2023 Biennial Transmission Projects Report

American Transmission Company, LLC
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
ITC Midwest LLC
L&O Power Cooperative
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services
Northern States Power Company
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency

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MPUC Docket No. E999/M-23-91

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1.0 Executive Summary

The 2023 Biennial Transmission Projects Report is the twelfth such report prepared since the requirement to prepare this report was established by the Minnesota Legislature in 2001. Previous Biennial Reports, beginning with the 2005 Report, are available for review on a webpage maintained by the utilities preparing the Report. That webpage is:

http://www.minnelectrans.com

The requirement is found in Minn. Stat. § 216B.2425. That law requires utilities that own or operate electric transmission facilities in the state to report by November 1 of each odd numbered year on the status of the transmission system, including identifying possible solutions to anticipated inadequacies in the transmission system. The Minnesota Transmission Owners (MTO) has consistently defined an "inadequacy" as essentially a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards.

The Minnesota Public Utilities Commission (Commission or MPUC) established six transmission planning zones across the state in 2003. Those six transmission planning zones are the Northwest Zone, the Northeast Zone, the West Central Zone, the Twin Cities Zone, the Southwest Zone, and the Southeast Zone. Information about transmission facilities in each of the zones is included in the Report.

The 2023 Biennial Report identifies the present and reasonably foreseeable transmission "inadequacies" in the transmission system that exist in each of these six transmission planning zones. Each inadequacy has been assigned a Tracking Number. Information about each inadequacy identified by a Tracking Number is provided. Projects that were identified in earlier reports and assigned a Tracking Number but which have been completed or withdrawn in the past two years are also identified.

Similar to previous reports, this 2023 Biennial Report is a joint effort of the MTO – those utilities that own or operate high voltage transmission lines in the state of Minnesota. These utilities include the following:[1]

American Transmission Company, LLC
Dairyland Power Cooperative
Great River Energy
L&O Power Cooperative
Minnkota Power Cooperative
Northern States Power Company
Rochester Public Utilities
Central Minnesota Municipal Power Agency
East River Electric Power Cooperative
ITC Midwest LLC
Minnesota Power
Missouri River Energy Services
Otter Tail Power Company
Southern Minnesota Municipal Power Agency

[1] Hutchinson Utilities Commission, Marshall Municipal Utilities and Willmar Municipal Utilities are being served by Missouri River Energy Services who does the reporting for them.

Information about each of the MTO utilities, including their transmission assets in the various zones, is provided in the Report.

As required by Minn. Stat. § 216B.2425, subd. 7, the Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard (RES) milestones under Minn. Stat. § 216B.1691. In 2023, the Legislature amended Minn. Stat. § 216B.1691 to include carbon-free energy standards (CFES) and additional renewable energy requirements. (Minn. Laws 2023, ch. 7.) Because the Commission is still developing guidance on compliance with the CFES, this 2023 Biennial Report includes the status of utilities' efforts to meet the RES standards but does not yet include a gap analysis related to the CFES.

In 2015, the Legislature established a new reporting requirement for certain utilities.[2] This reporting requirement is explained in further detail in Chapter 2, subsection 2.6. Pursuant to that requirement, Xcel Energy (currently the only utility to which the requirement applies), has submitted two separate reports entitled (1) Grid Modernization Report and (2) Hosting Capacity Report to the Commission in separate dockets.

In the Commission's June 12, 2018 Order Accepting Report, Granting Variance, and Setting Additional Requirements, the MTO was ordered to include an improved and expanded assessment on non-wire alternatives and a discussion of relevant actions by FERC, MISO, and the Commission related to distributed energy resources and distribution planning. This information can be found in Chapter 2, Sections 2.7 and 2.8.

In the Commission's August 19, 2020 Order Accepting Report, Granting Variance, and Setting Additional Requirements (2020 Order), the MTO was ordered to provide a full discussion and analysis of next steps for identifying gaps between the existing and currently planned transmission system and the transmission system that will be required to meet the companies' publicly stated clean energy goals and to address any need for new or expanded transmission to accommodate:

1) The public clean energy commitments of the MTO member utilities,
2) The requirements in all approved Minnesota resource plans, and
3) Relevant Minnesota statutory goals.

This information was included in Chapter 9 of the 2021 Report but has not been included in the 2023 Report given the intervening changes to the state's carbon-free and renewable energy standards adopted by the 2023 Legislature.

The 2020 Order also required the MTO to describe its efforts to engage with Midcontinent Independent Transmission System Operator (MISO) to ensure Minnesota's transmission needs have been met, and shall provide an assessment on whether MISO has been responsive to Minnesota's identified and likely transmission needs. This information can be found in Chapter 2, Section 2.9.

[2] Minn. Laws 2015, 1Sp2015, ch. 1, art 3, s 22, codified at Minn. Stat. § 216B.2425, subds. 2(e) and 8.

In the Commission's June 29, 2022 Order Accepting Report, the MTO was ordered to include the information that was required to be filed in the 2021 Report in their 2023 Report as well as the following:

1) Expected sustained HVTL or generation planned outages;
2) Whether those outages are anticipated to have new or incremental congestion; and
3) Whether those outages are anticipated to contribute to sustained incremental congestion.

This information is found in Chapter 9.

The following is a summary of each subsequent chapter of the 2023 Biennial Report.

Chapter 2 describes the biennial reporting requirements. This includes a discussion of the specific information the MPUC directed the utilities to include in the 2023 Biennial Report. Chapter 8 contains the information on clean energy goals.

Chapter 3 is titled Transmission Studies. This chapter includes a table listing a number of studies that have been completed over the past two years. In addition, a number of ongoing regional studies are described in some detail, and several more local, load-serving studies are identified in a separate table. A description of the MISO Transmission Expansion Plan (MTEP) Report is included since most planning is now approved by MISO, and the MTEP Reports show most of the information about the pending projects.

Chapter 4 is the Public Participation chapter. Several recent examples are provided regarding ways utilities have provided opportunities for the general public and local government to learn about and participate in the development of new transmission projects. This chapter summarizes the evolution of MPUC requirements relating to transmission planning and the preparation and submission of the Biennial Report. A section is included describing the webpage the MTO maintains (www.minnelectrans.com) that is available to the public to learn about ongoing transmission projects.

Chapter 5 provides general information about the six Transmission Planning Zones in the state.

Chapter 6 is where all the Transmission Needs are identified. The Report identifies approximately 164 separate transmission inadequacies across the state, including 97 new ones identified in the 2023 Biennial Report.

Each inadequacy is assigned a Tracking Number. The Tracking Number reflects the year the inadequacy was identified and the zone in which it is located. A brief description of each project is provided in the Report, and a reference is provided for each one to where detailed information can be found in the applicable MTEP Report. The 2022 MTEP Report, for example, would be called MTEP22. In addition, information about each pending project, by Tracking Number, is provided. This information addresses alternatives considered, a schedule, and the general impacts on the environment and the area once the project is constructed.

The MTEP Report referenced in the table for each Tracking Number will contain detailed information about the project, including alternatives, costs, and a schedule. Chapter 6 also presents comprehensive instructions on how to find the appropriate MTEP Report containing the desired information. The utilities have also attempted to indicate whether a Certificate of Need (CON) from the Commission might be required for a particular project selected to address a named inadequacy.

Certain projects have been completed since the 2021 Report was filed two years ago or are no longer necessary because of a change in demand or some other factor. These completed or cancelled projects are listed in a table for each zone in Chapter 6.

Chapter 7 focuses on the 14 utilities jointly filing this report. A brief description of each utility and the name and address of a contact person are provided. Information about the number of miles of transmission lines in Minnesota is also provided for each utility.

Chapter 8 provides an analysis of the utilities' progress toward compliance with state RES requirements. Not all utilities that own transmission lines are subject to the state RES, and some utilities that are not required to participate in the Biennial Report must meet the RES milestones. All utilities subject to the RES participated in providing information for this part of the Report.

The utilities subject to the RES have provided a Gap Analysis. A Gap Analysis is an estimate of how many more megawatts of renewable generating capacity a utility will require beyond what is presently available to meet an upcoming RES milestone of a certain percentage of retail sales from renewables. Generally, the Gap Analysis shows that the utilities are in compliance with present standards and expect to have enough generation and transmission to meet RES milestones into the future. Future guidance from the Commission regarding compliance with the CFES may also affect this analysis.

Chapter 9 discusses HVTL or generation planned outages, whether those outages are anticipated to have new or incremental congestion; and whether those outages are anticipated to contribute to sustained incremental congestion.

MPUC Process. Upon receipt of this Report, the Commission will solicit comments from the Department of Commerce, interested parties, and the general public. Any person interested in commenting on the Report or following the comments of others should check the efiling docket for this matter or in some other manner contact the Commission. The Docket Number is E999/M-23-91. The precise schedule for filing comments is established by Minn. Rule Chapter 7848 relating to the biennial reporting process. It is anticipated the MPUC will make a final decision on the 2023 Biennial Transmission Projects Report in May 2024.

2.0 Biennial Report Requirements

2.1 Generally

Prior Reports
This is the twelfth Biennial Transmission Projects Report to be filed by those utilities that own or operate electric transmission lines in Minnesota. The obligation to file such a report was created by the Minnesota Legislature in 2001.[3] The statute requires the utilities to file their transmission report by November 1 of each odd-numbered year.

All previous reports are all available on the Commission's eDockets webpage using the Docket Number from the table below. The past reports are also available on the webpage maintained by the utilities: http://www.minnelectrans.com/. The 2023 Report will also be posted on that webpage.

Biennial Report	MPUC Docket Number	MPUC Order
2023	E999/M-23-91	
2021	E999/M-21-111	June 29, 2022
2019	E999/M-19-205	August 19, 2020
2017	E999/M-17-377	June 12, 2018
2015	E999/M-15-439	May 27, 2016, Errata June 7, 2016
2013	E999/M-13-402	May 12, 2014
2011	E999/M-11-445	May 18, 2012
2009	E999/M-09-602	May 28, 2010
2007	E999/M-07-1028	May 30, 2008
2005	E999/TL-05-1739	May 31, 2006
2003	E999/TL-03-1752	June 24, 2004
2001	E999/TL-01-961	August 29, 2002

Minn. Stat. § 216B.2425 requires the utilities to list in the report specific present and reasonably foreseeable future inadequacies in the transmission system in Minnesota. The term "inadequacy" was not defined by the Legislature or by the Commission. The utilities have consistently stated that the term "inadequacy" is interpreted to be a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a consistently reliable fashion and in compliance with regulatory standards. This definition has been accepted by the Commission and others in past dockets.

The statute spells out certain categories of information that should be included in the report for each inadequacy, and the Commission has adopted rules to expand and clarify what is expected

[3] Minn. Stat. § 216B.2425.

to be in the report.[4] These laws generally require not only an identification of present and foreseeable inadequacies but also a discussion of alternative ways of addressing each inadequacy and the potential issues and impacts associated with possible solutions to the situation. The utilities are also required to provide opportunities for public input in the planning and development of solutions to the various inadequacies and to describe in the report the efforts undertaken to involve the public. The utilities discuss in Chapter 4 various efforts that have been undertaken to involve the public in transmission planning.

Over the years, in response to experiences with the rule requirements and to other developments in transmission planning, the MPUC has modified the application of the rules in a number of significant ways. One important modification recognizes that most transmission planning is now approved through MISO. MISO prepares a report each year, called the MTEP Report. MISO transmission planning is conducted in public forums and the MTEP Report is publicly available on the Internet. Unlike this state report, which is prepared every other year and focuses only on Minnesota, the MTEP Report is updated yearly and describes in detail transmission planning needs throughout the entire jurisdictional area of MISO, and not just in Minnesota.

Consequently, for the past six biennial reports – 2011, 2013, 2015, 2017, 2019 and 2021 – the Commission has allowed the utilities to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota. The 2023 Report, with the Commission's concurrence, also relies on the latest MTEP Report to identify upcoming transmission needs and to provide the necessary information about the possible alternatives considered to address each inadequacy. The utilities explain in section 6.1 ways to find the pertinent information about each inadequacy in the MTEP Report.

The MPUC has also recognized that holding public meetings around the state and holding a webinar to describe ongoing transmission planning and needs has not resulted in any substantial participation by the public. The MPUC has granted the utilities a variance for the past several years from the requirement in the rules to hold yearly planning meetings in each transmission planning zone. For 2023, the MPUC has continued this variance and exempted the utilities from holding a webinar. However, the utilities continue to conduct transmission planning in a manner that is open to the public and opportunities are provided for the public to participate in such planning and in the discussion of alternative solutions to the transmission needs under review. MISO also holds meetings open to the public to discuss their transmission plans and processes.

In its 2022 Order accepting the 2021 Biennial Report, the Commission said that the MTO shall include content similar to 2021 Report, and include:

1) Expected sustained HVTL or generation planned outages;
2) Whether those outages are anticipated to have new or incremental congestion; and
3) Whether those outages are anticipated to contribute to sustained incremental congestion.

[4] Minn. R. 7848.

