmission lines is decreased

> Generally, production cost savings potential for the Northern Area Study footprint was low as a result of the inclusion of the Multi-Value Project (MVP) portfolio approved in MTEP11, decreased forecasted demand growth rates, and low natural gas prices

The Northern Area Study was a collaborative effort between stakeholders and MISO staff. Meetings were open to all stakeholders and interested parties - study participants included state regulatory agencies, transmission owners, market participants, environmental groups, and industry experts. A stakeholder technical review group (TRG) was involved in all discussions and decisions.

MTEP12 reliability and economic models and assumptions were used as the starting point for the Northern Area Study analysis. Multiple Northern Area Study scenarios were developed to understand the effects on transmission investment from the study drivers and ensure transmission development was robust and beneficial under various political, economic, and industry uncertainty. Northern Area Study scenarios revolved around three study drivers: increased/decreased industrial load levels, the potential for new imports from Manitoba Hydro, and the retirement of thermal generating units.

The Northern Area Study benefits were evaluated solely based on production cost savings. The broader economic values of a Multi-Value Project (MVP) were not considered in this study. The MVP Portfolio report identified a fuller range of economic values including congestion and fuel saving and reductions in operating reserves, system planning reserve margins, transmission line losses, and future transmission investment needed for reliability. Additionally other qualitative and social benefits were not explored including enhanced generation policy flexibility, increased system robustness, decreased variable generation volatility, local investment and job creation, and carbon reduction.

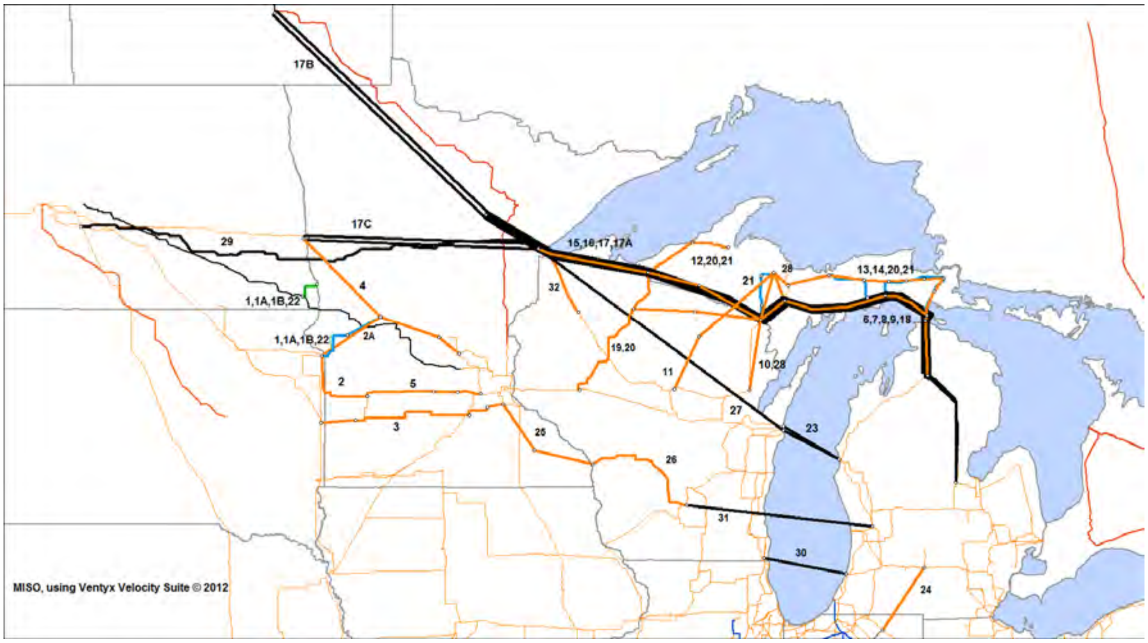


Figure E-2: Northern Area Study Transmission Options

Throughout the Northern Area Study, a total of thirty-eight different mitigation plans were proposed and evaluated. The Northern Area Study used an iterative process to refine projects. Generally, production cost saving potential for the Northern Area Study footprint was low as a result of the inclusion of the Multi-Value Project (MVP) portfolio approved in MTEP11, decreased forecasted demand growth rates, and low natural gas prices.

> HVDC options require significant upgrades to uphold reliability; minimal reliability upgrades needed for AC portfolios

Portfolios were formed by combining the most cost effective transmission options for each of the three identified congestion interfaces through a collaborative TRG effort. The Northern Area Study identified three transmission portfolios as the most economic options available to accomplish study objectives:

- **HVDC:** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Kewaunee – Ludington 500 kV HVDC* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)
- **High Voltage AC:** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV*, *National/Arnold – Livingston 345 kV* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)
- **Low Voltage AC:** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Marquette – Mackinac County 138 kV* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)

Three Northern Area Study developed portfolios mitigate 50 to 100 percent of the area congestion, produce synergic production cost savings, and nearly equalize area LMPs

The Northern Area Study portfolios mitigate 50 to 100 percent of the area congestion, produce synergic production cost savings, and nearly equalize northern area locational marginal prices, but projected production cost savings generally do not exceed costs. Northern Area Study HVDC options require significant additional upgrades to uphold reliability; minimal reliability upgrades needed for AC portfolios.

Northern Area Study Portfolio	Capture Rate[1] (%)	Synergic Benefits[2] (%)	Benefit to Cost Ratio
HVDC	94 – 100+	15	0.21 – 0.72
High Voltage AC	61 - 86	7	0.19 – 0.74
Low Voltage AC	50 - 68	0	0.29 – 1.22

Table E-1: Economic Results- Northern Area Study Portfolios

Northern Area Study Portfolio	Thermal Violations[3]	Voltage Violations[4]	Transient Stability Violations
HVDC	157	9	14
High Voltage AC	6	4	0
Low Voltage AC	1	0	Not evaluated

Table E-2: Reliability Results - Northern Area Study Portfolios

The Northern Area Study was developed as an exploratory study to understand how the development of new potential Manitoba – MISO tie-lines, changing mining/industrial load levels, and the retirement of generating units dictate transmission investment in MISO's footprint. The Northern Area Study's results will determine and feed future studies. MISO, through its MTEP process, analyses congestion annually to reassess if transmission expansion is justified based on updated congestion patterns. While the Northern Area Study's transmission options' projected benefits did not exceed costs under the study assumptions, the results present a prioritized and shortened list of options for future studies if benefits other than production cost savings are identified or assumptions about future conditions or needs change.

[1] Capture rate is percentage of Northern Area Study area congestion relief measured as a ratio of the portfolio's APC savings to the area's maximum economic potential. Historical MISO average capture rate is 70%.

[2] Synergic benefits are the percentage the portfolio's APC savings exceed the summation of the individual options APC savings – measures if a portfolio performs together "as a whole"

[3] Summer peak model; summation of new and worsened elements

[4] Summer peak model; summation of low and high voltage areas

1. Study Purpose, Drivers, and Overview

The Northern Area Study is a regional evaluation of the economic potential and reliability issues in the northern part of MISO's market footprint. Developed as an exploratory study to understand of how various drivers dictate transmission investment, the Northern Area Study's results and findings will determine and feed future studies. Given the hypothetical nature of the study drivers, transmission solutions stemming from the Northern Area Study analysis were excluded from MISO Transmission Expansion Plan (MTEP) Appendix A or B consideration. The Northern Area Study followed MISO's 7-Step Planning Process and was performed in an open and transparent manner.

> Originating because of multiple transmission proposals, the Northern Area Study is a regional exploratory analysis designed to evaluate the economic potential and reliability issues in the northern MISO Market Footprint.

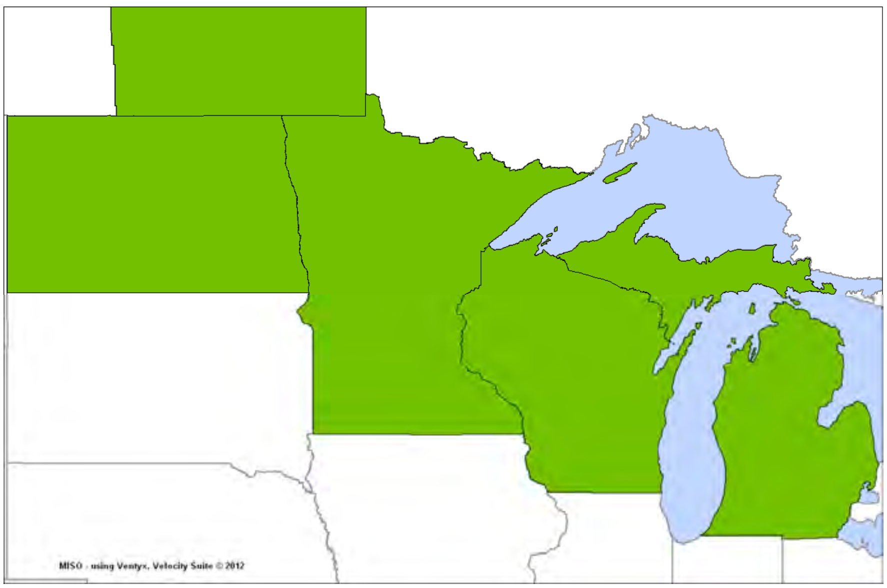


Figure 1-1: Northern Area Study Footprint

The Northern Area Study originated because of multiple transmission proposals and reliability issues located in MISO's northern footprint. Developed through the TRG, the objective of the Northern Area Study was 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

The Northern Area Study was a collaborative effort between stakeholders and MISO staff. Meetings were open to all stakeholders and interested parties - study participants included state regulatory agencies, transmission owners, market participants, environmental groups, and industry experts. A stakeholder technical review group (TRG) was involved in all discussions and decisions.

> The Northern Area Study was a collaborative effort between a stakeholder technical review group and MISO staff.

Multiple Northern Area Study scenarios were developed to understand the effects on transmission investment from the study drivers and ensure transmission development was robust and beneficial under various political, economic, and industry uncertainty. Northern Area Study scenarios revolved around three study drivers: increased/decreased industrial load levels, the potential for new imports from Manitoba Hydro, and the retirement of thermal generating units. Each of these study drivers are detailed in the following sections.

The Northern Area Study was closely coordinated with the Manitoba Hydro Wind Synergy Study, Manitoba Hydro – MISO Transmission Service Request Study, and the MTEP13 Market Efficiency Planning Study

The Northern Area Study was complimentary and closely coordinated with the Manitoba Hydro Wind Synergy Study, Manitoba Hydro – MISO Transmission Service Request Study, and Market Efficiency Planning Study. Figure 1-2 shows the various linkages and hand-offs between the analyses.

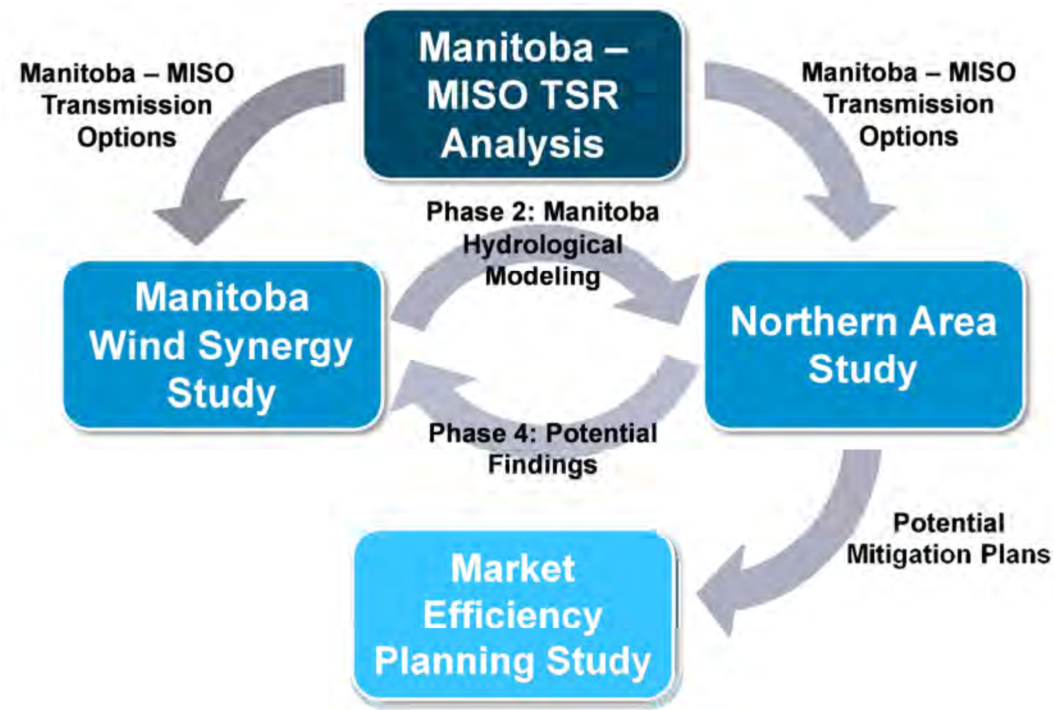


Figure 1-2: Concurrent Study Linkages and Hand-Offs

Throughout the Northern Area Study, a total of thirty-eight different mitigation plans were proposed and evaluated. The Northern Area Study used an iterative process to refine projects. Over 1,000 production cost simulations were performed totaling over 120,000 hours of computation time. This write-up includes only final results unless specifically noted.

The Northern Area Study was a twelve month effort where 4,200 hours of MISO staff time were spent. Additionally, the Northern Area Study stakeholder TRG spent an undetermined amount of time reviewing inputs, providing alternatives, and verifying outputs.

1.1 Industrial Load Levels

The potential for industrial load increases and decreases was the first scenario driver for the Northern Area Study. Industrial or mining load also known as non-conforming load differs from traditional or conforming load in that it does not vary over time; load is at a specific level all hours all days. The driver for studying industrial load levels in Northern Area Study scenarios originated with a request to evaluate transmission potential through the Upper Peninsula of Michigan to accommodate additional mining opportunities. Industrial load change potential were later expanded to the larger Northern Area Study region after the June 7, 2012 TRG meeting. After the June meeting, TRG members supplied both the magnitude and location of potential area industrial load changes. The increased non-conforming load potential included approximately 300 MW in northern Wisconsin/Michigan's Upper Peninsula, 600 MW in northern Minnesota, and 1,000 MW in western North Dakota. Additionally, there was a similar potential to decrease area non-conforming load through the closing of mines and industrial plants.

> Three different load levels were considered: business as usual, high growth, and low growth

The Business as Usual (BAU) future, described in Section 3.1, is generally viewed as exhibiting MISO's baseline demand and energy growth rate. The high and low book-end demand and energy growth rates are represented in the High Demand and Energy (HDE) and Low Demand and Energy (LDE) futures, respectively. The magnitude of non-conforming demand reported by the Northern Area Study TRG was generally in close proximity with the demand and energy increases/decreases between the BAU and the HDE/LDE, and therefore at the July 11th meeting the TRG recommended using the MTEP12 BAU, HDE, and LDE futures to represent the changing non-conforming load demand level study driver. The only exception was the increase in western North Dakota, which was modeled above and beyond the MTEP12 HDE future. To maintain out-year capacity planning reserve margins in western Northern Dakota additional generation added with collaboration from area TRG members. Additionally, northern Minnesota and Upper Peninsula Michigan demand was reallocated to more accurately reflect forecasted demand levels.

Northern Area Study reliability models focused on identifying potential reliability issues under stress case conditions and therefore used similar load additions to the HDE future.

The Northern Area Study analysis evaluated economic potential and reliability issues for three different load levels:

- Business as Usual (BAU) – Baseline
- High Growth Demand and Energy (HDE) – increased demand, includes +1000 MW in western North Dakota plus additional generation
- Low Growth Demand and Energy (LDE) – decreased demand

1.2 Increased Imports from Manitoba Hydro

Northern Area Study scenarios included the potential for approximately 1,100 MW in new imports from Manitoba Hydro via three different proposed tie-line configurations

The second scenario driver in the Northern Area Study was a potential for increased generation and imports from Manitoba Hydro. Manitoba Hydro has development plans for adding two additional hydro units, Keeyask (695 MW) and Conawapa (1,485 MW). The Conawapa and Keeyask units would be phased-in from 2019 through 2027. Together, the units would increase import potential into MISO by approximately 1,100 MW, the remaining capacity would serve Manitoba Hydro load. To deliver 1,100 MW of imports to the MISO three different tie-lines were proposed[5]. Those three tie-line configurations are shown in Figures 1-3 through 1-5.

Figure 1-3: Manitoba - Duluth 500 kV Tie-Line

5 Four additional tie-line configuration have been proposed and evaluated in the Manitoba – MISO TSR analysis to import 750 MW and 250 MW.

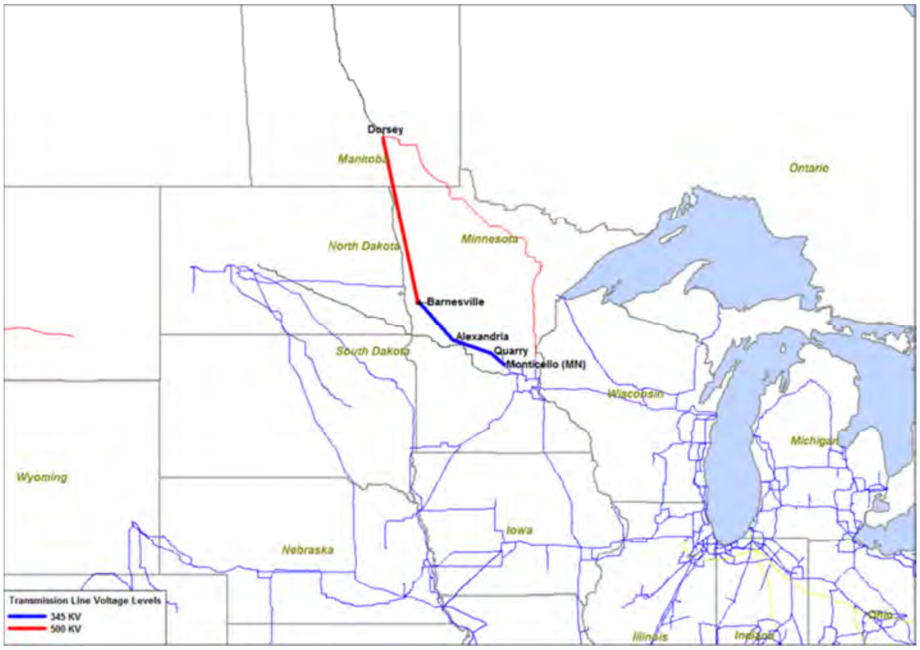


Figure 1-4: Manitoba – Fargo Area 500 kV Tie-Line

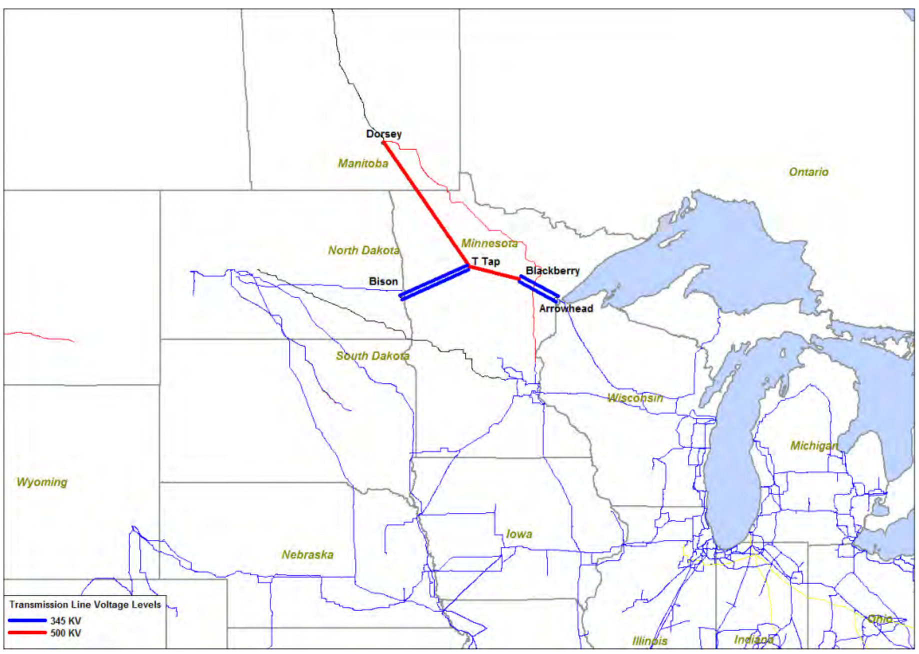


Figure 1-5: Manitoba – Fargo and Duluth “T” 500 kV Tie-Line

The economic potential and reliability of the Manitoba – MISO tie-lines and new generation, at the drafting time of this report, are being evaluated in the Manitoba Hydro Wind Synergy Study (MHWSS) and Manitoba – MISO Transmission Service Request (TSR) Analysis. The Northern Area Study provides no indication or comparison between 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 build-out is required for MISO’s entire northern footprint to realize the benefits of new Manitoba imports.

Manitoba Hydro's preferred development plan is the construction of Keeyask hydro station and a new 500 kV transmission line from Manitoba to MISO (in-service date 2020) followed by construction of the Conawapa hydro station. The Northern Area Study scenarios initially evaluated the three different tie-line configurations of this development plan as well as sensitivity or contingency evaluation from Manitoba Hydro's preferred development plan in which no new tie-line was constructed and only the Conawapa hydro station was constructed.

At the July 11th, TRG meeting four different Manitoba Hydro import scenarios were finalized for the Northern Area Study:

- Conawapa and Keeyask In-Service; New Manitoba – Duluth 500 kV Tie-Line (Figure 1-3)
- Conawapa and Keeyask In-Service; New Manitoba – Fargo Are 500 kV Tie-Line (Figure 1-4)
- Conawapa and Keeyask In-Service; New Manitoba – "T" 500 kV Tie-Line (Figure 1-5)
- Conwapa In-Service; No new tie-line

At the November 2nd TRG meeting the "T" option was eliminated from the evaluation, throughout this report only the remaining three scenarios are presented.

- Conawapa and Keeyask In-Service; New Manitoba – Duluth 500 kV Tie-Line (Figure 1-3)
- Conawapa and Keeyask In-Service; New Manitoba – Fargo Are 500 kV Tie-Line (Figure 1-4)
- Conwapa In-Service; No new tie-line

1.3 Unit Retirements

The final Northern Area Study driver was unit retirements, specifically the potential retirement of the Presque Isle Power Plant in Marquette, Michigan. Prior to the Northern Area Study kick-off meeting on June 7, 2012 a public announcement was made saying the Presque Isle Power Plant would likely retire by 2017/2018 due to the United States Environmental Protection Agency (EPA) regulations. The retirement of this plant was expected to cause area reliability issues; therefore, at the kick-off meeting multiple parties expressed opinions that a life extension option would occur to allow Presque Isle to continue operations. Because of the uncertainty around the future operational status of Presque Isle, at the July 11, 2012 TRG meeting the decision was made to study two different Presque Isle in-service scenarios:

> The Presque Isle plant will remain operational; additional unit retirement scenarios included in the MTEP12 base assumptions

- Presque Isle in-service
- Presque Isle retired in 2017

On November 27, We Energies and Wolverine Power Cooperative announced an agreement that would keep the Presque Isle Power Plant operational by adding emission controls to the five units. After the Presque Isle public announcement, the Northern Area Study eliminated all scenarios which retired Presque Isle from the analysis. All results in this report assume Presque Isle is in-service.

Baseline generation retirements, which forecast out-year probably levels of retirements driven by EPA regulation were included in all MTEP12 production cost models including the Northern Area Study. MTEP12 retirements were based on a MISO Planning Advisory Committee vetted generic process as the results of the MISO Asset Owner EPA Survey are confidential. MTEP12 retirements by Local Resource Zone are shown in Table 1-1.

Local Resource Zone (State)	Retirements (GW)
1 (MN,ND,SD)	1.45
2 (WI, UP)	0.89
3 (IA)	1.77
4 (IL)	1.3
5 (MO)	1.29
6 (IN)	2.88
7 (MI)	3.08
MISO Total	*12.66*

Table 1-1: MTEP12 MISO Forecasted Retirements by Local Resource Zone[6]

Supplementary to the retirements reflected in Table 1-1, the Kewaunee Nuclear Plant in Carlton, Wisconsin was retired in all Northern Area Study models and the associated Barnhart Lake Transmission Project removed. Additionally, Michigan unit retirements identified at the December 4, 2012 East Sub-Regional Planning Meeting (SPM) were reflected in the Northern Area Study planning models – 89 MW of incremental retirements to those reflected in Table 1-1.

[6] Totals do not include Kewaunee Nuclear Plant or 89 MW of additional retirements identified at the December 4, 2012 East SPM

2. Northern Area Study Process

The Northern Area Study was a collaborative effort between stakeholders and MISO staff. Meetings were open to all stakeholders and interested parties. Study participants included state regulatory agencies, transmission owners, market participants, environmental groups, and industry experts. A stakeholder technical review group (TRG) was involved in all discussions and decisions. All Northern Area Study results were publically posted and further presented at seven TRG meetings. The seven Northern Area Study TRG meeting dates are shown in Table 2-1.

> The Northern Area Study followed the MISO 7-Step Planning Process which has been used annually in MTEP since 2006

Date	Location	Purpose
June 7, 2012	St. Paul/Carmel	Kick-off study; Propose process and assumptions
July 11, 2012	Conference Call	Finalize study assumptions
September 21, 2012	St. Paul/Carmel	Present economic potential; Transmission design tutorial
November 2, 2012	St. Paul/Carmel	Design and gather transmission options
December 7, 2012	St. Paul	Present first round economic results
February 12, 2013	St. Paul/Carmel	Present final economic results for options, and propose best-fit portfolios
May 2, 2013	St. Paul	Present reliability analysis results and final economic benefits of portfolios; Final remarks

Table 2-1: Northern Area Study TRG Meetings

The Northern Area Study followed the MISO Seven-Step Planning Process which has been used annually in the MTEP process since 2006. The MISO Seven-Step Process was used to develop (via the Regional Generator Outlet Studies) the MISO Multi-Value Project (MVP) Portfolio. The MISO Seven-Step process with annotations for the Northern Area Study scope is shown in Figure 2-1.

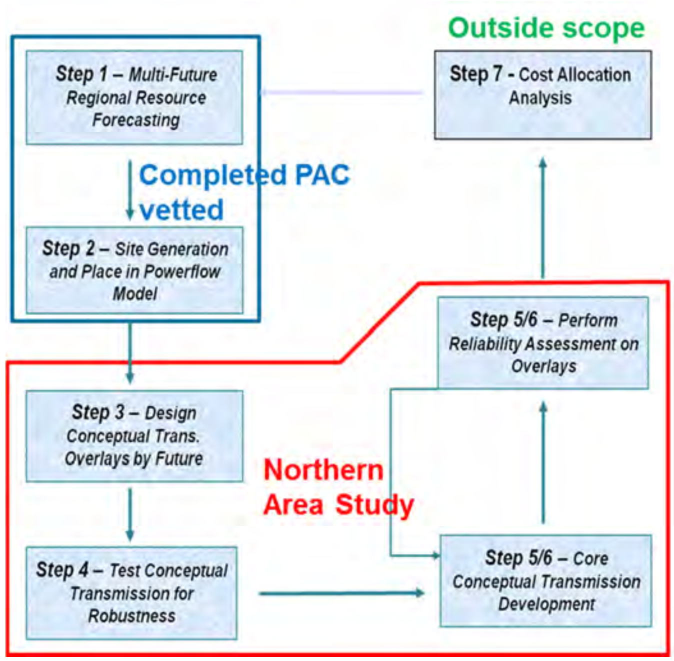


Figure 2-1: Northern Area Study Process in MISO Seven Step Process

The Northern Area Study used MTEP12 models and futures which were developed and vetted in an open stakeholder process through the MISO Planning Advisory Committee (Steps 1 and Steps 2). As detailed in Section 1, Northern Area Study specific scenarios were formulated inside of the futures to reflect additional non-conforming load changes, a potential increase in imports from Manitoba Hydro, and initially the retirement of the Presque Isle Power Plant. The Northern Area Study assumptions were finalized at the July 11, 2012 TRG meeting.

The Northern Area Study breadth of work began in Step 3 - Design Conceptual Transmission. At the September 21, 2012 TRG meeting stakeholders were presented a full package of economic potential data to identify congestion pockets, quantify the magnitude of transmission needed to unlock potential, and ultimately guide transmission plan development. The Northern Area Study economic potential data is detailed in Section 5. A collaborative effort between MISO staff and stakeholders was used to identify multiple transmission projects.

Transmission projects were economically tested both in the scenario for which they were designed (Step 3) and also all other scenarios (Step 4), and the results presented at the November 2, December 7, and February 12, 2013 TRG meetings. The Northern Area Study was different from previous efforts following MISO's Seven Step Process in that scenarios were not intended to be combined or weighted with relation to the Manitoba – MISO tie-line development. A final decision on an area transmission plan driven by new Manitoba imports would occur after the Manitoba – MISO tie-line decision plan was finalized. Thus, Northern Area Study transmission plans were developed in an "if - then" fashion i.e. "if this tie-line were built then this Northern Area Study plan would be potentially justified." The adjusted production cost benefits for all Northern Area Study plans are detailed in Section 6.

At the February 12, 2013 TRG meeting stakeholders narrowed the list of thirty-eight transmission options to five select core development options – Step 5. These options were combined into three portfolios in an effort to unlock synergic benefits where the adjusted production cost savings of the portfolio exceed the summation of individual plans. Each portfolio was tested for both thermal and reliability issues (Step 6) and retested for economics in an iterative process. The reliability and economic results are shown in Section 7.

The Northern Area Study was a first-take exploratory study to understand the reliability and economic effects of drivers and the magnitude of transmission build-out opportunities. As such, the Northern Area Study was not intended to produce ready to build projects or portfolios and therefore cost allocation (Step 7) was outside of the Northern Area Study scope. All projects identified in the Northern Area Study may be further analyzed in future studies including but not limited to the Market Efficiency Planning Study.

3. Northern Area Study Model Development

MTEP12 powerflow and economic models were the basis for the Northern Area Study analysis. MTEP12 models were updated with Northern Area Study TRG supplied assumptions and publically announced unit retirement decisions.

The Northern Area Study used the MTEP12 powerflow and economic models as the basis for the analysis. The MTEP12 models were developed through an open stakeholder process and vetted through the MISO Planning Advisory Committee. MTEP12 models were updated with Northern Area Study TRG supplied assumptions and publically announced unit retirement decisions. The details of the economic and reliability models used in the Northern Area Study are described in the following sections. Northern Area Study models are available on the MISO FTP site with proper licenses and confidentiality agreements.

3.1 Economic Models

The Northern Area Study used PROMOD IV® as the primary tool to evaluate the economic benefits of the potential transmission upgrade options. The MTEP12 Economic Study Model User Group (ESMUG) vetted economic models were used as the basis for the Northern Area Study models.

To account for uncertain future economic conditions and/or public policy decisions, multiple future scenarios were developed. Each future scenario represents a combination of uncertainty assumptions e.g. load growth, fuel prices, and public policies. The Northern Area Study models used three modified MTEP12 futures developed through state regulatory and stakeholder group:

Business as Usual (BAU): Status quo environment that assumes a slow recovery from the economic downturn and its impact on demand and energy projections. This scenario assumes existing standards for renewable mandates and little or no change in environmental legislation.

Business as Usual with Historic Demand and Energy (HDE): Status quo environment, but assumes a quicker recovery from the economic downturn and a return to historic demand and energy growth rates. This scenario uses existing standards for renewable mandates and predicts little or no change in environmental legislation.

Business as Usual with Low Demand and Energy (LDE): Status quo environment, but assumes little to no recovery from the economic downturn. Scenario assumed flat demand and energy growth rates. This scenario uses existing standards for renewable mandates and predicts little or no change in environmental legislation.

To ensure out-year reserve requirements were met, regional resource forecast (RRF) units were added to the production cost models. These units were incorporated using a least cost capacity expansion methodology through an open stakeholder process. The location of RRF units can impact flowgate congestion and therefore have an effect on the potential benefits of transmission upgrades. To alleviate these biases, multiple future scenarios, each with a different generation forecast, were used.

MTEP12 powerflow models for the year 2022 were used as the base transmission topology for the Northern Area Study. Because there are no significant transmission topology changes known between years 2022 and 2027, the 2027 production cost models use the same transmission topology as year 2022. The approved ATC Out of Cycle Project was included in all Northern Area Study models.

The Northern Area Study model includes the Eastern Interconnection minus ISO-New England, Eastern Canada, and Florida. A total of ten pools are defined in the PROMOD study footprint: MISO, PJM, SPP, MRO, SERC, TVA, TVA Other (LG&E, AECI, and EKPC), MHEB, NYISO, and IESO. Fixed hourly schedules (transactions) based on historical data were modeled to represent the purchases/sales between the study footprint and external regions. Entergy was modeled in the SERC pool, not as a MISO member, for all MTEP12 studies. The Northern Area Study models include representation of the "TVA Fence" which limits parties to which TVA can sell. The TVA Fence methodology developed in collaboration with PJM, TVA, and industry experts, limits sales by imposing a higher selling hurdle rate was.

PROMOD uses an "event file" to provide pre- and post-contingent ratings for monitored transmission lines. The latest MISO Book of Flowgates and the NERC Book of Flowgates were used to create the event file of transmission constraints in the hourly security constrained model. Ratings and configurations are updated for out-year models by taking into account all approved MTEP Appendix A projects. Additionally, MISO uses the PROMOD Analysis Tool (PAT) to forecast future flowgates based on the updated configurations. PAT added flowgates are included in the MTEP12 models, no additional flowgates were added specifically for the Northern Area Study. Rating and configuration updates from the Northern Area Study TRG were included in the event file. PROMOD is a DC model and therefore does not consider voltage or stability related ratings.

A key driver for the Northern Area Study was the dispatch of Manitoba Hydro's hydro plants. In Phase 2 of the Manitoba Hydro Wind Synergy Study, MISO and Manitoba Hydro co-developed models and algorithms to accurately reflect Manitoba Hydro's dispatch methodology. These algorithms optimized hydro and wind synergy on a five minute granularity and were developed inside of the Plexos model. The Northern Area Study used the hourly integrated hydrological data from the Manitoba Hydro Wind Synergy Study as an input.

Additional details on economic model study assumptions can be found at the following URL:

https://www.misoenergy.org/Library/Repository/Meeting Material/Stakeholder/Planning Materials/Economic Study Models User Group/20120809/20120809 ESMUG MTEP12 Economic Model Assumptions with LRZ Info.pdf

3.2 Reliability Models

3.2.1 Powerflow Model

MTEP12 2022 Summer Peak and Shoulder models were used as the powerflow cases. Both cases were updated to include only approved MTEP Appendix A projects. The Kewaunee Nuclear Plant and the associated Barnhart Lake Transmission Project were removed in response to the latest public retirement announcements.

Based on the drivers of this study, the generation import from Manitoba Hydro to the MISO Market Footprint was increased by 1100 MW over the existing MTEP12 model levels. This value represents the cumulative value of Transmission Service Requests tagged to new hydro generation in Manitoba. Because the no-harm tests performed in this study only look at incremental transmission projects added on top of the basecase, no additional proposed 500 kV transmission was added to accommodate the increased import from Manitoba. The reliability testing of that transmission will be performed through another study process outside of the Northern Area Study.

Another change to the models based on study drivers was the addition of load in the Northern Area Study footprint representing an increase in industrial and mining load. Any updated load projections submitted by Transmission Owners in the Northern Area Study footprint were reflected in the models. Northern Area Study industrial load projections are summarized in Section 1.1.

In the reliability analysis, the Michigan Straits Flow Control between the Upper and Lower Peninsulas was set to 30 MW South to North in the Summer Peak and 40 MW North to South in the Shoulder model. The 8760 hourly Northern Area Study economic models matched the reliability shoulder limitations; South to North flows were limited to the thermal rating. These values are based on historical flow and match the values presented to the Michigan Technical Study Task Force.

3.2.2 Transient Stability Model

A 2017 summer shoulder peak powerflow case was used to benchmark transient stability performance. The benchmark model was developed from MTEP12 series 2017 summer shoulder transient stability package and includes the Northern Area Study updates stated in Section 3.2.1. MTEP12 2017 summer shoulder transient stability includes transmission projects from planned MTEP Appendix A and B identified in July 2012.

The Northern Area Study transient stability models included representation of both the additional import potential from Manitoba Hydro as well as the MH-Duluth (Figure 1-3) and MH-Fargo (Figure 1-4) tie-line configurations in select scenarios.

Northern Area Study transient stability analysis disturbances were selected from the MTEP12 disturbance library and also included new disturbances for the proposed transmission. Disturbances defined in the MAPP standard library were simulated using the switching sequence from the library. The complete disturbance library used in the Northern Area Study is contained within Appendix I of this report.

Figure 3-1 shows the geographic location of the studied disturbances. Disturbances in black were selected from MTEP12 transient stability study disturbance library. Disturbances in red were new faults for testing the proposed transmission projects.

