APPENDIX F: TRANSMISSION PLANNING ACTIVITIES

This Appendix F to the 2025-2039 Integrated Resource Plan ("2025 IRP") includes information on Minnesota Power's transmission planning activities, presented in the following sections:

- Part 1: Minnesota Biennial Transmission Report Summary
- Part 2: MISO Long Range Transmission Planning
- Part 3: HVDC Modernization Project & 900 MW Capacity Upgrade
- Part 4: Generator Interconnection Network Upgrades and Assumptions
- Part 5: Grid North Partners
- Part 6: Update on Boswell Units 3 & 4 Transmission Impacts
- Part 7: Transmission System Analysis of Hibbard Retirement
- Part 8: MISO Hibbard Attachment Y-2 Study (Redacted Version)
- Part 9: Fleet Transition Experience with Small Coal Unit Closures (Section Reproduced in its Entirety from 2021 IRP Appendix F, Part 6)
- Part 10: System Strength Study
- Part 11: Trade Secret Boswell Synchronous Condenser Conversion Report with 2024 Cost Estimate and Schedule Updates

A. Part 1: Minnesota Biennial Transmission Projects Report Summary

Background

Every two years, Minnesota Power (or the "Company") participates with the other Minnesota Transmission Owners ("TOs") in the preparation and filing of the Minnesota Biennial Transmission Projects Report ("Biennial Report"). The Biennial Report is prepared pursuant to Minn. Stat. § 216B.2425, which requires any utility that owns or operates electric transmission facilities in the state of Minnesota to report on the status of its transmission system by November 1 of each odd numbered year. A major purpose of the Biennial Report is to provide information about all present and reasonably foreseeable transmission inadequacies that have been identified in the existing transmission system. An "inadequacy" is essentially a situation where the present transmission infrastructure is unable or unlikely to be able to perform in a consistently reliable fashion in compliance with regulatory standards in the reasonably foreseeable future. In addition to information about inadequacies and the projects proposed to address them, the Biennial Report provides information about the transmission planning process and about the utilities that own transmission lines in the state. The twelfth Biennial Report was filed with the Minnesota Public Utilities Commission ("Commission" or "MPUC") on November 1, 2023 in Docket No. E-999/M-23-91.[1] This report, along with reports from previous years dating back to 2005, is publicly available on the internet.[2] The 2025 Biennial Report, which will include an updated list of

[1] *In the Matter of the 2023 Minnesota Biennial Transmission Projects Report,* Docket No. E-999/M-23-91, 2023 Biennial Transmission Projects Report (Nov. 1, 2023).
[2] http://www.minnelectrans.com.

inadequacies and proposed projects, will be filed by November 1, 2025 in Docket No. E-999/M-25-99.[3]

Minnesota Power's Transmission Projects

For purposes of the Biennial Report, the state of Minnesota has been divided into six geographic Transmission Planning Zones. Of these six zones, Minnesota Power is located wholly in the Northeast Zone.

Table 1 below provides the current status and background information about each of the present and reasonably foreseeable future inadequacies that Minnesota Power reported in the 2023 Biennial Report. Table 1 also includes information on future needs that have been identified by Minnesota Power since the filing of the 2023 Biennial Report. The future needs listed at the end of Table 1 with MPUC Tracking Numbers beginning "2025" will be reported in the 2025 Biennial Report. There are several inadequacies for which projects have been completed and placed in service or the need profile has changed since the 2023 Biennial Report. Table 2 below provides information on projects that have been completed or cancelled since the filing of the 2023 Biennial Report.

In both tables, each project is identified by its MPUC Tracking Number as well as its Midcontinent Independent System Operator ("MISO") Transmission Expansion Plan ("MTEP") project number. The MTEP project numbers are utilized by the MISO to identify and track projects in the compilation of the annual MTEP Report. Tables 1 and 2 also include the MTEP Year, which identifies the year of the MTEP Report in which the project was approved. The tables also provide the most recent MTEP Appendix classification, which indicates the status of the project in the regional planning process. For example, "2024/A" indicates that the project was in the MISO MTEP Appendix A and approved in 2024. The MTEP Appendix definitions are as follows:

- Appendix A – Projects recommended for approval.
- Appendix B – Projects still in the planning and review process.

More information can be obtained on these projects by referring to the latest MTEP Report, available on the MISO website at http://www.misoenergy.org (click on "Planning").

Table 1. Minnesota Power's Transmission Needs

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2007-NE-N1	2014/B	2548	**Duluth 230 kV Project:** Expand Hilltop 230 kilovolt ("kV") Substation, add a second 230/115 kV transformer, and upgrade an existing line from 115 kV to 230 kV between the Arrowhead and Hilltop substations. **Location:** Duluth, St. Louis County **Timing:** Need delayed by Duluth Loop Reliability Project (*MTEP Project #20077*)

[3] *In the Matter of the 2025 Biennial Transmission Projects Report*, Docket No. E-999/M-25-99.

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2013-NE-N16	2024/A	4295	**High Voltage Direct Current ("HVDC") Modernization Project:** Replace the existing Center and Arrowhead HVDC converter stations with new voltage source converter ("VSC") HVDC converter stations. Includes construction of a new St. Louis County 345/230 kV substation and upgrade of the existing Arrowhead 230 kV Substation in Minnesota as well as construction of a new East Oliver 345 kV Substation and expansion of the planned Nelson Lake Substation in North Dakota. **Location:** Hermantown, St. Louis County and Center, ND **Timing:** Anticipated in-service date 2029-2030 *MPUC Docket Nos. CN-22-607 & TL-22-611*
2013-NE-N17	2024/A	3856	**HVDC 900 MW Transmission Line Upgrades:** Upgrade the capacity of the existing Square Butte – Arrowhead HVDC transmission line from 550 MW to 900 MW. **Location:** Hermantown, St. Louis County & Center, ND **Timing:** Anticipated in-service date 2029-2030
2017-NE-N3	2024/B	25266	**Little Falls Substation Modernization:** Age-related equipment replacements, site improvements, and electrical configuration improvements for reliability at existing Little Falls 115/34 kV Substation. **Location:** Morrison County **Timing:** Anticipated in-service date 2030
2019-NE-N4	2024/B	25281	**25 Line Upgrade:** Increase capacity of Hibbing – Virginia 115 kV Line. **Location:** St. Louis County **Timing:** Staged construction between 2027-2031
2019-NE-N8	2020/A	15598	**Badoura Transformer Replacement:** Replace existing Badoura 230/115 kV transformer and expand 230 kV substation to a ring bus. **Location:** Hubbard County **Timing:** Anticipated in-service date 2027

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2019-NE-N12	2022/A 2022/A	17868 20077	**Duluth Loop Reliability Project:** New 115 kV line from Hilltop to Haines Road to Ridgeview Substations to support redundancy to Duluth and the North Shore Loop. Increase capacity of Hilltop 230/115 kV transformer, add breakers, and sectionalize Arrowhead – Hilltop 230 kV Line. **Location:** Duluth, St. Louis County **Timing:** Staged implementation in 2024-26 *MPUC Docket Nos. CN-21-140 & TL-21-141*
2019-NE-N13	2020/A	17870	**National Breaker Replacements:** Age-related replacement of five 115 kV circuit breakers and associated equipment at National Substation. Construction staged over multiple years due to customer outage constraints. **Location:** Hibbing, St. Louis County **Timing:** Planned in-service date 2025
2021-NE-N1	2022/A	18058	**HVDC Line Hardening Project:** Structure replacements to improve HVDC line resiliency and restorability at critical infrastructure crossings. **Location:** Various locations between Duluth, St. Louis County, and Center, ND **Timing:** Planned in-service date 2025
2021-NE-N3	2020/A	18064	**Hibbing Substation Modernization:** Age-related equipment replacements and site improvements at existing Hibbing 115/23 kV Substation. Project deferred due to prioritization of Maturi Substation Expansion (MTEP ID #23707). **Location:** Hibbing, St. Louis County **Timing:** Anticipated in-service date 2027-28
2021-NE-N4	2024/B	25255	**Verndale Substation Modernization:** Age-related equipment replacements and site improvements at existing Verndale 115/34 kV Substation. **Location:** Verndale, Wadena County **Timing:** Anticipated in-service date 2028

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2021-NE-N5	2021/A	18066	**Badoura 115 kV Substation Modernization:** Age-related equipment replacements, site improvements, and electrical configuration improvements for reliability at existing Badoura 115 kV Substation. **Location:** Hubbard County **Timing:** Anticipated in-service date 2025
2021-NE-N12	2021/A	20075	**Forbes 230 kV Asset Renewal:** Age-related equipment replacements and site improvements at existing Forbes 230/115 kV Substation. **Location:** St. Louis County **Timing:** Anticipated in-service date 2027
2021-NE-N13	2021/B	20087	**Cloquet Substation Renewal:** Age-related equipment replacements, site improvements, and electrical configuration improvements for reliability at existing Cloquet 115/14 kV Substation. **Location:** Cloquet, Carlton County **Timing:** Anticipated in-service date 2030
2021-NE-N14	2022/A	21686	**Mesaba Junction 137L Extension:** Building new line section from Mesaba Junction Substation to end of 137L at North Shore Mining. **Location:** St. Louis County **Timing:** Anticipated in-service date 2026
2021-NE-N15	2022/B	21762	**137 Line Rebuild:** Age-related replacement of 115 kV transmission line. **Location:** St. Louis County **Timing:** Anticipated in-service date 2029
2021-NE-N17	2025/ Target A	50402	**Boswell Transformer Addition:** Addition of 115/23 kV distribution transformer at existing Boswell 230/115 kV Substation. (Replaced MTEP Project #21606) **Location:** Itasca County **Timing:** Anticipated in-service date 2026

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2021-NE-N19	2022/B	21764	**56 Line Upgrade:** Increase capacity of existing Colbyville – Ridgeview 115 kV Line. **Location:** St. Louis County **Timing:** Anticipated in-service date 2032
2021-NE-N21	2025/ Target A	50218	**Riverton 230 kV STATCOM:** Construction of a new 230 kV static synchronous compensators ("STATCOM") for steady state and dynamic voltage support when baseload generators are offline. **Location:** Crow Wing County **Timing:** Anticipated in-service date 2028
2021-NE-N22	2022/A	21766	**126 Line Asset Renewal:** Age and condition-related structure and hardware replacements on Little Fork – International Falls 115 kV Line. **Location:** Koochiching County **Timing:** Anticipated in-service date 2025
2021-NE-N23	2022/B	21767	**13 Line Rebuild:** Age-related rebuild of Riverton – Portage Lake 115 kV Line. **Location:** Crow Wing County – Aitkin County **Timing:** Staged construction between 2027 and 2030
2023-NE-N1	2021/A	23370	**Northland Reliability Project (LRTP Project #3):** Construction of new double circuit 345 kV lines from Iron Range to Benton County to Big Oaks Substations, includes new Cuyuna Series Compensation Station and rebuild of Benton County – Sherco 345 kV Line. **Location:** Itasca, Aitkin, Crow Wing, Morrison, Benton, and Sherburne Counties **Timing:** Anticipated in-service date 2030 *MPUC Docket Nos. CN-22-416 & TL-22-415*
2023-NE-N4	2023/A	23707	**Maturi Substation Expansion:** Expansion of existing Maturi Substation for increased reliability of the area distribution and transmission system. **Location:** St. Louis County **Timing:** Anticipated in-service date 2025

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2023-NE-N5	2023/A	23708	**Mahtowa Expansion:** Expansion of existing Mahtowa Substation for increased reliability of the area distribution and transmission system. **Location:** St. Louis County **Timing:** Anticipated in-service date 2028
2023-NE-N6	2024/A	23706	**158 Line Rebuild:** Age-related rebuild of Cromwell – Portage Lake 115 kV Line. **Location:** Carlton County – Aitkin County **Timing:** Staged construction between 2027 and 2030
2023-NE-N7	2024/A	25141	**Arrowhead 115 kV Single Point of Failure:** Adding redundancy and monitoring to existing equipment to mitigate single point of failure issues in compliance with NERC TPL-001-5. **Location:** St. Louis County **Timing:** Anticipated in-service date 2025
2023-NE-N8	2024/A	25142	**Forbes 115 kV Single Point of Failure:** Adding redundancy and monitoring to existing equipment to mitigate single point of failure issues in compliance with NERC TPL-001-5. **Location:** St. Louis County **Timing:** Anticipated in-service date 2025
2023-NE-N9	2025/A	25264	**Ridgeview Transformer Addition:** Addition of 115/34.5 kV transformer to support reliability of Duluth area distribution system. **Location:** St. Louis County **Timing:** Anticipated in-service date 2027
2023-NE-N10	2024/B	25265	**Wrenshall Substation Modernization:** Age-related equipment replacements, site improvements, and electrical configuration improvements for reliability at existing Wrenshall 115/14 kV Substation. **Location:** Carlton County **Timing:** Anticipated in-service date 2029

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2023-NE-N11	2022/B	22285	**133 Line Rebuild:** Rebuild and increase capacity of existing Verndale – Wing River 115 kV Line. **Location:** Wadena County **Timing:** Anticipated in-service date 2028
2025-NE-NX	2024/A	50553	**Maple River – Cuyuna 345 kV Project (LRTP Project #20):** Installing new single circuit 345 kV line on double-circuit capable structures between Maple River and Cuyuna substations. **Location:** Crow Wing County and other counties TBD pending transmission line routing) **Timing:** Anticipated in-service date 2033 *MPUC Docket Nos. CN-25-109 & TL-25-110*
2025-NE-NX	2024/A	50554	**Iron Range – St Louis County – Arrowhead 345 kV Project (LRTP Project #21):** Installing new single circuit 345 kV line between Iron Range and St. Louis County and installing double circuit 345 kV lines between St. Louis County and Arrowhead. **Location:** Itasca and St. Louis Counties **Timing:** Anticipated in-service date 2032 *MPUC Docket Nos. CN-25-111 & TL-25-112*
2025-NE-NX	2022/B	22286	**24 Line Rebuild:** Rebuild and increase capacity of existing Verndale – Dog Lake 115 kV Line. **Location:** Wadena County **Timing:** Anticipated in-service date 2028
2025-NE-NX	2025/ Target A	50149	**Arrowhead 230 kV Single Point of Failure:** Adding redundancy and monitoring to existing equipment to mitigate single point of failure issues in compliance with NERC TPL-001-5. **Location:** St. Louis County **Timing:** Anticipated in-service date 2028

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2025-NE-NX	2025/ Target A	50395	**Transmission Line Pole Replacement 2025:** Age-related replacement targeted poles across Minnesota Power's system. **Location:** Minnesota **Timing:** Anticipated in-service date 2025
2025-NE-NX	2025/ Target A	50393	**Iron Range 500 kV Reactor Addition:** Adding a third 500 kV line-end shunt reactor at existing Iron Range Substation for redundancy. **Location:** Itasca County **Timing:** Anticipated in-service date 2030
2025-NE-NX	2025/ Target A	50373	**HVDC Flood Diversion Project:** Raising structures on existing HVDC Line to accommodate Red River flood diversion project. **Location:** Clay County **Timing:** Anticipated in-service date 2026
2025-NE-NX	2025/ Target A	50365	**Shannon Capacitor Bank Replacement:** Age and condition replacement of the two existing 230 kV capacitor banks and existing 115 kV capacitor bank at existing Shannon Substation. **Location:** St. Louis County **Timing:** Anticipated in-service date 2025
2025-NE-NX	2025/B	50348	**26 Line Rebuild:** Age-related rebuild of existing Thomson – Mahtowa – Cromwell 115 kV Line. **Location:** Carlton County **Timing:** Staged construction between 2029 and 2033
2025-NE-NX	2025/B	50344	**Haines Road Substation Modernization:** Age-related replacement of 115 kV circuit breakers, transformers, and associated equipment at Haines Rd Substation. **Location:** St. Louis County **Timing:** Anticipated in-service date 2029

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2025-NE-NX	2025/ Target A	25267	**180 Line Rebuild:** Age-related rebuild of Hibbing – Maturi 115 kV Line. **Location:** St. Louis County **Timing:** Anticipated in-service date 2028

Table 2. Projects Completed or Cancelled since Filing the 2023 Biennial Report

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B. Part 2: MISO Long Range Transmission Planning

Background

MISO's Long Range Transmission Planning ("LRTP") is a staged effort by MISO, the regional transmission planner for Minnesota and the surrounding region, to develop regional transmission solutions to ensure the transmission system is positioned to reliably, efficiently, and economically meet long-term decarbonization, renewable integration, and load-serving needs over the next 20 years and beyond. The resulting project portfolios (or "tranches") are regionally cost-shared Multi-Value Projects ("MVPs") under the MISO Tariff. MISO approved LRTP Tranche 1 in July 2022 and Tranche 2.1 in December 2024 to address transmission needs within the MISO Midwest subregion. Subsequent phases of the MISO LRTP effort include Tranche 2.2 to further address the MISO Midwest subregion, Tranche 3 focused on the MISO South Subregion, and Tranche 4 focused on the MISO North/South interface. Minnesota Power is participating in the development of several LRTP Tranche 1 and Tranche 2.1 projects, as summarized below.

Minnesota Power Projects

Big Stone South – Alexandria – Big Oaks Transmission Project (LRTP Tranche 1, Project #2)

Xcel Energy, Great River Energy, Minnesota Power, Otter Tail Power Company, and Missouri River Energy Resources on behalf of Western Minnesota Municipal Power Agency (collectively, the "Project Developers") announced in July 2022 their intent to construct LRTP Project #2, a 150-mile, 345 kV transmission line to improve reliability in North Dakota, South Dakota, and western and central Minnesota. A Notice of Intent to Construct, Own, and Maintain the transmission line was filed with the Commission in October 2022. On September 29, 2023, the Project Developers submitted applications for a Certificate of Need and a Route Permit for the Alexandria-Big Oaks portion of the project with the Commission, which were approved on October 30, 2024.[4] The project is in its early stages, and total project costs are anticipated to be between $600 million and $700 million. Minnesota Power has asset ownership in the second 345 kV circuit on existing double circuit-capable structures on the Alexandria-Big Oaks portion of the project. This portion of the project is expected to be in service in 2027.

[4] *In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Docket No. E-002, E-017, E-T2, E-015, ET-10/CN-22-538 and *In the Matter of the Application for a Route Permit for the Alexandria to Big Oaks 345 kV Transmission Project in Central Minnesota*, Docket No. E-002, E-017, ET-2, E-015, ET-10/TL-23-159, Order Granting Certificate of Need and Issuing Route Permit (Oct. 30, 2024).

Northland Reliability Project (LRTP Tranche 1, Project #3)

Minnesota Power and Great River Energy announced in July 2022 their intent to construct LRTP Project #3, a 180-mile, double circuit 345 kV transmission line, connecting northern Minnesota to central Minnesota to support continued reliability in the Upper Midwest. A Notice of Intent to Construct, Own, and Maintain the transmission line was filed with the Commission in August 2022. On August 4, 2023, Minnesota Power and Great River Energy submitted an application for a Certificate of Need and Route Permit with the Commission, which was approved on February 28, 2025.[5] Based on the final route approved by the Commission, which generally follows existing rights-of-way in an established power line corridor, total project costs are anticipated to be over $1.37 billion (in 2022 dollars). Minnesota Power will own a 50 percent share of the new double-circuit 345 kV transmission line between the existing Iron Range and Benton County Substations, as well as the expanded Iron Range Substation and the new Cuyuna Series Compensation Station. The project is expected to be in service in 2030.

Bison – Alexandria 345kV Project (LRTP Tranche 2.1, Project #19)

This transmission line is associated with the Alexandria – Big Oaks portion of the LRTP Tranche 1, Project #2 discussed above and is anticipated to have the same ownership structure. MISO found that this project, along with others in northern Minnesota, provides outlets for generation from the west, supports large power transfers to load centers, and reduces congestion. Project costs in total are estimated to be over $200 million, and the project is expected to be completed by 2032. The Project Developers filed a Notice of Intent to Construct, Own, and Maintain the transmission line with the Commission in February 2025.[6] A Certificate of Need application for the project will be filed with the Commission by February 2026.

Maple River – Cuyuna 345kV Project (LRTP Tranche 2.1, Project #20)

This transmission line is a new, 166-mile 345kV single circuit line on double-circuit structures that will connect the Maple River Substation near Fargo, North Dakota to the Cuyuna Series Compensation Station near Riverton, Minnesota. MISO found that this project, along with others in northern Minnesota, provides outlets for generation from the west, supports large power transfers to load centers, and reduces congestion. Minnesota Power is the owner of the Cuyuna Series Compensation Station in Minnesota, which is being constructed as part of the Northland Reliability Project, a joint project with Great River Energy. Otter Tail Power Company is the owner of the Maple River Substation in North Dakota. Project costs in total are estimated to be approximately $910 million, and the project is expected to be completed by 2033. Minnesota Power, Otter Tail Power, and Great River Energy filed a Notice of Intent to Construct, Own, and Maintain the transmission line with the Commission in February 2025.[7] A Certificate of Need application for the project will be filed with the Commission by February 2026.

Iron Range – St. Louis County – Arrowhead 345kV Project (LRTP Tranche 2.1, Project #21)

[5] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket Nos. E-015, ET-2/CN-22-416 and E-015, ET-2/TL-22-415, Order Granting Certificate of Need and Issuing Route Permit (Feb. 28, 2025).
[6] Notice of Intent to Construct, Own, and Maintain the Bison – Alexandria 345 kV Transmission Line Project, Docket No. E-002, ET-2, E-015, E-017, ET-6135/CN-25-116 (Feb. 7, 2025).
[7] Notice of Intent to Construct, Own, and Maintain the Maple River – Cuyuna 345 kV Transmission Project, Docket No. E-015, ET-2, E-017/CN-25-109 (Feb. 7, 2025).

This transmission line is a new, 63-mile 345 kV single-circuit line on double-circuit structures that will connect the Iron Range Substation near Grand Rapids, Minnesota to the St. Louis County Substation near Hermantown, Minnesota, and then to the Arrowhead 345 kV Substation, also near Hermantown, Minnesota. MISO found that this project, along with others in northern Minnesota, provides outlets for generation from the west, supports large power transfers to load centers, and reduces congestion. Minnesota Power is the owner of the Iron Range and St. Louis County substations. American Transmission Company LLC by and through its corporate manager ATC Management Inc. ("ATC") is the owner of the Arrowhead 345 kV Substation. Project costs in total are estimated to be approximately $370 million, and the project is expected to be completed by 2032. Minnesota Power and ATC filed a Notice of Intent to Construct, Own, and Maintain the transmission line with the Commission in February 2025.[8] A Certificate of Need application for the project will be filed with the Commission by February 2026.

C. Part 3: HVDC Modernization Project and 900 MW Capacity Upgrade

Background

In early 2010, Minnesota Power finalized its purchase of a 465 mile, +/- 250 kV HVDC line with converter stations located in Center, North Dakota, and Hermantown, Minnesota ("HVDC Line"). The HVDC Line and its converter stations at the Center and Arrowhead substations were built in the 1970s to bring electricity from the coal-fired Milton R. Young 2 ("Young 2") generating station in Center, North Dakota, directly to Minnesota Power's customers. Minnesota Power's purchase of the HVDC Line in 2010 cleared the way for the line to be repurposed to facilitate the delivery of wind power generated in North Dakota directly to Minnesota Power's customers. Minnesota Power subsequently purchased and developed a portfolio of approximately 600 MW of North Dakota wind that now relies on the HVDC Line for reliable transmission deliverability. In 2024, the Commission approved Minnesota Power's Certificate of Need and Route Permit application for the HVDC Modernization Project,[9] which will replace and upgrade the existing HVDC Line converter stations that are beyond their anticipated operational lives. The upgraded converter stations will support the continued reliable operation of the HVDC Line and make it possible to increase the capacity of the HVDC Line up to 1,500 MW if needed in the future. Minnesota Power secured $75 million in state and federal funding awards to support this project and reduce overall costs for customers.

HVDC Modernization

The Center and Arrowhead HVDC converter stations were designed by General Electric ("GE") for a 30-year operating lifetime and have been operating for nearly 50 years, continuously delivering value for Minnesota Power customers. The main components of the HVDC converter stations include power electronics (thyristor valves) and their associated cooling system, converter transformers, smoothing reactors, harmonic filters, and reactive resources to complete

[8] *Notice of Intent to Construct, Own, and Maintain the Iron Range – St. Louis County – Arrowhead 345 kV Transmission Project*, Docket Nos. E-015/CN-25-111 and E-015/TL-25-112 (Feb. 7, 2025).
[9] *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/CN-22-607 and *In the Matter of the Application of Minnesota Power for a Route Permit for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/TL-22-611, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

the conversion between alternating current ("AC") and direct current ("DC"). The original vendor, GE, left the HVDC business in the 1980s, and in recent years it has been increasingly difficult to procure spare parts for the converter stations as the technology is becoming obsolete and the original designers are well into retirement. While the HVDC converter stations have operated reliably well beyond their intended operating lifetime, in recent years, Minnesota Power has experienced HVDC terminal outages due to failures in the control system, power electronics, transformers, and other components. Based on experience with other electric system components, the failure rate is expected to continually increase, which is of particular concern for the existing HVDC system because of limited parts availability.

Modernizing the converter stations will greatly reduce the likelihood of an extended outage due to component failures in the HVDC converter stations. The orderly replacement of the HVDC terminal equipment is prudent to ensure continuous efficient delivery (and potential expansion) of Minnesota Power's renewable, carbon-free energy resources into the future. In addition to the replacement of the existing HVDC terminals, the new VSC HVDC technology implemented for the HVDC Modernization Project will be designed to provide voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability, all of which will enable Minnesota Power and the region to continue to support the clean energy transition reliably. Modern HVDC technology at the converter stations will also enhance HVDC dispatch capability and allow energy to flow in both west to east and east to west directions, adding new flexibility and optionality for the regional transmission system.

The HVDC Modernization Project is scheduled to be placed in service between 2028 and 2030 and is a critical component of Minnesota Power's efforts to leverage existing infrastructure to efficiently maintain the current load, prepare for load growth, enable for flexible operations at Boswell Energy Center ("BEC"), gain additional access to renewable resources for customers, and keep momentum for reaching the state's Carbon-Free Standard ("CFS") by 2040. The Project also innovatively proposes flexible design options to allow for future expansion and additional energy transfer capability, leveraging the unique attributes of HVDC technology—the most efficient way to transfer power over long distances.

HVDC Capacity Upgrades

The modernization of the existing Center and Arrowhead HVDC converter stations presents a once-in-a-generation opportunity to consider enhancements to the long-term value of the HVDC system. At a time when there is increasing focus on long-term regional transmission needs and renewable energy integration, it is especially worthwhile to evaluate the costs and benefits of increasing the capacity and usefulness of the Center – Arrowhead HVDC corridor. Minnesota Power has assessed the capacity limitations associated with the existing HVDC Line and found that the total capacity of the HVDC Line may be reasonably increased from 550 MW to a maximum of 900 MW concurrently with modernization of the converter stations. Upgrades would also be needed along the 465-mile HVDC transmission line to achieve increased capacity above 550 MW. More significant changes to the capacity, operating voltage, and converter technology of the HVDC system could also provide enhanced long-term value for Minnesota Power and the region but would come at considerably higher cost. For a modest incremental cost as part of the HVDC Modernization Project, the upgraded converter stations will be designed to make it possible to increase the capacity of the HVDC Line up to 1,500 MW if needed in the future. Minnesota Power is in the process of carefully considering the long-term use and value of the HVDC corridor both internally and with MISO in order to determine the best path forward for further HVDC capacity upgrades for its customers and the region.

D. Part 4: Generator Interconnection Network Upgrade Assumptions

Background

Transmission network upgrade costs realized through the MISO definitive planning phase ("DPP") generator interconnection process are difficult to accurately predict. In order to provide a reasonable range of generator interconnection network upgrade cost assumptions for the purpose of modeling new resources in the 2025 IRP, Minnesota Power's Transmission Planning and Resource Planning collaboratively devised a methodology based on historical network upgrade costs reported in recent DPP cycles. This methodology is intended to establish generic assumptions for IRP modeling purposes and is not meant to be predictive of the actual network upgrades or costs associated with any specific (individual) future generation project. An overview of the methodology behind the generator interconnection network upgrade cost assumptions used for IRP modeling is provided below.

Methodology

To begin development of a methodology, Minnesota Power reviewed several recent MISO DPP cycles that employed MISO's present generator interconnection study practices and modeling assumptions. Specific DPP cycles included in the analysis were from the MISO West region only, with queue entry dates between August 2017 and April 2021. These cycles were selected for the 2025 IRP resource interconnection cost calculations because final system impact study ("SIS") reports for at least one phase had been issued since the calculation of costs for Minnesota Power's 2021 IRP.[10] Another reason this set of DPP cycles is logical is because they coincide with the MISO Tariff change to only require transient stability, short circuit, and Affected Systems studies in Phase 2 and beyond. Prior to this, all study types were required in all phases. DPP network upgrades identified in these cycles were categorized and grouped into the following three general network upgrade cost types:

- **C1 - Base MISO Network Upgrade Costs:** Steady State Thermal & Voltage, Transient Stability, Short Circuit, Network Resource Interconnection Service ("NRIS") Network Upgrades, Transmission Owner's Interconnection Facilities ("TOIF") Network Upgrades, TO-Owned Direct Assigned, (Disregard Shared Network Upgrade Costs), Local Planning Criteria except Great River Energy ("GRE") Coal Creek costs.
- **C2 - Backbone Network Upgrade Costs:** Backbone/Base Case Network Upgrades, Minnesota-Wisconsin Export interface ("MWEX") Voltage Stability, GRE Coal Creek Local Planning Criteria. These types typically involve extra high voltage ("EHV") transmission lines at a substantial project cost.
- **C3 - Affected Systems Network Upgrade Costs:** All Affected Systems costs, including for the Pennsylvania-New Jersey-Maryland Interconnect and Southwest Power Pool.

Subsequently, the costs for each type were linked to the generation projects they were allocated to in the DPP cycle in order to calculate a rate ($/kilowatt ("kW")) for network upgrades by generation project. The decision of each of the generation projects to continue, withdraw, or modify their interconnection request in light of the assigned transmission network upgrade costs

[10] *In the Matter of Minnesota Power's 2021-2035 Integrated Resource Plan*, Docket No. E-015/RP-21-33.

at each phase of the study process was also evaluated. Based on this assessment, the network upgrade costs at the time a generation project either withdrew or proceeded to a Generator Interconnection Agreement were combined and weighted to come up with a generic network upgrade rate ($/megawatt ("MW")) by fuel type. Weightings applied at each decision point are borrowed from the 2023 Organization of MISO States ("OMS")-MISO Survey used for accredited capacity projections to ensure consistency between processes and methodologies relying on generator queue uncertainty for future planning. The fuel-type rates for each of the three cost types (C1, C2, and C3) were then used to develop three different projections of interconnection costs for use when modeling new solar, wind, and battery resources in the 2025 IRP. The Base Cost Assumptions combines the C1, C2, and C3 cost buckets. The Low Interconnection Cost Sensitivity Assumption includes the full C1 cost bucket, with the C2 and C3 cost buckets discounted by 50 percent as a proxy for relief provided by the MISO LRTP and Joint Targeted Interconnection Queue ("JTIQ") portfolios. While LRTP and JTIQ may be expected to provide significant new transmission system capacity to alleviate some of the Backbone and Affected Systems Network Upgrade costs, they are unlikely to alleviate all of the need for these network upgrades, especially as the amount of generation requesting interconnection in DPP cycles continues to be historically large.

The cost ranges for wind and solar resources are shown in Table 3 below. The cost rates calculated were assumed to be in 2024 dollars and were escalated by an average of approximately 3 percent per year for use in the 2025 IRP modeling scenarios.

Table 3. Generator Interconnection Cost Assumptions

	Base Interconnection ($/kW)	Low Sensitivity ($/kW)
New Wind	$320	$220
New Solar	$190	$160
New Battery	$110	$80

E. Part 5: Grid North Partners Overview

Minnesota Power coordinates with the nine other investor-owned and not-for-profit cooperative and municipal utilities within the Grid North Partners ("GNP") group. The collaboration works to ensure continued safe, reliable, and affordable electric service. In 2020, GNP published the CapX2050 Transmission Vision Report ("CapX2050 Report") which analyzed how transitioning away from traditional dispatchable generating resources and increasing reliance on intermittent renewable (non-dispatchable) generating resources would affect the operation of the transmission grid in the coming decades.[11] While not intended to identify specific new transmission projects, the CapX2050 Report highlighted the need for additional grid infrastructure, either in the form of new high voltage lines or the development of new advanced technologies. The report also discussed how with more non-dispatchable resources there will be a wider variety of transmission flow patterns resulting in more uncertainty in predicting where and how often

[11] The CapX2050 Report and congestion assessment details are publicly available at http://www.capx2020.com/.

congestion will occur. Therefore, processes will need to evolve in order to proactively identify and mitigate transmission congestion.

In 2023, the group studied and announced the identification of 19 transmission upgrades to reduce system congestion. The study work that was performed looked at both historical and forward-looking congestion. The projects targeted the Minnesota region and are all expected to be implemented within three years. Individual work has been performed by utilities and will continue, but by taking a holistic approach to the analysis, regional benefits, and impacts were able to be prioritized. The estimated cost of the identified projects is approximately $130 million, with projected economic cost savings in excess of that amount as a result of reduced market congestion. Of the 19 projects that were identified in the analysis, two were Minnesota Power facilities. Additionally, it was determined that ambient adjusted ratings could be effectively applied as a low-cost solution to mitigate the potential congestion impacts. This was implemented prior to the announcement with an additional increase completed in the fall of 2024 as a permanent solution.

In 2024, Minnesota passed legislation requiring transmission owners within the state meeting certain requirements to perform a similar congestion assessment. This assessment will identify congestion experienced in the last three years, congestion forecasted during the next five years, estimated costs to ratepayers, and will evaluate Grid Enhancing Technologies ("GETs") as potential solutions. GNP has announced that this would be performed within the coordination of the group. Minnesota Power is actively reviewing information and developing potential solutions as they are identified in this process.

F. Part 6: Update on Boswell Units 3 & 4 Transmission Impacts

Background

BEC is the only remaining baseload generating station in the Minnesota Power system, as well as in all of northern Minnesota. This generating station provides essential reliability services – electrical support needed to ensure continuous reliable operation of the power system – and energy supply to a unique geographic area. The energy and reliability needs of both large industrial loads and sprawling rural areas must be served while also balancing regional power transfer needs, particularly as regional renewable energy production varies on a minute-by-minute basis. If BEC were shut down or transitioned to economic operation, the entire northern half of Minnesota and a large part of eastern North Dakota would be left with no operating baseload generators. With little support from the remaining small dispatchable generators, the majority of energy requirements and essential reliability services required to serve this area would need to be provided from remote resources. Operating in this manner in northern Minnesota permanently or for extended periods of time would be a major change for the local area and the region, and would result in both local and regional reliability concerns. As described in Parts 6, 7, and 8 of Appendix F to the 2021 IRP, Minnesota Power has been working diligently to understand these reliability concerns, and a thoughtful transition plan is crucial to ensuring continued safe and reliable operations in this region. This transition plan must include the development of new operational tools and criteria, coordination with MISO and other affected entities, and preparation of the transmission system to ensure regional and local reliability is not compromised by changing operations at BEC.

Background information from 2021 IRP Appendix F, Part 6, describing Minnesota Power's experiences from analysis and development of network upgrades to support the transition of its small coal fleet is reproduced in its entirety for reference in Part 9 of this Appendix F to the 2025 IRP. The remainder of this section will summarize the discussion of transmission system impacts from changing operations at BEC that was included in 2021 IRP Appendix F, Part 7 and Part 8, including a progress update on the status of the conceptual transmission network upgrades discussed in the 2021 IRP. At the end of this section, the development of updated conceptual transmission network upgrade cost estimate assumptions for BEC unit scenarios analyzed in the 2025 IRP will be also be discussed.

General Principles

In the 2021 IRP, Minnesota Power discussed six pillars that are key to understanding the significance of BEC to the region and the transmission system impacts from changing operations at BEC. These pillars to understanding were informed by Minnesota Power's recent experience from transition of its small coal fleet and supported by several different areas of analysis. The six pillars are summarized below.

Pillar #1: Northern Minnesota is Unique. A mixture of heavy industrial and rural residential load requirements, the configuration of the existing transmission system, and a dwindling number of dispatchable local generation resources, produce unique challenges for transitioning away from existing baseload generation in northern Minnesota. If the BEC units are shut down or transition to non-baseload operation, alternative solutions must be identified that can simultaneously meet the needs and expectations of large industrial sites, serve rural demand, and respond to significant variations in regional transfers across a large geographic footprint.

Pillar #2: Baseload Generator Retirements Require Holistic Replacements. Baseload generators provide more than just energy production. They also provide essential reliability services to local energy consumers and the regional power system that must be replaced when the generators are retired or transitioned to non-baseload operation. BEC is the last remaining baseload generating station providing essential reliability services for northern Minnesota. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that can replace the essential reliability services formerly provided by the local baseload generators on a continuous basis.

Pillar #3: Baseload Generators Supply Voltage Support and System Strength. Voltage support and system strength provided by local baseload generators must be replaced to ensure continued reliable operations, power quality, and system protection. If the BEC units are shut down or transition to non-baseload operations, alternative solutions must be identified that effectively and locally replace the voltage regulation, dynamic voltage support, and short circuit capability formerly provided by the local baseload generators on a continuous basis because these services cannot be imported from remote sources.

Pillar #4: Dispatchable Generators Deliver Power to the Local Area. Power formerly provided locally by dispatchable baseload generators must be delivered into the local system from new sources. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that strengthen delivery paths for energy from remote sources to be delivered to the local transmission system and/or maintain a presence of local dispatchable generation to be delivered to energy consumers in northern Minnesota.

Pillar #5: Dispatchable Generators Offset the Need for Regional Power Transfers. Power formerly provided locally by dispatchable generators must be delivered on the regional transmission network, which may have limited capacity to facilitate the delivery of the replacement power from remote resources. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that strengthen the regional transmission network to ensure continued stable and reliable operation in light of new and increased use and/or maintain a presence of local dispatchable generation in northern Minnesota.

Pillar #6: Solution Development is a Multi-Year Process. The detailed transmission, distribution, and resource planning studies necessary to identify and understand the impacts prompted by resource actions and develop a well-defined set of solutions are complex, resource-intensive, and time-consuming. If the BEC units are shut down or transition to non-baseload operation, impacts and solutions must be thoroughly vetted and coordinated with other affected entities through a multi-year process of detailed analysis and project development. Baseload retirement study decisions about resource actions should recognize and allow for a sufficient amount of time for the real-world implementation of these solutions.

Supporting Studies

In the 2021 IRP, Minnesota Power provided an overview of several studies assessing the impacts of BEC Unit 3 (“BEC3”) and BEC Unit 4 (“BEC4”) retirements, which helped inform the transmission network upgrade cost assumptions used for purposes of modeling different BEC operating scenarios in the 2021 IRP. The studies discussed in the 2021 IRP included:

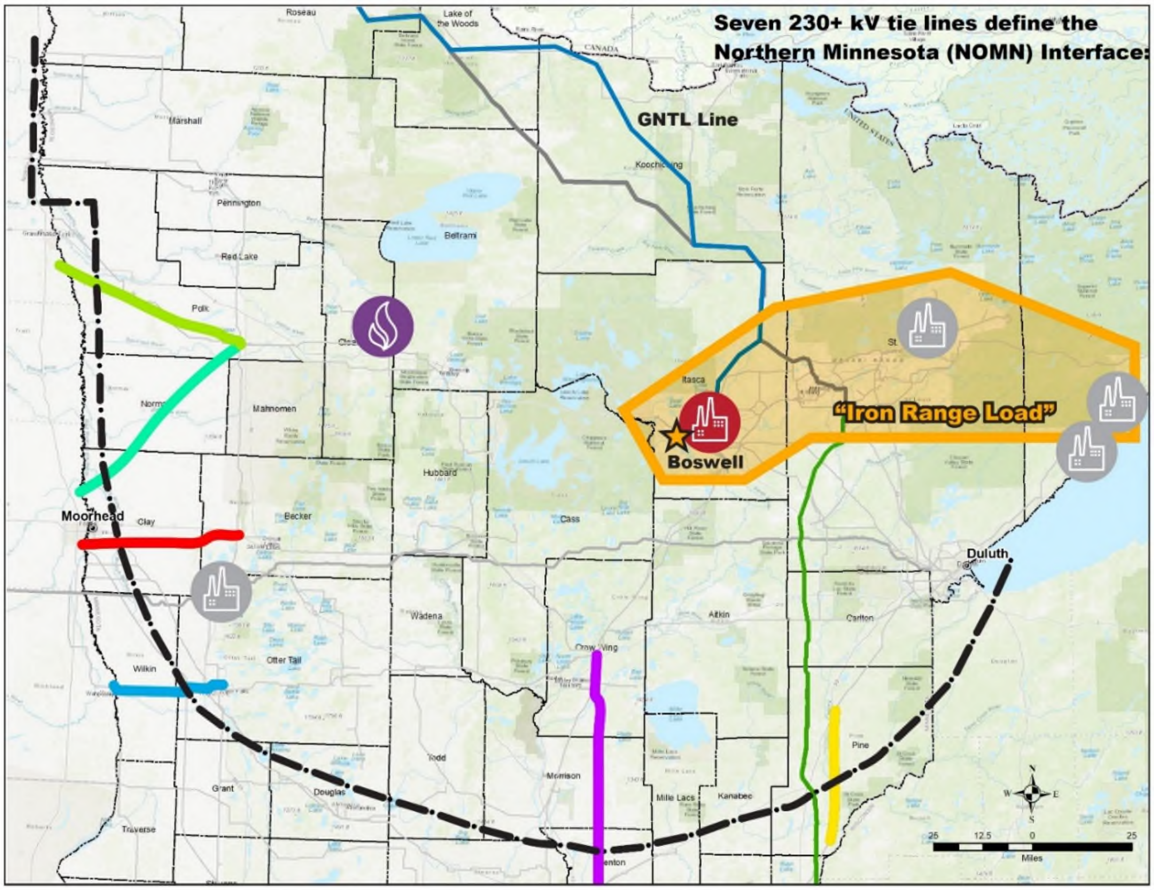
MISO Generator Retirement Study

In August 2018, Minnesota Power submitted an Attachment Y-2 Study request to MISO for a transmission system reliability assessment of various BEC retirement combinations. Mirroring the standard MISO generator retirement study (Attachment Y) process, the Attachment Y-2 Study was an information-only study of various scenarios to identify reliability issues due to the potential retirement of one or both of the BEC units. Due to regional voltage stability concerns identified in the Attachment Y-2 Study, MISO concluded that robust mitigating solutions would likely need to be built before the retirement of the BEC units could be allowed and that one or both of the BEC units could potentially be designated as a System Support Resource (“SSR”) if mitigation is not in place.

Northern Minnesota Voltage Stability Study

Minnesota Power conducted the Northern Minnesota Voltage Stability Study in order to build on and further understand the results from the MISO Attachment Y-2 Study and previous Minnesota Power studies. The Northern Minnesota Voltage Stability Study investigated the underlying cause and contributors to the previously-identified voltage stability issue, defined a voltage stability interface (the Northern Minnesota or “NOMN” interface) and thresholds to accurately characterize the issue, examined the impacts of and sensitivities to various regional drivers on the voltage stability issue and related facility overloads, and investigated potential NOMN interface operating limits for the combinations of BEC3 and BEC4 operating scenarios that were evaluated in the MISO Attachment Y-2 Study. Based on this analysis, Minnesota Power concluded that active monitoring and operational management of the NOMN interface may be sufficient to prevent regional voltage stability problems and related concerns with BEC3 offline, but a long-term permanent transmission or dispatchable generation solution for northern Minnesota was recommended to maintain reliability and a reasonable amount of operational flexibility with BEC4 or both BEC3 and BEC4 offline. Figure 1 below illustrates the NOMN interface that was identified as a result of this study.