Waiver Request for 2025 Report
The MTO requests the Commission to extend the rule variances granted in the June 29, 2022, Order accepting the 2021 Biennial Report (and previous orders) for the 2025 Biennial Report as well, such that the future report requirements will mirror the content, notice and participation requirements of this 2023 Biennial Report. The MTO requests it be allowed to continue to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota and that the public meeting or webinar requirements in Minn. Rule 7848.0900 and related to outreach in Minn. Rule 7848.1000 be waived. As has been demonstrated in previous biennial report proceedings, application of these rules would excessively burden the MTO by requiring them to spend money and divert engineers and other experts to producing duplicative information and attend meetings that do not appear to have a corresponding public benefit; prior lack of public participation in the public meetings and webinars demonstrates that waiving the rules does not adversely affect the public interest, and granting the variances is not contrary to any standard imposed by law.

We will provide a link to the report on the MTO website, www.minnelectrans.com as well as directions to access the report via eDockets.

2.2 Reporting Utilities

Minn. Stat. § 216B.2425 applies to those utilities that own or operate electric transmission lines in Minnesota. The MPUC has defined the term "high voltage transmission line" (HVTL) in its rules governing the Biennial Report to be any line with a capacity of 200 kilovolts or more and any line with a capacity of 100 kilovolts or more and that is either longer than ten miles or that crosses a state line.[5] Each of the entities participating in filing this report owns and operates a transmission line that meets the MPUC definition. Information about the utility and transmission lines owned by each utility is provided in Chapter 7 of this Report. In addition, a contact person for each utility is included in Chapter 7.

The statute allows the entities owning and operating transmission lines to file this report jointly. The MTO has elected each filing year to submit a joint report and does so again with this report. The utilities jointly filing this report are:

American Transmission Company, LLC
Central Minnesota Municipal Power Agency
Dairyland Power Cooperative
East River Electric Power Cooperative
Great River Energy
ITC Midwest LLC
L&O Power Cooperative
Minnesota Power
Minnkota Power Cooperative
Missouri River Energy Services

[5] Minn. R. Ch. 7848.0100, subp. 5.

Northern States Power Company d/b/a Xcel Energy
Otter Tail Power Company
Rochester Public Utilities
Southern Minnesota Municipal Power Agency

Of the above utilities, East River Electric Power Cooperative, L&O Power Cooperative and Minnkota Power Cooperative are not members of MISO; all the others are. Since the Mid-Continent Area Power Pool (MAPP) was dissolved in late 2015, resulting in the termination of MAPPCOR, the nonprofit organization that did the planning work for the MAPP utilities, MISO has performed many of the planning roles for Minnkota Power Cooperative.

2.3 Certification Requests

Minn. Stat. § 216B.2425, subd. 2, provides that a utility may elect to seek certification of a particular project identified in the Biennial Report. According to subdivision 3, if the Commission certifies the project, a separate CON under Minn. Stat. § 216B.243 is not required.

On May 30, 2023, the MTO filed a letter to the Commission in the instant docket that there would be no certification requests included with the 2023 Biennial Report.

2.4 General Impacts

In its May 12, 2014, Order approving the 2013 Biennial Report, the Commission recognized that reference to the latest MTEP Report was an appropriate way to provide useful information about the inadequacies identified in the Biennial Report, but that the MTEP Report did not provide general information about the potential environmental, social, and economic impacts of possible alternatives to address the inadequacy, as required by Minn. Stat. § 216B.2425, subd. 2(c)(3). The Commission stated in its Order at page 6 that "in the future the information [in the MTEP Report] must be supplemented with a fuller discussion of economic, environmental, and social issues related to proposed alternative solutions to inadequacies listed in the report."

The Commission stated in its May 27, 2016, Order approving the 2015 Report that the MTO "shall include in the 2017 Report the requirements addressed in Minn. Stat. § 216B.2425, subd. 2(c)(3)." Since the Commission and the Department of Commerce staff determined that the information the utilities provided in the 2015 Biennial Report satisfied the obligation to report on these impacts, the MTO will address the potential impacts of the various projects in the same manner in this Report. The discussion below describes how these impacts are addressed.

First, it is difficult to provide significant information about a transmission need expected several years in the future. The MPUC rules require the utilities to identify inadequacies that might affect reliability over the next ten years.[6] A transmission planner is often unable to identify possible alternatives or the impacts of the alternatives, for inadequacies ten years in the future.

[6] Minn. R. Ch. 7848.1300, subp. D.

Moreover, it is not uncommon for a potential reliability issue that may be several years in the future to subsequently be delayed for several more years or even indefinitely because of unforeseen events such as an economic recession or the closing of a large industrial customer or even a change in government policy or tax provisions. Also, more pressing problems may develop that take precedence over more minor concerns and transmission planners may have to focus their attention on other projects.

Importantly, the statute says the utilities are to identify general economic, environmental, and social issues associated with each alternative. These are issues not always possible to know during the planning stage; various issues may evolve when a particular project is developed in more detail. It is sufficient to address potential issues in a general way, as the utilities have done here.

While it is not possible for the utilities to provide specific discussion of potential impacts for each of the approximately 164 separate Tracking Numbers identified in this Biennial Report, transmission planners and utility staff are well aware of the kind of issues that arise with any large energy facility, whether a transmission line or a generating plant. For example, a transmission line may cross a wetland, or run through an agricultural field, or follow a residential street. A new generating plant has a certain footprint, and may result in the emission of various pollutants, and may require the transport of fuel. A large energy project has tax consequences for local government. Jobs will be created by the construction of a new facility, and the local area will be disrupted for a time while construction is ongoing. These are the kind of general impacts that can be addressed for projects that have not developed to the point of specific alternatives having been identified.

An in-depth analysis of potential impacts of a proposed project and the identified alternatives will be provided once the utility has determined that a need for new infrastructure is certain enough and imminent enough that a project must be pursued. This is the time the public generally begins to take notice of the need for a project and to participate in the analysis of alternatives. And this is the time the utility must begin to pull together the information required to complete applications for a CON and for a permit. These applications, and any environmental review conducted as part of the application process, will examine potential economic, environmental, and social issues in depth, with opportunities for public involvement and input.

The MTO can provide in this Biennial Report only a general discussion of the kind of impacts associated with certain types of energy projects, like transmission lines and substation upgrades and generating facilities. A more detailed discussion of impacts will be provided when a specific project has been identified, alternatives have been considered, and permit application have been submitted.

2.5 Renewable Energy Standards

The utilities are required to include in the Biennial Report a discussion of necessary transmission upgrades required to meet upcoming renewable energy standards.[7] In 2023, the Minnesota Legislature amended the objectives set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (CFES) (see Minn. Laws 2023, ch. 7). As with previous reports, this discussion is included in Chapter 8.

2.6 Distribution Report & Grid Modernization

In 2015 the Legislature amended Minn. Stat. § 216B.2425 to add two additional requirements for utilities operating under multiyear rate plans, a category that at present includes only Xcel Energy. Subdivision 2(e) requires Xcel Energy, at the time of the Biennial Transmission Projects Report filing, to report:

> *investments that it considers necessary to modernize the transmission and distribution system by enhancing reliability, improving security against cyber and physical threats, and by increasing energy conservation opportunities by facilitating communication between the utility and its customers through the use of two-way meters, control technologies, energy storage and microgrids, technologies to enable demand response, and other innovative technologies.*

This reporting requirement is often referred to as the Grid Modernization Report. The MPUC in May 2015 opened a separate docket for consideration of efforts related to modernization of the transmission and distribution grid. (MPUC Docket No. E999/CI-15-556.)

Further, subdivision 8, which was also added in 2015, provides:

> *Each entity subject to this section that is operating under a multiyear rate plan approved under section 216B.16, subdivision 19, shall conduct a distribution study to identify interconnection points on its distribution system for small-scale distributed generation resources and shall identify necessary distribution upgrades to support the continued development of distributed generation resources, and shall include the study in its report required under subdivision 2.*

These reporting requirements apply only to utilities operating under an approved multiyear rate plan approved by the MPUC under section 216B.16, subd. 1, and Xcel Energy is the only utility currently operating under such a plan and the only utility required to file a distribution study and grid modernization plan. The table below shows the Biennial Distribution-Grid Modernization Reports that Xcel Energy has submitted under Minn. Stat. § 216B.2425.

[7] Minn. Stat. § 216B.2425, subd. 7.

MPUC Docket Number	Date Filed
E002/CI-15-962	October 30, 2015
E002/CI-17-776	November 1, 2017
E002/CI-18-251	November 1, 2018
E002/M-19-666	November 1, 2019
E002/M-21-694	November 1, 2021
E002/M-23-452	November 1, 2023

2.7 Non-Wire Alternatives

Overview
In the Commission's June 12, 2018 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-17-377, Order Point 2 states:

> *In their 2019 Report, the MTO shall include content similar to 2017 Report, and include an improved and expanded assessment of non-wire alternatives . . . .*

This section provides a broad discussion of non-wires alternatives to give context for the analysis that follows in Chapter 6, where potential non-wires alternatives are discussed for applicable transmission projects.

Application of Non-Wires Alternatives
Overall, this Report identified approximately 164 transmission inadequacies in the State and proposes transmission or non-wires alternatives to address them. The identified transmission inadequacies fall into the following general categories: load interconnection, generator interconnection, thermal overloads and voltage violations.

Depending on the type of issue and its magnitude, each project's transmission owner may consider a broad range of alternatives for addressing reliability concerns. Alternatives considered may include both wire and non-wire solutions. The types of alternatives considered for a particular issue are dependent on the nature of the problem to be addressed. To be a viable alternative, a solution must be available (1) at the necessary time, (2) with the necessary response, and (3) for the necessary duration, to address the inadequacy at hand.

Non-wires alternatives are electric utility system supply-and demand-side projects and operating practices that defer or replace the need for specific transmission projects, at lower total resource cost, by reliably reducing transmission congestion at times of high demand in specific grid areas.[8] Examples of non-wires transmission alternatives may include: establishing new operating guides or procedures, demand side management (DSM), distributed generation (DG), and storage of electricity or heat or ponded water.

[8] www.nrri.org.

Generally speaking, certain categories of non-wires alternatives may be best suited to address certain categories of identified transmission inadequacies. For example, the need for local load serving transmission could potentially be alleviated or delayed with DSM or appropriately sited renewable generation including DG interconnections on the distribution system. The availability of DG has the effect of reducing the need to serve the load from the transmission system and has the greatest impact if the DG is available during peak load conditions. Solar PV offers a positive, but not perfect, correlation with high load periods during the summer, while a combination of distributed solar and/or wind with distributed storage offers the greatest impact to reduce effective loads served. Transmission planners continue to evaluate non-wire options that result in the avoidance of establishing new transmission lines. As the costs of non-wire alternatives become more competitive with traditional wire solutions, the transmission planners are closely examining DG and other distribution solutions against transmission alternatives.

Implementation of non-wires alternatives can also bring different challenges. For example, as DG penetration grows, the communication technology will have to be improved to manage DG installations. There will be more points to monitor to ensure load can be reliably served from multiple generation resources. Real time system operations will become more complex as the generation becomes more variable and concentrated. Distribution automation likely will be needed to assist the operator in shifting load to other systems if the expected generation resources are not available.

More DG on the system and in closer proximity to load decreases reliance on the transmission system. Solar is anticipated to be the more common type of DG in the future, but fuel-cell technology or some yet unknown generation source or Load Modifying Resource (LMR) may also become viable alternatives. It is expected that storage capabilities will follow the adoption and installation of solar and wind to allow more full use of the renewable resources and increase their value throughout the daily load cycle. Storage can also increase the off-the-grid opportunities for existing and future electric users.

The table below describes the benefits and challenges of different types of non-wires alternatives in addressing identified categories of transmission deficiencies.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar + Storage**	**Wind + Storage**	**Demand Side Management**
Load Inter-connection	A combination of solar and storage may be an option for load serving deficiencies. Storage needs to be implemented in ways to ensure reliability performance equal to the reliability provided by transmission options. Based on geographic locations, land constraints may be a challenge to installation of adequate solar generation to meet the new or expanding load. In addition, current costs for solar/storage installations are often higher than transmission load serving options.	A combination of wind and storage may be an option for load serving deficiencies. Storage needs to be implemented in ways to ensure reliability performance equal to the reliability provided by transmission options. In addition, current costs for wind/storage installations are often higher than transmission load serving options.	Demand side management is not applicable for load interconnection projects as the deficiencies are driven by new load. For existing load expansions, DSM is considered but may not be available in quantities or durations needed to reliably address the deficiency.
Generator Inter-connection	Not applicable for these projects.	Not applicable for these projects.	Not applicable for these projects.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar + Storage**	**Wind + Storage**	**Demand Side Management**
Thermal Overloads	Solar and storage are looked at individually and in combination for transmission thermal overloads. Since transmission availability is ~99%, viable alternatives will have to have similar availability. Solar and storage can help alleviate overloads on a transmission line depending on their duration and location, but the current costs of these options are typically significantly more expensive than traditional transmission solutions.	Wind and storage are looked at individually and in combination for transmission thermal overloads. Since transmission availability is ~99%, any option will have to have similar availability. Wind and storage can help alleviate overloads on a transmission line depending on their duration and location, but the current costs of these options are typically significantly more expensive than traditional solutions.	Demand Side Management is an option for transmission thermal overloads. DSM must be available in adequate amounts and duration and be sufficiently reliable to be called upon to address these transmission inadequacies.
Voltage Violations	Solar and storage are looked at individually and in combination for voltage violations. Since transmission availability is ~99%, any option will have to have similar availability. Solar and storage can help alleviate low and high voltages depending on location, duration and applicability of the installation, but the current costs of these options typically are significantly more expensive than traditional transmission solutions.	Wind and storage are looked at individually and in combination for transmission voltage violations. Since transmission availability is ~99%, any option will have to have similar availability. Wind and storage can help alleviate low and high voltages depending on location, duration and applicability of the installation, but the current costs of these options typically are significantly more expensive than traditional transmission solutions.	Demand Side Management is an option for transmission voltage violations. DSM must be available in adequate amounts and duration and be sufficiently reliable to be called upon to address these transmission inadequacies. DSM is not generally a viable solution for high-voltage inadequacies.