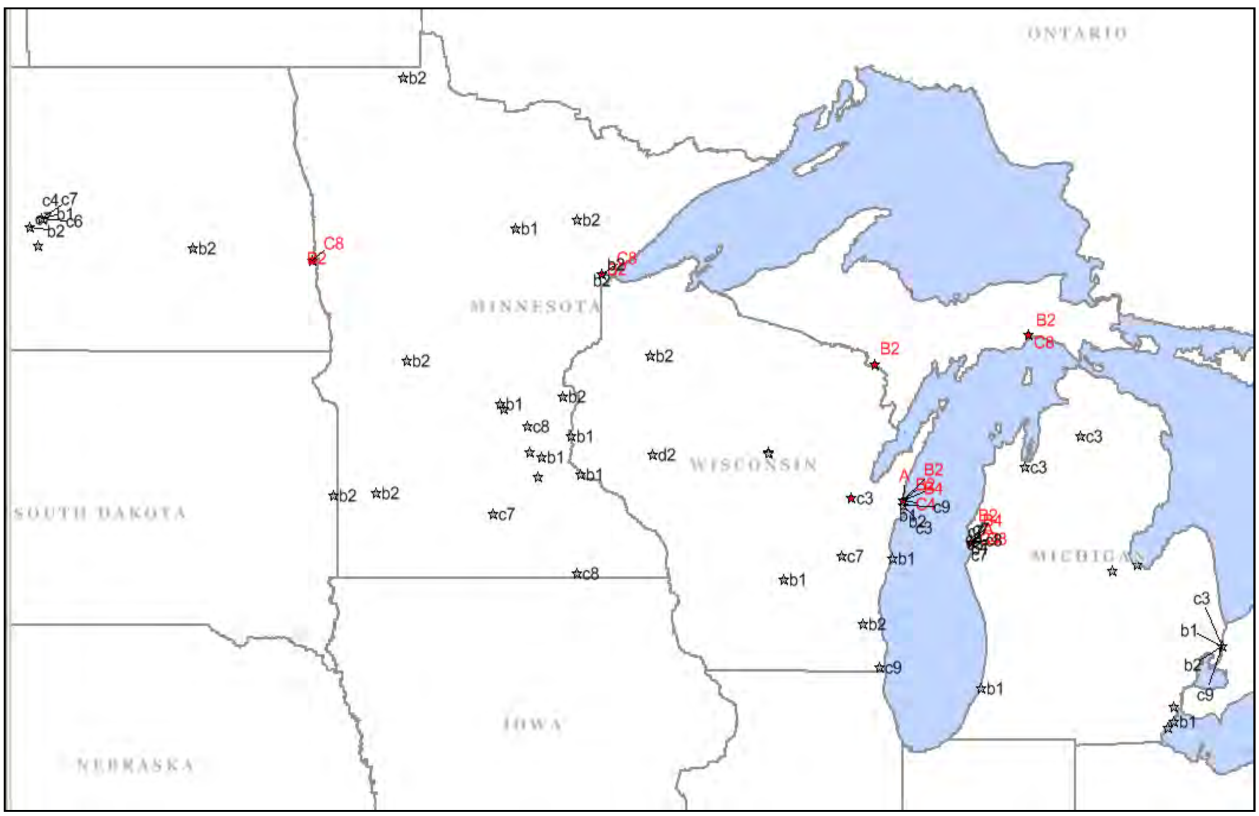


Figure 3-1: Stability Disturbances Map

Table 3-1 defines the generic assumption used for modeling the switching sequence for new disturbances; admittances used to simulate single-line-ground faults in new switching sequences were estimated assuming that the impedance in the positive, negative and zero sequences at the fault point were equal.

Voltage	Normal Clearing (Cycles)	Delayed Clearing (Cycles)
765	3	8
500	4	11
345	4	11
230 and below	6	18

Table 3-1: Generic Breaker Clearing Time

The following channels were monitored in Northern Area Transient Stability study:

- Key Generator Rotor Angle and speed
    - 89 machines
- Critical Bus Voltage
    - 131 buses
- Critical Bus Frequency
    - Monitor frequency across long transmission path
        - Dorsey – Forbes
        - Center – Arrowhead
        - Coal creek - Dickinson
- HVDC
    - DC voltage, current, active power and reactive power, AC voltage
- Synchronous Condenser
    - Bus Voltage and Y output
    - Forbes, Lake Yankton, Fargo and Watertown

Figure 3-2 shows the geographic location of the monitored channels; green circle indicates generators and orange circle indicates buses.

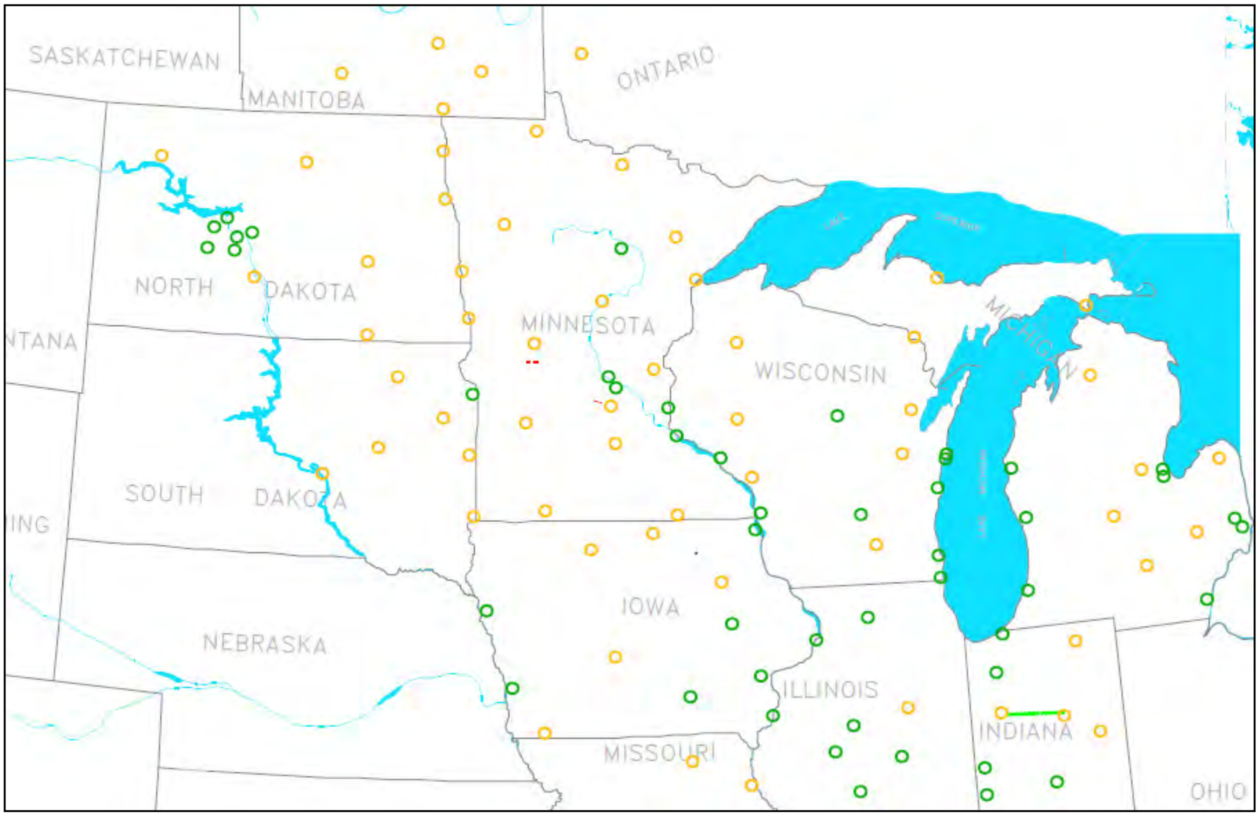


Fig. 3-2: Geographic Location of Monitored Channels

Simulation results were evaluated using the criteria in the MISO Members Reliability Criteria and Study Procedures Manual. Transient voltages were analyzed to be within the MISO default limits of 0.70-1.20 per unit with the exception of a few specific buses, areas, or companies that have different requirements. All machine rotor angle oscillations where evaluated to ensure they were positively damped with a minimum damping factor of 5% for disturbances with a fault or 10% for line trips without a fault.

4. Benefit and Cost Assumptions

Throughout the Northern Area Study, a common set of assumptions and formulas were used to calculate economic benefits. While there are multiple benefits to transmission projects such as wind curtailment reduction, improved system reliability, decreased line losses, and deferred capacity investment, the Northern Area Study economic benefits focused solely on adjusted production cost savings.

> Northern Area Study economic benefits were measured in adjusted production cost savings. Benefit-to-cost ratios were used to compare the cost effectiveness of options.

The Northern Area Study benefits were evaluated solely based on production cost savings. The broader economic values of a Multi-Value Project (MVP) were not considered in this study. The MVP Portfolio report identified a fuller range of economic values including congestion and fuel saving and reductions in operating reserves, system planning reserve margins, transmission line losses, and future transmission investment needed for reliability. Additionally other qualitative and social benefits were not explored including enhanced generation policy flexibility, increased system robustness, decreased variable generation volatility, local investment and job creation, and carbon reduction.

Adjusted Production Cost Savings

To calculate the economic benefit savings for transmission mitigation plans, two cases were defined 1) a base case and, 2) a project case. All aspects of the base case and project case were identical with the exception that the analyzed transmission solution was contained in the project case. Adjusted production cost was calculated. The difference in adjusted production costs between the base and project case is the adjusted production cost savings.

Adjusted production cost (APC) is the combined cost of fuel, emissions, variable operations, maintenance, etc. required for a generation fleet to produce energy, adjusted for import costs and export revenue. As transmission congestion is relieved, there is greater access to less expensive generation and thus adjusted production cost decreases.

Benefit to Cost Ratios

The purpose of a benefit to cost (B/C) ratio is to compare the cost-effectiveness of multiple projects. The benefits are the adjusted production costs savings for the MISO Market Footprint (weighted 100%). The cost is the capital cost of the project. A higher benefit to cost ratio indicates a more cost effective option.

When available, TRG supplied project costs were used for all Northern Area Study transmission options. The capital cost for options without a TRG supplied project cost were calculated using the generic $/mile costs in Table 4-1. The values in Table 4-1 were formulated by the Northern Area Study TRG after examining the actual costs and final estimates of transmission construction in their respective service territories. The costs in Table 4-1 are indicative in nature; actual costs associated with an individual project may significantly differ than those generically calculated because of factors including geography, right-of-way, environmental considerations, and project scope. Throughout this report generically calculated project costs are denoted with an asterisk (*).

Voltage (kV)	MN	DAK	WI	WI-ATC	UP	MI	IA
115	$1.00	$0.75	$1.10			$1.10	
138				$1.50	$1.50		
138-2				$1.60	$1.60		
161	$1.25	$0.90	$1.30				$1.10
230	$1.60	$1.25	$1.70			$1.20	
345	$2.70	$2.30	$2.90	$2.70	$2.50	$2.20	$2.20
345-2	$3.25	$3.00	$3.50	$3.00	$2.80	$2.75	$2.75
500	$3.20	$2.80	$3.40				
765	$4.00	$3.50	$4.50			$3.80	$3.80

Table 4-1: Generic Indicative Transmission Line Costs ($M-2012)

High voltage direct-current (HVDC) 500 kV costs were applied using a common set of generic $/mile assumptions. The Northern Area Study HVDC over land line cost assumption was $2.7M/mile – calculated as the average Northern Area Study footprint 345 kV $/mile which has similar line and right-of-way requirements as HVDC. Submarine cable under Lake Michigan used a TRG supplied project estimate of $7.3M/mile. All HVDC terminals pairs (source and sink), including voltage source convertors, were estimated at $400M. All project costs throughout this report are in year 2012 dollars unless specifically noted.

The in-service date for all Northern Area Study projects was assumed as year 2022. The benefits and costs applied in the benefit to cost (B/C) ratio calculations were the present value for the first twenty years of the project life after the in-service year. In the economic screening of all Northern Area Study options (Section 6) a single year 2027 PROMOD production cost simulation was performed to calculate the adjusted annual production cost benefits. The same inflation adjusted APC benefit was assumed for all twenty years of the project life. For Northern Area Study portfolios (Section 7), APC savings were also simulated for year 2022. The benefit savings for years between the simulated years were derived using linear interpolations. Net present value (NPV) APC savings were calculated using an 8.2% discount rate.

A MISO average transmission owner specific estimated annual charge rate (ACR) was used in the Northern Area Study to determine the annual cost of transmission projects. ACRs in year one of a project's in-service life in the Northern Area Study were 19.2%, and decline in each subsequent year as depreciation expense on the project is booked. The 2012 project costs were escalated to the in-service date's dollars using a 1.74% inflation rate. The B/C ratio was calculated by dividing the NPV benefits by the NPV annual costs.

Cross-border adjusted production cost savings were not included in any calculations.

5. Economic Potential Identification

The Northern Area Study identified $138 million to $9 million ($-2027) in potential production cost savings within the Northern Area Study footprint. The production cost savings potential for the Northern Area Study footprint is relatively small as a result of the MISO Multi-Value Project (MVP) Portfolio being assumed in-service, low natural gas prices, and relatively flat demand and energy growth rates. Three interfaces were identified to unlock the economic potential within the Northern Area Study footprint. This section details the economic potential and location as well as the process used in determining the potential.

There is a maximum of $138 million ($-2027) in annual production cost savings available from congestion relief in MISO's northern footprint

Generally, production cost savings potential for the Northern Area Study footprint was low as a result of the inclusion of the Multi-Value Project (MVP) portfolio approved in MTEP11, decreased demand growth rates, and low natural gas prices

Economic potential provides the magnitude of the production cost saving benefits from congestion relief and how to capture those benefits through transmission solutions. Production cost savings potential is determined by comparing a case which represents the status quo transmission system (constrained) to a modeled optimal transmission system (unconstrained). In the optimal transmission system or unconstrained case transmission limits are relaxed (allowed to go to plus or minus infinity); all other aspects of the constrained and unconstrained cases are identical including line impedances. The unconstrained case yields an optimal system generation dispatch without regard for how the energy gets to the sources.

The Northern Area Study unconstrained case relaxed all transmission constraints within the study footprint identified as the green area of Figure 5-1.

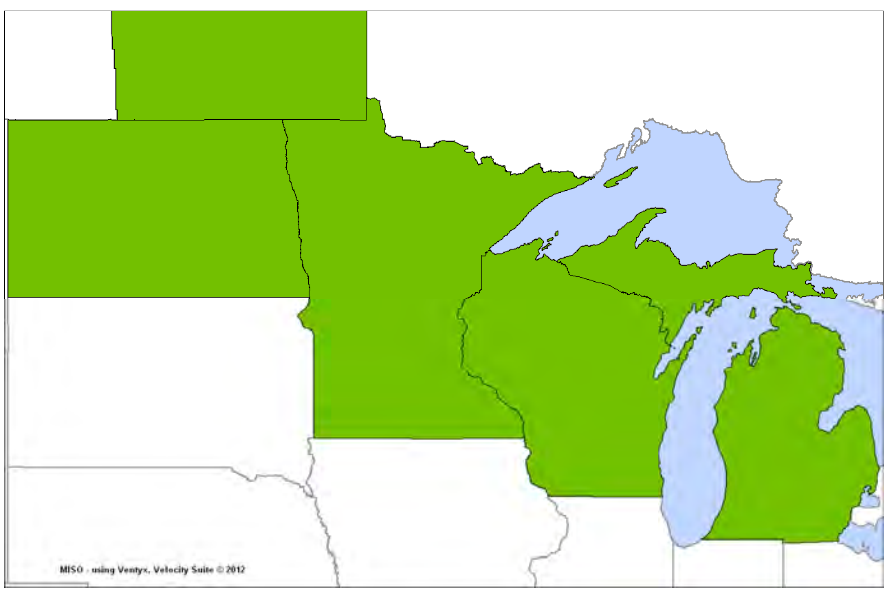


Figure 5-1: Northern Area Study Footprint

Economic potential provides a "road map" for transmission planning. Transmission line losses were ignored in the economic potential results to prevent the results from being skewed. Transmission line losses are considered in all other benefit calculations in the Northern Area Study.

Magnitude of Production Cost Savings Potential

The total maximum production cost savings potential to MISO in the Northern Area Study footprint is $138 - $9 million based on the assumptions used for this study. This value represents the total MISO production cost savings if all congestion were relieved within the green area in Figure 5-1.The distribution of maximum benefits by scenario are provided in Table 5-1.

Scenario	Business as Usual MISO APC Savings ($M-2027)	High Growth MISO APC Savings ($M-2027)	Low Growth MISO APC Savings ($M-2027)
No new Manitoba - MISO Tie-Line	35.7	137.6	8.6
Manitoba - Duluth Tie-Line	37.0	135.4	14.8
Manitoba – Fargo Area Tie-Line	28.2	120.3	8.7

Table 5-1: Maximum MISO Production Cost Savings Potential in Northern Area Study Footprint

The maximum production cost savings potential sets expectations and provides a budget for transmission development. A transmission development budget can be obtained by back calculating the maximum capital investment allowed to achieve a desired benefit to cost ratio.

Historically, through projects such as the Regional Generator Outlet Study (RGOS), Joint Coordinated System Plan (JCSP), and ultimately the MVP Portfolio, MISO has been able to capture 70% of the maximum production cost savings potential from transmission projects. The remaining 30% difference between captured production cost savings and maximum production cost savings potential represents areas where cost-effective mitigation is not possible and the little remaining congestion from a “non-gold plated” system.

Location of Adjusted Production Cost Savings Potential

The Northern Area Study identified three interfaces that account for the majority of the congestion relief opportunities within the study footprint. The mitigation of these three interfaces, identified in Figures 5-2 and 5-3, produces benefits nearly equal to the maximum production cost savings potential. All Northern Area Study scenarios displayed similar locational economic potential trends and therefore throughout this section a single scenario representative of all futures is displayed.

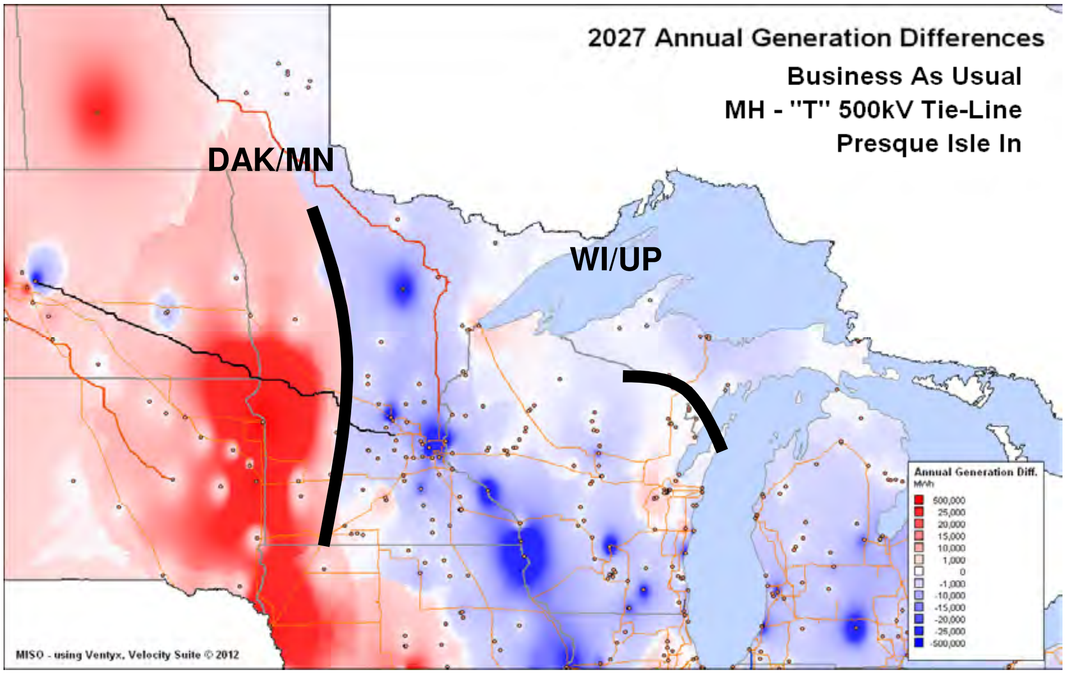


Figure 5-2: Northern Area Study Economic Potential Interfaces

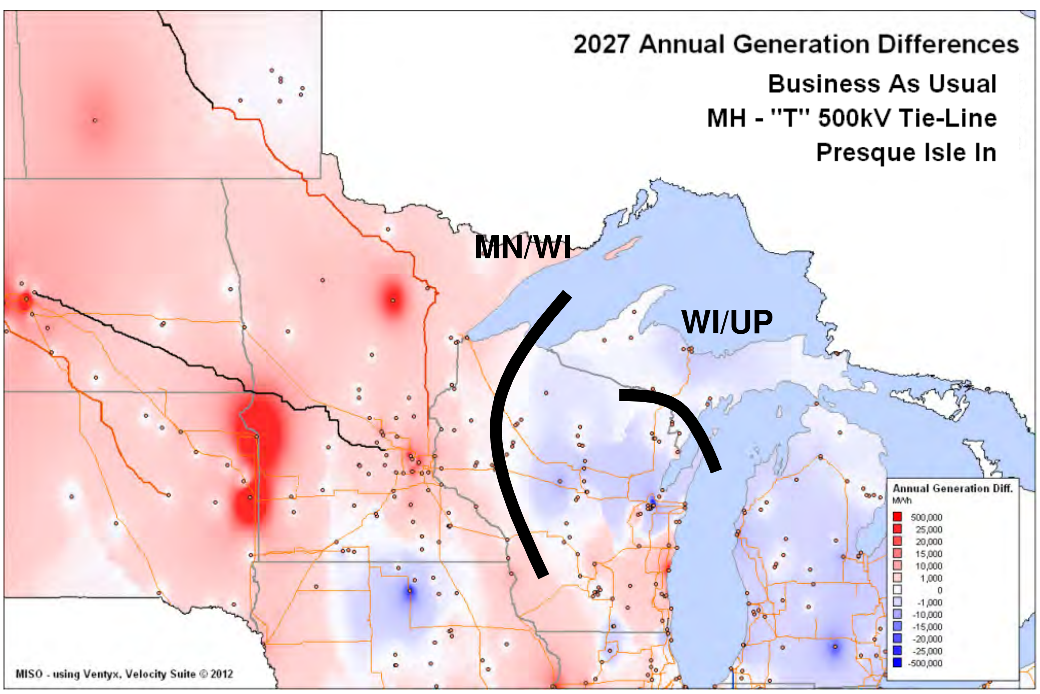


Figure 5-3: Northern Area Study Economic Potential Interfaces after DAK/MN Interface is Mitigated

Adjusted production cost savings are the result of less expensive generation sources replacing more expensive units in the dispatch. Generation differences or source and sink plots are used to identify areas that economically should generate more but cannot export because of transmission constraints and also areas that economically should generate less but cannot import. Source and sink plots are produced by calculating the annual generation difference (MWh) between the unconstrained/optimal dispatch case and constrained/status quo dispatch case for each generator. Export limited areas or “generation sources” are identified in red in Figures 5-2 and 5-3. Import limited areas or “generation sinks” are identified in blue in Figures 5-2 and 5-3. When a system is dispatched optimally there is no generation difference and all areas are displayed as white. Congestion interfaces are identified where the export limited (red) and imported limited (blue) areas collide. The severity of congestion is reflected in the intensity of red/blue – the darker the color the greater the congestion.

As shown in Figures 5-2 and 5-3, the Northern Area Study identified three congestion interfaces:

- **MN/DAK** - The Minnesota, North Dakota, and South Dakota border
- **WI/UP** – Lake Michigan
- **MN/WI** – The northern Minnesota and Wisconsin border; only present in Manitoba – Duluth tie-line scenarios.

Each interface is explored in more detail in the following sections.

5.1 Minnesota – Dakotas Economic Potential

The MN/DAK congestion interface is attributed to primarily wind resources in North and South Dakota trying to reach Twin Cities load centers and higher Eastern prices. The Northern Area Study models assume an additional 2,600 MW of forecast wind is sited at the Minnesota and Dakotas border (1,312 MW at Big Stone, 832 MW at Brookings County, 363 MW at Ellendale, and 132 MW at Ramsey) to meet 2027 state renewable portfolio standards and goals in the Business as Usual future. Wind was cited based upon a Planning Advisory Committee approved process. The MN/DAK flowgate congestion could change if either the magnitude or location of out-year wind resources was modified. The out-year interface congestion is contained within two transmission corridors Hankinson – Wahpeton 230 kV and Ortonville – Johnson Junction – Morris 115 kV. Table 5-2 displays the High Demand and Energy scenario's congestion report for limiting elements of this interface. Flowgate congestion was measured in terms of the number of binding hours and total shadow prices. Binding hours are the number hours an element is congested. Shadow price is the cost in dollars from relieving a constraint by 1 MW.

> Congestion on the Minnesota – Dakotas' border is primarily attributed to wind resources, and can be unlocked by adding 320 MW of additional capacity

Flowgate	Area	Total Binding Hours	Total Shadow Price ($k/MWh)
Hankinson - Wahpeton 230 kV FLO Bigstone - Blair 230 kV	OTP	1384	1384
Hankinson - Wahpeton 230 kV FLO Lakefield – Lakefield Jct. 345 kV	OTP	62	62
Johnson Jct. - Ortonville 115 kV FLO Bigstone - Blair 230 kV	GRE/OTP	997	997

Table 5-2: Congestion Report for Elements Limiting Flow from the Dakotas to Minnesota

The majority of Minnesota – Dakotas interface production cost savings potential can be unlocked with 320 MW in incremental transmission capability. Incremental transmission capacity was determined by summing the hourly flow differences between the unconstrained and constrained cases over all lines making up the interface for a year. The hourly incremental flows are arranged in descending order into a duration curve, as shown in Figure 5-4.

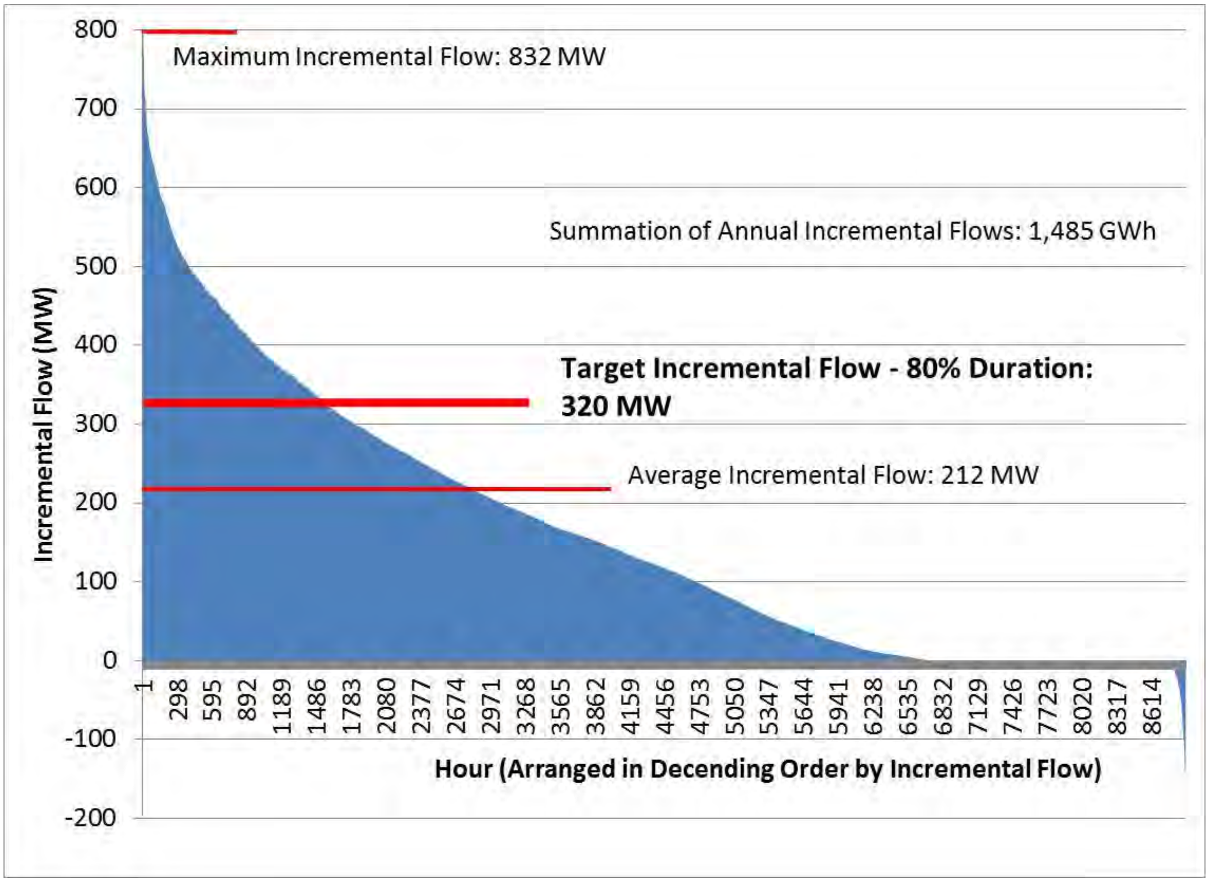


Figure 5-4: Annual Dakotas to Minnesota Incremental Interface Flow High Demand and Energy Future

The general industry target for economic transmission development is to build or upgrade transmission capable of capturing 80% of the annual incremental flows. Designing to the 80% standard allows development of expansion plans which promote economic market efficiency but also don't "gold plate" the system.

5.2 Wisconsin/Upper Peninsula Economic Potential

The Wisconsin/Upper Peninsula economic potential is attributed to energy trying to get from the West side of Lake Michigan to the East. Because of existing system impedances, the majority of energy is trying to get around the southern part of Lake Michigan through the Commonwealth Edison system; however, even within the existing system energy is trying to flow through Upper Michigan to Lower Michigan via the McGulpin Interface.

> Approximately 2,700 MW in incremental capability is needed to relieve congestion around Lake Michigan.

Flowgate	Area	Total Binding Hours	Total Shadow Price ($k/MWh)
McGulpin Interface	ATC/ITC	3925	27
Marengo - Pleasant Valley 138 kV FLO Cherry Valley-Silver Lake 345 kV	COMED	2649	610
Cherry Valley 345/138 kV Xfmr FLO Cherry Valley-Silver Lake 345 kV	COMED	1829	380
Oak Creek - St. Rita 138 kV FLO Racine - Elm Road 345 kV	ATC	507	63
ATC Flow South Interface	ATC	219	6
Albers - Kenosha 138 kV FLO Bain - Kenosha 138 kV	ATC	140	26

** Note: Displaying only top binding flowgates within Commonwealth Edison service territory*

Table 5-3: Congestion Report for Elements Limiting Flow across Lake Michigan

Incremental interface flows show that 2,700 MW incremental transmission capability would unlock the majority of the production cost savings potential associated with Lake Michigan congestion under all studied scenarios. Incremental transmission capacity was determined by summing the hourly flow differences between the unconstrained and constrained cases over all lines making up the interface for a year. The Northern Area Study Lake Michigan interface contained both the McGulpin Interface (UP to mainland MI) and the Wisconsin to Commonwealth Edison lines. Using the same process as shown in Figure 5-4, hourly incremental flows were arranged in descending order into a duration curve to determine the capability to capture 80% of the incremental flows (2,700 MW).The large geographic scope of this interface makes it difficult to define which lines are contained within the interface therefore, the incremental transmission capacity for this interface has a greater degree of uncertainty relative to the other interfaces.

5.3 Minnesota – Wisconsin Economic Potential

Under current stability limits, the Arrowhead – Stone Lake 345 kV line is congested in Manitoba – Duluth tie-line scenarios. Per TRG performed analysis, the Manitoba – Duluth tie-line increases the Arrowhead – Stone Lake 345 kV stability limit; increase has not been verified through MISO Operations study.

The Minnesota – Wisconsin congestion interface is present only in scenarios which include the Manitoba – Duluth 500 kV tie-line and increased imports from Manitoba Hydro. Under those scenarios, the Arrowhead – Stone Lake 345 kV line, part of the MWEX interface, is congested in out-year models assuming flows are limited to the stability limit as defined in the current MISO Operations Guide. Per TRG performed analysis, the Manitoba – Duluth 500 kV tie-line has the potential to increase the Arrowhead – Stone Lake 345 kV stability limit; however, such an increase has yet to be verified through a MISO operations study. The Northern Area Study analysis assumed the Arrowhead – Stone Lake 345 kV and MWEX interface ratings were unchanged from the levels defined in the current MISO Operations Guide for all base simulations and analysis. The stability limit increase from the TRG analysis was considered as a Northern Area Study option in Section 6.3 with the benefits quantified in the Northern Area Study.

Flowgate	Area	Total Binding Hours	Total Shadow Price ($k/MWh)
Arrowhead – Stone Lake 345 kV	MP/ATC	583	2.5

Table 5-3: Congestion Report for Elements Limiting Flow from Northern Minnesota to Wisconsin

Incremental interface flow analysis shows that the majority of the Arrowhead – Stone Lake 345 kV congestion could be mitigated with 250 MW in incremental capability. This 250 MW increase is still within the thermal limit of the Arrowhead – Stone Lake 345 kV conductor. Incremental transmission capacity was determined by summing the hourly flow differences between the unconstrained and constrained cases over the MWEX Interface. Using the same process as shown in Figure 5-4, hourly incremental flows were arranged in descending order into a duration curve to determine the capability to capture 80% of the incremental flows (250 MW).

6. Economic Evaluation of Transmission Options

The Northern Area Study individual transmission options could realize up to $84.4M in adjusted production cost savings with benefit to cost ratios ranging up to 14.7:1. The most cost-effective options mitigate out-year congestion from wind on the Minnesota/Dakotas border and were sub-345 kV. Additionally, the Northern Area Study analysis found economic benefits of equalizing Michigan LMPs; however, transmission options' adjusted production cost savings did not exceed costs under tested conditions. High-voltage direct-current (HVDC) and alternating-current (AC) solutions produced similar benefit to cost ratios in each of the scenarios – the decision on AC or DC should be based on factors outside of production cost savings.

> The most cost-effective options yielded a benefit to cost ratio up to 14:1 and were sub-345 kV

> The Northern Area Study analyzed 38 different TRG developed options to mitigate three congestion interfaces

The goal of the Northern Area Study was to find the best-fit transmission portfolios to unlock the economic potential and improve area reliability for the study footprint. To develop the best-fit portfolios, individual options were studied first for each of the three interfaces defined in Section 5. The most cost effective plans were further combined and analyzed as a portfolio in Section 7. Guided by the economic potential information, the TRG in collaboration with MISO staff developed a total of thirty-eight transmission options. Although this report presents a single final list, transmission options were developed and refined through multiple iterations.

To determine the cost effectiveness of each option, the adjusted production cost saving and associated benefit to cost ratio was calculated for each option using a year 2027 production cost simulation. Because there was little to no Northern Area Study system congestion or associated total production cost saving potential in the Low Demand and Energy (LDE) future, options were not simulated under the LDE future. It is recognized that under LDE conditions, little to no transmission development would be economically justified in terms of APC savings.

Additionally, pre and post congestion reports were provided to explain the adjusted production cost savings from congestion relief as well as line loading/capacity factors to provide an indication of size appropriateness of the transmission line. Line loading is calculated by summing the annual hourly absolute energy across a line and dividing by the line rating multiplied by 8760 hours/year. The targeted industry standard for alternating current (AC) line loading under normal operating conditions is 40-45%. Additionally, previous MISO studies indicate an 80% capacity factor is necessary for an HVDC line to be economically justified. The 40 – 45% and 80%, AC and HVDC, respectively, line loadings were used as targets throughout the Northern Area Study.

While cost justification was outside of the Northern Area Study scope, a benefit to cost ratio in excess of 1.25 or 1.25:1 was targeted.

The following sections detail the economic evaluation of each of the Northern Area Study transmission options. Options are organized by the interface congestion for which they were designed to mitigate.

6.1 Minnesota - Dakotas Solutions

The Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrade was the most cost-effective option to mitigate out-year congestion on the Dakotas – Minnesota border (B/C ratio 3.46 – 14.74 depending on scenario assumption)

The Northern Area Study concluded there are economic opportunities the mitigate the remaining out-year congestion from wind on the Minnesota and Dakotas border, as evident in Table 6-1.