Figure 1. Northern Minnesota Voltage Stability Interface Tie Lines



Beyond Boswell Study

The Beyond Boswell Study was performed by Siemens PTI and Minnesota Power in 2016-2017. The study investigated the technical transmission issues surrounding the possible retirement of BEC3 and BEC4, in order to identify the load-serving and reliability impacts of retiring all Minnesota Power coal-fired generation. The study included steady state analysis, voltage stability analysis, and transient stability analysis performed on a range of historically challenging peak and off-peak system conditions, laying important groundwork for understanding the northern Minnesota voltage stability issue and providing additional understanding of potential facility overloads and transient stability impacts from BEC3 and BEC4 retirements.

Short Circuit Analysis

At the time of the 2021 IRP, Minnesota Power was in the process of determining how best to evaluate system strength and voltage support to ensure a minimum level of system strength is maintained for northern Minnesota in the event BEC3 and BEC4 are retired or transitioned to long-term economic operation. Minnesota Power's operational experiences from small coal unit fleet transition demonstrated the importance of this issue, and preliminary short circuit analysis provided insight into the nature of the issue and the main non-BEC sources of short circuit capability. As discussed in further detail below, Minnesota Power provided an update on its in-depth analysis of system strength and voltage support issues in a report submitted with the Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities docket in 2022.[12]

Synchronous Motor Starting Analysis

Based on previous experiences evaluating synchronous motor starting following fleet transition in the North Shore Loop, Minnesota Power commissioned Siemens PTI to study potential impacts on motor starting capability for large power customers on the Iron Range if BEC3 and BEC4 were to be retired. This study was meant to be indicative in nature only, not representative of any single customer or actual equipment. From this analysis, Minnesota Power concluded that large synchronous motor starting is primarily dependent on pre-starting steady-state voltage at the transmission bus, which must be adequately and predictably regulated with or without BEC units online. The motor starting study results and the previous generator retirement experiences both indicate that the most effective leading indicator of whether or not large industrial customer motor starting and other processes will be negatively impacted by BEC unit retirements is Minnesota Power's ability to provide a healthy, predictable transmission system voltage similar to what is presently available with the BEC units online.

Additional Studies

Minnesota Power has continued to evaluate the transmission system impacts of BEC unit retirements since the 2021 IRP. Two additional studies, both of which are primarily concerned with system strength and voltage support issues, are discussed below. Further analysis and discussion of regional voltage stability issues related to BEC unit retirement scenarios is also provided in Chapter 3 of the Certificate of Need application for the Northland Reliability Project.[13]

System Strength Report

Minnesota Power's full system strength and voltage support analysis, including short circuit, transient stability, and motor starting analysis, was summarized in the technical report titled *Summary Report on System Strength & Voltage Support Impacts in Northeastern Minnesota*, which was filed in the Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities docket on July 22, 2022 ("System Strength Report").[14]

The purpose of the System Strength Report is to provide an overview of Minnesota Power's investigations and analyses pertaining to the system strength-related issues expected to arise if BEC3 and BEC4 were to transition to normally-offline operation for any extended period of time. The report provided insight into areas of interest related to system strength and a summary of the findings and conclusions are outlined below:

[12] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Docket No. E-999/CI-19-704, Compliance Filing (July 22, 2022).
[13] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket Nos. E-015, ET-2/CN-22-416 and E-015, ET-2/TL-22-415, Combined Certificate of Need and Route Permit Application, Section 3.3 (Aug. 4, 2023).
[14] *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*, Docket No. E-999/CI-19-704, Compliance Filing (July 22, 2022).

- **Section 2:** *Industry Perspectives* provides a brief discussion of perspectives on system strength from neighboring transmission owners as well as regulatory bodies, technical working groups, and the international community. External references are provided in this section to enable readers to evaluate these industry perspectives for themselves.
- **Section 3:** *Minnesota Power's Experience* provides discussion of several recent planning and operating experiences in Minnesota Power's transmission system stemming from the loss of strength and voltage support during and after the transition of Minnesota Power's fleet of small coal units to peaking, idled, and retired statuses.
- **Section 4:** *Short Circuit Impacts* provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential short circuit impacts from the BEC units being offline. The detailed study report, which contains power system information considered to be Critical Energy Infrastructure Information ("CEII"), is available upon request to individuals possessing a signed CEII non-disclosure agreement.
- **Section 5:** *Motor Starting Impacts* provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential impacts from BEC units being offline on the starting of large synchronous motors by Minnesota Power's large industrial customers. The detailed study report, which contains power system information considered CEII, is available upon request to individuals possessing a signed CEII non-disclosure agreement.
- **Section 6:** *Transient Stability Impacts* provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential impacts from BEC units being offline on voltage response and other potential impacts in the transient period (immediately after a disturbance). The study also includes an investigation into the effectiveness of various synchronous condenser solutions for replacing voltage support and system strength formerly provided by the BEC units. The detailed study report, which contains power system information considered to be CEII, is available upon request to individuals possessing a signed CEII nondisclosure agreement.
- **Section 7:** *Conclusions* provides a summary of the findings, conclusions, and recommendations from the above-referenced investigations into system strength and voltage support impacts from the BEC units being offline.

Based on the findings of the System Strength Report, Minnesota Power concluded that the degradation of the Minnesota Power transmission system when the BEC units are offline, particularly in terms of steady state and dynamic voltage regulation, is a substantial area of concern that requires continued evaluation and solution development. Without improvements to the transmission system to replace the voltage support provided by the BEC units, long-term intentional operation of the transmission system without the BEC units – such as when both units would be offline due to economic operation – would result in an unacceptable level of reliability risk and uncertainty. Therefore, long-term solutions focused on steady state and dynamic voltage support should be developed without delay and prior to putting both BEC units into economic operations. Such long-term solutions should focus on steady state and dynamic reactive power capability and voltage regulation, which may be provided by STATCOMs, voltage source converter ("VSC") HVDC systems, or synchronous condensers. Future-proof technologies that are relatively immune to changes in short circuit level, like VSC HVDC, should be considered as a priority when scoping transmission projects on the Minnesota Power transmission system.

Finally, Minnesota Power should continue to regularly assess transient and voltage stability, short circuit ratio, capacitor switching, transformer energization, harmonic impacts, and other potential weak system issues in future analysis and development of the Minnesota Power transmission system.

The full System Strength Report, excluding appendices containing CEII, is attached as Appendix F, Part 10.

Boswell Synchronous Condenser Conversion Study

From late 2021 to early 2022, Minnesota Power contracted Burns & McDonnell ("BMCD") to conduct a feasibility study to identify a preliminary design concept and develop an indicative cost estimate for BEC3 or BEC4 seasonal synchronous condenser conversion. In theory, a seasonal conversion would allow the units to continue generation of power during peak seasons while being modified to operate as synchronous condensers during times of the year when demand is lower.

Conversion of an existing generator to a synchronous condenser requires disconnection or modification of the existing turbine, modification of the generator lube oil and cooling systems, evaluation and possible upgrade of excitation, protection and control systems, and development of a new starting scheme. The results of the BMCD feasibility study indicate that synchronous condenser conversion is feasible for both BEC3 and BEC4 and identify a preliminary technical scope for implementation of such conversion. The technical scope was developed for conversion of a single BEC unit independent of the remaining (non-converted) unit. A new variable frequency drive ("VFD") is required for starting of the synchronous condenser, in addition to modifications of the relevant mechanical, electrical, structural, and control systems for the converted unit. The scope of work did not include winterization efforts, assuming that either the existing cross-tied auxiliary steam systems will allow the converted unit to be kept warm by the other (non-converted) unit or that additional improvements, such as new auxiliary heating boilers, will be added outside the scope of the synchronous condenser conversion. With respect to BEC4 in particular, it was noted that known historical vibration issues may be exacerbated by the altered operating characteristics of synchronous condenser conversion. These vibration issues would need to be evaluated during detailed design for a BEC4 synchronous condenser conversion and could lead to increased costs if the BEC4 machine requires reconditioning. For either BEC unit, the design basis of the synchronous condenser conversion assumed that the associated improvements have a design life of approximately 10-15 years.

The BMCD report also raises concerns relating to the feasibility of changing between generator mode and synchronous condenser mode to support seasonal operation. Seasonal operation was found to be challenging as it would require an outage, estimated to be about one week, to modify systems and equipment to complete the cutover between operating modes. In particular, transition to synchronous condenser mode would require operations and maintenance staff to make modifications to the following systems and equipment:

- Boiler fuel handling system: To avoid spontaneous combustion of sub-bituminous coal, the fuel handling system needs to be brought to safe layup state. The day-bins would need to be emptied of coal and inerted.
- Boiler water/steam side: Boiler water side would be brought to safe state by wet-layup for short duration outages or drained for dry-layup during long duration outages.

- Turbine/generator coupling: The generator must be physically isolated from the low-pressure turbine by removing coupling bolts and taking out the spacer coupling. It may be necessary to check for generator balance and shifting balance shots.
- Cooling tower/circulating water system: The main circulating water system and cooling water system has valves to be actuated and systems walked down for verification.
- Lube oil system: Many valves need to be actuated and system walked down for verification.

Furthermore, with MISO's new seasonal resource adequacy construct requiring generation to be available across all seasons to fully accredit the generation, it will be a challenge to operate in synchronous condenser mode and accredit BEC capacity in each season. With the weeklong outage required for conversion between energy production and synchronous condenser mode, the unit will have limited capability to respond to energy price volatility in the market or reliability events. Based on the technical findings of the feasibility study, resource adequacy, and market price volatility, Minnesota Power concluded that seasonal synchronous condenser operation was not a viable solution for the BEC units as long as they continue to be utilized as energy resources. Essentially, the mission of the BEC units must either be to operate as an energy and capacity resource or to be retired and convertered to a synchronous condenser used solely for the purpose of supporting transmission system reliability. They cannot effectively support both missions. However, Minnesota Power will continue to consider BEC unit synchronous condenser conversion as an option for providing needed system strength and voltage support in planning scenarios where one or both BEC units are permanently retired.

While the original BMCD report from 2022 does provide a preliminary indicative cost and lead-time for synchronous condenser conversion of BEC3 and BEC4, the costs and lead-times from the original report are no longer valid due to changing market and supply chain conditions. Minnesota Power re-engaged with BMCD in 2024 to obtain an updated outlook for the conceptual cost and leadtime of BEC unit synchronous condenser conversions. Based on recent experience, including two different projects that were in the execution phase during the 2024 update, BMCD provided the updated costs shown in Table 4 below. The BMCD cost estimate does not include owner costs and contingencies, which have been added by Minnesota Power to provide a more comprehensive indicative cost in Table 4.

Table 4. Bosewell Synchronous Condenser Conversion Conceptual Cost Estimates

[TRADE SECRET DATA BEGINS

[redacted]

TRADE SECRET DATA ENDS]

In addition to the cost impacts, BMCD indicated that project delivery leadtimes have more than doubled from 18 months in the original report, to 46 months in the 2024 update. The 2024 cost estimate and schedule updates are also attached with the original BMCD synchronous condenser conversion report in Part 11 of this Appendix F, the entirety of which is Trade Secret.

Status Update on Transmission Network Upgrades

Minnesota Power developed transmission network upgrade cost assumptions for the purpose of modeling different BEC operating scenarios in the 2021 IRP. This section provides an update on the status of Minnesota Power's evaluation and development of the various network upgrades discussed in the 2021 IRP.

To provide a holistic understanding of the potential transmission upgrade costs associated with various changes in the operation of the BEC units, four potential operating modes were considered for each BEC unit. **Baseload Operation** means that the unit is online with a high capacity factor similar to its historical baseload operations. **Economic Operation** means that the unit may be dispatched offline, but is available to be turned online to resolve potential transmission issues. This could represent economic operation of the existing BEC units or economic operation of a replacement unit utilizing a different fuel type. **Shutdown** means that the generator has been permanently shut down and is not available to run under any circumstances to mitigate transmission system constraints. For this planning exercise, replacement generation was assumed to be sited outside Minnesota Power's transmission system. Several combinations were considered for the BEC units in order to develop IRP cost estimates for mitigation of transmission system impacts. Table 5 below shows the unique scenarios developed for this exercise.

Table 5. Boswell Unit Scenarios Evaluated

Scenario	BEC3	BEC4
E1	Economic Operation	Baseload Operation
E2	Economic Operation	Economic Operation
S1	Shutdown	Baseload Operation
S2	Baseload Operation	Shutdown
S3	Shutdown	Shutdown

Based on a review of the studies and operational experiences discussed in the 2021 IRP, a list of expected transmission issues associated with changing operations at BEC was developed. The issues in the list were then categorized according to whether they were primarily related to voltage support and system strength, local power delivery, or regional power delivery. A conceptual solution was then developed for each of the identified issues. These issues and conceptual solutions are summarized in Table 6 below, along with a progress update and summary of the current status of each solution since the 2021 IRP. Further discussion is provided for each of the projects in progress following the table.

Table 6. Status Update on Transmission Network Upgrades Identified in 2021 IRP

Scenarios	Category	Solution	Constraints Addressed	Progress Update
ALL	Voltage Support & System Strength ("VSSS")	Synchronous Condenser or STATCOM #1	Replace VSSS formerly provided by BEC units for: • Normal steady state operations • Contingency conditions • Prior outages	Identified that STATCOM or similar voltage source converter ("VSC") solution could provide needed support. Two projects currently in progress: • **Riverton STATCOM:** Planned with ISD in Early 2028 (MPUC Project Tracking No. 2021-NE-N21) • **HVDC Modernization Project (VSC):** Planned with ISD 2029-2030 (MPUC Project Tracking No. 2013-NE-N16) Boswell synchronous condenser conversion feasibility study completed.
E2, S1, S2, S3	VSSS	Synchronous Condenser or STATCOM #2		
S3	VSSS	Synchronous Condenser or STATCOM #3		
S1, S2, S3	VSSS	300 megavolt ampere reactive ("MVAR") of additional capacitor banks	Steady state reactive power support	**No longer necessary.** STATCOM and VSC HVDC can supply without needing additional capacitor banks
ALL	Local Power Delivery	Rebuild Iron Range – Blackberry 230 kV Lines	Overload of Iron Range 230 kV Outlets	**105 Line & 106 Line Upgrade** completed and placed in service in 2024. (MPUC Project Tracking No. 2021-NE-N20)
S1, S2, S3	Local Power Delivery	Replace **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Transformer	Overload of **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Transformer	Need & timing impacted by changing system conditions, including LRTP Tranche 1 and Tranche 2.1. Constraints will continue to be monitored in reliability studies, but no longer considered required for BEC Unit scenarios.
S1, S2, S3	Local Power Delivery	Build new **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Line	Overload of **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Transformer and related prior outage overloads in	Need & timing impacted by changing system conditions, including LRTP Tranche 1 and Tranche 2.1. Constraints will continue to be monitored in reliability studies, but no longer considered required for BEC Unit scenarios.

Scenarios	Category	Solution	Constraints Addressed	Progress Update
			the area	
ALL	Regional Power Delivery	Define NOMN interface & manage in real-time	Northern Minnesota Voltage Stability & related issues	Ongoing coordination with MISO to evaluate and respond to real-time indicators associated with the voltage stability issue, ensuring reliability until Northland Reliability Project is placed in service.
S1	Regional Power Delivery	Upgrade existing **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Lines	Underlying transmission overloads along NOMN interface	**No longer necessary.** Underlying system constraints will be mitigated by Northland Reliability Project.
S2, S3	Regional Power Delivery		Northern Minnesota Voltage Stability & related issues	**Northland Reliability Project:** MISO LRTP Tranche 1 Project #3 with planned in-service date June 2030. Recently granted Certificate of Need and Route Permit by the Commission (Dockets No. E-015, ET-2/CN-22-416 and E-015, ET-2/TL-22-415, MPUC Project Tracking No. 2023-NE-N1)

Riverton STATCOM Project

To address voltage support and system strength concerns, Minnesota Power is moving forward with the development of a new STATCOM project to provide steady state and dynamic voltage support to the local backbone 230 kV network. The new ±300 MVAR STATCOM will be constructed at the existing Riverton 230/115 kV Substation, with a targeted in-service date in early 2028.

HVDC Modernization Project

In June 2023, Minnesota Power filed a combined Certificate of Need and Route Permit application for the HVDC Modernization Project, which was subsequently granted by the Commission in October 2024.[15] The HVDC Modernization Project will implement grid-supporting VSC HVDC technology, which operates very much like a STATCOM and will therefore also contribute to the long-term need for steady state and dynamic voltage support on Minnesota Power's local 230 kV network through the HVDC system connection to the Minnesota Power Arrowhead 230/115 kV Substation. The HVDC Modernization Project is currently planned to be constructed and placed in service between 2029-2030.

105 Line & 106 Line Upgrade Project

To address local power delivery concerns, Minnesota Power recently implemented an upgrade of the Iron Range – Blackberry 230 kV transmission lines ("105 Line" and "106 Line"), as discussed in Appendix F, Part 8 of the 2021 IRP. This project was completed and placed into service in 2024.

Define NOMN Interface & Manage in Real Time

When one or both of the BEC units are offline, several Minnesota Power and MISO studies have identified that there is a regional voltage stability concern under certain combinations of transmission system conditions. Minnesota Power continues to work with MISO to ensure that this voltage stability issue is understood, monitored, and managed effectively in MISO real-time operations, as well as being evaluated and planned for in MISO long-range transmission planning studies.

Short periods have occurred where both BEC units have been offline together because of a combination of planned and unplanned outages. Through close coordination with MISO and other impacted utilities, reliability has been maintained but only because of ideal timing of the planned activities. During all occurrences of simultaneous outages, a more conservative approach to operations has been requested by MISO to limit the potential for reliability issues to arise should another unplanned event occur. Because of these limited periods of operation without BEC, both MISO and Minnesota Power are monitoring and responding to real-time indicators associated with the voltage stability issue, including regional transfer interface flows and individual tie line flows. Over time, additional tools and improvements may be developed to increase operational awareness and management of the issue. It is also important to note that the voltage stability

[15] *In the Matter of the Application of Minnesota Power for a Certificate of Need for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/CN-22-607 and *In the Matter of the Application of Minnesota Power for a Route Permit for a High Voltage Transmission Line for the HVDC Modernization Project in Hermantown, Saint Louis County*, Docket No. E-015/TL-22-611, Order Granting Certificate of Need and Issuing Route Permit (Oct. 25, 2024).

concerns are primarily associated with system conditions that typically occur during winter months. With at least one BEC unit expected to be running through the winter months, the near-term risk of encountering voltage stability issues is lessened.

Northland Reliability Project

To address regional voltage stability concerns, MISO evaluated and in July 2022 ultimately approved a new double-circuit 345 kV transmission line connecting the Minnesota Power Iron Range Substation to the Great River Energy Benton County Substation as part of the LRTP Tranche 1 portfolio of multi-value projects. This LRTP project, which is now called the Northland Reliability Project, is very similar to the "proxy regional transmission solution" discussed in Appendix F, Part 8 of the 2021 IRP. In August 2023, Minnesota Power and Great River Energy filed a combined Certificate of Need and Route Permit Application for the Northland Reliability Project. As stated in the application, the "[Northland Reliability] Project is needed to maintain transmission system reliability and optimize regional transfer capability as coal-fired generation ceases operations in northern Minnesota and significant renewable generation comes online in the upper Midwest." On February 28, 2025, the Commission granted a Certificate of Need and Route Permit for the Northland Reliability Project.[16] The Northland Reliability Project is targeted to be in-service by June 2030.

Remaining Network Upgrades

As indicated in Table 6, the need for certain of the conceptual network upgrades discussed in the 2021 IRP has changed. Additional capacitor banks are no longer needed for voltage support and system strength due to the reactive power capabilities provided by the planned STATCOM and VSC HVDC projects being sufficient for both steady state and dynamic support. Certain underlying transmission system upgrades identified as an interim solution for regional power delivery issues are also no longer necessary now that the Northland Reliability Project is moving forward. Recent assessments by Minnesota Power and MISO indicate that the need for and timing of two of the local power delivery network upgrades, which would involve replacing two transmission-level transformers and building a new transmission line, is impacted by changing system conditions including the development of the LRTP Tranche 1 and Tranche 2.1 portfolios. Minnesota Power will continue to monitor the long-term need for these reliability upgrades, but they are no longer considered necessary to implement in advance of BEC retirement scenarios.

Therefore, the only remaining transmission network upgrade from the 2021 IRP that does not already have a project in progress is the need for a third source of voltage support and system strength (synchronous condenser or STATCOM) in the event that both BEC units are retired. The development of updated cost assumptions for this lone remaining transmission network upgrade is discussed in the next section.

Transmission Network Upgrade Cost Assumptions for 2025 IRP

In the 2021 IRP, Minnesota Power developed its assumptions for voltage support and system strength network upgrades based on the premise that transmission solutions would be required to provide short circuit capability similar to what has been provided by BEC3 (the smaller unit) at

[16] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for an Approximately 180-mile, Double Circuit 345 kV Transmission Line*, Docket Nos. E-015, ET-2/CN-22-416 and E-015, ET-2/TL-22-415, Order Granting Certificate of Need and Issuing Route Permit (Feb. 28, 2025).

all times, considering both single-contingency events (unintended loss of a facility) and prior outage events (scheduled maintenance on one facility followed by unintended loss of another facility). What this effectively means is that three local sources of voltage support and system strength equivalent to BEC3 are necessary at any given time. Potential sources considered in the 2021 IRP included synchronous condensers, new dispatchable generators, and the existing BEC generators. Based on the findings of the System Strength Report, Minnesota Power later determined that STATCOMs and similar power electronics-based systems such as the VSC HVDC converters would also be effective solutions for the voltage support needs of the network with little or no local generation in northern Minnesota.

With planned additions of the Riverton STATCOM in 2028 and the HVDC Modernization Project in 2029-2030, the only remaining scenario requiring a network upgrade for voltage support and system strength is when both BEC units are shutdown (scenario S3). For that scenario, one additional synchronous condenser, STATCOM, or equivalent voltage support system ("VSS") would be needed to ensure a continuous source of voltage support and system strength following unintended loss of one VSS and for prior outage of one VSS followed by loss of a second VSS.

For the purpose of this exercise, it was assumed that the additional VSS would involve a new STATCOM addition similar in scope and scale to the planned Riverton STATCOM (230 kV, ±300 MVAR). Since scenario S3 involves permanent retirement of both BEC units, synchronous condenser conversion of one of the two BEC units could also be considered as an alternative, with a potentially lower initial capital cost compared to the STATCOM solution. However, the drawbacks of a slower dynamic voltage response from the synchronous condenser, shorter service life (10-15 years for synchronous condenser conversion versus 30+ years for STATCOM), and higher operating and maintenance costs of the synchronous condenser conversion solution would need to be analyzed alongside the STATCOM solution to develop a comprehensive assessment and lifecycle cost comparison of alternatives.

In order to provide a range of estimated costs associated with the conceptual STATCOM solution for BEC scenario S3, Minnesota Power utilized MISO's Transmission Cost Estimate Guide for MTEP24 (the "MISO Guide").[17] The MISO Guide documents the per-unit costs assumptions used by MISO for assessing the business justification for transmission projects identified in MISO planning studies. Cost assumptions are provided for new and upgraded transmission lines, new and expanded substations, and reactive resources. Due to the preliminary and conceptual nature of the solutions applied to transmission impacts from BEC retirement, cost assumptions used by Minnesota Power were based on the MISO "exploratory" (Class 5) cost estimate. The basis of this estimate, including expected accuracy range, is shown in Table 7 below.

[17] "MISO Transmission Cost Estimation Guide for MTEP24," available at https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

Table 7. MISO Exploratory Cost Estimate Assumptions[18]

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

The underlying assumptions behind MISO's cost estimates are discussed in detail in the MISO Guide, and the estimates are intended to be inclusive of all aspects of a transmission project. MISO specifically states that the cost estimates include contingency and AFUDC, as shown in Figure 2 below. The specific contingency and Allowance for Funds Used During Construction ("AFUDC") assumptions (30 percent and 7.5 percent, respectively) have been added to the figure for clarity.

Figure 2. Contingency & AFUDC Assumptions[19]

[18] "MISO Transmission Cost Estimation Guide for MTEP24," at 5, available at https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

[19] "MISO Transmission Cost Estimate Guide for MTEP24" at 4, available at https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24337433.pdf.

For the conceptual STATCOM solution described previously in this section, components of the solution were delineated including the STATCOM and interconnection 230 kV substation modifications, assuming it is interconnected at an existing 230 kV substation. The per-unit cost estimating assumptions from the MISO Guide were then applied to these components and totaled up to represent an estimated cost for the conceptual solution. The total mid-level estimated cost, in 2024 dollars, is approximately $71 million. This mid-level estimated cost was escalated by an average of approximately 3 percent per year for use in the 2025 IRP modeling scenarios.[20]

While a single cost assumption is necessary to apply to IRP modeling scenarios, the estimated transmission solution cost should be viewed in context with an upper and lower bound applied to reflect uncertainties inherent at this early point in their development. Based on the MISO Guide, Minnesota Power applied an upper bound of +65 percent and a lower bound of -35 percent. The resulting cost range is shown in Table 8 below.

Table 8. Scenario S3, Transmission Network Upgrade Cost Range

STATCOM: ±300 MVAR, 230 kV Conceptual Cost in 2024 Dollars	
Upper Bound	$ 117 million
Estimated Cost	$ 71 million
Lower Bound	$ 53 million

G. Part 7: Transmission System Analysis of HREC Retirement

Background

The Hibbard Renewable Energy Center ("HREC"), consisting of Unit 3 and Unit 4, is a dispatchable generator which contributes to supporting the reliability of the electric grid in the Duluth, Minnesota area. The retirement of HREC would remove one of the primary options within Minnesota Power's direct control for relieving heavy loading on the Duluth-area 230/115 kV transformers. These three transformers, two at the **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Substation and one at the **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Substation, provide the main source of power delivery into the local Duluth area transmission system. Without HREC, there are very limited options for relieving heavy loading on these three transformers as power is delivered from the higher voltage 230 kV network to the local area during peak load periods. If two of these three transformers are offline, the remaining transformer is responsible for delivering most of the power needed for serving load on the Duluth 115 kV network. When Duluth-area loads are at or near peak levels, this condition would cause the remaining transformer to overload. This section provides discussion of the different planning studies, operating scenarios, and anticipated transmission system network upgrades that are associated with a potential HREC retirement.

Planning Studies

[20] This escalation is based on an average staggered rate developed by an independent cost trend report for transmission capital projects published by Handy Whitman. Escalation started in 2025 at 4.75 percent and decreased gradually to 3.00 percent in 2030 which was held through the study period.

Several steady-state planning studies have been conducted to contribute to Minnesota Power's understanding of the system impacts of a HREC retirement. Historically, HREC has supported the reliability of the Duluth electric grid by providing power and support on the 115 kV level so that less support is needed from the higher voltage 230 kV network tied in through 230/115 kV transformers at the **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** substations. Through various studies, the Duluth-area 230/115 kV transformer loading and HREC generation status have been monitored to build Minnesota Power's understanding of a HREC retirement.

MISO Generator Retirement Study

Regional impacts of generating unit closures on the transmission system consider transmission lines 100 kV and above owned and operated by the generation owner and neighboring utilities. Because Minnesota Power is a member of MISO, the regional transmission planner and operator for much of the Midwest, any generating unit closure on the Minnesota Power system is required to utilize the MISO Attachment Y (unit retirement) process. Section 38.2.7 of the MISO Tariff describes the process for generator retirements:

1. First, the MISO market participant owning the generation resource involved must submit an Attachment Y to MISO stating when the generation resource is to be retired. This must be done at least 26 weeks before the targeted retirement date.
2. Second, MISO will perform reliability analyses to determine if the unit may be retired without causing reliability issues on the transmission system. North American Electric Reliability Corporation ("NERC") Transmission Planning ("TPL") standards and other applicable reliability criteria are applied.
3. Third, if the unit closure does not impact reliability, the unit is allowed to shut down as scheduled. If the unit closure results in reliability criteria violations on the transmission system, the unit is placed on an SSR agreement per Attachment Y-1 of the MISO Tariff. The unit will then remain operational under the SSR agreement until the transmission upgrades necessary to provide adequate transmission system reliability are constructed.

The Attachment Y process ultimately results in a binding agreement between the generation owner and MISO to either close the unit or keep it online as a SSR for the reliability of the regional transmission system. MISO also offers a parallel investigative option, called the Attachment Y-2 process, by which a utility can request an information-only study of the regional reliability impacts of a particular generating unit closure without entering into a binding agreement to close the unit or keep it online.

In January 2024, Minnesota Power submitted an Attachment Y-2 Study request to MISO for a transmission system reliability assessment of a HREC retirement. Mirroring the standard MISO generator retirement study (Attachment Y) process, the Attachment Y-2 Study was an information-only study of various scenarios to identify reliability issues due to the potential retirement of the HREC units. Based on the results of the Attachment Y-2 study, MISO concluded that all identified constraints could be mitigated by redispatching remaining online generation and therefore the HREC units would not be designated as SSR units. The full MISO Attachment Y-2 Study Report contains CEII and is non-public. A redacted version of the report is attached in Part 9 of this Appendix F. Upon analyzing the results of the Attachment Y-2 study, Minnesota Power noted that some of the constraints identified by MISO in the Attachment Y-2 study were similar to Duluth-area 230/115 kV transformer constraints Minnesota Power had observed in previous planning studies and real-time operations. While MISO's methodology for Attachment Y-2 studies allows for redispatching remaining online generators out of economic merit order to address these constraints, the approach represents a short-term solution. Additional targeted analysis of the local area is necessary to identify the appropriate long-term solution for the underlying issues leading to these constraints. To gain a deeper understanding of transmission impacts from potential HREC retirement with a greater focus on long-term solution development, Minnesota Power conducted a targeted power flow study of the local Duluth-area network impacts.

HREC Retirement Targeted Investigation

A "HREC Retirement Targeted Investigation" was performed that targets specific contingencies that have historically been stressful for the Duluth-area 230 kV and 115 kV transmission system using models that simulate more locally stressed power flow scenarios than those in standard model sets but are similar to those experienced under real operating conditions. This study showed that certain contingencies cause the Duluth-area 230/115 kV transformers to overload past their emergency rating with the HREC units offline in the 5-Year Winter Peak cases. When HREC was turned online, the loading on these transformers was reduced to within the emergency rating, mitigating the overload. Within the 10-Year Summer and Winter Peak, these same contingencies significantly overloaded the Duluth-area 230/115 kV transformers past their emergency rating with HREC offline. With HREC online, the transformer loading was reduced drastically but was still above the emergency ratings. This targeted study demonstrates the importance that HREC has for local power delivery in the Duluth, Minnesota area. While there is a long-term need for more 230/115 kV transformer capacity in the Duluth area with or without HREC available, retaining HREC on the local 115 kV network provides important near-term relief for these heavily-loaded transformers. If HREC were to be retired, this 10-year planning horizon need for more transformer capacity would become an immediate need within the next one to five years, and there would be a risk of reliability issues related to overloading these transformers in real-time operations during peak load periods. These findings align with Minnesota Power's experiences in real-time operations, where HREC is called upon from time to time to preserve local reliability during outages of the Duluth-area 230/115 kV transformers.

Conceptual Upgrades

Based on a review of the studies and the operational experience discussed above, a list of expected transmission issues associated with changing operations at HREC was developed. The only issue on the list is related to local power delivery and Duluth-area transformer loading, and a conceptual solution was then developed. The following discussion will provide more information on the issue and conceptual solution.

The Duluth transmission system is dependent on the 230/115 kV substations for the delivery of power locally from remote resources, especially when the HREC units are offline. For the purpose of this exercise, a transmission network upgrade was included for HREC retirement scenarios to address local power delivery concerns based on a review of the study results to date. For scenarios involving the shutdown of both HREC units, this upgrade would involve installing a second 230/115 kV transformer at the **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Substation to provide redundancy and load-serving capacity for 230/115 kV sources into the Duluth area. The 230 kV bus at the substation would be expanded into a ring bus configuration, and an existing 115 kV line would be rebuilt and reconfigured to operate at 230 kV, providing fully redundancy between the **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** Substations. This project is nearly identical to the Duluth

230 kV Project, which has been included with the Minnesota Biennial Transmission Projects Report for almost two decades under MPUC tracking number 2007-NE-N1. This local power delivery issue and solution is summarized in Table 9 below.

Table 9. Summary of HREC Generator Retirement Transmission Issues and Solutions

Category	Impact	Solution
Local Power Delivery	Overload of Duluth-area 230/115 kV Transformers	New **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** 230/115 kV Transformer. New **[TRADE SECRET DATA BEGINS** [redacted] **TRADE SECRET DATA ENDS]** 230 kV Line: Rebuild part of 115 kV line to operate at 230 kV and construct 3 miles of new 230 kV line

Estimated Costs

In order to provide a range of estimated costs associated with the transmission solution shown in Table 9 and total the estimated HREC generator retirement costs, Minnesota Power used the MISO Guide as discussed previously for the BEC retirement scenario S3. The MISO Guide documents the per-unit cost assumptions used by MISO for assessing the business justification for transmission projects identified in MISO planning studies. Cost assumptions are provided for new and upgraded transmission lines, new and expanded substations, and reactive resources. Due to the preliminary and conceptual nature of the solutions applied to transmission impacts from HREC retirement, cost assumptions used by Minnesota Power were based on the MISO "exploratory" (Class 5) cost estimate. The basis of this estimate, including expected accuracy range, is shown in Table 7, included with the discussion of the BEC scenario.

The underlying assumptions behind MISO's cost estimates are discussed in detail in the MISO Guide, and the estimates are intended to be inclusive of all aspects of a transmission project. MISO specifically states that the cost estimates include contingency and AFUDC, as shown in Figure 2, included with the discussion of the BEC scenario.

For the transmission solution described previously in this section, components of the solution were delineated, including apparatus and line length assumptions. The per-unit cost estimating assumptions from the MISO Guide were then applied to these components and totaled to represent an estimated cost for the conceptual solution. The total mid-level cost estimate in 2024 dollars is shown in Table 10 below.

Table 10. HREC Retirement Transmission Impact Cost Assumptions

Hibbard Operating Scenarios	**Estimate ($M)**	
Type of Transmission Impact	Economic Operation	Retired
Local Power Delivery	$ -	$ 28
TOTAL		**$ 28**

These mid-level estimated costs were escalated by approximately 3 percent per year for use in the 2025 IRP modeling scenarios.[21]

While a single cost assumption is necessary to apply to IRP modeling scenarios, the estimated transmission solution costs should be viewed in context with an upper and lower bound applied to reflect uncertainties inherent at this early point in their development. Based on the MISO Guide, Minnesota Power applied an upper bound of +65 percent and a lower bound of -35 percent. The resulting cost range is shown in Table 11 below.

Table 11. HREC Retirement Transmission Network Upgrade Cost Range

Duluth 230 kV Project Conceptual Cost in 2024 Dollars	
Upper Bound	$ 46 million
Estimated Cost	$ 28 million
Lower Bound	$ 21 million

[21] This escalation is based on an independent cost trend report for transmission capital projects published by Handy Whitman.

H. Part 8: MISO Hibbard Attachment Y-2 Study (Redacted Version)

Public Version (Redacted)

Attachment Y-2 Study Report

Minnesota Power
Hibbard Renewable Energy Center
Unit 3 & 4: 59.9 MW
Study Effective Date: June 1, 2029

May 22, 2024

MISO

P.O. Box 4202
Carmel, IN 46082-4202
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EXECUTIVE SUMMARY

On January 17, 2024, *Minnesota Power* submitted an Attachment Y-2 study request to *MISO* for the potential change of status of *Hibbard Renewable Energy Center Unit 3 and 4* with the study effective date of June 1, 2029.

MISO performed a Transmission System reliability assessment of *Hibbard Renewable Energy Center Unit 3 and 4* set forth in the MISO Business Practices Manuals and was discussed and reviewed with the impacted Transmission Owners (TOs): *GRE(615), MP(608), OTP(620), XEL(600), WPS(696)*

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are no reliability issues identified related to the potential change of status of *Hibbard Renewable Energy Center Unit 3 and 4*, that may require the unit to be designated as a System Support Resources ("SSR") unit.

Majority of thermal violations are pre-existing issues. All remaining thermal violations can be mitigated by generator redispatch.

For voltage violations most of them are pre-existing issues as well. The remaining voltage violations can be mitigated by reducing the load and adjusting switched shunt output.

An Attachment Y-2 study is a non-binding assessment of the Transmission System reliability for the potential suspension or retirement of a Generation Resource(s). The results of the study are not definitive and the analysis is to provide information to the Market Participant to assist them in evaluating their options. However, it does not commit the Market Participant to proceed with plans for suspension or retirement.

Furthermore, while the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted.

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1. INTRODUCTION

The Market Participant *Minnesota Power* submitted an Attachment Y-2 study request to *MISO* on January 17, 2024 for the potential change of status of *Hibbard Renewable Energy Center Unit 3 and 4* effective June 1, 2029.

The total capacity of *Hibbard Renewable Energy Center Unit 3 and 4* is 59.9 MW. It is connected to 115 kV transmission systems, and is located in Duluth, MN.

1-I Study Unit(s)

Power Flow Area	Unit Description	kV Network[1]	Total MW[2]	Start Date
MP	Hibbard Renewable Energy Center Unit 3	115	30	6/1/2029
MP	Hibbard Renewable Energy Center Unit 4	115	29.9	6/1/2029
Total			**59.9MW**	

[REDACTED]

Figure 1: General Location of Hibbard Renewable Energy Center Generating Station

[1] In study models
[2] Generator Verification Test Capacity (GVTC) Value. Auxiliary Loads of Study Units are not modelled. These values are the Net MW Output.

2. STUDY OBJECTIVE

Under Section 38.2.7 of MISO's Tariff, SSR procedures maintain system reliability by providing a mechanism for MISO to enter into agreements with Market Participants (MP) that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that have requested to either Retire or Suspend, but are required to maintain system reliability.

The principal objective of an Attachment Y-2 study is to determine if the unit(s) for which a potential change in status requested is necessary for system reliability based on the criteria set forth in the MISO Business Practices Manuals. The study work included monitoring and identifying the steady state branch/voltage violations on transmission facilities due to the unavailability of the Generation Resource or SCU. The relevant MISO Transmission Owner(s) and/or regional reliability criteria are used for monitoring such violations.

An Attachment Y-2 study is a non-binding informational study intended to determine whether it is likely that the Generation Resource(s) would qualify as an SSR Unit(s). While the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted. A final SSR determination would only result from completion of the processes stated in the MISO Tariff, including discussion with stakeholders to determine whether a feasible alternative to SSR designation exists.

The purpose of this study is to assess the reliability impacts from the potential change of status of *Hibbard Renewable Energy Center* located in Duluth, MN effective June 1, 2029.

3. STUDY ASSUMPTIONS & INPUTS

3.1 Study Models

Studies performed using the following power flow models:

- The near-term starting models are from the MISO MTEP23 2028 case, changes will be made to the models to reflect system topology for the start date of the generation's change of status request:
  - 2028 Summer Shoulder (Source: MISO23_2028_SHAW_TA)
  - 2028 Summer Peak (Source: MISO23_2028_SUM__TA)
  - 2028 Winter Peak (Source: MISO23_2028_WINNF_TA)
- Similarly, the out-term starting model are from MISO MTEP23 2033 case, changes will be made to the model to reflect system topology changes submitted to MISO:
  - 2033 Summer Peak (Source: MISO23_2033_SUM__TA)

For each model, two scenarios were created which represent the "before" and "after" generator(s) change of status.

3-I Study Models

Model Name	Loads	Topology	Study Unit(s)	Dispatch Type[3]	Contingencies Category
2028SH_HIBBARD_OFF	Summer Shoulder	2028	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2028SH_HIBBARD_ON	Summer Shoulder	2028	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2028SP_HIBBARD_OFF	Summer Peak	2028	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2028SP_HIBBARD_ON	Summer Peak	2028	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2028WP_HIBBARD_OFF	Winter Peak	2028	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2028WP_HIBBARD_ON	Winter Peak	2028	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6
2033SP_HIBBARD_OFF	Summer Peak	2033	OFF	SCED	P1,P2,P4,P5,P7, Selected P3, P6
2033SP_HIBBARD_ON	Summer Peak	2033	ON	SCED + Scale	P1,P2,P4,P5,P7, Selected P3, P6

[3] Dispatching according to procedure explained in BPM-020. "SCED + Scale" in the online cases means that all generators in the vicinity of the generator under study will remain dispatched at their SCED values identified in the corresponding offline case, and the rest of MISO will be scaled down to balance the overall generation in MISO after turning on the study unit(s).

3.2 Study Assumptions

3.2.1 Generation

- All applicable approved Attachment Y (Retirement/Suspension) generators were modelled offline
- Only new generators with signed GIA will be modelled.