Conclusion

Non-Wire Alternatives are discussed in Chapter 6 and are deployed as deemed appropriate by the project transmission owner based on the nature of the transmission inadequacy. The Minnesota Transmission Owners remain committed to evaluating non-wires alternatives to proposed transmission projects and may revisit these analyses based on future technological improvements and cost efficiencies.

2.8 FERC, MISO, and Commission Actions Related to Distributed Energy Resources and Distribution Planning

In the Commission's June 12, 2018 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-17-377, Order Point 2 states:

> *In their 2019 Report, the MTO shall include content similar to 2017 Report, and include . . . a discussion of relevant actions by FERC, MISO, and the Commission related to distributed energy resources and distribution planning.*

The Commission, the Federal Energy Regulatory Commission (FERC), and MISO, discuss distributed energy resources and distribution planning in a wide range of dockets and contexts. In this section we include the discussion of relevant actions by the Commission, FERC and MISO related to distributed energy resources and distribution planning.

Minnesota Public Utilities Commission

Broadly speaking, the Minnesota Public Utilities Commission has addressed distribution planning and distributed energy resources in a wide variety of policy,[9] planning,[10] fact specific[11] and annual reporting dockets.[12]

[9] *See, e.g.*, *In the Matter of a Commission Investigation into the Potential Role of Third-Party Aggregation of Retail Customer*, Docket No. E999/CI-22-600; *In the Matter of a Commission Investigation on Grid and Customer Security Issues Related to Public Display or Access to Electric Distribution Grid Data*, Docket Nos. E999/CI-20-800 and E002/M-19-685; *In the Matter of Xcel Energy's Tariff Revisions Updating Interconnection Standards for Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket No. E002/M-18-714; *In the Matter of a Commission Inquiry into the Creation of a Subcommittee under Minn. Stat. §216A.03, subd. 8*, Docket No. E999/CI-17-284; *In the Matter of Xcel Energy's Petition for Tariff Modifications Implementing Rules on Cogeneration and Small Power Production*, Docket No. E002/M-16-222; *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Docket Nos. E999/CI-16-521 and E999/CI-01-1023; *In the Matter of a Commission Inquiry into Fees Charged to Qualifying Facilities*, Docket No. E999/CI-15-755; *In the Matter of a Commission Inquiry into Standby Service Tariffs*, Docket No. E999/CI-15-115; *In the Matter of the Commission Investigation on Grid Modernization*, Docket No. E999/CI-15-556; *In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10(e) and (f)*, Docket No. E999/M-14-65; and *In the Matter of Possible Amendments to Rules Governing Cogeneration and Small Power Production, Minnesota Rules, Chapter 7835*, Docket No. E999/R-13-729.

[10] *See, e.g.*, *In the Matter of the Xcel Energy 2022 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8*, Docket No. E-002/M-22-574; *In the Matter of the Xcel Energy 2021 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8*, Docket No. E-002/M-21-767; *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan*, Docket No. E002/M-21-694; *In the Matter of the Xcel Energy 2020 Hosting Capacity Report Under Minn. Stat. §216B.2425, Subd. 8*, Docket No. E002/M-20-812; *In the Matter of Xcel Energy's Integrated*

FERC

The 2021 Biennial Report discussed FERC Order Nos. 841 and 2222 as they pertain to storage and non-storage Distributed Energy Resource (DER) aggregations participating in wholesale markets. Since the last report, FERC issued Order No. 2023, adopting reforms to modernize the transmission grid by streamlining the interconnection processes for transmission providers.

Order No. 2023, adopted in July of 2023, includes several reform to the interconnection processes, such as instituting a first-ready-first-served cluster study process, increased financial commitments for interconnection customers, improved efficiency of the interconnection process, firm deadlines and penalties for transmission providers if they fail to complete their interconnection studies on time, and incorporating technological advancements into the interconnection process, such as consideration of advanced transmission technologies in the interconnection study process and an update of modeling and performance requirements for inverter-based resources to ensure continued system reliability. The final rule requires all public utilities to adopt revised pro forma generator interconnection procedures and agreements to ensure that interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, and timely manner, and to prevent undue discrimination.

MISO

In 2021, MISO noted on its website that "[a] high penetration of [DERs] could have notable implications for MISO and require a stronger transmission and distribution interface. The DER issue [in the MISO stakeholder process] is intended to explore and advance collaboratively developed DER priorities with stakeholders." MISO subsequently held a number of stakeholder workshops that resulted in a number of changes supporting the coordination of DER between DER interconnection customers, distribution providers, transmission owners, and MISO. Most notably, the creation of the MISO DER Affected System Study (AFS) will promote coordination and study of DER that exceed certain impact thresholds on the transmission system. The changes and improvements resulting from this new process may act as an important catalyst for enabling DER participation in the larger power system.

Distribution Plan and Advanced Grid Intelligence and Security Certification Request, E002/M-19-666*;* Docket No. E002/CI-18-251; *In the Matter of Xcel Energy's 2018 Integrated Distribution Plan*, Docket No. E002/CI-18-251; *In the Matter of Distribution System Planning for Dakota Electric Association*, Docket No. E111/CI-18-255; *In the Matter of Distribution System Planning for Minnesota Power*, Docket No. E015/CI-18-254, *In the Matter of Distribution System Planning for Otter Tail Power*, Docket No. E017/CI-18-253.

[11] *See, e.g.*, *In the Matter of a Formal Complaint and Petition for Relief by Nokomis Energy LLC and Union Garden LLC Against Northern States Power Company d/b/a Xcel Energy*, Docket No. E002/C-22-212; *In the Matter of a Formal Complaint and Petition for Expedited Relief by Sunrise Energy Ventures LLC Against Northern States Power Company d/b/a Xcel Energy,* Docket No. E002/C-21-160; *In the Matter of the Appeal of an Independent Engineer Review Pertaining to the SunShare Linden Project (Community Solar Gardens Program)*, Docket No. E002/M-19-29; *In the Matter of a Formal Complaint Against Xcel Energy by Sunshare, LLC*, Docket No. E002/CI-19-203; *In the Matter of the Petition of Northern States Power Company, dba Xcel Energy, for Approval of its Proposed Community Solar Garden Program*, Docket No. E002/M-13-867; *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket No. E002/CN-12-1240.

[12] *See, e.g.*, *In the Matter of Annual Cogeneration and Small Power Production Filings*, Docket No. E999/PR-21-9; *Distributed Generation Interconnection Report*, Docket No. E999/PR-21-10.

MISO filed its Order No. 841 compliance filing in December 2018 with the provisions regarding DERs. Subsequently, in their response to FERC's request for more information filed in April 2019, MISO updated their Distribution Connected Electric Storage Resource (ESR) form agreement to require an attestation from the ESR that all necessary metering and other arrangements are completed before they can participate as a distribution connected ESR in MISO. FERC accepted MISO's Order No. 841 compliance filing in November 2019 with an effective date of June 2022. The changes associated with this filing went into production on September 1, 2022.[13]

In Order No. 2222, FERC established a compliance date for the Regional Transmission Operators (RTO) and Independent System Operators (ISO) of July 19, 2021. MISO filed a request to extend that date until April 18, 2022, and FERC granted MISO's request. MISO's proposal was submitted is currently awaiting ruling after additional comments were requested from MISO and submitted to FERC. MISO's DER Task Force (DERTF) has continually met to discuss the topic of implementing Order No. 2222, which may transition to other DER related topics after the ruling on MISO's filing of Order No. 2222 is complete.

Grid North Partners (GNP)
Grid North Partners, an evolution of CapX2020, is a voluntary partnership of 10 Minnesota and surrounding area transmission owning utilities[14] formed in 2004 to collaboratively expand the Upper Midwest transmission grid. Approximately three years ago, GNP, recognizing a rapid change was occurring and the challenges facing the transmission grid needed to be identified, published the CapX2050 Transmission Vision Report so solutions could be identified.[15] GNP has been working to identify solutions to address those key findings via two primary avenues:

- Technical efforts – consisting of collaborative participation in MISO's Long-Range Transmission Planning (LRTP) effort, and
- Education & stakeholder engagement – including dialog with policy makers, utilities, stakeholders, and landowners to discuss needed improvements to ensure the transmission system in the Upper Midwest is prepared to deliver tomorrow's energy 24 hours a day, 7 days a week.

GNP Technical Effort: GNP Members have been actively coordinating as MISO develops their LRTP Tranche 2 study. Coordination around system modeling, study assumptions and solution alternatives will help develop provide feedback as the LRTP Tranche 2 effort continues into 2024. A transmission congestion study was also completed by the GNP Technical Team. The study reviewed historical and projected transmission system congestion in the MISO market with an effort to identify potential system upgrades that could potentially reduce congestion in the

[13] For more information about this process and timeline *see* https://www.misoenergy.org/stakeholder-engagement/MISO-Dashboard/storage-participation--ferc-order-841-compliance/.
[14] Grid North Partners member utilities include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.
[15] https://gridnorthpartners.com/wp-content/uploads/2021/02/CapX2050_TransmissionVisionReport_FINAL.pdf

GNP footprint. The congestion effort was wrapped up in 2023 and at least 21 projects from several GNP member companies are underway to increase transmission capacity and reduce market congestion in the GNP footprint.

Institute of Electrical and Electronics Engineers (IEEE)
While not specifically requested by Commission, another important aspect is various entities' work on IEEE 1547-2018, which is a recently published DER interconnection and interoperability standard.

The revised standard addresses three new broad types of capabilities for DER: local grid support functions; response to abnormal grid conditions; and exchange of information with the DER for operational purposes. The standard was written with a large set of required capabilities with an expectation that not all capabilities would be immediately implemented in the field. In this way, it offers options for grid operators preparing for scenarios with high penetration of DER. Some details associated with implementing the standard are part of the Commission's E002/M-16-521 docket, especially in Phase II which considers statewide technical standards, and other details are expected to be associated in utility business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates the Authority Governing Interconnection Requirements and Regional Reliability Coordinator possess a guidance role in implementing these capabilities, which, in Minnesota, are the Minnesota Commission and MISO respectively. Commission Staff requested information and guidance from MISO through a working group associated with the E002/M-16-521 docket. The response from MISO included a plan to convene a stakeholder group so guidance on the topic could be provided on a regional basis. The Commission's interest in resolving questions associated with adopting these capabilities is helping to drive important stakeholder conversations.

Local grid support functions have generated interest in the industry in recent years based on implementation of these functions in states such as Hawaii and California in areas of high DER deployment. The IEEE 1547-2018 standard allows a utility to specify ways local grid support functions are to be used. Xcel Energy proposed in the E002/M-16-521 docket that use of the local grid support functions should be published in utility-specific technical manuals.

The interoperability aspects of IEEE 1547-2018, which include concepts of DER monitoring and control, mark the most future leaning required capabilities. When certified equipment is available, every DER will have a standardized communication interface for exchanging data and performing remote operations. A communication network would be necessary for making use of the interoperability interface.

Electric Power Research Institute (EPRI)
EPRI has led several efforts to understand the general technical needs to meet compliance with FERC Order 2222. The EPRI workplan is divided into phase 1 and phase 2. EPRI released several collaborative reports for phase 1 in July of 2021. Various MTO utilities have been participating in the working groups to aid in the development of the collaborative reports.

The first report focuses on the metering, data, information and telemetry requirements for ISOs and RTOs, distribution utilities, transmission utilities, DERs and aggregators. The report is a guidance for future market and interconnection requirement design.

The second report focuses on the systems interoperability and cyber security of DER and aggregators to ensure best practices are identified to maintain system security in the decentralized environment.

The third report focuses on the role of the distribution utility in enabling market participation for DERs and aggregators in wholesale markets. The report is intended to provide high level technical guidance for what is required to fulfill various roles.

Finally, EPRI is also providing guidance to the Transmission Operators with a shorter technical briefing to provide guidance on the various ways to ensure reliability in a distributed environment.

2.9 MISO and Minnesota's Transmission Needs

In the Commission's August 19, 2020 ORDER ACCEPTING REPORT, GRANTING VARIANCE, AND SETTING ADDITIONAL REQUIREMENTS, in Docket No. E999/M-19-205, Order Point 5(d). states:

> *The MTO shall describe its efforts to engage with MISO to ensure that Minnesota's transmission needs have been met, and shall provide an assessment of whether MISO has been responsive to Minnesota's identified and likely transmission needs.*

Minnesota TOs participate in many different MISO processes to ensure our needs are being addressed and our voices are being heard. MISO has several different TO groups set up to address various functions under MISO control. Below are the MISO Groups and processes that Minnesota TOs are involved in.