Option	MISO APC Savings ($M – 2027)	Estimated Capital Cost ($M – 2012)	Benefit to Cost Ratio
Upgrade Hankinson – Wahpeton 230 kV, Big Stone – Morris 115 kV	15.1 – 64.3	22.2	3.46 – 14.74
Upgrade Hankinson – Wahpeton 230 kV, Big Stone – Morris 115 kV, new Morris – Alexandria 115 kV	15.2 – 63.3	67.2*	1.15 – 4.79*
Upgrade Hankinson – Wahpeton 230 kV (2010 TCFS), Big Stone – Morris 115 kV	16.5 – 75.0	41.6	2.02 – 9.17
Upgrade Hankinson – Wahpeton 230 kV (2010 TCFS), Big Stone – Morris 115 kV, 2nd Big Stone Transformer	16.1 – 84.4	49.7	1.65 – 8.64
Big Stone – Hazel Creek 345 kV	13.9 – 53.4	160.2	0.44 – 1.70
Big Stone – Alexandria 345 kV	19.2 – 78.9	150.6	0.65 – 2.67
Brookings – Hampton Corners 345 kV	11.3 – 28.0	160	0.36 – 0.89
Fargo – Monticello 345 kV	-	110	-
Corridor Project	6.2 – 13.2	375	0.08 – 0.18
Upgrade Square Butte – Arrowhead DC	0.5 – 3.3	175	0.01 – 0.10

Table 6-1: Summary of Economic Benefits of Minnesota – Dakotas Solutions

The Minnesota/Dakotas congestion interface is attributed to primarily wind resources in North and South Dakota trying to reach Twin Cities load centers and higher Eastern prices. The Northern Area Study models assume an additional 2,600 MW of forecast wind is sited at the Minnesota and Dakotas border (1,312 MW at Big Stone, 832 MW at Brookings County, 363 MW at Ellendale, and 132 MW at Ramsey) to meet year 2027 state renewable portfolio standards and goals in the Business as Usual future. Wind was cited based upon a Planning Advisory Committee approved process. The MN/DAK flowgate congestion could change if either the magnitude or location of out-year wind resources was modified. The out-year interface congestion is contained within two transmission corridors Hankinson – Wahpeton 230 kV and Ortonville – Johnson Junction – Morris 115 kV. The majority of Minnesota – Dakotas interface economic potential can be unlocked with 320 MW in incremental transmission capability.

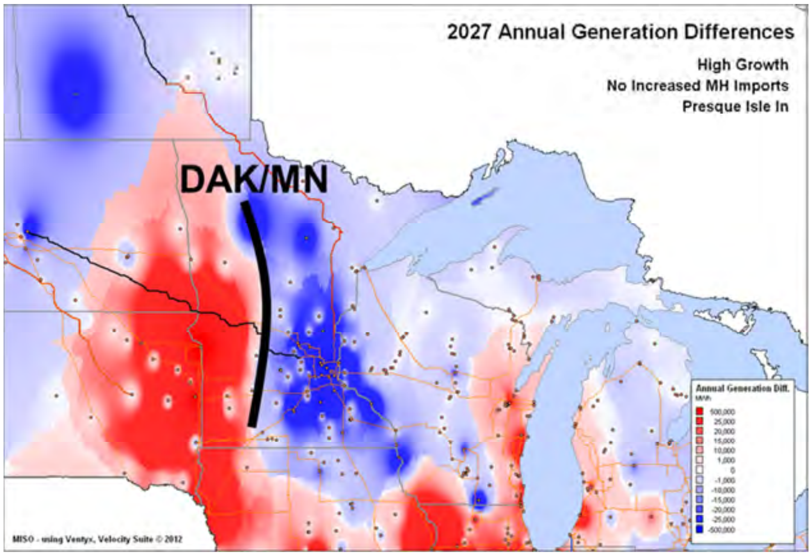


Figure 6-1: Dakotas – Minnesota Economic Potential Interface

In collaboration with the TRG, ten different options were developed to unlock the potential of this interface. The findings and economic benefits of each option are presented in the following sections.

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

Estimated Cost: $22.2M

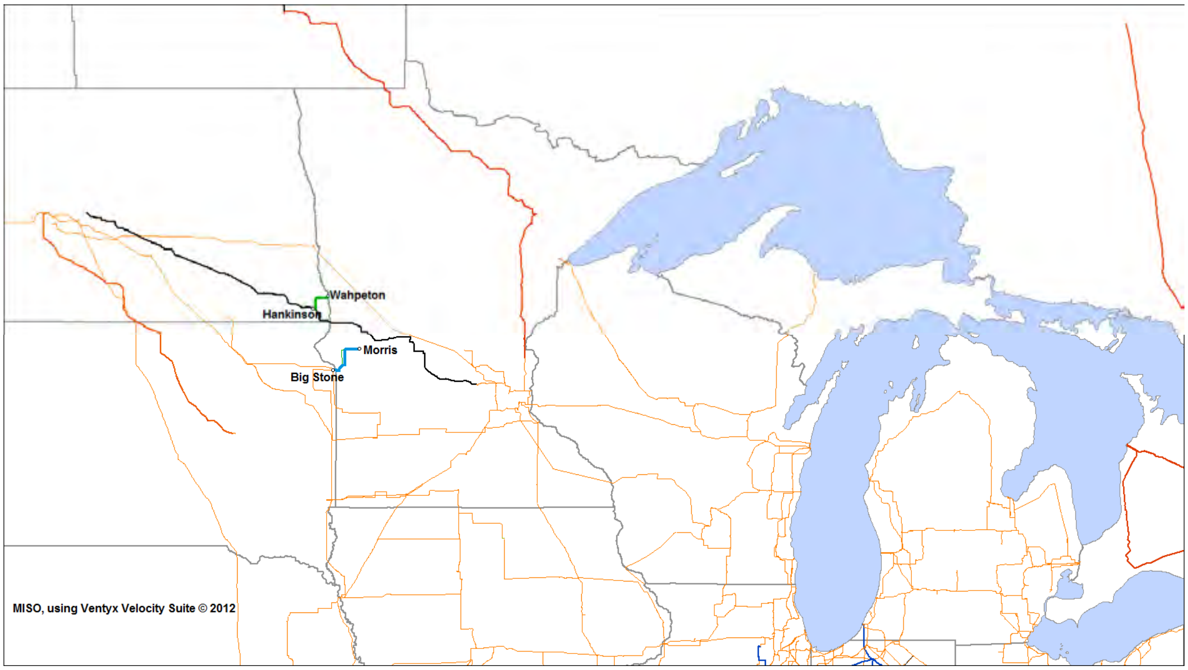


Figure 6-2: *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade*

The *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV Upgrade* was proposed by the TRG. The project upgrades the Big Stone – Morris 115 kV to 300 MVA and replaces the Wahpeton wave trap which allows the Hankinson – Wahpeton 230 kV rating to increase to 409 MVA.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	24.4	5.59
Business As Usual Demand, MH - Duluth Tie-Line	19.0	4.35
Business As Usual Demand, MH - Fargo Tie-Line	15.1	3.46
High Demand and Energy, No new MH Tie-Line	64.3	14.47
High Demand and Energy, MH - Duluth Tie-Line	62.8	14.41
High Demand and Energy, MH - Fargo Tie-Line	51.3	11.17

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-2: Economic Benefits of *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade*

As evident in Table 6-2, projected APC savings associated with the option are proportional to wind and load levels and therefore highest in the HDE future. Benefits exceed project costs in all scenarios evaluated, but were lower when the Manitoba - Fargo tie-line was in-service because the tie-line itself lessened the base area congestion. APC savings were attributed to a 75% reduction in congestion on the Hankinson – Wahpeton 230 kV flowgate and 100% reduction of the Johnson Jct. – Ortonville 115 kV flowgate. The Big Stone Transformer was the next limiting element. The line loading of Hankinson – Wahpeton and Big Stone – Morris was consistent across all scenarios at 60% and 25%, respectively.

Upgrade Hankinson - Wahpeton 230 kV to 2010 TCFS Rating and Upgrade Big Stone - Morris 115 kV

Estimated Cost: $41.6M

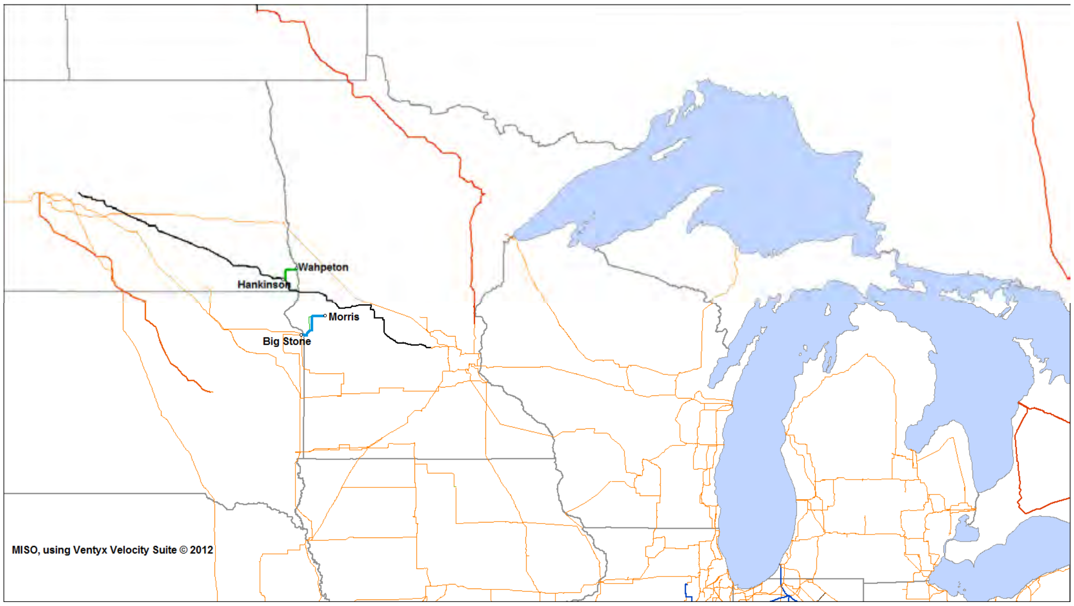


Figure 6-3: *Hankinson - Wahpeton 230 kV to 2010 TCFS & Big Stone - Morris 115 kV Upgrade*

The previous option, *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV Upgrade*, mitigated all the congestion on Johnson Jct. – Morris 115 kV; however, did not fully mitigate Hankinson – Wahpeton 230 kV. In an effort to mitigate additional congestion and increase APC savings, this option increases the Hankinson – Wahpeton 230 kV rating from 409 MVA to 674 MVA. The Big Stone – Morris 115 kV upgrade remains at 300 MVA.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	25.9	3.17
Business As Usual Demand, MH - Duluth Tie-Line	20.1	2.46
Business As Usual Demand, MH - Fargo Tie-Line	16.5	2.02
High Demand and Energy, No new MH Tie-Line	75.0	9.17
High Demand and Energy, MH - Duluth Tie-Line	69.3	8.48
High Demand and Energy, MH - Fargo Tie-Line	60.7	7.43

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-3: Economic Benefits of *Hankinson - Wahpeton 230 kV to 2010 TCFS & Big Stone - Morris 115 kV Upgrade*

Similar to the previous option, APC savings are proportional to wind and load levels and therefore highest in the HDE future and are lower when in the Manitoba-Fargo tie-line scenarios because of the lessened base congestion. This project fully mitigates the congestion on the Hankinson – Wahpeton 230 kV flowgate; however, the additional associated APC savings are do not exceed the additional costs – B/C ratios are relatively lower. This option further increases congestion on the Big Stone Transformer. The line loading of Hankinson – Wahpeton and Big Stone – Morris was consistent in all the futures at 35% and 25%, respectively.

Upgrade Hankinson - Wahpeton 230 kV to 2010 TCFS rating and Upgrade Big Stone - Morris 115 kV and Add 2nd Big Stone XFMR

Estimated Cost: $49.7M

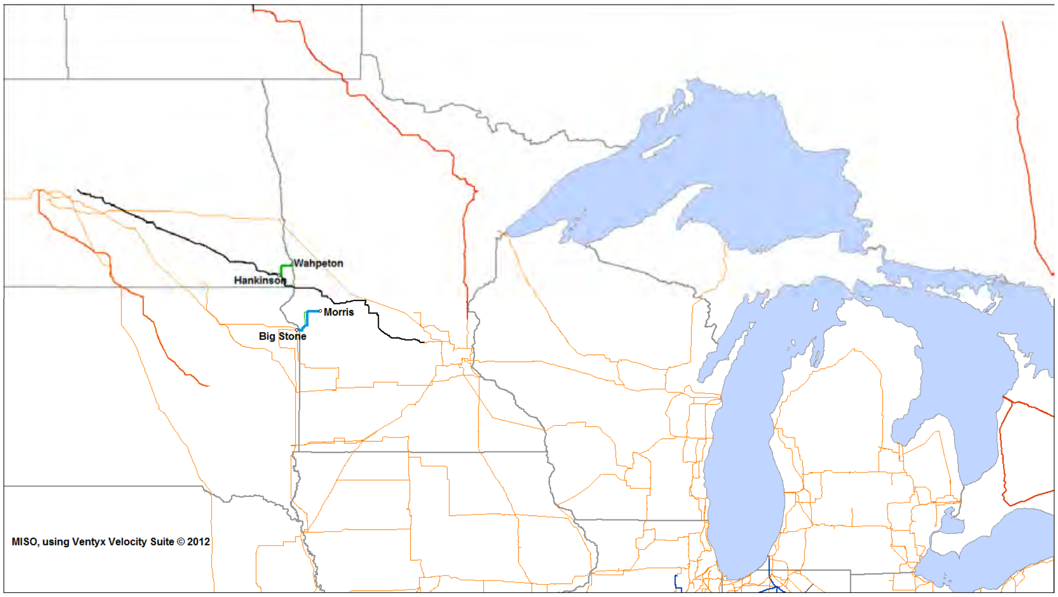


Figure 6-4: *Hankinson - Wahpeton 230 kV to 2010 TCFS & Big Stone - Morris 115 kV Upgrade and 2nd Big Stone Transformer*

The previous option which upgraded Hankinson - Wahpeton 230 kV rating and upgraded Big Stone - Morris 115 kV, mitigated all congestion on both Johnson Jct. – Morris 115 kV and Hankinson – Wahpeton 230 kV; however, increased congestion on the Big Stone Transformer. In an effort to mitigate additional congestion, this option adds a second Big Stone Transformer.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	26.1	2.67
Business As Usual Demand, MH - Duluth Tie-Line	20.3	2.08
Business As Usual Demand, MH - Fargo Tie-Line	16.1	1.65
High Demand and Energy, No new MH Tie-Line	84.4	8.64
High Demand and Energy, MH - Duluth Tie-Line	80.7	8.26
High Demand and Energy, MH - Fargo Tie-Line	70.5	7.22

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-4: Economic Benefits of *Hankinson - Wahpeton 230 kV to 2010 TCFS & Big Stone - Morris 115 kV Upgrade and 2nd Big Stone Transformer*

As evident in Table 6-4 and similar to the previous two projects, APC savings are proportional to wind and load levels and therefore highest in the HDE future and, are lower in the Manitoba-Fargo tie-line scenarios because of the lessened base congestion. This project fully mitigates the congestion on the Big Stone Transformer; however, the additional associated APC savings do not exceed the additional costs resulting in a decreased B/C ratio relative to previous upgrades. The line loading of Hankinson – Wahpeton and Big Stone – Morris were consistent across the futures at 35% and 25%, respectively.

Upgrade Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV; New Morris – Alexandria 115 kV

Estimated Cost: $67.2M* **Cost estimate based on generic $/mile cost*

Figure 6-5: ***Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade; Morris – Alexandria 115 kV***

The *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV upgrade and new Morris – Alexandria 115 kV*, builds upon the first option. This option directly connects Morris to the 345 kV system at Alexandria. Currently, Morris is connected to Alexandria via 115 kV with multiple intermediate branches and buses. This option adds a second Morris – Alexandria 115 kV circuit with direct routing. The Hankinson – Wahpeton 230 kV rating for this option is 409 MVA.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	24.4	1.85
Business As Usual Demand, MH - Duluth Tie-Line	19.1	1.45
Business As Usual Demand, MH - Fargo Tie-Line	15.2	1.15
High Demand and Energy, No new MH Tie-Line	63.3	4.79
High Demand and Energy, MH - Duluth Tie-Line	60.4	4.58
High Demand and Energy, MH - Fargo Tie-Line	50.6	3.83

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-5: Upgrade ***Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade; Morris – Alexandria 115 kV***

As evident in Table 6-4 and similar to the original project, APC savings are proportional to wind and load levels and therefore highest in the HDE future and are lower in the Manitoba - Fargo tie-line scenarios because of the lessened base congestion. In base models the existing 115 kV branches between Morris and Alexandria are not congested and adding the additional Morris – Alexandria 115 kV connection does not create APC savings from the upgrade alone.

Big Stone – Canby – Hazel Creek 345 kV

Estimated Cost: $160.2M

Figure 6-6: *Big Stone – Canby – Hazel Creek 345 kV*

The *Big Stone – Canby – Hazel Creek 345 kV* was proposed by TRG. The project adds a new 345/138 kV transformer at Canby and new 345 kV lines from Big Stone – Canby and Canby – Hazel Creek. APC savings are shown in Table 6-6.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	21.2	0.67
Business As Usual Demand, MH - Duluth Tie-Line	16.1	0.51
Business As Usual Demand, MH - Fargo Tie-Line	15.8	0.50
High Demand and Energy, No new MH Tie-Line	54.6	1.73
High Demand and Energy, MH - Duluth Tie-Line	52.7	1.67
High Demand and Energy, MH - Fargo Tie-Line	50.9	1.62

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-6: Economic Benefits of *Big Stone – Canby – Hazel Creek 345 kV*

Big Stone – Hazel Creek 345 kV APC savings are proportional to wind and load levels and therefore highest in the HDE future. Benefits exceed the project costs in only the High Demand and Energy future. APC savings were lower when the Manitoba-Fargo tie-line was in-service because the tie-line itself lessened the congestion seen on Johnson Jct. – Ortonville and Hankinson – Wahpeton. APC savings were directly attributed to a 75% reduction in congestion on the Hankinson – Wahpeton 230 kV flowgate and nearly 100% reduction of the Johnson Jct. – Ortonville 115 kV flowgate. The line loading of Big Stone – Canby – Hazel Creek was consistent in all futures at 25%.

Big Stone – Alexandria 345 kV

Estimated Cost: $150.6M** *Cost from 2010 TCFS*

Figure 6-7: *Big Stone – Alexandria 345 kV*

The *Big Stone – Canby – Hazel Creek 345 kV* option mitigated all Johnson Jct. – Morris 115 kV congestion; however, did not fully mitigate Hankinson – Wahpeton 230 kV. In an effort to mitigate additional Hankinson – Wahpeton 230 kV congestion, this option was reconfigured to *Big Stone – Alexandria 345 kV* with a new 345/138 kV transformer at Big Stone.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	26.9	0.91
Business As Usual Demand, MH - Duluth Tie-Line	20.4	0.69
Business As Usual Demand, MH - Fargo Tie-Line	19.2	0.65
High Demand and Energy, No new MH Tie-Line	78.9	2.67
High Demand and Energy, MH - Duluth Tie-Line	73.9	2.50
High Demand and Energy, MH - Fargo Tie-Line	63.4	2.14

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-7: Economic Benefits of *Big Stone – Alexandria 345 kV*

As evident in Tables 6-7 and 6-6, *Big Stone – Alexandria 345 kV* is more cost-effective than the previous 345 kV configuration of *Big Stone – Hazel Creek 345 kV*; however, projected benefits only exceed costs in High Demand and Energy scenarios. This project reduces congestion at the Hankinson – Wahpeton 230 kV flowgate by 90% and fully relieves the Johnson Jct. – Ortonville 115 kV flowgate. Similar to the DAK/MN interface options, APC savings are proportional to wind and load levels and therefore highest in the HDE future and are lower in the Manitoba-Fargo tie-line scenarios because of the lessened base congestion. The line loading of Big Stone – Alexandria was consistent across the futures at 20%.

Brookings – Hampton Corners 345 kV

Estimated Cost: $160M

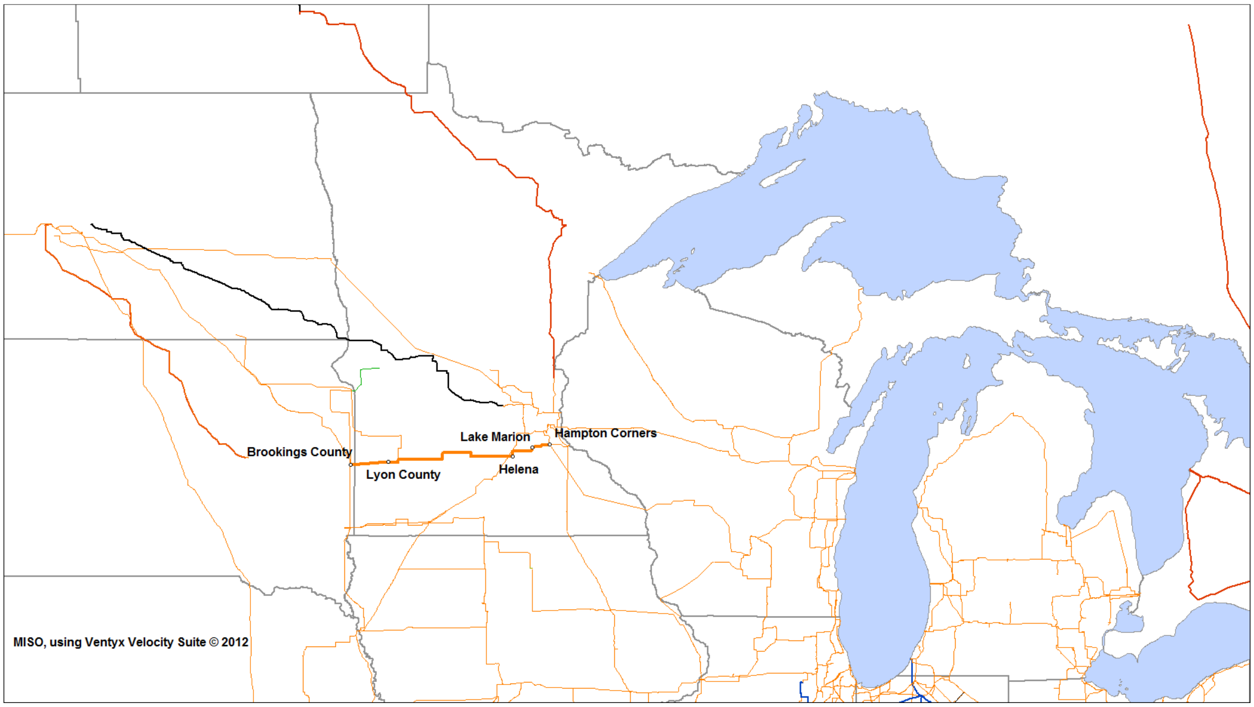


Figure 6-8: *Brookings – Hampton Corners 345 kV*

The TRG proposed, *Brookings – Hampton Corners 345 kV* double-circuits Brookings – Hampton 345 kV, and a second circuit of the Brookings – Lyon City 345 kV and Helena – Lake Marion – Hampton Corners 345 kV. APC savings are shown in Table 6-8.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	15.2	0.48
Business As Usual Demand, MH - Duluth Tie-Line	11.4	0.36
Business As Usual Demand, MH - Fargo Tie-Line	11.3	0.36
High Demand and Energy, No new MH Tie-Line	28.0	0.89
High Demand and Energy, MH - Duluth Tie-Line	26.6	0.85
High Demand and Energy, MH - Fargo Tie-Line	22.3	0.71

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-8: Economic Benefits of *Brookings – Hampton Corners 345 kV*

Brookings – Hampton Corners 345 kV option reduces Hankinson – Wahpeton 230 kV and the Johnson Jct. – Ortonville 115 kV flowgate congestion by 50%; however, projected APC savings for the option do not exceed estimated costs under any studied scenario. The line loading of *Brookings - Hampton Corners 345 kV* ranged 15 – 20% depending on the scenario.

Fargo – Monticello 345 kV (Second Circuit)

Estimated Cost: $110M

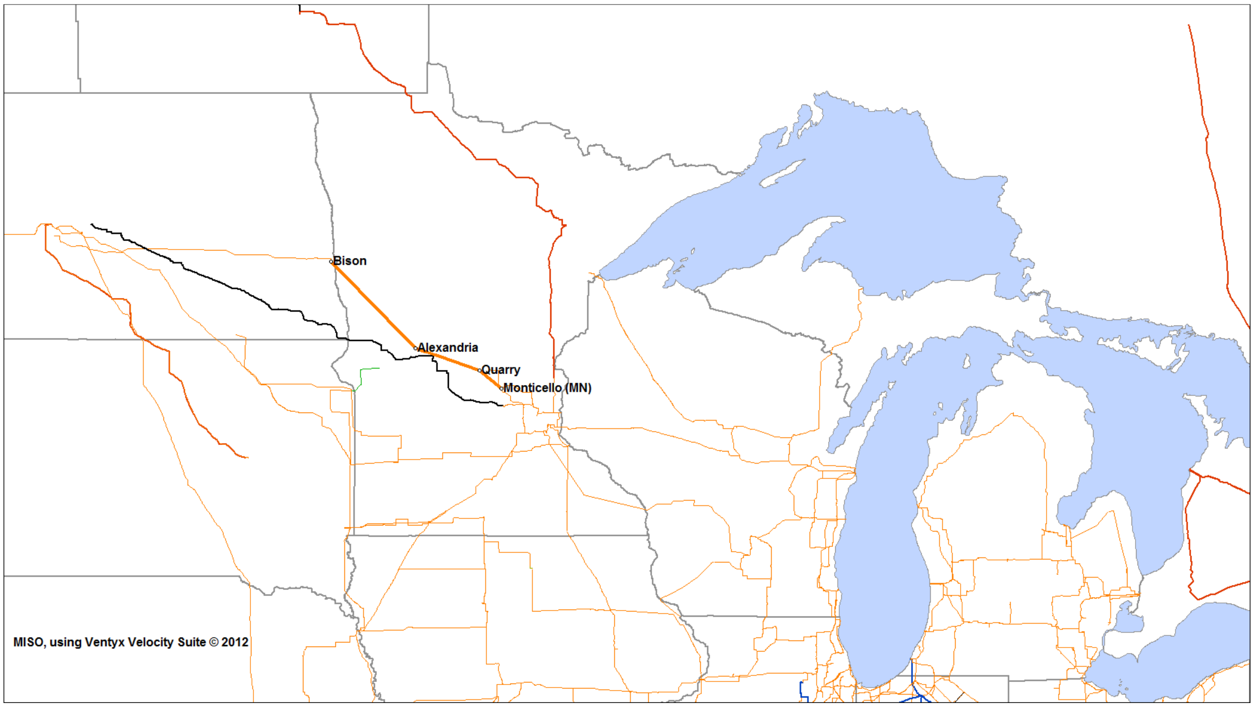


Figure 6-9: ***Fargo – Monticello 345 kV (Second circuit – First circuit is currently under construction***

The *Fargo – Monticello 345 kV (Second Circuit)* was proposed by the TRG. The project adds a second conductor to the existing Bison – Alexandria – Quarry - Monticello 345 kV structure and right-of-way. This option is included as part of the Manitoba – Fargo tie-line and therefore not analyzed under that scenario. The benefit savings of the Manitoba – Fargo tie-line are calculated in the Manitoba Hydro Wind Synergy Study.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	Included in Scenario	Included in Scenario
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	Included in Scenario	Included in Scenario

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-9: Economic Benefits of *Fargo – Monticello 345 kV (Second Circuit)*

There is little to no projected APC savings associated with this option when there is no new MH tie-line or after development of a MH – Duluth tie-line. Under the other tie-line scenarios the existing single circuit is not congested in the pre-project case due to a line loading less than 10%.

Corridor Project: Convert Hazel – Blue Lake from 230 kV to 345 kV

Estimated Cost: $375M

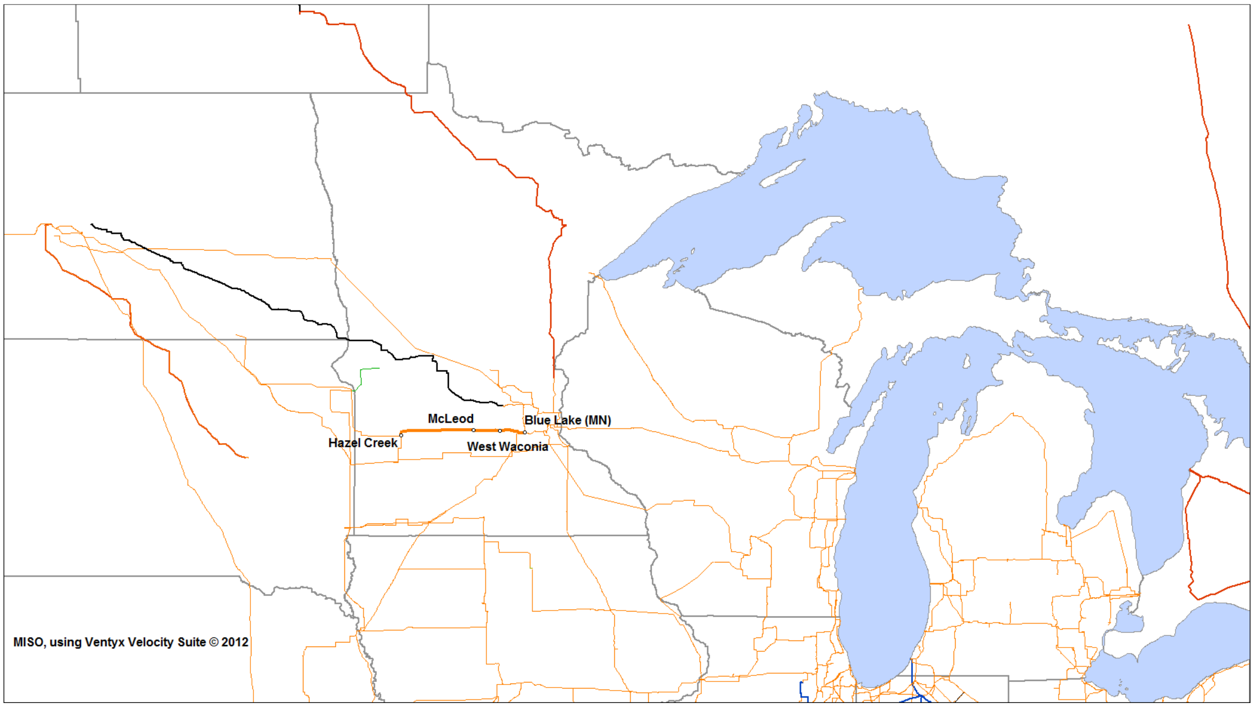


Figure 6-10: *Corridor Project*

The TRG proposed, "*Corridor Project*" (MTEP Project #2177) converts the existing Minnesota Valley - Panther - McLeod - Blue Lake 230 kV line to double circuit 345 kV from Hazel Creek - McLeod - West Waconia - Blue Lake.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	7.2	0.10
Business As Usual Demand, MH - Duluth Tie-Line	6.2	0.08
Business As Usual Demand, MH - Fargo Tie-Line	6.2	0.08
High Demand and Energy, No new MH Tie-Line	12.7	0.17
High Demand and Energy, MH - Duluth Tie-Line	13.2	0.18
High Demand and Energy, MH - Fargo Tie-Line	10.2	0.14

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-10: Economic Benefits of *Corridor Project*

As evident in Table 6-10, the APC savings of the *Corridor Project* did not exceed the project costs under any of the tested conditions. The project reduces congestion by 25% on the Hankinson – Wahpeton 230 kV flowgate and provides minimal congestion relief on the Johnson Jct. – Ortonville 115 kV flowgate. APC savings are proportional to wind and load levels and therefore highest in the HDE future. The line loading of Hazel – Blue Lake was consistent across the futures at 15%.

Square Butte – Arrowhead DC Upgrade

Estimated Cost: $175M

Figure 6-11: *Square Butte – Arrowhead DC Upgrade*

The *Square Butte – Arrowhead DC Upgrade* was proposed by the TRG which upgrades the existing Square Butte – Arrowhead HVDC line to 750 MW capacity. APC savings are shown in Table 6-11.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	3.3	0.10
Business As Usual Demand, MH - Duluth Tie-Line	0.5	0.01
Business As Usual Demand, MH - Fargo Tie-Line	2.4	0.07
High Demand and Energy, No new MH Tie-Line	1.2	0.03
High Demand and Energy, MH - Duluth Tie-Line	1.4	0.04
High Demand and Energy, MH - Fargo Tie-Line	0.9	0.03

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-11: Economic Benefits of *Square Butte – Arrowhead DC Upgrade*

APC savings associated with HVDC lines are proportional to the LMP differences between the sending and receiving ends of the line. Under projected 2027 scenarios there is not adequate LMP differences between Square Butte (36.1$/MWh – average annual BAU MH – Duluth tie-line scenario) and Arrowhead (37.3$/MWh) to make the project cost-effective. The Square Butte – Arrowhead HVDC line has little effect on system congestion. The line loading of Square Butte – Arrowhead HVDC was consistent across the futures at 90+%.

6.2 Wisconsin/Upper Peninsula Solutions

There is adjusted production cost savings associated with building additional paths around Lake Michigan; however, because of the high cost of the transmission, options were not cost-effective in the conditions tested

The Wisconsin/Upper Peninsula economic potential is attributed to energy trying to get from the West to the East side of Lake Michigan. There are adjusted production cost savings associated with building additional paths around Lake Michigan and equalizing Michigan LMPs; however, because of the high cost of transmission, options were not cost effective in the conditions tested. As evident in Table 6-12 high-voltage direct-current (HVDC) options were as cost effective as similar alternating-current (AC) options.

Option	MISO APC Savings ($M – 2027)	Estimated Capital Cost ($M – 2012)	Benefit to Cost Ratio
Morgan – Plains - National 345 kV	-	405	-
Gardener Park – Plains - National 345 kV	-	500	-
Morgan – Arnold 345 kV and Plains – National 345 kV	-	487*	-
Arnold – Livingston 345 kV (South Route)	6.1 – 20.4	537.6	0.06 – 0.19
Morgan – Livingston 345 kV (Extended South Route)	5.1 – 23.4	843.8*	0.03 – 0.14*
National – Livingston 345 kV (Direct Route)	4.9 – 16.5	606.7*	0.04 – 0.14*
National – Livingston 345 kV (North Route)	4.3 – 18.4	686.2	0.03 – 0.14
Marquette – Mackinac County 138 kV	2.5 – 15.5	262.85	0.05 – 0.30
Low Voltage Northern Wisconsin Upgrade	-	375.8	-
Hiple to Duck Lake 345 kV	2.1 – 6.1	259.3*	0.04 – 0.12*
DC Option: Kewaunee – Ludington 500 kV	19.6 – 67.9	872	0.11 – 0.40
DC Option: Pleasant Prairie – Palisade 500 kV	3.1 – 19.0	981*	0.02 – 0.10*
DC Option: Madison – Tallmadge 500 kV	24.6 – 77.4	1251*	0.10 – 0.31*

Table 6-12: Summary of Economic Benefits of Wisconsin/Upper Peninsula Solutions

Incremental interface flows show that a 2,700 MW incremental transmission capability would unlock the majority of the economic potential associated with Lake Michigan congestion under all studied scenarios.

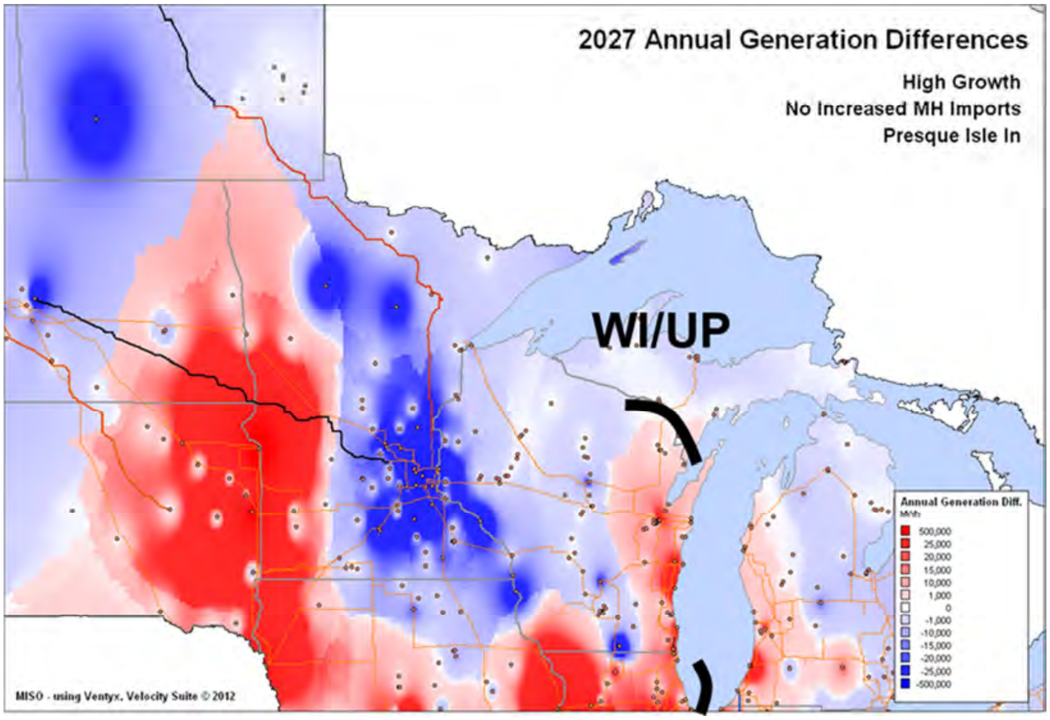


Figure 6-12: Lake Michigan Economic Potential Interface

Thirteen different transmission options were developed to mitigate the congestion around Lake Michigan. The findings and economic benefits of each option are presented in the following sections.