3-II Generation Assumptions

[REDACTED]

3.2.2 Transmission

A Future Projects included in 2028 study models

3-III MTEP Future Projects in Models

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
ATC_(24093)_Z1_RRN_T2-T4_345-115_Replacement	162350	MTEP A	Planned	6/1/2027
ATC_(24613)_Z3_J1214_Koshkonong_Solar	162369	Generator	Planned	10/31/2025
ATC_(24613)_Z3_J1326_Koshkonong_ES	162372	Generator	Planned	11/1/2025
ATC_(20201)_Z3_Brodhead_SS_Asset_Renewal	164398	MTEP B	Target MTEP A	12/1/2026
ATC_(24575)_Z1_T-T_DPC_Clearfield_Y-74	164401	MTEP A	Planned	6/1/2026
ATC_(20204)_Z3_T-D_ALTE_Belleville_SS_Rebuild	164476	MTEP B	Target MTEP A	12/31/2025
ATC_(Z5)_J1316_Paris_ES_50MW	164520	Generator	Planned	9/1/2025
ATC_(24838)_Z4_J1316_NAPL121_NAP-FOX_345kV_Rebuild	164523	MTEP B	Target MTEP A	12/31/2027
ATC_(Z3)_J1377_Rock_County_Solar	164707	Generator	Planned	11/12/2026
ATC_(24758)_Z3_J1410_Great_Dane_Solar	164722	Generator	Planned	6/3/2026
ATC_(Z3)_J1411_Great_Dane_Energy_Storage	164725	Generator	Planned	6/4/2026
ATC_(20203)_Z2_X-118_PRI-HNN_138kV_Rerate	164761	MTEP A	Planned	2/28/2025
ATC_(24473)_Z3_T-D_ALTE_Rock_River	164800	MTEP B	Target MTEP A	7/1/2024
ATC_(24373)_Z3_T-D_REC_ANR_Manogue_Rd	164802	MTEP B	Target MTEP A	8/1/2025
ATC_(14909)_Z5_AM_Lakeview_Asset-Renewal	164812	MTEP A	Planned	12/15/2023
ATC_(24802)_Z3_J1460_Dawn_Harvest_Solar_and_ES	166360	Generator	Planned	12/27/2025
ATC_(Z4)_J1253_Silver_Maple_Solar	166376	Generator	Planned	3/19/2027
ATC_(21925)_Z4_T-D_PMU_Plymouth#5	166452	MTEP A	Planned	11/15/2026
ATC_(20204)_Z1_Retire Northern_Steel_Castings_Tap_69kV	166455	MTEP B	Target MTEP A	2/23/2024
ATC_(24782)_Z3_J1460_UNIG52_UNI-MUK_138kV_PartialRcnd	166547	MTEP A	Planned	12/31/2025
ATC_(24819)_Z5_Racine_150MVAR_of_345kV_Caps	166556	MTEP B	Target MTEP A	12/1/2027
ATC_(24785)_Z5_Pl_Prairie_300MVAR_of_345kV_Caps	166559	MTEP B	Target MTEP A	12/1/2027
ATC_(16766)_Z5_Dewey_SS_Asset_Renewal	166630	MTEP A	Planned	2/4/2024

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
ATC_(24801)_Z4_J1253_G-111_NFL-AVN_138 kV_Rebuild	166721	MTEP B	Target MTEP A	11/12/2027
ATC_(24801)_Z4_J1253_X-50_AVN - PRG_138kV_Rebuild	166724	MTEP B	Target MTEP A	11/12/2027
ATC_(24801)_Z4_J1253_X-50_PRG-EOD_138kV_Rebuild	166727	MTEP B	Target MTEP A	11/12/2027
ATC_(23913)_Z1_T-D_ACEC_Colburn	166730	MTEP A	Planned	5/1/2027
ATC_(24784)_Z4_T-D_WPS_Ellisville	166750	MTEP B	Target MTEP A	6/1/2025
ATC_(20204)_Z2_CEC_LoadShifts_6913_to_6912	166801	MTEP B	Target MTEP A	12/31/2024
ATC_(16766)_Z3_Rock_Branch_AR	166825	MTEP A	Planned	12/1/2025
ATC_(14909)_Z3_Y-59_SBD-CES_69_Uprate_r1	167009	MTEP A	Planned	3/1/2024
ATC_(24841)_Z3_J1214-1326-1377-1410-1411_9043_CCD-CRF_Uprate	167107	Generator	Planned	4/21/2025
ATC_(20201)_Z4_Q-303_KEW-POB_Wavetrap_replacement	167124	MTEP A	Planned	10/11/2024
ATC_(22988)_Z3_T-D_ALTE_Gaston_Rd-SS_Rebuild	167127	MTEP A	Planned	12/31/2024
ATC_(24783)_Z1_T-D_WPS_Hodag_Bk2	167228	MTEP B	Target MTEP A	6/1/2025
ATC_(24296)_Z4_Valders_138-69_SS	167516	MTEP B	Target MTEP A	7/31/2028
ATC_(23915)_Z2_T-D_UPPC_Delta_County_DIC	167522	MTEP B	Target MTEP A	12/31/2026
ATC_(20201)_Z5_RLN_CNL_FBZT_138kV_reconfig	167653	MTEP B	Target MTEP A	6/30/2025
ATC_(20201)_Z3_RockRiver_138kV_Bus_Tie_1-3_Uprate	167656	MTEP B	Target MTEP A	6/30/2025
ATC_(23858)_Z3_Y-62_WKS-BLE_69kV_Partial_Rebuild	168043	MTEP B	Target MTEP A	12/31/2026
ATC_(24474)_Z4_T-D_WPS_Winnebago_Co	168232	MTEP B	Target MTEP A	11/1/2025
ATC_(23838)_Z4_AR_Y-77_HIF-MTN_69kV_Rbld	168246	MTEP B	Target MTEP A	12/1/2028
ATC_(20204)_Z3_T-D_MGE_OakRidge_T2	170959	Base Case Change	Field Change	12/1/2025
ATC_(24475)_Z1_T-D_WPS_Tommys_Turnpike	171007	MTEP A	Planned	12/31/2025
ATC_(14907)_Z3_T-D_ALTE_Lake_Geneva_69kV_New SS	172236	MTEP A	Planned	3/31/2026
ATC_(Z1)_X-11_SAL-WAU_138kV_Uprate1	172270	Non-MTEP MISO	Planned	4/30/2024
ATC_(Z1)_X-11_7MC-SAL_138kV_Uprate1	172273	Non-MTEP MISO	Planned	4/30/2024
ATC_(Z1)_X-11_SAL-WAU_138kV_Uprate2	172276	Non-MTEP MISO	Planned	11/30/2024
ATC_(Z1)_X-11_7MC-SAL_138kV_Uprate2	172279	Non-MTEP MISO	Planned	11/30/2024
ATC_(Z1)_X-159_7MC-POE_138kV_Uprate	172282	Non-MTEP MISO	Planned	2/6/2024
ATC_(20805)_Z3_RockRiver_138kV_BT2-3_Uprate	172287	MTEP A	Planned	3/30/2024
ATC_(22798)_Z1_Y-90_SALT-HAN_69kV_Uprate	172290	MTEP B	Target MTEP A	6/30/2025
ATC_(24575)_Z1_New_Lisbon_Area_SS	172325	MTEP A	Planned	6/3/2026
ATC_(22798)_Z1_Retire_NW_Ripon_5-4MVAR_Cap	172430	MTEP B	Target MTEP A	12/1/2027

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
ATC_(50041)_Z5_West_Jct_Bus_and_Retire_WJCT-BMD_138	172432	MTEP B	Target MTEP A	6/30/2026
ATC_(Z4)_Q-303_KEW-POB_345kV_Uprate	172517	Non-MTEP MISO	Planned	5/31/2024
ATC_(3127)_Z3_W-19_release_of_X-13_and_X-20_SE_Ratings	172604	MTEP A	Planned	6/30/2024
ATC_(22911)_Z3_T-D_BEEU_Black_Earth_2nd_Tap	172651	MTEP B	Target MTEP A	6/1/2025
ATC_(17585)_Z3_AM_Colley_Rd_Tr_Replacement_Part2	172740	MTEP A	Planned	4/1/2024
ATC_(22798)_Z3_Birchwood_Asset Renewal_138kV	172749	MTEP B	Target MTEP A	12/1/2027
ATC_(10486)_Z1_AM_Rebuild_Y-18_CHC-LPS_69-1	172833	MTEP A	Planned	6/5/2024
ATC_(12134)_Z4_AM_FIRY11_BLN-WMK_69kV_Rebuild-1	172836	MTEP A	Planned	3/1/2024
ATC_(JAN03)_20240103_Update_Type2	172842	Base Case Change	Field Change	1/3/2024
ATC_(Z4)_Chalk_Hill_GSU_Replacement	172914	Non-MTEP MISO	Planned	10/31/2024
ATC_(16486)_Z5_Retire_Arcadian_345-138kV_T3	173209	MTEP A	Planned	1/22/2024
ATC_(16486)_Z5_Rerate_Arcadian_345-138kV_T2	173344	MTEP A	Planned	4/1/2024
GRE-25338-Victor-Woodland	169646	MTEP B	Target MTEP A	12/1/2027
GRE-25391-MudLake-RivertonUpgrade230	169677	MTEP B	Target MTEP A	6/1/2027
GRE-25381-Princeton-Milaca69	169686	MTEP B	Target MTEP A	12/1/2027
GRE-25374-BlackberryArea69	169692	MTEP B	Target MTEP A	12/3/2027
GRE-25337-Meadowbrook-Sidelake69	169702	MTEP B	Target MTEP A	12/1/2027
GRE-25396-MapleLake-Otsego69	169878	MTEP B	Target MTEP A	2/5/2029
GRE-25399-JamestownGRE-JamestownXEL69	170956	MTEP B	Target MTEP A	2/1/2028
GRE-23761-NWLitchfield69_R1	171861	MTEP A	Planned	6/18/2026
MP-3831-MISO-GNTL500kV-2015.04.16	18208	MTEP A	Planned	6/1/2020
MP-MISO-17870-53Lratingupgrade	170086	MTEP A	Planned	12/31/2025
MP-MISO-21767-13Lratingupgrade	170092	MTEP A	Planned	3/31/2028
MP-MISO-23706-158Lratingupdate	170104	MTEP A	Planned	3/31/2028
MP-MISO-25311-BypassStinsonPST	170659	MTEP A	Planned	12/31/2028
OTP_EXPEDITED_Jamestown_load_expansion	167732	MTEP B	Target MTEP A	6/1/2024
XEL-24278-EDINA-SWITCH-REPLACEMENT	166642	MTEP A	Planned	6/30/2024
XEL-25270-0760-REDWING-LAKECITY-STR217-REBUILD	171178	MTEP B	Target MTEP A	12/31/2026
XEL-25286-0754-BUFFALO-MAPLELAKE-REBUILD	171181	MTEP B	Target MTEP A	12/15/2025
XEL-25287-W3402-LOYAL-SPOKESVILLE-REBUILD_R2	171184	MTEP B	Target MTEP A	12/31/2025
XEL-25288-0774-GOODVIEW-STR444-REBUILD	171187	MTEP B	Target MTEP A	12/31/2025
XEL-25293-0725-TRACY-SWITCHING-STATION-TO-5535-STR191-REBUILD	171193	MTEP B	Target MTEP A	12/31/2024
XEL-25295-2023-LINE-CLEARANCE-MITIGATIONS	171204	MTEP B	Target MTEP A	3/15/2024
XEL-25300-NOBLES-COUNTY-THIRD-TRANSFORMER	171207	MTEP B	Target MTEP A	5/1/2028

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
XEL-25342-MISSOURI-CREEK-SUBSTATION	171216	MTEP B	Target MTEP A	6/1/2029
XEL-25377-DPC-NORTH-WAL-INTERCONNECTION	171220	MTEP B	Target MTEP A	12/1/2024
XEL-25506-INVER GROVE-INVER HILLS-115KV-REBUILD-TO-DOUBLE-CIRCUIT-115KV	171223	MTEP B	Target MTEP A	12/31/2025
XEL-25323-STCROIX-VALLEY-UPGRADES	171228	MTEP B	Target MTEP A	6/1/2029
XEL-25324-DOWNING-SUBSTATION	171236	MTEP B	Target MTEP A	10/15/2025
XEL-25507-UMORE-PARK-115KV-SUBSTATION	171293	MTEP B	Target MTEP A	12/31/2025
XEL-50020-0711-REDWING-STR11-REBUILD	172129	MTEP B	Target MTEP A	12/31/2026
XEL-1-23-2024-BUS-VOLTAGE-LIMIT-UPDATES	173275	Base Case Change	Correction	1/23/2024
XEL-1-24-2024-BUS-VOLTAGE-LIMIT-UPDATES	173293	Base Case Change	Correction	1/24/2024
XEL-1-25-2024-J926-POI-EMERALD-RATINGS	173354	Base Case Change	Correction	1/25/2024
XEL-1-25-2024-DER_UPDATES	173377	Base Case Change	Correction	1/25/2024
XEL-1-25-2024-FREEBORN-WIND-OWNERSHIP-UPDATES	173406	Base Case Change	Correction	1/25/2024
Freeborn_Wind_Ownership_Number_Change	173467	Base Case Change	Error Correction	1/26/2024

B Future Projects removed from 2028 study model (Target Date 6/1/2029)

3-IIV Future Projects Removed from 2028 Study Model

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
ATC_(23910)_Y-106_EEN_ROB_69kV_Rebuild-OPGW	154929	MTEP B	Target MTEP A	12/31/2030
ATC_(23911)_Z4_K-11_SOT-MIRT-NRE_69kV-Rbld	154932	MTEP B	Target MTEP A	12/31/2029

C **In addition to Future Projects in Table 2-III, Future Projects in Table 2-V are included in 2033 study model**

3-V Additional Future Projects in 2033 Study Model

MOD Project Name	MOD ID	Project Type	Status	MOD Effective Date
None				

3.3 Monitoring and contingencies

3.3.1 Monitor

Monitor all 100 kV and above facilities in areas GRE(615), MP(608), OTP(620), XEL(600), WPS(696)

3.3.2 Contingencies

NERC Category P1, P2, P4, P5, and P7 used in MTEP23 study of facilities within areas GRE(615), MP(608), OTP(620), XEL(600), WPS(696)

Category P3 contingencies were created using all single generator contingencies (P1-1), extracted from the P1 contingencies provided above, combined with all P1 contingencies provided above. To limit the number of possible P3 combinations:

- Only Category P1 events of facilities 100 kV or above within 6 Buses from the Study Unit(s) were used in creating the required P3 combinations.
- Generator contingencies (Category P1-1) with aggregated generation above 50 MW were used in creating the required P3 contingencies.

Similarly, Category P6 contingencies were created using all non-generator contingencies (P1-2 to P1-5) of facilities 100 kV or above within 6 Buses from the Study Unit(s).

4. STUDY CRITERIA

4.1 Applicable Reliability Criteria

4.1.1 Steady State Thermal Reliability Criteria

ATC Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.
-

Great River Energy Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

Minnesota Power Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

Xcel Energy Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

Otter Tail Power Transmission Planning Criteria applied for thermal analysis:

- For System Intact (NERC Category P0), all thermal loadings within 100% of the normal rating.
- For NERC Category P1-P7 contingencies, all thermal loadings within 100% of the emergency rating.

4.1.2 Steady State Voltage Reliability Criteria

ATC Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
≥ 69 kV	0.95	1.05	0.90	1.10

Great River Energy Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
Ramsey 230 kV	0.95	1.05	0.90	1.05
Balta 230 kV	0.95	1.05	0.90	1.05
Hubbard 230 & 115 kV	0.97	1.05	0.92	1.05
Wing River 230 & 115 kV	0.97	1.05	0.92	1.05
All Load Serving Buses	0.95	1.05	0.92	1.05
Remaining Buses	0.95	1.05	0.90	1.05

Minnesota Power Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
500 kV	1.00	1.05	0.95	1.10
230 kV	1.00	1.05	0.95	1.10
161 kV	1.00	1.05	0.95	1.10
138 kV	1.00	1.05	0.95	1.10
118 kV	1.00	1.05	0.95	1.10
115 kV	1.00	1.05	0.95	1.10
Warroad River SC 500 kV	0.90	1.20	0.90	1.20
Western MP 230 kV	0.97	1.05	0.92	1.10
North Dakota MP 230 kV	0.97	1.05	0.92	1.10
Western MP 115 kV	0.97	1.05	0.92	1.10

Xcel Energy Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Rated Voltage	Pre Contingent		Post Contingent	
	Min PU	Max PU	Min PU	Max PU
Default for all buses > 100 kV	0.95	1.05	0.92	1.05
Default for all buses < 100 kV*	0.95	1.05	0.92	1.05
Default for all generator buses**	0.95	1.05	0.95	1.05
Roseau 500 kV bus	0.95	1.10	0.92	1.10
Prairie 115 kV main bus	0.95	1.09	0.90	1.09
Prairie 115 kV capacitor bus	0.95	1.15	0.92	1.15
Sheyenne 115 kV capacitor bus	0.95	1.15	0.92	1.15
Running 230 kV capacitor bus	0.95	1.10	0.92	1.10
Roseau 230 kV capacitor bus	0.95	1.05	0.92	1.10
Chisago 500 kV bus	0.95	1.10	0.92	1.10
Forbes 500 kV bus	0.95	1.10	0.92	1.10
Bison 345 kV bus	0.95	1.05	0.92	1.10
Briggs Road 345 kV bus	0.95	1.05	0.92	1.10

Otter Tail Power Transmission Planning Criteria applied for voltage analysis:

- For NERC Category P0 (System Intact) – Pre Contingent
- For NERC Category P1-P7 contingencies – Post Contingent

Contingency BES Level	Contingency Category	Pre Contingent		Post Contingent	
		Min PU	Max PU	Min PU	Max PU
EHV	P1, P2.1-2.3, P3, P4.1-4.5, P5	0.97	1.07 (115 kV) 1.05 (≥230kV)	0.92	1.10
	P2.4, P4.6, P6, P7	0.92	1.07 (115 kV) 1.05 (≥230kV)	0.92	1.10
HV	P1, P2.1, P3	0.97	1.07 (115 kV) 1.05 (≥230kV)	0.92	1.10
	P2.2-P2.4, P4, P5, P6, P7	0.92	1.07 (115 kV) 1.05 (≥230kV)	0.92	1.10

4.2 MISO Transmission Planning BPM SSR Criteria

In accordance with MISO BPM-020, System Support Resource (SSR) criteria for determining if an identified facility is impacted by the generator change of status are:

- Under NERC Category P0 conditions and category P1-P7 contingencies, branch thermal violations are only valid if the flow increase on the element in the "after" retirement scenario is equal to or greater than:
  - Five percent (5%) of the "to-be-retired" unit(s) MW amount (i.e. 5% PTDF) for a "base" violation compared with the "before" scenario, or
  - Three percent (3%) of the "to-be-retired" unit(s) MW amount (i.e. 3% OTDF) for a "contingency" violation compared with the "before" scenario.
- Under NERC category P0 conditions and category P1-P7 contingencies, high and low voltage violations are only valid if the change in voltage is greater than one percent (1%) as compared to the "before" scenario

Available mitigation may be applied for the valid NERC Category P1-P7 thermal and voltage violations describe above as allowed by NERC Standards

- The need for the SSR is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.
- Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

5. STUDY METHODOLOGY

5.1 Steady-State Performance Analysis

PTI – PSS/E version 35 and PowerGEM – TARA were used to perform AC contingency analysis and SCED. Cases were solved with automatic control of LTCs, phase shifters, DC taps, switched shunts enabled (regulating), and area interchange disabled. Contingency analysis was performed on before and after cases. The results were compared to find if there were any criteria violations due to the unit(s) change of status.

5.2 Voltage Stability Criteria

Voltage stability assessment (Power-voltage curve analysis) was not performed (no specific concern was raised by the TO's or MISO).

5.3 Dynamic Stability Criteria

Dynamic (transient) stability assessment was not performed (no specific concern was raised by the TO's or MISO).

6. STUDY RESULTS

Appendices 8.1 and 8.2 of this report include all constrained elements impacted by the potential change of status of *Hibbard Renewable Energy Center Unit 3 and 4*.

6.1 2028 Summer Shoulder Analysis

Analysis of the 2028 Summer Shoulder case identified the following

6.1.1 2028 Summer Shoulder Post Contingent Thermal Overloads

- The top post contingent thermal overloads reported in Table 6-I Top Post Contingent Thermal Overloads 2028 Summer Shoulder Offline Case met the MISO SSR criteria
  - Greater than or Equal to 3% OTDF or 5% PTDF of the study unit
- All post contingent thermal overloads that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.1
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-I Top Post Contingent Thermal Overloads 2028 Summer Shoulder Offline Case

Area Name	Monitored Element	Rating (MVA)	Loading (%)	PTDF (> 5%)	OTDF (> 3%)
MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	**180.65**	**13.2%**	**40.2%**
MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	**168.05**	**13.5%**	**39.7%**

6.1.2 2028 Summer Shoulder Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-II met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-II Top Post Contingent Issues 2028 Summer Shoulder Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
GRE	615523 GRE-DEER RV7	1.094	**1.1115**	**0.0175**
MP	618006 GRE-IRON 7	1.0956	**1.1112**	**0.0156**

6.2 2028 Summer Peak Analysis

Analysis of the 2028 Summer Peak case identified the following

6.2.1 2028 Summer Peak Post Contingent Thermal Overloads

- Post contingent thermal overloads reported in Table 6-III met the MISO SSR criteria
  - Greater than or Equal to 3% OTDF or 5% PTDF of the study unit
- All post contingent thermal overloads that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.1
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-III Top Post Contingent Thermal Overloads 2028 Summer Peak Offline Case

Area Name	Monitored Element	Rating (MVA)	Loading (%)	PTDF (> 5%)	OTDF (> 3%)
MP	608663 FLDWDTP7 115 608670 MDWLNDS7 115 1	86	**104.3**	**4.84%**	**19.5%**
MP	608670 MDWLNDS7 115 608671 BURNETT7 115 1	86	**103.15**	**4.84%**	**19.4%**
MP	608671 BURNETT7 115 618019 GRE-KNFFLTP7 115 1	85.8	**102.38**	**5%**	**19.4%**

6.2.2 2028 Summer Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-IV met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-IV Top Post Contingent Voltage Issues 2028 Summer Shoulder Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
None				

6.3 2028 Winter Peak Analysis

Analysis of the 2028 Winter Peak case identified the following

6.3.1 2028 Winter Peak Post Contingent Thermal Overloads

- Post contingent thermal overloads reported in Table 6-V met the MISO SSR criteria
  - Greater than or Equal to 3% OTDF or 5% PTDF of the study unit
- All post contingent thermal overloads that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.1
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-V Top Post Contingent Thermal Overloads 2028 Winter Peak Offline Case

Area Name	Monitored Element	Rating (MVA)	Loading (%)	PTDF (> 5%)	OTDF (> 3%)
MP	657755 PRAIRIE4 230 657798 LKARDCH4 230 1	400	**100.43**	**2.2%**	**3.7%**
MP	608673 ARD1BUS7 115 996738 ARD7 115 2	391	**100.25**	**18.7%**	**58.8%**
MP	608615 ARROWHD4 230 996738 ARD7 115 2	391	**100.07**	**18.4%**	**56.9%**

6.3.2 2028 Winter Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VI met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-VI Top Post Contingent Voltage Issues 2028 Winter Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
MP	615523 GRE-DEER RV7	0.9744	**0.9139**	**-0.0605**
MP	615523 GRE-DEER RV7	0.9788	**0.9132**	**-0.0656**
MP	615523 GRE-DEER RV7	0.9897	**0.9167**	**-0.073**

6.4 2033 Summer Peak Analysis

Analysis of the 2033 Summer Peak case identified the following

6.4.1 2033 Summer Peak Post Contingent Thermal Overloads

- Post contingent thermal overloads reported in Table 6-VII met the MISO SSR criteria
  - Greater than or Equal to 3% OTDF or 5% PTDF of the study unit
- All post contingent thermal overloads that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.1
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-VIIII Top Post Contingent Thermal Overloads 2033 Summer Peak Offline Case

Area Name	Monitored Element	Rating (MVA)	Loading (%)	PTDF (> 5%)	OTDF (> 3%)
MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	**157.08**	**12.2%**	**42.6%**
MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	**148.13**	**13%**	**43.4%**

6.4.2 2033 Summer Peak Post Contingent Voltage Issues

- The top post contingent voltage issues reported in Table 6-VIII met the MISO SSR criteria
  - +/- 1% adverse impact of study unit
- All post contingent voltage issues that met the MISO SSR Criteria can be mitigated
  - Details are provided in Appendix 8.2
- Pre-Existing and Non-SSR issues are provided for informational purposes

6-VIIIII Top Post Contingent Voltage Issues 2033 Summer Peak Offline Case

Area Name	Monitored Bus	Voltage [ON]	Voltage [OFF]	Voltage [DIF] (>1%)
MP	615466 GRE-BEARCK 4	1.0181	**1.0522**	**0.0341**

7. CONCLUSION

After being reviewed for power system reliability impacts as provided for under Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff ("Tariff"), the analysis determined that there are no reliability issues identified related to the potential change of status of *Hibbard Renewable Energy Center Unit 3 and 4*, that may require the unit to be designated as a System Support Resources ("SSR") unit.

Majority of thermal violations are pre-existing issues. All remaining thermal violations can be mitigated by generator redispatch.

For voltage violations most of them are pre-existing issues as well. The remaining voltage violations can be mitigated by reducing the load and adjusting switched shunt output.

An Attachment Y-2 study is a non-binding informational study intended to determine whether it is likely that the Generation Resource(s) would qualify as an SSR Unit(s). While the analysis conducted for the Attachment Y-2 study may be used in preparing a subsequent Attachment Y study, further study may be required to evaluate the impacts due to change in assumptions of system conditions when an Attachment Y Notice is submitted. A final SSR determination would only result from completion of the processes stated in the MISO Tariff, including discussion with stakeholders to determine whether a feasible alternative to SSR designation exists.

8. APPENDICES

8.1 Thermal Results

8-I Thermal Results and Mitigations

Model	Contingency Name	Area Name	Monitored Element	Rating MVA	ON Base MVA	ON Cont. MVA	ON Load %	OFF Base MVA	OFF Cont. MVA	OFF Load %	Off – On DIFF	PTDF (>5 %)	OTDF (>3 %)	Mitigations
2028SH	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	27.6	131.3	152.72	35.5	155.4	**180.65**	24.1	**13.19%**	**40.23%**	Pre-Existing Issue
2028SH	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	27.6	131.1	152.4	35.5	154.5	**179.65**	23.4	**13.19%**	**39.07%**	Pre-Existing Issue
2028SH	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	27.6	130.9	152.25	35.5	154.3	**179.45**	23.4	**13.19%**	**39.07%**	Pre-Existing Issue
2028SH	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	39.5	142.6	144.02	47.6	166.4	**168.05**	23.8	**13.52%**	**39.73%**	Pre-Existing Issue
2028SH	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	39.5	142.1	143.55	47.6	165.5	**167.19**	23.4	**13.52%**	**39.07%**	Pre-Existing Issue
2028SH	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	39.5	142	143.39	47.6	165.3	**167.01**	23.3	**13.52%**	**38.90%**	Pre-Existing Issue
2028SP	**[REDACTED]**	MP	608663 FLDWDTP7 115 608670 MDWLNDS7 115 1	86	10.4	78	90.72	13.3	89.7	**104.3**	11.7	**4.84%**	**19.53%**	can be mitigated by redispatch 24.8MW
2028SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	14.6	120.8	140.46	21.5	145.4	**169.04**	24.6	**11.52%**	**41.07%**	can be mitigated by redispatch 150MW
2028SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	14.6	120	139.51	21.5	144.4	**167.93**	24.4	**11.52%**	**40.73%**	can be mitigated by redispatch 150MW

Model	Contingency Name	Area Name	Monitored Element	Rating MVA	ON Base MVA	ON Cont. MVA	ON Load %	OFF Base MVA	OFF Cont. MVA	OFF Load %	Off – On DIFF	PTDF (>5 %)	OTDF (>3 %)	Mitigations
2028SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	14.6	119.9	139.44	21.5	144.5	**168.06**	24.6	**11.52%**	**41.07%**	can be mitigated by redispatch 150MW
2028SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	26.4	131.6	132.95	33.6	156.9	**158.46**	25.3	**12.02%**	**42.24%**	can be mitigated by redispatch 150MW
2028SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	26.4	130.8	132.15	33.6	155.9	**157.5**	25.1	**12.02%**	**41.90%**	can be mitigated by redispatch 150MW
2028SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	26.4	130.8	132.09	33.6	156	**157.62**	25.2	**12.02%**	**42.07%**	can be mitigated by redispatch 150MW
2028SP	**[REDACTED]**	MP	608668 CLOQUET7 115 618019 GRE-KNFFLTP7 115 1	85.8	7.6	75.1	87.49	10.5	86.7	**101.05**	11.6	**4.84%**	**19.37%**	can be mitigated by redispatch 24.8MW
2028SP	**[REDACTED]**	MP	608670 MDWLNDS7 115 608671 BURNETT7 115 1	86	9.8	77.1	89.62	12.7	88.7	**103.15**	11.6	**4.84%**	**19.37%**	can be mitigated by redispatch 24.8MW
2028SP	**[REDACTED]**	MP	608671 BURNETT7 115 618019 GRE-KNFFLTP7 115 1	85.8	8.7	76.2	88.81	11.7	87.8	**102.38**	11.6	**5.01%**	**19.37%**	can be mitigated by redispatch 24.8MW
2028WP	**[REDACTED]**	XEL	603077 GOOSELK7 115 603178 MNPIP 7 115 1	242.8	83.1	271.5	111.81	83.8	275.3	**113.37**	3.8	**1.17%**	**6.34%**	Pre-Existing Issue
2028WP	**[REDACTED]**	MP	608615 ARROWHD4 230 996738 ARD7 115 2	391	156.8	357.2	91.35	167.8	391.2	**100.06**	34	**18.36%**	**56.76%**	can be mitigated by redispatch 1.6MW
2028WP	**[REDACTED]**	MP	608615 ARROWHD4 230 996738 ARD7 115 2	391	156.8	357.2	91.36	167.8	391.3	**100.07**	34.1	**18.36%**	**56.93%**	can be mitigated by redispatch 1.6MW
2028WP	**[REDACTED]**	MP	608615 ARROWHD4 230 996738 ARD7 115 2	391	156.8	357.3	91.37	167.8	391.3	**100.07**	34	**18.36%**	**56.76%**	can be mitigated by redispatch 1.6MW

Model	Contingency Name	Area Name	Monitored Element	Rating MVA	ON Base MVA	ON Cont. MVA	ON Load %	OFF Base MVA	OFF Cont. MVA	OFF Load %	Off – On DIFF	PTDF (>5 %)	OTDF (>3 %)	Mitigations
2028WP	**[REDACTED]**	MP	608673 ARD1BUS7 115 996738 ARD7 115 2	391	156.8	356.8	91.25	168	391.9	**100.24**	35.1	**18.70%**	**58.60%**	can be mitigated by redispatch 1.6MW
2028WP	**[REDACTED]**	MP	608673 ARD1BUS7 115 996738 ARD7 115 2	391	156.8	356.8	91.26	168	392	**100.25**	35.2	**18.70%**	**58.76%**	can be mitigated by redispatch 1.6MW
2028WP	**[REDACTED]**	MP	608673 ARD1BUS7 115 996738 ARD7 115 2	391	156.8	356.9	91.27	168	391.9	**100.24**	35	**18.70%**	**58.43%**	can be mitigated by redispatch 1.6MW
2028WP	**[REDACTED]**	OTP	657755 PRAIRIE4 230 657798 LKARDCH4 230 1	400	297.9	399.5	99.87	299.2	401.7	**100.42**	2.2	**2.17%**	**3.67%**	can be mitigated by redispatch 7.7MW
2028WP	**[REDACTED]**	OTP	657755 PRAIRIE4 230 657798 LKARDCH4 230 1	400	297.9	399.5	99.87	299.2	401.7	**100.43**	2.2	**2.17%**	**3.67%**	can be mitigated by redispatch 7.7MW
2033SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	13.1	109.6	127.43	20.4	135.1	**157.08**	25.5	**12.19%**	**42.57%**	can be mitigated by redispatch 92.8MW
2033SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	13.1	108.4	126.08	20.4	133.4	**155.13**	25	**12.19%**	**41.74%**	can be mitigated by redispatch 92.8MW
2033SP	**[REDACTED]**	MP	608665 THOMSON7 115 608666 FONDULAC 115 1	86	13.1	108.6	126.32	20.4	133.7	**155.42**	25.1	**12.19%**	**41.90%**	can be mitigated by redispatch 92.8MW
2033SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	24.7	120.7	121.91	32.5	146.7	**148.13**	26	**13.02%**	**43.41%**	can be mitigated by redispatch 92.8MW
2033SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	24.7	119.7	120.88	32.5	145	**146.44**	25.3	**13.02%**	**42.24%**	can be mitigated by redispatch 92.8MW
2033SP	**[REDACTED]**	MP	608666 FONDULAC 115 608676 HIBBARD7 115 1	99	24.7	119.8	121.01	32.5	145.2	**146.71**	25.4	**13.02%**	**42.40%**	can be mitigated by redispatch 92.8MW

8.2 Voltage Results

8-II Voltage Results and Mitigations

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	XEL	FORBES 2	500	0.92	1.1	1.0588	1.0589	1.1202	1.1347	WHigh	-1.44	Manually verified no voltage violation
2028SH	[REDACTED]	XEL	ROSEAUN2	500	0.92	1.1	1.1559	1.1561	1.2435	1.2634	WHigh	-1.971	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSEAUS2	500	0.92	1.1	1.1748	1.1752	1.2242	1.2391	High	-1.448	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSEAUS2	500	0.92	1.1	1.1748	1.1752	1.3314	1.3652	WHigh	-3.337	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSEAUM 2	500	0.92	1.1	1.1652	1.1655	1.2023	1.2135	High	-1.091	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSEAUM 2	500	0.92	1.1	1.1652	1.1655	1.2874	1.3142	WHigh	-2.656	Pre-Existing Issue
2028SH	[REDACTED]	MP	LFSWCP 4	230	0.92	1.1	1.1048	1.105	1.1813	1.1992	High	-1.764	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSSWCP4	230	0.92	1.1	1.1603	1.1606	1.1935	1.2058	High	-1.205	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSSWCP4	230	0.92	1.1	1.1603	1.1606	1.2749	1.3003	WHigh	-2.521	Pre-Existing Issue
2028SH	[REDACTED]	XEL	ROSEAU 4	230	0.92	1.1	1.1603	1.1606	1.1935	1.2058	High	-1.205	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	XEL	ROSEAU 4	230	0.92	1.1	1.1603	1.1606	1.2749	1.3003	WHigh	-2.521	Pre-Existing Issue
2028SH	[REDACTED]	XEL	PEACE GARD 5	230	0.92	1.05	1.0889	1.0895	1.147	1.1641	High	-1.65	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRN2	500	0.9	1.2	1.1491	1.1495	1.285	1.3074	WHigh	-2.203	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRM2	500	0.9	1.2	1.1788	1.1791	1.2119	1.222	High	-0.973	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRM2	500	0.9	1.2	1.1788	1.1791	1.3214	1.349	WHigh	-2.737	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2566	1.2708	High	-1.399	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2548	High	-1.126	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2541	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2427	1.2539	High	-1.096	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2541	High	-1.055	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.054	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2547	High	-1.116	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2543	High	-1.077	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.064	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.066	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2541	High	-1.061	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.061	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.061	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.055	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.062	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.3578	1.3907	WHigh	-3.27	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.2539	High	-1.057	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.243	1.2539	High	-1.069	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.059	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.058	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.2541	High	-1.058	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.254	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2432	1.254	High	-1.062	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2543	High	-1.079	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2431	1.254	High	-1.063	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2542	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.243	1.254	High	-1.068	Pre-Existing Issue
2028SH	[REDACTED]	MP	WARRVRS2	500	0.9	1.2	1.2086	1.2089	1.2433	1.2542	High	-1.062	Pre-Existing Issue
2028SH	[REDACTED]	MP	IRONRNG2	500	0.95	1.1	1.0785	1.0787	1.2067	1.2287	WHigh	-2.169	Pre-Existing Issue
2028SH	[REDACTED]	MP	IRRN-RX2	500	0.95	1.1	1.0787	1.0789	1.2074	1.2293	WHigh	-2.172	Pre-Existing Issue
2028SH	[REDACTED]	MP	ZEMPLE 4	230	0.95	1.1	1.0372	1.0374	1.0999	1.1176	WHigh	-1.757	Manually verified no voltage violation
2028SH	[REDACTED]	MP	SWATARAX3 A4	230	0.92	1.1	1.0463	1.0465	1.0977	1.1112	WHigh	-1.341	Manually verified no voltage violation
2028SH	[REDACTED]	MP	IRONRNG4	230	0.95	1.1	1.0582	1.0584	1.1462	1.1649	High	-1.838	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MINNTAC4	230	0.95	1.1	1.0365	1.0368	1.0979	1.1142	WHigh	-1.602	Manually verified no voltage violation
2028SH	[REDACTED]	MP	FORBES 4	230	0.95	1.1	1.0518	1.0521	1.1125	1.1275	WHigh	-1.475	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	BLCKBRY4	230	0.95	1.1	1.0575	1.0578	1.1446	1.1632	WHigh	-1.833	Manually verified no voltage violation
2028SH	[REDACTED]	MP	BOSWELL4	230	0.95	1.1	1.0399	1.04	1.1066	1.125	WHigh	-1.822	Manually verified no voltage violation
2028SH	[REDACTED]	MP	SHANNON4	230	0.95	1.1	1.0443	1.0445	1.1103	1.1275	WHigh	-1.699	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MCARTHY4	230	0.95	1.1	1.0424	1.0426	1.1091	1.1268	WHigh	-1.75	Manually verified no voltage violation
2028SH	[REDACTED]	MP	CALUMET4	230	0.95	1.1	1.0422	1.0423	1.1089	1.1266	WHigh	-1.759	Manually verified no voltage violation
2028SH	[REDACTED]	MP	KEWTNTP7	115	0.95	1.1	1.0323	1.0325	1.0969	1.1138	WHigh	-1.658	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MNTACT27	115	0.95	1.1	1.0303	1.0305	1.0877	1.1039	WHigh	-1.596	Manually verified no voltage violation
2028SH	[REDACTED]	MP	VIRGNIA7	115	0.95	1.1	1.0302	1.0304	1.0855	1.1016	WHigh	-1.578	Manually verified no voltage violation
2028SH	[REDACTED]	MP	INLAND 7	115	0.95	1.1	1.028	1.0283	1.0853	1.1014	WHigh	-1.592	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MINNTAC7	115	0.95	1.1	1.0295	1.0297	1.0886	1.1049	WHigh	-1.601	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MNTCPTC7	115	0.95	1.1	1.0281	1.0284	1.0874	1.1037	WHigh	-1.604	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	MNTCPTA7	115	0.95	1.1	1.0282	1.0285	1.0875	1.1038	WHigh	-1.603	Manually verified no voltage violation
2028SH	[REDACTED]	MP	16L TAP7	115	0.95	1.1	1.0333	1.0336	1.0913	1.1072	WHigh	-1.557	Manually verified no voltage violation
2028SH	[REDACTED]	MP	FBS2BUS7	115	0.95	1.1	1.0442	1.0445	1.1031	1.1186	WHigh	-1.526	Manually verified no voltage violation
2028SH	[REDACTED]	MP	COTTNTP7	115	0.95	1.1	1.0331	1.0334	1.0912	1.107	WHigh	-1.559	Manually verified no voltage violation
2028SH	[REDACTED]	MP	ETCO 7	115	0.95	1.1	1.0336	1.0339	1.0919	1.1078	WHigh	-1.554	Manually verified no voltage violation
2028SH	[REDACTED]	MP	FBS1BUS7	115	0.95	1.1	1.0442	1.0445	1.1031	1.1186	WHigh	-1.527	Manually verified no voltage violation
2028SH	[REDACTED]	MP	HIBBING7	115	0.95	1.1	1.0329	1.0331	1.0993	1.1163	WHigh	-1.672	Manually verified no voltage violation
2028SH	[REDACTED]	MP	44L TAP7	115	0.95	1.1	1.0331	1.0334	1.0992	1.1161	WHigh	-1.667	Manually verified no voltage violation
2028SH	[REDACTED]	MP	HTC PMP7	115	0.95	1.1	1.0334	1.0336	1.1001	1.1172	WHigh	-1.695	Manually verified no voltage violation
2028SH	[REDACTED]	MP	HIBBTAC7	115	0.95	1.1	1.0311	1.0314	1.098	1.1152	WHigh	-1.693	Manually verified no voltage violation
2028SH	[REDACTED]	MP	78L TAP7	115	0.95	1.1	1.0343	1.0345	1.1015	1.1185	WHigh	-1.674	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	14L TAP7	115	0.95	1.1	1.0341	1.0343	1.1036	1.1209	WHigh	-1.702	Manually verified no voltage violation
2028SH	[REDACTED]	MP	NATIONL7	115	0.95	1.1	1.0332	1.0335	1.1028	1.12	WHigh	-1.703	Manually verified no voltage violation
2028SH	[REDACTED]	MP	IRON TP7	115	0.95	1.1	1.0393	1.0395	1.0957	1.1113	WHigh	-1.538	Manually verified no voltage violation
2028SH	[REDACTED]	MP	TBIRD S7	115	0.95	1.1	1.0357	1.036	1.0902	1.106	WHigh	-1.545	Manually verified no voltage violation
2028SH	[REDACTED]	MP	T-BIRD 7	115	0.95	1.1	1.0294	1.0296	1.0848	1.1008	WHigh	-1.579	Manually verified no voltage violation
2028SH	[REDACTED]	MP	NASHWAK7	115	0.95	1.1	1.0384	1.0386	1.1106	1.1281	WHigh	-1.727	Manually verified no voltage violation
2028SH	[REDACTED]	MP	DMNDLAK7	115	0.95	1.1	1.0395	1.0397	1.1107	1.1284	WHigh	-1.747	Manually verified no voltage violation
2028SH	[REDACTED]	MP	BLCKBRY7	115	0.95	1.1	1.0497	1.0499	1.1283	1.1462	WHigh	-1.769	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GR RPDS7	115	0.95	1.1	1.0414	1.0416	1.1108	1.1284	WHigh	-1.739	Manually verified no voltage violation
2028SH	[REDACTED]	MP	LIND 7	115	0.95	1.1	1.0408	1.0409	1.1098	1.1276	WHigh	-1.762	Manually verified no voltage violation
2028SH	[REDACTED]	MP	MATURI 7	115	0.95	1.1	1.0313	1.0315	1.0928	1.1094	WHigh	-1.632	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	CANSTEO7	115	0.95	1.1	1.04	1.0402	1.1105	1.1283	WHigh	-1.758	Manually verified no voltage violation
2028SH	[REDACTED]	MP	BOSWELL7	115	0.95	1.1	1.0403	1.0405	1.1089	1.1269	WHigh	-1.784	Manually verified no voltage violation
2028SH	[REDACTED]	MP	SHANNON7	115	0.95	1.1	1.0396	1.0398	1.1057	1.1228	WHigh	-1.693	Manually verified no voltage violation
2028SH	[REDACTED]	MP	BLANDGM7	115	0.95	1.1	1.036	1.0362	1.1054	1.1233	WHigh	-1.779	Manually verified no voltage violation
2028SH	[REDACTED]	MP	BLANDPM7	115	0.95	1.1	1.036	1.0362	1.1057	1.1236	WHigh	-1.772	Manually verified no voltage violation
2028SH	[REDACTED]	MP	ZEMPLEN7	115	0.95	1.1	1.0373	1.0374	1.0946	1.112	WHigh	-1.727	Manually verified no voltage violation
2028SH	[REDACTED]	MP	20L TAP7	115	0.95	1.1	1.0416	1.0418	1.1118	1.1294	WHigh	-1.743	Manually verified no voltage violation
2028SH	[REDACTED]	MP	28L TAP7	115	0.95	1.1	1.0401	1.0403	1.1088	1.1268	WHigh	-1.783	Manually verified no voltage violation
2028SH	[REDACTED]	MP	ZEMPLES7	115	0.95	1.1	1.0318	1.032	1.0948	1.1126	WHigh	-1.765	Manually verified no voltage violation
2028SH	[REDACTED]	MP	WESTCOH7	115	0.95	1.1	1.0402	1.0404	1.1088	1.1268	WHigh	-1.783	Manually verified no voltage violation
2028SH	[REDACTED]	MP	TIOGA 7	115	0.95	1.1	1.0373	1.0374	1.1064	1.1244	WHigh	-1.78	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	COHSSTTP	115	0.95	1.1	1.0401	1.0403	1.1088	1.1268	WHigh	-1.783	Manually verified no voltage violation
2028SH	[REDACTED]	MP	LAKEHD 7	115	0.95	1.1	1.0317	1.0318	1.0947	1.1125	WHigh	-1.766	Manually verified no voltage violation
2028SH	[REDACTED]	MP	37L TAP7	115	0.95	1.1	1.0336	1.0338	1.0869	1.1026	WHigh	-1.55	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-4CORNRS7	115	0.9	1.05	1.0336	1.0362	1.0484	1.0585	WHigh	-0.747	Manually verified no voltage violation
2028SH	[REDACTED]	GRE	GRE-DEER RV7	115	0.9	1.05	1.037	1.0372	1.094	1.1115	WHigh	-1.725	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	MP	GRE-ORTMN 4	230	0.9	1.05	1.0867	1.0869	1.1596	1.1773	WHigh	-1.747	Pre-Existing Issue
2028SH	[REDACTED]	MP	GRE-BERGNLK7	115	0.92	1.05	1.0334	1.0361	1.0481	1.0583	WHigh	-0.743	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-BERGNTP7	115	0.9	1.05	1.0338	1.0365	1.0485	1.0586	WHigh	-0.743	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-HILLCTY7	115	0.92	1.05	1.0382	1.0384	1.0827	1.0971	WHigh	-1.419	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	MP	GRE-COHASST7	115	0.92	1.05	1.0401	1.0402	1.1087	1.1267	WHigh	-1.784	Pre-Existing Issue
2028SH	[REDACTED]	MP	GRE-LAKELND7	115	0.92	1.05	1.0314	1.0315	1.0698	1.0849	WHigh	-1.495	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	GRE-COTTON 7	115	0.92	1.05	1.0331	1.0334	1.0911	1.107	WHigh	-1.559	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-IRON 7	115	0.92	1.05	1.0392	1.0394	1.0956	1.1112	WHigh	-1.538	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	MP	GRE-PEARY 7	115	0.92	1.05	1.0333	1.0336	1.0913	1.1071	WHigh	-1.557	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-KEEWATN7	115	0.92	1.05	1.0322	1.0325	1.0969	1.1137	WHigh	-1.658	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-POKEGMT7	115	0.9	1.05	1.0396	1.0398	1.0944	1.1101	WHigh	-1.552	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	OTP	GRE-POKEGMA7	115	0.92	1.05	1.0395	1.0397	1.0943	1.11	WHigh	-1.552	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	MP	GRE-SHOALLT7	115	0.92	1.05	1.0389	1.0391	1.1108	1.1283	WHigh	-1.735	Pre-Existing Issue
2028SH	[REDACTED]	MP	GRE-SHOALLK7	115	0.92	1.05	1.0389	1.0391	1.1108	1.1283	WHigh	-1.736	Pre-Existing Issue
2028SH	[REDACTED]	MP	GRE-HILLCTP7	115	0.92	1.05	1.0383	1.0385	1.0827	1.0971	WHigh	-1.419	can be mitigated by switching off shunt at buses 667035 and 667679
2028SH	[REDACTED]	GRE	GRE-CRMWLLD7	115	0.92	1.05	1.0229	1.0235	1.0401	1.0507	WHigh	-0.994	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-HINGX4A7	115	0.92	1.05	1.0216	1.0223	1.0468	1.0586	WHigh	-1.11	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	MP	GRE-KNFFLTP7	115	0.9	1.05	1.0273	1.0284	1.041	1.0517	WHigh	-0.954	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-KNIFEFL7	115	0.92	1.05	1.0273	1.0284	1.041	1.0517	WHigh	-0.954	Manually verified no voltage violation
2028SH	[REDACTED]	MP	GRE-CEDARVL7	115	0.92	1.05	1.0215	1.0222	1.0515	1.064	WHigh	-1.174	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	KARLSTA7	115	0.97	1.07	1.0627	1.0628	1.1125	1.1254	WHigh	-1.273	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	CASS LK7	115	0.97	1.07	1.0277	1.0279	1.0616	1.0745	WHigh	-1.268	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	CASS N 7	115	0.97	1.07	1.0276	1.0277	1.0615	1.0743	WHigh	-1.267	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	PLUMTAP7	115	0.97	1.07	1.0418	1.0419	1.0752	1.0854	WHigh	-1.013	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	PLUMMER7	115	0.97	1.07	1.0417	1.0418	1.0751	1.0853	WHigh	-1.012	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	PLUMPIP7	115	0.97	1.07	1.0414	1.0415	1.0752	1.0854	WHigh	-1.017	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	VIKING 7	115	0.97	1.07	1.0463	1.0464	1.0901	1.1019	WHigh	-1.175	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	DONALDS7	115	0.97	1.07	1.0747	1.0748	1.1285	1.1419	WHigh	-1.334	Pre-Existing Issue