MISO Planning Advisory Committee (PAC): The PAC is formed to provide advice to the MISO Planning Staff on policy matters related to the process, adequacy, integrity and fairness of the MISO-wide transmission expansion plan. The Planning Advisory Committee reports to the MISO Advisory Committee.

Issues the MISO PAC deal with are typically related to generation interconnection process, annual MTEP reliability process, and tariff and policy issues.

MISO Planning Advisory Committee (misoenergy.org)

MISO Planning Subcommittee (PSC): The PSC advises, guides, and provides recommendations to MISO staff with the goal to enable better execution of its planning responsibilities, in an efficient and timely manner, as set forth in the MISO Tariff, Transmission Owner Agreement, FERC Order 2000 and other applicable documents.

Recent issues have revolved around how storage is going to be treated in MTEP and Interconnection studies. A link to that Committee follows.

MISO Planning Subcommittee (misoenergy.org)

MISO Subregional Planning Meeting (SPM): In accordance with FERC Order 890 Attachment K, MISO will host a series of SPMs to encourage an open and transparent planning process. Early in the process, stakeholders will participate in discussions of planning issues and proposals on a more local basis to discuss projects, issues and concepts potentially driving new transmission expansion on the grid. A link to those follows.

Subregional Planning Meeting (misoenergy.org)

MISO Regional Expansion Criteria and Benefits Working Group (RECBWB): The RECBWG is the forum for stakeholders to discuss existing or proposed criteria and cost allocation policies for regional and interregional cost-shared transmission projects.

The main issue for this group currently is cost allocation related to the recent LRTP effort on-going in MISO. Efforts to split MISO vs maintaining MISO as one RTO for cost-allocation purposes, as it relates to benefits and who pays is causing some tension across MISO stakeholders. A link to that group follows.

MISO Regional Expansion Criteria and Benefits Working Group (misoenergy.org)

MISO Interconnection Process Working Group (IPWG): The purpose of the Interconnection IPWG is to provide stakeholders a forum to develop revised generator interconnection queue process procedures with the goal of reducing study time and increasing certainty. It is intended that the work product of this Working Group will be included in Tariff filings to FERC and modifications to the Generator Interconnection Business Practice Manual. (BPM-015).

MISO is looking to streamline the process to help with timelines for Interconnection Customers. Some TOs feel this will put pressure on them with an already tight timeframe and MISO should just stick with the timelines already in the tariff. A link to that group follows.

MISO Interconnection Process Working Group (misoenergy.org)

MISO Reliability Operations Working Group (ROWG): This is a closed group with focus on grid operation and reliability of the system.

A recent issue brought to MISO is related to Transmission System reconfiguration requests from third party sources for economic reasons only. During construction or outages there is some significant congestion noted on the system that is costing some customers money, and they feel reconfiguring the transmission system to accommodate outages is a good option. TOs feel these types of requests and studies do not adequately address reliability concerns.

MISO Transmission Owners Compliance Task Team (TOCTT): This is a closed group to deal with the compliance efforts at MISO relating to FERC and North American Electric Reliability Corporation (NERC).

MISO Coordination
In the Commission's June 29, 2022 ORDER ACCEPTING REPORT, in Docket No. E999/M-21-111, Order Point 6 states:

> *The MTO must file, within 90 days, additional information as set forth in ordering paragraph 5(d) of the Commission's August 19, 2020, order, in Docket E-999/M-19-205, which required a filing within 90 days that included "an assessment of whether MISO has been responsive to Minnesota's identified and likely transmission needs."*

The MTO believes MISO has been responsive to Minnesota's identified and likely needed transmission, recognizing a number of challenges that abate progress in these areas.

The need for transmission in Minnesota, and throughout the region, is currently being driven by the continuing transition from central station conventional generation to a generation fleet geographically dispersed and highly dependent on wind and solar as primary fuels, supplemented with hydro, nuclear, and natural gas generation. MISO and the MTO are experiencing continued acceleration in this transition, despite limitations related to planning and constructing the transmission needed to fully facilitate the transition.

Partially in response to a request from the MTO via Grid North Partners and the State, MISO undertook a long-term transmission expansion planning initiative in late 2020 to assist in planning for this transition. MISO's Renewable Integration Impact Assessment (RIIA) identified renewables in the MISO footprint would reach 40% penetration in the next decade, based on public announcements, and transmission solutions are needed to significantly reduce curtailment of wind and solar generation sources.

The LRTP considered three generation and load profile "futures" (i.e., scenarios), with Future 3 being the more aggressive penetration of renewables and electrification. This comprehensive analysis required the development of robust models incorporating changes in generation and load to reflect Future 1. MISO and the MISO stakeholders engaged in multiple meetings to vet modeling assumptions, study results, and transmission alternatives to address the reliability issues presented by Future 1, which was developed to meet 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences. While the MTO would have preferred a more accelerated study process, we recognize the many challenges MISO addressed leading up to the MISO Board of Directors approving $10.4 billion in transmission enhancement on July 25, 2022.

MISO and the upper Midwest transmission owners are now beginning studies to leverage and build upon the no-regret Tranche 1 transmission projects and identify additional transmission projects to address reliability, economic, and resiliency issues present in the MISO Futures 2 and 3. The goal is to put forward another set of transmission projects (labeled Tranche 2) which could be approved by the MISO Board in late 2023 or 2024.

3.0 Transmission Studies

3.1 Introduction

The Commission requires the utilities include in each Biennial Report a "list of studies that have been completed, are in progress, or are planned that are relevant to each of the inadequacies identified" in the Report.[16] Since the 2011 Biennial Report, the utilities have broken this chapter up into several subsections, each addressing different types of studies. The same arrangement for reporting the studies is continued in this 2023 Report.

Section 3.2 describes studies completed to either address expansion of the transmission network to provide for generation expansion or address local inadequacy issues (noted with a Tracking Number). Section 3.3 describes ongoing regional studies that focus on expansion of the bulk electric system to address broad regional reliability issues and support expansion of renewable energy in the upper Midwest. Section 3.4 focuses on ongoing load serving studies done to address local inadequacy issues.

The MPUC rules state that the utilities must include in the Biennial Report a copy of "the most recent regional load and capability report of the Mid-Continent Area Power Pool."[17] As the utilities reported in the 2011 Report, however, MISO has taken over most of the planning that occurs in this part of the country. MAPP has not prepared a Load & Capability Report since May 2009. MAPP, in fact, discontinued its existence in October 2015.

3.2 Completed Studies

The following studies were completed since the last Biennial Report was submitted in October 2021. Previously completed studies can be found in previous Biennial Reports and are not repeated here. Where specific transmission projects have been identified, a Tracking Number is provided. The Tracking Number identifies the year the project was first considered for inclusion in a Biennial Report and the zone where the project is located.

Study Title	Year Completed	Utility Lead	Description
Worthington Area Study	2021	GRE ITCM MRES	GRE, ITCM & MRES studied the transmission system in the Worthington area to serve a potential load addition as well as mitigating existing reliability and operational concerns. See chapter 6, Southwest Zone, Worthington Area Projects.

[16] Minn. R. 7848.1300(F).
[17] Minn. R. 7848.1300(B).

Study Title	Year Completed	Utility Lead	Description
Barnesville Area	2022	GRE MRES OTP	GRE, MRES, and OTP are studying the transmission system in the Barnesville area to address local load serving concerns, and potential reliability benefits for the surrounding load pocket looking out towards the end of the planning horizon. The study is expected to be completed early 2022.
Pilot Knob Area Study	2022	GRE	Evaluate long range options for the Pilot Knob area. There is a future need to rebuild the Pilot Knob substation due to age and condition. This study will determine the feasibility of converting the area to 115 kV.
Minnkota Power Cooperative 2022 GFA Load Increase Study	2022	OTP	MPC requested an increase in their load limit under several Grandfathered Agreements in OTP's area. This study was performed to identify potential system needs related to the load increase.
Winton	2022	MP	Evaluated the need for capacitor banks and long-term reliability upgrades on the 115/46 kV system serving Tower, Ely, Winton, and Babbitt.
Duluth 34 kV	2023	MP	Evaluated the configuration of the existing 34.5 kV network within Duluth, looking at expanding the network to help offload the 13.8 kV system and provide full capacity ties to the 13.8 kV feeders. This study impacted the 15th Ave West Transformer Addition Project (2021-NE-N6) and the Ridgeview Transformer Addition Project (2023-NE-N9).
Verndale	2023	MP	Evaluated load-serving needs in the Verndale area to identify long-term transmission and distribution solutions, particularly as they may impact the scope of the Verndale Substation Modernization Project (2021-NE-N4).
Onigum Area Study	2023	GRE	Study the Onigum area for a possible 115 kV conversion.

3.3 Regional Studies

While every study undertaken adds to the knowledge of the transmission engineers and helps to determine the transmission facilities required to address long-term reliability and to transport renewable energy from various parts of the state to the customers, some studies are intentionally designed to take a broader look at overall transmission needs. Regional studies analyze the limitation of the regional transmission system and develop transmission alternatives to support multiple generation interconnection requests, regional load growth, and the elimination of transmission constraints that adversely affect utilities' ability to deliver energy to the market in a cost-effective manner.

MISO started a Regional Transmission Overlay Study (RTOS) in 2016, but due to limited benefits identified in the study MISO has put the study effort on hold.

3.3.1 MISO Transmission Expansion Plans

MISO engages in annual regional transmission planning and documents the results of its planning activities in the MTEP reports. The MTEP process is explained in detail in chapter 6 since the latest MTEP reports are being relied on to provide information about the transmission inadequacies identified in this Report. Earlier MTEP Reports were summarized in past Biennial Reports. For convenience, the following brief description of the latest MTEP reports is presented here. The MISO Expansion Plans are available on the MISO webpage. Visit http://www.misoenergy.org and click on "Planning."

MTEP20 Report
The MTEP20 report identified projects required to maintain reliability for the ten-year period through the year 2029 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP20 Executive Summary, the MISO staff recommended approval of approximately $2.5 billion in new transmission infrastructure investment. Of the $2.5 billion, $1 billion is new Baseline Reliability Projects, $606 million is Generation Interconnection Projects, and the remainder falls into the Other category.

MTEP21 Report
The MTEP21 report identified projects required to maintain reliability for the ten-year period through the year 2030 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP21 Executive Summary, the report included 335 new transmission projects, equaling $3 billion in investment to address near-term reliability needs and aging infrastructure. Of the $3 billion, $345 million were Generator Interconnection Projects, $187 million were new Baseline Reliability Projects, and approximately $2.5 billion fell into the Other category.

MTEP22 Report
The MTEP22 report identified projects required to maintain reliability and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP22 Executive Summary, the report proposed approval of 382 new transmission projects with $4.3 billion in investment to address current reliability needs and regional upgrades. Of the $4.3 billion, $8 million were Market Participant Funded projects,

$547 million were Generator Interconnection Projects, $545 million were new Baseline Reliability projects, and approximately $3.17 billion fell into the Other category.

MTEP23 DRAFT Report
The MTEP23 DRAFT report identifies projects required to maintain reliability and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future. MISO updated the MTEP portal on October 17, 2023, which can be found at MTEP23 Report (misoenergy.org).

3.4 Load-Serving Studies

Load-serving studies focus on addressing load serving needs in a particular area or community. Since many of the inadequacies in Chapter 6 are driven by load serving needs, many of these studies relate to specific Tracking Numbers.

Study Title	Anticipated completion	Utility lead for Study	Description
South Washington Load Serving Study	2019	NSP	Develop a comprehensive plan to serve the growing load around the City of Woodbury in eastern Twin Cities Area.
Great River Energy Large Load Studies	N/A	GRE	Great River Energy has had multiple requests across its member systems' service areas for potential large load installations. These loads have ranged from 2.5 MW to 500 MW. These requests have non-disclosure agreements and therefore are not communicated until the requesting party makes a decision to allow communication to other parties. Smaller load requests on occasion can be supplied by the existing transmission system, however in most cases new transmission will be required to serve these loads. Upon approval by the requesting party, Great River Energy will work with neighboring transmission owners in assessing the system for impacts for certain desired locations. Great River Energy will work with the State, if needed, upon notification of approval of a selected location for the new load.

Study Title	Anticipated completion	Utility lead for Study	Description
Fergus Falls Area Study	2024	GRE MRES OTP	The Fergus Falls area study is needed to evaluate the transmission system for any reliability violations (voltage or thermal), assess the capability the transmission system to serve a large load, and determine the best value plan that addresses system violations (if any) and reliably serves new and existing load in the Fergus Falls area.

4.0 Public Participation

4.1 Public Involvement in Transmission Planning

Both the statute (Minn. Stat. § 216B.2425) and the MPUC rule (Minn. R. 7848.0900) emphasize the importance of providing the public and local government officials with an opportunity to participate in transmission planning. Over the years of filing biennial reports, the utilities have tried, in accordance with MPUC requirements, various methods of advising the public of opportunities to learn about and participate in transmission planning activities.