Morgan – Plains – National 345 kV

Estimated Cost: $405M

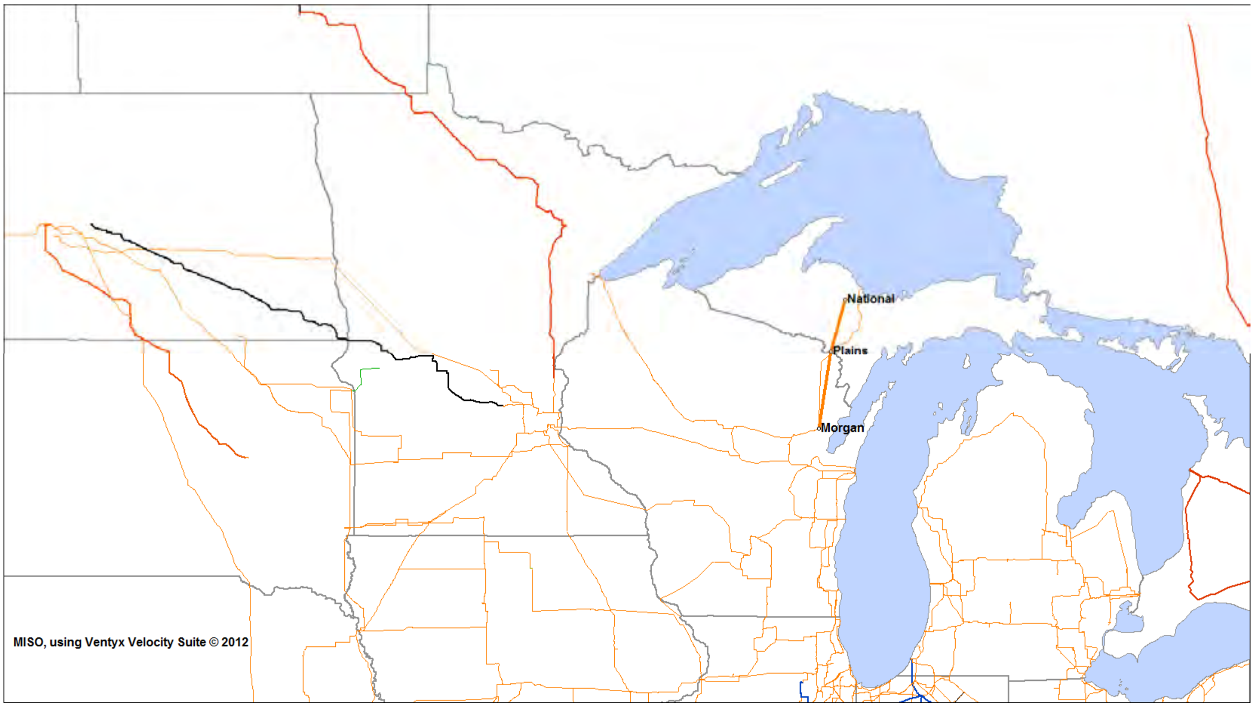


Figure 6-13: *Morgan – Plains – National 345 kV*

Morgan – Plains – National 345 kV was proposed by the TRG and is the combination of two projects contained in the MTEP Project Database, corresponding to Project ID's 3838 and 3950. The project consists of double circuiting the existing Morgan – Plains 345 kV and adding a new 345 kV line from Plains – National. This project was designed to capture stability and economic benefits associated with the retirement of Presque Isle; however on November 27, 2012 We Energies and Wolverine Power Cooperative announced that the plant will remain operational.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-13: Economic Benefits of *Morgan – Plains – National 345 kV*

As evident in Table 6-13 APC savings are minimal for all futures, resulting in APC savings that do not exceed project costs. The existing system is not congested for these futures with Presque Isle in-service. The line loading of Morgan – Plains and Plains – National were consistent across the futures at less than 5%.

Gardener Park – National 345 kV

Estimated Cost: $500M

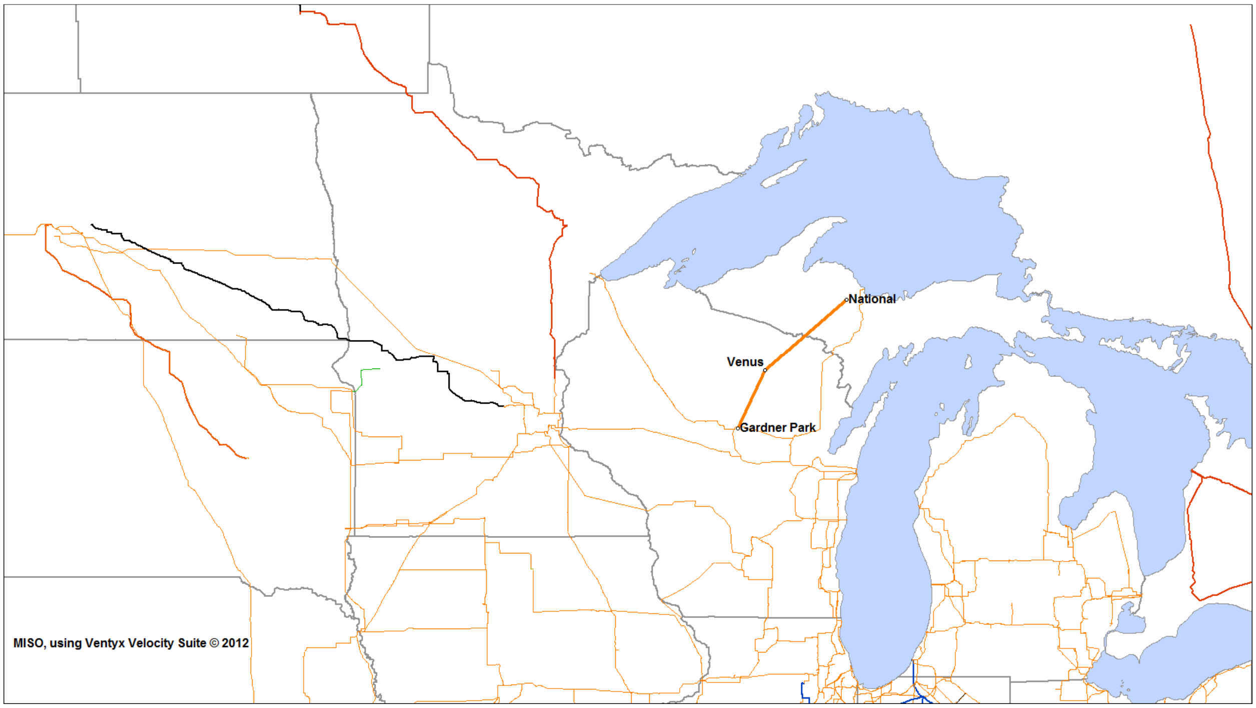


Figure 6-14: *Gardener Park – National 345 kV*

The TRG proposed *Gardener Park – National 345 kV* (MTEP Project ID 3681), consisting of a new 345 kV line from Gardner Park – Venus – National. This project, similar to the previous project, was designed to mitigate reliability issues and capture economic benefits associated with the retirement of Presque Isle Plant. APC savings are shown in Table 6-14.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-14: Economic Benefits of *Gardener Park – National 345 kV*

Projected APC savings associated with *Garner Park – National 345 kV* are minimal for all studied scenarios. The existing system is not congested for these futures resulting in little change in system congestion.

Morgan – Arnold 345 kV and Plains – National 345 kV

Estimated Cost: $487M* *Cost estimate based on generic $/mile cost*

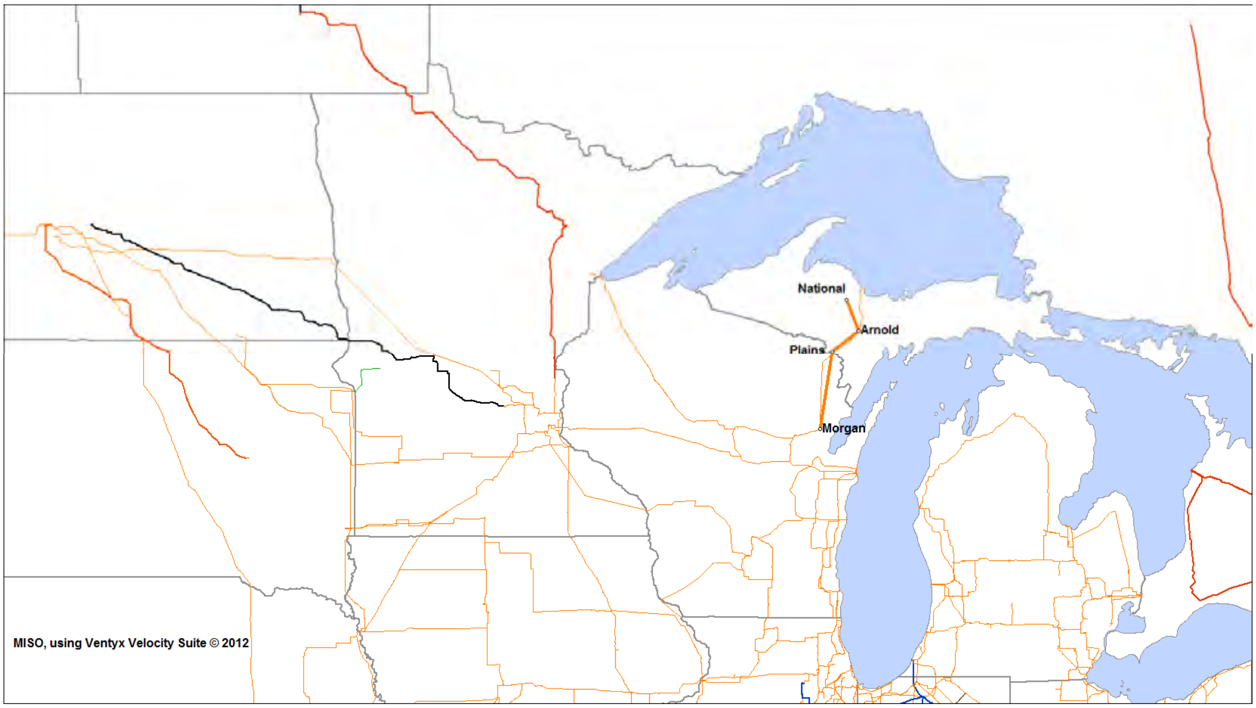


Figure 6-15: *Morgan – Arnold 345 kV and Plains – National 345 kV*

Morgan – Arnold 345 kV and Plains – National 345 kV was proposed by the TRG and consists of a direct Morgan – Arnold 345 kV line and direct Plains – National 345 kV line. Similar to the previous two projects, this project was designed to capture stability and economic benefits associated with the retirement of Presque Isle.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-15: Economic Benefits of *Morgan – Arnold 345 kV and Plains – National 345 kV*

As evident in Table 6-15, APC savings are minimal for all studied scenarios. The existing system is not congested in these scenarios resulting in little change in system congestion.

National/Arnold – Livingston 345 kV

Estimated Cost: $537.6M – 686.2M

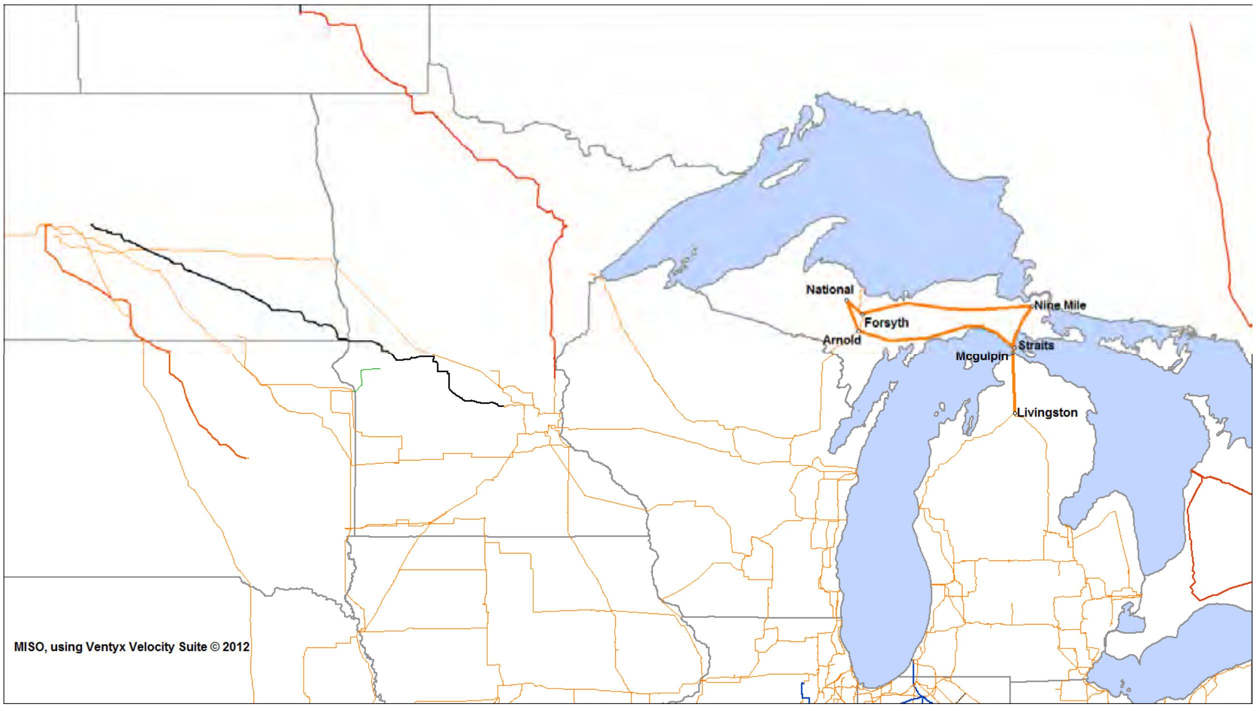


Figure 6-16: *National/Arnold – Livingston 345 kV* (North, South or Direct Route)

The *National/Arnold – Livingston 345 kV* options were designed to capture the economic benefits of transmitting power around Lake Michigan and originated as three different options proposed by the TRG: North, South, and Direct options. Because of their similar economic potential, the three were combined into a single indicative 345 kV Upper Peninsula line. The final routing decision of the line should be based upon factors outside the scope of the Northern Area Study. Without the retirement of the Presque Isle plant there was no economic difference in sourcing between National or Arnold.

The original North Route, National – Forsyth – Nine Mile – Straits - McGulpin – Livingston 345 kV represents the combination of MTEP Project Database entries with Project ID's 3819 (National – Livingston 345 kV) and 3838 (National Substation). The North Route includes a 138 kV step-down at Nine Mile. The South Route (MTEP Project ID 3820), is a 345 kV line from Arnold - Hiawatha – Straits - McGulpin – Livingston and a step-down transformer at Hiawatha. The Direct Route includes a conceptual line directly connecting National – Livingston 345 kV. With all National options a pair of step-up transformers were included.

These options assume that the ATC Flow South Interface is allowed to exceed its current stability limit of 500 MW. The addition of a new 345 kV line through the UP could change the operating scheme from the current which is focused on serving local load to transportation – with such change new operating limits would be established and if necessary mitigation plans placed in service. The study to re-establish the stability rating of the ATC Flow South interface was outside the scope of the Northern Area Study and therefore not performed. The Northern Area Study did not include any cost adders to the proposed project costs to unlock the ATC Flow South Stability limitation. As shown in Figure 6-17 approximately 200 MW of additional interface capacity is needed to unlock the flowgate.

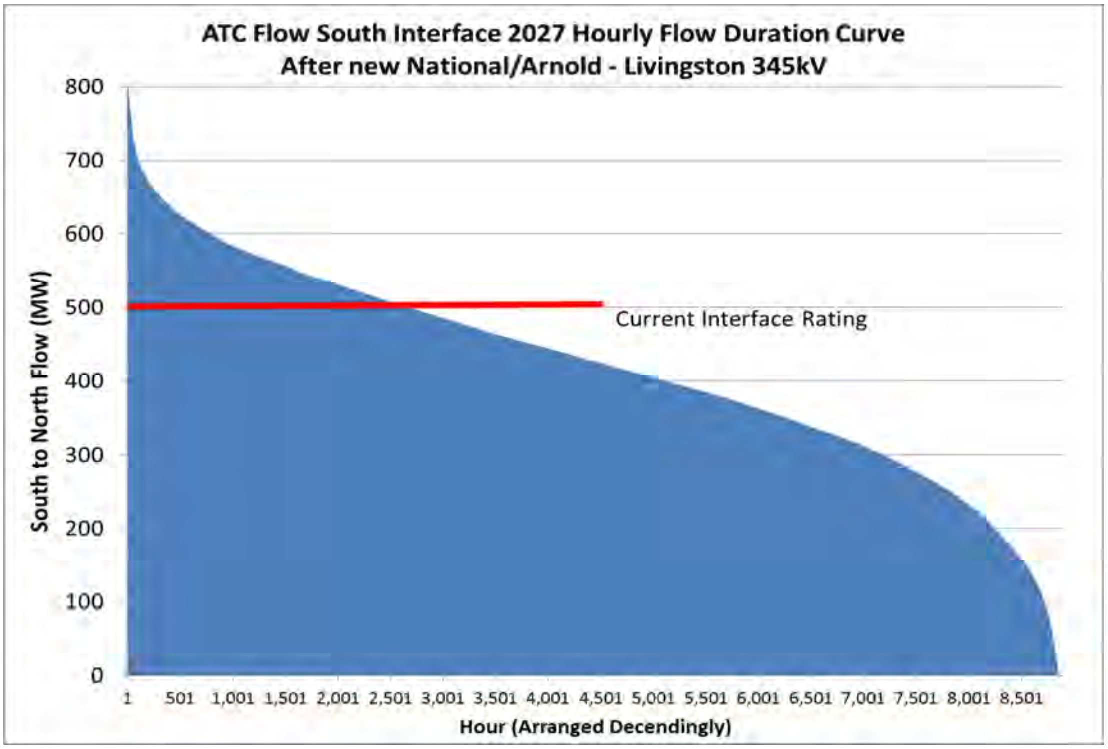


Figure 6-17: ATC Flow South Interface Hourly Flow Curve for *National/Arnold – Livingston 345 kV*

The range of APC savings for the combined three options are shown in Table 6-16.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	4.3 – 6.3	0.03 – 0.06
Business As Usual Demand, MH - Duluth Tie-Line	5.3 – 6.1	0.04 – 0.06
Business As Usual Demand, MH - Fargo Tie-Line	4.9 – 7.7	0.04 – 0.07
High Demand and Energy, No new MH Tie-Line	14.9 – 18.1	0.12 – 0.17
High Demand and Energy, MH - Duluth Tie-Line	16.5 – 20.4	0.14 – 0.19
High Demand and Energy, MH - Fargo Tie-Line	15.7 – 19.0	0.12 – 0.18

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-16: Economic Benefits of *National/Arnold – Livingston 345 kV*

National/Arnold – Livingston 345 kV APC savings are proportional to UP load levels and therefore highest in the HDE future, however, benefits do not exceed the project costs in the tested condition. *National/Arnold – Livingston 345 kV* lines bypass the McGulpin Interface and also help to decrease the congestion around the south of Lake Michigan.

The Northern Area Study also evaluated the cost effectiveness of adding a phase shifter located at Livingston. Under this configuration, the line loading increased to ~15%; however the benefit increase was proportional to the cost increase – neutral B/C ratio.

Morgan – Livingston 345 kV

Estimated Cost: $843.8M* *Cost estimate based on generic $/mile cost*

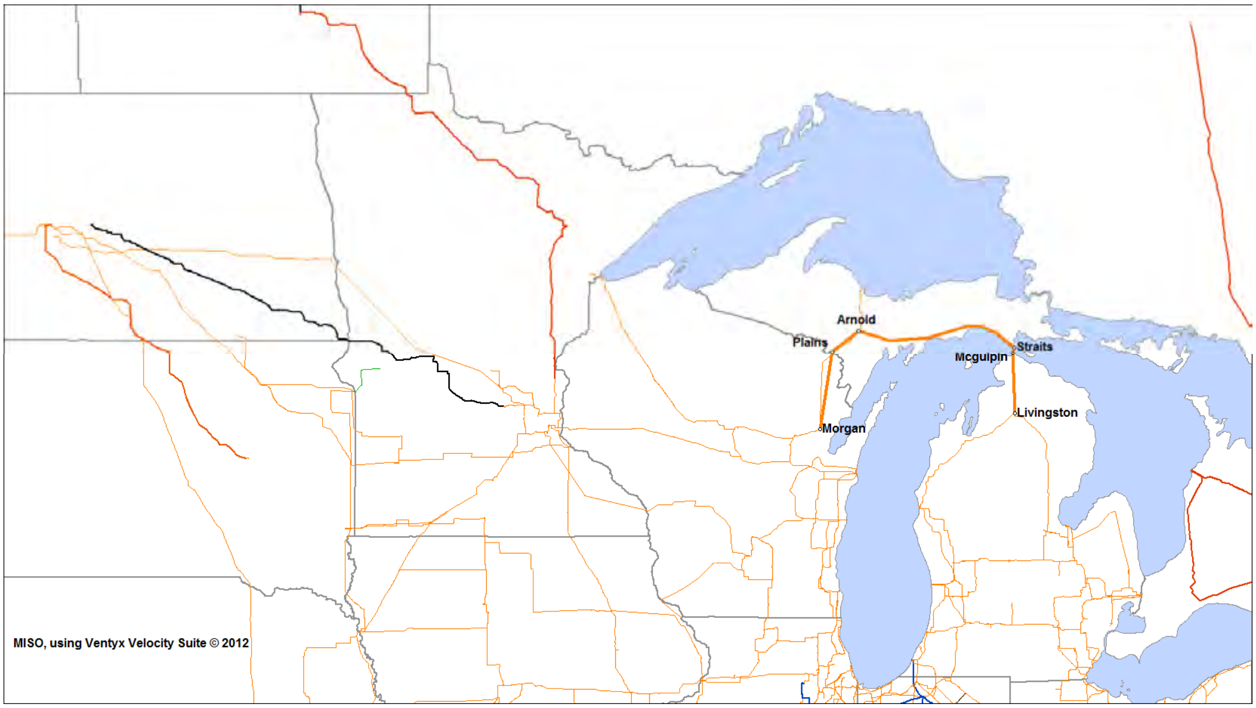


Figure 6-18: *Morgan – Livingston 345 kV*

Morgan – Livingston 345 kV extends the previous *Arnold – Livingston 345 kV* to Morgan via a second Morgan – Plains 345 kV branch. This project in itself mitigates the ATC Flow South interface and therefore the current ATC Flow South stability limit was observed.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	6.6	0.04
Business As Usual Demand, MH - Duluth Tie-Line	5.1	0.03
Business As Usual Demand, MH - Fargo Tie-Line	7.2	0.04
High Demand and Energy, No new MH Tie-Line	19.8	0.12
High Demand and Energy, MH - Duluth Tie-Line	23.4	0.14
High Demand and Energy, MH - Fargo Tie-Line	22.6	0.14

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-17: Economic Benefits of *Morgan – Livingston 345 kV*

As evident in Tables 6-17 and 6-16, extending the UP circuit to Morgan slightly increases APC savings compared to the circuit alone; however, the incremental benefits do not exceed the incremental costs – B/C ratios decrease. Incremental benefits are attributed to the mitigation of the ATC Flow South interface. Similar to the previous project, APC savings are proportional to load levels and therefore highest in the HDE future. The line loading of Morgan – Arnold and Arnold – Livingston were consistent across the futures at 5% and 15%, respectively.

Marquette – Mackinac County 138 kV

Estimated Cost: $262.85M

Figure 6-19: *Marquette – Mackinac County 138 kV*

The TRG proposed *Marquette – Mackinac County 138 kV* (MTEP Project ID 3678) upgrades the native system shown in Figure 6-19 to 138 kV which in-turn allows the Straits Back-to-Back DC Converter to operate at its thermal limit of 200 MVA – previously limited to 40 MVA from North to South. This project assumes that the ATC Flow South Interface is allowed to exceed its current stability limit as explained under the National/Arnold – Livingston 345 kV option. APC savings are shown in Table 6-18.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	4.2	0.08
Business As Usual Demand, MH - Duluth Tie-Line	2.5	0.05
Business As Usual Demand, MH - Fargo Tie-Line	4.3	0.08
High Demand and Energy, No new MH Tie-Line	14.2	0.27
High Demand and Energy, MH - Duluth Tie-Line	15.5	0.30
High Demand and Energy, MH - Fargo Tie-Line	14.8	0.29

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-18: Economic Benefits of *Marquette – Mackinac County 138 kV*

Marquette – Mackinac County 138 kV increases the McGulpin Interface limits to the thermal ratingand therefore provides additional power transfer around Lake Michigan. This project provides approximately half of the economic benefits of the 345 kV UP options; however, due to lower cost the associated B/C ratios are relatively higher. APC savings are proportional to load levels and therefore highest in the HDE future.

Low Voltage Northern Wisconsin Upgrade

Estimated Cost: $375.8M

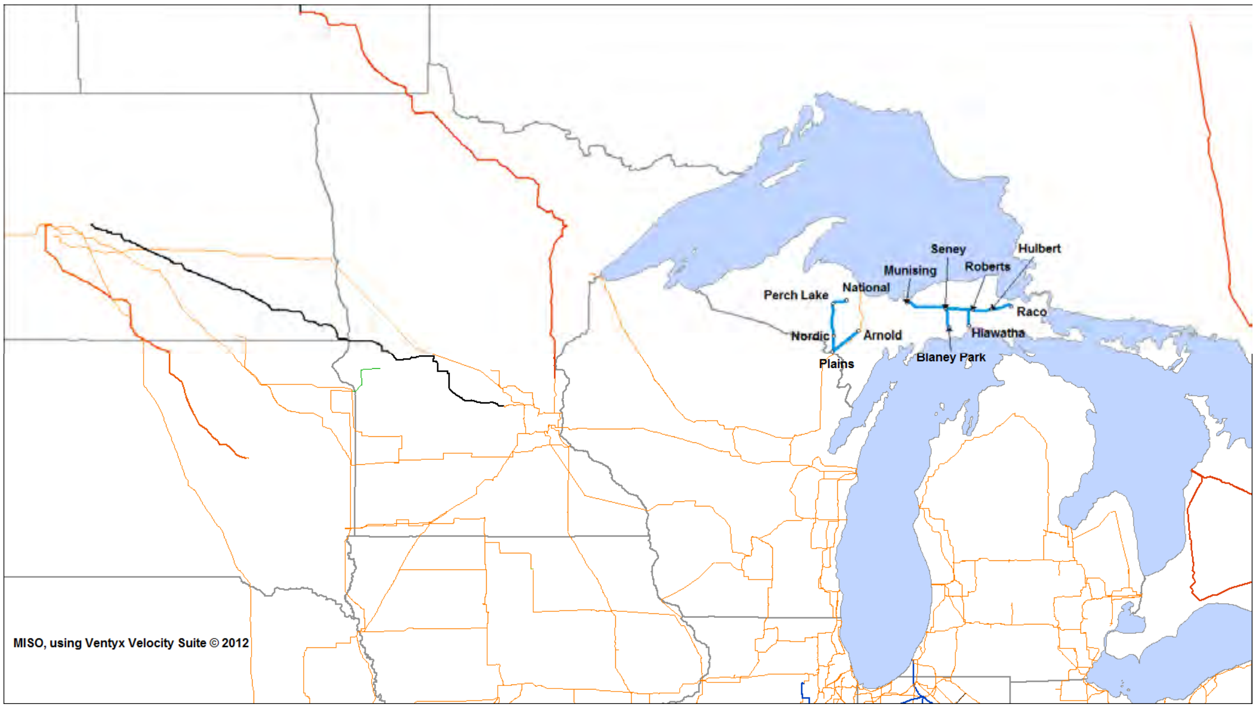


Figure 6-20: *Low Voltage Northern Wisconsin Upgrade*

The *Low Voltage Northern Wisconsin Upgrade* was proposed by the TRG to improve area reliability. The project consists of upgrading the native system to 138 kV in Figure 6-20. The upgrades do not change the proposed operating limits of the Straits Back-to-Back DC Converter. APC savings are shown in Table 6-19.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-19: Economic Benefits of *Low Voltage Northern Wisconsin Upgrade*

Because the *Low Voltage Northern Wisconsin Upgrade* does not increase transfers around Lake Michigan, APC savings are minimal for all studied scenarios. This option has little effect on system congestion.

Hiple – Duck Lake 345 kV

Estimated Cost: $259.3M* *Cost estimate based on generic $/mile cost

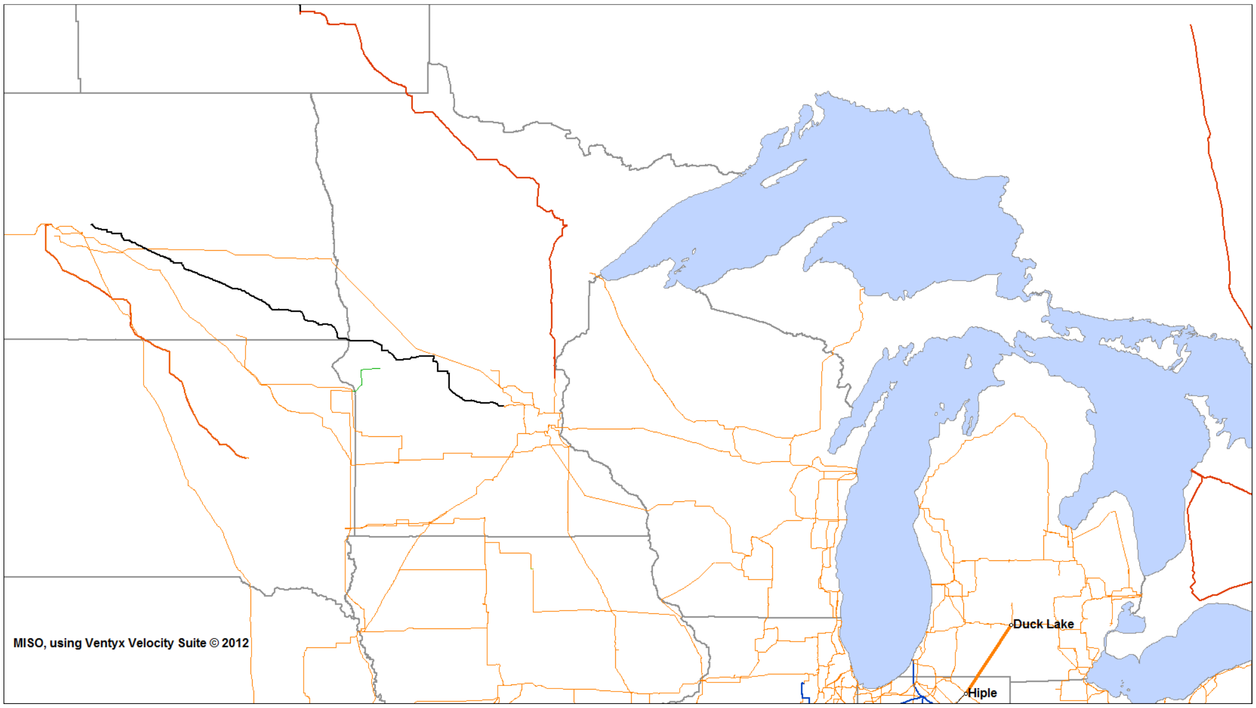


Figure 6-21: *Hiple – Duck Lake 345 kV*

Hiple – Duck Lake 345 kV was proposed by the TRG. The project adds a new substation at Duck Lake and new a 345 kV line from Hiple – Duck Lake.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	2.2	0.04
Business As Usual Demand, MH - Duluth Tie-Line	2.1	0.04
Business As Usual Demand, MH - Fargo Tie-Line	2.5	0.05
High Demand and Energy, No new MH Tie-Line	4.6	0.09
High Demand and Energy, MH - Duluth Tie-Line	6.1	0.12
High Demand and Energy, MH - Fargo Tie-Line	5.1	0.10

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-20: Economic Benefits of *Hiple – Duck Lake 345 kV*

APC savings for *Hiple – Duck Lake 345 kV* are shown in Table 6-20. This project does not completely circumvent Lake Michigan and therefore does not exploit the potential of the WI/UP interface; however, it does relieve area congestion. The line loading of Hiple – Duck Lake was consistent across the futures at 5%.

Kewaunee – Ludington 500 kV HVDC

Estimated Cost: $872M* **Cost estimate based on generic $/mile cost*

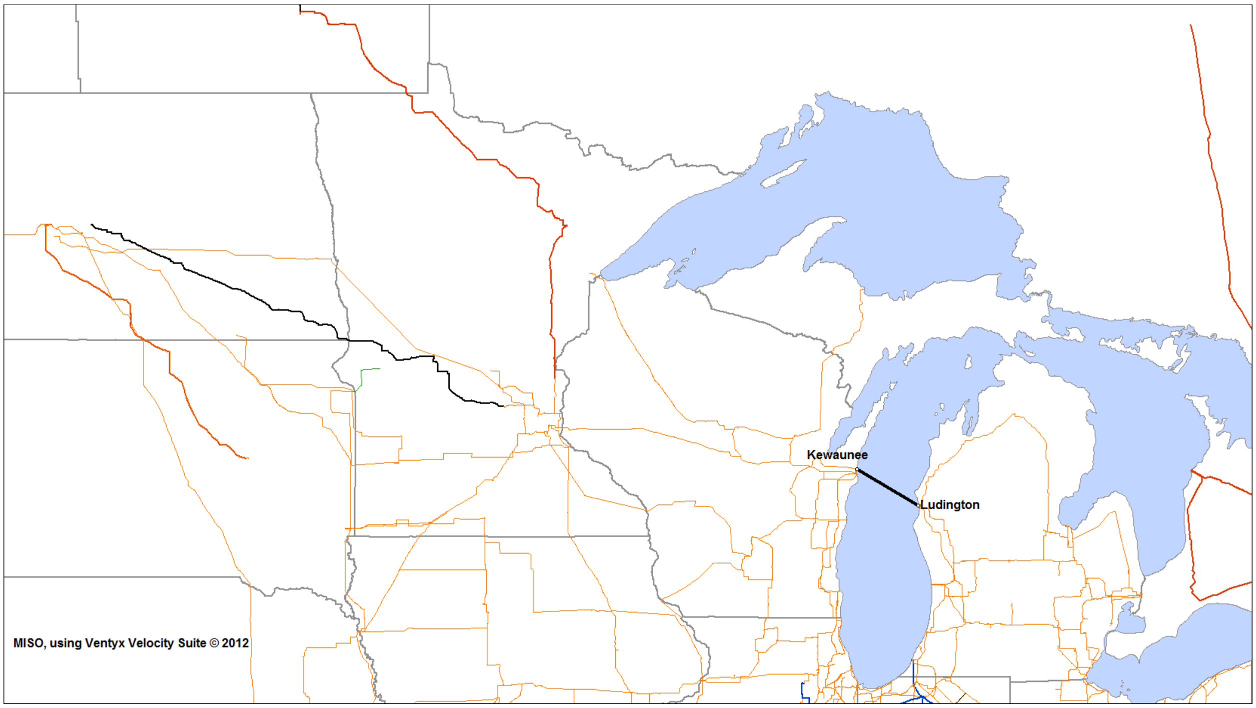


Figure 6-22: *Kewaunee – Ludington 500 kV HVDC*

The TRG proposed *Kewaunee – Ludington 500 kV HVDC* (MTEP Project ID 3164 – year 2009) adds a new DC terminal pair at Kewaunee and Ludington connected by a bipole 500 kV submarine HVDC cable capable of transmitting a total of 1,600 MW. APC savings are shown in Table 6-21.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	19.6	0.11
Business As Usual Demand, MH - Duluth Tie-Line	20.7	0.12
Business As Usual Demand, MH - Fargo Tie-Line	22.8	0.13
High Demand and Energy, No new MH Tie-Line	61.2	0.36
High Demand and Energy, MH - Duluth Tie-Line	65.4	0.38
High Demand and Energy, MH - Fargo Tie-Line	67.9	0.40

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-21: Economic Benefits of *Kewaunee – Ludington 500 kV HVDC*

Kewanee – Ludington 500 kV HVDC was most effective at unlocking the WI/UP economic interface potential. The option projected the highest APC savings of all options analyzed; however, benefits did not exceed the project costs. This project halves McGulpin Interface congestion and reduces congestion around Lake Michigan, but increases congestion on Arrowhead – Stone Lake 345 kV. The line loading of Kewaunee – Ludington was consistent in all studied scenarios at ~70% (target line loading for HVDC is 80%).