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	OTP	DONDPIP7	115	0.97	1.07	1.0746	1.0747	1.1284	1.1419	WHigh	-1.335	Pre-Existing Issue
2028SH	[REDACTED]	OTP	OSLO SS 7	115	0.92	1.1	1.0612	1.0613	1.1017	1.1125	WHigh	-1.076	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	OSLO TN7	115	0.97	1.07	1.0608	1.0608	1.1012	1.1121	WHigh	-1.076	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	CASS LK4	230	0.97	1.05	1.031	1.0312	1.0724	1.0862	WHigh	-1.359	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	DONALDS CAP7	115	0.97	1.07	1.0747	1.0748	1.1285	1.1419	WHigh	-1.334	Pre-Existing Issue
2028SH	[REDACTED]	OTP	DRAYTON7	115	0.92	1.1	1.0986	1.0987	1.1604	1.1753	WHigh	-1.477	Pre-Existing Issue
2028SH	[REDACTED]	OTP	WARSAW 7	115	0.92	1.1	1.064	1.0641	1.1085	1.1202	WHigh	-1.156	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	HALMA 7	115	0.92	1.1	1.0679	1.068	1.1194	1.1325	WHigh	-1.299	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	OSLO 7	115	0.97	1.07	1.0612	1.0613	1.1017	1.1125	WHigh	-1.076	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	ALVARAD7	115	0.92	1.1	1.0592	1.0592	1.0995	1.1104	WHigh	-1.08	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	WARREN 7	115	0.92	1.1	1.0557	1.0558	1.0958	1.1067	WHigh	-1.084	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028SH	[REDACTED]	OTP	DRAYTON4	230	0.92	1.1	1.0946	1.0948	1.1647	1.1814	WHigh	-1.656	Pre-Existing Issue
2028SH	[REDACTED]	MP	LTLFRK 4	230	0.92	1.1	1.1048	1.105	1.1813	1.1992	High	-1.764	Pre-Existing Issue
2028SH	[REDACTED]	MP	MORANVI4	230	0.92	1.1	1.1578	1.158	1.19	1.2022	High	-1.191	Pre-Existing Issue
2028SH	[REDACTED]	MP	MORANVI4	230	0.92	1.1	1.1578	1.158	1.2701	1.2952	WHigh	-2.479	Pre-Existing Issue
2028SH	[REDACTED]	MP	LUND 4	230	0.92	1.1	1.1416	1.1418	1.1683	1.1796	High	-1.105	Pre-Existing Issue
2028SH	[REDACTED]	MP	LUND 4	230	0.92	1.1	1.1416	1.1418	1.2406	1.263	WHigh	-2.213	Pre-Existing Issue
2028SH	[REDACTED]	OTP	LKARDCH4	230	0.92	1.1	1.0732	1.0733	1.1207	1.1327	WHigh	-1.188	Manually verified no voltage violation
2028SH	[REDACTED]	OTP	LKARDCH7	115	0.92	1.1	1.065	1.0651	1.1074	1.1185	WHigh	-1.105	Manually verified no voltage violation
2028SP	[REDACTED]	XEL	PEACE GARD 5	230	0.92	1.05	1.0378	1.0379	1.0397	1.0555	High	-1.573	Manually verified no voltage violation
2028SP	[REDACTED]	XEL	PEACE GARD 5	230	0.92	1.05	1.0378	1.0379	1.0397	1.0555	WHigh	-1.572	Manually verified no voltage violation
2028SP	[REDACTED]	XEL	PEACE GARD 5	230	0.92	1.05	1.0378	1.0379	1.0396	1.0553	High	-1.574	Manually verified no voltage violation

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	HILLTOP4	230	0.95	1.1	1.0221	1.0239	0.9931	0.9204	WLow	7.453	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HILLTOP4	230	0.95	1.1	1.0221	1.0239	0.9952	0.9295	Low	6.745	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HILLTOP4	230	0.95	1.1	1.0221	1.0239	0.9924	0.9293	Low	6.483	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STINSON5	161	0.95	1.1	1.0157	1.0181	0.9744	0.9139	WLow	6.288	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STINSON5	161	0.95	1.1	1.0157	1.0181	0.9741	0.9211	Low	5.54	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STINSON5	161	0.95	1.1	1.0157	1.0181	0.973	0.9201	Low	5.53	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	DAHLBRG7	115	0.95	1.1	1.012	1.0153	0.9872	0.9346	WLow	5.59	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	DAHLBRG7	115	0.95	1.1	1.012	1.0153	0.9873	0.941	Low	4.955	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	DAHLBRG7	115	0.95	1.1	1.012	1.0153	0.9861	0.9404	Low	4.904	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	FAIRMPK7	115	0.95	1.1	1.0185	1.0223	0.9863	0.9184	WLow	7.173	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	FAIRMPK7	115	0.95	1.1	1.0185	1.0223	0.9873	0.9268	Low	6.443	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	FAIRMPK7	115	0.95	1.1	1.0185	1.0223	0.9852	0.9262	Low	6.288	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	MAHTOWA7	115	0.95	1.1	1.0147	1.0151	0.9844	0.9305	WLow	5.433	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	MAHTOWA7	115	0.95	1.1	1.0147	1.0151	0.9905	0.9442	Low	4.669	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	MAHTOWA7	115	0.95	1.1	1.0147	1.0151	0.9853	0.9448	Low	4.095	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WRENSHL7	115	0.95	1.1	1.0258	1.0259	0.9959	0.9346	WLow	6.142	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WRENSHL7	115	0.95	1.1	1.0258	1.0259	1.0001	0.9462	Low	5.4	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WRENSHL7	115	0.95	1.1	1.0258	1.0259	0.9959	0.9469	Low	4.914	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	THOMSON7	115	0.95	1.1	1.03	1.03	1.0002	0.9368	WLow	6.345	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	THOMSON7	115	0.95	1.1	1.03	1.03	1.0038	0.9476	Low	5.614	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	THOMSON7	115	0.95	1.1	1.03	1.03	0.9999	0.9484	Low	5.157	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	FONDULAC	115	0.95	1.1	1.0286	1.0294	0.9999	0.9345	WLow	6.619	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	FONDULAC	115	0.95	1.1	1.0286	1.0294	1.0032	0.9451	Low	5.888	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	FONDULAC	115	0.95	1.1	1.0286	1.0294	0.9995	0.9457	Low	5.463	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	POTLTCH7	115	0.95	1.1	1.0227	1.0237	0.993	0.9331	WLow	6.085	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	POTLTCH7	115	0.95	1.1	1.0227	1.0237	0.996	0.9434	Low	5.369	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	POTLTCH7	115	0.95	1.1	1.0227	1.0237	0.9921	0.9446	Low	4.854	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	CLOQUET7	115	0.95	1.1	1.0218	1.0231	0.9921	0.9331	WLow	6.028	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	CLOQUET7	115	0.95	1.1	1.0218	1.0231	0.9951	0.9431	Low	5.316	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	CLOQUET7	115	0.95	1.1	1.0218	1.0231	0.9911	0.9444	Low	4.789	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	BURNETT7	115	0.95	1.1	1.0208	1.022	0.9984	0.9492	WLow	5.037	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HILLTOP7	115	0.95	1.1	1.0227	1.0266	0.9932	0.9204	WLow	7.666	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HILLTOP7	115	0.95	1.1	1.0227	1.0266	0.9953	0.9296	Low	6.957	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	HILLTOP7	115	0.95	1.1	1.0227	1.0266	0.9924	0.9294	Low	6.695	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HANESRD7	115	0.95	1.1	1.0192	1.0225	0.989	0.9239	WLow	6.837	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HANESRD7	115	0.95	1.1	1.0192	1.0225	0.9911	0.9324	Low	6.2	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HANESRD7	115	0.95	1.1	1.0192	1.0225	0.9883	0.9321	Low	5.945	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	RIDGEVW7	115	0.95	1.1	1.0196	1.0226	0.9902	0.9284	WLow	6.484	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	RIDGEVW7	115	0.95	1.1	1.0196	1.0226	0.9923	0.9365	Low	5.878	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	RIDGEVW7	115	0.95	1.1	1.0196	1.0226	0.9895	0.9362	Low	5.63	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HIBBARD7	115	0.95	1.1	1.0224	1.0271	0.995	0.9212	WLow	7.847	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HIBBARD7	115	0.95	1.1	1.0224	1.0271	0.9971	0.9304	Low	7.128	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	HIBBARD7	115	0.95	1.1	1.0224	1.0271	0.9943	0.9303	Low	6.867	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	NEMADJI7	115	0.95	1.1	1.0179	1.0213	0.983	0.9177	WLow	6.873	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	NEMADJI7	115	0.95	1.1	1.0179	1.0213	0.9837	0.9257	Low	6.139	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	NEMADJI7	115	0.95	1.1	1.0179	1.0213	0.9819	0.925	Low	6.029	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	GARY 7	115	0.95	1.1	1.0186	1.0215	0.9788	0.9132	WLow	6.861	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	GARY 7	115	0.95	1.1	1.0186	1.0215	0.9795	0.9212	Low	6.122	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	GARY 7	115	0.95	1.1	1.0186	1.0215	0.9777	0.9205	Low	6.012	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WNTR ST7	115	0.95	1.1	1.0195	1.0237	0.9894	0.9185	WLow	7.51	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WNTR ST7	115	0.95	1.1	1.0195	1.0237	0.9909	0.9273	Low	6.785	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	WNTR ST7	115	0.95	1.1	1.0195	1.0237	0.9885	0.9269	Low	6.579	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	LSPI 7	115	0.95	1.1	1.0227	1.0273	0.9952	0.9214	WLow	7.833	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	LSPI 7	115	0.95	1.1	1.0227	1.0273	0.9972	0.9306	Low	7.115	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	LSPI 7	115	0.95	1.1	1.0227	1.0273	0.9944	0.9305	Low	6.854	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	STIN-MN7	115	0.95	1.1	1.0186	1.022	0.9844	0.9194	WLow	6.849	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STIN-MN7	115	0.95	1.1	1.0186	1.022	0.9851	0.9274	Low	6.118	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STIN-MN7	115	0.95	1.1	1.0186	1.022	0.9833	0.9267	Low	6.009	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STIN-WI7	115	0.95	1.1	1.0186	1.022	0.9844	0.9194	WLow	6.848	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STIN-WI7	115	0.95	1.1	1.0186	1.022	0.9851	0.9274	Low	6.116	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	STIN-WI7	115	0.95	1.1	1.0186	1.022	0.9833	0.9267	Low	6.007	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	15TH AV7	115	0.95	1.1	1.021	1.0244	0.9897	0.9167	WLow	7.652	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	15TH AV7	115	0.95	1.1	1.021	1.0244	0.9918	0.9259	Low	6.939	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	15TH AV7	115	0.95	1.1	1.021	1.0244	0.989	0.9257	Low	6.676	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	COLBYVL7	115	0.95	1.1	1.0245	1.0272	1.0017	0.9478	WLow	5.663	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	CANOSIA7	115	0.95	1.1	1.0223	1.024	0.9916	0.9325	WLow	6.078	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

Model	Contingency Name	Area Name	Bus Name	kV	LV Limit	HV Limit	ON Base Volt	ON Cont. Volt	OFF Base Volt	OFF Cont. Volt	Violation Type	Voff -Von (< -1%)	Mitigations
2028WP	[REDACTED]	MP	CANOSIA7	115	0.95	1.1	1.0223	1.024	0.9946	0.9426	Low	5.365	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2028WP	[REDACTED]	MP	CANOSIA7	115	0.95	1.1	1.0223	1.024	0.9906	0.9439	Low	4.838	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)
2033SP	[REDACTED]	MP	GRE-BEARCK 4	230	0.9	1.05	1.0261	1.0267	1.0181	1.0522	WHigh	-3.349	can be mitigated by switching load off at local buses(608688 P0,608679 P0,608686 P2 and 608919 P2)

8.3 Contingency Details

8-III Details of Impacting Contingencies

Contingency Name	Contingency Detail
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]

Contingency Name	Contingency Detail
[REDACTED]	[REDACTED]
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8.4 Redispatch Mitigations

8-IV Details of Redispatch Mitigations

Redispatch Scenario	Contingency Name	Bus#	Bus Name	Volt	ID	Area	Area Name	Min MW	Max MW	Initial MW	Final MW	MW Change	BTyp	Status	DsSt
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2028SP	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
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Redispatch Scenario	Contingency Name	Bus#	Bus Name	Volt	ID	Area	Area Name	Min MW	Max MW	Initial MW	Final MW	MW Change	BTyp	Status	DsSt
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Redispatch Scenario	Contingency Name	Bus#	Bus Name	Volt	ID	Area	Area Name	Min MW	Max MW	Initial MW	Final MW	MW Change	BTyp	Status	DsSt
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Redispatch Scenario	Contingency Name	Bus#	Bus Name	Volt	ID	Area	Area Name	Min MW	Max MW	Initial MW	Final MW	MW Change	BTyp	Status	DsSt
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I. Part 9: Fleet Transition Experience with Small Coal Unit Closures (Section Reproduced in its Entirety from 2021 IRP Appendix F, Part 6)

Part 6: Fleet Transition Experience with Small Coal Unit Closures

This section provides an update on transmission system impacts and projects implemented as a result of previous small coal unit fleet transition decisions at Laskin Energy Center, Taconite Harbor Energy Center, and Boswell Energy Center Units 1 and 2. The discussion focuses on specific transmission projects needed to mitigate transmission system impacts from small coal unit closures, with added context around the underlying concepts that drive these needs. The understanding gained from our experience of implementing small coal unit closures on our system has been foundational to informing our understanding and expectations for the broader impacts from similar consideration of Boswell Energy Center Units 3 and 4. While those units and their area of impact are much larger than the small coal units discussed in this section, we believe that the same general concepts may be applied – albeit on a much larger scale – to understand and anticipate the impacts from shutting down Boswell Units 3 and 4. Our analysis of Boswell Unit 3 and 4 closures will be discussed in Part 7.

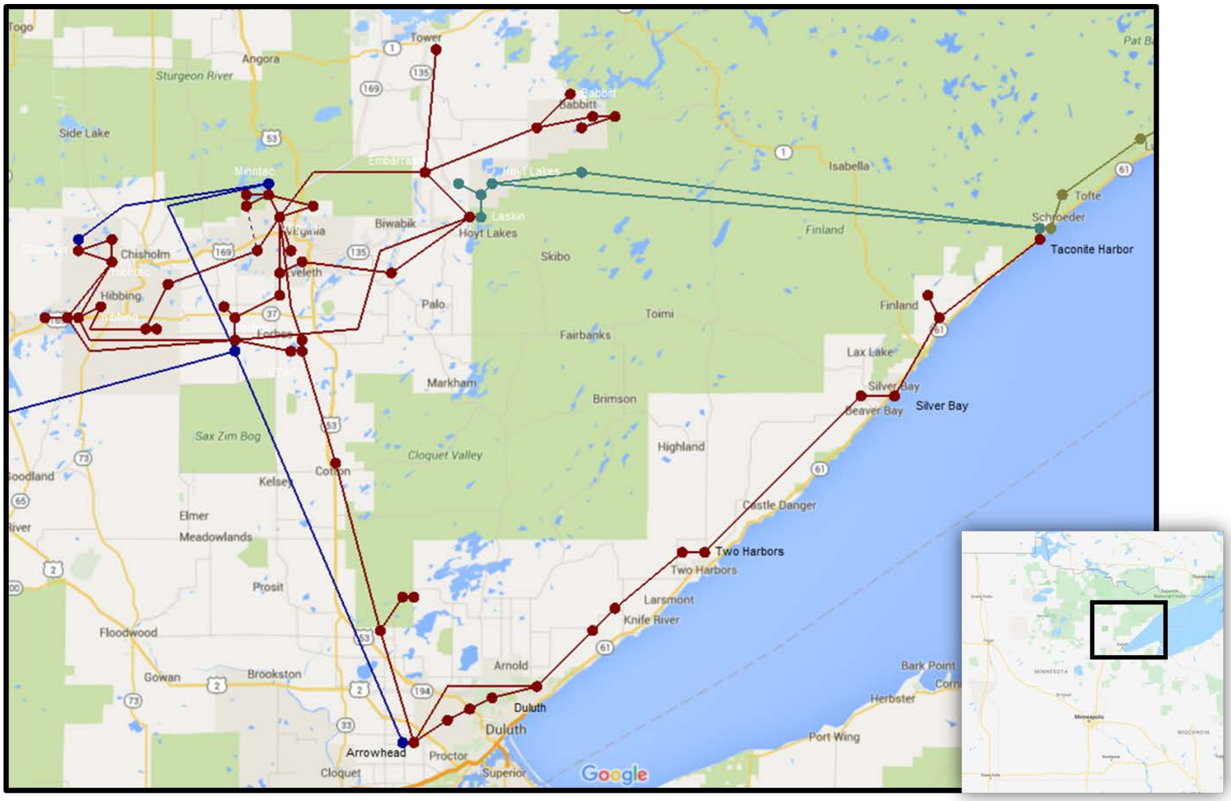
The initial discussion in this section will focus on the North Shore Loop transmission system, which includes the Laskin and Taconite Harbor Energy Centers. The impact of small coal unit closures on voltage support and system strength, local power delivery and redundancy in the North Shore Loop and the surrounding area will be illustrated, including fundamental concepts, specific projects implemented and a summary of project costs to date. Following the North Shore Loop discussion, a briefer discussion of the Grand Rapids Area and impacts from shutting down Boswell Energy Center Units 1 and 2 is also provided.

The North Shore Loop: Laskin & Taconite Harbor

Background

The North Shore Loop is a 140-mile system of 115 kV and 138 kV lines that extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to serve customers in an area extending from Duluth to the Canadian border to the eastern end of the Mesabi Iron Range, including east Duluth, Two Harbors, Silver Bay, Grand Marais, Hoyt Lakes, and the surrounding areas. The North Shore Loop transmission system is shown in Figure 1.

Figure 1: North Shore Loop Transmission System



Historically, the North Shore loop contained an abundance of coal-fired baseload generation, and the transmission system was designed from the mid-1900s onward to rely on the power and system support provided by the local baseload generators to serve customers. North Shore Loop coal-fired generators included Minnesota Power's Laskin Energy Center and Taconite Harbor Energy Center, as well as a large industrial cogeneration facility located in Silver Bay. The Silver Bay generators are owned by Silver Bay Power Company, a subsidiary of Cliffs Natural Resources Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to peaking natural gas capacity units. Also in 2015, Minnesota Power retired one of the units at the Taconite Harbor Energy Center. In 2016, Minnesota Power idled the other two Taconite Harbor Energy Center units. Coal-fired operations at Taconite Harbor ceased by 2020 with full retirement scheduled for September 2021. In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, in September 2019 Silver Bay Power Company idled both of the Silver Bay units. The cumulative impact of these operational changes has effectively decarbonized the North Shore Loop, leaving no baseload generators normally online.

The local baseload generators at Laskin Energy Center, Taconite Harbor Energy Center, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing voltage support, power delivery capability, and redundancy, among other things. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016 and several more projects are planned between 2020 and 2025. Below is a summary of the types of transmission impacts identified as a result of moving beyond baseload generation in the North Shore Loop and the projects Minnesota Power has implemented or is planning to implement to address these impacts.

Voltage Support & System Strength

Local baseload generators provide reactive power and voltage support to the local transmission system. Electric power generated in an alternating current power system includes the generation of both real power, measured in megawatts, as well as reactive power, measured in mega voltage amperes reactive ("MVAR"). Reactive power is required to maintain an appropriate system voltage, stabilize the system, and enable the delivery of real power. Generators provide a dynamic source of reactive power, able to ramp MVAR output up and down within the limits of the generator to regulate system voltage. This dynamic reactive support becomes particularly important for system reliability, as abrupt changes in the power system can result in rapid voltage collapse if there is not a fast-responding source of reactive power. Unlike real power, which can be transmitted over long distances with relatively minimal losses, reactive power tends to be consumed locally by loads and by the transmission system itself as transmission lines load up above their optimal power delivery capability. As more power is transferred on the transmission system, the reactive power needed to maintain appropriate system voltage increases. Without the local baseload generators in the North Shore Loop, the main sources of reactive power and voltage support have been lost. The resulting voltage support-related issues include increased difficulty regulating transmission system voltage, post-contingent high or low voltage conditions, and increased risk of voltage collapse.

To illustrate the voltage regulation impacts, Figure 2 below shows the Taconite Harbor 138 kV bus voltage for the second half of 2016. As noted on the figure, Taconite Harbor Unit 1 and Unit 2 were idled in October 2016. The impact of the transition of these generators on transmission system voltage regulation is noticeable. Without the local voltage regulation provided by the Taconite Harbor units, the transmission system voltage becomes less predictable – varying more rapidly and over a broader range than it did when the Taconite Harbor units were online and regulating the voltage. Without the voltage support and system strength from the generators, which acted like shock absorbers any time there was a significant change on the system, the transmission system voltage is also impacted more significantly by minute-to-minute and day-to-day changes, such as large motor starting or other changes in load, switching of fixed reactive support devices like capacitor banks, and events outside of the North Shore Loop transmission system.

Figure 2: Taconite Harbor 138 kV Bus Voltage, June – December 2016

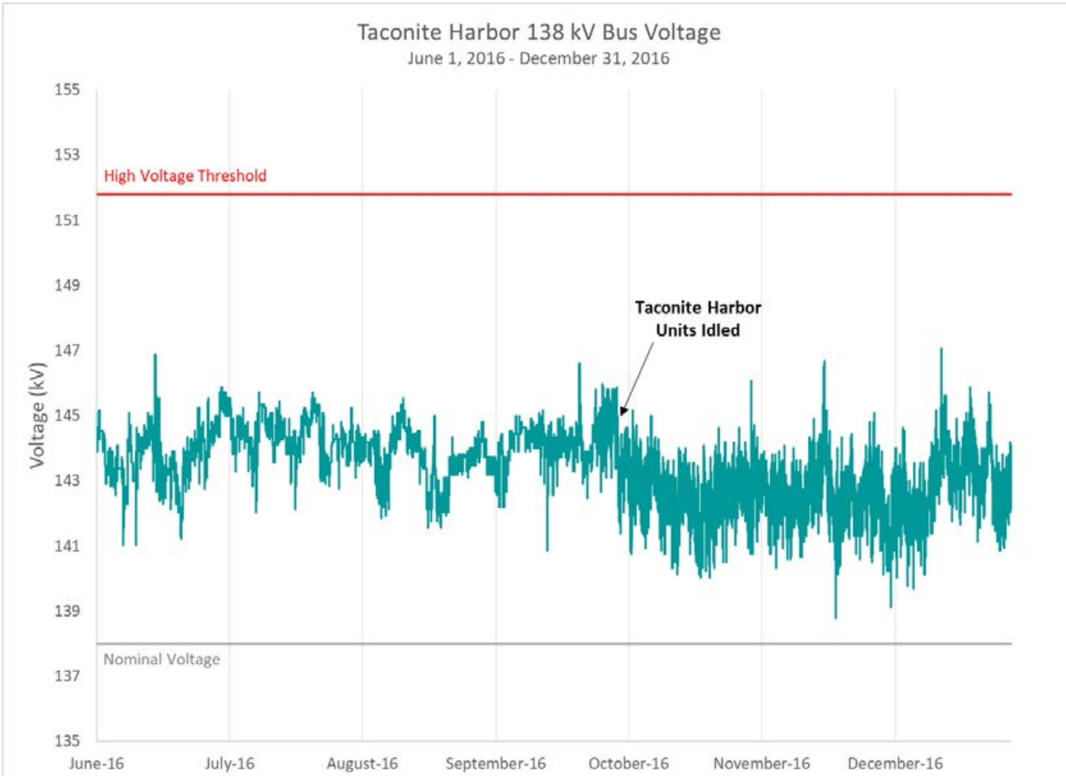
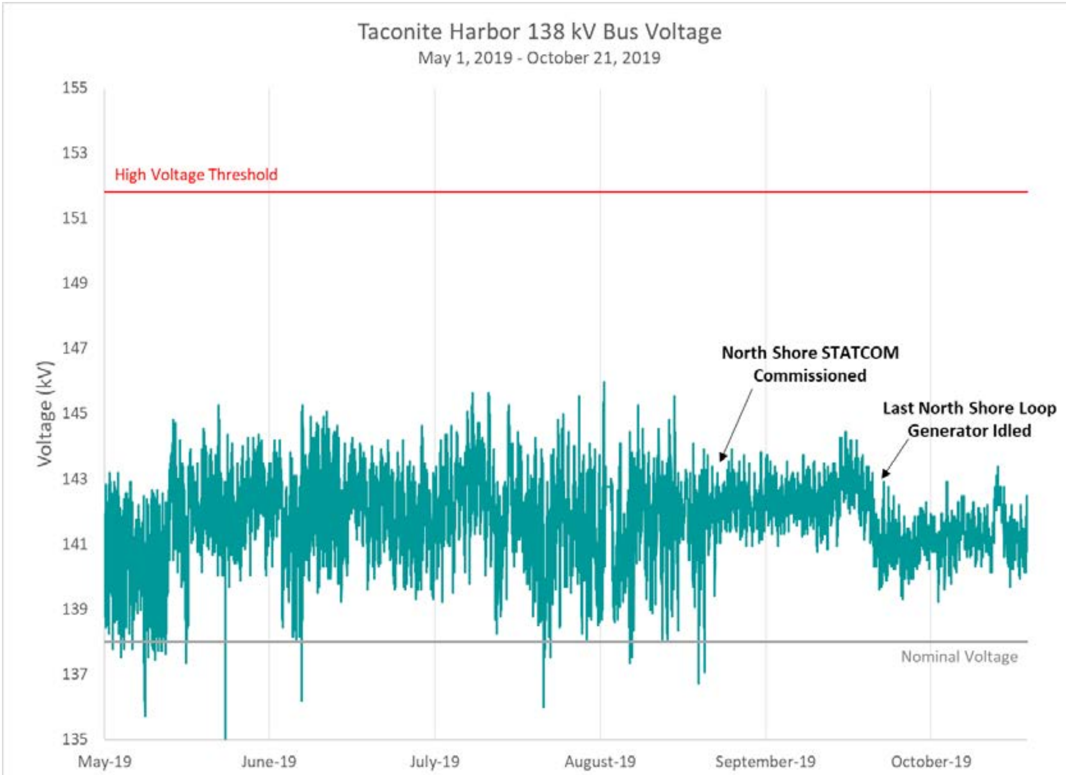


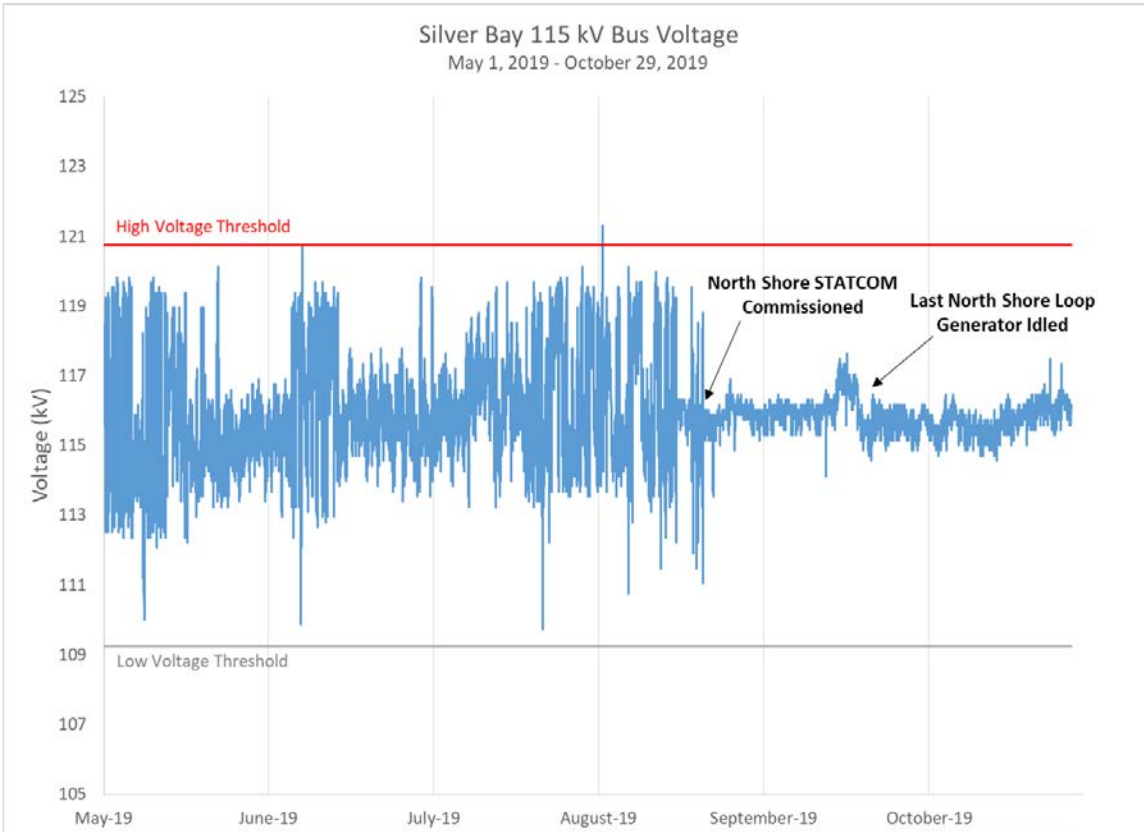
Figure 3: Taconite Harbor 138 kV Bus Voltage, May – October 2019



The North Shore Static Synchronous Compensator ("STATCOM") Project was designed to replace dynamic voltage support, including voltage regulation capability, for the North Shore Loop following the conversion, idling or retirement of all local baseload generators. Figure 3 shows the voltage at the same Taconite Harbor bus in the middle of 2019. As noted on the figure, the North Shore STATCOM was energized and commissioned in late August 2019. Though it is located 30 miles away from Taconite Harbor, the impact of the voltage regulating capability provided by the North Shore STATCOM is obvious. Even after the retirement of the last North Shore Loop generator – resulting in a step change in power flow through Taconite Harbor on the transmission system – the North Shore STATCOM is capable of supporting and regulating a robust bus voltage at Taconite Harbor.

The restorative impact of the North Shore STATCOM on North Shore Loop voltage regulation is most obvious in Figure 4, which shows the changing operation of the 115 kV bus voltage at the Silver Bay Substation from widely varying and unpredictable to tightly regulated and predictable following implementation of the STATCOM less than a mile away at the North Shore Switching Station.

Figure 4: North Shore 115 kV Bus Voltage, May – October 2019

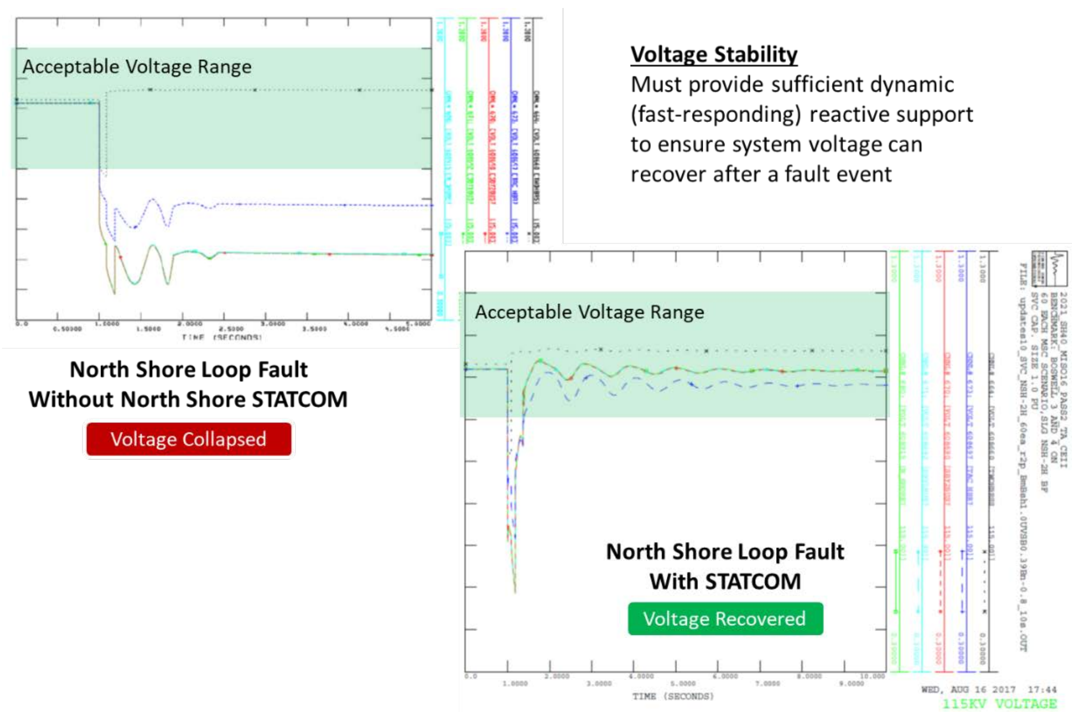


Without the more finely-tuned voltage regulation capability of the North Shore Loop generators or the STATCOM, the only voltage support resources available in the North Shore were mechanically switched capacitor banks ("MSCs"). Existing MSCs at the Colbyville and Big Rock Substations, as well as new MSCs at the North Shore Switching Station, are only capable of switching in large fixed chunks of reactive support. In a weak system, such as the North Shore Loop has become without the local baseload generators online, it becomes difficult to switch large fixed amounts of reactive support due to the increased sensitivity of the system. For example, where low voltage may necessitate additional reactive support, switching in a capacitor bank of a fixed size into a weak system may prove to increase the voltage too far in some circumstances – resulting in high voltage – and not enough in other circumstances. Besides offering finely-tuned voltage regulating capability from its own reactive power range (+/-75 MVAR), the North Shore STATCOM was designed to control four existing North Shore Switching Station MSCs in order to extend the capacitive end of its reactive capability by another 100 MVAR for voltage regulation and dynamic voltage support. Thus the North Shore STATCOM Project restored 175 MVAR of dynamic support and voltage regulating capability to the North Shore Loop, which represents slightly more than a one-for-one replacement of the total nameplate reactive support capability of the idled/retired Taconite Harbor and Silver Bay generators (166 MVAR).

The primary driver for the North Shore STATCOM, however, was not voltage regulation but voltage stability. Without the fast-responding voltage support of the generators, power flow studies determined that the transmission system was not capable of supporting all existing

North Shore Loop load under certain contingency conditions. Without replacing the support previously provided by the generators, there would be a risk of voltage collapse anytime the 140-mile transmission path between Colbyville and Laskin was severed. Voltage stability simply refers to the ability of the system to recover from an event and rapidly restore voltage to within the acceptable range. A voltage collapse is what occurs when the voltage in some part of the system cannot recover following an event – resulting in extremely low voltages and possibly localized blackouts. Figure 5 below shows a comparison of the same transmission system contingency with and without the North Shore STATCOM. Without dynamic reactive support from the STATCOM or the retired baseload generators, the contingency leads to voltage collapse on the North Shore Loop. With the STATCOM the transmission system voltage following the same event rapidly recovers to within the acceptable range.

Figure 5: North Shore Loop Voltage Stability Comparison



Finally, in terms of voltage support, studies identified several low voltage violations throughout the North Shore Loop and the surrounding area following transition away from the local baseload generators. Some of these low voltage violations are in the North Shore Loop and related to the voltage regulation and voltage collapse concerns discussed above. Those violations were mitigated by the addition of the MSCs and STATCOM at the North Shore Switching Station. Other voltage violations were identified in an area of the system adjacent to the North Shore Loop that is far away from the remote sources of power and voltage support that replace the local baseload generators and along heavily-loaded transmission paths between those remote sources and the loads in the North Shore Loop and on the eastern end of the Iron Range. To resolve these issues, MSCs were added at three additional locations:

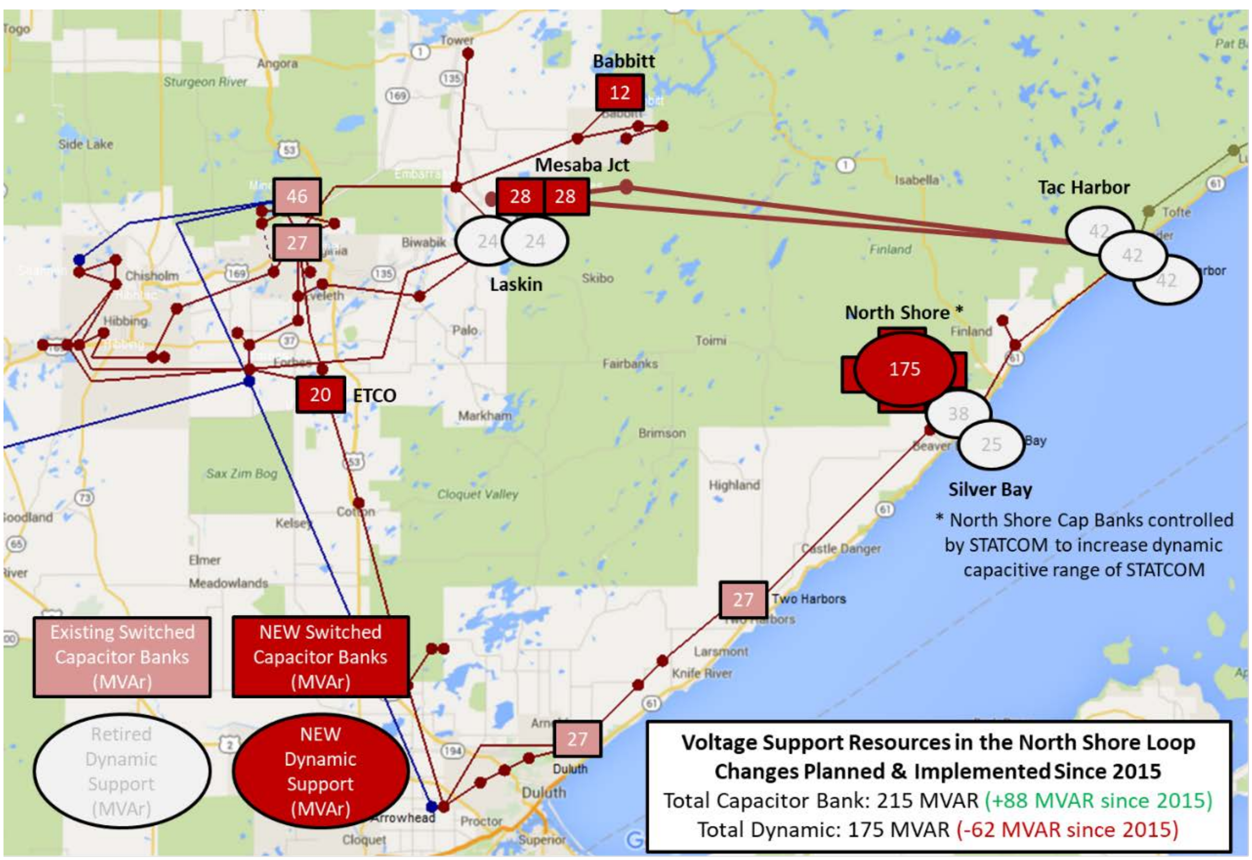
- **Babbitt Substation** (12 MVAR): On a radial (single source) transmission system approximately 40 miles from the nearest 230/115 kV source;

- **ETCO Substation** (20 MVAR): At a substation near a large industrial site along a heavily loaded 115 kV outlet 6 miles from the Forbes 230/115 kV source; and
- **Mesaba Junction Switching Station** (2x28 MVAR): 5.5 miles away from the Laskin Substation at the beginning of a 60-mile transmission path into the North Shore Loop that can become heavily loaded under certain contingency conditions.