The MPUC adopted rules for public involvement in transmission planning as part of the biennial report requirements in 2003. Initially, in accordance with Minn. Rule part 7848.0900, the utilities held public meetings across the state in each transmission planning zone to advise the public of potential transmission projects and to solicit input regarding development of alternative solutions to various inadequacies. These public meetings were poorly attended, with little input being offered.

As a result, in May 2008 when the MPUC approved the 2007 Report, the MPUC granted a variance from the obligation to hold these zonal meetings, and that variance has been extended each time since, including in the June 29, 2022 Order regarding this year's Biennial Report. No public meetings were required in the transmission planning zones as part of this year's biennial report submission.

In lieu of the public meetings, beginning with the preparation of the 2009 Report, the utilities held six webinars, one for each transmission planning zone, to report on the transmission inadequacies identified in the Biennial Report for each zone. These webinars were not any better attended than the zonal meetings were in previous years. Few questions and comments were generated.

For the 2011 Report, with Commission approval, the utilities held one webinar. Despite widespread notice of the webinar in a statewide newspaper, only a few people participated, and most of those were utility or state employees. In 2013, after the 2013 Biennial Report was filed, the utilities held another webinar. Again, essentially nobody participated – only one person joined in the webinar.

As a result, the Commission has now determined the utilities are not required to hold a webinar with regard to the Report.

4.2 MISO Transmission Planning

As has been described in previous biennial reports and again in this report, most transmission planning is now conducted through MISO. MISO provides numerous opportunities for the public to be involved in transmission planning. The reality is, however, that not many members of the general public avail themselves of these opportunities. This is understandable because transmission planning is an extremely technical endeavor.

4.3 MTO Website

The MTO have maintained a website (www.minnelectrans.com) for several years now; interested persons can obtain various information there about ongoing transmission planning efforts. Biennial Reports going back to 2005 are available on that website, as are many different transmission-related studies. There is a contact form on the webpage where visitors can ask questions of utilities about proposed projects. Only a handful of questions have ever been submitted using that method.

The MTO have even developed two short videos, available on the webpage, detailing items of interest to the general public about transmission lines. One video describes generally how the transmission planning process is done at utilities in Minnesota. The second video describes how to read the Biennial Transmission Report and engage with transmission owning utilities.

The utilities will continue to post the biennial reports on the webpage and to monitor any questions submitted. The utilities are open to comments from the public about how to improve the webpage.

4.4 Efforts to Involve the General Public and Local Officials on Specific Projects

The MTO utilities are aware of the importance of notifying the general public and local governmental officials of any potential large energy project in their area. The public may not get involved in early transmission planning activities, but public interest and awareness rises when projects are under consideration in a particular locale. The utilities often engage local governmental officials and the public in public meetings to discuss upcoming projects.

Minn. Stat. § 216E.03, subds. 3a and 3b, requires any utility planning to file an application for a route permit with the Commission for a new transmission project to notify local governmental officials within a possible route of the existence of the project and the opportunity for a preapplication meeting. The utilities do this, of course, and often local governmental bodies request a meeting with the utility.

As described further below, utilities implemented several best practices to encourage public input and stakeholder engagement in transmission planning efforts.

4.4.1 Transmission Project Public Involvement

During the last few years, utilities have developed early stakeholder engagement and public outreach efforts to increase participation in transmission planning and permitting dockets. Utilities' efforts related to the MISO LRTP Tranche 1 projects provide a good example of these efforts. Public outreach efforts for the Northern Reliability Project are described as an example; however, most other utility-led transmission projects utilize a similar approach to early public outreach.

- Northland Reliability Project
    - Minnesota Power and Great River Energy employed various engagement methods to provide information about the Northland Reliability Project to the public and federal, state, and local agencies, Tribal Nation representatives, and non-government organizations. The Project team developed a public engagement plan in late summer 2022 that consisted of two engagement phases – Route Corridor and Preliminary Route notifications – with the goal to share information about the project and gather insights on routing opportunities and constraints within the Project Area. Early coordination with stakeholders included project introduction letters along with a series in-person stakeholder workshops held fall 2022. The two phases of public engagement included in-person open houses, virtual self-guided public open houses, direct mailings, paid advertisements in local newspapers, social media posts, a dedicated email and hotline to field questions and comments, an interactive online comment map, a Project website, and detailed maps that could be downloaded and printed from the Project website and mailed project information packets. During the engagement process, the Northland Reliability Project team connected with hundreds of meeting attendees (in-person and virtual), gathered hundreds of routing comments, and had thousands of website visitors reviewing maps and project information.

These are the kind of efforts that utilities follow prior to the time an application for a route permit for a new transmission line is filed with the Commission and have proven successful in engaging a wide variety of stakeholders in the transmission planning process.

5.0 Transmission Planning Zones

5.1 Introduction

The Commission divided Minnesota geographically into the following six Transmission Planning Zones when it adopted the rules in chapter 7848 in 2003:

- Northwest Zone
- Northeast Zone
- West Central Zone
- Twin Cities Zone
- Southwest Zone
- Southeast Zone

The map below shows the six Zones.

Chapter 5 describes each of the Transmission Planning Zones in the state. The zones have not changed over the years so the description below for each zone is identical to what was provided in past reports, although any changes in the transmission system in a particular zone that occurred over the past two years are described in each section.

The discussion for each zone contains a list of the counties in the zone and the major population centers. The utilities that own high voltage transmission lines in the zone are also identified. A description of the major transmission lines in the zone is provided.

Transmission systems in one zone are highly interconnected with those in other zones and with regional transmission systems. A particular utility may own transmission facilities in a zone that is outside its exclusive service area, or where it has few or no retail customers. Different segments of the same transmission line may be owned or operated by different utilities. A transmission line may span more than one zone, and transmission projects may involve more than one zone.

Chapter 6 describes the needs for additional transmission facilities identified for each zone. Chapter 7 contains additional information about each of the utilities filing this report, including their existing transmission lines.

5.2 Northwest Zone

The Northwest Planning Zone is located in northwestern Minnesota and is bounded by the North Dakota border to the west and the Canadian border to the north. The Northwest Planning Zone includes the counties of Becker, Beltrami, Clay, Clearwater, Kittson, Lake of the Woods, Mahnomen, Marshall, Norman, Otter Tail, Pennington, Polk, Red Lake, Roseau, and Wilkin.

Primary population centers within the Northwest Planning Zone (population greater than 10,000) include the cities of Bemidji, Fergus Falls, and Moorhead.

The following utilities own transmission facilities in the Northwest Zone:

- Great River Energy
- Minnkota Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Xcel Energy

A major portion of the transmission system that serves the Northwest Planning Zone is located in eastern North Dakota. Four 230 kV lines and two 345 kV lines reach from western North Dakota to substations in Drayton, Grand Forks, Fargo, and Wahpeton, North Dakota, along with a 230 kV line from Manitoba and a 230 kV line from South Dakota. Five 230 kV lines run from eastern North Dakota into Audubon, Moorhead, Fergus Falls, and Winger, Minnesota. These five lines then proceed through northwestern Minnesota and continue on to substations in west-central and northeastern Minnesota. Additionally, a 230 kV line from Manitoba to the Northeast

Zone crosses the northeastern corner of this zone and provides power to local loads. The 230 kV system supports an extensive 115 kV, 69 kV, and 41.6 kV transmission system to deliver power to local loads.

5.3 Northeast Zone

The Northeast Planning Zone covers the area north of the Twin Cities suburban area to the Canadian border and from Lake Superior west to the Walker and Verndale areas. The zone includes the counties of Aitkin, Carlton, Cass, Cook, Crow Wing, Hubbard, Isanti, Itasca, Kanabec, Koochiching, Lake, Mille Lacs, Morrison, Pine, St. Louis, Todd, and Wadena counties.

The primary population centers in the Northeast Planning Zone include the cities of Brainerd, Cambridge, Cloquet, Duluth, Ely, Grand Rapids, Hermantown, Hibbing, International Falls, Little Falls, Long Prairie, Milaca, Park Rapids, Pine City, Princeton, Verndale, Virginia, and Walker.

The following utilities own transmission facilities in the Northeast Zone:

- American Transmission Company, LLC
- Great River Energy
- Minnkota Power Cooperative
- Minnesota Power
- Southern Minnesota Municipal Power Agency
- Xcel Energy

The transmission system in the Northeast Planning Zone consists mainly of 230 kV, 138 kV and 115 kV lines that serve lower voltage systems comprised of 69 kV, 46 kV, 34.5 kV, 23 kV and 14 kV. Xcel Energy, Great River Energy, and Minnesota Power own a 500 kV interconnection coming from Manitoba Hydro with interconnections in Minnesota at Forbes and Chisago County. Minnesota Power owns a second 500 kV interconnection from Manitoba Hydro (the Great Northern Transmission Line), placed in service in 2020, which connects at the Iron Range Substation near Grand Rapids, Minnesota. American Transmission Company's 345 kV line runs between Duluth, Minnesota, and Wausau, Wisconsin. Minnesota Power's +/- 250 kV DC line runs from Center, North Dakota to Duluth, Minnesota. The CapX2020 230 kV line connects the Bemidji area in the Northwest Zone and the Grand Rapids area in the Northeast Zone (the CapX2020 Bemidji-Grand Rapids project). The 345 kV and 230 kV system is used as an outlet for generation and to deliver power to the major load centers within the zone. From the regional load centers, 115 kV lines carry power to lower voltage substations where it is distributed to outlying areas. In a few instances, 230 kV lines serve this purpose. Lastly, Minnesota Power and GRE plan to build the Northland Reliability Project, an approximately 180-mile, double-circuit 345 kV transmission line from northern Minnesota to central Minnesota. The project will support grid reliability and resilience in Minnesota and the Upper Midwest, and it was approved by MISO in 2022.

5.4 West Central Zone

The West Central Transmission Planning Zone extends from Sherburne and Wright counties on the east, to Traverse and Big Stone counties on the west, bordered by Grant and Douglas counties on the north and Renville County to the south. The West Central Planning Zone includes the counties of Traverse, Big Stone, Lac qui Parle, Swift, Stevens, Grant, Douglas, Pope, Chippewa, Renville, Kandiyohi, Stearns, Meeker, McLeod, Wright, Sherburne, and Benton.

The primary population centers in the zone include the cities of Alexandria, Buffalo, Elk River, Glencoe, Hutchinson, Litchfield, Sartell, Sauk Rapids, St. Cloud, St. Michael, and Willmar.

The following utilities own transmission facilities in the West Central Zone:

- Central Minnesota Municipal Power Agency and Services (CMPAS)
- Great River Energy
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Xcel Energy

This transmission system in the West Central Planning Zone is characterized by a 115 kV loop connecting Grant County-Alexandria-West St. Cloud-Paynesville-Willmar-Morris and back to Grant County. These 115 kV transmission lines provide a hub from which 69 kV transmission lines provide service to loads in the zone.

A 345 kV line from Sherburne County to St. Cloud and 115 kV and 230 kV lines from Monticello to St. Cloud provide the primary transmission supply to St. Cloud and much of the eastern half of this zone. Two 230 kV lines from Granite Falls – one to the Black Dog generating plant in the Twin Cities and one to Willmar – provide the main source in the southern part of the zone.

Demand in the St. Cloud area continues to grow and several individual projects have been completed to address the need for more power into this area. The CapX2020 Quarry substation provides significant load-serving capability to the St. Cloud area system deficiencies. The CapX2020 Fargo-St. Cloud 345 kV project was completed in 2015 and transfers power between Fargo, North Dakota and the St. Cloud area. The CapX2020 Brookings, South Dakota-Twin Cities 345 kV project was also completed in 2015. The Riverview 345/115/69 kV substation was built in the St. Cloud Area along the CapX2020 Fargo-Monticello 345 kV line to address some of the area's 69 kV issues. This is a Great River Energy substation connecting to Xcel Energy's 69 kV system.

A pending major addition to the Southeast Planning Zone is the addition of the 345 kV MISO LRTP 2 Project. The planned 345 kV line will extend from the Big Stone, S.D. Substation to Alex Substation to the Big Oaks substation near the Sherco Power Plant. The Alex-Big Oaks portion of the 345 kV line will complete the CAPX Fargo-Monticello Project. The line was approved as part of MISO MTEP 21 Expansion Plan and is currently pending before the Commission.

5.5 Twin Cities Zone

The Twin Cities Planning Zone comprises the Twin Cities metropolitan area. It includes the counties of Anoka, Carver, Chisago, Dakota, Hennepin, Ramsey, Scott and Washington.

The following utilities own transmission facilities in the Twin Cities Zone:

- CMPAS
- Great River Energy
- Missouri River Energy Services
- Otter Tail Power
- Xcel Energy

There are no major changes in the transmission facilities located in the Twin Cities Zone since 2013, although several projects are under review by the Commission.

The transmission system in the Twin Cities Planning Zone is characterized by a 345 kV double circuit loop around the core Twin Cities and first tier suburbs. Inside the 345 kV loop, a network of high capacity 115 kV lines serves the distribution substations. Outside the loop, a number of 115 kV lines extend outward from the Twin Cities with much of the local load serving accomplished via lower capacity, 69 kV transmission lines.