Pleasant Prairie – Palisades 500 kV HVDC

Estimated Cost: $981M* **Cost estimate based on generic $/mile cost*

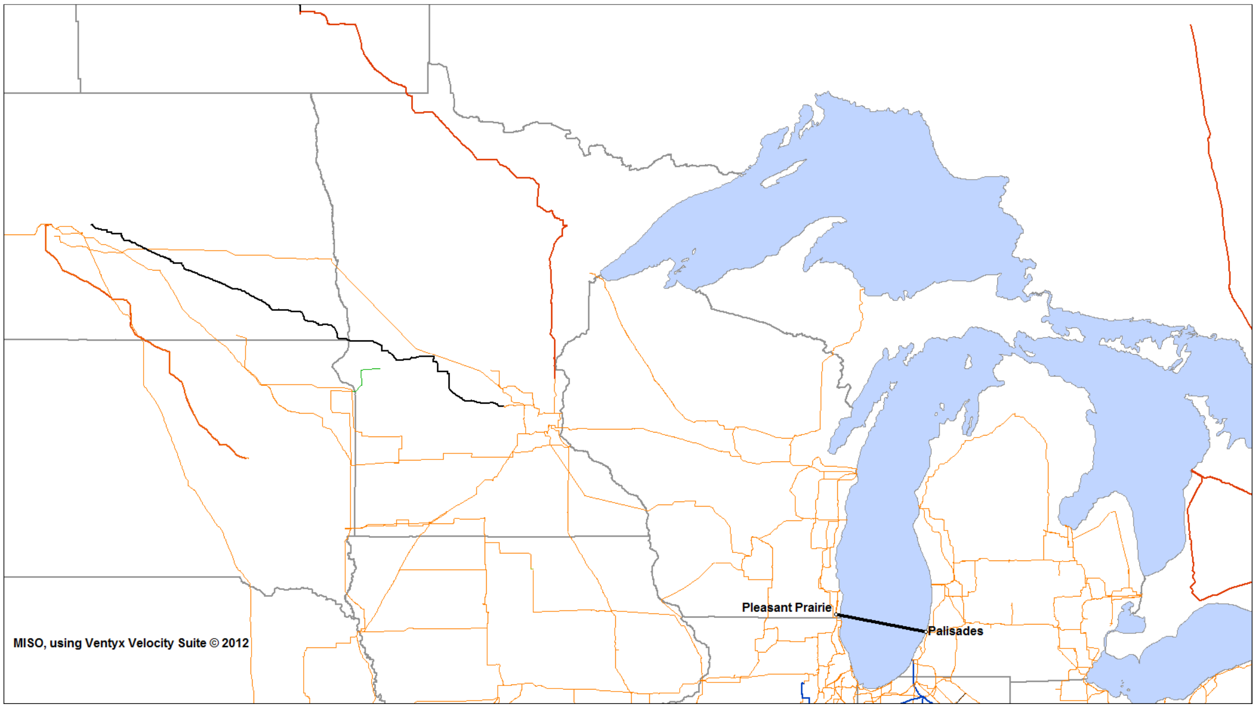


Figure 6-23: ***Pleasant Prairie – Palisades 500 kV HVDC***

Pleasant Prairie – Palisades 500 kV HVDC was configured from *Kewaunee – Ludington 500 kV HVDC*, in an effort to increase HVDC line loading to the 80% loading target and consequently increase APC savings. This option moves the DC terminals south to Pleasant Prairie and Palisades. Pleasant Prairie and Palisades are connected via a bipole 500 kV submarine HVDC cable capable of transmitting 1,600 MW.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	3.1	0.02
Business As Usual Demand, MH - Duluth Tie-Line	3.8	0.02
Business As Usual Demand, MH - Fargo Tie-Line	3.1	0.02
High Demand and Energy, No new MH Tie-Line	15.5	0.08
High Demand and Energy, MH - Duluth Tie-Line	19.0	0.10
High Demand and Energy, MH - Fargo Tie-Line	15.7	0.08

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-22: Economic Benefits of ***Pleasant Prairie – Palisades 500 kV HVDC***

As shown in Table 6-22, APC savings of *Pleasant Prairie – Palisades 500 kV HVDC* are lower than *Kewaunee – Ludington 500 kV HVDC*. Coupled with a higher estimated in service cost, this project's option's B/C ratios are much lower than *Kewaunee – Ludington 500 kV HVDC*. This project helps to reduces congestion around the south of Lake Michigan, while increasing congestion on Arrowhead – Stone Lake 345 kV. The line loading of Pleasant Prairie – Palisades was consistent across the futures at 50%.

Madison – Tallmadge 500 kV HVDC

Estimated Cost: $1,251M* **Cost estimate based on generic $/mile cost*

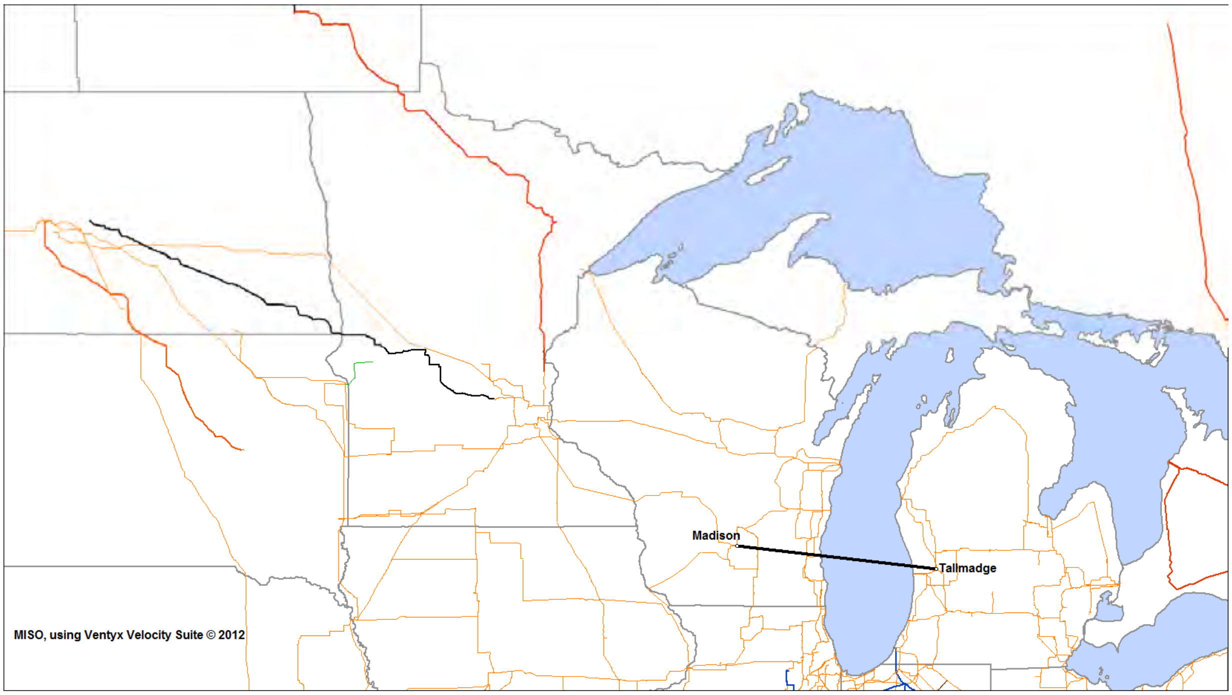


Figure 6-24: *Madison – Tallmadge 500 kV HVDC*

Madison – Tallmadge 500 kV HVDC was the final Lake Michigan HVDC cable iteration. This project directly connects the Multi-Value Project Portfolio at Madison to the Michigan 345 kV system at Tallmadge via bipole 1600 MW HVDC conductor. This option includes 100 miles of over land conductor, and 80 miles of submarine HVDC cable. APC savings are shown in Table 6-23.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	24.6	0.10
Business As Usual Demand, MH - Duluth Tie-Line	25.8	0.10
Business As Usual Demand, MH - Fargo Tie-Line	29.0	0.12
High Demand and Energy, No new MH Tie-Line	70.5	0.29
High Demand and Energy, MH - Duluth Tie-Line	71.7	0.29
High Demand and Energy, MH - Fargo Tie-Line	77.4	0.31

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-23: Economic Benefits of *Madison – Tallmadge 500 kV HVDC*

Madison – Tallmadge 500 kV HVDC produces additional APC savings than *Kewaunee – Ludington 500 kV HVDC*; however, the incremental benefits for this project do not exceed the additional costs. This project mitigates half of the congestion on the McGulpin Interface and reduces (additional compared to Kewaunee – Ludington) congestion around the south of Lake Michigan. The line loading of Madison – Tallmadge was ~80%.

6.3 Minnesota - Wisconsin Solutions

Mitigating the Arrowhead – Stone Lake 345 kV stability limit yields MISO adjusted production cost savings of $3.1 million – $6.4 million ($-2027).

The Minnesota – Wisconsin congestion interface is present only in scenarios which include the Manitoba – Duluth 500 kV tie-line as is contained solely to the Arrowhead – Stone Lake 345 kV line. As evident in Table 6-24, the most cost-effective solutions mitigated the stability limitations of Arrowhead – Stone Lake 345 kV and the MWEX Interface.

Option	MISO APC Savings ($M – 2027)	Estimated Capital Cost ($M – 2012)	Benefit to Cost Ratio
Upgrade Arrowhead – Stone Lake 345 kV (MWEX)	3.1– 6.4	0 – TBD	Inf. - TBD
Arrowhead – National 345 kV	1.4 – 10.5	1140.1	0.01 – 0.05
Arrowhead – Arnold - Livingston 345 kV	7.9 – 32.5	1456.5*	0.03 – 0.11*
Eau Claire – Park Falls – National 345 kV	1.7 – 8.8	679.7	0.01 – 0.07
Eau Claire – M38	-	238.5	-
Eau Claire – Arnold - Livingston 345 kV	7.7 – 27.2	1300*	0.03 – 0.11*
Double circuit Hampton – Briggs Road 345 kV	-		-
Double circuit Hampton – Briggs Road - Madison 345 kV	-		-
DC Option: Blackberry – Livingston – Tittabawassee 500 kV	26.5 – 85.7	2,020*	0.07 – 0.22*
DC Option: Blackberry – Plains 500 kV	4.1 – 14.3	1,143*	0.02 – 0.06*
DC Option: Blackberry – Plains – Livingston – Tittabawassee 500 kV	29.0 – 95.8	2,420*	0.06 – 0.20*
DC Option: Arrowhead – Plains – Livingston – Tittabawassee 500 kV	23.1 – 96.4	2,245*	0.05 – 0.22*
DC Option: Bison – Plains – Livingston – Tittabawassee 500 kV	30.9 – 86.2	2,852*	0.06 – 0.15*
DC Option: Arrowhead – Point Beach – Ludington 500 kV	23.5 – 85.6	2,028*	0.06 – 0.21*

Table 6-24: Summary of Economic Benefits of Minnesota - Wisconsin Solutions

The Northern Area Study analysis assumed the Arrowhead – Stone Lake 345 kV and MWEX interface ratings were unchanged from the levels defined in the current MISO Operations Guide for all simulations and analysis. Incremental interface flow analysis shows that the majority of the Arrowhead – Stone Lake 345 kV congestion could be mitigated with 250 MW in incremental capability. This 250 MW increase is still within the thermal limit of the Arrowhead – Stone Lake 345 kV conductor.

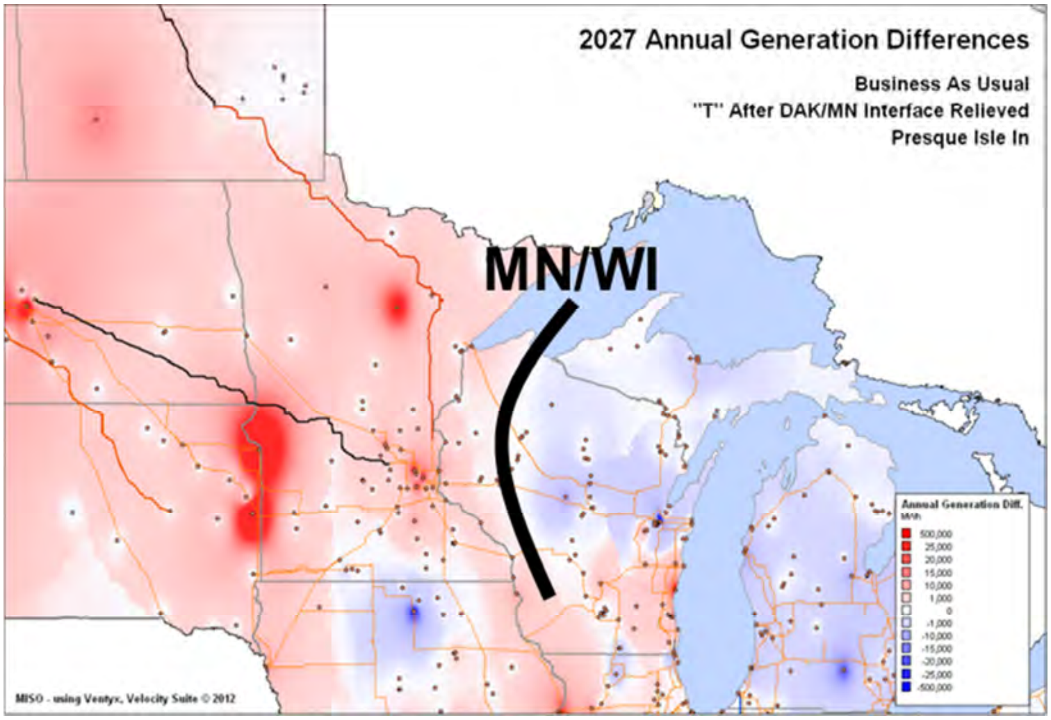


Figure 6-25: Minnesota – Wisconsin Economic Potential Interface

In collaboration with the TRG, fourteen different options were developed to unlock the potential of this interface. The findings and economic benefits of each option are presented in the following sections.

Upgrade Arrowhead – Stone Lake 345 kV (MWEX)

Estimated Cost: $0 – To Be Determined

Figure 6-26: ***Upgrade Arrowhead – Stone Lake 345 kV***

After the December 7th TRG meeting, MISO received a Transmission Owner study which reported that the stability limit of Arrowhead – Stone Lake 345 kV increased from 705 MVA to at least 972 MVA with the installation of the new Manitoba – Duluth tie-line. MISO verified that a 972 MVA operating limit would unlock the full economic potential of this interface; however, a full operating study to reestablish/verify new operating limits of the MWEX Interface was outside the scope of the Northern Area Study. The subsequent costs associated with this project are displayed as a range from $0 which represents the increase is a product of the new tie-line to a value "to be determined" through an operations study.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	6.4	Inf. – TBD
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	3.1	Inf. – TBD
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-25: Economic Benefits of ***Upgrade Arrowhead – Stone Lake 345 kV***

Table 6-25 shows the range of APC savings for the *Arrowhead – Stone Lake 345 kV upgrade*. Because Arrowhead – Stone Lake 345 kV was not congested in other scenarios, APC savings are only available in the MH – Duluth Tie-Line scenarios. The benefits in the HDE future are less than those in the BAU future, because loads in northern Minnesota absorb more power in the HDE future than they do in the BAU future and thus less power is transferred through this branch. The upgrade fully mitigates congestion on Arrowhead – Stone Lake 345 kV. The line loading of upgraded Arrowhead – Stone Lake 345 kV is 60%.

Arrowhead – National 345 kV

Estimated Cost: $1,140.1M

Figure 6-27: *Arrowhead – National 345 kV*

The TRG proposed *Arrowhead – National 345 kV* (MTEP Projects 3833 and 3838) builds a new 345 kV line from Arrowhead – Ironwood – Watersmeet – Plains - National. It adds a new 345 kV substation at National. APC savings of *Arrowhead – National 345 kV* are shown in Table 6-26.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	1.4	0.01
Business As Usual Demand, MH - Duluth Tie-Line	7.2	0.03
Business As Usual Demand, MH - Fargo Tie-Line	1.8	0.01
High Demand and Energy, No new MH Tie-Line	6.5	0.03
High Demand and Energy, MH - Duluth Tie-Line	10.5	0.05
High Demand and Energy, MH - Fargo Tie-Line	7.4	0.03

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-26: Economic Benefits of *Arrowhead – National 345 kV*

Arrowhead – National 345 kV reduces congestion on Arrowhead – Stone Lake 345 kV, which is only present in MH – Duluth tie-line scenarios and some underlying system congestion, but increases congestion at the McGulpin interface. APC savings increase as the demand and energy increase; however, the benefits do not exceed the cost of the option. Line loading is under the targeted 40% capacity factor at ~10%.

Arrowhead – Arnold – Livingston 345 kV

Estimated Cost: $1,456.5M* **Cost estimate based on generic $/mile cost*

Figure 6-28: *Arrowhead – Arnold - Livingston 345 kV*

Arrowhead – Arnold - Livingston 345 kV was proposed to mitigate both the MN – WI congestion interface and the Lake Michigan interface. This option combines MTEP Projects 3820 and 3833 and builds a new Arrowhead – Ironwood – Watersmeet - Plains – Arnold – Hiawatha – Straits – McGulpin - Livingston 345 kV line. A step-down transformer is included at Hiawatha. APC savings for this option are shown in Table 6-27.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	7.9	0.03
Business As Usual Demand, MH - Duluth Tie-Line	20.0	0.07
Business As Usual Demand, MH - Fargo Tie-Line	9.9	0.03
High Demand and Energy, No new MH Tie-Line	23.1	0.08
High Demand and Energy, MH - Duluth Tie-Line	32.5	0.11
High Demand and Energy, MH - Fargo Tie-Line	28.9	0.10

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-27: Economic Benefits of *Arrowhead – Arnold – Livingston 345 kV*

Arrowhead – Arnold - Livingston 345 kV provides increased APC savings compared to Northern Area Study options *Arrowhead – National 345 kV* and *Arnold – Livingston 345 kV*, the projects which were combined to make this option; however, the incremental benefits to do justify the incremental costs – B/C ratios decrease. The majority of the benefits of this project are from relieving congestion around Lake Michigan. The line loading is 10-20%.

Eau Claire – Park Falls – National 345 kV

Estimated Cost: $679.7M

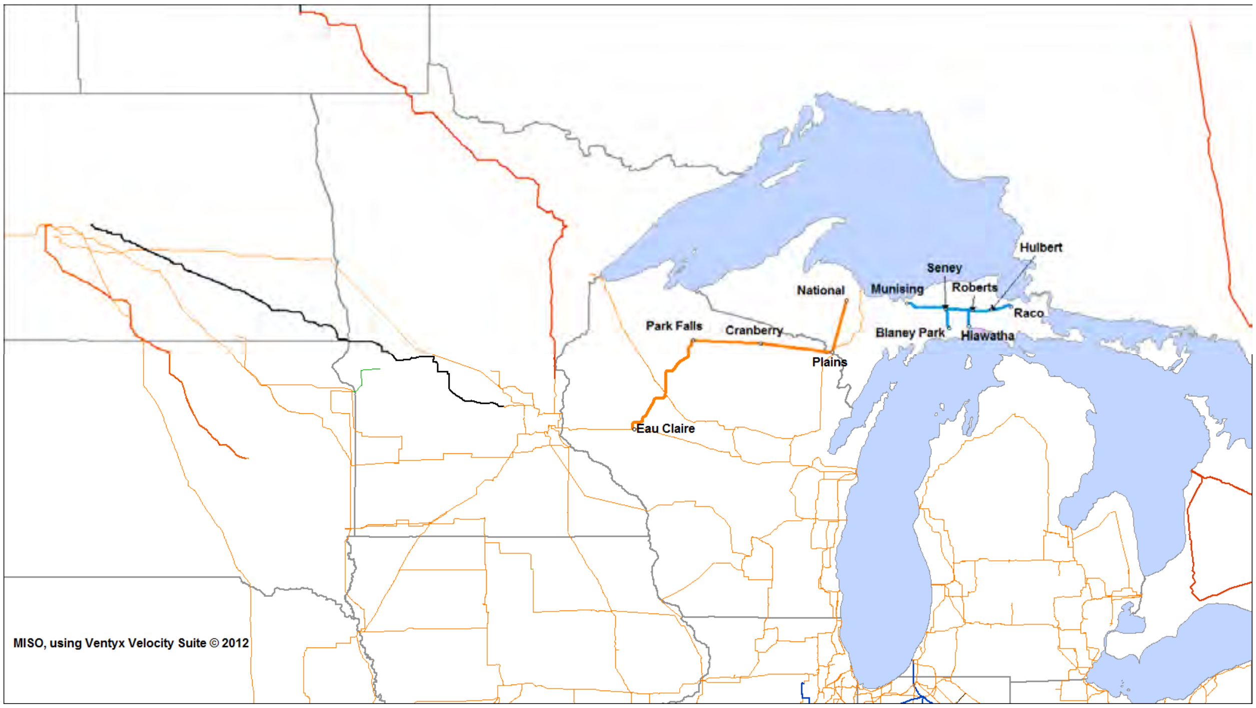


Figure 6-29: *Eau Claire – Park Falls – National 345 kV*

The TRG proposed, *Eau Claire – Park Falls – National 345 kV* adds Eau Claire – Park Falls – National 345 kV, and upgrades the native system in northern Wisconsin.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	3.3	0.02
Business As Usual Demand, MH - Duluth Tie-Line	4.7	0.04
Business As Usual Demand, MH - Fargo Tie-Line	1.7	0.01
High Demand and Energy, No new MH Tie-Line	5.7	0.04
High Demand and Energy, MH - Duluth Tie-Line	8.8	0.07
High Demand and Energy, MH - Fargo Tie-Line	6.9	0.05

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-28: Economic Benefits of *Eau Claire – Park Falls – National 345 kV*

As shown in Table 6-28, the APC savings of *Eau Claire – Park Falls – National 345 kV* are comparable to those of *Arrowhead – National 345 kV*; however, B/C ratios are slightly higher because of the lesser capital cost. In the conditions tested, the option reduces congestion on Arrowhead – Stone Lake 345 kV, but increases congestion at the McGulpin interface. The line loading is 10-15% from Eau Claire – Cranberry 345 kV, and less than 5% for Cranberry – National 345 kV.

Eau Claire – M38 345 kV

Estimated Cost: $238.5M

Figure 6-30: *Eau Claire – M38 345 kV*

Eau Claire – M38 345 kV was proposed by TRG. This option adds new 345 kV and 161kV lines between Eau Claire and M38.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-29: Economic Benefits of *Eau Claire – M38 345 kV*

Eau Claire – M38 345 kV didn't change system congestion patterns and therefore minimal associated APC savings were projected for all tested conditions. The line loading of the 345 kV and 161kV lines was ~10% and ~25%, respectively.

Eau Claire – Arnold – Livingston 345 kV

Estimated Cost: $1,300M* **Cost estimate based on generic $/mile cost*

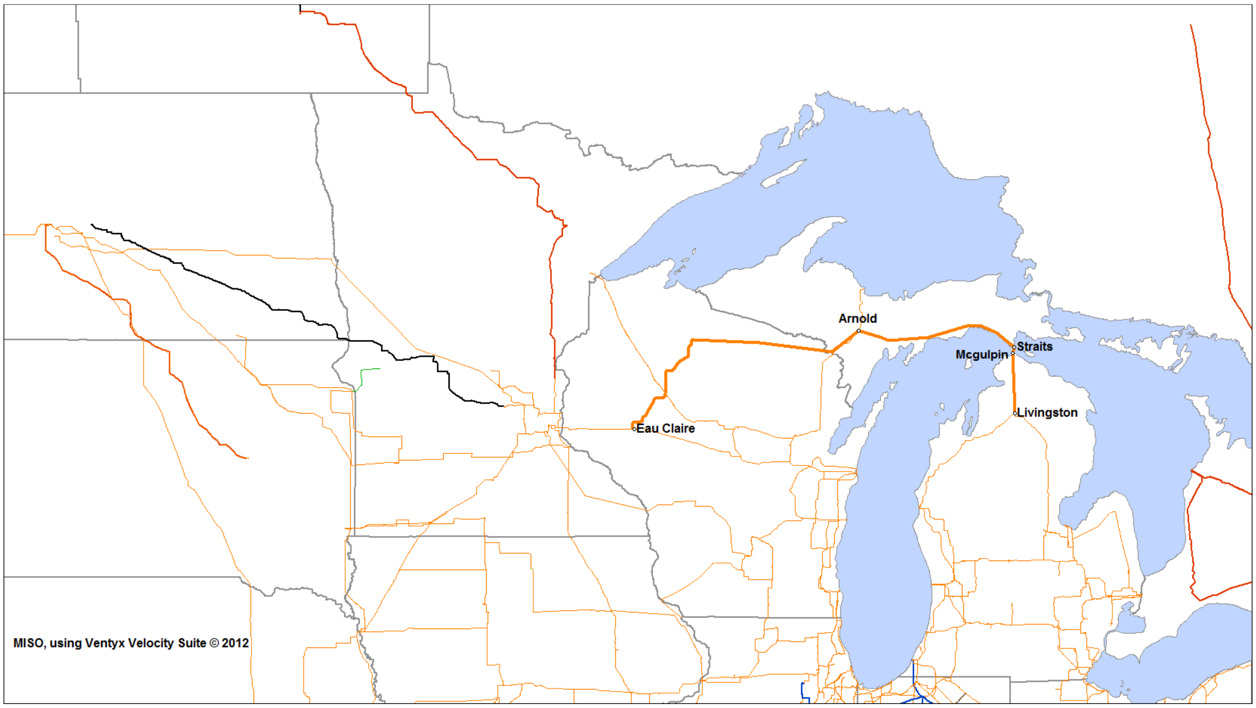


Figure 6-31: *Eau Claire – Arnold – Livingston 345 kV*

The TRG proposed *Eau Claire – Arnold – Livingston 345 kV* combines the Northern Area Study options *Eau Claire – Park Falls – National 345 kV* and *Arnold – Livingston 345 kV*.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	7.7	0.03
Business As Usual Demand, MH - Duluth Tie-Line	10.1	0.04
Business As Usual Demand, MH - Fargo Tie-Line	9.9	0.04
High Demand and Energy, No new MH Tie-Line	22.8	0.09
High Demand and Energy, MH - Duluth Tie-Line	27.2	0.11
High Demand and Energy, MH - Fargo Tie-Line	26.1	0.10

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-30: Economic Benefits of *Eau Claire – Arnold - Livingston 345 kV*

As shown in Table 6-30, *Eau Claire – Arnold – Livingston 345 kV* provides roughly double the benefits of provides *Arnold – Livingston 345 kV*; however, the cost is more than double. This project's benefits are primarily attributed to relieving congestion around Lake Michigan. Eau Claire – Arnold – Livingston 345 kV line loading is 12-15%.

Double Hampton – Briggs Road 345 kV

Estimated Cost: *To Be Determined*

Figure 6-32: *Double Hampton – Briggs Road 345 kV*

The *Double Hampton – Briggs Road 345 kV* project was proposed by TRG and adds a second 345 kV circuit from Hampton Corners – North Rochester – Briggs Road. This project was indicative in nature and because of the minimal APC savings shown in Table 6-31 engineering time was not spent to determine an associated cost estimate.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-31: Economic Benefits of *Double Hampton – Briggs Road 345 kV*

Double Hampton – Briggs Road 345 kV doesn't change system congestion patterns, because the existing Hampton Corners – Briggs Road 345 kV circuit is not congested. There were minimal APC savings associated with this option in all tested conditions. The line loading on the second circuit is 12-16%.

Double Hampton – Madison 345 kV

Estimated Cost: *To Be Determined*

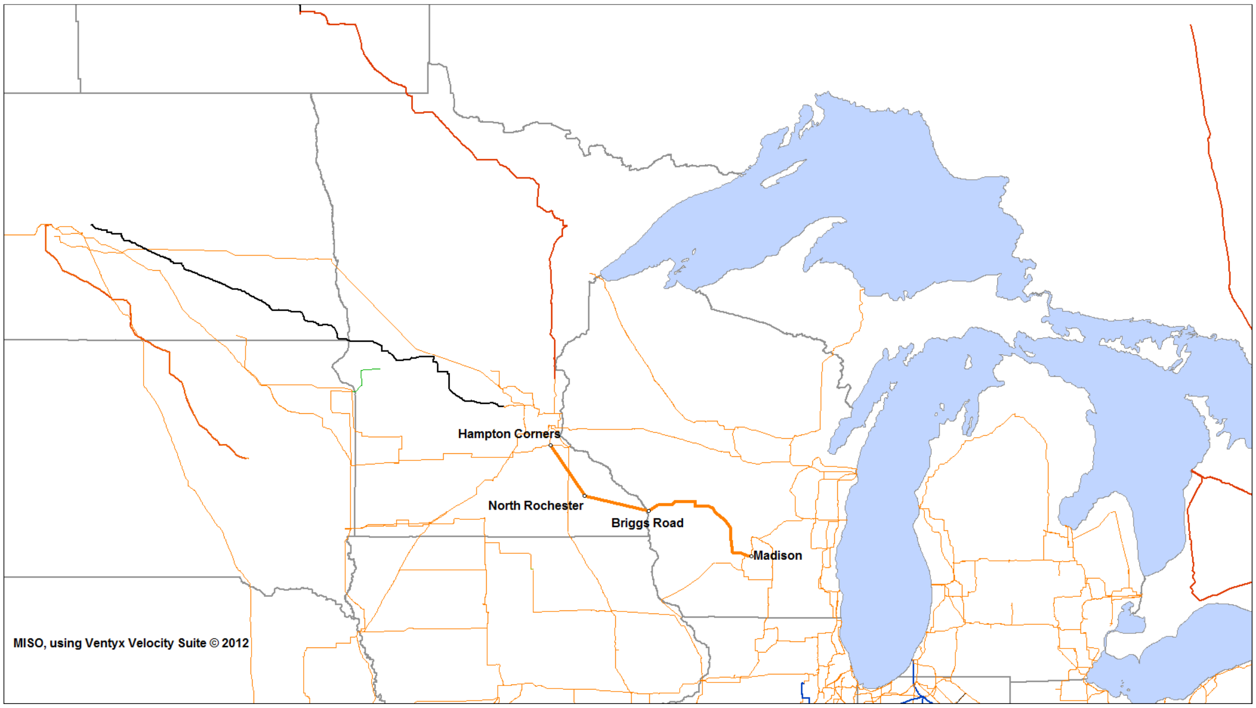


Figure 6-33: *Double Hampton – Madison 345 kV*

Double Hampton – Madison 345 kV extends the *Hampton – Briggs Road 345 kV* second circuit to Madison. Because of the minimal APC savings shown in Table 6-32 engineering time was not spent to determine an associated cost estimate at this time.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	-	-
Business As Usual Demand, MH - Duluth Tie-Line	-	-
Business As Usual Demand, MH - Fargo Tie-Line	-	-
High Demand and Energy, No new MH Tie-Line	-	-
High Demand and Energy, MH - Duluth Tie-Line	-	-
High Demand and Energy, MH - Fargo Tie-Line	-	-

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-32: Economic Benefits of *Double Hampton – Madison 345 kV*

Double Hampton – Madison 345 kV does not change system congestion patterns and therefore provides little to no APC savings.

Blackberry – Livingston/Tittabawassee 500 kV HVDC

Estimated Cost: $2,020M* **Cost estimate based on generic $/mile cost*

Figure 6-34: *Blackberry – Livingston/Tittabawassee 500 kV HVDC*

At the direction of the TRG, multiple HVDC options were evaluated to simultaneously mitigate multiple interfaces. HVDC lines operate on price signals as opposed to AC lines which operate based on power angles. The *Blackberry – Livingston/Tittabawassee 500 kV HVDC* adds terminal stations at Blackberry, Livingston, and Tittawabasse (1 terminal pair) and a 600 mile bi-pole line conductor connecting them – one pole from Blackberry – Livingston and one from Blackberry – Tittawabasee. Each pole was capable of carrying 800 MW, 1,600 MW total. Each pole was forced to be equally loaded and was limited to an easterly direction.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	26.5	0.07
Business As Usual Demand, MH - Duluth Tie-Line	45.8	0.12
Business As Usual Demand, MH - Fargo Tie-Line	33.0	0.08
High Demand and Energy, No new MH Tie-Line	68.6	0.17
High Demand and Energy, MH - Duluth Tie-Line	85.7	0.22
High Demand and Energy, MH - Fargo Tie-Line	80.6	0.20

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-33: Economic Benefits of *Blackberry – Livingston/Tittabawassee 500 kV HVDC*

APC savings for DC lines are proportional to LMP differences between the terminals and therefore highest in the HDE futures. *Blackberry – Livingston/Tittabawassee 500 kV HVDC* reduces congestion on Arrowhead – Stone Lake 345 kV and around Lake Michigan; however, projected benefits do not exceed estimated costs. The line loading of the HVDC line is about 65%, less than the target loading of 80%.

Blackberry – Plains 500 kV HVDC

Estimated Cost: $1,143M* **Cost estimate based on generic $/mile cost*

Figure 6-35: *Blackberry – Plains 500 kV HVDC*

Blackberry – Plains 500 kV HVDC was the second HVDC option evaluated. This option adds DC terminals at Blackberry and Plains and a 275 mile bi-pole conductor. APC savings of *Blackberry – Plains 500 kV HVDC* are shown in Table 6-34.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	4.1	0.02
Business As Usual Demand, MH - Duluth Tie-Line	10.6	0.05
Business As Usual Demand, MH - Fargo Tie-Line	4.1	0.02
High Demand and Energy, No new MH Tie-Line	10.0	0.04
High Demand and Energy, MH - Duluth Tie-Line	14.3	0.06
High Demand and Energy, MH - Fargo Tie-Line	10.6	0.05

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-34: Economic Benefits of *Blackberry – Plains 500 kV HVDC*

Blackberry – Plains 500 kV HVDC relieves Arrowhead – Stone Lake 345 kV congestion, which is only present in the MH – Duluth Tie-Line scenarios, and changes underlying system congestion patterns; however, Blackberry – Plains 500 kV HVDC does not mitigate Lake Michigan congestion and therefore is less effective than *Blackberry – Livingston/Tittawabassee 500 kV HVDC*. The LMP difference between Blackberry and Plains is much smaller than the LMP difference between Blackberry and Tittabawassee. The line loading is 25%, reflective of the small LMP difference.

Blackberry – Plains – Livingston/Tittabawassee 500 kV HVDC

Estimated Cost: $2,420M* **Cost estimate based on generic $/mile cost*

Figure 6-36: *Blackberry – Plains – Livingston/ Tittabawassee 500 kV HVDC*

Blackberry – Plains - Livingston/Tittabawassee 500 kV HVDC adds an intermediate bus and additional pair of terminal stations to *Blackberry – Livingston/Tittabawassee 500 kV HVDC* at Plains.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	29.0	0.06
Business As Usual Demand, MH - Duluth Tie-Line	44.0	0.09
Business As Usual Demand, MH - Fargo Tie-Line	35.7	0.08
High Demand and Energy, No new MH Tie-Line	80.6	0.17
High Demand and Energy, MH - Duluth Tie-Line	95.8	0.20
High Demand and Energy, MH - Fargo Tie-Line	90.5	0.19

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-35: Economic Benefits of *Blackberry – Plains – Livingston/Tittabawassee 500 kV HVDC*

As evident in Table 6-35, adding a Plains terminal to *Blackberry – Livingston/Tittabawassee 500 kV HVDC,* does not significantly increase APC savings. Contrary to original expectations Plains serves as a source as opposed to a sink. The line loading of *Blackberry – Plains - Livingston/Tittabawassee 500 kV HVDC* is ~60% from Blackberry – Plains and ~70% from Plains to Michigan.

Arrowhead – Plains – Livingston/Tittabawassee 500 kV HVDC

Estimated Cost: $2,245M* **Cost estimate based on generic $/mile cost*

Figure 6-37: *Arrowhead – Plains – Livingston/Tittabawassee 500 kV HVDC*

Arrowhead – Plains - Livingston/Tittabawassee 500 kV HVDC moves the primary source terminal of the Northern Area Study iterative HVDC line to Arrowhead. The cost of this project reflects two pairs of terminal stations and a shortened 535 mile bi-pole conductor. The APC savings of this option are shown in Table 6-36.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	23.1	0.05
Business As Usual Demand, MH - Duluth Tie-Line	45.8	0.10
Business As Usual Demand, MH - Fargo Tie-Line	29.8	0.07
High Demand and Energy, No new MH Tie-Line	76.7	0.17
High Demand and Energy, MH - Duluth Tie-Line	96.4	0.22
High Demand and Energy, MH - Fargo Tie-Line	86.9	0.20

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-36: Economic Benefits of *Arrowhead – Plains – Livingston/Tittabawassee 500 kV HVDC*

The APC savings of *Arrowhead – Plains - Livingston/Tittabawassee 500 kV HVDC* are similar in magnitude to *Blackberry – Plains – Livingston – Tittabawassee 500 kV HVDC*; however, because of a slightly lower capital cost B/C ratios are relatively higher. This option reduces congestion on Arrowhead – Stone Lake 345 kV and around Lake Michigan. As deduced through previous HVDC options, the removal of the Plains terminal may increase B/C ratio of this project. The line loading of this HVDC option is 65-70%.