Planned and completed reactive resource additions in the North Shore Loop following conversion, idling, or retirement of local baseload generation resources are shown in Figure 6 below. As noted on the figure, the cumulative reactive resource additions in and adjacent to the North Shore Loop are slightly more than a one-for-one replacement of the reactive support that was removed with the generators.

In summary, several transmission projects were necessary throughout and adjacent to the North Shore Loop in order to replace the voltage support historically provided by baseload generators. These transmission projects involved both dynamic voltage support, capable of rapid response times and finely-tuned voltage regulation, as well as mechanically switched capacitor banks to provide fixed amounts of voltage support at particular locations of concern. Total reactive support additions in the area slightly exceeded the total nameplate reactive support of the generators that were retired.

Figure 6: Voltage Support Resources in the North Shore Loop



Power Delivery Capability

Local baseload generators provide a dependable, available, and controllable source of power to the local transmission system. When baseload power is no longer provided locally, the replacement power must come from remote sources. In some cases, like the North Shore Loop, this can cause power flows on the transmission system well in excess of what the system was originally designed to accommodate. The North Shore Loop was historically an area with sufficient to excessive amounts of local generation going back to the mid-1900s when the local baseload generators were built. As such, the transmission system was not designed to accommodate significant flows of power into the North Shore Loop from remote sources. Without the local baseload generators online, the North Shore Loop now imports 100 percent of its power over the transmission system from remote sources. In Minnesota Power's transmission system, those remote sources are the nearest connections between Minnesota Power's 230 kV backbone transmission system and the local 115 kV network. This changing use of the transmission system has led to issues affecting both the remote 230/115 kV sources and the transmission paths that connect those sources to the North Shore Loop. At the remote 230/115 kV sources, issues include transformer overloads and increased severity associated with contingencies that weaken or sever the 230/115 kV connection. Along the 115 kV transmission paths connecting the remote sources to load, issues include transmission line overloads and increased severity associated with outages that weaken or sever the connection between the remote sources and the expanded area they must now supply.

Figure 7 and Figure 8 illustrate the shifting of the predominant source of power delivery in the North Shore Loop from local baseload generators to remote 230/115 kV sources. As shown in Figure 7, prior to the conversion, idling, and retirement of local baseload generators, there was approximately 205 MW more power generation capability in the North Shore Loop than the local peak load. This made the North Shore Loop a net exporter of power under most circumstances. In fact, due to the amount of excess generation compared to load in the North Shore Loop, special protection systems were maintained to runback or trip Taconite Harbor generation to avoid transmission line overloads and instability under certain contingency conditions. As the decarbonization of the North Shore Loop progressed, more and more of the power formerly supplied locally had to be delivered from the remote 230/115 kV sources at the Minntac, Forbes, and Arrowhead Substations. With all the North Shore Loop generators now offline, the area has become a constant importer of power with a local peak load up to 250 MW, as shown in Figure 8. This represents a 455 MW swing, from a net exporter of 205 MW to a net importer of 250 MW.

Figure 7: North Shore Loop Power Delivered from Local Generators

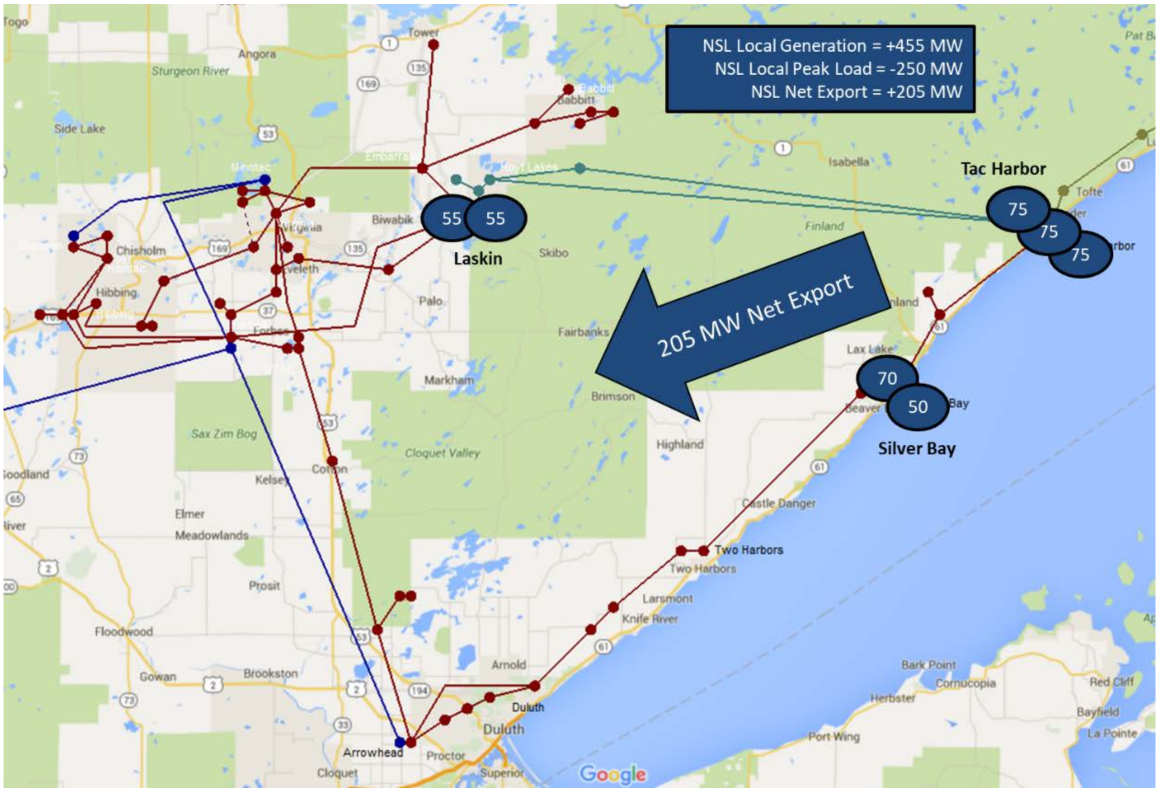
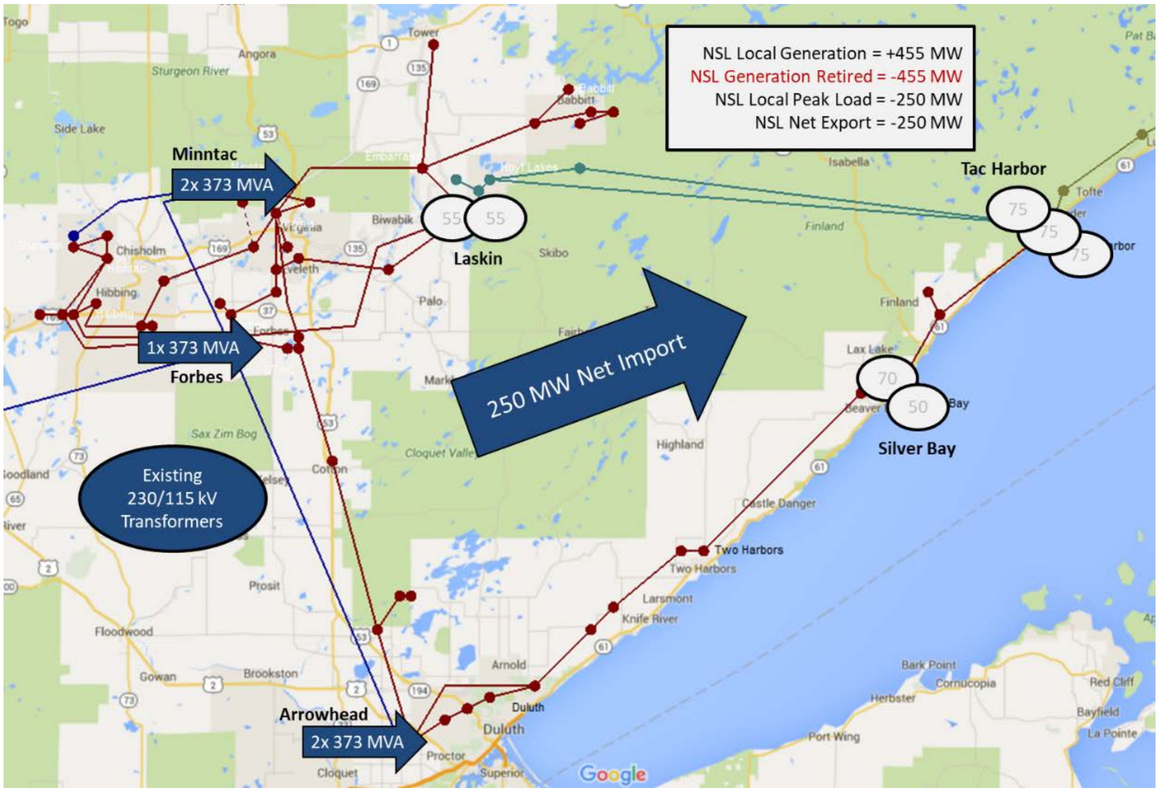


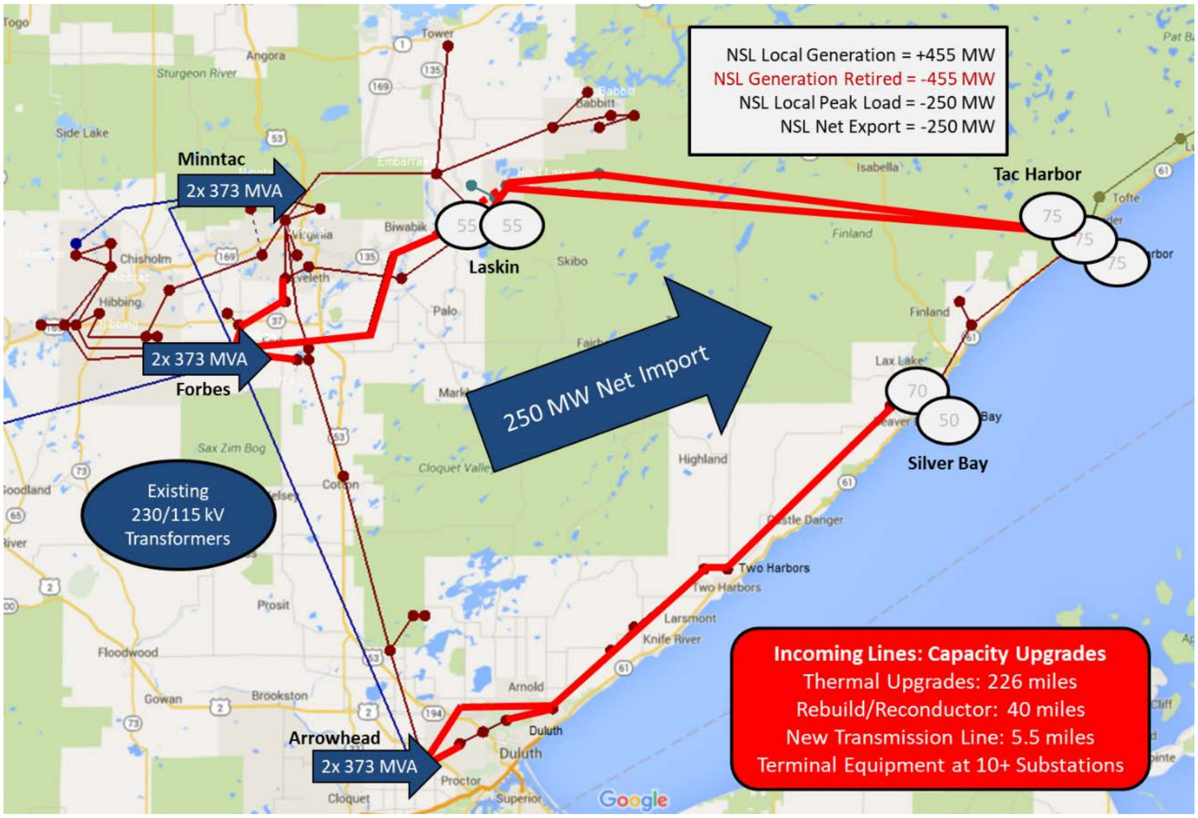
Figure 8: North Shore Loop Power Delivered from Remote 230/115 kV Sources



The impact of this transition on the 230/115 kV sources has been significant. Some of the earliest transmission improvements implemented in relation to the decarbonization of the North Shore Loop were reinforcements of the Forbes and Minntac 230/115 kV sources. At both substations, certain contingency events resulting in loss of the 230/115 kV connection at the substation were causing widespread and severe low voltages and transmission line overloads. To address the issues at the Forbes Substation, a second 230/115 kV transformer was added to ensure a constant connection between the 230 kV and 115 kV systems under the majority of contingency conditions. A breaker failure relay was also added to limit the impact of a particular contingency that could otherwise have resulted in loss of the entire 230 kV bus. A subsequent 115 kV bus reconfiguration project is planned to mitigate the last remaining potential contingency that could sever the Forbes 230/115 kV connection. At the Minntac Substation, the 230 kV bus was reconfigured and three additional 230 kV breakers were added to establish a more reliable bus configuration, ensuring that no single breaker failure would result in the loss of more than one transmission line and one transformer. In all of these cases, potential contingency conditions that existed and did not require mitigation for many years while the local baseload generators were online became unacceptably severe due to increasing reliance on the 230/115 kV sources.

In addition to driving upgrades at the 230/115 kV sources themselves, the changing use of the transmission system has driven the need for increased capacity on many of the transmission lines connecting the Minntac, Forbes, and Arrowhead sources to the North Shore Loop. Figure 9 illustrates the capacity upgrades that have been completed on the incoming lines connecting the North Shore Loop to the remote 230/115 kV sources.

Figure 9: Transmission Line Capacity Upgrades for Delivery of Power to the North Shore Loop



Capacity upgrades become necessary when the limiting element of a transmission line does not have sufficient capacity to deliver the power that is expected to flow on it under the worst single contingency condition. The scope of capacity upgrades ranges from replacement of limiting terminal equipment at a substation, to targeted structure replacements on a transmission line aimed at increasing the thermal rating of the line, to rebuilding or reconductoring the line with a higher-capacity conductor, to building a new transmission line. As noted in Figure 9, planned and implemented capacity upgrades on incoming North Shore Loop transmission lines have consisted of terminal equipment replacements at more than 10 different substations, thermal upgrades on approximately 226 miles of transmission lines, rebuilding or reconductoring of approximately 40 miles of transmission lines, and the construction of 5.5 miles of new 115 kV transmission line. Together, these capacity upgrades were necessary to provide sufficient power delivery capability to serve all North Shore Loop under all reasonable conditions with the same level of reliability historically achieved when the power was being delivered by the local baseload generators.

In summary, the power once generated locally by North Shore Loop baseload units must now be delivered over the transmission system from remote 230/115 kV sources. As a result, several transmission projects were needed to strengthen and reinforce the 230/115 kV sources as they became more heavily used. Capacity upgrades were also required on many miles of transmission lines and at many substations in order to facilitate the reliable delivery of power from those remote 230/115 kV sources into the North Shore Loop over a transmission system that was not originally designed to facilitate such power flows.

Redundancy

Local baseload generators provide a redundant source of power delivery and voltage support to the local transmission system. In many cases, the redundancy provided by the generators can offset the need for additional transmission connections. When a local baseload generating facility consists of multiple generating units, even more redundancy is built in to both the generating facility and the local power system. The Taconite Harbor Energy Center, for example, consisted of three 75 MW generating units. At any given time, the redundancy built into the generating facility meant that it was highly likely that at least two of the three units would be running and it was practically guaranteed that at least one unit would be running at all times, barring some abnormal conditions. In that sense, Taconite Harbor provided a dependable source capable of delivering 75 MW to 150 MW of power, along with voltage support, to the North Shore Loop with availability comparable to that of the transmission system. In the event of a planned or unanticipated transmission line outage, the generation facility could continue to provide power to the area, and its output and voltage schedule could be adjusted up or down to mitigate transmission line loading or voltage issues.

In an area of the system where transmission sources are relatively sparse, like the North Shore Loop, local baseload generators can even be designed to operate while isolated from the rest of the transmission system ("islanded") in order to restore electric service to the local area following multiple-contingency events resulting in loss of all transmission sources. Without these local baseload generators in the North Shore Loop, electric service redundancy for the area has been lost. The resulting redundancy-related issues include post-contingent transmission line overloads following multiple-contingency events, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

While all of the voltage support and power delivery capability projects discussed in the previous sections are related in some ways to the loss of redundancy from local baseload generators in the North Shore Loop, two projects in particular illustrate the types of transmission improvements that are necessary to restore redundancy. The Mesaba Junction 115 kV Project provides redundancy related to single points of failure on the Hoyt Lakes end of the North Shore Loop. The Duluth 115 kV Loop Project provides reduncancy related to multiple-contingency events, establishing consistent redundancy on the Duluth end of the North Shore Loop.

Mesaba Junction 115 kV Project

The Mesaba Junction 115 kV Project involves the development of a new switching station interconnected to existing transmission lines in the Hoyt Lakes area. Approximately 5.4 miles of new 115 kV line will be constructed along the existing Laskin – Hoyt Lakes transmission line corridor to extend the Forbes – Laskin 115 kV "38 Line" into Mesaba Junction. The existing 38 Line connection to the Laskin Substation will then be eliminated. In addition to the transmission line connections, the new switching station will include two switched capacitor banks to provide voltage support. To facilitate interconnection of the Mesaba Junction 115 kV Project, eliminate single points of failure, and modernize the area transmission system, existing 138 kV transmission facilities between Laskin, Hoyt Lakes, and Taconite Harbor will be converted to 115 kV operation in coordination with the Mesaba Junction 115 kV Project. The Mesaba Junction 115 kV Project and the Laskin – Taconite Harbor Voltage Conversion Project are shown in Figure 10 below.

As shown in Figure 11, single points of failure on the Hoyt Lakes end of the North Shore

Loop have the potential to leave the entire North Shore Loop served via single source from the Colbyville Substation, located 140 transmission line-miles away from Hoyt Lakes. In addition to voltage support and power flow issues, this configuration also leaves the area vulnerable during a prior outage of the Laskin – Hoyt Lakes transmission line to a second contingency potentially severing the connection to Colbyville and leaving the North Shore Loop without any adequate sources of power. The Mesaba Junction 115 kV Project and the Laskin – Taconite Harbor Voltage Conversion were designed to address these redundancy issues, in addition to voltage support, power delivery capability, and age and condition concerns.

Specifically, the Mesaba Junction 115 kV Project supports redundancy by providing a third transmission source into the area, establishing a more robust substation configuration, and enabling a standardized network voltage. The Mesaba Junction 115 kV Project establishes a new 115 kV line parallel to the existing Laskin – Hoyt Lakes transmission line and a new switching station that replaces the simple straight bus configuration of the existing Hoyt Lakes Substation with a more reliable ring bus configuration. The new transmission line provides a redundant connection on the Hoyt Lakes end of the North Shore Loop, alleviating single-contingency concerns about losing the connection to Laskin and prior outage concerns about losing all sources to the North Shore Loop. The new switching station relocates the critical bulk electric system path out of an aging customer-owned substation and into a modern, utility-controlled switching station in a more reliable configuration designed, owned, operated, and maintained by Minnesota Power. Finally, as mentioned above, the Mesaba Junction 115 kV Project will be coordinated with the Laskin – Tac Harbor Voltage Conversion Project, greatly enhancing the constructability of both projects and enabling Minnesota Power to realize all the benefits of a standardized network voltage for the area, including eliminating single points of failure by removing the 138/115 kV transformers.

Figure 10: Mesaba Junction 115 kV Project

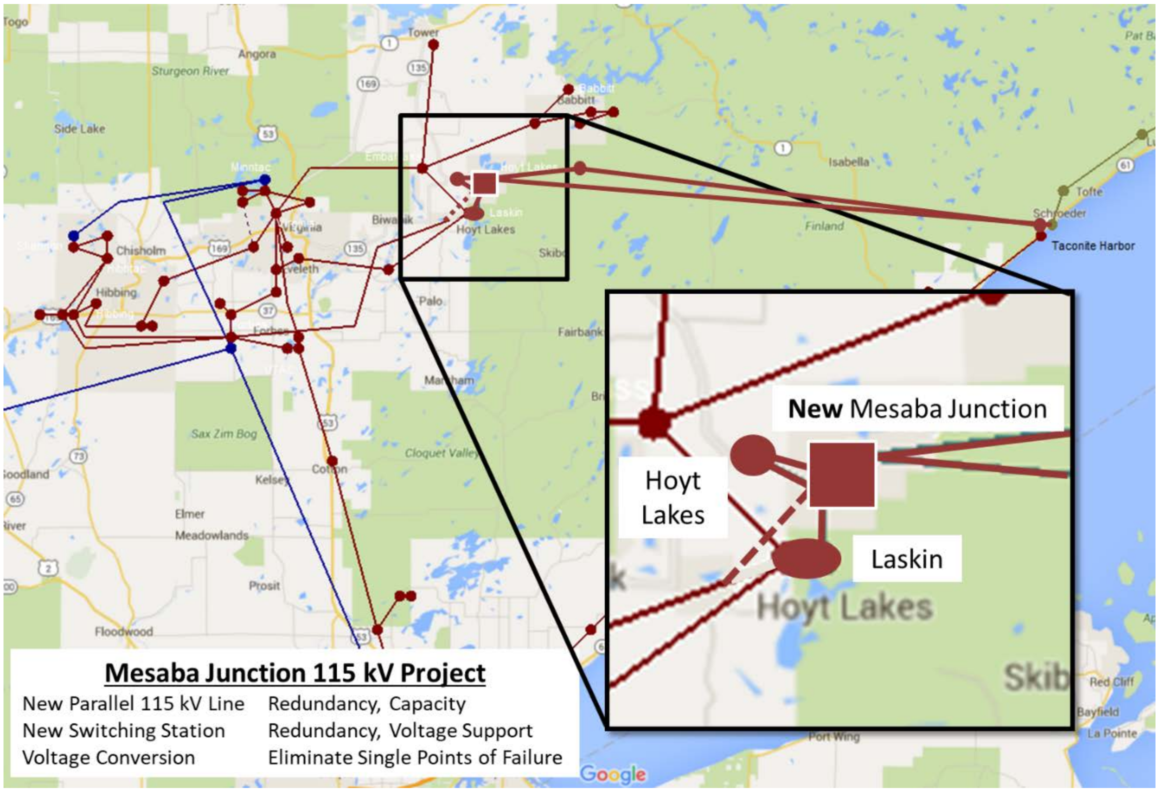
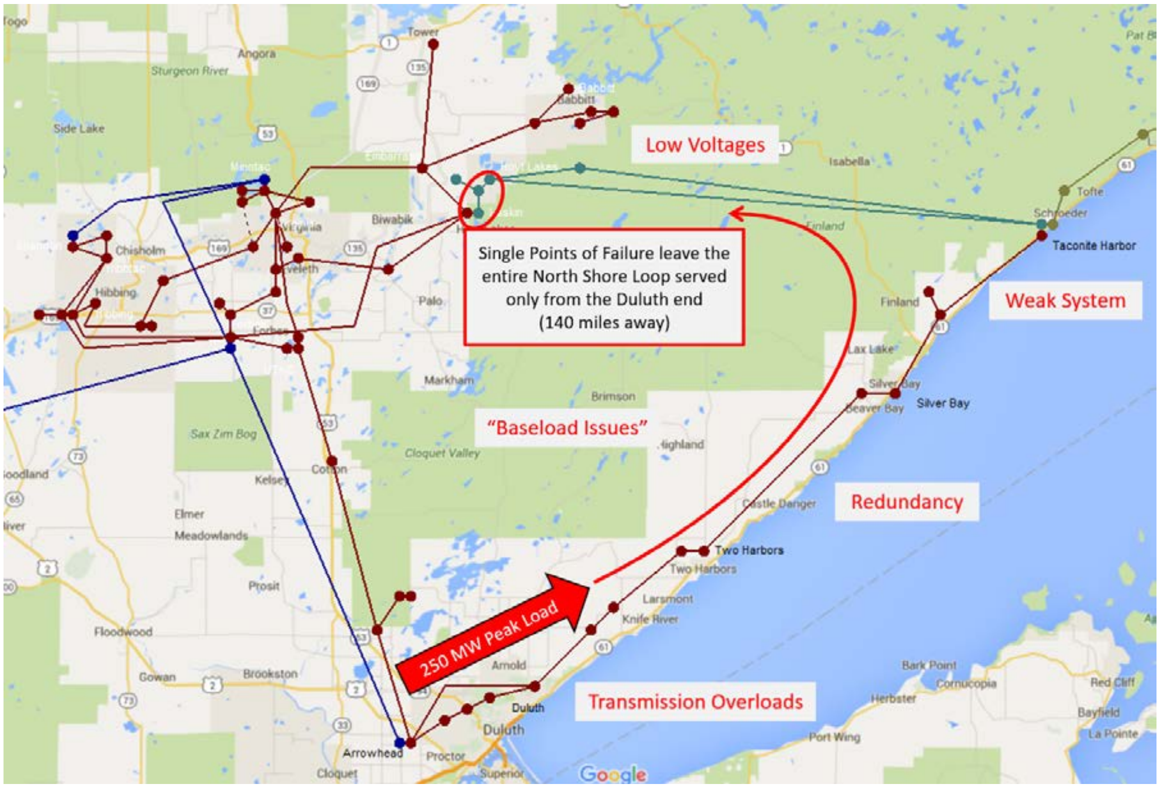


Figure 11: Hoyt Lakes Area Redundancy Concerns

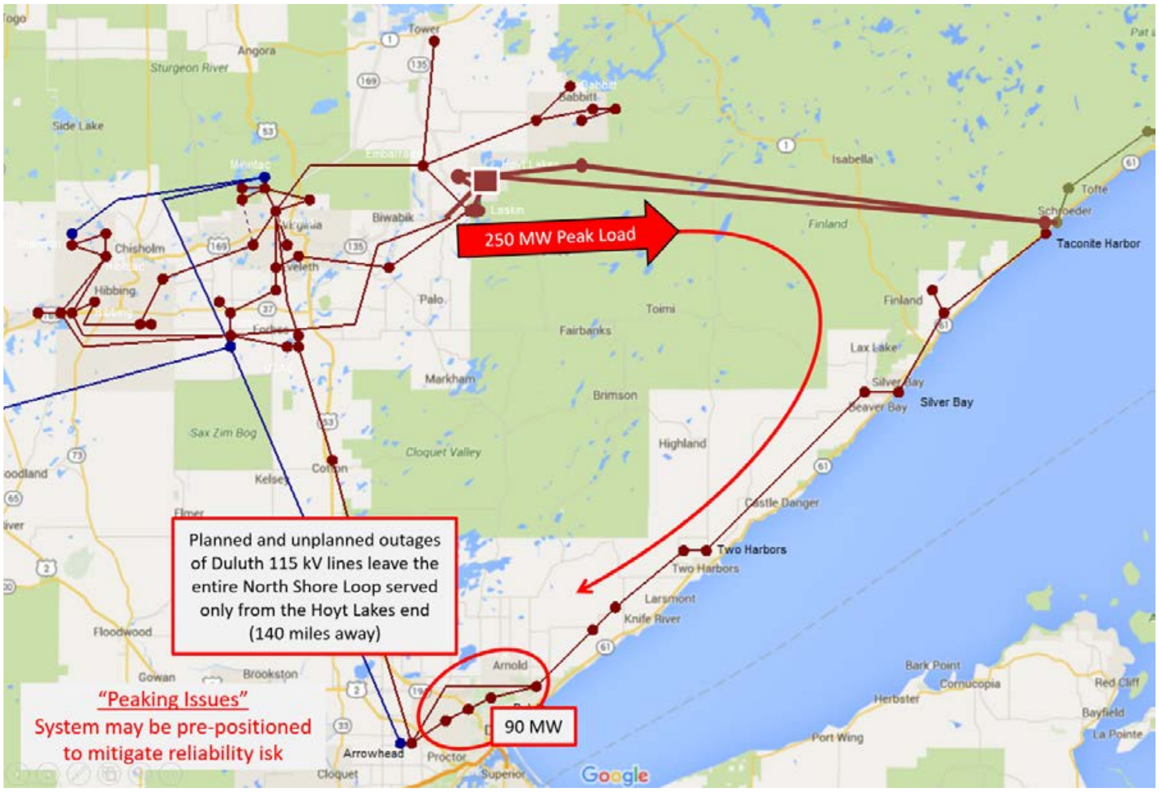


Duluth Loop Reliability Project

The Duluth Loop Reliability Project involves the development of a new 115 kV connection between the existing Hilltop and Ridgeview Substations along with short extension of the Hilltop 230 kV "98 Line" Tap to the Arrowhead Substation. While preferred routes have not yet been identified as of the date of this document, the project is estimated to include approximately 15 miles of new transmission construction, mostly collocated along existing transmission corridors in the Duluth area. Additionally, modifications will take place at the Ridgeview, Hilltop, and Arrowhead substations to accommodate project. It is expected that a certificate of need will be filed for this project mid-year 2021.

The concerns driving the need for the Duluth Loop Reliability Project stem from a risk of voltage collapse, thermal overloads, and low voltage issues caused by certain contingency events during a prior outage of one of the 115 kV lines between the Arrowhead, Haines Road, Swan Lake Road, Ridgeview, and Colbyville Substations in the eastern part of Duluth. Similar to the issues discussed above at the Hoyt Lakes end of the North Shore Loop, the loss of a second transmission line during a prior outage in the Duluth Loop area would leave this part of Duluth on the end of a single 140-mile transmission line originating in the Hoyt Lakes Area. This scenario is shown in Figure 12 below.

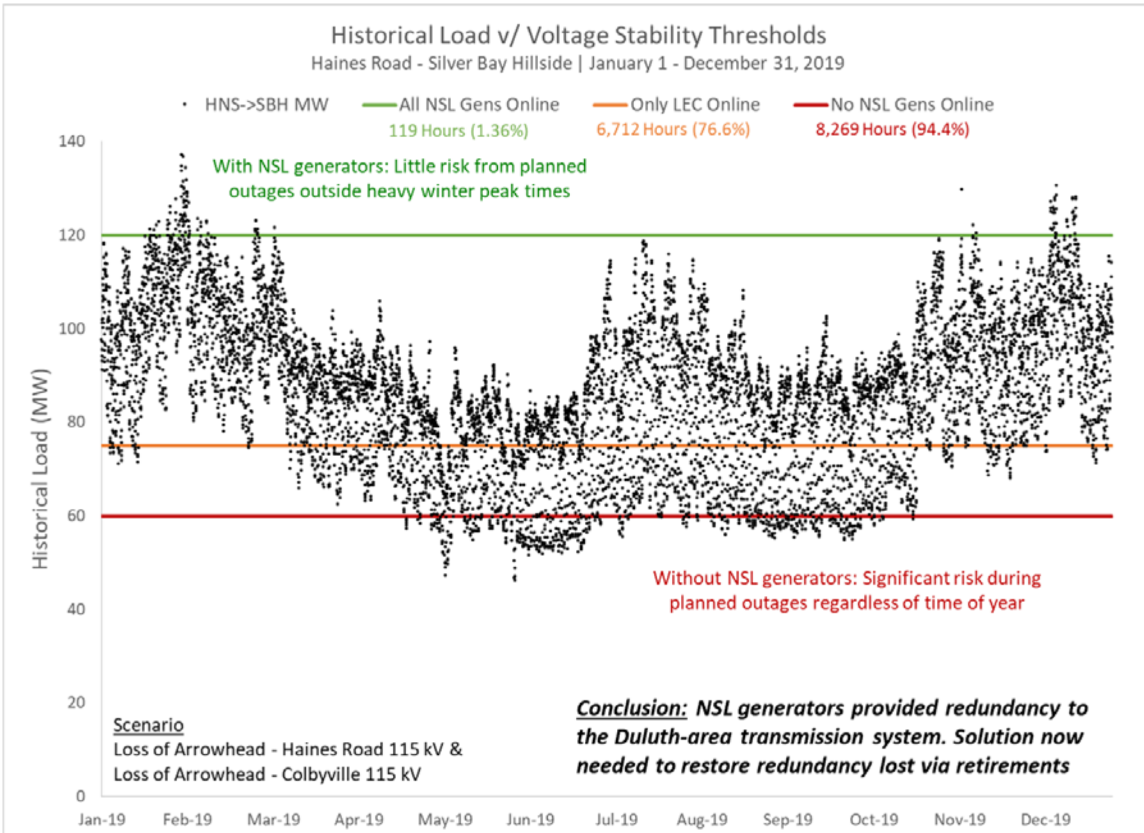
Figure 12: Duluth Loop Area Redundancy Concerns



Without the local baseload generators at Laskin, Taconite Harbor, and Silver Bay, the transmission system is no longer able to support the large amount of Duluth area load over the long distance of the transmission system between Hoyt Lakes and Duluth. The Duluth Loop Reliability Project will restore redundancy and load-serving capability to this area, mitigating the risk of voltage collapse and low voltage issues.

To illustrate the impact of fleet transition on the Duluth Loop, Figure 13 below shows historical coincident loading in the North Shore Loop between the Arrowhead substation and the North Shore Switching Station. This area includes the Duluth Loop substations plus Minnesota Power and Great River Energy load served from the French River, Clover Valley, Two Harbors, Big Rock, Waldo, and Silver Bay Hillside substations. When the transmission lines connecting this area to the Arrowhead Substation are lost, all load towards Duluth is served through the North Shore Switching Station. While the North Shore STATCOM provides sufficient voltage support for the Silver Bay area, the reactive power produced there cannot fully support the Duluth Loop area at the end of the radial system. The result, if load in the area is high enough, is a post-contingent voltage collapse. Figure 13 shows one year of historical load in the area versus the voltage stability threshold for different combinations of North Shore Loop generators online.

Figure 13: Duluth – Silver Bay Historical Load versus Voltage Stability Threshold



With all North Shore Loop generators online, the voltage stability threshold (**green** line on the plot) is generally only present during the heaviest periods of winter peak load. Since the voltage stability concern is associated with a prior outage situation, the issue could historically be handled reasonably well by scheduling planned outages in the spring or fall, when demand is much lower. However, as fewer local baseload generators are online in the North Shore Loop transmission system, the voltage stability threshold degrades significantly. With all North Shore Loop generators except Laskin offline (**orange** line), over 75 percent of hours are above the threshold. With all North Shore Loop generators offline (**red** line), there are less than 500 hours in the entire year when load does not exceed the stability threshold. There are only two days in this particular historical data sample period for which an 8-hour maintenance outage could have been scheduled without exceeding the stability threshold. These two days occurred several weeks apart in May and would have been very difficult to predict in advance so that work could have been coordinated successfully. The demonstrably degraded load-serving capability makes operating around this limitation during prior outages infeasible as a long-term solution. The Duluth Loop Reliability Project is designed to replace the redundancy previously provided by the local baseload generators such that there is sufficient load-serving capability to support all loads in the area and sufficient flexibility to operate and maintain the system reliably.

The issues described above show the extent to which the North Shore Loop baseload generators historically provided critical redundancy to the transmission system. Without these local baseload generators online, transmission system upgrades such as the Mesaba Junction

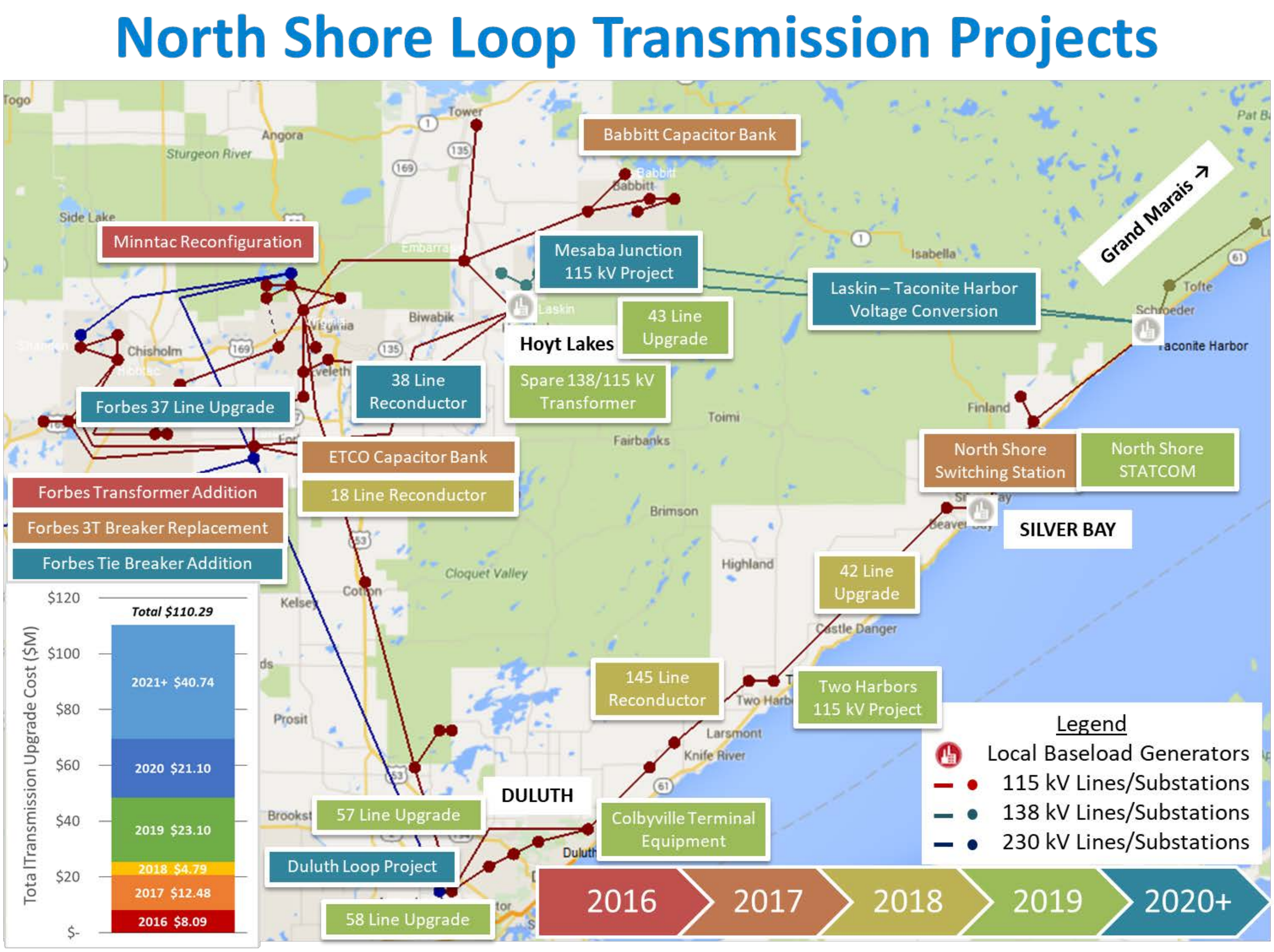
115 kV Project and the Duluth Loop Reliability Project are now required to replace the redundancy and power delivery capability they once provided. These upgrades are necessary to ensure that the system has sufficient backup capability for contingencies and planned outages, provide operational flexibility, and reduce exposure to events potentially causing extended power outages in the area when the few remaining sources of local power delivery are unexpectedly lost.

North Shore Loop Summary

The transmission system is designed to be highly reliable and redundant, yet affordable. Where local baseload generators have provided reliability services to the local transmission system for many years, the transmission system tends to be designed to rely on the local baseload generators being online. As long as the baseload generators were around to provide these reliability services, the cost of transmission upgrades that would decrease reliance on the generators was difficult to justify. With the removal of the local baseload generators, the transmission system in the surrounding area is practically guaranteed to require some amount of upgrading in order to offset the loss of reliability services formerly provided by the generators. The more dependent the transmission system was on the local baseload generators, the more significant the upgrades are likely to be.

In the particular case of the North Shore Loop, Minnesota Power has found that the transmission system was highly dependent on the local baseload generators. Many transmission projects were necessary in the North Shore Loop to replace the voltage support formerly provided by the generators, strengthen and reinforce remote sources of power delivery and transmission paths as they became more heavily used to deliver replacement power formerly generated locally, and restore redundancy formerly provided by the local baseload units. Figure 14 below provides a summary of all the transmission projects related to the decarbonization of the North Shore Loop. As noted on the figure, the total estimated cost of these projects through their completion in the mid-2020s is approximately $110 million.

Figure 14: Summary of North Shore Loop Transmission Projects Related to Fleet Transformation

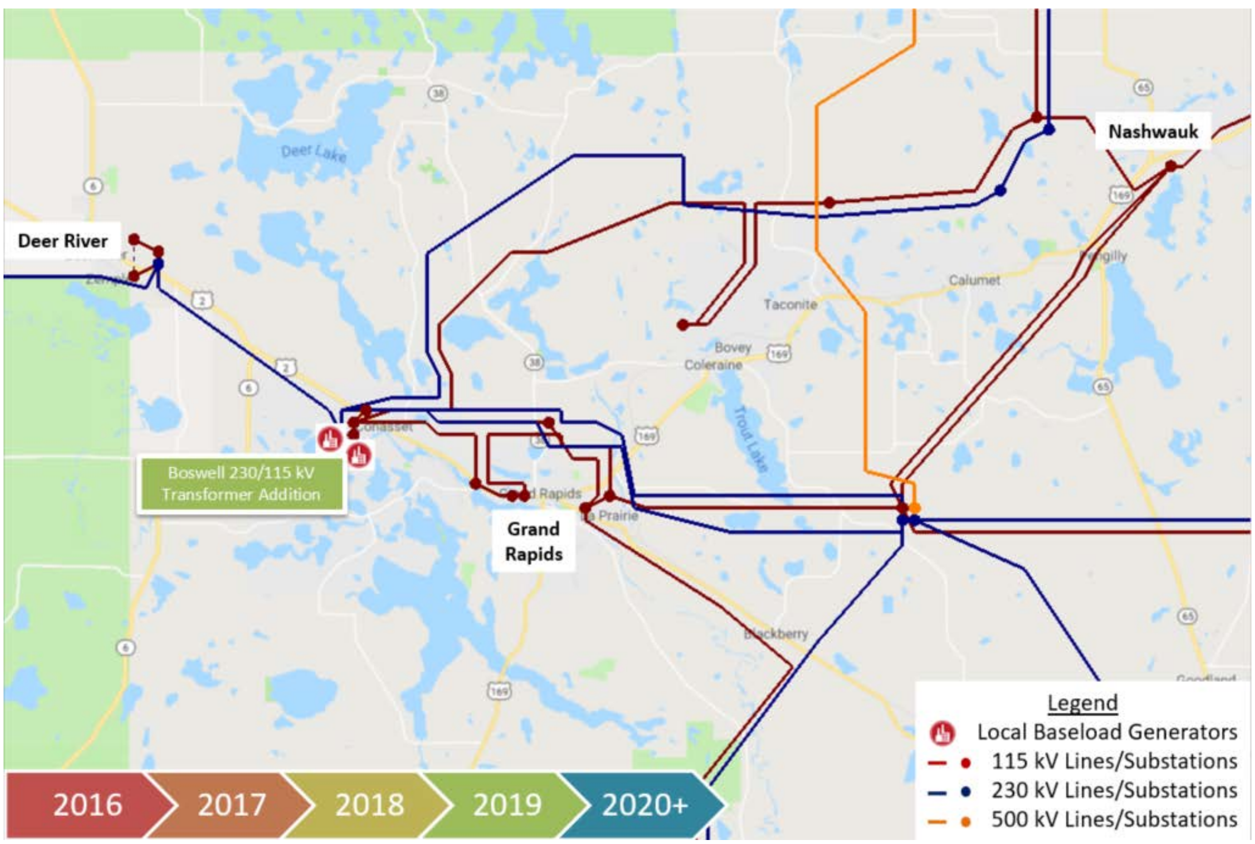


The Grand Rapids Area: Boswell Units 1 & 2

Background

The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230/115 kV sources at the Blackberry and Riverton substations. While four coal-fired generators were historically located at the Boswell Energy Center, only BEC Units 1 and 2 were interconnected directly to the Grand Rapids area 115 kV system. BEC Units 3 and 4 interconnect directly to the 230 kV system and, prior to the Boswell Transformer Project discussed below, the nearest 230/115 kV transformer that tied back to the Grand Rapids area 115 kV system was located at the Blackberry Substation. There was no local electrical connection between the 230 kV and 115 kV systems in the Grand Rapids area, in part because the 115 kV system was supported by the operation of BEC Units 1 and 2. The transmission system in the Grand Rapids area is shown in Figure 15 below, including the local generators and one transmission upgrade related to the retirement of BEC Units 1 and 2.