The GRE DC line and its outlet 345 kV circuits tie into the northwest side of the 345 kV loop and are dedicated to bringing generation to Twin Cities and Minnesota loads.

Tie lines extend from the Twin Cities 345 kV loop to three 345 kV lines: one to eastern Wisconsin, one to southeast Iowa and one to southwest Iowa. The other tie is the Xcel Energy 500 kV line from Canada tied into the northeast side of the 345 kV loop.

Major generating plants are interconnected to the 345 kV transmission loop at the Sherburne County generating plant and the Monticello generating plant in the northwest, the Allen S. King plant in the northeast, and Prairie Island in the southeast. On the 115 kV transmission system in the Twin Cities Planning Zone there are three intermediate generating plants: Riverside (located in northeast Minneapolis), High Bridge (located in St. Paul), and Black Dog (located in north Burnsville). There are also two peaking generating plants – Blue Lake and Inver Hills – interconnected on the southeast and the southwest, respectively.

The CapX2020 Brookings-Twin Cities 345 kV project was completed in 2015 and transfers power between the southwest corner of the Twin Cities and Brookings, South Dakota. The CapX2020 345 kV project between the southeast corner of the Twin Cities area, Rochester, and LaCrosse, Wisconsin, was also completed in 2015.

5.6 Southwest Zone

The Southwest Transmission Planning Zone is located in southwestern Minnesota and is generally bounded by the Iowa border on the south, Mankato on the east, Granite Falls on the north and the South Dakota border on the west. It includes the counties of Brown, Cottonwood, Jackson, Lincoln, Lyon, Martin, Murray, Pipestone, Redwood, Rock, Watonwan, and Yellow Medicine.

The primary population centers in the Southwest Zone include the cities of Fairmont, Granite Falls, Jackson, Marshall, New Ulm, Pipestone, St. James, and Worthington.

The following utilities own transmission facilities in the Southwest Zone:

- ITC Midwest LLC
- East River Electric Power Cooperative
- Great River Energy
- L&O Power Cooperative
- Missouri River Energy Services
- Otter Tail Power Company
- Southern Minnesota Municipal Power Agency
- Xcel Energy

The transmission system in the Southwest Zone consists mainly of three 345 kV transmission lines, one beginning at Split Rock Substation near Sioux Falls and traveling to Lakefield Junction, the second traveling from Mankato, through Lakefield Junction and south into Iowa and a third line, completed in 2018 from Lakefield Junction, east to Huntley and then south into Iowa. Lakefield Junction also serves as a major hub for several 161 kV lines throughout the zone. A number of 115 kV lines also provide transmission service to loads in the area, particularly the large municipal load at Marshall. Much of the load in the southwestern zone is served by 69 kV transmission lines which have sources from 115/69 kV or 161/69 kV substations.

The 115 kV lines also provide transmission service for the wind generation along Buffalo Ridge. The transmission system in this zone has changed significantly in recent years with new transmission additions to enable additional generation delivery. Continuing these changes, the system was also enhanced by the addition of the 345 kV Multi-Value Project (MVP) Portfolio, including the Twin Cities-Brookings 345 kV transmission line in 2015 and the MVP 3 Project in 2018, providing additional outlet for the wind generation in the Southwest Zone. In addition to enabling additional delivery of wind generation, these lines provide opportunities for new transmission substations to improve the load serving capability of the underlying transmission system.

Two major planned transmission lines to the Southwest Planning Zone include the addition of (1) the 345 kV Minnesota Energy Connection, and (2) the Brookings-Lyon Co. and Hampton-

Helena sections of the double circuit 345 kV line from the CAPX Brookings-TC project. The Minnesota Energy Connection would extend from the Sherco Power Plant in Sherburn County to somewhere in Lyon County. The planned line will carry renewable generation back Sherco Plant as part of the renewable repowering effort. The Brookings-Lyon Co. and Hampton-Helena double circuits are needed to help relieve congestion for renewable power coming from Southwest Minnesota and is a joint project between Xcel Energy, Great River Energy, Otter Tail Power, Missouri River Energy Services, and Central Municipal Power Agency and Services.

5.7 Southeast Zone

The Southeast Planning Zone includes Blue Earth, Dodge, Faribault, Fillmore, Freeborn, Goodhue, Houston, Le Sueur, Mower, Nicollet, Olmsted, Rice, Sibley, Steele, Wabasha, Waseca, and Winona Counties. The zone is bordered by the State of Iowa to the south, the Mississippi River to the east, the Twin Cities Planning Zone and West Central Planning Zone to the north, and the Southwest Planning Zone to the west.

The primary population centers in the zone include the cities of Albert Lea, Austin, Faribault, Mankato, North Mankato, Northfield, Owatonna, Red Wing, Rochester, and Winona.

The following utilities own transmission facilities in the Southeast Zone:

- CMPAS
- Dairyland Power Cooperative
- Great River Energy
- ITC Midwest LLC
- Missouri River Energy Services
- Otter Tail Power
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Xcel Energy

The transmission system in the Southeast Planning Zone consists of 345 kV, 161 kV, 115 kV and 69 kV lines that serve lower voltage distribution systems. The 345 kV system is used to import power from generation stations outside of the area to the Southeast Planning Zone for lower voltage load service. The 345 kV system also allows the seasonal and economic exchange of power from Minnesota to the east and south from large generation stations located within and outside of the zone. The 161 kV and 115 kV systems are used to carry power from the 345 kV system and from local generation sites to the major load centers within the zone. From the regional load centers and smaller local generation sites, 69 kV lines are used for load service to the outlying areas of the Southeast Planning Zone.

A recent major addition to the Southeast Planning Zone was the addition of the Huntley-Wilmarth 345 kV line which was completed in 2021. This line improves power flow across the transmission system. It was an economic project that connects part of Southern Minnesota to the Mankato area. The project was identified through the MISO Economic Planning effort.

A planned major transmission line addition to the Southeast Planning Zone is planned 345 kV MISO LRTP 4 Project. This planned 345 kV line will extend from the Wilmarth Substation to North Rochester to the Mississippi River. The line was approved as part of MISO MTEP 21 Expansion Plan and is expected to the filed the Commission in 2024.

6.0 Needs

6.1 Introduction

Chapter 6 contains information on each of the present and reasonably foreseeable future inadequacies identified in the six transmission zones. First, for each zone, a table of present inadequacies is presented. The table is ordered by when the inadequacy was first identified, so the older inadequacies are listed first. Following the table of inadequacies, a discussion of each pending project, by Tracking Number, is provided. Finally, a table of completed projects is included.

6.1.1 Needed Projects

For each transmission planning zone, the discussion begins with a table that looks like this.

MPUC Tracking Number	MISO Project Name	MTEP Year & Appendix	MTEP Project Number	CON?	Non-Wire Alt.	Utility

The following describes the information found in each of the columns.

MPUC Tracking Number
The first column in the table is labeled "MPUC Tracking Number." Each inadequacy is assigned a Tracking Number. This numbering system was created in 2005 and has been utilized in every report since. The Tracking Number has three parts to it: the year the inadequacy was first reported, the zone in which it occurs, and a chronological number assigned in no particular order. Tracking Number 2015-NE-N10, for example, indicates this matter is first reported in the 2015 Report and is an inadequacy in the Northeast Zone. An inadequacy with a Tracking Number beginning with 2017, on the other hand, was first identified in the 2017 Report.

MISO Project Name
The second column contains the MISO Project Name for each project. This is the name used in the pertinent MTEP Report for that project. In some cases, for projects that were first identified in earlier years and are still under development, the MISO Project Name may not be exactly the same as the name given in an earlier biennial report, but the project is the same.

MTEP Year & Appendix
The third column contains a reference to a MTEP Report and an Appendix in the report. The MTEP Report is prepared annually by MISO, and each utility that is a member of MISO must participate in the MTEP process. Each report is referred to by the year it is adopted. Thus, the most recent report is MTEP23, although it won't be finally approved by MISO until the end of the year. Additional information about the MISO planning process and the MTEP reports is included in section 3.3.1 of this Biennial Report, and an explanation of how to find a particular MTEP Report and an Appendix is provided in subsection 6.2.

MTEP Project Number

The fourth column of the table provides a Project Number assigned by MISO for each project. This Project Number is important for finding a particular project in the appropriate MTEP Report. The only utility reporting transmission needs in this biennial report that is not a member of MISO is Minnkota Power Cooperative, and all the MPC projects are in the Northwest Zone. The other non-MISO utilities are East River Electric Power Cooperative (EREPC), and L&O Power Cooperative (L&O), but these utilities are not reporting any transmission needs in this report.

As shown in the table in section 6.3.1, the Minnkota Power Cooperative projects are shown to be "Non-MISO" projects in column three of the table of Needed Projects. Nonetheless, several of these "Non-MISO" projects do include an MTEP Project Number in column four. The reason for this is even though Minnkota is not a MISO member. MISO performs some of Minnkota's transmission planning work.

Certificate Of Need (CON)

The MPUC rules state the biennial report shall contain an approximate timeframe for filing a CON application for any projects identified that are large enough to require a CON.[18] This column provides a simple "Yes" or "No" indication of whether a CON is required. If a CON has already been applied for, the MPUC Docket Number for that filing can be found in the discussion for that particular project. If a Docket Number is given, that docket can be checked to determine whether the CON has already been issued by the Commission.

Non-wires Alternative

This column provides a "Yes" or "No" indication as to whether a non-wires alternative is potentially viable for the identified inadequacy. Section 2.7 of this Report provides a summary of the types of non-wires alternatives able to address certain categories of inadequacies. Where a non-wires alternative was considered, further discussion of the alternative is included in the narrative provided for that particular project.

Utility

This column simply identifies the utility or utilities involved in the project.

6.1.2 Description of Each Project by Tracking Number

In the 2005, 2007, and 2009 Biennial Reports, the utilities provided a separate subsection for each pending project by Tracking Number and included certain information about each project. In the 2011 and 2013 Report, those discussions were eliminated because the Commission had understandably authorized the utilities to rely on the MTEP Reports to provide all the necessary information regarding each project, because transmission facility approval was being conducted by and through MISO.

In 2014, as part of its approval of the 2013 Biennial Report, the Commission determined perhaps the MTEP Reports did not satisfy one requirement of the state statute to "identify [in the biennial

[18] Minn. R. 7848.1300 § M.

report] general economic, environmental, and social issues associated with each alternative."[19] The utilities did not object to providing that information in the 2015 Report, but would raise the caveat that for many of the projects, particularly those several years into the future, detailed information is often not available at this stage of development of the project. Also, for many smaller projects, like replacing a transformer, there are no likely alternatives available and not much information is available.

To assist the Commission, and other readers of the report, the utilities have included in this Biennial Report a separate discussion of various matters relating to each project, even though nearly all that information can be found in the MTEP Reports. As part of this discussion, the utilities provide available information on the general impacts associated with the project. In those cases where a certificate of need or a routing permit or both have been applied for, or even granted, most of this type of information is available in the records created in those dockets, and a reference to the MPUC Docket Number is provided. Any reader desiring in-depth information about a project that has been approved or is being considered by the Commission can review the record in that matter for more detailed information.

6.1.3 Completed Projects

The table for Completed Projects is similar to the table for Needed Projects described above.

MPUC Tracking Number	Description	MTEP Year & Appendix	MTEP Project Number	Utility	Date Complete

Most of the columns contain the same information provided for the ongoing projects. However, the last column provides the date the project was completed, and the second column contains a more precise description of the project than just the MISO title. If a certificate of need or a route permit or both were required from the Commission, the docket numbers are provided in the last column. While the last column is entitled "Date Completed," in some cases the project is being removed from the list because the need once perceived is no longer present, and the project is being withdrawn. Readers interested in more information about a completed project can consult earlier Biennial Reports, the MTEP Report, or the MPUC Docket, whichever are applicable.

6.2 The MISO Planning Process

6.2.1 The MISO Transmission Expansion Plan Report

Because nearly all the projects identified in this Report are being undertaken by utilities that are members of MISO, this subsection is provided to assist the reader in finding information about the MISO planning process and the annual MTEP Report prepared each year. Much of the information provided in this subsection was also available in the 2013, 2015, 2017, 2019, and 2021 Biennial Reports.

[19] Minn. Stat. §216B.2425, subd. 2(c)(3).

The latest MTEP Reports are available on the MISO webpage at:

> http://www.misoenergy.org (Click on "Planning" on the top of the page)

The MTEP process is ongoing at all times at MISO. Generally, utilities submit a list of their newly proposed projects in September. MISO staff evaluates these projects over the next several months, and prepares a draft of the annual MTEP Report around July of the following year. After review by utilities and other interested parties, the MISO board of directors approves the report, usually in December. The process continues with another report finalized the following December. The MTEP23 Report should be approved by the MISO Board of Directors in December of this year.

Each of the MTEP Reports separates transmission projects into two categories and lists them in Appendices as follows:

> Appendix A – Projects recommended for approval;
> Appendix B – Projects with documented need and effectiveness and long lead time making them not needing approval immediately.

Generally, as projects are first identified, they are listed in Appendix B, and then they move up to Appendix A as they are further studied and ultimately brought forth for construction. Some projects never advance to the final stage – Appendix A – of actually being approved and constructed.