Bison – Plains – Livingston/Tittabawassee 500 kV HVDC

Estimated Cost: $2,852M* **Cost estimate based on generic $/mile cost*

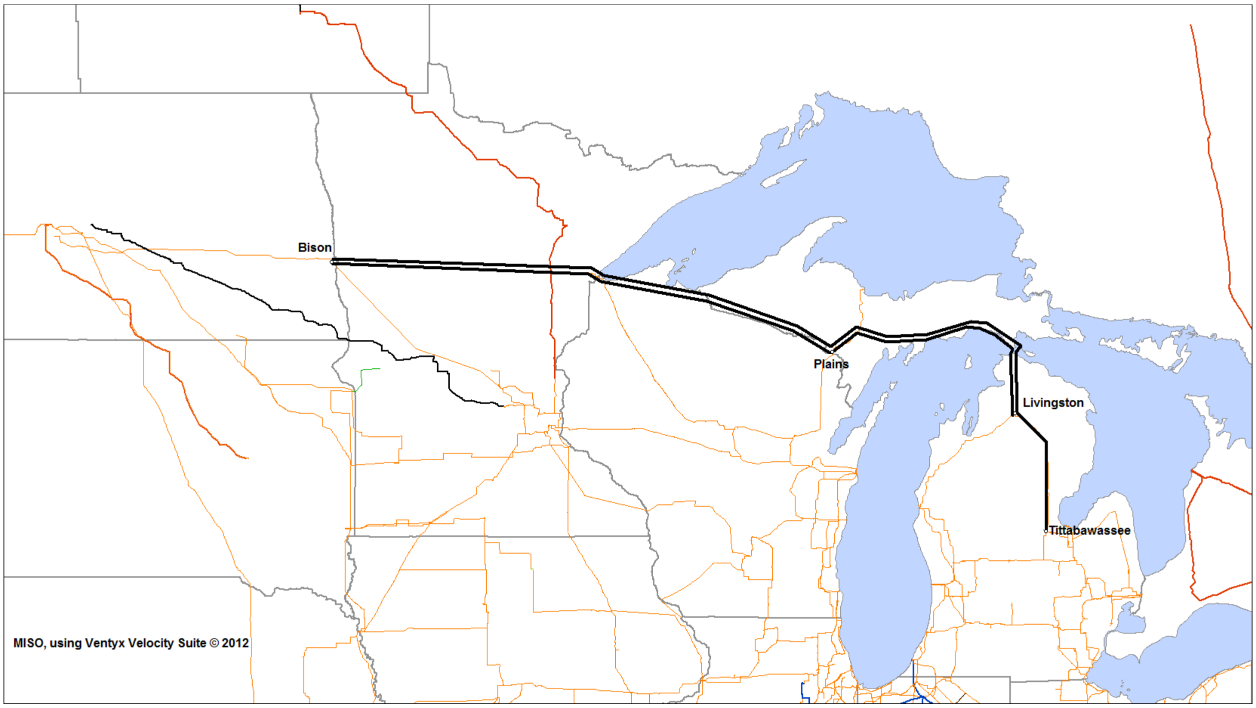


Figure 6-38: *Bison – Plains – Livingston/Tittabawassee 500 kV HVDC*

Bison – Plains - Livingston/Tittabawassee 500 kV HVDC moves the primary source terminal of the Northern Area Study iterative HVDC line to Bison. The cost of this project reflects two pairs of terminal stations and a 760 mile bi-pole conductor. The APC savings of this option are shown in Table 6-37.

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	30.9	0.06
Business As Usual Demand, MH - Duluth Tie-Line	38.2	0.07
Business As Usual Demand, MH - Fargo Tie-Line	38.8	0.07
High Demand and Energy, No new MH Tie-Line	73.9	0.13
High Demand and Energy, MH - Duluth Tie-Line	84.0	0.15
High Demand and Energy, MH - Fargo Tie-Line	86.2	0.15

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-37: Economic Benefits of *Bison – Plains – Livingston/Tittabawassee 500 kV HVDC*

The APC savings and associated B/C ratio of *Bison – Plains - Livingston/Tittabawassee 500 kV HVDC* is higher than *Blackberry – Plains – Livingston – Tittabawassee 500 kV HVDC* because of a larger LMP differential between Fargo and Michigan; however, this option's projected benefits do not exceed estimated costs in the conditions tested. The option reduces congestion on Arrowhead – Stone Lake 345 kV, and around Lake Michigan. The *Bison – Plains - Livingston/Tittabawassee 500 kV HVDC* line loading is 55-65%.

Arrowhead – Point Beach – Ludington 500 kV HVDC

Estimated Cost: $2,028M* **Cost estimate based on generic $/mile cost*

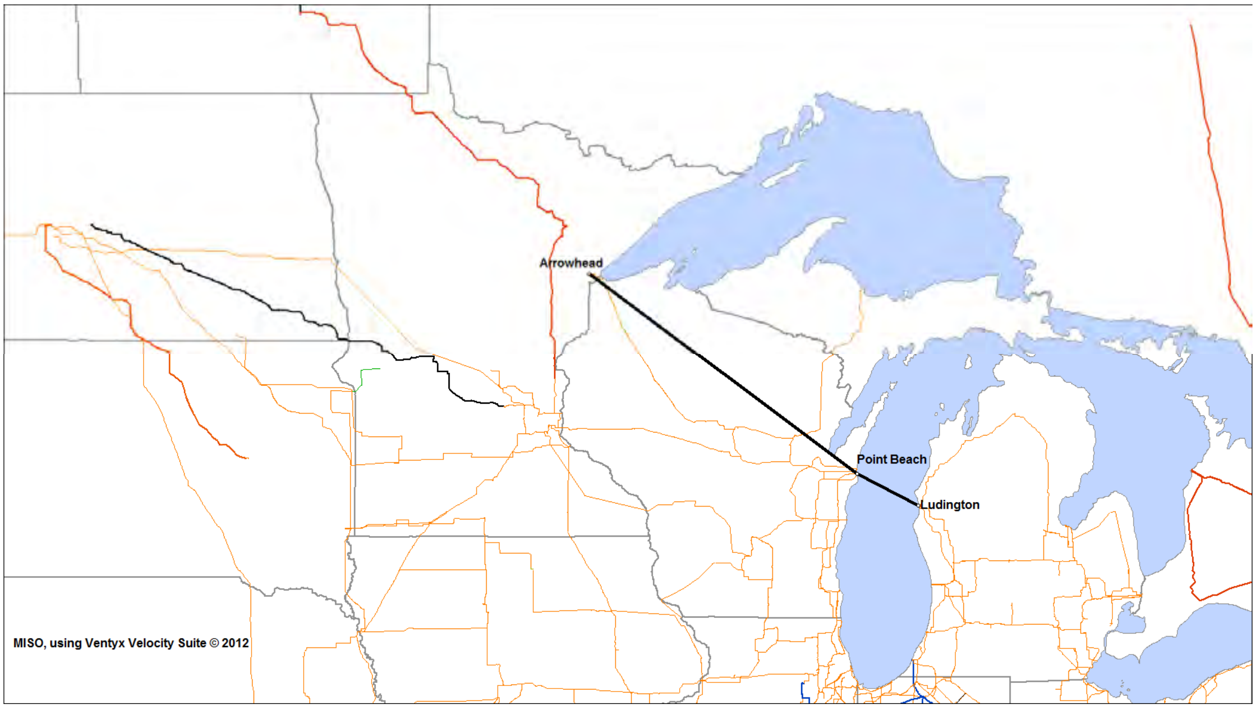


Figure 6-39: *Arrowhead – Point Beach – Ludington 500 kV HVDC*

The TRG proposed *Arrowhead – Point Beach – Ludington 500 kV HVDC* extends *Kewaunee – Ludington 500 kV HVDC* to Arrowhead. This option consists of two pairs of terminal stations and 345 miles of bi-pole conductor (65 miles of submarine).

Scenario	MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	23.5	0.06
Business As Usual Demand, MH - Duluth Tie-Line	44.4	0.11
Business As Usual Demand, MH - Fargo Tie-Line	27.5	0.07
High Demand and Energy, No new MH Tie-Line	68.2	0.17
High Demand and Energy, MH - Duluth Tie-Line	85.6	0.21
High Demand and Energy, MH - Fargo Tie-Line	76.8	0.19

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 6-38: Economic Benefits of *Arrowhead – Point Beach – Ludington 500 kV HVDC*

As seen in Tables 6-38 and 6-21, *Arrowhead – Point Beach – Ludington 500 kV HVDC*'s incremental benefits do not exceed the incremental costs – lower B/C ratio compared to *Kewaunee – Ludington 500 kV HVDC*. Increased benefits are attributed to a greater price differential and the mitigation of Arrowhead – Stone Lake 345 kV in the Duluth tie-line scenarios. *Arrowhead – Point Beach – Ludington 500 kV HVDC* line loading is 60-80%.

7. Northern Area Study Portfolios

The Northern Area Study portfolios mitigate 50% - 100% of the area congestion, produce synergic production cost savings, nearly equalize northern area LMPs, but projected benefits generally do not exceed costs. Northern Area Study HVDC options would require significant additional upgrades to uphold reliability; however, they were the most effective at mitigating Lake Michigan congestion. The Northern Area Study identified three transmission portfolios as the most economic options available to accomplish the study objectives:

Northern Area Study portfolios mitigate 50% - 100% of the area congestion, produce synergic production cost savings, nearly equalize northern area LMPs, but projected benefits generally do not exceed costs

- ***Portfolio 1* (HVDC):** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Kewaunee – Ludington 500 kV DC* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)
- ***Portfolio 2* (High Voltage AC):** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV*, *National/Arnold – Livingston 345 kV* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)
- ***Portfolio 3* (Low Voltage AC):** *Upgrade Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV, Marquette – Mackinac County 138 kV* (Includes *MWEX upgrade* in MH-Duluth tie-line scenarios)

Each portfolio and the associated benefits are described in the following sections.

HVDC options would require significant additional upgrades to uphold reliability; however, they were the most effective at mitigating Lake Michigan congestion

The Northern Area Study portfolios were formed by combining the most cost-effective transmission options for each of the three identified congestion interfaces (Section 6) through a collaborative TRG effort. Because of the similar cost effectiveness but different scale of the three Lake Michigan (WI/UP congestion interface) solutions, three portfolio variations were formed and evaluated.

Northern Area Study portfolios were formed by combining the most cost-effective transmission options for each of the three identified congestion interfaces

The goal of portfolios is to achieve synergic benefits where the portfolio’s benefits exceed the summation of the individual plans’ devising the portfolio benefits. Synergic benefits indicate that a portfolio is performing as a single inter-related system and also that segments are “doubling-up” and trying to alleviate the same issues. Each of the three portfolios was evaluated both for economic effectiveness and reliability.

Economic Effectiveness

The Northern Area Study portfolios yielded benefit to cost ratios ranging from 0.21 – 1.22. The majority of the cost effectiveness (B/C ratio) was directly attributed to the *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrade*; the most cost effective portfolio had the smallest incremental cost to implement the upgrade. While portfolios all yielded some synergic benefits, no portfolio's benefits exceeded their costs in the tested conditions.

To determine the cost effectiveness of each option, the adjusted production cost saving and associated benefit to cost ratio was calculated for each option using year 2022 and 2027 production cost simulations. Because there was little to no Northern Area Study system congestion or associated total production cost saving potential in the Low Demand and Energy (LDE) future, options were not simulated under the LDE future. It is recognized that under LDE conditions, little to no transmission development could be economically justified in terms of APC savings.

To measure the synergic benefits of each portfolio the year 2027 production cost simulation for the portfolio was compared to the summation of the individual plan's benefits (Section 6). Figure 7-1 details the equation used to quantify synergic benefits.

$$Synergic\ APC\ Savings\ (\%) = \frac{\left(APC\ Savings_{portfolio} - \sum_{n}^{portfolio} APC\ Savings_{option\ n}\right)}{APC\ Savings_{portfolio}}$$

Figure 7-1: Synergic APC Savings Equation

Additionally, portfolio's 2027 APC savings were compared against the total available area production cost savings from Section 5. Expressed as a percentage of the maximum production cost savings (Table 7-1), a capture rate quantifies the total area congestion relief attributed to the portfolio. Historically, MISO transmission planning efforts have been able to capture 70% of the total economic potential.

Scenario	Business as Usual MISO APC Savings ($M-2027)	High Growth MISO APC Savings ($M-2027)
No new Manitoba - MISO Tie-Line	35.7	137.6
Manitoba - Duluth Tie-Line	37.0	135.4
Manitoba – Fargo Area Tie-Line	28.2	120.3

Table 7-1: Maximum MISO Production Cost Savings Potential in Northern Area Study Footprint

The capture rate equation is shown in Figure 7-2.

$$Capture\ Rate\ (\%) = \frac{APC\ Savings_{portfolio}}{Maximum\ Area\ APC\ Savings}$$

Figure 7-2: Capture Rate Equation

Finally, portfolios' economic effectiveness was visually measured by observing the equalization of area locational marginal prices (LMP). As congestion is mitigated from an area the energy and congestion components of LMP equalize – in a congestion free system the only remaining LMP differences are from line losses. LMP equalization was observed by comparing the pre-portfolio average annual LMP plot to the post-portfolio average annual LMP plot. As mentioned in Section 5 out-year system congestion is relatively low; resultantly, the color scales for LMP plots were "zoomed-in" three times more granular than the standard market scale to show differences. The pre-portfolio or base LMP plots are shown in Figures 7-3 and 7-4.

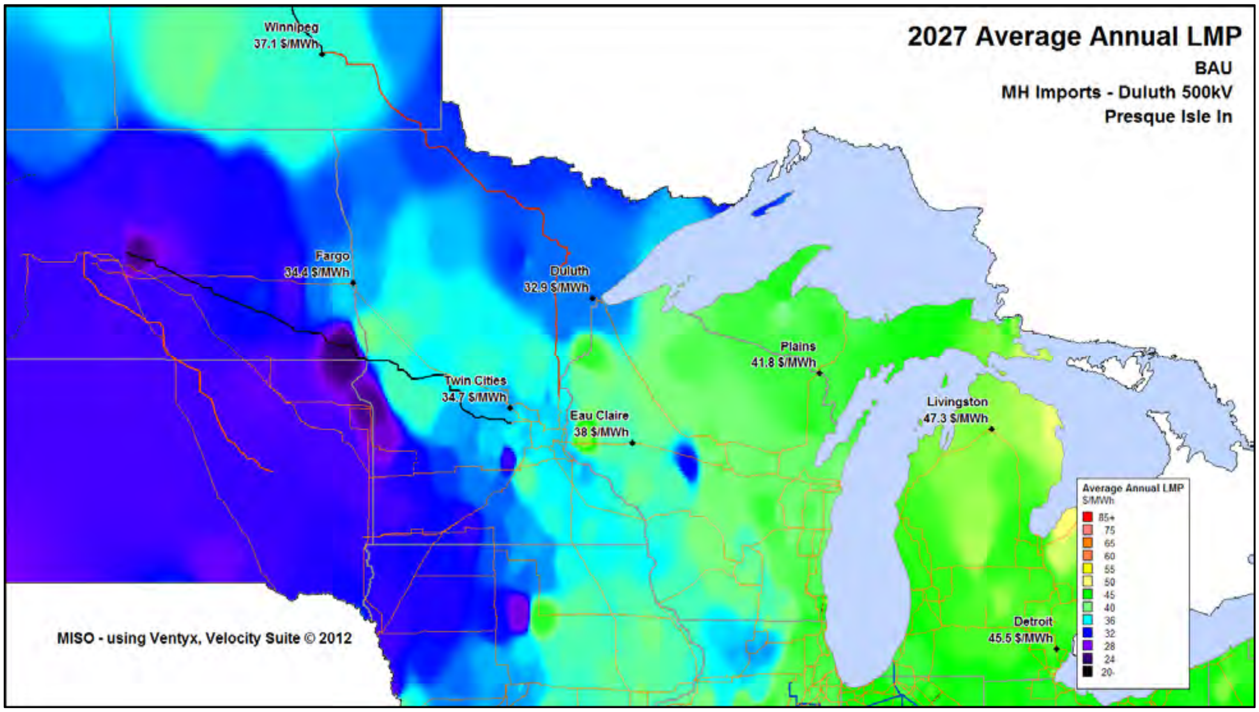


Figure 7-3: Pre-Portfolio LMP Plots – x3 "Zoomed-In" Scale

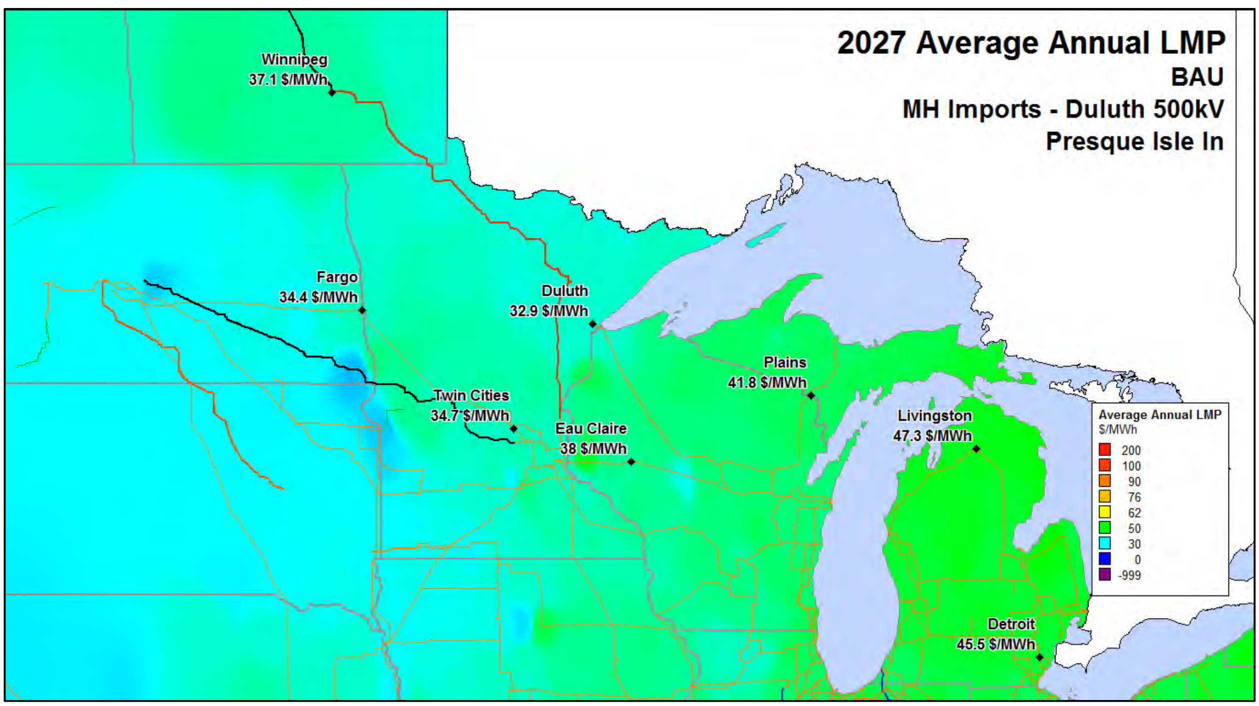


Figure 7-4: Pre-Portfolio LMP Plots – Standard Market Scale

Reliability Analysis

The three portfolios were run though a set of no-harm study analyses to determine whether the addition of the portfolio would create new reliability constraints. These constraints will drive underlying or accompanying mitigation needed were the portfolio to be approved. No-harm thermal, voltage, and transient stability analyses were performed on each portfolio.

The reliability constraints shown in this report were not verified with the appropriate Transmission Owners and should be viewed only as indicative in nature. The goal of the reliability analysis was to assess the amount of mitigation needed and not to propose specific mitigation. Further analysis of the portfolios or projects would be required for approval through another study process outside of the Northern Area Study.

Thermal Analysis

PSS®MUST was used to perform an AC contingency study monitoring 100 kV and above facilities and running all NERC Category A, B and C contingencies in the study area. MTEP12 monitored element and contingency files were used along with RTEP10 ComEd and AEP contingencies used in the MTEP11 MVP study. Non-converged contingencies were ignored in keeping with the goal of assessing the amount of mitigation and not determining the cause and mitigation for every constraint.

Portfolios were added to the basecase models to create a pre- and post-transmission case. A comparison between the resulting constraints of the two cases yielded the new and worsened constraints caused by the portfolio. New constraints were defined to be facilities which were below 100% loaded in the pre-transmission case, were above 100% loaded in the post-transmission case and had at least a 3 MVA increase in loading between the cases. A worsened constraint was defined to be a facility which was over 100% loaded in both the pre- and post-transmission case and had at least a 10 MVA increase in loading in the post-transmission case. The worsened constraints are informational and show facilities where a larger mitigation may be required if the loading is brought below 100% by 2022 but could overload again with the addition of the portfolio.

Voltage Analysis

The contingency study performed in the thermal analysis was also used to output voltage violations based on the MTEP12 bus voltage ranges. A new bus with violations was defined to be one which had a violation in the post-transmission case and no violations, under any contingency, in the pre-transmission case. Many new buses in an area would indicate a potential need for additional reactive power support. Pursuant to that, areas with at least five new buses with violations were reported.

Transient Stability Analysis

The Northern Area Study transient stability analysis focused on the impact of the new transmission, violations identified between study scenario and reference scenarios were addressed and mitigations were proposed. Violations and issues identified between reference scenario and benchmark scenario were for information only. Benchmark violations are addressed through the annual MTEP study. Reference case issue will be addressed in MH Synergy Study or TSR Study.

7.1 Portfolio 1: HVDC

Estimated Cost: $894.2M** ***Assumes $0 for MWEX upgrade*

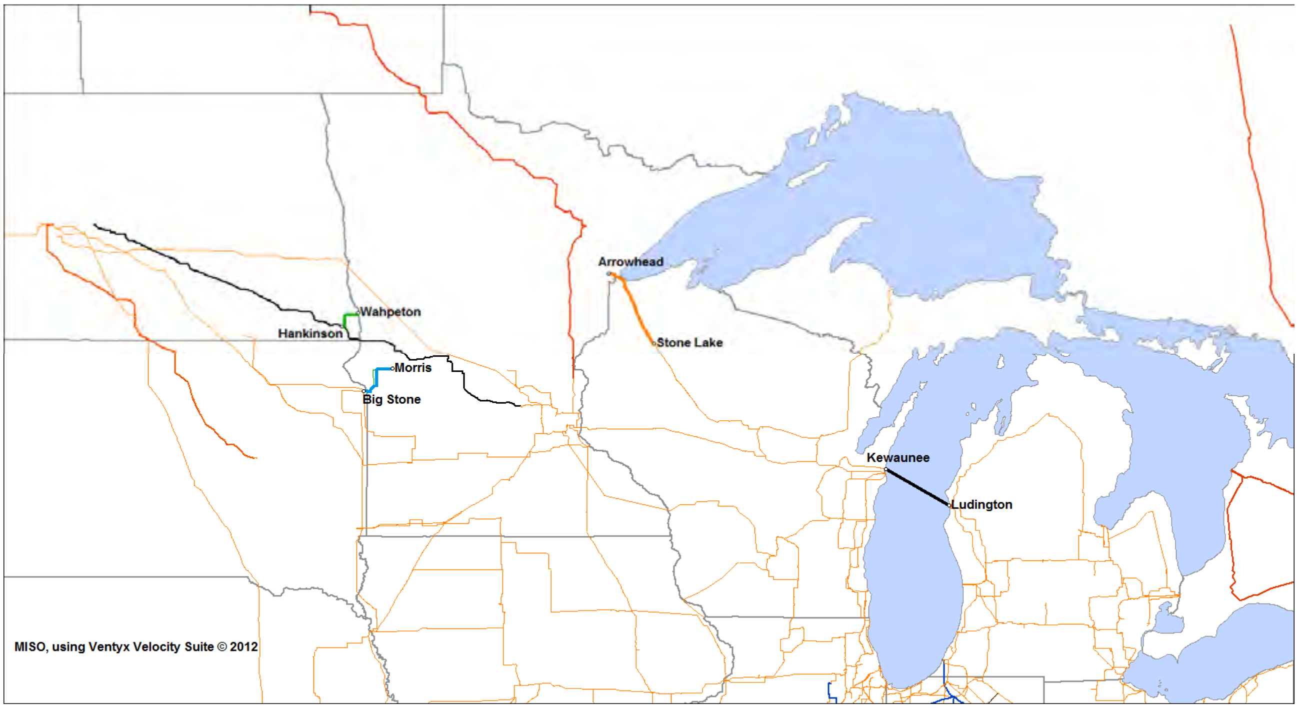


Figure 7-5: *Portfolio 1* (HVDC)

Portfolio 1 includes the following projects:

- *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade*
- *Kewaunee – Ludington 500 kV HVDC*
- *Upgrade Arrowhead – Stone Lake 345 kV* (MWEX); Only in Duluth tie-line scenarios

The economic benefits and reliability findings for *Portfolio 1* are outlined in the following sections:

7.1.1 Economic Analysis of Portfolio 1

The adjusted production cost savings for *Portfolio 1* are shown in Table 7-2.

Scenario	2022 MISO APC Savings ($M-2022)	2027 MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	16.7	45.3	0.24
Business As Usual Demand, MH - Duluth Tie-Line	17.3	53.1	0.28
Business As Usual Demand, MH - Fargo Tie-Line	17.2	39.0	0.21
High Demand and Energy, No new MH Tie-Line	40.5	129.0	0.69
High Demand and Energy, MH - Duluth Tie-Line	41.0	135.3	0.72
High Demand and Energy, MH - Fargo Tie-Line	39.4	120.7	0.64

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 7-2: *Portfolio 1* (HVDC) Adjusted Production Cost Savings

The majority of *Portfolio 1*'s benefits are from mitigating wind congestion on the Minnesota and Dakotas' border; as such, adjusted production cost benefits are proportional to wind and load levels. *Portfolio 1* increases *Kewaunee – Ludington 500 kV HVDC* line loading from ~65% in the stand-alone option (Section 6) to ~85% when operated in a portfolio; consequently, up to 15% of *Portfolio 1*'s adjusted production cost savings are synergic. Adjusted production cost benefits are relatively less in the MH – Fargo Tie-Line Scenarios because the tie-line lessens MN/DAK congestion.

Portfolio 1 relieves a large portion of the congestion around Lake Michigan – a much higher level than what was originally scoped in the economic potential identification. Because the portfolio mitigates nearly all of the Northern Area Study footprint congestion and helps relieve additional congestion outside of the study footprint the capture rate was 94% - 100%+.

Portfolio 1 serves to nearly equalize LMPs between Michigan and the rest of study the footprint. Comparing Figures 7-6 and 7-4, the LMP difference between Wisconsin and Michigan was \$5.5/MWh before the portfolio in the Business as Usual scenario and was reduced to \$1.3/MWh through the inclusion of *Portfolio 1*. LMP plots scales are three times more granular to show small differences; in the standard market scale there are no visible color differences in the post portfolio plot.

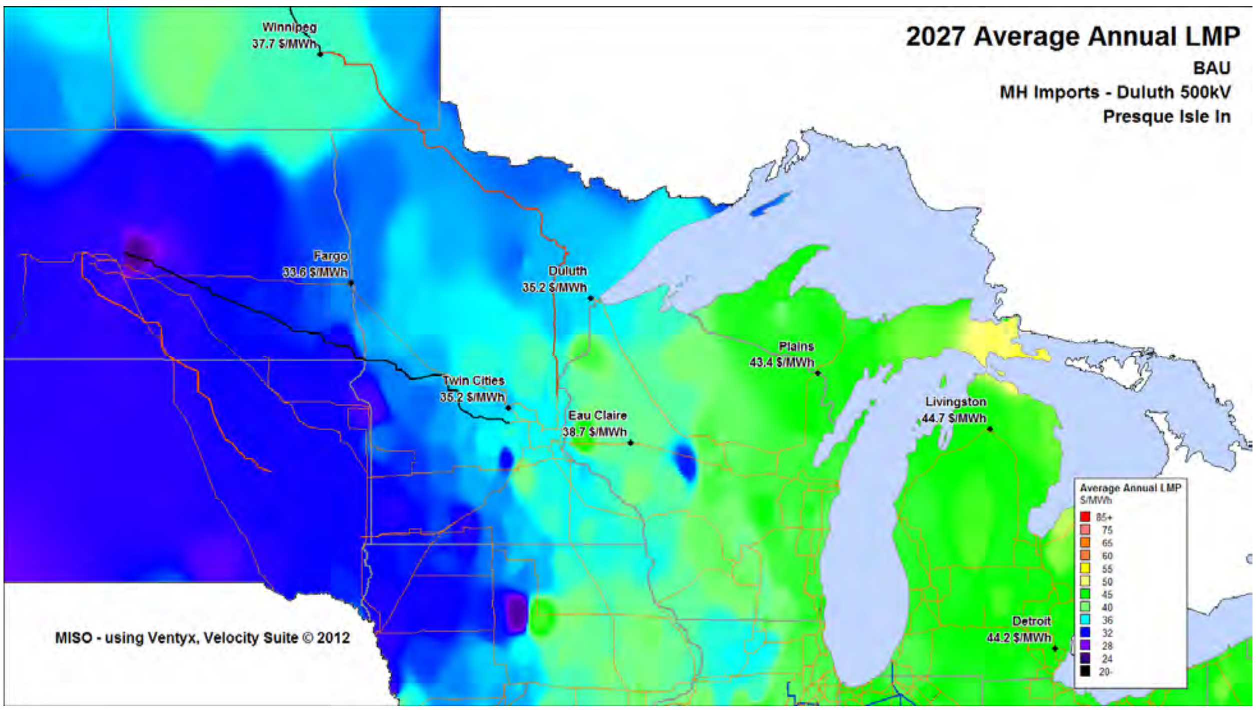


Figure 7-6: Post-*Portfolio 1* LMP Plot (Comparable to Figure 7-4) - x3 "Zoomed-In" Scale

The remaining post-portfolio LMP differences seen in Figure 7-6 are primarily attributed to transmission line losses and congestion outside of the Northern Area Study footprint. Figure 7-7 displays the post-*Portfolio 1* LMP plot without line losses.

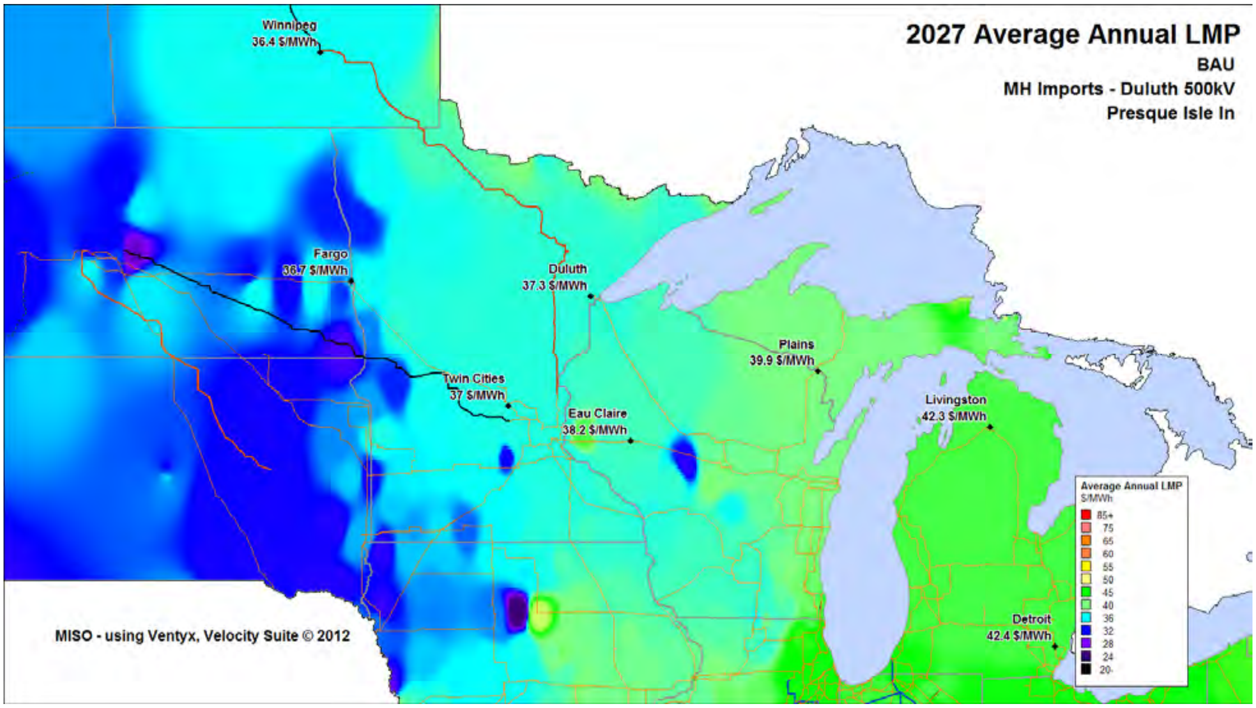


Figure 7-7: Post-*Portfolio 1* LMP Plot Without Line Losses - x3 "Zoomed-In" Scale

7.1.2 Reliability Analysis of Portfolio 1

Thermal Analysis

Twenty-four new and 25 worsened constraints were found in the 2022 Shoulder model with the HVDC Portfolio. The 2022 Summer Peak model had 80 new and 77 worsened constraints. Table 7-3 shows the Shoulder results and Table 7-4 lists the Summer Peak results.