Figure 15: Grand Rapids Area Transmission System



Similar to the North Shore Loop units, the presence of BEC Units 1 and 2 on the local 115 kV system contributed to the reliability of the Grand Rapids area transmission system for several decades by providing redundancy, voltage support, and local power delivery capability, among other things. Without the support provided by BEC Units 1 and 2, contingencies impacting one or more transmission facilities in the Grand Rapids area may lead to transmission line overloads, post-contingent high or low voltage conditions, increased risk of voltage collapse, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area. In order to mitigate these concerns, Minnesota Power identified that a 230/115 kV source needed to be established in the Grand Rapids area by expanding the Boswell 230 kV Substation and connecting it to the existing 115 kV system ("Boswell Transformer Project").

Transmission System Impacts

The Boswell Transformer Project was needed to ensure the system could continue to be operated at the same or better level of reliability after the retirement of BEC Units 1 and 2. Therefore, Minnesota Power planned the development and construction of the Boswell Transformer Project to be completed in late 2018 prior to the retirement of BEC Units 1 and 2. However, a manufacturing issue caused a significant delay in the completion of the project to the point where it was not possible to put the new transformer in service by the end of 2018. As a result, there was an approximately eight-month period of time in 2019 when BEC Units 1 and 2 were retired, but the Boswell Transformer Project had not yet been placed in service.

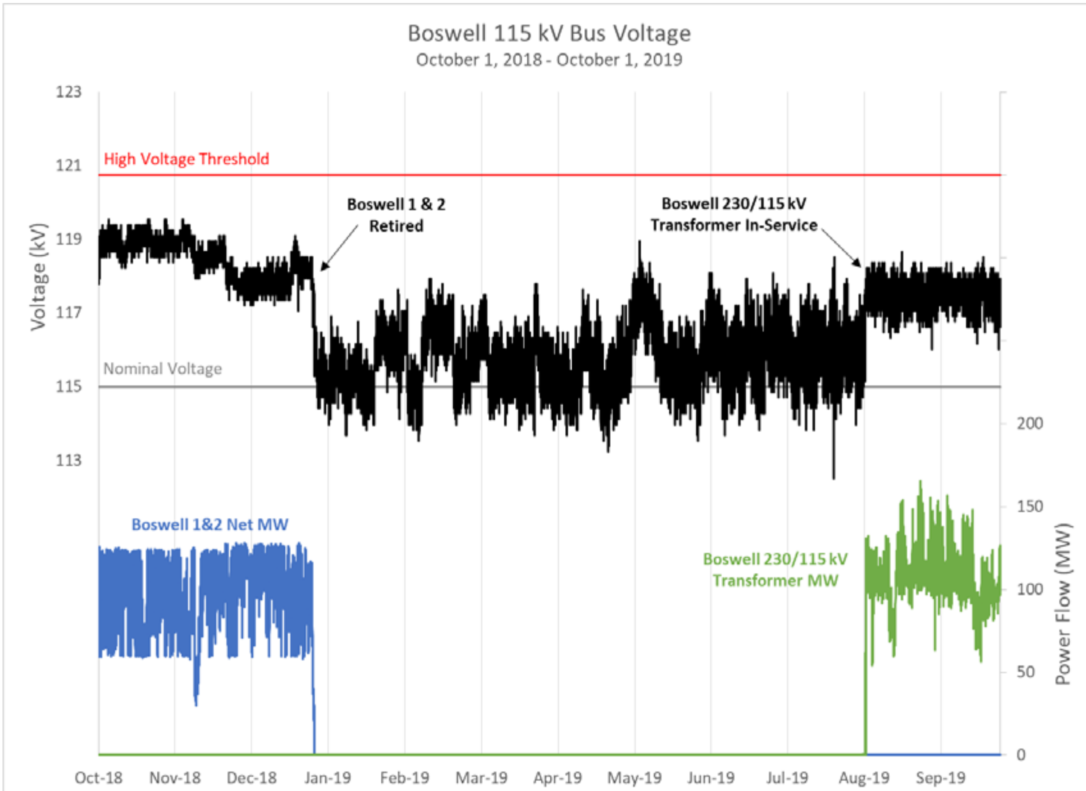
When the manufacturing delay was identified, Minnesota Power evaluated the reliability impacts and risks of the delay. It was expected that no negative reliability impacts would be experienced as long as the 115 kV transmission paths and a local capacitor bank were available. As a result, planned outages of these facilities were restricted until the Boswell transformer could be placed in service. Even with this planning in place, two experiences during this period of time illustrate the reliability risks and uncertainties inherent with operating the system in an entirely new paradigm without BEC Units 1 and 2 and prior to implementing the necessary transmission reliability solution:

- During the polar vortex in late January 2019, a circuit breaker on one of the 115 kV transmission paths into the Grand Rapids area was locked out due to severe cold temperatures. This caused a forced outage of one of the transmission sources to the Grand Rapids area. During this forced outage, MISO's real-time contingency analysis tool identified that a subsequent outage on a second 115 kV path into the Grand Rapids area would lead to low voltage. While the next contingency never happened, Minnesota Power's system operators found that there were limited options in the local area for mitigating the low voltage without BEC Units 1 and 2. This is precisely the condition that the Boswell Transformer Project was intended to mitigate by providing an additional source to the Grand Rapids area.
- Toward the end of June and into early July 2019, a large power customer in the Grand Rapids area notified Minnesota Power that system events had caused a machine on the plant distribution system to trip offline on three occasions. The timing of the machine tripping was correlated with faults elsewhere in the Grand Rapids area on an entirely separate distribution system, where the only connection between the two is the 115 kV transmission system. After each of the first two events Minnesota Power adjusted the settings of a digital fault recorder in the area so that even a modest instantaneous voltage drop would record future fault events. Finally, the third event was successfully captured in a detailed record and analyzed. The voltage levels recorded did not violate operating or planning criteria voltage levels. Using details of the recorded fault, studies were then performed that demonstrated lower voltage during a fault with BEC Units 1 and 2 offline than experienced with them online. The study also confirmed that the planned 230/115 kV transformer mitigated and actually lessened the voltage impacts when compared to BEC Units 1 and 2 online. In all measured and studied conditions

> fault recovery was within Minnesota Power's planning criteria. The fact that there was a significant enough impact on the large power customer during these events to cause a machine to trip without any voltage deviations outside Minnesota Power's planning criteria illustrates some of the inherent risk with transitioning away from the support previously provided by the local baseload generators. It is a paradigm shift for an area that has been designed and built over many decades to rely on the voltage support and system strength provided by the local generators. This paradigm shift potentially has as much or more impact on customer-owned distribution systems as it has on Minnesota Power's transmission and distribution systems.

The Boswell Transformer Project was completed and placed in service about a month and a half after the last of the fault events noted above. Similar to what was noted previously in discussion of the North Shore Loop, voltage in the Grand Rapids area was noticeably more variable and generally lower during the period of time after retirement of the BEC units and before energization of the Boswell Transformer Project. Figure 16 below illustrates the differences in system voltage during these time periods. The experience in the Grand Rapids area indicates that the loss of voltage support and system strength from additional changes in operation of the remaining BEC units may have unintended consequences for Minnesota Power's customers if mitigating solutions are not placed into service prior to implementing the changes. Also of note from Figure 16 is the fact that power flow through the new Boswell 230/115 kV transformer is roughly equivalent to the power formerly produced locally by BEC Units 1 and 2. All of these findings generally work together to confirm Minnesota Power's conclusion that the essential reliability services provided by local generators must be replaced before they are retired.

Figure 16: Boswell Substation 115 kV Bus Voltage, October 1, 2018 – October 1, 2019



J. Part 10: System Strength Study

Summary Report on

System Strength & Voltage Support

Impacts in Northeastern Minnesota

Transmission Planning &
System Performance Departments
June 2022

Revision History

Date	Rev	Description
17 Jan 2022	0	Preliminary Outline
28 Jun 2022	1	Initial Release

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Section 1: Background & Purpose

System Strength is a term that is used in the electric utility industry to describe a broad range of related issues. The CapX2050 Transmission Vision Report, which will be discussed in Section 2 along with other industry perspectives on system strength, defines system strength as the ability of the system to quickly and reliably respond to and mitigate disturbances.[1] System strength, as such, touches on a number of important technical concepts, including short circuit capability (or fault current), steady state voltage regulation, transient-period voltage control and response, generating unit stability and frequency response, and protection system operations. Historically, large synchronous generators have provided the foundation upon which the strength of the power system, including all of these technical concepts, has been built and maintained. The physical construction of these synchronous generators is such that they inherently resist rapid changes in the power system, responding automatically to maintain the status quo. The intrinsic benefit of this and a fundamental component of the power system as it has evolved over the last century is that many synchronous generators working together in concert make the power system relatively impervious to major deviations in voltage and frequency due to disturbances. In other words, they give strength to the power system. As the industry-wide transition to clean energy resources grows, the number of large synchronous (typically fossil-fueled) generators is dwindling. Some of these generators are being retired while others are transitioning away from baseload (round-the-clock) operations to peaking or seasonal dispatch. The replacement of these synchronous generators in the everyday operation of the power system with other forms of generation that have different characteristics and different locations is leading to concerns about a loss of the system strength-supporting characteristics historically supplied by the synchronous generators.

For Minnesota Power and Northern Minnesota in particular, several coal-fired baseload generators have historically provided system strength and voltage support in addition to local energy production. Most of these generators have been retired or transitioned to normally-offline operation in recent years, leaving Boswell Energy Center ("BEC") Units 3 and 4 as the only remaining large synchronous generators regularly online in all of Northern Minnesota. As the last remaining large synchronous generators, the BEC units' system strength and voltage-supporting characteristics help maintain consistent and predictable system operations and properly functioning utility protection systems for the transmission system and the lower-voltage distribution systems that depend on it. In addition, Minnesota Power's significant concentration of large industrial customers depend on the predictable voltages and fault currents historically and presently provided by the BEC units to support their large industrial processes and power quality needs. It is typical for large industrial plant design, like utility distribution system design, to take into account as a design basis the fault current contributions and normal operating voltages of the utility transmission system. Similarly, projects involving extra-high voltage transmission, large power transformers, flexible AC transmission system (FACTS) devices, or high voltage direct current (HVDC) transmission also typically take into account the fault current contributions and normal operating voltages of the transmission system as a basis for system performance studies and detailed design. Without the BEC units online, the Northern Minnesota transmission system would operate for extended periods of time without any local generators online providing fault current and voltage regulation. This mode of operation would be unprecedented in the modern history of the Northern Minnesota transmission system and, if not adequately assessed and mitigated, would lead to a great deal of uncertainty and potential unreliable operation in the transmission system and the lower-voltage industrial, municipal, and other utility distribution systems connected to it.

[1] CapX2050 Transmission Vision Report, Page 17

The purpose of this Report on System Strength & Voltage Support is to provide an overview of Minnesota Power's investigations and analyses pertaining to the system strength-related issues expected to arise if the BEC units were to transition to normally-offline operation for any extended period of time. The report will touch on five main areas of interest related to system strength:

- **Section 2: Industry Perspectives** provides a brief discussion of perspectives on system strength from neighboring transmission owners as well as regulatory bodies, technical working groups, and the international community. External references are provided in the section to enable the readers to evaluate these industry perspectives for themselves.
- **Section 3: Minnesota Power's Experience** provides discussion of several recent planning and operating experiences in Minnesota Power's transmission system stemming from the loss of strength and voltage support during and after the transition of Minnesota Power's fleet of small coal units to peaking, idled, and retired statuses.
- **Section 4: Short Circuit Impacts** provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential short circuit impacts from the BEC units being offline. The detailed study report from the consultant is included in Appendix A: Short Circuit Study Report.
- **Section 5: Motor Starting Impacts** provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential impacts from BEC units being offline on the starting of large synchronous motors by Minnesota Power's large industrial customers. The detailed study report, which contains power system information considered to be Critical Energy Infrastructure Information (CEII), is available upon request to individuals possessing a signed CEII non-disclosure agreement.
- **Section 6: Transient Stability Impacts** provides an overview of a consultant study Minnesota Power commissioned to develop a better understanding of the potential impacts from BEC units being offline on voltage response and other potential impacts in the transient period (immediately after a disturbance). The study also includes an investigation into the effectiveness of various synchronous condenser solutions for replacing voltage support and system strength formerly provided by the BEC units. The detailed study report, which contains power system information considered to be CEII, is available upon request to individuals possessing a signed CEII non-disclosure agreement.
- **Section 7: Conclusions** provides a summary of the findings, conclusions, and recommendations from the above-referenced investigations into system strength and voltage support impacts from the BEC units being offline.

Section 2: Industry Perspectives

Minnesota Power approaches concerns about system strength and voltage support primarily from the perspective of a local utility with an obligation to provide reliable service to its customers. There is a great deal of uncertainty involved in operating the transmission system with both Boswell Energy Center (BEC) units offline, and that uncertainty could potentially have direct impacts on Minnesota Power's customers, as discussed in Section 3 on Minnesota Power's Experiences. At the same time, Minnesota Power and its neighboring transmission owners in Minnesota, the Midcontinent Independent System Operator (MISO), the North American Electric Reliability Corporation (NERC), and others have been working to understand and address similar system strength and voltage support concerns for many years. This section will provide a very brief survey of selected industry perspectives on system strength and voltage support concerns related to the declining presence of traditional synchronous generation in utility power systems in North America and around the world.

CapX 2050 Transmission Vision Report

The CapX2050 Transmission Vision Report defines system strength as the ability of the system to quickly and reliably respond to and mitigate disturbances. A fundamental component of a strong system is fault current – the amount of current flowing from generators to a short circuit on the transmission system. The CapX2050 Report explains that transmission system protection and control systems require a minimum amount of fault current in order to reliably identify and respond to disturbances. In a weak system with fewer generators online to contribute fault current, protection and control system mis-operations become increasingly likely because differentiating between normal and abnormal system conditions becomes increasingly complex. Voltage regulation is another important indicator of system strength that is discussed in the CapX2050 Report. Voltage regulation refers to the control local generators provide for maintaining predictable system voltages at necessary levels in the surrounding area. One of the key findings in the report was "Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot. They provide physical attributes that help maintain a stable and reliable grid. As dispatchable resources are retired, it will be essential that new and existing generation and transmission technologies are deployed with the ability to provide grid support in the appropriate locations to ensure reliability is maintained." The CapX2050 Transmission Vision Report is publicly available on the Grid North Partners (formerly CapX2020) website[2].

Midcontinent Independent System Operator (MISO)

MISO recently completed an analysis of renewable energy growth to better understand impacts to the bulk electric system. The work was called the Renewable Integration Impact Assessment (RIIA) and included greater details over a wider geographic range than previous renewable integration studies. One of the five key RIIA findings was "Risk to system stability from changing type and location of generation resources." Specifically as inverter-based resources increased in penetration level there was a corresponding decrease in online conventional generation which intensified reliability issues in weak grid areas in the study. MISO noted a sharp increase in these issues starting at a level of 30% load served by renewables. However an area of low SCR (Short Circuit Ratio) or weak system strength appeared in the area of Boswell very early in the model evolution (10% renewable on a MISO wide basis) as shown below.

[2] CapX2050 Transmission Vision Study: https://gridnorthpartners.com/resources/

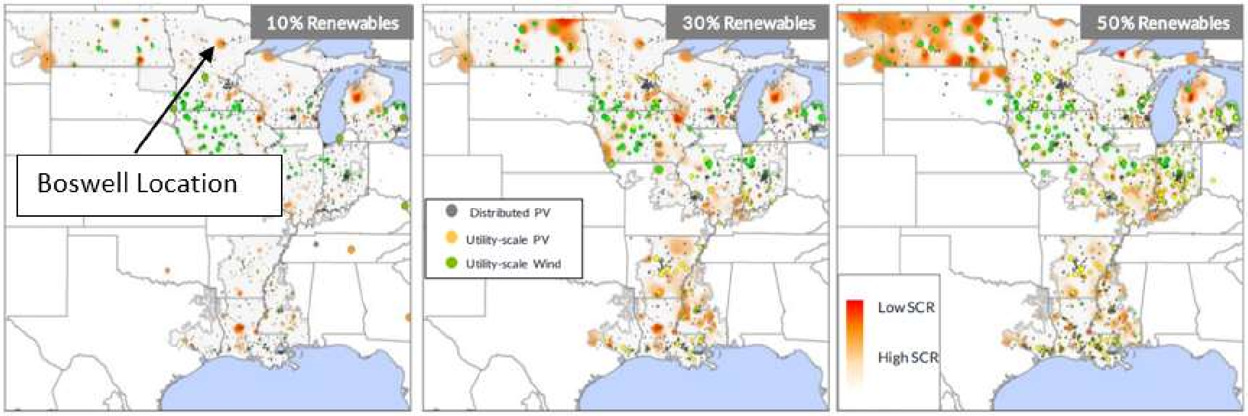

Figure 1: MISO RIIA study, areas of low SCR based on % renewable penetration

Besides low SCR, other areas of system stability that were reviewed in the assessment included post-contingent low voltages severe to the point of transient instability, frequency response, and rotor angle stability. Common to all of these issues is that they are more likely to be present in areas of the system that are weak. The mitigation options explored within RIIA included control tuning of local generation, synchronous condensers, STATCOM, and VSC-HVDC. MISO published an extensive summary on their findings in a report that is publicly available on the MISO website[3]. Specific to this topic is the section titled *Operating Reliability – Dynamic Stability* starting on page 109 of the report.

MISO also hosted a workshop on February 16th 2021 that explored new ideas, approaches and technologies to be used in developing solutions to grid performance issues. During the workshop a presentation was given on the historic role of synchronous machines as generators and how they might continue to play a significant role in the future grid. Specifically called out was the ability to act as voltage sources, regulate voltage by acting as a reactive power source or sink, provide inertia, and enhance short-circuit strength. A link to the meeting and materials can be found on the MISO website.[4]

North American Electric Reliability Corporation (NERC)

NERC's 2017 'Integrating Inverter-Based Resources into Low Short Circuit Strength Systems' guideline[5] explains the challenges of weak system conditions, particularly for new generator interconnections. Within that, grid strength is defined and calculations are given to quantify system strength. When connecting inverter-based resources to a weak system, common issues are supplied as well as recommendations for mitigation of those issues. As generation on the transmission system transitions away from synchronous machines to more inverter-based resources, proper modeling, coordination, and studies will be needed to ensure reliable operation. NERC also published a whitepaper on Essential Reliability Services in 2016[6] and the Midwest Reliability Organization maintains several educational resources related to Essential Reliability Services on its website[7].

[3] MISO RIIA Report: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf
[4] MISO New Approaches and Technologies Workshop: https://www.misoenergy.org/past-events/2021/new-ideas-approaches-and-technologies-to-be-considered-in-planning-for-a-renewable-heavy-market---february-16-2021/
[5] NERC: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf
[6] NERC: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf
[7] MRO: https://www.mro.net/clarity/the-changing-resource-mix/essential-reliability-services/Pages/default.aspx

International Council on Large Electric Systems (CIGRE)

The 'System Strength' CIGRE whitepaper[8] provides an overview of what system strength is, the factors influencing it, the issues encountered due to low system strength and appropriate ways to solve those issues. In contrast to a strong system, a weak system is more prone to disturbances due to low fault short circuit levels, resulting in higher voltage and angle sensitivities to power flow changes. As synchronous machines are retired and displaced by Inverter Based Resources, the system inertia is weakened. Low system inertia leads to an increase in the Rate of Change of Frequency which in turn makes the system more susceptible to faults resulting in further voltage depression. The CIGRE paper references examples of low system strength issues from around the world (Australia, USA & Europe) and its impact on "power system stability, power quality and protection coordination" and presents various solutions and tools that can be used to address those impacts such that the "power system can be planned and operated securely and reliably".

ERCOT and Inertia Monitoring

ERCOT's 'Inertia: Basic Concepts and Impacts on the ERCOT Grid' whitepaper[9] discusses the impacts of low inertia on the ERCOT (Texas) power system based on historical analysis and dynamic simulations and presents a methodology to calculate Critical Inertia - "minimum inertia required to reliably operate their system using existing frequency control mechanisms." ERCOT describes System Inertia as the ability of the power system to withstand sudden frequency changes. Inertia response following a generation trip or a step load change is determined by the Rate of Change of Frequency (RoCoF). Low inertia results in a faster decline in system frequency and a higher RoCoF which in turn could result in involuntary tripping of Under Frequency Load Shedding (UFLS) schemes. ERCOT forecasts an "inevitable decline in synchronous inertia, especially during low load conditions" due to replacement of synchronous generation with Inverter Based Resources in their generation mix. In addition to monitoring inertia in Real-time and forecasting it hourly to maintain adequate inertia and frequency reserves, ERCOT "continues to work with its stakeholders to develop reliable, efficient and where possible, market-based solutions to address low inertia issues."[10]

Other Entities

Various entities or organizations have published case studies or documented how system changes resulting in a weaker system have resulted in the need change how reliability criteria is defined, measured, and maintained.

Australia

In 2017 the Australian Energy Market Operator (AEMO) was required by its Commission to establish a framework for the management of system strength.[11] Historically the main concern has been fault levels being too high but falling system strength is now the emerging issue. Significant resources and methodologies have been developed to monitor and manage these issues in AEMO.[12]

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[8] Page 5, CIGRE Science & Engineering Volume No. 20, February 2021. System Strength | ELECTRA (cigre.org)

[9] Inertia: Basic Concepts and Impacts on the ERCOT Grid https://www.ercot.com/files/docs/2018/04/04/Inertia_Basic_Concepts_Impacts_On_ERCOT_v0.pdf

[10] ESIG presentation - https://www.esig.energy/event/webinar-inertia-monitoring

[11] https://www.aemc.gov.au/sites/default/files/content/4645acea-e66f-4b5b-94a1-1dd14e7f8a93/ERC0211-Final-determination.pdf

[12] System strength in the NEM explained, March 2020. Available at: https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf

Great Britain

Great Britain has the fastest decarbonizing electric system in the world with the stated goal of operating using 100% zero carbon electricity by 2025. National Grid ESO as the System Operator published an Operating Strategy Report[13] in December 2021 which identifies five key areas as challenges to this goal. Three of those are directly related to weak system issues, and are Frequency, Stability, and Voltage. An entire page of their website is also focused on operability due to changes of the electric system.[14]

Electric Power Research Institute (EPRI)

EPRI has recognized that with a shift to significant levels of variable generation technology that are remote from load centers and have significantly different dynamic behavior from synchronous generation, new transmission planning criteria and methods may be required to meet reliability requirements. Areas of research that EPRI is planning in 20222 as they relate to this report include focus on dynamic models for existing systems as well as emerging technologies, methods to consideration system protection in forward looking assessments, automation to screen analysis to focus on most critical reliability issues and others.[15]

Southwest Power Pool (SPP)

SPP has been studying operational and reliability impacts from increasing levels of wind integration since 2009 when they published their first study in the topic. In their most recent phase of this analysis, called the Inverter Based Generation Integration Study (IBIS) [16] they assessed transient stability, SCR analysis, system damping, voltage response, and other aspects. Within the SCR analysis SPP reviewed three different methodologies for calculating the ratios. Comparisons between the methods are explained in detail. Locations for potential instability were determined, which will serve as a starting point for more detailed transient analysis using PSCAD. The report summarized other major findings and included eight recommendations for future implementation or consideration with a focus on grid strength.

[13] National Grid, Key areas: https://www.nationalgrideso.com/document/227081/download
[14] National Grid, Operability page: https://www.nationalgrideso.com/research-publications/system-operability-framework-sof
[15] EPRI, Transmission Planning Program Overview: https://www.epri.com/research/programs/027570/overview

[16] SPP IBIS Report: https://www.spp.org/documents/64834/20190828%20-%20spp%202019%20inverter%20based%20generation%20integration%20study.pdf

Section 3: Minnesota Power's Experience

This section provides an overview of Minnesota Power's real-world experiences from implementation of previous small coal unit fleet transition decisions at Laskin Energy Center, Taconite Harbor Energy Center, and Boswell Energy Center Units 1 and 2. The understanding gained from the experience of implementing small coal unit closures has been foundational to developing an informed understanding and expectations for the broader system impacts from similar consideration of Boswell Energy Center (BEC) Units 3 and 4. While BEC Units 3 and 4 and their area of impact are much larger than the small coal units discussed in this section, many of the same general concepts may be applied – albeit on a much larger scale – to understand and anticipate impacts from operating with BEC Units 3 and 4 offline.

The North Shore Loop: Laskin and Taconite Harbor

The North Shore Loop is a 140-mile system of 115 kV and 138 kV lines that extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to serve customers in an area extending from Duluth to the Canadian border to the eastern end of the Mesabi Iron Range, including east Duluth, Two Harbors, Silver Bay, Grand Marais, Hoyt Lakes, and the surrounding areas. The North Shore Loop transmission system is shown in Figure .

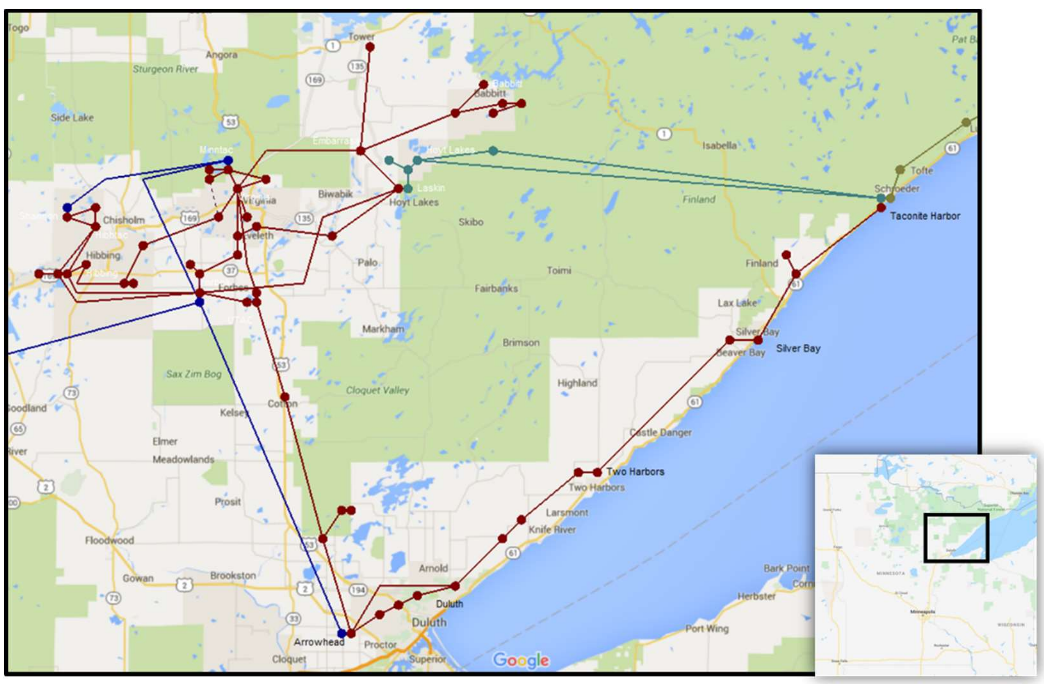

Figure 2: North Shore Loop Transmission System

Historically, the North Shore Loop contained an abundance of coal-fired baseload generation, and the transmission system was designed from the mid-1900s onward to rely on the power and system support provided by the local baseload generators to serve customers. North Shore Loop coal-fired generators included Minnesota Power's Laskin Energy Center and Taconite Harbor Energy Center, as well as a large industrial cogeneration facility located in Silver Bay. The Silver Bay generators are owned by Silver Bay Power Company, a subsidiary of Cliffs Natural Resources Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to peaking natural gas capacity units. Also in 2015, Minnesota Power retired one of the units at the Taconite Harbor Energy Center. In 2016, Minnesota Power idled the other two Taconite Harbor Energy Center units. Coal-fired operations at Taconite Harbor ceased by 2020 with full retirement scheduled for September 2021. In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, in September 2019 Silver Bay Power Company idled both of the Silver Bay units. The cumulative impact of these operational changes has effectively decarbonized the North Shore Loop, leaving no baseload generators normally online.

The local baseload generators at Laskin Energy Center, Taconite Harbor Energy Center, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing voltage support, power delivery capability, and redundancy, among other things. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016 and several more projects are planned between 2020 and 2025. Below is a summary of the transmission impacts related to system strength and voltage support that were identified as a result of moving beyond baseload generation in the North Shore Loop and the projects Minnesota Power has implemented or is planning to implement to address these impacts.

Voltage Support: The North Shore STATCOM & Mechanically Switched Capacitors

Baseload generators provide reactive power and voltage support to the local transmission system. Electric power generated in an alternating current power system includes the generation of both real power, measured in megawatts, as well as reactive power, measured in mega voltage amperes reactive (“MVAR”). Reactive power is required to maintain an appropriate system voltage, stabilize the system, and enable the delivery of real power. Generators provide a dynamic source of reactive power, able to ramp MVAR output up and down within the limits of the generator to regulate system voltage. This dynamic reactive support contributes to overall system strength and becomes particularly important for system reliability, as abrupt changes in the power system can result in rapid voltage collapse if there is not a fast-responding source of reactive power. Unlike real power, which can be transmitted over long distances with relatively minimal losses, reactive power tends to be consumed locally by loads and by the transmission system itself as transmission lines load up above their optimal power delivery capability. As more power is transferred on the transmission system, the reactive power needed to maintain appropriate system voltage increases. Without the local baseload generators in the North Shore Loop, the main sources of reactive power and voltage support have been lost. The resulting voltage support-related issues include increased difficulty regulating transmission system voltage, post-contingent high or low voltage conditions, and increased risk of voltage collapse.

To illustrate the voltage regulation impacts, Figure below shows the Taconite Harbor 138 kV bus voltage for the second half of 2016. As noted on the figure, Taconite Harbor Unit 1 and Unit 2 were idled in October 2016. The impact of the transition of these generators on transmission system voltage regulation is noticeable. Without the local voltage regulation provided by the Taconite Harbor units, the transmission system voltage becomes less predictable – varying more rapidly and over a broader range than it did when the Taconite Harbor units were online and regulating the voltage. Without the voltage support and system strength from the generators, which acted like shock absorbers any time there was a significant change on the system, the transmission system voltage is also impacted more significantly by minute-to-minute and day-to-day changes, such as large motor starting or other changes in load, switching of fixed reactive support devices like capacitor banks, and events outside of the North Shore Loop transmission system.

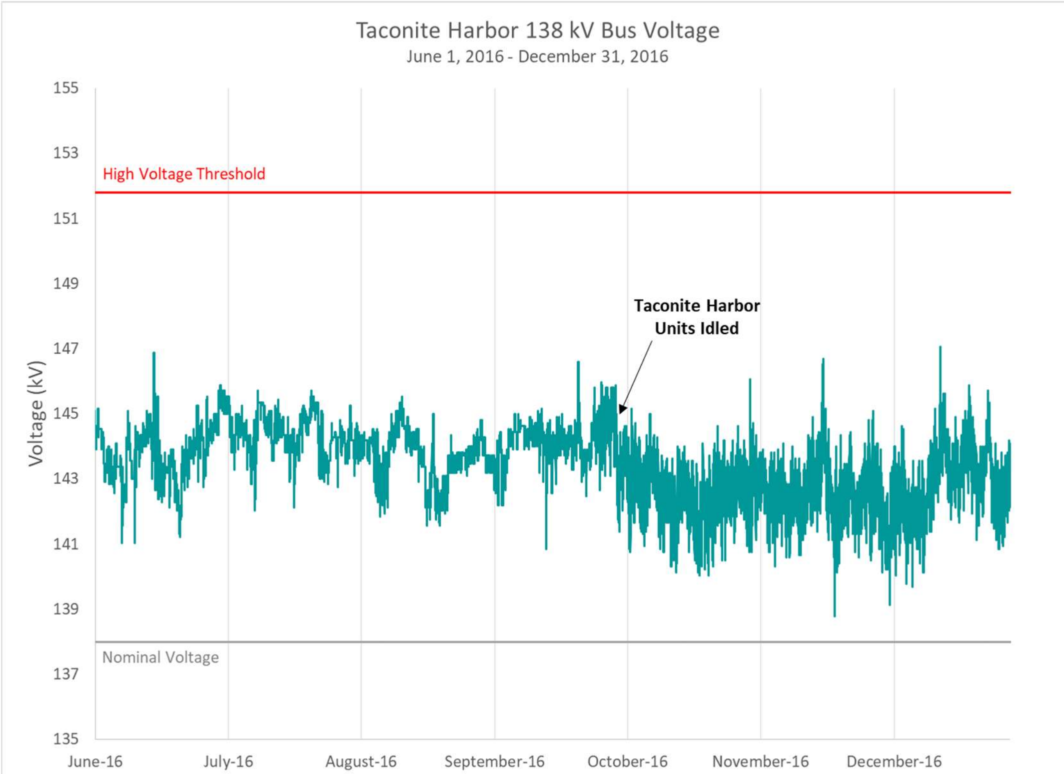

Figure 3: Taconite Harbor 138 kV Bus Voltage, June – December 2016

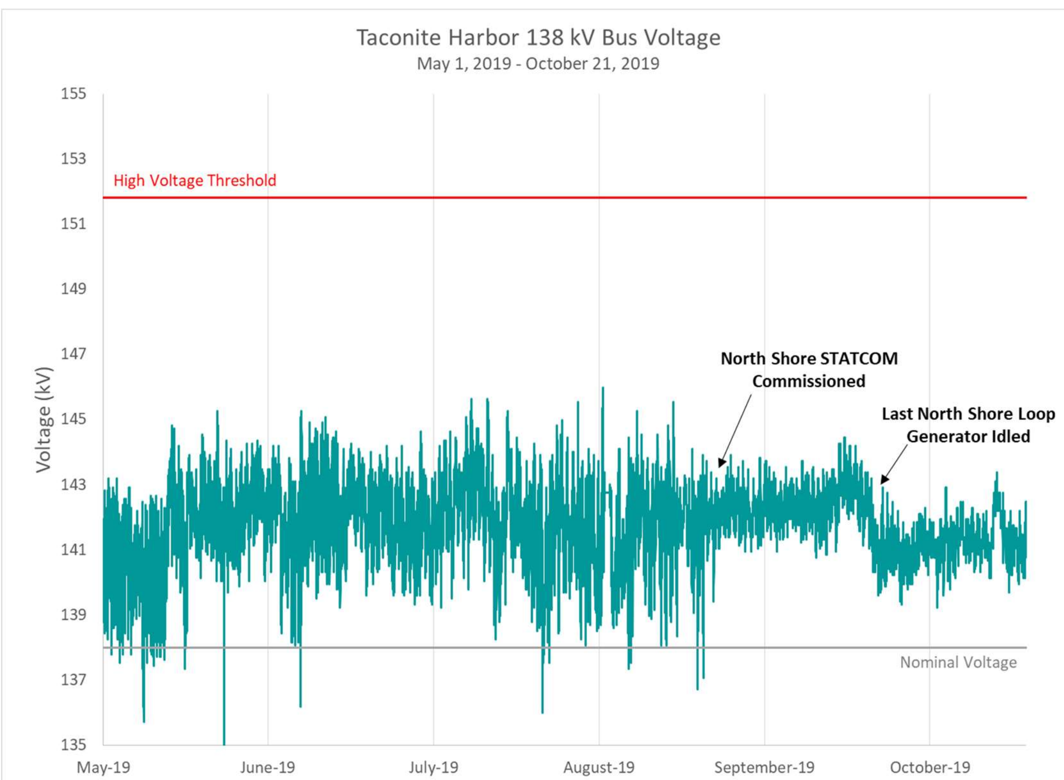

Figure 4: Taconite Harbor 138 kV Bus Voltage, May – October 2019

The North Shore Static Synchronous Compensator ("STATCOM") Project was designed to replace dynamic voltage support, including voltage regulation capability, for the North Shore Loop following the conversion, idling or retirement of all local baseload generators. Figure 4 shows the voltage at the same Taconite Harbor bus in the middle of 2019. As noted on the figure, the North Shore STATCOM was energized and commissioned in late August 2019. Though it is located 30 miles away from Taconite Harbor, the impact of the voltage regulating capability provided by the North Shore STATCOM is obvious. Even after the retirement of the last North Shore Loop generator – resulting in a step change in power flow through Taconite Harbor on the transmission system – the North Shore STATCOM is capable of supporting and regulating a robust and predictable bus voltage at Taconite Harbor.

The restorative impact of the North Shore STATCOM on North Shore Loop voltage regulation is most obvious in, Figure 5 which shows the changing operation of the 115 kV bus voltage at the Silver Bay Substation from widely varying and unpredictable to tightly regulated and predictable following implementation of the STATCOM less than a mile away at the North Shore Switching Station.

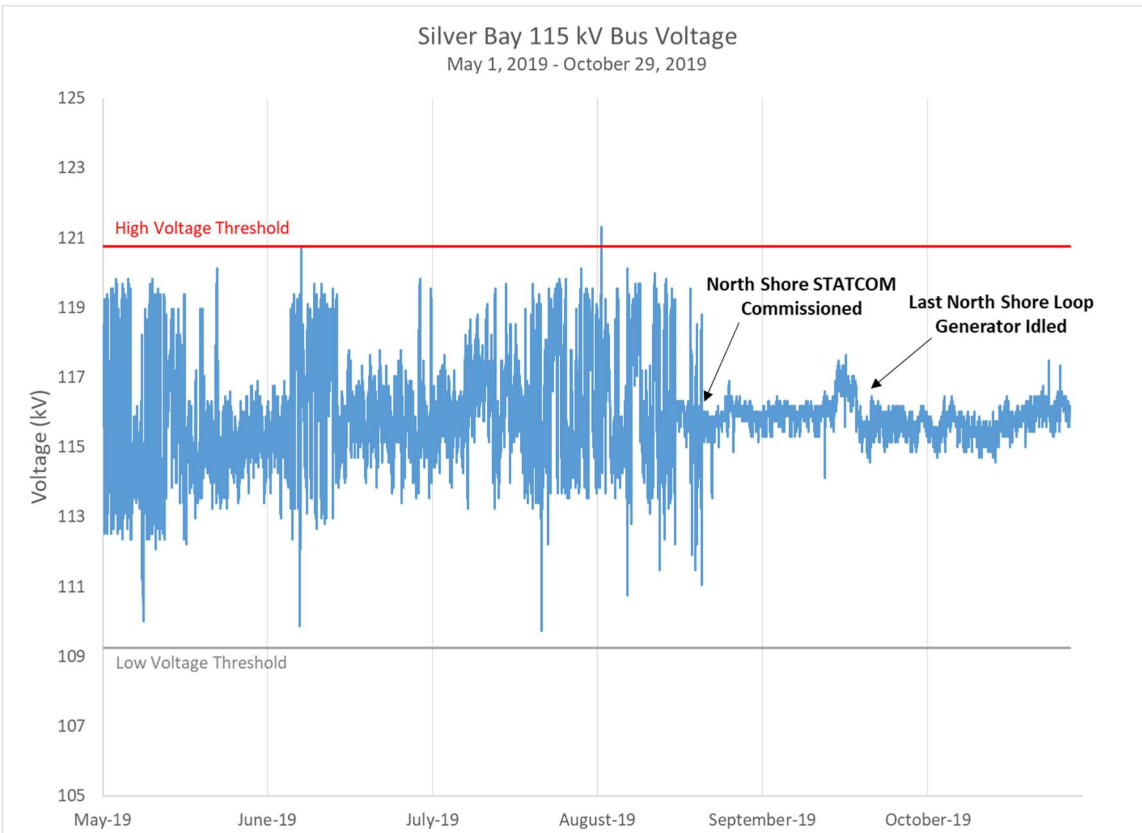

Figure 5: North Shore 115 kV Bus Voltage, May – October 2019

Without the more finely-tuned voltage regulation capability of the North Shore Loop generators or the STATCOM, the only voltage support resources available in the North Shore were mechanically switched capacitor banks ("MSCs"). Existing MSCs at the Colbyville and Big Rock Substations, as well as new MSCs at the North Shore Switching Station, are only capable of switching in large fixed chunks of reactive support. In a weak system with low short circuit levels, such as the North Shore Loop has become without the local baseload generators online, it becomes difficult to switch large fixed amounts of reactive support due to the increased sensitivity of the system. For example, where low voltage may necessitate additional reactive support, switching in a capacitor bank of a fixed size into a weak system may prove to increase the voltage too far in some circumstances – resulting in high voltage – and not enough in other circumstances. Besides offering finely-tuned voltage regulating capability from its own reactive power range (+/- 75 MVAR), the North Shore STATCOM was designed to control four existing North Shore Switching Station MSCs in order to extend the capacitive end of its reactive capability by another 100 MVAR for voltage regulation and dynamic voltage support. Thus the North Shore STATCOM Project restored 175 MVAR of dynamic support and voltage regulating capability to the North Shore Loop, which represents slightly more than a one-for-one replacement of the total nameplate reactive support capability of the idled/retired Taconite Harbor and Silver Bay generators (166 MVAR).

The primary driver for the North Shore STATCOM, however, was not voltage regulation but voltage stability. Without the fast-responding voltage support of the generators, power flow studies determined that the transmission system was not strong enough to support all existing North Shore Loop load under certain contingency conditions. Without replacing the support previously provided by the generators, there would be a risk of voltage collapse anytime the 140-mile transmission path between Colbyville and Laskin was severed. Voltage stability is another system strength-related concept that simply refers to the ability of the system to recover from an event and rapidly restore voltage to within the acceptable range. A voltage collapse is what occurs when the voltage in some part of the system cannot recover following an event – resulting in extremely low voltages and possibly localized blackouts. Figure below shows a comparison of the same transmission system contingency with and without the North Shore STATCOM. Without dynamic reactive support from the STATCOM or the retired baseload generators, the contingency leads to voltage collapse on the North Shore Loop. With the STATCOM implemented to mitigate the loss of system strength and voltage support previously provided by baseload generators the transmission system voltage following the same event rapidly recovers to within the acceptable range.