The MTEP Report is an excellent source of information about ongoing transmission studies and projects in Minnesota and throughout a wide area of the country.

- The MTEP Report is prepared annually, so it provides very timely information. The Biennial Report is prepared only every other year.
- The MISO planning process is comprehensive. MISO considers all regional transmission issues, not just Minnesota transmission issues.
- MISO conducts an independent review & analysis of all projects to confirm the benefits stated by the project sponsor. This adds further verification of the benefits of projects.
- MISO holds various planning meetings during the year at which stakeholders can have input into the planning process, so there are more frequent opportunities for input (see next paragraph.)
- All completed projects are listed on the MISO webpage.
- Not duplicating the MTEP Report will save ratepayers money. It is costly to require the utilities to produce all the information found in the MTEP Report.

6.2.2 Finding a Project in a MTEP Report

For each zone, a table is included to describe certain information about each project by Tracking Number. The table looks like this (MPUC Tracking Number 2019-NE-N17 is used for illustrative purposes):

MPUC Tracking Number	MISO Project Name	MTEP Year & Appendix	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-NE-N17	Running Cap Bank Retirement	2019/A	16145	No	No	XEL

MPUC Tracking Number 2019-NE-N17 is the Running Capacitor Bank Retirement Project. The project can be found in Appendix A of the MTEP19 Report by following these steps:

Step 1. Go to the MISO homepage at: https://www.misoenergy.org.

Step 2. Click on "Planning" at the top of the page. Click on "MTEP" from the drop-down menu. Then click on the "Previous MTEP Reports" link on the left side of the page.

Step 3. Click on the link for the MTEP19 Report and download the .zip file.

Step 4. Click on the "MTEP19 Appendix A – New Projects."

Step 5. Select the "Projects" tab at the bottom of the spreadsheet downloaded. Hold down the "Ctrl" key and press the "F" key to bring up the "Find" dialog box. Enter the MTEP Project Number, which in this case is 16145, in the dialog box and select "Find Next." Information about the project can then be read from the row the MTEP Project was found during this search.

Similar steps can be followed for all other projects identified in Chapter 6, including those few that are not Appendix A projects (recommended by MISO for approval). If the MTEP Report you are seeking is an older one, you may have to click on Study Repositories to find these other reports at Step 2.

Project Facilities
Appendices A and B also contain information on the specific facilities (such as transmission lines, substations, etc.) that are part of a particular project. The steps below show how to find this information for the example project.

Step 1. To find information on specific facilities (transmission lines, substations, etc.) that are part of a project click on the "Facilities" tab located at the bottom of the spreadsheet that was downloaded at Step 5 in the above example.

Step 2. Hold down the "Ctrl" key and hit the "F" key to bring up the "Find" dialog box. Enter the MTEP Project Number, "16145" in this example, in the dialog box and then click on "Find Next." The "Find Next" link can be clicked until all rows containing information about Project Number 16145 have been found. There will usually be more than one row since most projects involve more than one transmission line or substation or other facility.

This same procedure can be used to find this kind of information for other projects and their associated facilities for the projects listed in the tables in Chapter 6 using the MTEP Report and the MTEP Project Number.

Detailed Project Information

Starting in 2008, if the project has been either approved or recommended for approval by the MISO board of directors (i.e., designated an Appendix A project), additional, more detailed information about the project can be found in Appendix B in the MTEP Report for the year the project was approved by MISO. For large projects, this information includes a project map, project justification and information about the system inadequacy the project is intended to correct. For smaller projects, a subset of this information is included. Starting with the MTEP08 Report, projects located in Minnesota are contained in the "West Region Project Justifications" portion of Appendix A or Appendix B in the MTEP Report year that the project was approved or recommended for approval. For information on Minnesota projects approved by MISO prior to 2008, see the appropriate year Minnesota Biennial Transmission Projects Report for the appropriate year.

Continuing with our example of the Running Capacitor Bank Retirement Project, Tracking Number 2019-NE-N17, which is an approved Appendix A project, this additional information can be found by going to Appendix B through the following steps.

Step 1. After following the first three steps described above to get to the appropriate MTEP report, click on the MTEP19 Appendices link.

Step 2. Select MTEP19 Appendix B Projects.

Step 3. Once the desired Appendix B is downloaded, use the .pdf search tool to find Project Number 2019-NE-N17and locate information about this project.

This same procedure can be used to find more detailed information on most projects shown in the tables in Sections 6.3 through 6.8 that have moved to MISO Appendix A since 2008. In addition, if you search for a specific utility's name, you can find information on projects that utility has submitted and have been or are being considered for approval by the MISO board of directors.

Specific Utility Projects

One additional useful tool with the MTEP Reports is the ability to find projects an individual utility has submitted to MISO. Also, the Appendices can be sorted to show all projects for a particular utility, (or, depending on the version of Excel you are using, a group of utilities). To do this, select the most recent MTEP Appendix A Status Report,[20] click on the down arrow located in the column D heading "Geographic Location by TO Member System," and then select the code for

[20] Project Lists and Status Reports (misoenergy.org)

the individual utility you are interested in from the drop-down list. (NOTE: some versions of Excel will allow you to select multiple utilities).

Utility	MISO Code
American Transmission Company, LLC	ATC LLC
Central Minnesota Municipal Power Agency	CMMPA
Dairyland Power Cooperative	DPC
Great River Energy	GRE
ITC Midwest LLC	ITCM
Minnesota Power	MP
Minnkota Power Cooperative	MPC
Missouri River Energy Services	MRES
Otter Tail Power Company	OTP
Southern Minnesota Municipal Power Agency	SMP
Xcel Energy	XEL

It is also possible to sort other columns in the Appendices in a similar manner. For example, only projects or facilities in Appendix A can be identified by clicking on the arrow in Column A and selecting the desired choice from the drop-down list.

6.3 Northwest Zone

6.3.1 Needed Projects

The following table provides a list of transmission needs in the Northwest Zone. As explained in Section 6.1.1, even though Minnkota Power Cooperative is not a member of MISO, some of its planning work is done by MISO. A MTEP Project Number is provided for those Minnkota projects reported in the MTEP reports.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2007-NW-N3	NW MN Reliability Upgrades	2019/A	4232 & 17424	No	No	OTP/ MPC
2015-NW-N7	Richwood-Oakland 69 kV (Load Transfers)	Non-MISO	N/A	No	No	MPC
2019-NW-N3	Erie-Frazee 115 kV Project	2019/A	15344	No	Yes	GRE/ OTP
2019-NW-N5	Erie/Audubon Alternate Service	Non-MISO	17144	No	No	MPC
2021-NW-N2	Henning 230 kV Breaker Addition	Future	TBD	No	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2021-NW-N3	Inman 230 kV Breaker Addition	Future	TBD	No	No	GRE
2021-NW-N4	Cormorant to Pelican Rapids Install Storm Structures	2022/A	21825	No	No	GRE
2023-NW-N1	Willmar 230/115 kV Interconnection	2022/A	21848	No	No	XEL
2023-NW-N2	Silver Lake Transformer Replacement	2024/A	25469	No	No	GRE
2023-NW-N2	Cormorant Junction – Tamarac – Pelican Rapids (LR-PC) Line Rebuild	Future	TBD	Yes	No	GRE

NW MN Reliability Upgrades

MPUC Tracking Number: 2007-NW-N3

Utilities: Minnkota Power Cooperative (MPC) & Otter Tail Power Company (OTP)

Project Description: A suite of 115 kV projects including a second Winger 230/115 kV transformer in 2023, a new 230/115 kV substation (Lake Ardoch), including one new 230/115 kV transformer, tapping the existing Drayton-Prairie 230 kV line and associated new transmission to the Oslo 115 kV switching station in 2024, and a 115 kV line from Lake Ardoch to Oslo. Depending on future load growth, a potential second Winger-Plummer 115 kV line and associated substation expansions may also be needed sometime after 2028. This was previously called "The Winger-Thief River Falls 230 kV Line Project." Automatic Under Voltage Load Shedding (UVLS) will be added to ~100 MW of peak demand in the area.

Need Driver: The Northwestern Minnesota area is a developing hub of crude oil pipelines, and those pipelines require pumping stations. These pumping stations are served by a network of 115 kV lines with three 230 kV sources at Drayton, Grand Forks and Winger. Loss of any one source forces the load to be served from the remaining two sources. Additionally, loss of any transmission between Drayton, Grand Forks and Winger weakens the reliability of the Northwest Minnesota transmission system. The automatic UVLS is needed to mitigate N-1-1 issues.

Alternatives:

Transmission Alternatives

Several different transmission alternatives were developed as part of OTP's High Voltage Study to assess the ability of the transmission system to serve the Northwest Minnesota load. These included:

- A new Thief River Falls 230 kV substation, an expanded Winger 230 kV substation, and a new Winger-Thief River Falls 230 kV line,
- a new Lake Ardoch Substation (230 kV), a new substation at Thief River Falls (230 kV), and a new Lake Ardoch-Thief River Falls 230 kV line,
- a new Drayton-Kennedy-Donaldson 115 kV line,
- a new Lake Ardoch Substation (230 kV and 115 kV), a new substation at Oslo (115 kV), and a new Lake Ardoch-Oslo 115 kV line, or
- a new Drayton-Kennedy-Donaldson 115 kV line, a new Winger-Plummer Pipe 115 kV line, and a second Winger 230/115 kV transformer.

The options above have been considered and compared with the aforementioned suite of 115 kV projects and it was determined the benefits of such a project are more robust and cost effective than the other options considered.

Non-Wires Alternatives

One part of the NW MN Reliability Upgrades project is the addition of Automatic Undervoltage Load Shedding (UVLS) at several locations, which is a non-wires alternative. This UVLS mitigates some of the most severe but unlikely contingencies in the NW MN area and is not expected to operate frequently.

Additional non-wires alternatives beyond UVLS would not have sufficient availability or would be prohibitively expensive.

Analysis: Reliability improvements from the previously mentioned projects were evaluated in the "2018 NW MN Timing Analysis," which was performed by OTP with support from MPC. The study showed that a fault on one of the 115 kV lines into Northwest Minnesota from the three 230 kV sources caused violations within Northwest Minnesota. The study demonstrated a final upgrade requirement of several new 230 kV sources between 2021 and 2028.

Schedule: The 230/115 kV transformer addition at Winger is expected to be completed in early 2024. The Lake Ardoch – Oslo 115 kV line and associated substations are expected to be completed by the end of 2024. The associated UVLS has been implemented. A Certificate of Need is not expected to be filed in Minnesota unless load growth warrants the construction of the second Winger – Plummer 115 kV line.

General Impacts: The area where this project will occur is almost entirely rural. There are no notable sites or locations along the route of any new transmission line between the endpoints. Any new transmission line will likely have to navigate through some wetlands and avoid some lakes along any route. There may be some impact on farmland from the location of a new transmission line, but assuming a one-hundred-and-thirty-foot right-of-way and some general estimates on electrical poles and farm equipment navigation, of a project area of 741 acres, only 65 acres will actually be impacted.

The economic and social impacts will be slight for any project to address this situation. The project may require a temporary project crew to construct the equipment, which could bring some business to the area in the form of room and board. Some landowners may receive a financial payment as a result of this project. Finally, the project will improve the reliability of the system in the area, although it is difficult to measure the quantified value of improved reliability.

Richwood-Oakland 69 kV Line (Load Transfers)

MPUC Tracking Number: 2015-NW-N7

Utility: Minnkota Power Cooperative (MPC)

Project Description: The scope and schedule of the project has changed to increase reliability to a larger number of area loads.

A new 69 kV line from Richwood Distribution Substation to Oakland Distribution Substation (with conversion of White Earth distribution substation onto the 69 kV system) has been deemed necessary sometime in the future. The proposed project includes 20.0 miles of transmission line work (all new line) and a potential conversion of White Earth 41.6 kV to 69 kV. Previously, this project contained additional transmission in the Erie and Audubon areas; however, that has been moved to project 2019-NW-N5 for administrative purposes.

Need Driver: In response to a neighboring system's request, a new transmission line and substation conversion are being planned for the White Earth Substation. The intent is to transfer load off their system that has grown beyond available back-up capacity. Additionally, a member cooperative has requested service improvements for Richwood and Oakland Substations.

Alternatives:

Transmission Alternatives

> There are several transmission alternatives being considered as part of these load transfers. In a previous Biennial Report, the preferred alternative was a 115 kV line and a substation conversion was the preferred project. However, that project was dismissed in favor of a looped 69 kV line.
>
> The alternatives involve further investigation of a Mahnomen/Ulrich 115 kV load tap (the project that was originally proposed). Alternatives may also include parts of described project (solely Richwood-White Earth or White Earth-Oakland. Investigations are ongoing, and these alternatives will be compared with the proposed transmission line options.

Non-Wires Alternatives

> Non-transmission solutions such as battery backup are being investigated. The transmission plan may be changed if these investigations provide equally cost-effective projects that are robust.

Analysis: Reliability impacts from the new transmission lines are currently evaluated in the annual MTEP assessments (in terms of forecasting the existing White Earth load). Impacts to the bulk power system are not the reason for these projects. Limitations of the 41.6 kV transmission and member systems are the reason for the transmission projects (and load transfers).