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
699211 PT BCH3 345 699630 KEWAUNEE 345 1	1071	158.8	< 80	> 843.9	New
699244 ARP 345 345 699245 ARP 138 138 1	381	112.4	97.0	58.7	New
256102 18PLUM 138 256275 STOVER 138 1	202	110.7	86.1	49.7	New
271921 LISLE; R 138 272855 YORK ;RT 138 1	449	101.5	90.8	48.0	New
681543 ALMA 5 161 681545 LUFKIN 161 1	213.4	116.1	96.5	41.8	New
698878 DEWEY 4 138 699366 NORWCH N 138 1	225	110.4	91.9	41.6	New
693537 MONTANA 138 699297 DEWEY 5 138 1	225	106.2	87.8	41.4	New
608683 STIN-MN7 115 608684 STIN-WI7 115 1	220	116.4	97.9	40.7	New
699332 HARBOR-1 138 699344 KANSAS-6 138 1	213	113.1	94.4	39.8	New
256246 18PERMQT 138 256277 18STRONC 138 1	233	110.1	94.3	36.8	New
699059 PAD 138 138 699141 TOWNLINE 138 1	403	106.0	97.2	35.5	New
698058 NW_BELOIT 138 699059 PAD 138 138 1	403	101.4	93.9	30.2	New
270809 LISLE; R 345 991307 LISLE 84 1.00 1	480	101.3	95.6	27.4	New
272375 ROMEO; R 138 272783 WILL ; R 138 1	397	102.8	96.3	25.8	New

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
270766 GOODI;3B 345 275190 GOODI;3M 138 1	480	101.9	98.2	17.8	New
271564 GOODI; B 138 275190 GOODI;3M 138 1	480	101.9	98.2	17.8	New
698800 MAINE115 115 699703 HILLTP 115 1	244	105.1	99.0	14.9	New
271328 DIXON;BT 138 271332 DIXON; B 138 1	148	103.8	95.3	12.6	New
271331 DIXON;8R 138 272097 NELSO;RT 138 1	440	100.2	97.5	11.9	New
603131 AIRLAKE7 115 615440 GRE-LKMARN 7 115 1	197.7	101.5	97.3	8.3	New
271320 DP 46;7I 138 271656 HIGGI; B 138 1	270	101.9	99.5	6.5	New
699732 BUNKERHL 115 699784 BLACK BK 115 1	95	100.1	94.3	5.5	New
652508 S3 7 115 658072 ERIE RD7 115 1	154.4	102.2	99.2	4.6	New
603010 LKYNKTN7 115 603046 LYON CO7 115 1	156	101.5	99.4	3.3	New
602016 REDCDR 5 161 602035 CRYSTAL5 161 1	223.1	131.9	109.6	49.8	Worsened
256145 18FOURMI 138 256524 18HWTHNJ 138 1	259	149.6	134.4	39.4	Worsened
608676 HIBBARD7 115 608680 WNTR ST7 115 1	200	140.2	124.3	31.8	Worsened
608633 FAIRMPK7 115 608680 WNTR ST7 115 1	200	130.1	114.3	31.6	Worsened
608633 FAIRMPK7 115 608683 STIN-MN7 115 1	200	125.2	109.5	31.4	Worsened
270700 CORDO; B 345 270828 NELSO; B 345 1	1479	113.9	111.8	31.1	Worsened
681532 WABACO 5 161 681537 ROCHSTR5 161 1	221.1	114.1	100.4	30.3	Worsened
270808 LISLE; B 345 275197 LISLE;2M 138 1	465	112.1	106.7	25.1	Worsened
271920 LISLE;2B 138 275197 LISLE;2M 138 1	465	112.2	107.0	24.2	Worsened
256135 18EASTNJ 138 256209 18MARQTT 138 1	117	190.2	169.7	24.0	Worsened
256044 18AMBMPJ 138 256135 18EASTNJ 138 1	117	179.0	158.6	23.9	Worsened
608632 DAHLBRG7 115 608684 STIN-WI7 115 1	107	144.9	123.9	22.5	Worsened
603141 IRONRIV7 115 608632 DAHLBRG7 115 1	107.8	134.8	114.0	22.4	Worsened
270731 ELECT;4R 345 275184 ELECT;4M 138 1	465	113.1	108.8	20.0	Worsened
271393 ELECT;4R 138 275184 ELECT;4M 138 1	465	113.3	109.1	19.5	Worsened
601001 FORBES 2 500 601013 ROSEAUS2 500 1	2165.1	127.0	126.1	19.5	Worsened
631052 LANSINGW 161 681523 GENOA 5 161 1	264	110.5	103.6	18.2	Worsened
601012 ROSEAUN2 500 667501 RIEL 2 500 1	1905.3	126.2	125.3	17.1	Worsened
601012 ROSEAUN2 500 601038 ROSEAUM 2 500 1	1732	123.0	122.1	15.6	Worsened
601013 ROSEAUS2 500 601038 ROSEAUM 2 500 1	1732	123.0	122.1	15.6	Worsened
270767 GOODI;1R 345 275240 GOODI;1M 138 1	480	112.0	109.1	13.9	Worsened
271565 GOODI; R 138 275240 GOODI;1M 138 1	480	112.0	109.1	13.9	Worsened
255115 17AETNA 138 255149 17LKGORG 138 1	253	119.1	114.5	11.6	Worsened
603065 CHISAGO7 115 605269 LINDSTM7 115 1	347.9	103.2	100.0	11.1	Worsened
631064 BVR CH 5 161 631067 ALBANY 5 161 1	223	108.5	104.0	10.0	Worsened

Table 7-3: HVDC Shoulder Thermal Results

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
699211 PT BCH3 345 699630 KEWAUNEE 345 1	1071	203.9	96.2	1153.5	New
699253 ARCADN1 345 699432 PLS PR1 345 1	872	114.6	< 80	> 301.7	New
256000 18ARGNTA 345 256024 18TALLMG 345 1	896	106.6	< 80	> 238.3	New
699432 PLS PR1 345 699471 RACINE1 345 1	1096	101.5	< 80	> 235.6	New
270770 GOODI;4B 345 270810 LOCKP; B 345 1	1479	113.1	99.9	195.2	New
270729 E FRA; R 345 274804 UPNOR;RP 345 1	1091	110.3	93.0	188.7	New
255109 17MUNSTR 345 270677 BURNH;0R 345 1	1069	104.5	87.0	187.1	New
693580 CYPRESS 345 699304 FORST JT 345 1	488	115.9	< 80	> 175.2	New
270715 DP 46;RT 345 270781 ITASC; R 345 1	1242	101.9	89.4	155.3	New
270780 ITASC; B 345 270812 LOMBA; B 345 1	1528	101.8	93.6	125.3	New
270808 LISLE; B 345 270810 LOCKP; B 345 1	1341	104.5	95.3	123.4	New
698864 BLUMND5 138 699268 BUTLER 138 1	211	132.2	< 80	> 110.1	New
698865 BLUMND6 138 699268 BUTLER 138 2	196	133.2	84.6	95.3	New
699157 COL 345 345 699167 COL 138 138 2	499	106.5	90.1	81.8	New
243212 05BENTON 345 243250 05BENTON 138 1	564	110.7	97.4	75.0	New
256201 18LVNSTN 138 256202 18LIVPKR 138 1	136	134.6	< 80	> 74.3	New
270769 GOODI;2R 345 270811 LOCKP; R 345 1	1479	103.8	98.8	74.0	New
699175 NFL 138 138 699677 AVIATION 138 1	230	119.3	87.3	73.6	New
256049 18ABILKJ 138 263653 18BRADLEY 138 1	191	122.0	84.3	72.0	New
698863 BLUMND3 230 699370 OC CRK6 230 2	535	112.1	98.8	71.2	New
256045 AMBER 1 138 256257 18DONLDS 138 1	210	113.3	< 80	> 69.9	New
270796 KINCA; B 345 347962 7PAWNEE 345 1	717	100.0	90.8	66.0	New
699663 PROGRESS AVE 138 699677 AVIATION 138 1	230	106.5	< 80	> 61.0	New
256055 18BARRYJ 138 263653 18BRADLEY 138 1	191	108.1	< 80	> 53.7	New
699663 PROGRESS AVE 138 699673 EOD_BUS2 138 1	230	102.5	< 80	> 51.8	New
256281 18TALLMG 138 256314 18WEALTH 138 2	389	101.7	89.6	47.1	New
255104 17GRNACR 345 255130 17GRNACR 138 1	560	105.2	96.9	46.5	New
699332 HARBOR-1 138 699344 KANSAS-6 138 1	213	112.0	90.6	45.6	New
271131 BUTTE; R 138 271551 G ELL; R 138 1	449	100.7	90.8	44.5	New
699299 ELKHT L 138 699955 SAUKVL4 138 1	88	145.2	95.5	43.7	New
698878 DEWEY 4 138 699366 NORWCH N 138 1	225	108.9	90.7	41.0	New
693537 MONTANA 138 699297 DEWEY 5 138 1	225	106.9	89.2	39.8	New
681543 ALMA 5 161 681545 LUFKIN 161 1	213.4	100.8	82.6	38.8	New
256281 18TALLMG 138 256524 18HWTHNJ 138 1	435	101.9	93.1	38.3	New
243349 05NEWCAR 138 255184 17TRALCK 138 1	151	111.7	87.1	37.1	New
256257 18DONLDS 138 256317 18WHITLK 138 1	168	101.8	< 80	> 36.6	New
699251 ALERTON8 138 699371 OC CRK-2 138 1	241	111.7	96.8	35.9	New
271079 B ROA;RT 138 271565 GOODI; R 138 1	397	103.4	94.4	35.7	New
255124 17CHIAVE 138 255169 17PRAX 3 138 1	189	100.8	81.9	35.7	New

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
255156 17MITCHL 138 255186 17USCOKE 138 1	191	114.0	95.3	35.7	New
699251 ALERTON8 138 699352 LINCOLN3 138 1	225	101.9	86.2	35.3	New
243327 05LAPORT 138 243353 05OLIVE 138 1	167	108.8	88.5	33.9	New
271563 GOLF ; R 138 272105 NILES;RT 138 1	449	103.3	95.8	33.7	New
699299 ELKHT L 138 699533 FOREST J 138 1	96	114.8	< 80	> 33.4	New
271901 LANDM; R 138 272603 TONNE;1R 138 1	321	106.8	96.4	33.4	New
255115 17AETNA 138 255149 17LKGORG 138 1	253	108.3	95.5	32.4	New
271130 BUTTE; B 138 272854 YORK ;BT 138 1	449	100.8	93.7	31.9	New
243250 05BENTON 138 243365 05RIVRSD 138 1	167	106.5	87.6	31.6	New
243250 05BENTON 138 243365 05RIVRSD 138 2	167	106.4	87.5	31.6	New
271074 BEDFO;BT 138 271216 CLEAR;BT 138 1	440	100.7	93.8	30.4	New
270714 DP 46;BT 345 275178 DP 46;4M 138 1	465	105.1	98.6	30.2	New
699366 NORWCH N 138 699473 RAMSY-5 138 1	293	105.4	95.3	29.6	New
699361 NICHLSON 138 699371 OC CRK-2 138 1	332	106.4	97.5	29.5	New
243349 05NEWCAR 138 255152 17MAPLE 138 1	137	109.6	89.1	28.1	New
271318 DP 46; B 138 275178 DP 46;4M 138 1	465	104.2	98.4	27.0	New
272078 W601 ;BT 138 272248 PLAIN; B 138 1	223	104.0	92.1	26.5	New
270917 WAYNE; R 345 275229 WAYNE;4M 138 1	465	103.2	97.8	25.1	New
256246 18PERMQT 138 263666 18LAKE CNTY 138 1	117.1	112.6	91.7	24.5	New
272741 WAYNE; R 138 275229 WAYNE;4M 138 1	465	102.6	97.4	24.2	New
698840 ACEC BADGERW 138 699808 PETENWEL 138 1	94	103.0	< 80	> 21.6	New
270811 LOCKP; R 345 270813 LOMBA; R 345 1	1528	100.1	98.7	21.4	New
608633 FAIRMPK7 115 608680 WNTR ST7 115 1	200	101.5	91.0	21.0	New
270733 ELECT;3R 345 275183 ELECT;3M 138 1	465	102.6	98.3	20.0	New
698840 ACEC BADGERW 138 699240 SAR 138 138 1	94	100.3	< 80	> 19.1	New
270659 BEDFO; R 345 275157 BEDFO;4M 138 1	465	103.3	99.6	17.2	New
255130 17GRNACR 138 255179 17STJOHN 138 1	253	102.6	96.6	15.2	New
271073 BEDFO; R 138 275157 BEDFO;4M 138 1	465	103.1	99.9	14.9	New
608632 DAHLBRG7 115 608684 STIN-WI7 115 1	107	100.0	86.8	14.1	New
698800 MAINE115 115 699703 HILLTP 115 1	244	103.7	98.4	12.9	New
271107 J323 ;RT 138 271781 JO 9; R 138 1	214	103.2	97.3	12.6	New
698857 OC CRK8 230 699367 ELM ROAD 345 1	300	101.5	97.4	12.3	New
271328 DIXON;BT 138 271332 DIXON; B 138 1	148	103.0	94.7	12.3	New
271218 CLYBO; B 138 271326 DIVER; B 138 1	275	102.6	98.6	11.0	New
271462 FISK ; B 138 990952 FISK 82 1.00 1	480	101.4	99.3	10.1	New
270738 FISK; B 345 990952 FISK 82 1.00 1	480	101.5	99.7	8.6	New
270810 LOCKP; B 345 270812 LOMBA; B 345 1	1528	100.2	99.7	7.6	New
271230 CRAWF; G 138 990756 CRAWFORD 82 1.00 1	480	101.1	99.6	7.2	New
699732 BUNKERHL 115 699784 BLACK BK 115 1	95	102.3	97.5	4.6	New

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
255150 17LNG 138 255152 17MAPLE 138 1	136	101.4	98.6	3.8	New
255150 17LNG 138 255180 17STLWEL 138 1	136	101.4	98.6	3.8	New
270728 E FRA; B 345 270766 GOODI;3B 345 1	1399	126.2	114.1	169.3	Worsened
270733 ELECT;3R 345 270847 PLANO; R 345 1	1341	122.5	110.3	163.6	Worsened
270781 ITASC; R 345 270813 LOMBA; R 345 1	1341	114.4	103.1	151.5	Worsened
270730 ELECT; B 345 270846 PLANO; B 345 1	1341	114.5	103.2	151.5	Worsened
270679 BYRON; R 345 270918 WEMPL; B 345 1	1726	126.4	118.5	136.4	Worsened
699525 BD MRT2 138 699551 NEEVIN-WEC 138 1	332	134.4	103.4	102.9	Worsened
270729 E FRA; R 345 270767 GOODI;1R 345 1	1399	118.4	111.5	96.5	Worsened
271627 HANOV; R 138 272601 TOLLW; R 138 1	349	130.8	110.0	72.6	Worsened
271067 BATAV;RT 138 274747 AUROR;RP 138 1	449	125.7	111.7	62.9	Worsened
272487 S ELG;RT 138 272741 WAYNE; R 138 1	449	131.7	120.2	51.6	Worsened
271551 G ELL; R 138 271925 LOMBA;2R 138 1	321	131.9	116.9	48.2	Worsened
699443 PORT WSH 138 699487 SAUKV6 138 1	481	151.6	141.6	48.1	Worsened
699443 PORT WSH 138 699482 SAUKVL5 138 1	481	151.5	141.6	47.6	Worsened
699443 PORT WSH 138 699955 SAUKVL4 138 1	481	151.1	141.2	47.6	Worsened
699371 OC CRK-2 138 699422 PENNSYLV 138 1	332	122.2	108.9	44.2	Worsened
255172 17ROXANA 138 272502 SLINE; B 138 1	253	119.4	102.0	44.0	Worsened
271131 BUTTE; R 138 272855 YORK ;RT 138 1	349	137.4	125.4	41.9	Worsened
272486 S ELG;BT 138 272740 WAYNE; B 138 1	449	119.7	110.5	41.3	Worsened
256145 18FOURMI 138 256524 18HWTHNJ 138 1	259	166.2	151.4	38.3	Worsened
271550 G ELL; B 138 271922 LOMBA; B 138 1	321	119.9	108.0	38.2	Worsened
271562 GOLF ; B 138 272104 NILES;BT 138 1	449	109.5	101.1	37.7	Worsened
270739 FISK; R 345 270899 TAYLO; R 345 1	874	109.9	105.7	36.7	Worsened
271921 LISLE; R 138 272855 YORK ;RT 138 1	449	130.9	123.0	35.5	Worsened
255115 17AETNA 138 255169 17PRAX 3 138 1	189	118.9	100.2	35.3	Worsened
271130 BUTTE; B 138 271550 G ELL; B 138 1	349	119.9	109.9	34.9	Worsened
255155 17MILLER 138 255186 17USCOKE 138 1	191	134.7	116.9	34.0	Worsened
631095 E CALMS5 161 636616 SB 56 5 161 1	223	128.4	113.4	33.5	Worsened
270763 GARFI; R 345 270899 TAYLO; R 345 1	791	126.8	122.7	32.4	Worsened
255133 17HENDRK 138 255188 17USWMIL 138 1	143	132.3	110.4	31.3	Worsened
693720 BARLAND 138 699361 NICHLSON 138 1	293	116.0	106.0	29.3	Worsened
693720 BARLAND 138 699473 RAMSY-5 138 1	293	110.5	100.5	29.3	Worsened
270658 BEDFO; B 345 275155 BEDFO;2M 138 1	465	108.4	102.1	29.3	Worsened
255155 17MILLER 138 255185 17US TIN 138 1	191	121.7	106.4	29.2	Worsened
271072 BEDFO; B 138 271216 CLEAR;BT 138 1	440	107.6	101.0	29.0	Worsened
255115 17AETNA 138 255188 17USWMIL 138 1	143	144.3	124.0	29.0	Worsened
271921 LISLE; R 138 991307 LISLE 84 1.00 1	480	118.1	112.3	27.8	Worsened
271918 LISLE;1B 138 272854 YORK ;BT 138 1	449	122.8	116.8	26.9	Worsened

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
699344 KANSAS-6 138 699474 RAMSY-6 138 1	293	109.1	100.0	26.7	Worsened
699371 OC CRK-2 138 699474 RAMSY-6 138 1	293	115.0	105.9	26.7	Worsened
270762 GARFI; B 345 270898 TAYLO; B 345 1	791	130.0	126.7	26.1	Worsened
270808 LISLE; B 345 275197 LISLE;2M 138 1	465	128.3	122.7	26.0	Worsened
271920 LISLE;2B 138 275197 LISLE;2M 138 1	465	127.6	122.0	26.0	Worsened
271072 BEDFO; B 138 275155 BEDFO;2M 138 1	465	107.2	101.9	24.6	Worsened
255160 17MRKTNE 138 255176 17SHEFLD 138 1	243	118.1	108.0	24.5	Worsened
270809 LISLE; R 345 991307 LISLE 84 1.00 1	480	119.4	114.3	24.5	Worsened
271073 BEDFO; R 138 275154 BEDFO;1M 138 1	442	106.1	100.6	24.3	Worsened
270658 BEDFO; B 345 275154 BEDFO;1M 138 1	442	106.1	100.8	23.4	Worsened
270898 TAYLO; B 345 270922 WLOOP; B 345 1	874	125.9	123.4	21.9	Worsened
608676 HIBBARD7 115 608680 WNTR ST7 115 1	200	115.3	104.4	21.8	Worsened
271074 BEDFO;BT 138 272012 D775 ;BT 138 1	449	109.0	104.2	21.6	Worsened
271988 MCCOO; B 138 272012 D775 ;BT 138 1	449	109.0	104.3	21.1	Worsened
270766 GOODI;3B 345 275190 GOODI;3M 138 1	480	119.1	114.7	21.1	Worsened
271564 GOODI; B 138 275190 GOODI;3M 138 1	480	119.1	114.7	21.1	Worsened
270715 DP 46;RT 345 275176 DP 46;2M 138 1	465	108.1	103.7	20.5	Worsened
699368 OK CRK-5 230 699371 OC CRK-2 138 1	397	114.2	109.1	20.2	Worsened
601001 FORBES 2 500 601013 ROSEAUS2 500 1	2165.1	110.0	109.1	19.5	Worsened
271391 ELECT;3R 138 275183 ELECT;3M 138 1	465	104.0	100.0	18.6	Worsened
255132 17HARTSD 138 255179 17STJOHN 138 1	229	109.1	101.2	18.1	Worsened
271320 DP 46;7I 138 271656 HIGGI; B 138 1	270	122.1	115.4	18.1	Worsened
270731 ELECT;4R 345 275184 ELECT;4M 138 1	465	134.8	131.0	17.7	Worsened
270813 LOMBA; R 345 275198 LOMBA;2M 138 1	465	104.0	100.2	17.7	Worsened
271393 ELECT;4R 138 275184 ELECT;4M 138 1	465	134.2	130.4	17.7	Worsened
271565 GOODI; R 138 275240 GOODI;1M 138 1	480	120.2	116.7	16.8	Worsened
270812 LOMBA; B 345 275199 LOMBA;4M 138 1	465	104.8	101.2	16.7	Worsened
271319 DP 46; R 138 275176 DP 46;2M 138 1	465	107.1	103.7	15.8	Worsened
270717 DRESD; R 345 275180 DRESD;3M 138 1	480	110.7	107.7	14.4	Worsened
270767 GOODI;1R 345 275240 GOODI;1M 138 1	480	120.2	117.2	14.4	Worsened
271231 CRAWF; Y 138 275171 CRAWF;3M 138 1	480	114.8	111.8	14.4	Worsened
255139 17ISG 2 138 255172 17ROXANA 138 1	138	113.5	103.2	14.2	Worsened
699250 ARCADN6 138 990462 ARCADIAN T3 1.00 1	268	110.5	105.3	13.9	Worsened
271336 DRESD; B 138 275180 DRESD;3M 138 1	480	108.2	105.3	13.9	Worsened
270703 CRAWF; R 345 275171 CRAWF;3M 138 1	480	114.8	111.9	13.9	Worsened
601012 ROSEAUN2 500 601038 ROSEAUM 2 500 1	1732	106.5	105.7	13.9	Worsened
601013 ROSEAUS2 500 601038 ROSEAUM 2 500 1	1732	106.5	105.7	13.9	Worsened
256149 18GARFLD 138 256166 18HEMPHILL 138 1	200	130.2	123.6	13.2	Worsened
256044 18AMBMPJ 138 256135 18EASTNJ 138 1	117	137.8	127.8	11.7	Worsened

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
256135 18EASTNJ 138 256209 18MARQTT 138 1	117	150.9	141.2	11.3	Worsened

Table 7-4: HVDC Summer Peak Thermal Results

Voltage Analysis

Two high voltage and two low voltage areas were found in the 2022 Shoulder model with the HVDC Portfolio. The 2022 Summer Peak model had zero high voltage and nine low voltage areas. Table 7-5 shows the Shoulder results and Table 7-6 lists the Summer Peak results.

High Voltage

Area	# of New Buses with Violations
600 XEL	10
696 WPS	7

Low Voltage

Area	# of New Buses with Violations
218 METC	8
694 ALTE	66

Table 7-5: HVDC Shoulder Voltage Results

Low Voltage

Area	# of New Buses with Violations
218 METC	6
295 WEC	7
600 XEL	22
608 MP	15
615 GRE	30
620 OTP	8
627 ITCM	11
694 ALTE	5
696 WPS	8

Table 7-6: HVDC Summer Peak Voltage Results

Transient Stability Analysis

Northern Area Study transient stability analysis observed multiple voltage violations associated with Kewaunee – Ludington 500 kV HVDC.

The Kewaunee – Ludington 500 kV HVDC was models as follows within the transient stability analysis:

- ±500 kV 1600MW HVDC cable from Kewaunee to Ludington
  - The HVDC conversion station is assumed to maintain 0.8 ~ 0.9 Power Factor
  - 1200 Mvar switch shunt at Kewaunee to maintain Kewaunee voltage within [1.01,1.04]
    - Kewaunee AC bus voltage: 1.025
  - 1000 Mvar switch shunt at Ludington to maintain Ludington voltage within [1.01,1.04]
    - Ludington AC bus voltage: 1.038
  - PSS/e standard two terminal HVDC model
    - CDC4T

Thirteen disturbances were added to the fault list for Portfolio 1 to test the Kewaunee – Ludington HVDC dynamic model and the impact of Portfolio 1. The new disturbances included NERC TPL Category A, B and C. The Portfolio 1 added disturbances are listed in Appendix II of this report.

Voltage violations were identified in fault *NAS_KEW_PTB* and fault *0632_w_atc__c9__npir_bf1pobbs2-bs3* as shown in Table 7-7.

Fault	Violation	Fault Description
0632_w_atc__c9__npir_bf1pobbs2-bs3	Voltage Damping Violation	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs4	Transient Voltage Violation	SLG PTB bus fault
NAS_KEW_PTB	Voltage Damping Violation	3 phase fault at KEW, normal clearing, trip PTB-KEW, DC unblocked at clearing

Table 7-7: Voltage Violation Identified in Kewaunee-Ludington ±500 kV 1600MW HVDC

Tables 7-8 and 7-9 display the high and low transient violations observed in Kewaunee-Ludington ±500 kV 1600 MW HVDC scenario. The MTEP base case and Northern Area Study base case simulation results are also listed in the table for comparison.

CASE	Channel	MTEP Base Case	NAS Base Case	NAS +KEW-LUD DC	Description
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699766 [MACKINAC N 138.00]	1.019	1.008	0.4665	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699753 [STRAITS 138.00]	1.019	1.008	0.4694	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699630 [KEWAUNEE 345.00]	1.013	1.019	0.5874	SLG PTB bus fault

Table 7-8: Low Voltage Violations Identified in Kewaunee-Ludington ±500 kV 1600MW HVDC

Disturbance	CHANNEL NAME	MTEP Base Case	NAS Base Case	NAS+ KEW-LUD DC	Description
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699630 [KEWAUNEE 345.00]	1.0130	1.0170	1.5490	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699766 [MACKINAC N 138.00]	1.0190	0.9985	1.5210	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699753 [STRAITS 138.00]	1.0190	1.0080	1.5180	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699547 [MORGAN 345.00]	1.0100	1.0190	1.2270	SLG PTB bus fault
0632_w_atc__c9__npir_bf1pobbs2-bs3	VOLT 699359 [N APPLETON 345.00]	1.0040	1.0190	1.2180	SLG PTB bus fault

Table 7-9: High Voltage Violations Identified in Kewaunee-Ludington ±500 kV 1600MW HVDC

Figure 7-8 shows the voltage oscillations identified at the Kewaunee 345 kV bus in the fault of NAS_KEW_PTB, this fault simulated a 3-phase fault at Kewaunee with normal clearing to trip Kewaunee – Point Beach 345 kV, Kewaunee – Ludington HVDC unblocked at clearing.

Voltage oscillation and violations were identified in the Category B2 fault and Category C9 fault. To mitigate these violations two potential network upgrades were explored (summarized in Table 7-10).

Potential Network Upgrades
Second Circuit of Kewaunee - Point Beach 345 kV
600 MW Kewaunee – Ludington DC Reduction Scheme

Table 7-10: Portfolio 1 Potential Network Upgrades

As shown in Figure 7-9, a 345 kV second circuit from Kewaunee – Point Beach could potentially mitigate the oscillations and system performance issues shown in Figure 7-8.

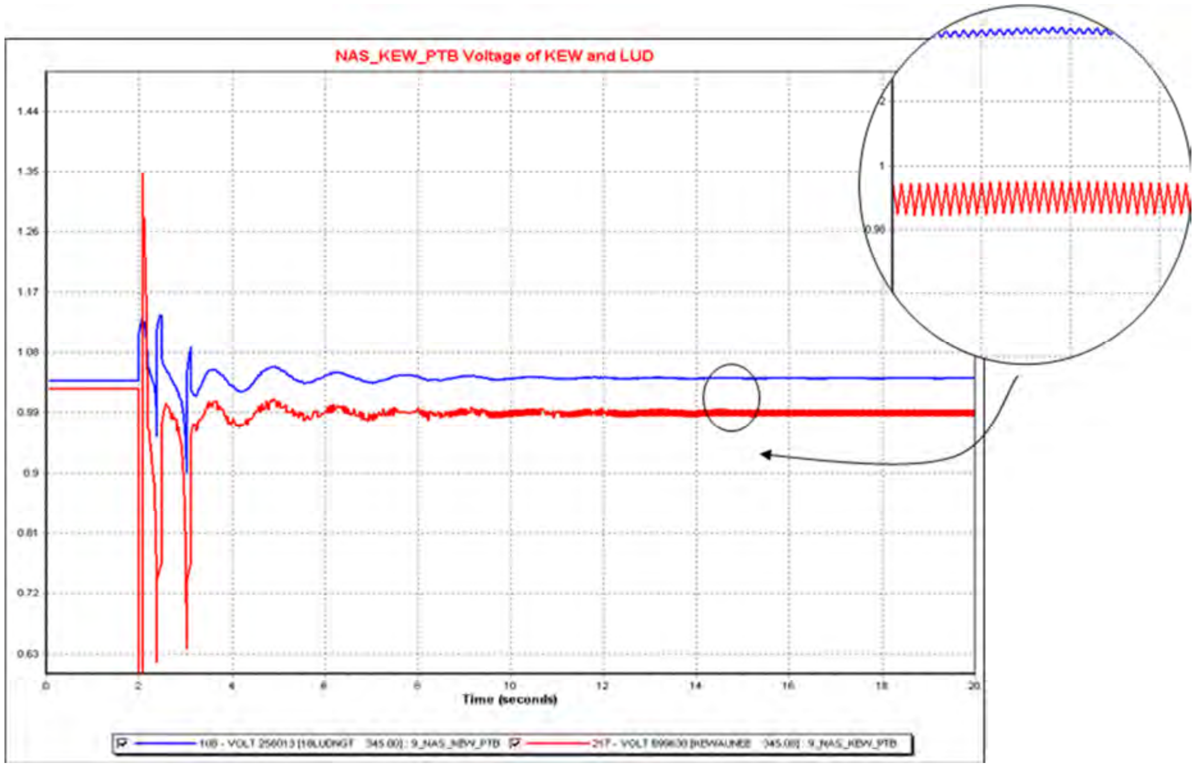


Figure 7-8: Voltage Oscillation Observed at Kewaunee 345 kV Bus in Fault NAS_KEW_PTB

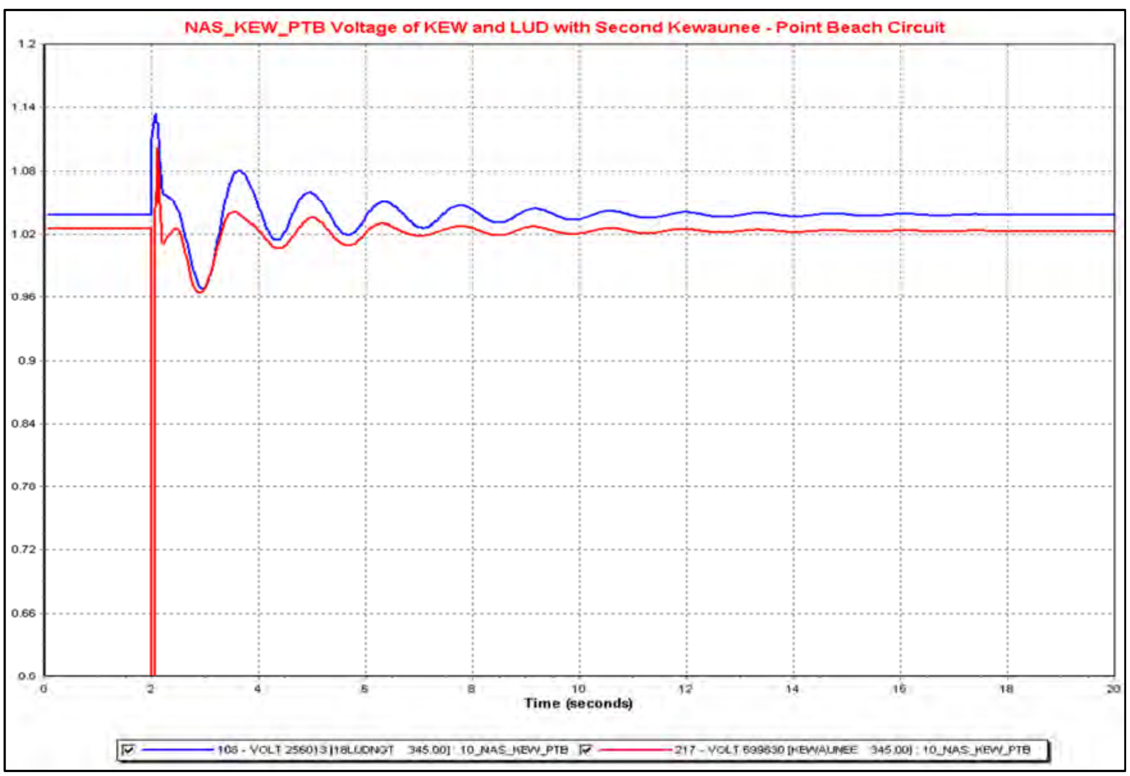


Figure 7-9: Voltage Trace of Kewaunee 345 kV Bus in Fault NAS_KEW_PTB with Second Kewaunee – Point Beach 345 kV Line

The voltage oscillation and transient voltage violation identified in Kewaunee 345 kV bus and Ludington 345 kV bus in the fault *0632_w_atc__c9__npir_bf1pobbs2-bs3* are shown in Figure 7-10. Significant voltage oscillation and transient voltage violation were identified at Kewaunee 345 kV bus, Mackinac 138 kV bus, Straits 138 kV bus, Morgan 345 kV bus and Appleton 345 kV bus. This fault simulated a single line ground bus fault at Point Beach nuclear power plant with normal clearing to trip both Point Beach nuclear generator as well as all branches connected to Point Beach Nuclear Power Plant, which includes branches to Forest Junction, Fox River and Granville.

Both Point Beach Nuclear Units were dispatch at 546.3 MW, which represents a total of 1092.6 MW. Since this fault dropped both Point Beach Nuclear Units, a 600 MW DC reduction was proposed as mitigation to improve system performance. Figure 7-11 shows the voltage swing trace of Kewaunee 345 kV bus and Ludington 345 kV bus with 600 MW DC reduction scheme – both the oscillation and transient system performance violations are mitigated.

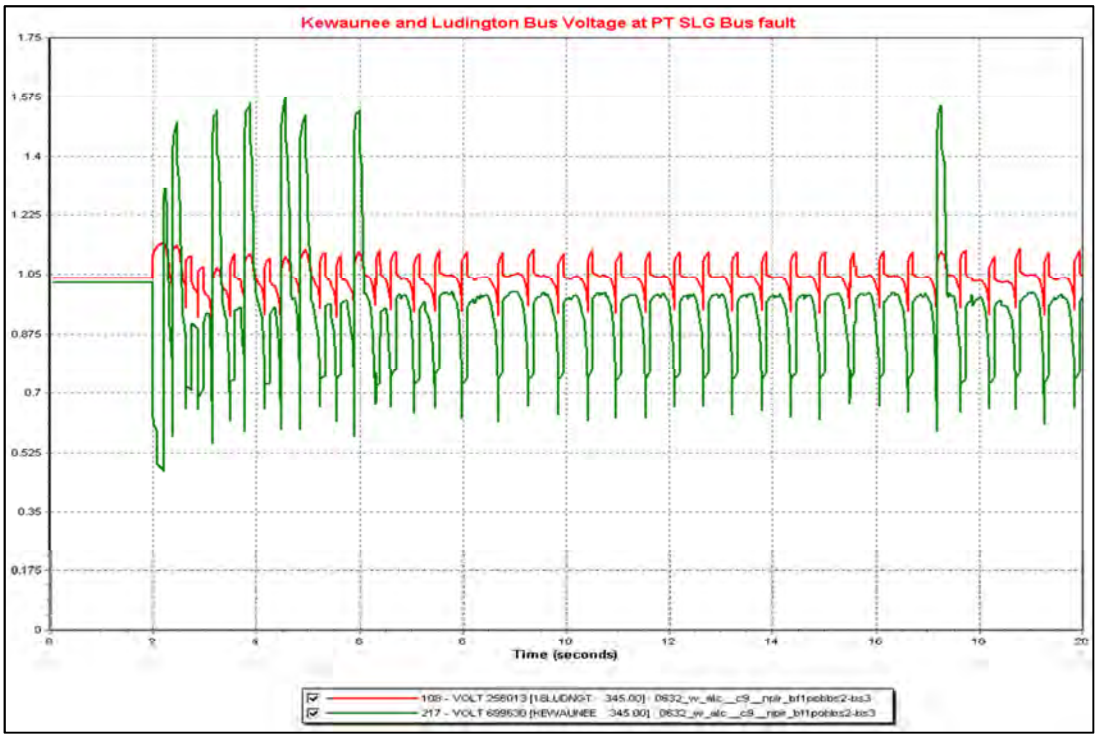


Figure 7-10: Voltage Oscillation Observed at Kewaunee and Ludington 345 kV Bus in Fault *0632_w_atc__c9__npir_bf1pobbs2-bs4*

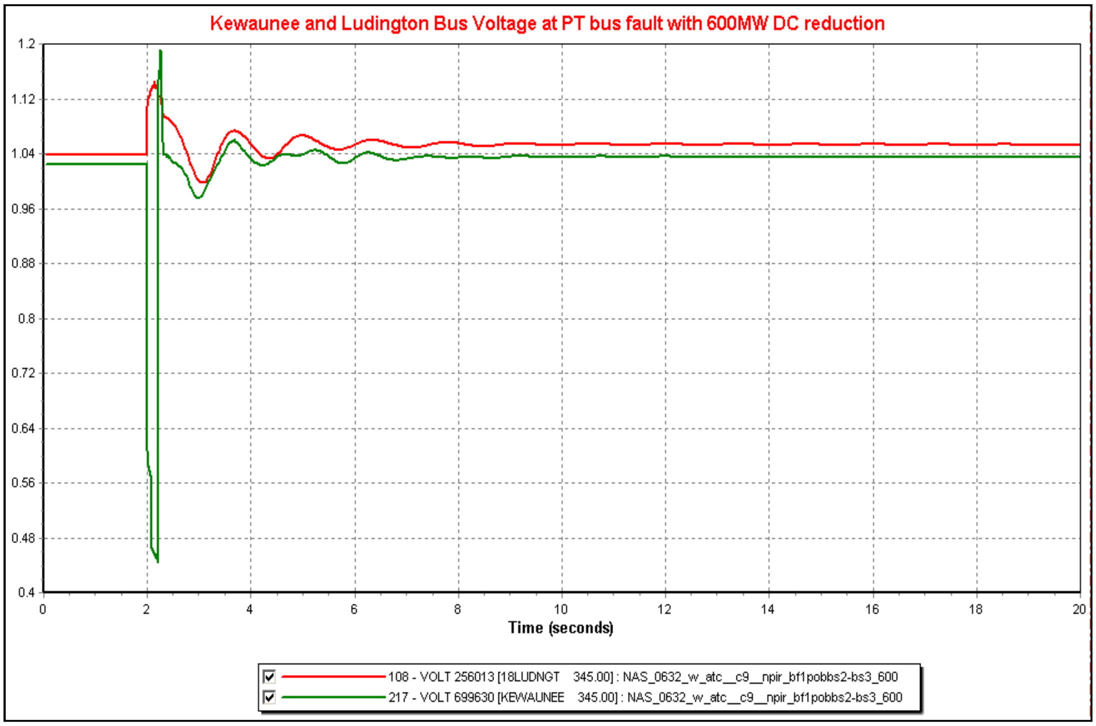


Figure 7–11: Voltage Trace Observed at Kewaunee and Ludington 345 kV Bus in Fault *0632_w_atc__c9__npir_bf1pobbs2-bs4* with 600MW DC Reduction Scheme

7.2 Portfolio 2: High Voltage AC

Estimated Cost: $559.8M** ***Assumes $0 for MWEX upgrade*

Figure 7-12: *Portfolio 2* (High Voltage AC)

Portfolio 2 includes the following projects:

- *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade*
- *Arnold – Livingston 345 kV*
- *Upgrade Arrowhead – Stone Lake 345 kV* (MWEX); Only in Duluth tie-line scenarios

The economic benefits and reliability findings for *Portfolio 2* are outlined in the following sections:

7.2.1 Economic Analysis of Portfolio 2

The adjusted production cost savings for *Portfolio 2* are shown in Table 7-11.