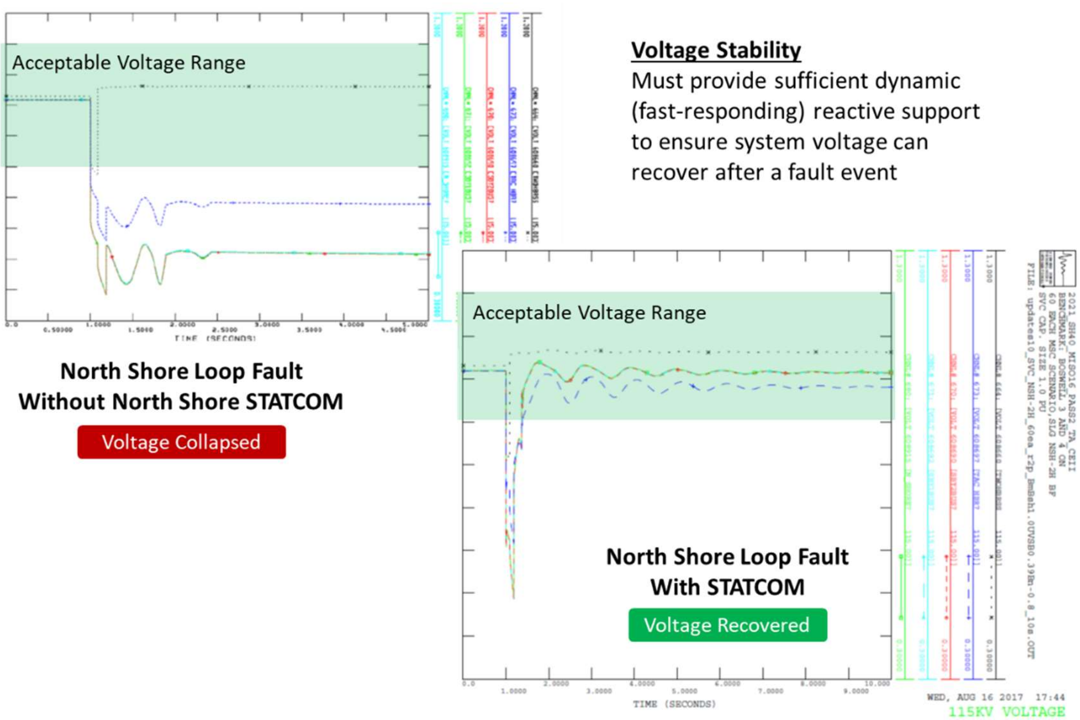

Figure 6: North Shore Loop Voltage Stability Comparison

In addition to the system strength and voltage support issues that drove the need for the North Shore STATCOM, Minnesota Power's North Shore Loop studies identified several localized low voltage violations throughout the North Shore Loop and the surrounding area following transition away from the local baseload generators. Some of these low voltage violations were in the North Shore Loop and related to the voltage regulation and voltage collapse concerns discussed above. Those violations were mitigated by the addition of the STATCOM and associated mechanically switched capacitors (MSCs) at the North Shore Switching Station. Other voltage violations were identified in an area of the system adjacent to the North Shore Loop that is far away from the remote sources of power and voltage support that replace the local baseload generators and along heavily-loaded transmission paths between those remote sources and the loads in the North Shore Loop and on the eastern end of the Iron Range. To resolve these issues, Minnesota Power added MSCs at three additional locations:

- **Babbitt Substation** (12 MVAR): On a radial (single source) transmission system approximately 40 miles from the nearest 230/115 kV source;
- **ETCO Substation** (20 MVAR): At a substation near a large industrial site along a heavily loaded 115 kV outlet 6 miles from the Forbes 230/115 kV source; and
- **Mesaba Junction Switching Station** (2x28 MVAR): 5.5 miles away from the Laskin Substation at the beginning of a 60-mile transmission path into the North Shore Loop that can become heavily loaded under certain contingency conditions.

Planned and completed reactive resource additions in the North Shore Loop that were necessary to replace system strength and voltage support following conversion, idling, or retirement of local baseload generation resources are shown in Figure below. These transmission projects involved both dynamic voltage support, capable of rapid response times and finely-tuned voltage regulation, as well as mechanically switched capacitor banks to provide fixed amounts of voltage support at particular locations of concern. As noted on the figure, the cumulative reactive resource additions in and adjacent to the North Shore Loop are slightly more than a one-for-one replacement of the reactive support that was removed with the generators.

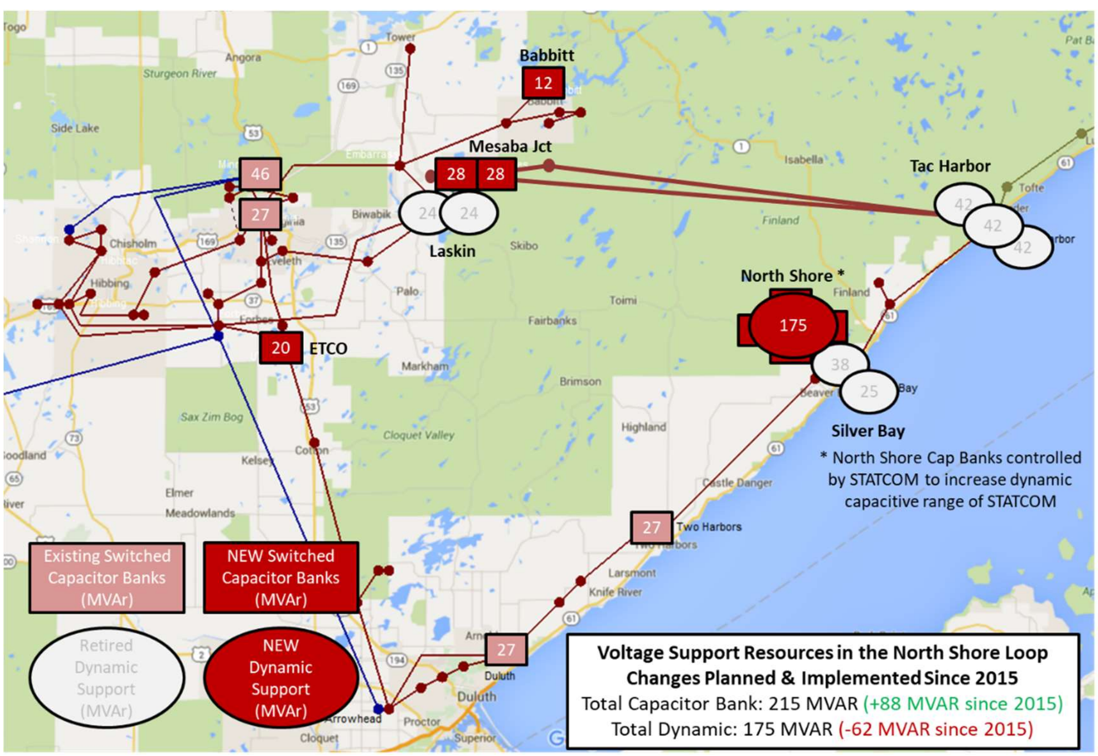

Figure 7: Voltage Support Resources in the North Shore Loop

Voltage Stability: Duluth Loop Reliability Project

The Duluth Loop, illustrated electrically in Figure Figure 8: , is a network of 115 kV transmission lines and substations, which form two parallel connections between the regional 230/115 kV transmissions source at the Arrowhead Substation and the North Shore Loop connection at the Colbyville Substation. The transmission system in the Duluth area has historically been supported by coal-fired baseload generators in the North Shore Loop. As Minnesota Power and its customers have transitioned away from reliance on coal to increasingly lower-carbon sources of energy, the idling of the generators on the North Shore has led to an increased reliance on the transmission system to deliver replacement power and system support to the Duluth area and along the North Shore. In order to maintain a continuous supply of safe and reliable electricity while replacing the support once provided by these local coal-fired generators, the Duluth area transmission system must be upgraded.

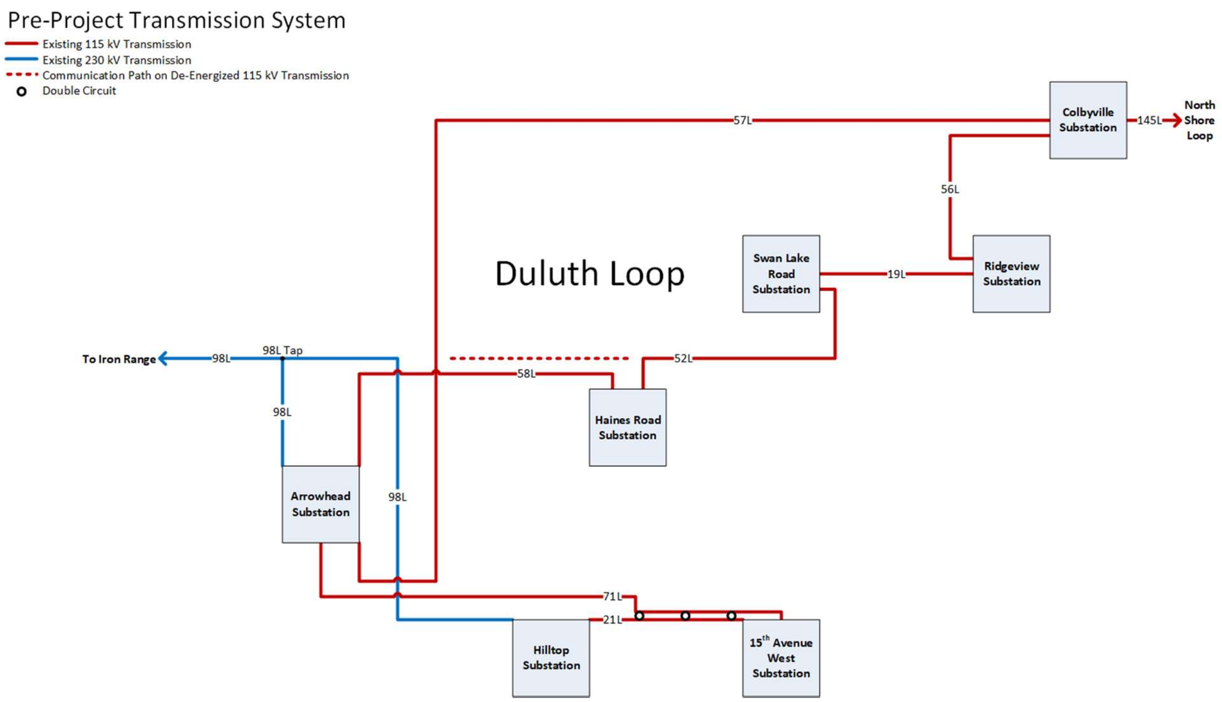

Figure 8: Relevant Duluth Area Transmission System

The Duluth Loop Reliability Project includes the construction of about 14 miles of new 115 kV transmission line between the Ridgeview, Haines Road, and Hilltop Substations and the construction of an approximately one-mile extension connecting an existing 230 kV transmission line to the Arrowhead Substation. The project is illustrated electrically in Figure and addresses severe voltage stability concerns which exist without coal-fired baseload generators located along Minnesota's North Shore.

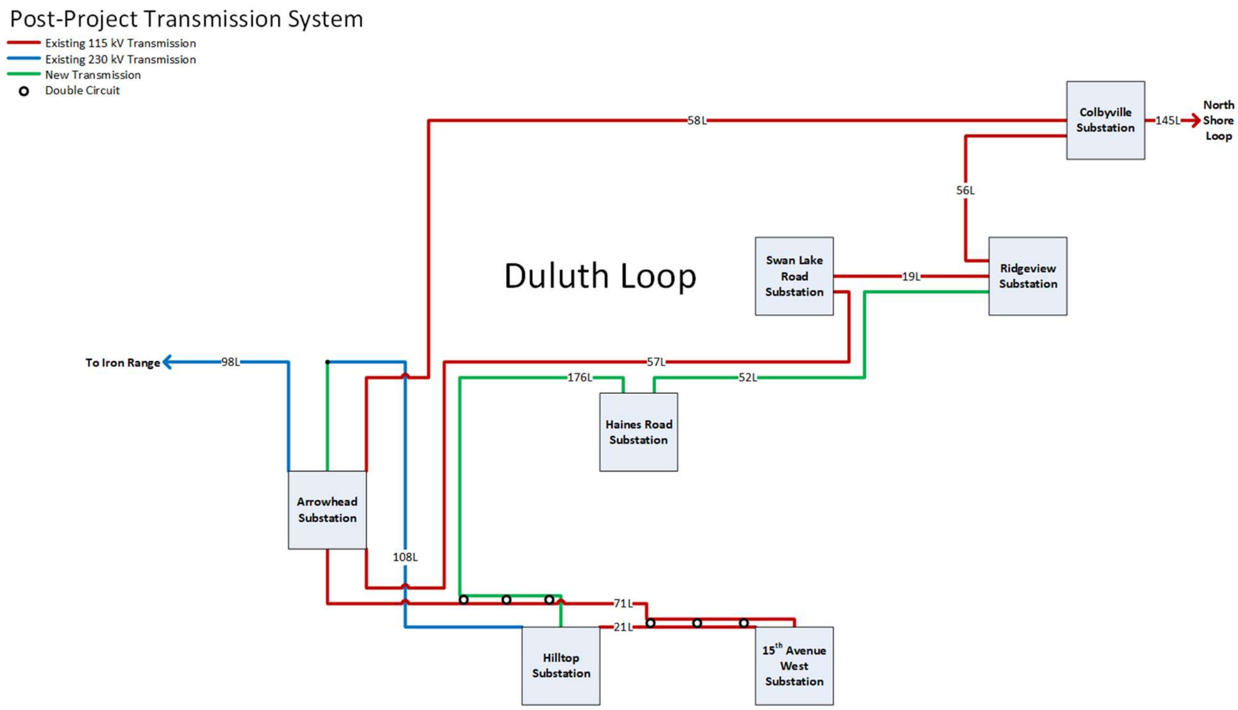

Figure 9: Post-Project Duluth Area Transmission System

For most transmission outages in the Duluth Loop, the loss of a second Duluth Loop transmission line during the outage would leave the North Shore and all or part of the Duluth Loop served by a single 140-mile-long transmission line originating in the Hoyt Lakes area. Without the generation support previously provided by the local baseload generators on the North Shore, the transmission system is no longer able to support the large amount of Duluth Loop load over such a long distance. The expected result would be a post-contingency voltage collapse in the Duluth Loop area that would then extend up the North Shore toward Silver Bay. A voltage collapse is what occurs when the voltage in some part of the system cannot recover following a contingency event, resulting in loss of system voltage control and extremely low voltages which can lead to damages to end-user electrical equipment and possibly localized blackouts.

Figure 2 illustrates the four primary Duluth Loop voltage collapse scenarios of concern. These scenarios all involve an outage of Arrowhead – Colbyville 115 kV (57 Line) along with an outage of one of the following other transmission lines:

- Arrowhead – Haines Road 115 kV (58 Line)
- Haines Road – Swan Lake Road 115 kV (52 Line)
- Swan Lake Road – Ridgeview 115 kV (19 Line)
- Ridgeview – Colbyville 115 kV (56 Line)

Figure 2: Duluth Loop Voltage Collapse Scenarios

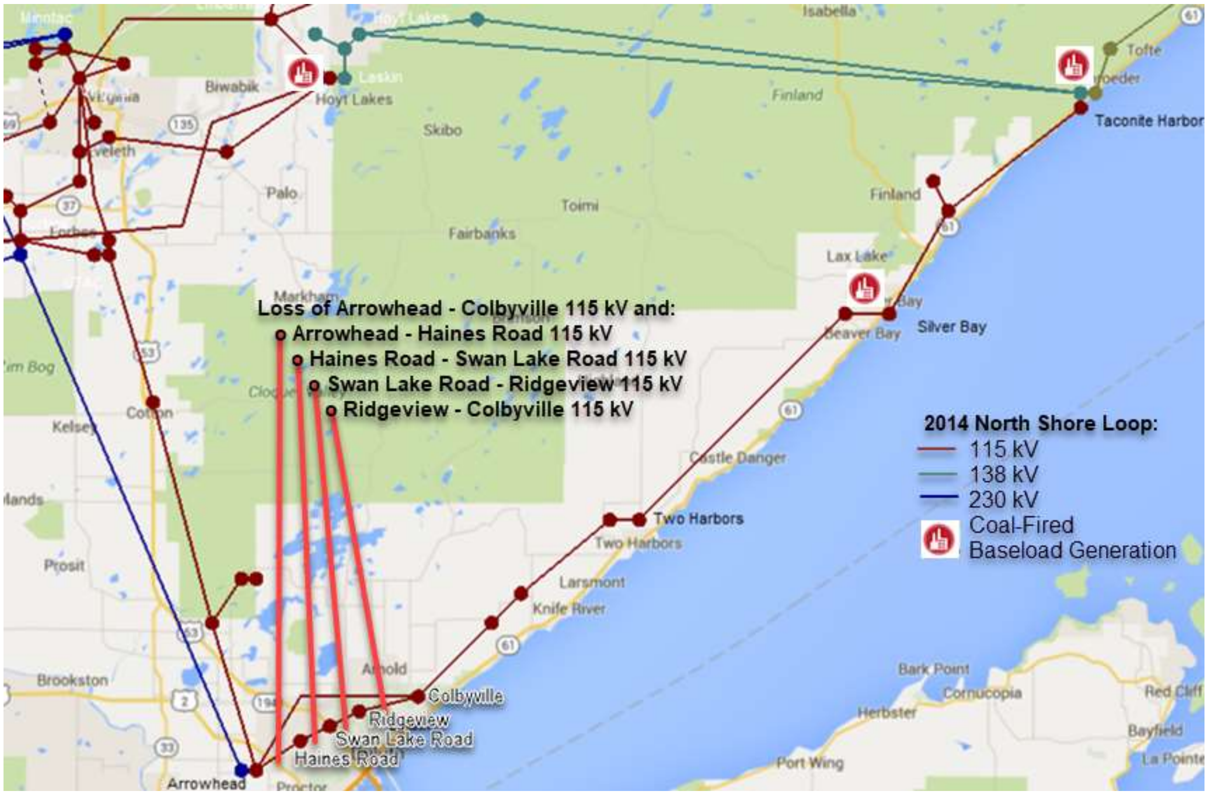

Figure 10: Duluth Loop Voltage Collapse Scenarios

In order to understand the Duluth Loop voltage collapse issue and begin to develop a long-term solution for it, the maximum Duluth Loop load level was identified which could be served radially from Silver Bay without causing a voltage collapse. This condition is called the "stability limit" – the last point at which the system is stable. This load level was found by scaling load at substations between the Silver Bay Hillside and Haines Road substations in a power flow model. Consistent with typical transmission planning practices for voltage stability issues, the practical voltage stability threshold (or operating limit) was defined to be 90% of the stability limit in order to preserve some margin between the operating limit and the point of voltage collapse.

As generation in the North Shore Loop was retired, idled, or transitioned to peaking operation, the Duluth Loop voltage stability threshold was steadily reduced, effectively reducing reliable load-serving capability for the Duluth Loop. This is clearly shown when comparing the calculated Duluth Loop voltage stability threshold over time, as shown in **Error! Reference source not found.**.

Year	North Shore Loop Generators Online (Output)	Voltage Stability Threshold
2014	All North Shore Loop Generators Online (459 MW)	108 MW
2020	Only Laskin Energy Center Online (118 MW)	65.7 MW
2020	No North Shore Loop Generators Online (0 MW)	54.0 MW

Table 1: Duluth Loop Voltage Stability Thresholds

In order to better understand the significance and risk associated with the identified voltage stability issue, historical data for the Duluth Loop and along the North Shore was evaluated using these defined stability thresholds. Figure 3 below is an example of this analysis that illustrates the severity of the Duluth Loop voltage stability issues relative to historical load levels in the area. The plot shows the historical loading on the transmission system between the Haines Road Substation and the North Shore Switching Station. Silver Bay Hillside is the first substation towards the City of Duluth from the North Shore Switching Station. Historical data for 2019, depicted by the black dots in the plot, represents a typical year for the area with heavy winter peak loading, moderate to high summer peak loading, and lighter loading in the shoulder months. The plot also shows the voltage stability thresholds from **Error! Reference source not found.** along with the hours, days, and consecutive days which loading was below the threshold. The **green** line indicates the stability threshold with all historical North Shore Loop generation online. The **orange** line indicates the stability threshold with only Laskin generation online. The **red** line indicates the stability threshold with no North Shore Loop generation online, which is the normal condition in today's system. For time periods where loading remains below the voltage stability thresholds, a maintenance outage would be acceptable on the Arrowhead – Colbyville 115 kV line or the Arrowhead – Haines Road 115 kV line without incurring the risk of a voltage collapse for loss of a second Duluth Loop 115 kV line.

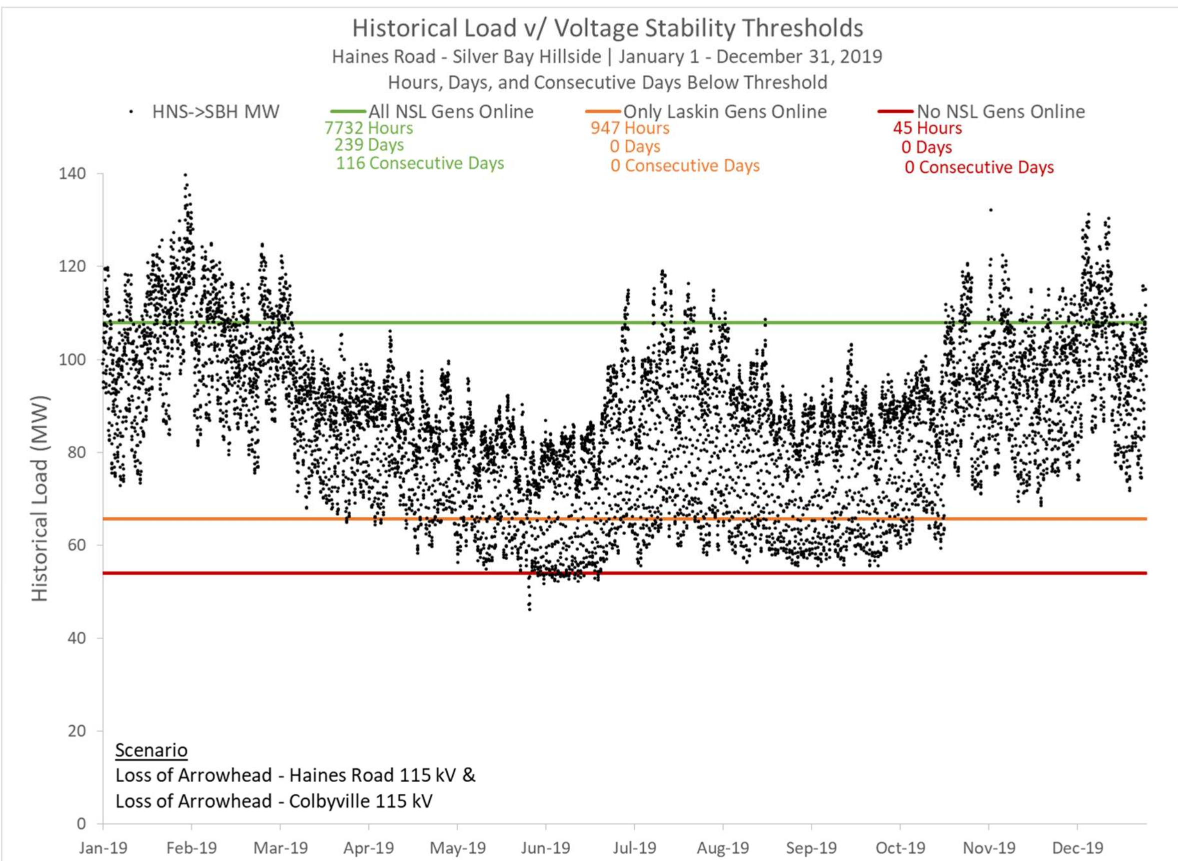

Figure 3: Historical Load v/ Voltage Stability Thresholds (Haines – Silver Bay)

With all North Shore Loop generation online as indicated by the green line, there were significant opportunities for maintenance outside the summer and winter peak seasons, with up to 116 consecutive days at one point throughout the year for maintenance work to occur on these lines.

With only Laskin generation online as indicated by the orange line, there are no days throughout the year during which loading is within the voltage stability threshold for the entire day. This means there are very limited opportunities for maintenance work to occur without putting Duluth and the North Shore at additional reliability risk.

With no North Shore Loop generation online as indicated by the red line, there also are no days throughout the year and only 45 hours total when loading is within the voltage stability threshold. This means that any planned maintenance in the Duluth Loop will result in putting a considerable amount of load at risk of outage with no other available mitigation. With the transition away from local baseload generation in the North Shore Loop, outages along either the Arrowhead – Colbyville 115 kV Line or the Arrowhead – Haines Road 115 kV Line have become significant reliability issues which must be resolved.

Analysis of 2019 historical data for the Duluth Loop illustrates how the idling of North Shore Loop generation and associated loss of the support they historically provided to the transmission system has impacted Minnesota Power's ability to perform maintenance on transmission lines and substation components that require a transmission outage on any of the Duluth Loop 115 kV lines.

The Duluth Loop Project will resolve these voltage stability concerns by constructing a new 115 kV transmission line between the Hilltop and Ridgeview substations. This new 115 kV transmission line will establish a third parallel transmission path in the Duluth Loop, replacing the redundancy once provided by the local baseload generators and providing sufficient load-serving capability and flexibility to operate and maintain the system without putting customers at risk when transmission facilities are out of service.

The Grand Rapids Area: Boswell Units 1 & 2

The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230/115 kV sources at the Blackberry and Riverton substations. While four coal-fired generators were historically located at the Boswell Energy Center (BEC), only BEC Units 1 and 2 were interconnected directly to the Grand Rapids area 115 kV system. BEC Units 3 and 4 interconnect directly to the 230 kV system and, prior to the Boswell Transformer Project discussed below, the nearest 230/115 kV transformer that tied back to the Grand Rapids area 115 kV system was located at the Blackberry Substation. There was no local electrical connection between the 230 kV and 115 kV systems in the Grand Rapids area, in part because the 115 kV system was supported by the operation of BEC Units 1 and 2. The transmission system in the Grand Rapids area is shown in Figure 4 below, including the local generators and one transmission upgrade related to the retirement of BEC Units 1 and 2.

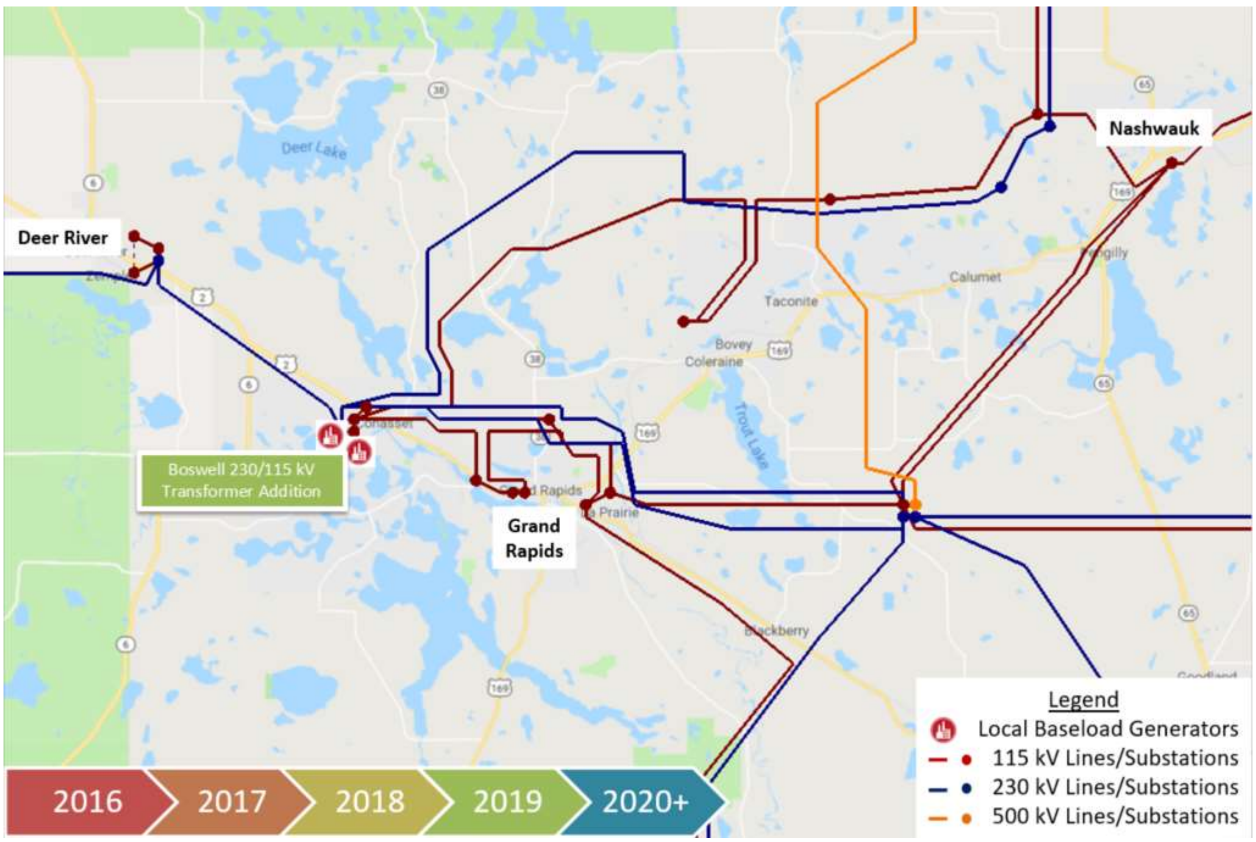

Figure 4: Grand Rapids Area Transmission System

Similar to the North Shore Loop units, the presence of BEC Units 1 and 2 on the local 115 kV system contributed to the reliability of the Grand Rapids area transmission system for several decades by providing redundancy, voltage support, and local power delivery capability, among other things. Without the support provided by BEC Units 1 and 2, contingencies impacting one or more transmission facilities in the Grand Rapids area may lead to transmission line overloads, post-contingent high or low voltage conditions, increased risk of voltage collapse, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area. In order to mitigate these concerns, Minnesota Power identified that a 230/115 kV source needed to be established in the Grand Rapids area by expanding the

Boswell 230 kV Substation and connecting it to the existing 115 kV system ("Boswell Transformer Project").

Transmission System Impacts

The Boswell Transformer Project was needed to ensure the system could continue to be operated at the same or better level of reliability after the retirement of BEC Units 1 and 2. Therefore, Minnesota Power planned the development and construction of the Boswell Transformer Project to be completed in late 2018 prior to the retirement of BEC Units 1 and 2. However, a manufacturing issue caused a significant delay in the completion of the project to the point where it was not possible to put the new transformer in service by the end of 2018. As a result, there was an approximately eight-month period of time in 2019 when BEC Units 1 and 2 were retired, but the Boswell Transformer Project had not yet been placed in service.

When the manufacturing delay was identified, Minnesota Power evaluated the reliability impacts and risks of the delay. It was expected that no negative reliability impacts would be experienced as long as the 115 kV transmission paths and a local capacitor bank were available. As a result, planned outages of these facilities were restricted until the Boswell transformer could be placed in service. Even with this planning in place, two experiences during this period of time illustrate the reliability risks and uncertainties inherent with operating the system in an entirely new paradigm without BEC Units 1 and 2 and prior to implementing the necessary transmission reliability solution:

- During the polar vortex in late January 2019, a circuit breaker on one of the 115 kV transmission paths into the Grand Rapids area was locked out due to severe cold temperatures. This caused a forced outage of one of the transmission sources to the Grand Rapids area. During this forced outage, MISO's real-time contingency analysis tool identified that a subsequent outage on a second 115 kV path into the Grand Rapids area would lead to low voltage. While the next contingency never happened, Minnesota Power's system operators found that there were limited options in the local area for mitigating the low voltage without the system strength and voltage support formerly provided to the area by BEC Units 1 and 2. This is precisely the condition that the Boswell Transformer Project was intended to mitigate by providing an additional source to the Grand Rapids area.
- Toward the end of June and into early July 2019, a large power customer in the Grand Rapids area notified Minnesota Power that system events had caused a machine on the plant distribution system to trip offline on three occasions. The timing of the machine tripping was correlated with faults elsewhere in the Grand Rapids area on an entirely separate distribution system, where the only connection between the two is the 115 kV transmission system. After each of the first two events Minnesota Power adjusted the settings of a digital fault recorder in the area so that even a modest instantaneous voltage drop would record future fault events. Finally, the third event was successfully captured in a detailed record and analyzed. The voltage levels recorded did not violate operating or planning criteria voltage levels. Using details of the recorded fault, studies were then performed that demonstrated lower voltages would be experienced in the area during a fault with BEC Units 1 and 2 offline than experienced with them online. The study also confirmed that the planned 230/115 kV transformer mitigated and actually lessened the voltage impacts when compared to BEC Units 1 and 2 online. In all measured and studied conditions, fault recovery was within Minnesota Power's planning criteria. Planning criteria do not typically cover the period of time before fault clearing while the fault is active, which is where the lower voltages were primarily noted. The fact that there was a significant enough impact on the large power customer during these events to cause a machine to trip without any voltage deviations outside Minnesota Power's planning criteria illustrates some of the inherent risk with transitioning away

from the support previously provided by the local baseload generators. It is a paradigm shift for an area that has been designed and built over many decades to rely on the system strength and voltage support provided by the local generators. This paradigm shift potentially has as much or more impact on customer-owned distribution systems as it has on Minnesota Power's transmission and distribution systems.

The Boswell Transformer Project was completed and placed in service about a month and a half after the last of the fault events noted above. Similar to what was noted previously in discussion of the North Shore Loop, voltage in the Grand Rapids area was noticeably more variable and generally lower during the period of time after retirement of the BEC units and before energization of the Boswell Transformer Project. Figure 5 below illustrates the differences in system voltage during these time periods. The experience in the Grand Rapids area indicates that the loss of system strength and voltage support from additional changes in operation of the remaining BEC units may have unintended consequences for Minnesota Power's customers if mitigating solutions are not placed into service prior to implementing the changes. Also of note from Figure 5 is the fact that power flow through the new Boswell 230/115 kV transformer is roughly equivalent to the power formerly produced locally by BEC Units 1 and 2. All of these findings generally work together to confirm Minnesota Power's conclusion that the essential reliability services provided by local generators must be replaced before they are retired.

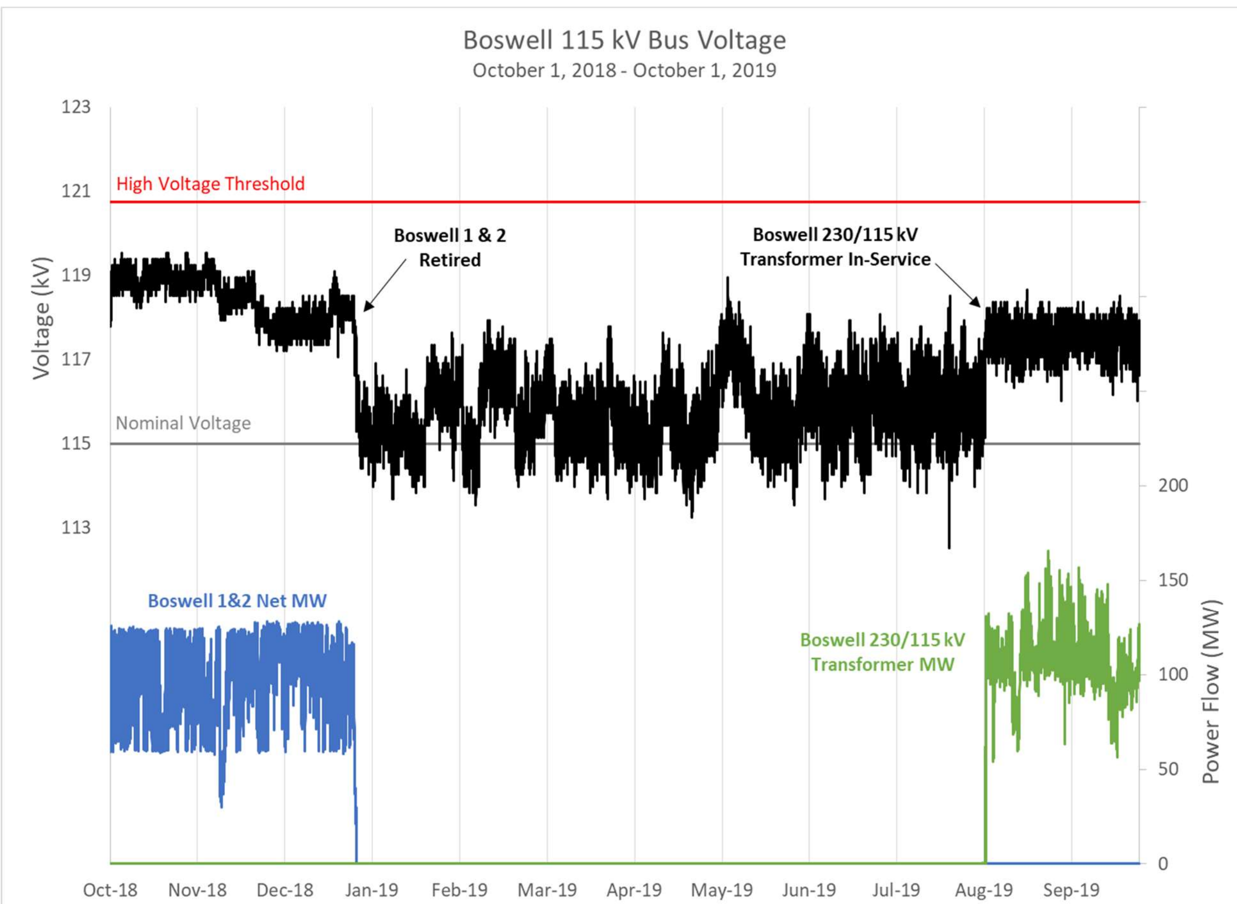

Figure 5: Boswell Substation 115 kV Bus Voltage, October 1 2018 – October 1 2019

Section 4: Short Circuit Impacts

Short circuit level is one of the main system strength indicators of interest in practically every evaluation of system strength currently taking place in the industry, as highlighted in Section 2. Minnesota Power's preliminary analysis of short circuit impacts from the Boswell Energy Center ("BEC") units being offline is discussed in the 2021 Integrated Resource Plan[17]. The preliminary analysis indicated that the primary non-BEC sources of short circuit capability to Minnesota Power's transmission system are the extra-high voltage ("EHV") transmission sources, such as existing 500/230 kV and 345/230 kV substations that interconnect the local 230 kV system to the regional transmission system.

Without the BEC units, Minnesota Power's local transmission system essentially imports short circuit capability from the regional transmission system. It was noted in the Integrated Resource Plan discussion that there is an inherent risk involved in depending entirely on these EHV Substations for access to external sources – the long-term planning of which Minnesota Power has no control or influence in – for essential reliability services such as system strength and voltage support that directly impact the reliability and operations of Minnesota Power's customers and protection systems. Some amount of local short circuit capability and voltage support is needed to provide a continuous, predictable, and redundant source to Minnesota Power's system.

Historically, short circuit level has not been a significant challenge for the regional transmission system or for Minnesota Power's local transmission system due to the large number of synchronous baseload generators spread throughout the system. As these generators, like the BEC units, continue to be replaced by inverter-based resources, the system strength characteristics of the system are changing. One of the main challenges with evaluating short circuit impacts and long-term needs for Minnesota Power's transmission system is that there is no historical industry standard planning criteria for minimum short circuit level that is universally applicable. Different indicators, such as short circuit ratio, have been developed for specific applications, but system-wide planning criteria for short circuit level, such as are applied for voltage and facility loading, do not exist.

To gain a better understanding of the magnitude and significance of short circuit impacts from the BEC units being offline and to assist in develop applicable criteria and solutions, Minnesota Power procured a consultant, RBJ Engineering, to perform a short circuit study. The RBJ Engineering short circuit study is summarized below. The full report is attached in Appendix A: Short Circuit Study Report

RBJ Engineering Short Circuit Study

The study performed by RBJ Engineering focused primarily on 115 kV, 230 kV, and 500 kV transmission in Minnesota Power's local area. Regional power flow models in PSS/E format were utilized by RBJ Engineering to calculate the short circuit level at various buses through the Minnesota Power transmission system with and without the BEC generating units in service[18]. After quantifying the short circuit level impact of the BEC units being offline, RBJ Engineering then evaluated several potential criteria that may be applicable for understanding and addressing the short circuit level impacts. Finally, based on the

[17] See Appendix F, Part 7 - "Short Circuit Analysis" on page 52

[18] Minnesota Power also maintains a more detailed short circuit database of the local transmission system in ASPEN OneLiner format. While the ASPEN OneLiner results are generally more precise for the local system, the PSS/E models were selected for use by RBJ Engineering due to the ability to represent impacts from regional generation dispatch assumptions outside of Minnesota Power's local area. The short circuit levels calculated in PSS/E may not exactly coincide with maximum short circuit levels calculated in ASPEN OneLiner, but will generally provide an accurate reflection of the relative short circuit impacts that may occur due to changes in the network.

criteria, RBJ Engineering was tasked with developing recommended mitigation solutions as necessary to maintain an acceptable level of short circuit capability on Minnesota Power's system.

The short circuit impact calculations indicate that the reduction in short circuit levels (SCL) without the BEC units in service is quite localized and the most significant reductions occur near the Boswell generating plant. The reduction in SCL exceeds the review guideline of -15% (as defined in NERC Standard PRC-027) at only four 230 kV buses and one 115 kV bus on Minnesota Power's system. At all of these buses, the short circuit levels without the BEC units plus severe single contingency (N-1) transmission element outages appear to be adequate to meet a number of criteria that are commonly used to assess the adequacy of system short circuit levels. These criteria, which are discussed in detail in Section 5 of the report, are summarized in Table 2 below[19]. Thus, there is no clear and obvious criteria violation that would require immediate mitigation or improvement of short circuit levels based the findings of the study.

If it were decided to ensure that there is no reduction in minimum SCL with the BEC units off-line, then mitigation measures focused on the Boswell area – such as a conversion of BEC units to synchronous condensers or installation of stand-alone synchronous condensers at Boswell would be sufficient to achieve that outcome. It is estimated in Section 9.2 of the report that it would require three synchronous condensers with a rating of about 300MVA to ensure that short circuit levels at Boswell under N-1 conditions do not drop lower than the worst N-1 outage case with the two BEC units in service. This is coincidently about equal to the aggregate rating of both BEC units and roughly similar to Minnesota Power's preliminary analysis and conclusions included in the Integrated Resource Plan assumptions[20].

Related to short circuit impacts, loss of the regulating capability of synchronous generators may lead to a requirement for increased numbers of capacitor bank switching operations, greater number of transformer tap-changer operations and possibly the requirement for installation of more capacitor banks or dynamic reactive power solutions to replace the variable reactive capability of the generators. These types of improvements may prove to be required to avoid relatively large fluctuations in voltages around the mean level that historically have not been seen on the Minnesota Power system while operating with the BEC units on-line.

Aside from lost regulating capacity, one of the most limiting of the criteria considered in the report for minimum short circuit level is the voltage change that occurs at capacitor switching. The calculated short circuit levels at the busses where capacitor banks are currently installed on the Minnesota Power system have been summarized in Table 5-2 of the report. In all cases the voltage change on switching is within Minnesota Power's rapid voltage change criterion of 3% change during system intact (N-0) conditions. During N-1 outage conditions, the 3% voltage change may be exceeded but generally the level of change is not significantly larger than Minnesota Power's post-contingent rapid voltage change criterion of maximum 5% voltage change during N-1 outages.

If the only system performance consideration was decline in static short circuit level, it does not appear that the BEC units being offline would degrade short circuit capability on Minnesota Power's transmission system to the point of requiring mitigation when considering any of the criteria listed in Table 2. However, reduction of static short circuit level is only one quantifiable metric which, taken by itself, may not fully reflect the decline in operational performance when synchronous generators are taken off-line. Replacement of regulating capacity of synchronous generators may also be necessary if there is an increase in voltage fluctuation that results in customer complaints, increased tap-change operations or increased capacitor switching. Replacement of regulating capacity generally requires much lower ratings of synchronous condenser than replacement of short circuit capacity, typically only 1% of the maximum

[19] This table is the same as Table 5-6 of the full report

[20] See discussion in Appendix F, Part 8

short circuit capacity at a given bus, and can also be resolved by other dynamic reactive solutions such as Static VAR Compensators (SVCs) or Static Synchronous Compensators (STATCOMs). This type of need can also be solved with more dispersed and smaller solutions targeted to the specific impacts and areas of concern that are identified.

Short circuit impacts related to potential future developments in the system such as electric vehicle charging, connections of new transmission or distribution-connected inverter-based renewable generation, motor starting and upgrading of the Square Butte HVDC converters have also been discussed but these developments would require project-specific evaluations and localized upgrades rather that system-wide short circuit improvements.

Determination of the equipment requirements for dynamic reactive solutions designed to support voltage stability and offset the loss of regulating capability from the BEC units was beyond the range of the exploratory short circuit study completed by RBJ Engineering. Those impacts and potential solutions would need to be further studied in transient stability studies, reactive margin studies, post transient reactive studies or voltage stability studies.

Short Circuit Study Conclusions

The RBJ Engineering short circuit study demonstrated that the short circuit level impacts from the BEC units being offline are localized around the Boswell area. Of the many potential underlying drivers for the development of short circuit level criteria that were considered by RBJ Engineering, no clear and obvious objectively weak conditions were identified due to the change in status of the BEC units. A handful of objectively weak scenarios exist on Minnesota Power's system, but these are typically related to multiple transmission outages and relatively unaffected by the status of the BEC units. From these findings, Minnesota Power concludes that the regional transmission system is robust to provide short circuit levels adequate enough to maintain a strong transmission system with or without the BEC units offline, and no mitigation solutions are required solely based on the calculated short circuit level impacts.

Concerns about being fully dependent on the regional transmission system for local short circuit level support were not directly addressed by the study. These concerns continue to point to a need for local sources of system strength and voltage support. The RBJ Engineering study also did not directly address the impact of losing the steady state and dynamic voltage regulating capability of the BEC units, which is a distinct impact from the decline in short circuit level. These types of impacts must be addressed in separate targeted studies, such as the motor starting and transient stability studies discussed in subsequent sections of this report.

Table 2: Summary of Potential System Strength Impacts and Criteria

Basis of Criterion		Value or limit on SCL	Potential Solutions	Comment
1-	Voltage change on Switching	dV=3% normal no outage dV=5% infrequent or N-1 SCLmin ≥ $Qc(1+dV^{-1})$	Smaller banks New line Synchronous condenser	Most existing capacitors meet the criterion with Boswell off-line
2-	High Dynamic Overvoltage	Limit DOV to <1.3pu SCR > 2.8 at a rectifier SCR >2.3 at an inverter	Capacitor tripping New line Synchronous condenser STATCOM	Generally applicable to LCC HVDC only which has high var demand and many capacitor banks.
3-	Low order harmonic resonance	SCLmin ≥ $Qt*n^2$	Lower Capacitor Rating New line Synchronous condenser STATCOM	This should only be an issue for stations with multiple capacitor banks such as LCC HVDC converter stations
4-	Avoiding commutation failure	Similar to 1	Synchronous condenser STATCOM	Applicable to LCC HVDC only
5-	Relay coordination	To be checked if SCL declines by 15%	Re-coordination of settings New line or synchronous condenser if SCL is within 25% of the load current or line thermal current	In most cases it should be possible to successfully re-coordinate the settings and avoid other remedial measures.
6-	Voltage drop due to transformer switching	For normal transformers SCL ≥ 22.5*MVAt High knee point transformers SCL ≥ 4.5*MVAt	Synchronous condenser STATCOM Specify a higher knee point	The voltage drop is variable depending in time instant of breaker closing and remanent flux.
7-	Distributed Generation	SCL > 3	New line Synchronous condenser	SCL >3 needed to ensure good performance and to minimize studies with 3-phase models
8-	Motor starting	Not defined at HV bus	DSTATCOM Switchable capacitors	Optimal solution may be localized solution
9-	Decline of Voltage Quality	Frequent voltage change between 1% and 3% leading to increase tap changes or capacitor switching	STATCOM Synchronous Condenser	Solution requires increase of the continuous regulation capacity of the ac system at a given bus between 1% and 1.5%
10-	EV charging (slow)	Not related at HV bus	New line (for thermal constraints)	Optimal solution may be localized solution. Similar to Criterion 9
	EV charging (fast)		DSTATCOM or Battery storage for voltage issues.	

Section 5: Motor Starting Impacts

Minnesota Power has a number of large industrial customers whose processes place uniquely demanding requirements on the transmission system. Within many taconite processing facilities in northeastern Minnesota, large synchronous motors are used in various applications to process raw material into a finished product. These motors may take an extended amount of time to start up and eventually synchronize with the transmission system. During starting, the motors may draw an immense amount of reactive power, causing significant voltage drop on the transmission system and the plant distribution system. The longer it takes to start a motor successfully, the more stress is placed on the transmission system, the plant distribution system, and the motor itself. The strength of the transmission system, typically measured by short circuit level, along with dynamic reactive power availability will aid in starting motors faster and reducing the voltage dip that is experienced during the starting sequence. It is not uncommon for synchronous motors to take 60-90 seconds to start up successfully. Beyond that duration, excess heat generated during the process may damage equipment and protective equipment may interrupt the sequence to prevent such damage.

Based on previous experiences evaluating synchronous motor starting in a large industrial setting following fleet transition in the North Shore Loop, Minnesota Power commissioned Siemens PTI to study potential impacts on motor starting capability for large power customers on the Iron Range if BEC Units 3 and 4 were to be retired. This study was meant to be indicative in nature only, not representative of any single customer or actual equipment. Much of the detailed industrial plant data needed to perform a specific motor starting study is not readily available to Minnesota Power (if it is readily available at all), and the study was only intended to give a general idea of principles and impacts independent of the specifics of any given site. An existing large power 115 kV bus on the Minnesota Power transmission system was selected as a representative site for the analysis. From there, a slightly more detailed lower voltage system was added in, modeling the path from the 115 kV bus down to the synchronous motor terminal bus using parameters similar to actual known customer configurations.

The generic configuration for synchronous motor start screening is shown in Figure 6 below. As shown in the figure, there are at least two stages of transformation involved in stepping down the voltage between the transmission system and the motor terminals. "As Modeled" transformer steps down the voltage from transmission to plant distribution. "Transformer T" steps down the voltage from plant distribution to motor terminals (here assumed to be 4,160 Volts). There is also a branch ("Branch F") that represents the power wiring and cabling involved in distributing power from the main transmission substation to the motor stepdown transformer. All three of these components contribute to the effective impedance between the transmission system and the motor, a key factor as discussed later on.

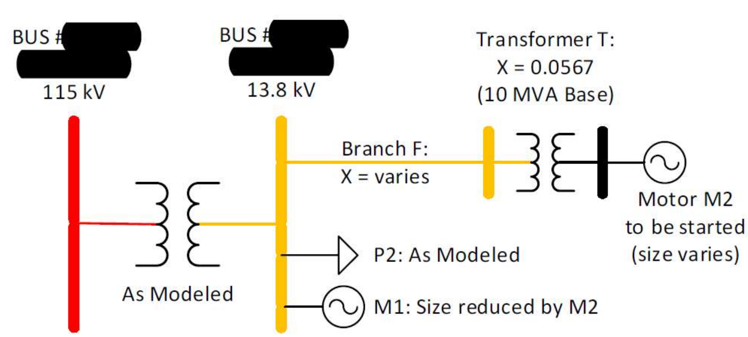

Figure 6: Generic Synchronous Motor Starting Configuration

Siemens PTI performed a number of motor starting simulations by considering synchronous motor sizes from 3,000 to 9,000 horsepower (hp), varying lower voltage system ("Branch F") impedances across a range of potential values, and toggling BEC unit status. Key metrics considered in the study were the success and duration of motor starting attempts, defined as the time it takes from start until motor torque equals load torque (the point when motor is "synchronized"), as well as the voltage dip magnitude and duration observed at the point of common coupling with the transmission system – the 115 kV bus. Key findings from the study are that successful synchronous motor starting is primarily dependent on the pre-starting steady state voltage and the total impedance between the motor and the transmission system.

Steady-state voltages prior to motor starting are typically lower in the cases with BEC generation offline due to a loss of reactive power support. When motor starting simulations are performed with lower initial transmission system voltages, motor starting durations are extended and voltage dips during starting are more significant, both of which have a negative impact on motor starting. Additional sensitivity analysis was performed to generically replace the reactive power generated by the BEC units in the form of a fixed shunt capacitor bank at the representative 115 kV bus. Fixed shunt sizes were chosen in each scenario to perfectly match the 115 kV steady state voltage between the pre- and post-BEC retirement cases. Performing the motor starting simulations again with additional reactive support on the transmission system and BEC units offline, the differences in motor starting duration and voltage dip with and without the BEC units were negligible. For example, Figure 7 below shows a comparison of the Benchmark case with BEC units online, the Sensitivity case without BEC units online and lower starting transmission voltage, and the Sensitivity case with a fixed shunt to return transmission starting voltage to that of the Benchmark case. This plot covers only one of the motor size and impedance combinations, but is representative of the trend observed across all cases. The values plotted are motor torque versus time, with the flat line on the right size representing the point at which the synchronous motor is synchronized with the transmission grid.

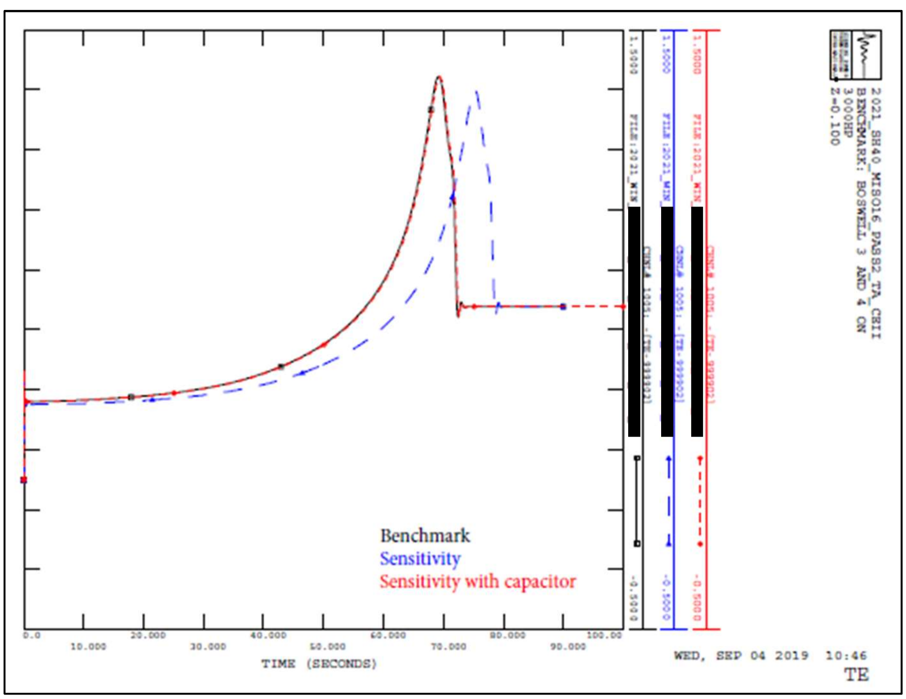

Figure 7: 3000 HP Synchronous Motor Starting Electrical Torque Plot

As described above, the cases with a higher starting transmission voltage allow the motor to successfully start in a shorter amount of time. This trend was observed across the entire range of synchronous motor sizes and lower voltage impedances. From this, Minnesota Power concludes that large synchronous motor starting is primarily dependent on pre-starting steady-state voltage, which must be adequately and predictably regulated with or without BEC units online. Another primary factor in successful motor starting is the impedance between the motor and the transmission system, which is dependent on the local plant distribution system configuration and generally out of Minnesota Power's control.

Study results also indicate that, unlike the North Shore Loop, the transmission system on the Iron Range is capable of providing sufficient dynamic reactive support during motor starting with or without the BEC units online, as long as a robust pre-starting steady state voltage is maintained. This may allow for some of the voltage support presently provided by the BEC units to be replaced with fixed-size reactive resources like shunt capacitor banks. On the other hand, Minnesota Power's previous experiences in the Grand Rapids area and the North Shore Loop, as well as transient stability simulations from the Beyond Boswell Study and post-event analysis of the 2019 Grand Rapids-area fault events, show that adequate steady state and dynamic regulation of system voltages depends on a combination of both dynamically-responding reactive support and fixed-size reactive resources. The motor starting study results and the previous generator retirement experiences both indicate that the most effective leading indicator of whether or not large industrial customer motor starting and other processes will be negatively impacted by BEC unit retirements is Minnesota Power's ability to provide a healthy, predictable transmission system voltage similar to what is presently available with the BEC units online.

Section 6: Transient Stability Impacts

Minnesota Power also worked with Siemens PTI to understand the stability impacts from retiring both units at Boswell. From previous work detailed within this report it was known that with the Boswell units offline the system strength would be reduced and as a result disturbances could have a larger impact, but it was important to check for transient criteria violations as well as understand and begin to quantify the resulting changes and degradations in a detailed way.

As background, the transient period generally spans the period of 5 seconds after a system fault is applied. In order to remove the fault from the system, transmission lines are opened by relay action and the resulting system response can be simulated and studied. The analysis that was performed was reviewed to examine the impact to transient voltage recovery, damping, frequency regulation, power system oscillations, and angular stability. The system's ability to rapidly respond to an event and return to pre-disturbance levels is critical in order to maintain reliability and be prepared for future disturbances. Along with impacts from Boswell retirements, the effectiveness of replacing voltage support and system strength with various solutions was reviewed, including the addition of synchronous condensers, re-establishment of synchronous generation, and changes to control strategies.

A number of seasonal models were developed to simulate the stressed conditions of summer peak, shoulder season with high transfers, and winter peak north flow. Historically from a transient stability perspective, the lower load levels found in the shoulder case that result in higher transmission line loading presents the most challenging scenario. However under winter north flow conditions new issues were observed within this analysis that are related to the Northern Minnesota voltage stability issues Minnesota Power has identified in other Boswell-related analyses. Summer Peak conditions showed the least amount of stress, as expected. The full Siemens PTI transient stability study report contains Critical Energy Infrastructure Information (CEII) and may be made available upon request to individuals possessing a signed CEII non-disclosure agreement (NDA). The remainder of this section will provide a high-level summary of the findings and conclusions from the study.

Overall the analysis showed lower voltage levels and slower voltage recovery during and immediately following disturbances with the Boswell units offline. Under most conditions the impact did not result in actual violations of Minnesota Power's transient reliability criteria. The exceptions to this were issues at a 230KV bus where voltage did not recover resulting in an interruption to the DC to AC conversion process of a nearby HVDC line, which ultimately resulted in a voltage collapse. This issue is detailed in section 3.2.1 of the full report and is shown in Figure 16 below. The other issue is detailed in section 3.3.1 of the full report and involves power transfers north through Minnesota in the winter peak case. Under these conditions if a disturbance were to occur that removed a critical transmission line from service, a voltage collapse would likely occur. The issue is directly related to the Northern Minnesota voltage stability issues identified in previous analyses, and both the voltage stability and the transient stability impacts must be resolved by adding transmission, adding generation, reducing transmission line transfers, or a combination of the three. This instability is shown in Figure 9 below.

These issues, while severe, can be addressed in a number of ways; however, their occurrence underscores the fact that careful analysis is required to understand when changes result in impacts and how best to resolve them. Instability occurring after a change is made to a system regardless of what it is related to points to an increase in stress or a change in the system strength resulting in degradation and potential reliability impacts.

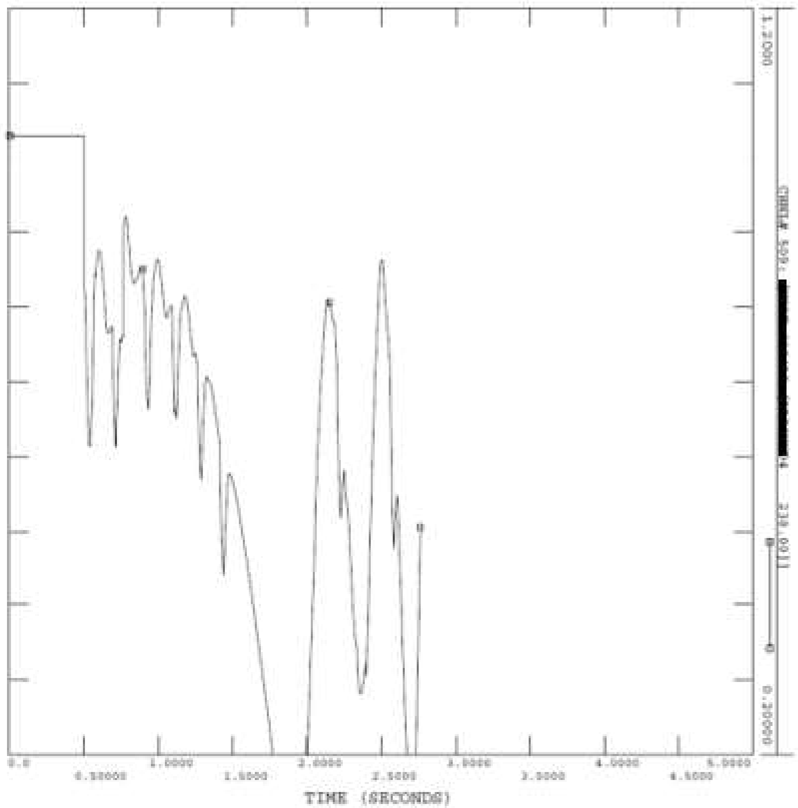

Figure 8: Voltage Collapse Due to HVDC Commutation Failure

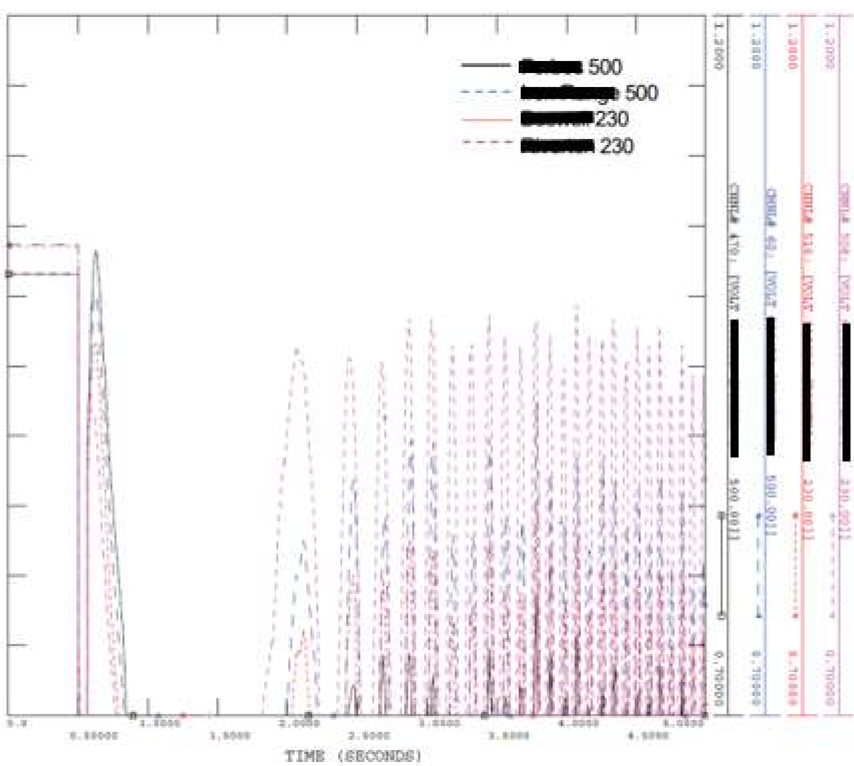

Figure 9: Voltage Collapse in Winter North Flow Case

It was very obvious even before the study started that removing two large generators from the analysis would have impacts. It was this need to more accurately capture the magnitude of change even in the absence of a criteria violation that resulted in MP working with Siemens PTI to define a “voltage sag severity index”. This metric conveys how close a value is to actually being a violation and can provide a good indication of how much margin is left in the system before and after a change. Its development is detailed in section 4 of the full report. Almost all the analysis performed appeared similar to the plots shown below in Figure 10 where a clear change in performance was present. In this example when comparing the Base Case that included both Boswell units on-line to Scenario 3 in which they were both off-line, there was a notable decrease in voltage recovery. Neither Scenario 3 voltage recovery shown below resulted in a criteria violation which made assessing the magnitude of change difficult without the additional voltage sag severity index metric.

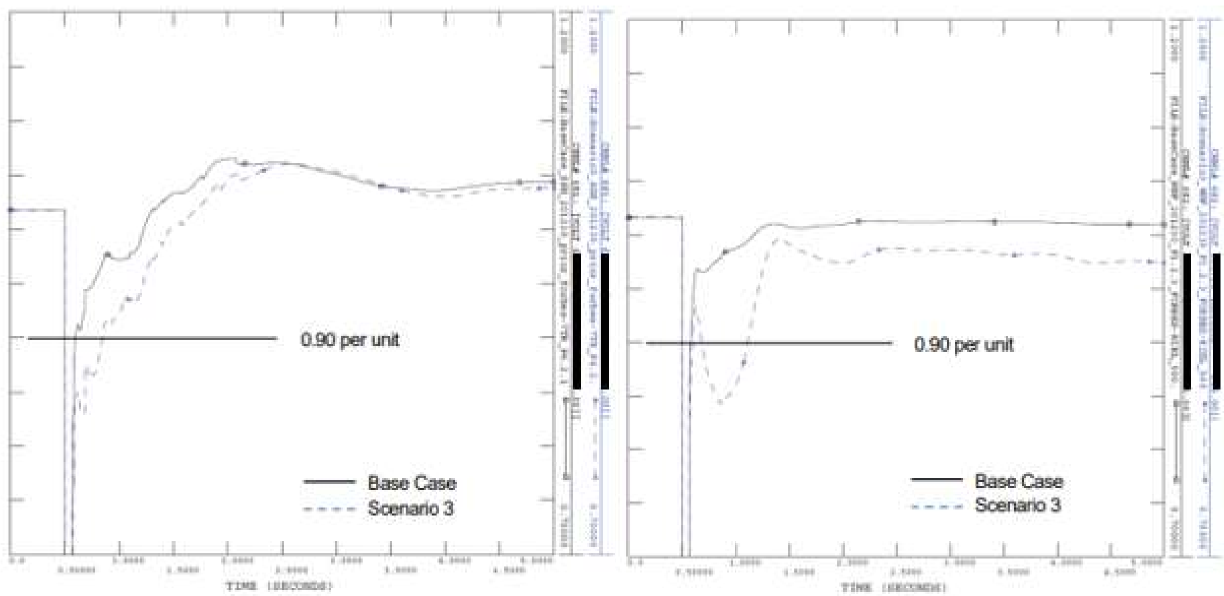

Figure 10: Examples of voltage response to Boswell unit retirement

The Voltage Sag Severity Index compares the simulated voltage response value with the MP transient voltage recovery planning criteria. A value of 1.0 would mean the voltage during recovery is equal to a point on the MP voltage limit curve while a value less than 1.0 would be over the curve where there is a violation of MP’s criteria. A value less than 1.0 means that the response is within the curve and no criteria violations are present. The smaller the value, the more margin that is available between the response of the system and a criteria violation. Figure 11 below shows, for the same two bus voltages shown above in Figure 108, the performance without Boswell generation online in response to a system disturbance (orange curve) and the MP reliability criteria (blue curve).

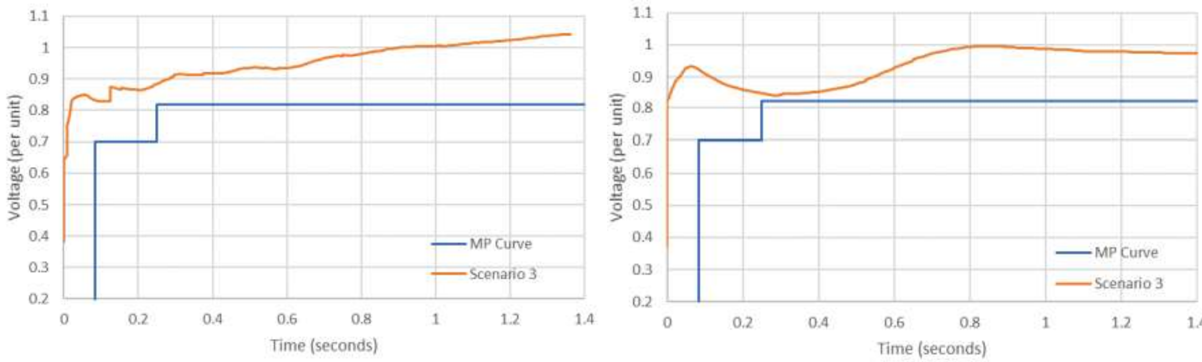

Figure 11: Example of voltage response and MP criteria limit

The margin available between the MP criteria and the studied voltage response shown on the left was calculated to be 0.63 while the other bus voltage shown on the right falls much closer to the criteria level. The voltage sag severity index for that instance was determined to be 0.88. Neither of these simulations resulted in criteria violations but it was clearly shown in Figure 19 that without Boswell generation online the voltage shown on the right could near a violation following a disturbance and should be monitored closely as the power system continues to change. Along with being able to assess how close performance is to becoming a criteria violation it can also be determined what the amount of change is by comparing the Base Case with Boswell units online to the change case with Boswell units offline, as shown below in Table 3. For the bus on the right of Figure 11, voltage sag severity index increases from 0.13 to 0.88, resulting in a change of 0.75. For the bus on the left of Figure 11, voltage sag severity index increases by 0.51. The increase in the voltage sag severity index helps quantify the degradation in transient voltage response attributable to the Boswell units being offline.

	Base Case (Boswell Online)	Scenario 3 (Boswell Offline)
Bus on the left of Figure	0.12	0.63
Bus on the right of Figure	0.13	0.88

Table 3: Voltage Sag Severity Index Comparison for Two Buses

Another way in which the impact of changing system strength is shown was during disturbances that are geographically remote from the MP system there is increased impact to the MP system. An example of this is shown below in Figure 12, where during the time that a fault is applied to the transmission system in the Twin Cities area the voltage at a bus on the Iron Range is reduced. Once the fault is removed from the transmission system the voltage recovers. In can be seen that during the fault, the voltage is reduced noticeably more in Scenario 3 compared to the Base Case due to the loss of the support that the Boswell generation provides. When looking at violations of reliability criteria, the voltage during a fault is not considered. However this is an notable example of impact, and it is something that could potentially result in noticeable end-use customer impacts if the voltage during the voltage becomes low enough to cause protection systems to take action.

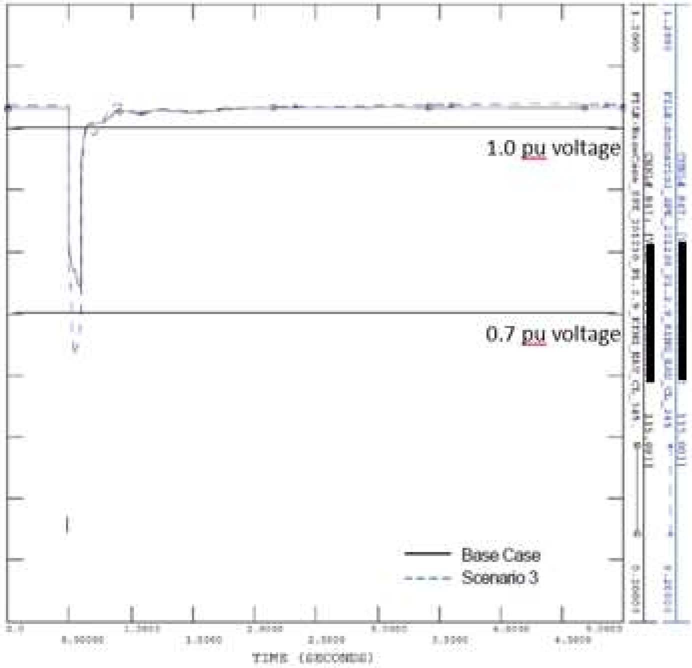

Figure 12: Local MP Impact to Regional Disturbance

In addition to the expected local impact it was also observed that voltage response at buses outside of Minnesota Power were also impacted when Boswell generation was offline. In the plot shown in Figure 21 below for a fault on a regional transmission line where it connects to Minnesota Power's system, the 115kV bus voltage at a substation in the Grand Forks area is substantially impacted. This illistrates the regional nature of transient stability issues, as well as the regional nature of impacts associated with the Boswell units being offline. Changes in one area of the system result in measurable impacts across a broad area of the system.

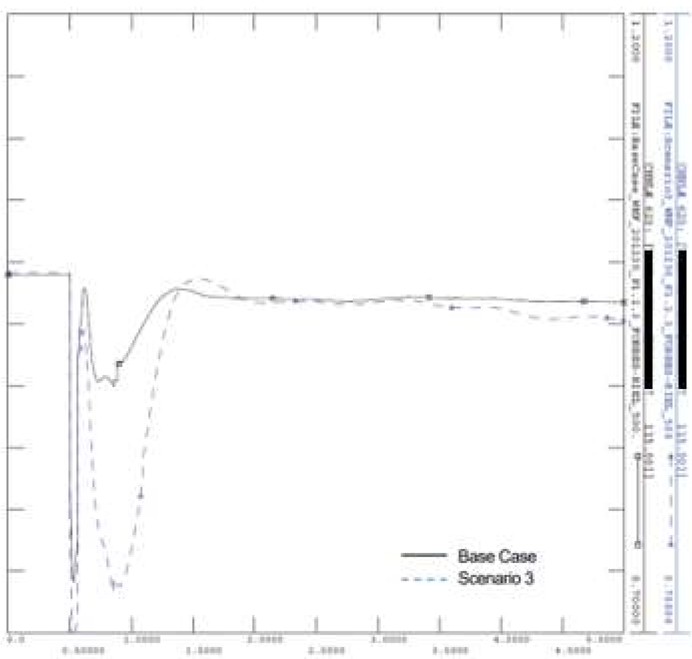

Figure 13: Remote system impact to regional system disturbance

The analysis also studied how the decreases in voltage response could be improved or restored to levels experienced with the Boswell generation online through the use of synchronous condensers (SC). Different scenarios including converting Boswell unit #3 to SC operation as well as combinations of new units at other locations were reviewed to compare results. The plots in Figure below show three different 230kV and 115kV buses on the MP system and the voltage response following a system fault for the Base Case, Scenario 3 with Boswell units offline, and several SC addition scenarios. The best performing response was the Base Case scenario with both Boswell units online while the most impact was Scenario 3 where they were both offline. Generally the SC scenarios studied improved the voltage response to levels in between and in some cases to levels that restored voltage to near Base Case levels. The review also showed that location was important due to the localized support SC provide. Siting support devices as close to the most impacted area to minimize reactive power losses would result in the biggest improvement to voltage response. This review was not meant to determine or design a preferred solution or solution set but instead illustrate the impact that adding these types of resources have. Futher investigation to optimize the addition of system support devices would be required.

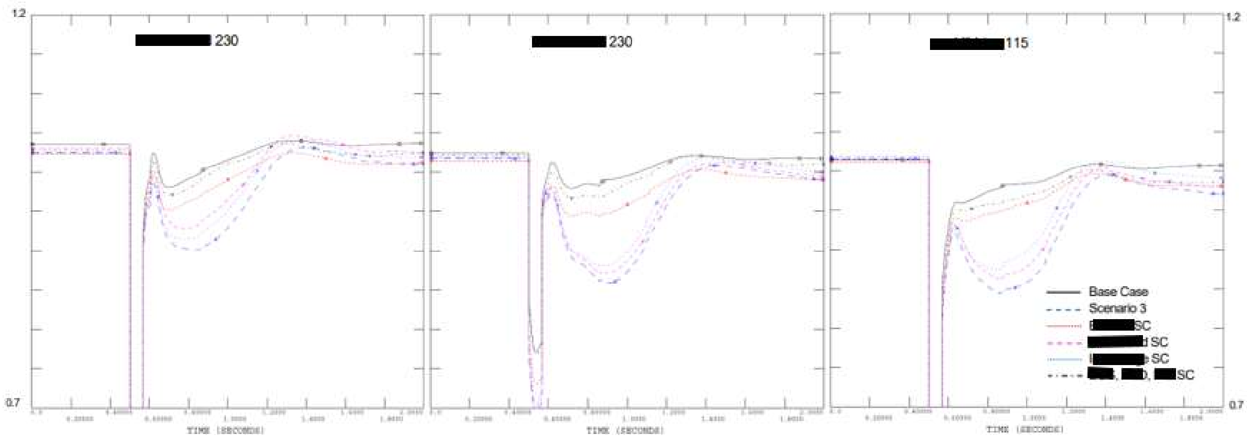

Figure 22: Impact of adding SC resources to the MP system

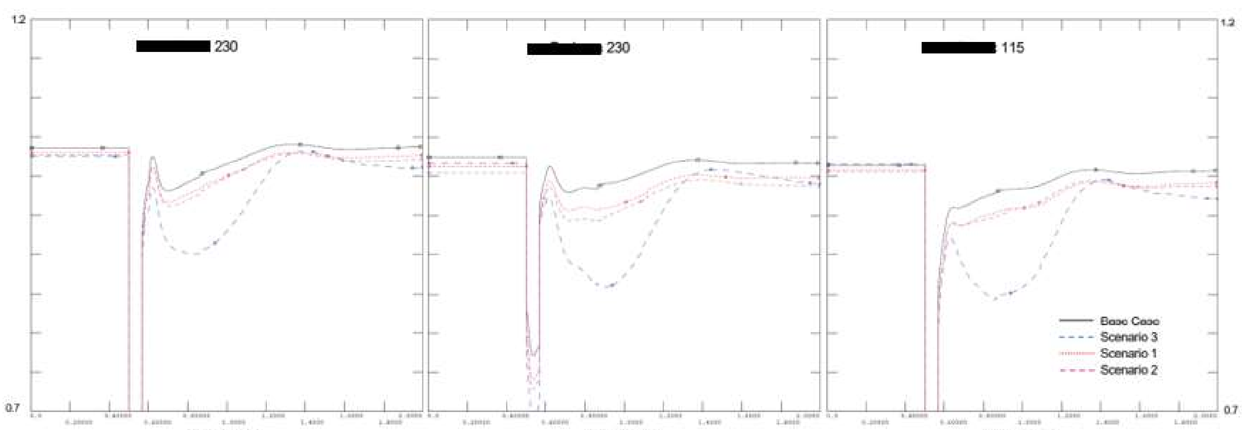

Figure 14: Impact of adding Boswell generation

Finally, the analysis studied the impact of having a single Boswell unit online which could also be assumed as a placeholder for a replacement generator at the site. The same MP buses shown in the SC analysis (Figure 22) above are displayed in Figure . As expected the voltage response with one unit online (Boswell #4 online in Scenario 1 and Boswell #3 online in Scenario 2) was between the Base Case and both offline

(Scenario #3). The issue that might not be as expected was the difference in performances. In some of the voltage responses reviewed in the full report the progression of change in performance from both units online to one unit online to both offline is about equal. However in the below plots there is a much larger decrease once the second unit is taken offline than experienced with the first unit. This illustrates that once the system becomes weak in an area the decreases in performance can become much greater even with small amounts of additional change.

In summary the transient stability analysis that was performed by Siemens PTI showed a clear reduction in transient voltage response that should continue to be evaluated going forward to ensure issues do not arise. There is the potential that limitations need to be put in place during certain operating conditions to limit impacts. Solutions or mitigations are available but should be carefully evaluated to optimize the benefit. Additional transient stability analysis should be performed to further develop potential long-term solutions for supporting robust and predictable transient performance in the Minnesota Power system.

Section 7: Conclusions

This report documents Minnesota Power's investigations into system strength and voltage support concerns related to the transition of the Boswell Energy Center (BEC) units from baseload operation to being normally-offline for extended periods of time.

It is clear from the limited survey of industry perspectives provided in Section 2 that system strength is a matter of intense interest locally and globally as the utility industry worldwide continues to transition away from large synchronous generating resources toward more renewable, intermittent, and dispersed resources. The issue is complex, striking at the heart of some of the most fundamental physical properties of the power system and driving many different types of impacts and areas of concern. What is evident is that local utilities and transmission owners, regional transmission operators, industry technical groups, regulators, and others are taking an increasingly proactive approach to ensuring that the essential reliability needs of the power system, including system strength and voltage support, continue to be met during and after the clean energy transition.

Minnesota Power's recent experiences and observations from the transition of its small baseload coal fleet, discussed in Section 3, also provide a basis for understanding how system strength and voltage support issues have actually manifested in the local transmission system in recent years. Minnesota Power's experiences give a real-world illustration of the types of impacts, risk and uncertainty that must be navigated as the larger BEC units transition away from baseload operation. These experiences also demonstrate the types of network upgrades that may be necessary to ensure the transmission system continues to be reliable according to Minnesota Power, MISO, and NERC standards as well as the expectations of Minnesota Power's customers.

In response to concerns about system strength and voltage support impacts from the BEC units being offline, Minnesota Power has evaluated three general types of impacts and provided the results and conclusions in this report. While none of the individual evaluations provides a comprehensive picture of the issue on its own, together they begin to illustrate the big-picture story for how system strength and voltage support in Minnesota Power's system will be impacted by the transition of the BEC units.

Section 4: Short Circuit Impacts describes the impact of BEC units being offline on short circuit levels in Minnesota Power's system. The evaluation demonstrates that this impact is primarily localized to the area of the transmission system immediately surrounding the BEC units. There are no places where short circuit capability is degraded to objectively weak levels due to the change in status of the BEC units, but there are many different potential areas of impact discussed in the report that must be carefully analyzed, monitored and planned for once the local short circuit capability of the BEC units is removed. Degraded voltage regulation capability and dynamic voltage response is an example of one such impact that may not be adequately or fully anticipated by simply evaluating short circuit level impacts. The short circuit analysis report also provides an overview of what potential mitigation solutions might look like for maintaining consistent short circuit level in the Boswell area with or without the BEC units, as well as more targeted solutions focused on voltage regulation.

Section 5: Motor Starting Analysis describes the impact of BEC units being offline on the starting of large electric motors, such as often are used by Minnesota Power's large industrial customers. The evaluation demonstrates that the primary factor contributing to successful motor starting that has historically been supported by the BEC units is the provision of a predictable and robust steady state voltage at the transmission level. As the operation of the BEC units transitions going forward, the most effective leading indicator of whether or not large industrial customer motor starting and other processes will be negatively impacted is Minnesota Power's ability to provide a healthy, predictable transmission system voltage similar to what is presently available with the BEC units online.

Section 6: Transient Stability Impacts describes the impact of the BEC units being offline on transient-period voltage recovery, damping, frequency regulation, power system oscillations, and angular stability following system fault events. While only limited violations of Minnesota Power's transient stability criteria were identified in the analysis, notable degradation in transient period voltage recovery was observed in several instances. To help understand and quantify the amount of degradation and flag areas for further analysis and monitoring in the future, a voltage sag severity index was developed for the study. In addition, the impact and effectiveness of various solutions involving synchronous condensers and local generation was evaluated. The transient voltage recovery impacts identified in the study are concerning and continue to illustrate the significance of voltage regulation as an impact from the BEC units being offline, and the need for continued analysis to identify appropriate long-term solutions.

In conclusion, Minnesota Power's assessment of system strength and voltage support impacts from the BEC units being offline identified that the degradation of the Minnesota Power system, particularly in terms of steady state and dynamic voltage regulation, is a substantial area of concern that requires continued evaluation. While specific criteria violations were not identified in any of the analyses described in this report, the results of these analyses when taken together with Minnesota Power's own real-world experience and general industry trends strongly support the need to develop long-term solutions to limit operational risk and uncertainty created by the degraded level of support for Minnesota Power's system.

Because these impacts are a matter of risk rather than criteria violations, it may be possible to operate with the Boswell units offline at times without causing noticeable reliability impacts. However, long-term intentional operation of the transmission system without the Boswell units would result in a level of risk and uncertainty Minnesota Power deems to be unacceptable, and therefore long-term solutions focused on steady state and dynamic voltage support should be developed without delay. The following recommendations are made based on the findings of this report:

1. **Continue transient stability studies** to identify specific areas of concern and optimal long-term solutions to improve transient voltage recovery and restore margin on the Minnesota Power system when the Boswell units are offline. Consider the impact of regional transmission additions as well as targeted synchronous condenser or STATCOM additions.
2. **Investigate dynamic reactive power solution options** that can provide both consistent steady state voltage regulation as well as transient-period response, including conversion of existing generators to synchronous condensers, new synchronous condensers, and STATCOMs
3. **Consider future-proof technologies** that are relatively immune to changes in short circuit level and do not depend on synchronous generators to regulate system voltages, such as STATCOMs and VSC-HVDC, when scoping transmission projects on the Minnesota Power system
4. **Pay careful attention** to potential weak system impacts and indicators such as short circuit ratio, capacitor switching, transformer energization, and harmonic impacts in all future analysis and development of the Minnesota Power system

Appendix A: Short Circuit Study Report

K. Part 11: Boswell Synchronous Condenser Conversion Report with 2024 Cost Estimate and Schedule Updates

PUBLIC DOCUMENT
TRADE SECRET INFORMATION HAS BEEN EXCISED

Part 11 of Appendix F, the Boswell Synchronous Condenser Conversion Report with 2024 Cost Estimate and Schedule Updates, has been designated as Trade Secret in its entirety. The information contained in this appendix is confidential information related to transmission and cost information that the Company considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b). This information has economic value to Minnesota Power, as a result of this information remaining not public, and Minnesota Power has taken reasonable precautions to maintain its confidentiality. Portions of Part 11 also contain Critical Energy Infrastructure Information ("CEII") regarding the transmission system that could be useful to a person or organization planning an attack on critical infrastructure. Minnesota Power strictly limits access to CEII.

In accordance with Minn. R. 7829.0500, subp. 3, Minnesota Power provides the following information regarding the Boswell Synchronous Condenser Conversion Report with 2024 Cost Estimate and Schedule Updates:

Nature of Material – Burns & McDonnell's 2022 Boswell Unit 3/Unit4 Synchronous Condenser Conversion Study and 2024 estimated cost and schedule updates.

Authors - Burns & McDonnell

General Import - Minnesota Power contracted Burns & McDonnell to conduct a feasibility study to identify a preliminary design concept and develop an indicative cost estimate for BEC3 or BEC4 seasonal synchronous condenser conversion. While the original BMCD report from 2022 does provide a preliminary indicative cost and lead-time for synchronous condenser conversion of BEC3 and BEC4, the costs and lead-times from the original report are no longer valid due to changing market and supply chain conditions. Minnesota Power re-engaged with Burns & McDonnell in 2024 to obtain an updated outlook for the conceptual cost and lead time of BEC unit synchronous condenser conversions.

Date(s) Prepared – February 2022 and September 2024