Scenario	2022 MISO APC Savings ($M-2022)	2027 MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	8.3	28.6	0.24
Business As Usual Demand, MH - Duluth Tie-Line	7.1	31.8	0.27
Business As Usual Demand, MH - Fargo Tie-Line	7.9	22.7	0.19
High Demand and Energy, No new MH Tie-Line	20.8	85.3	0.72
High Demand and Energy, MH - Duluth Tie-Line	19.6	87.3	0.74
High Demand and Energy, MH - Fargo Tie-Line	17.7	73.5	0.62

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 7-11: *Portfolio 2* (High Voltage AC) Adjusted Production Cost Savings

As seen in *Portfolio 1*, the majority of *Portfolio 2*'s adjusted production cost savings are attributed to wind mitigation via the *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV upgrade* and therefore the highest benefits are present in the high demand and energy scenarios. Because of the smaller incremental price addition over the cost effective *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV upgrade*, the benefit to cost ratios for *Portfolio 2* are higher than *Portfolio 1*. Up to 7% of the portfolio's benefits are synergic; *Arnold – Livingston 345 kV* line loading increases from ~14% in the stand-alone option to 16% in the portfolio.

Portfolio 2 relieves a large portion of the Northern Area Study footprint congestion; though, because of existing system impedances, does not mitigate as much Lake Michigan congestion as *Portfolio 1*. *Portfolio 2* has a maximum economic potential capture rate of 61% - 86%.

Additionally, *Portfolio 2* approximately halves the LMP spread between Michigan and the rest of the Northern Area Study footprint in the Business as Usual scenarios - $5.5/MWh pre-portfolio and $3.5/MWh post-*Portfolio 2*. The *Portfolio 2* LMP plot is shown in Figure 7-13. The remaining LMP differences are attributed to Lake Michigan congestion, congestion outside of the study footprint, and transmission line losses. LMP plots scales are three times more granular to show small differences; in the standard market scale there are no color differences in the post portfolio plot.

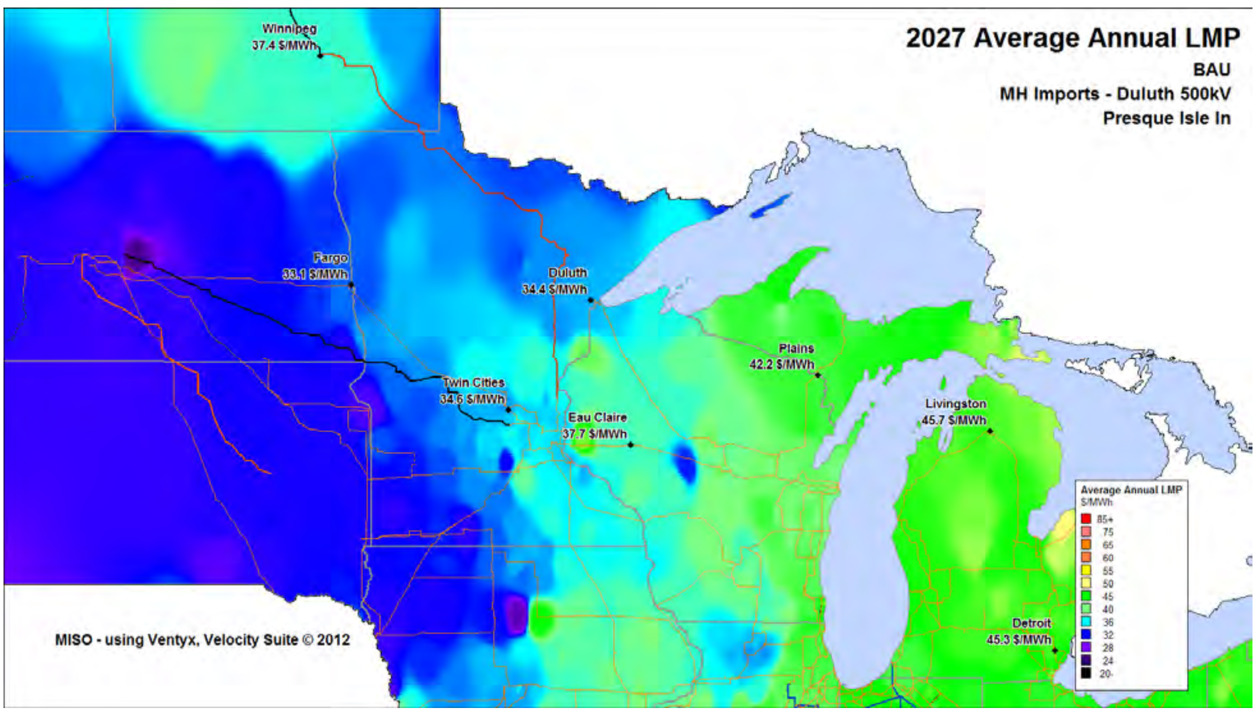


Figure 7-13: Post-*Portfolio 2* LMP Plot (Comparable to Figure 7-4) - x3 "Zoomed-In" Scale

7.2.2 Reliability Analysis of Portfolio 2

Thermal Analysis

One new and zero worsened constraints were found in the 2022 Shoulder model with the High Voltage AC Portfolio. The 2022 Summer Peak model had three new and three worsened constraints. Table 7-13 shows the Shoulder results and Table 7-12 lists the Summer Peak results.

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
698917 TILDEN2 138 699892 NATIONAL 138 1	202	119.8	97.4	45.2	New
699892 NATIONAL 138 699915 TILDEN1 138 1	202	119.4	97.1	45.0	New
270695 CHERR; R 345 275166 CHERR;2M 138 1	465	100.5	99.4	5.1	New
698917 TILDEN2 138 699915 TILDEN1 138 Z	143	140.1	107.6	46.5	Worsened
270694 CHERR; B 345 275165 CHERR;1M 138 1	442	116.3	113.7	11.5	Worsened
271193 CHERR; R 138 275165 CHERR;1M 138 1	442	114.6	112.1	11.1	Worsened

Table 7-12: HVAC Summer Peak Thermal Results

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
693656 BIGBAY 138 699904 PRESQ IS 138 1	145	101.4	95.4	8.7	New

Table 7-13: HVAC Shoulder Thermal Results

Voltage Analysis

One high voltage and one low voltage areas were found in the 2022 Shoulder model with the High Voltage AC Portfolio. The 2022 Summer Peak model had four high voltage and zero low voltage areas. Table 7-14 shows the Shoulder results and Table 7-15 lists the Summer Peak results. Approximately half of the high voltage bus violations shown in Area 218 may be due to an invalid contingency. However, there are still enough violations to report this high voltage area.

High Voltage

Area	# of New Buses with Violations
218 METC	198

Low Voltage

Area	# of New Buses with Violations
698 UPPC	17

Table 7-14: HVAC Shoulder Voltage Results

High Voltage

Area	# of New Buses with Violations
218 METC	138
295 WEC	19
600 XEL	9
698 UPPC	47

Table 7-15: HVAC Summer Peak Voltage Results

Transient Stability Analysis

No system degrades or system violation was identified in this scenario. No transient stability constraints were identified in this scenario. All faults met the transient period criteria.

Additional disturbances added for Portfolio 2 are detailed in Appendix III of this report. The new disturbances included NERC TPL Category B and C; NERC stability standards were implemented to evaluate the system performance.

7.3 Portfolio 3: Low Voltage AC

Estimated Cost: $285.1M** ***Assumes $0 for MWEX upgrade*

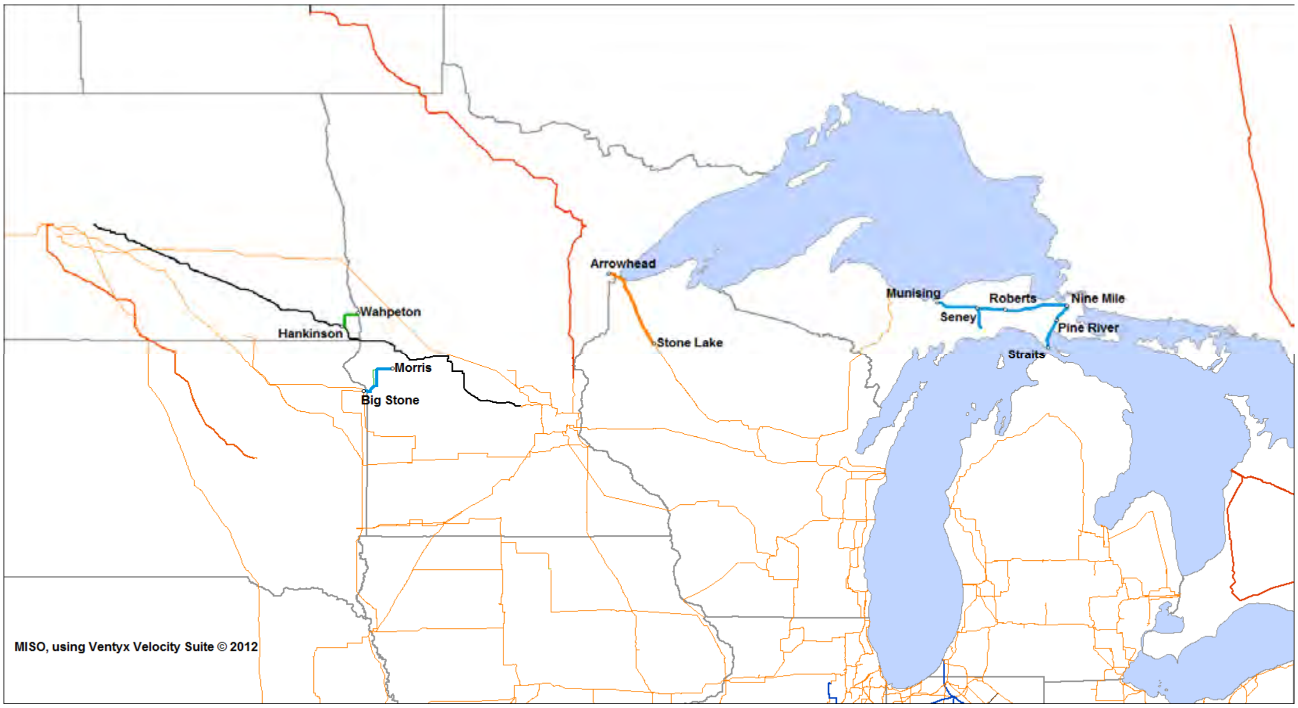


Figure 7-14: Portfolio 3 Low Voltage AC

Portfolio 3 includes the following projects:

- *Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV Upgrade*
- *Marquette – Mackinac County 138 kV*
- *Upgrade Arrowhead – Stone Lake 345 kV* (MWEX); Only in Duluth tie-line scenarios

The economic benefits and reliability findings for *Portfolio 3* are outlined in the following sections:

7.3.1 Economic Analysis of Portfolio 3

The adjusted production cost savings and benefit to cost ratios for *Portfolio 3* are shown in Table 7-16.

Scenario	2022 MISO APC Savings ($M-2022)	2027 MISO APC Savings ($M-2027)	Benefit to Cost Ratio
Business As Usual Demand, No new MH Tie-Line	3.8	24.4	0.4
Business As Usual Demand, MH - Duluth Tie-Line	2.6	24.5	0.4
Business As Usual Demand, MH - Fargo Tie-Line	2.5	17.4	0.29
High Demand and Energy, No new MH Tie-Line	12.7	73.9	1.22
High Demand and Energy, MH - Duluth Tie-Line	10.5	73.5	1.21
High Demand and Energy, MH - Fargo Tie-Line	10.6	60.4	0.99

* *In modeled Low Demand and Energy conditions little to no APC savings were present*

Table 7-16: *Portfolio 3* (Low Voltage AC) Adjusted Production Cost Savings

Portfolio 3 produced the least adjusted production cost savings, did not yield any synergic benefits, and did little to equalize Michigan LMPs with the rest of the Northern Area Study footprint; however had the highest benefit to cost ratio of the Northern Area Study portfolio because of its lower capital cost. In all Northern Area Study portfolios the majority of the cost effectiveness (benefit to cost ratio) was attributed to the *Hankinson – Wahpeton 230 kV and Big Stone – Morris 115 kV upgrade*. Portfolio 3's low voltage Upper Peninsula upgrade added the least additional cost and therefore was comparatively the most cost effective portfolio. The *Marquette – Mackinac County 138 kV* line loading is similar in the stand-alone options and portfolio simulations.

Portfolio 3 relieves a large portion of the Northern Area Study footprint congestion; though, does not mitigate as much Lake Michigan congestion as *Portfolio 1* or *Portfolio 2*. *Portfolio 3* has a maximum economic potential capture rate of 50% - 68%.

As shown comparing Figures 7-15 and 7-4, *Portfolio 3* does little to equalize Michigan LMPs with the rest of the Northern Area Study footprint. Remaining LMP differences are primarily attributed to Lake Michigan area congestion. LMP plots scales are three times more granular to show small differences; in the standard market scale there are no color differences in the post portfolio plot.

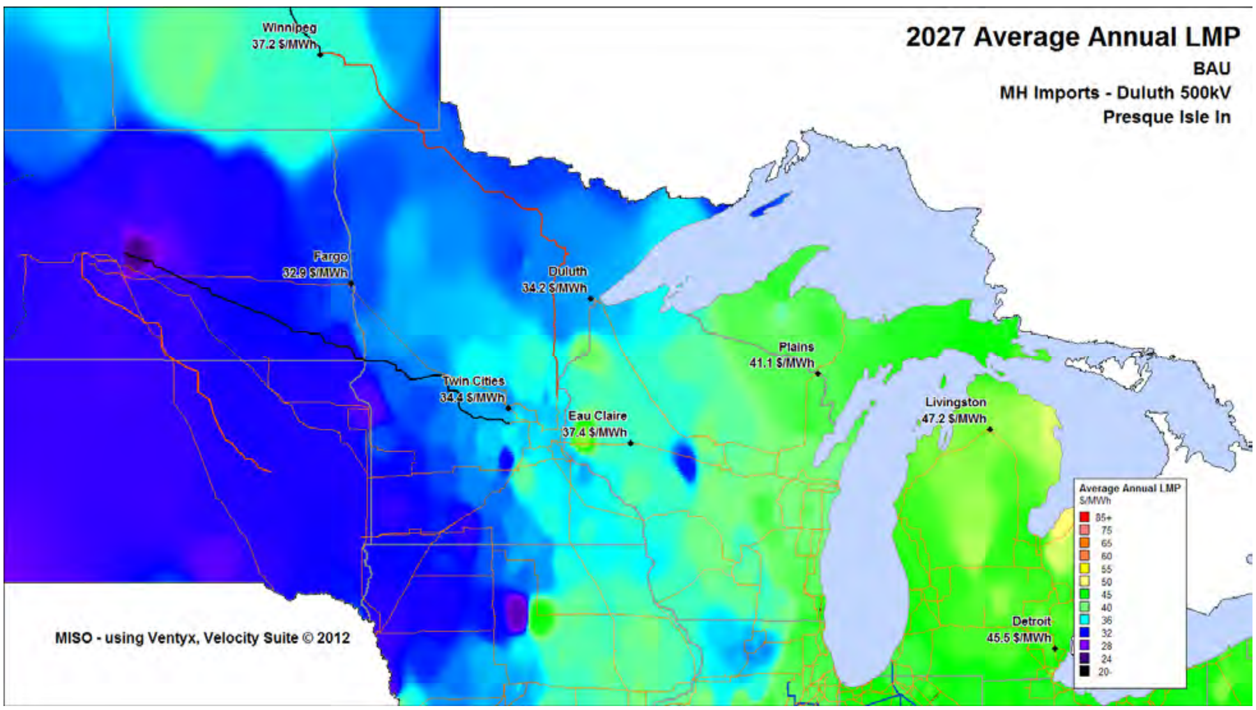


Figure 7-15: Post-*Portfolio 3* LMP Plot (Comparable to Figure 7-4) - x3 "Zoomed-In" Scale

7.3.2 Reliability Analysis of Portfolio 3

Thermal Analysis

No new or worsened constraints were found in the 2022 Shoulder model with the Low Voltage AC Portfolio. The 2022 Summer Peak model had one new and zero worsened constraints. Table 7-17 lists the Summer Peak results.

Monitored Element	MVA Rating	Post-Project Worst Loading %	Pre-Project Worst Loading %	MVA Increase with Project	Constraint
699581 ARNOLD 138 699887 FORSYTH 138 1	245	100.2	96.3	9.6	New

Table 7-17: LVAC Summer Peak Thermal Results

Voltage Analysis

No high or low voltage areas were found in either the 2022 Shoulder or Summer Peak models.

Transient Stability Analysis

Transient stability analysis was not performed for Portfolio 3 as part of the Northern Area Study analysis because of its low potential impact.

8. Conclusions and Going Forward

The Northern Area Study found that large-scale regional transmission expansion in MISO's northern footprint is not cost-effective based on production cost savings, under the current business as usual conditions. Production cost savings benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission investment. The Northern Area Study identified *Hankinson – Wahpeton 230 kV* & *Big Stone – Morris 115 kV* upgrade as a cost-effective option to mitigate the remaining out-year congestion from wind on the Dakotas – Minnesota border (B/C ratio 3.46 – 14.74 depending on scenario assumption). The *Hankinson – Wahpeton 230 kV* & *Big Stone – Morris 115 kV* option is being further analyzed in the MTEP13 Market Efficiency Planning Study. The Northern Area Study makes no conclusions regarding the broader multi-value benefits that might be achieved, or the need for future localized reliability upgrades.

> Large-scale regional transmission expansion in MISO's northern footprint is not cost-effective based solely on production cost savings, under the Northern Area Study current business as usual conditions

> Production cost savings benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission investment

With Presque Isle staying online, the production cost savings potential for new Upper Peninsula transmission lines is decreased. Even under the scenarios which significantly increased UP mining load levels, Upper Peninsula transmission options' benefits to cost ratios peaked at 0.4 in the tested conditions. The Northern Area Study results show there are economic benefits of equalizing Michigan locational marginal prices with the rest of the footprint; however, options' production cost savings did not exceed project costs. Northern Area Study HVDC options require significant additional upgrades to uphold reliability, but were most effective at mitigating Lake Michigan congestion. New high-voltage Upper Peninsula transmission lines could potentially change the operating schemes and may require additional reliability upgrades and operations studies.

> With Presque Isle staying online, the economic potential for new Upper Peninsula transmission lines is decreased

The Northern Area Study identified three transmission portfolios as the most economic options available to accomplish the study objectives. Generally, economic potential for the Northern Area Study footprint was low as a result of the inclusion of the Multi-Value Project (MVP) portfolio, decreased forecasted demand growth rates, and low natural gas prices. Projects not deemed as best-fit solutions through the Northern Area Study will have opportunities to be re-evaluated in future analyses.

The Northern Area Study was developed as an exploratory study to understand how the development of new potential Manitoba – MISO tie-lines, changing mining/industrial load levels, and the retirement of generating units dictate transmission investment in MISO's footprint. The Northern Area Study's results will determine and feed future studies. Through the study process, several issues requiring additional analysis outside of the scope of the Northern Area Study were identified including but not limited to the stability limit of the MWEX interface after the development of MH – Duluth tie-line, the stability limit of the ATC Flow South interface after new UP transmission expansion, and upgrades needed to mitigate reliability issues associated with HVDC lines spanning Lake Michigan. The specific analysis which will evaluate identified issues will be determined after a decision is made on Manitoba Hydro tie-lines and when system conditions justify. MISO through its MTEP process analyses congestion to annually reassess if transmission expansion is justified based on updated congestion patterns. While the Northern Area Study's transmission options' projected benefits did not exceed costs under the study assumptions, the results present a prioritized and shortened list of options for future studies if benefits other than production cost savings are identified or assumptions about future conditions or needs change.

Appendix I. Northern Area Study Stability Disturbances

Fault	Category	Area	Description
0294_e_itct_b1__single_units_above_100_264854_1	b1	ITCT	
0298_e_itct_b1__single_units_above_100_264856_2	b1	ITCT	
0322_e_itct_b2__cmvp_19bauer__18hamptn_to	b2	METC	3ph fault; generic clearing; on 19bauer - 18HAMPTN 345 kv ckt 1; at 18HAMPTN 345
0333_e_itct_b2__cmvp_19fitz___19blrpp__fr	b2	ITCT	3ph fault; generic clearing; on 19FITZ - 19BLRPP 345 kv ckt 1; at 19FITZ 345
0346_e_itct_c3__belr_19fitz_2_3ph_belr_lenx	c3	ITCT	belr to 19fitz 345 kv ckt 2 out. 3ph fault on belr to lenox 345 kv ckt 1. close in at belr 345 kv
0355_e_itct_c3__brns_wayn_3ph_ent_brnn	c3	ITCT	brns to wayne 345 kv ckt 1 out. 3ph fault on fermi to brnn 345 kv ckt 1. close in at fermi 345 kv
0381_e_itct_c5__1ph-dctw_mon34_covt_mon12_wayn	c5	ITCT	simult slg faults on common tower: mon34 to coventry 345 kv & mon12 to wayne 345 kv ckt 1. close in at mon12/mon34 345
0387_e_itct_c7__2ph_mon34_covt_bk-lf	c7	ITCT	2ph fault on mon34 to coventry 345 kv ckt1. mon34 345 kv bk lf stuck. close in at mon34 345 kv
0396_e_itct_c9__2ph_belr_bus301_bk-cf	c9	ITCT	2ph fault on belr 345 kv bus 301. trip belr unit 1. belr bk cf stuck. delayed tripping belr to stc 345 kv ckt 1.
0404_e_itct_d7__brnn-mon34-enf_brns-mon12-enf	d7	ITCT	shared row: brns to fermi 2, brns to monroe 1, brnn to fermi 3, brnn to monroe 2 345 kv. drop fermi unit 2
0407_e_metc_b1__single_units_above_100_256338_1	b1	METC	3ph fault at bus 18palisd 22.000 with normal clearing
0409_e_metc_b1__single_units_above_100_256340_2	b1	METC	3ph fault at bus 18ludn12 20.000 with normal clearing
0419_e_metc_c3__keys_livs_3ph_livs_tita	c3	METC	keys to livs 345 kv ckt 1 out. 3ph fault on livs to gallagher to tita 345 kv ckt 1. close in at livs 345 kv
0422_e_metc_c3__livs_tita_3ph_keys_livs	c3	METC	livs to gallagher to tita 345 kv ckt 1 out. 3ph fault on keys to livs 345 kv ckt 1. close in at keys 345 kv
0426_e_metc_c3__lud_kenw_1_3ph_lud_keys	c3	METC	lud to kenowa 345 kv ckt 1 out. 3ph fault on lud to keys 345 kv. close in at lud 345 kv
0430_e_metc_c3__lud_tall_1_3ph_lud_kenw_1	c3	METC	lud to tall 345 kv ckt 1 out. 3ph fault on lud to kenowa 345 kv ckt 1. close in at lud 345 kv

Fault	Category	Area	Description
0436_e_metc_c3__pals_cook_3ph_pals_covt	c3	METC	pals to cook 345 kv ckt 2 out. 3ph fault on pals to covert 345 kv ckt 1. drop covert plant with 3 st and 3 gt.
0460_e_metc_c7__2ph_lud_kenw_1_bk-24h9	c7	METC	2ph fault on lud to kenowa 345 kv ckt 1. lud 345 kv bk 24h9 stuck. delayed tripping lud unit 3&4. close in at lud 345
0462_e_metc_c7__2ph_lud_keys_bk-26r8	c7	METC	2ph fault on lud to keys 345 kv ckt 1. lud 345 kv bk 26r8 stuck. close in at lud 345 kv.
0466_e_metc_c7__2ph_lud_tall_1_bk-22r8	c7	METC	2ph fault on lud to tall 345 kv ckt 1. lud 345 kv bk 28r8 stuck. close in at lud 345 kv
0481_e_metc_c8__2ph_lud_tb_2_bk-24h9	c8	METC	2ph fault on lud 345/20 kv tb 2. trip lud unit 3&4. lud 345 kv bk 24h9 stuck. delayed trip lud to kenowa 345 kv
0484_e_metc_c8__sb_gct_near_256337_18mcvst1	c8	METC	2ph fault near 256337 18mcvst1 on the 18mcv-18titbaw line; trip at 5 cyc; stuck brkr; generic clearing at 12 cyc
0510_w_atc__b1__npir_pobg1trip	b1	WEC	
0514_w_atc__b1__single_units_above_100_699153_2	b1	ALTE	3ph fault at bus col g2 22.000 with normal clearing
0515_w_atc__b1__single_units_above_100_699207_4	b1	ALTE	3ph fault at bus edg g4 22.000 with normal clearing
0533_w_atc__b1__single_units_above_100_699662_4	b1	WPS	3ph fault at bus wes g4 19.000 with normal clearing
0545_w_atc__b2__col-sfl_345	b2	MGE	
0554_w_atc__b2__npir_l151_pob5-fox	b2	WEC	
0566_w_atc__b2__ya3_arrowhead	b2	WPS	3ph arrowhead 345 kv; clear arrowhead - gardner park 345 kv
0567_w_atc__b2__zion-adn_345	b2	WEC	
0578_w_atc__c2__arcadian_345 kV_bustie1-2	c2	WEC	1ph fault normal clr arcardian 345 kv bus tie 1-2 brkr normal clr opening adn-plp, adn-gvl, adn t1, adn-erg, adn bt2-3
0580_w_atc__c3__col-nma_345_po_col-roe_345	c3	MGE	
0586_w_atc__c3__npir_l111_pob1-sec_po_q303_pob3-kew	c3	WEC	
0590_w_atc__c3__npir_r304_kew-nap_po_l6832_nap-fox	c3	WEC	
0593_w_atc__c5__col-roe_345_col-sfl_345	c5	MGE	
0613_w_atc__c7__y2s_at_edgewater-sfl	c7	ALTE	slg fault delayed clearing (multiple circuit) edgewater-sfl 345-kv and edgewater-saukville 345-kv
0619_w_atc__c8__sb_gct_near_699152_col_g1	c8	MGE	slg fault near 699152 col g1 on the col 345-nma 345 line; trip

Fault	Category	Area	Description
			at 4 cyc; stuck brkr; generic clearing at 13.5 cyc
0620_w_atc__c8__sb_gct_near_699207_edg_g4	c8	ALTE	slg fault near 699207 edg g4 on the edg 345-cedrsauk line; trip at 4 cyc; stuck brkr; generic clearing at 13.5 cyc
0625_w_atc__c8__sb_gct_near_699662_wes_g4	c8	WPS	slg fault near 699662 wes g4 on the st lake-gardr pk line; trip at 5 cyc; stuck brkr; generic clearing at 18.5 cyc
0632_w_atc__c9__npir_bf1pobbs2-bs3	c9	WEC	
0640_w_atc__c9__pleasant_prairie_bus2	c9	WEC	slg fault, dly clr pleasant prairie 345 kv bus 2 w/ dly clr bus tie 2-3. normal clr at 4 cycle opening bus tie 1-2
0641_w_atc__d1__edgewater_unit4	d1	ALTE	3ph fault w/ dly clr high side edgewater unit 4 gsu w/ failure brkr 304. normal clr at 5 cycle with opening of edg u4
0646_w_atc__d2__col_345_b2238	d2	MGE	
0650_w_atc__d2__plp-adn_345_b612	d2	WEC	
0670_w_atc__d2__y7z_at_arpin-eauclaire	d2	XEL	3ph fault with delayed clearing on the arpin - eau claire 345 kv line
0676_w_atc__d5__arcadian_bustie1-2	d5	WEC	3ph fault normal clr 345 bus tie 1-2 brkr normal clr at 4.5 opening and-plp, adn-gvl, adn-t1, adn-erg, adn bt2-3
0678_w_gre__b1__single_units_above_100_615002_2	b1	GRE	3ph fault at bus gre-coal 42g22.000 with normal clearing
0680_w_gre__b2__bl3_stanton-leland	b2	GRE	3ph fault stanton 230 kv; trip stanton-leland
0682_w_gre__c4__ei2_coalcreek	c4	GRE	
0685_w_gre__c6__fq1_coalcreek	c6	GRE	slg fault coal creek 230 kv; stuck breaker, trip coal creek unit 1, trip coal creek dc pole 2, ramp pole 1 to 500 mw
0689_w_gre__c7__eq1_coalcreek	c7	GRE	SLGBF Coal Creek 230 kV; clear CU HVDC #1; Coal Creek Gen #2
0691_w_gre__c7__gu1_at_stanton-coaltp	c7	GRE	5 cycle slgf at stanton 230 on unit 1, breaker 31rb2 stuck. clear at 17 cycles by tripping unit 1 & leland olds tie.
0731_w_itcm_c8__mitchell_adams_bk1130	c8	XEL	near g172. slg fault on mitchell-adams 161 kv with failed mitchell bk 1130. dly clr on mitchell unit g2
0798_w_mp___b1__single_units_above_100_608775_4	b1	MP	3ph fault at bus boswe44g 22.800 with normal clearing
0800_w_mp___b2__fds_sqbutte	b2	OTP	5.0 cy 3 ph flt at square butte

Fault	Category	Area	Description
			230 on stanton line clr square butte end at 4 cy, stanton end at 5 cy
0801_w_mp___b2__rx3_at_boswell-blackberry	b2	MP	3ph 4 cycle fault at boswell 230 kv; clear the boswell-blackberry 230 kv line 1
0803_w_mp___b2__yb3_at_arrowhead-stonelk	b2	WPS	3ph fault at arrowhead 345 kv, clear the arrowhead-stone lake 345 kv line
0805_w_mp___b2__yd3_at_stonelk-gardnerpk	b2	WPS	3ph fault at stone lake 345 kv, clear the stone lake-gardner park 345 kv line
0807_w_mp___c7__rxs_at_boswell-blackberry	c7	MP	slg fault at boswell 230 kv on boswell-blackberry 230 kv line 1; boswell brkr 83l stuck, clear by tripping line
0811_w_mp___c8__ybs_at_weston	c8	WPS	3ph fault applied at weston 345 kv, trip weston-rocky run 345, slg remains until weston t1 tripped
0818_w_otp__b1__single_units_above_100_657749_1	b1	OTP	3ph fault at bus center1g 22.000 with normal clearing
0823_w_otp__b2__ec3_center	b2	OTP	3ph center230 kv; clear center - heskett 230 kv line
0825_w_otp__b2__evs_sqbutte_dc	b2	OTP	3ph Square Butte DC P1; clear Square Butte DC Pole #1; Ramp Square Butte Pole 2 > 1100 Amps
0829_w_otp__c7__fd1_sqbutte	c7	OTP	slgbf square butte 230 kv; clear square butte end fault; breaker 18 stuck, trip square butte-stanton 230 at11 cylces, ac feed to pole 2, pole 1 restart at 17 cycles
0833_w_otp__c8__ev6_sqbutte	c8	OTP	slg fault sq. butte 230 kv; stuck breaker, sqbt p1, p2 blocked, fault cleared, trip bus and ramp sqbt dc p2 back
0836_w_xel__b1__single_units_above_100_600001_2	b1	XEL	3ph fault at bus sherc32g 24.000 with normal clearing
0839_w_xel__b1__single_units_above_100_600004_2	b1	XEL	3ph fault at bus pr is32g 20.000 with normal clearing
0840_w_xel__b1__single_units_above_100_600005_1	b1	XEL	3ph fault at bus mntce31g 22.000 with normal clearing
0841_w_xel__b1__single_units_above_100_600006_1	b1	XEL	3ph fault at bus king 31g 20.000 with normal clearing
0844_w_xel__b1__single_units_above_100_600014_4	b1	XEL	3ph fault at bus blk d74g 18.000 with normal clearing
0852_w_xel__b2__bas_trip_roseaus-roseaun	b2	XEL	no fault, trip roseaus2 - roseaun2. invalid.
0857_w_xel__b2__cmvp_brkngco3_lyon_co__fr	b2	XEL	3ph fault; generic clearing; on BRKNGCO3 - LYON CO 3; at BRKNGCO3 345

Fault	Category	Area	Description
0867_w_xel__b2__cmvp_hmpt_cnr_lkmarion_fr	b2	XEL	3ph fault; generic clearing; on HMPT CNR3 - LKMARION3; at HMPT CNR3 345
0872_w_xel__b2__cmvp_lyon_co__hazel_ck_to	b2	XEL	3ph fault; generic clearing; on LYON CO 3 - HAZEL CK3; at HAZEL CK3 345
0874_w_xel__b2__fa3_alexandria	b2	OTP	3ph alexandria ss 345 kv; clear alexandria ss - maple river 345 kv
0879_w_xel__b2__hn3_hamptoncorner	b2	XEL	3ph hampton corner 345; clear hampton corner - north rochester 345 kv
0888_w_xel__b2__nmz_chisagoco	b2	XEL	3ph chisago co 500 kV; clear chisago co - forbes 500 kV line; 100% dc reduction
0889_w_xel__b2__pas_forbes	b2	XEL	SLGBF Forbes 500 kV; clear Forbes - Dorsey 500 kV line; Forbes-Chisago Co
0890_w_xel__b2__pc3_at_king-eauclaire	b2	XEL	3ph fault on king–eau claire line, cross trip eau claire-arpin
0916_w_xel__c7__mqs	c7	XEL	
0917_w_xel__c7__mts	c7	XEL	
0919_w_xel__c7__pcs	c7	XEL	
0924_w_xel__c7__wilmarth-8s23-stuck	c7	XEL	slg fault on wilmarth-fieldon 345; at 4c trip trimont/lgs gen, wlmrth-lkfld jct, fldn byps; at 7c lkfld jct-nobles, mec st
0926_w_xel__c8__sb_gct_near_600001_sherc32g	c8	XEL	slg fault near 600001 sherc32g on the sherco 3-gre-benton 3 line; trip at 4 cyc; stuck brkr; generic clearing at 19.25 cyc
0928_w_xel__c8__sb_gct_near_600005_mntce31g	c8	XEL	slg fault near 600005 mntce31g on the elm crk3-parkers3 line; trip at 4 cyc; stuck brkr; generic clearing at 19.25 cyc
0930_w_xel__c9__edp-8m45	c9	XEL	13.75 cycle slg fault at eden prairie 345 kv bus with failure of 8m45; trip eden prairie-parkers lake/-blue lake
0932_w_xel__d12_nad_forbes	d12	XEL	3ph forbes 500 kV; clear forbes - dorsey 500 kV; 100% dc reduction
0934_w_xel__d2__cmvp_brkngco3_lyon_co__to	d2	XEL	3ph fault; generic delayed clearing; on BRKNGCO3 - LYON CO 3; at LYON CO 345
0943_w_xel__d2__cmvp_hmpt_cnr_lkmarion_fr	d2	XEL	3ph fault; generic delayed clearing; on HMPT CNR3 - LKMARION3;at HMPT CNR3 345

Appendix II. Portfolio 1 Analysis Added Disturbances

Fault	Category	Description
NAS_BBY_AHD_StuckBreaker_SLG	C8	SLG at HIA 345, trip HIA-LIV, Stuck Breaker, clear fault at 11 cycle
NAS_Dorsey_Blackberry_500 kV	B2	4 cycle 3 phase fault at BlackBerry 500 kV, trip Dorsey - BlackBerry 500 kV
NAS_GRB_KEW_StuckBreaker_SLG	C8	SLG at GreenBay 345, trip GRB-NAP, Stuck Breaker, clear fault at 11 cycle and trip GRB-KEW
NAS_KEW_1DC	B4	3 phase fault at KEW, one pole permanently blocked
NAS_KEW_3ph	A	3 phase fault at KEW, both pole unblocked at clearing
NAS_KEW_BDC	C4	3 phase fault at KEW, both pole permanently blocked
NAS_KEW_GRB	B2	3 phase fault at KEW, normal clearing, trip GRB-KEW, DC unblocked at clearing
NAS_KEW_PTB	B2	3 phase fault at KEW, normal clearing, trip PTB-KEW, DC unblocked at clearing
NAS_LUD_1DC	B4	3 phase fault at LUD, one pole permanently blocked
NAS_LUD_3ph	A	3 phase fault at LUD, both pole unblocked at clearing
NAS_LUD_BDC	C4	3 phase fault at LUD, both pole permanently blocked
NAS_LUD_KEN	B2	3 phase fault at LUD, normal clearing, trip LUD-Kenowa
NAS_LUD_TAL_StuckBreaker_SLG	C8	SLG at LUD 345, trip LUD-Tallmadge, Stuck Breaker, clear fault at 11 cycle, drop LUD unit1&2

Appendix III. Portfolio 2 Analysis Added Disturbances

Fault	Category	Description
NAS_Dorsey_Bison_500 kV	B2	4 cycle 3 phase fault at Bison 500 kV, trip Dorsey - Bison 500 kV
NAS_BFL_BSN_StuckBreaker_SLG *	C8	SLG fault at Bison 345, trip Buffalo-Bison, Stuck Breaker, clear fault at 11 cycle
NAS_HIA_LIV_StuckBreaker_SLG *	C8	SLG fault at HIA 345, trip Hiawatha-Livingston, Stuck Breaker, clear fault at 11 cycle
NAS_HIAWATHA_LIVINGSTON_345 kV	B2	4 cycle 3 phase fault at HIA 345 kV, trip Hiawatha - Livingston 345 kV
NAS_Morgan_Plains345 kV	B2	4 cycle 3 phase fault at Plains 345 kV, trip Morgan - Plains 345 kV