Schedule: The study efforts mentioned above determined that the new transmission lines do not have a strict completion date. A schedule will be developed as definite plans are determined.

General Impacts: This project is primarily rural in location. The route will have to navigate around some lakes, forested areas, and potentially some reservation land within the area. Assuming a one-hundred-foot right-of-way, the project area will be nearly 275 additional acres (some existing transmission may be used for the project), but the affected farmland should only be about 15 acres, assuming some general estimates on electrical poles and farmland equipment navigation. No notable environmental, human, or health concerns exist beyond the aforementioned new transmission. This project is still in its early stages of planning, so all of this information is subject to change.

This project may require a short-term project crew. If so, this may bring some business to the area in the form of room and/or board. In terms of local government benefits, it is possible that permit costs may be enforced on this project, but this is determined on a case-by-case basis. Also, some landowners may receive income as a result of this project, and the income may be taxable.

This project is the result of a reliability measure, and will probably not have a substantial or lasting impact on the community in terms of the environment or health. It will likely impact some farmland; however, it should only amount to about 15 acres, as stated in the environmental considerations.

Erie – Frazee 115 kV Project

MPUC Tracking Number: 2019-NW-N3

MPUC Docket Number: ET-2/TL-20-423

Utility: Great River Energy (GRE) and Otter Tail Power Company (OTP)

Project Description: This project consists of a new Erie 230/115 kV substation that will tap the existing Audubon to Hubbard 230 kV line. The 115 kV side of the Frazee substation will be rebuilt to a ring bus configuration to accommodate a new 115 kV line from Erie. Approximately 9 miles of 115 kV line will be constructed between the new Erie substation and the Frazee substation. A 30 MVAr capacitor bank will be installed at the Frazee substation.

Need Driver: Driven by load growth and retirement of Hoot Lake generation.

Alternatives:
Transmission Alternatives

The following alternatives were considered in the study. These alternatives were not preferred for the reasons related to not providing significant reliability improvement, high cost, or low incremental load serving capability when compared with the project (preferred plan).

1. Audubon 230/115 kV upgrade
2. Audubon 230/115 kV upgrade with 115 kV line to future Lake Eunice Tap
3. 230/115 kV substation along Audubon – Hubbard 230 kV line with 115 kV line to a breaker point on existing 115 kV system
    a. Todd Lake 230/115 kV sub with 115 kV line to Frazee
    b. Mountain Road 230/115 kV sub with 115 kV line to DLPU
4. Fergus Falls to Edgetown to Pelican Rapids 115 kV double circuit line

Non-Wires Alternatives

The following two NWA were identified to address the Frazee area reliability issues in the Frazee area, but they were not preferred. For detailed analysis, refer to the NWA report done by GRE.

NWA – 1

- 40 MVAr STATCOM at Frazee
- 10 MW solar PV with 20 MWh ES at Pelican Turkey
- 40 MW solar PV with 80 MWh ES at Frazee

NWA – 2 (with capacitor banks)

- 20 MW solar PV with 40 MWh ES at Pelican Turkey
- 20 MW solar PV with 40 MWh ES at Frazee

Analysis: The Erie – Frazee project was determined to be the most reliable and cost-effective solution for addressing existing reliability issues and facilitating growth in the transmission system.

Schedule: The Erie – Frazee project is planned to be in-service by winter 2023.

General Impacts: The project will require approximately 9 miles of new 115 kV transmission line from the Erie Junction substation to the Frazee substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design is along existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 9 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas. The MPUC's environmental assessment was issued May 14, 2021. The MPUC issued the route permit for this project in October 2021.

Erie/Audubon Alternate Service

MPUC Tracking Number: 2019-NW-N5

Utility: Minnkota Power Cooperative (MPC)

Project Description: From the planned Erie Jct. 230/115 kV substation which taps the Audubon-Hubbard 230 kV line, a new 69 kV or 25 kV 7-mile line with associated transformer will be constructed to MPC's Erie distribution substation.

In order to provide alternate service to MPC's Audubon distribution substation, an optional conversion of OTP's Oak Lake-Erie Jct. 41.6 kV line may be converted to 69 kV. This line is part of a previous project (2015-NW-N7) and there is some overlap between these projects.

Need Driver: There is about 10 MW of load in the Detroit Lakes, MN area served by one substation (Erie) on the OTP 41.6 kV system. Extended outage times have been required for planned maintenance and emergency repairs because no alternate source is available. This is a concern for the Detroit Lakes, MN area. Low load management signals are also a concern.

Alternatives:
Transmission Alternatives

Initial project alternatives included a second transformer at Ulrich, an Audubon-Christensen 69 kV line, or Ulrich 69 kV capacitors. All of these failed to provide fully redundant service to Audubon and Erie. Several options exist to provide similar service; however, they are not as cost effective. These include:

- Normal 41.6 kV service from Erie Jct. 230 kV with backup service from Ulrich (or Audubon)
- Normal 41.6 kV service from Audubon, alternate 41.6 kV service from new load tap.
- Normal or alternate 25 kV underground service from Erie Jct. 230 kV

Non-Wires Alternatives

Battery backup for use as a non-wire alternative was explored but was found to far less cost effective.

Analysis: Reliability impacts from the new transmission lines are currently evaluated in the annual MTEP assessments (in terms of forecasting the existing Audubon and Erie area loads). Impacts to the bulk power system are not the reason for these projects. Limitations of the 41.6/69 kV transmission and member systems are the reason for the transmission projects (and load transfers).

Schedule: This project is budgeted for completion in 2024 to coincide with the construction of the Erie Jct. load tap (2009-NW-N2). A schedule will be developed as definite plans are determined.

General Impacts: This project is primarily rural in location. The route will have to navigate around some lakes, forested areas, and potentially some reservation land within the area. Assuming a one-hundred-foot right-of-way, the project area will be nearly 121 additional acres (some existing transmission may be used for the project), but the affected farmland should only be about 7 acres, assuming some general estimates on electrical poles and farmland equipment navigation. No notable environmental, human, or health concerns exist. This project is still in its early stages of planning, so all of this information is subject to change.

This project may require a short-term project crew. If so, this may bring some business to the area in the form of room and/or board. In terms of local government benefits, it is possible that permit costs may be enforced on this project, but this is determined on a case-by-case basis. Also, some landowners may receive income as a result of this project, and the income may be taxable.

This project is the result of a reliability measure, and will probably not have a substantial or lasting impact on the community in terms of the environment or health. It will likely impact some farmland; however, it should only amount to about 15 acres, as stated in the environmental considerations.

Henning 230 kV Breaker Addition

MPUC Tracking Number: 2021-NW-N2

Utility: Great River Energy (GRE)

Project Description: Add two 230 kV breakers at the Henning substation.

Need Driver: Installation of two-line termination breakers were necessitated to prevent faults on Henning – Inman 230 kV line or Henning – Silver Lake 230 kV line from tripping off entire substation.

Alternatives:

Transmission Alternatives

> The breaker addition was the only option considered to improve reliability due to cost effectiveness.

Non-Wires Alternatives

> This project installs a breaker at an existing substation. NWA were not considered for this project.

Analysis: Installation of breakers at the existing substation is the best value plan that would enhance reliability in all areas that are served by the Henning 230/41.6 kV substation.

Schedule: The project is planned to be in service by Summer 2029.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Inman 230 kV Breaker Addition

MPUC Tracking Number: 2021-NW-N3

Utility: Great River Energy (GRE)

Project Description: Add a 230 kV breaker at the Inman substation on the line to Wing River.

Need Driver: This project was needed to prevent faults on the Inman – Wing River 230 kV line from tripping off the 230/115 kV transformer.

Alternatives:
Transmission Alternatives

The breaker addition was the only option considered to improve reliability due to cost effectiveness and minimal impact to landowners.

Non-Wires Alternatives

This is a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by Summer 2035.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Cormorant – Pelican Rapids Storm Structures

MPUC Tracking Number: 2021-NW-N4

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Cormorant – Pelican Rapids 115 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10-mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

Storm Structures were considered the most cost-effective solution to limit outages from line cascading.

Non-Wires Alternatives

This is a reliability improvement to an existing line to prevent cascading structure failure and no other alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by August 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Cormorant substation to Pelican Rapids substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Willmar 230/115 kV Interconnection

MPUC Tracking Number: 2023-NW-N1

Utility: Xcel Energy (XEL)

Project Description: Build new dead-end structure to re-terminate the Maynard Tap - Willmar line to a southern position at the Willmar sub to accommodate GRE's substation reconfiguration

Need Driver: Projected needed to address multiple N-2 low voltage and thermal violations in the area.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This is a reliability improvement to an existing line to prevent thermal overloads, no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went in service on July 29, 2022.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Maynard Tap to Willmar substation. During construction Xcel and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Silver Lake Transformer Replacement

MPUC Tracking Number: 2023-NW-N2

Utility: Great River Energy (GRE)

Project Description: Replace existing 230/41.6 kV transformer with a new 56 MVA unit, install 2-41.6 kV breakers with switches and move existing transformer for use as a spare.

Need Driver: A spare unit for this voltage class is needed for continued reliable service to the area. The existing Silver Lake transformer will be used as a spare and the new transformer will be installed in its place. The addition of two-line termination 41.6 kV breakers is needed to prevent tripping at the Silver Lake substation during line faults.

Alternatives:

Transmission Alternatives

There was a need for a larger transformer and no alternatives were considered.

Non-Wires Alternatives

This is a reliability improvement at the substation and no alternatives were considered.

Analysis: The spare transformer will enable GRE to promptly address transformer failures, aligning with GRE's strategy to maintain a spare transformer for every voltage class that serves loads.

Schedule: This project is planned to be in-service by January 2028.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Cormorant Junction – Tamarac – Pelican Rapids (LR-PC) Line Rebuild

MPUC Tracking Number: 2021-NW-N3

Utility: Great River Energy (GRE)

Project Description: Rebuild all sections of the LR-PC line.

Need Driver: The existing line has a low composite reliability grade and is overdue for replacement due to its age and deteriorating condition. This transmission line has historically experienced congestion issues, impeding the integration of renewables into the transmission system. The rebuild will boost capacity, ensuring a reliable service and creating opportunities for interconnection or transfer of renewables within the transmission system.

Alternatives:

Transmission Alternatives

This is an age and condition driven line replacement project. No additional alternatives were considered.

Non-Wires Alternatives

This is an age and condition driven line replacement project. No additional alternatives were considered.

Analysis: The line rebuild project is intended to address the historical reliability issues stemming from the line's age and condition. Furthermore, the increased capacity of the new line will enable interconnection of renewable resources into either the distribution or transmission systems, addressing previous congestion concerns.

Schedule: The project is planned to be in service by Winter 2030.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Cormorant Junction switch to Tamarac substation to Pelican Rapids substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

6.3.2 Completed Projects

The table below identifies projects that have been completed since our 2021 report.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-NW-N1	Hoot Lake 115 kV Capacitor Bank Addition	N/A	OTP	2021
2019-NW-N2	Norcross Area Upgrades	LR-20-487	OTP	2022
2021-NW-N1	Hoot Lake 115/41.6 kV Transformer Replacement	N/A	OTP	2022

6.4 Northeast Zone

6.4.1 Needed Projects

The following table provides a list of transmission needs identified in the Northeast Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2007-NE-N1	Duluth Area 230 kV	2014/B	2548	Yes	Yes	MP
2013-NE-N16	HVDC Modernization Project	2013/B	4295	Yes	No	MP
2013-NE-N17	HVDC 900 MW Transmission Line Upgrades	2014/B	3856	No	No	MP
2015-NE-N12	Iron Range-Arrowhead 345 kV Project	2014/B	3832	Yes	No	MP
2017-NE-N3	Little Falls Substation Modernization	2020/A	18110	No	No	MP
2019-NE-N4	25 Line Rebuild	2024/B	25281	No	No	MP
2019-NE-N5	29 Line Upgrade	2019/B	15594	No	Yes	MP
2019-NE-N6	Long Prairie Substation Modernization	2019/A	15596	No	No	MP
2019-NE-N8	Badoura Transformer Replacement	2020/A	15598	No	No	MP
2019-NE-N10	Babbitt Area 115 kV Project	2018/B 2018/B	16069 16070	No	Yes	MP
2019-NE-N12	Duluth Loop Reliability Project	2022/A 2022/A	17868 20077	Yes	Yes	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-NE-N13	National Breaker Replacements	2020/A	17870	No	No	MP
2019-NE-N15	Portage Lake 115/69 kV Project	2020/A	17664	No	No	GRE
2021-NE-N1	HVDC Line Hardening	2022/A	18058	No	No	MP
2021-NE-N3	Hibbing Substation Modernization	2020/A	18064	No	No	MP
2021-NE-N4	Verndale Substation Modernization	2020/A	18065	No	No	MP
2021-NE-N5	Badoura 115 kV Substation Modernization	2021/A	18066	No	No	MP
2021-NE-N6	15th Ave West Transformer Addition	2020/A	18109	No	Yes	MP
2021-NE-N8	LSPI Cap Bank Asset Renewal	2021/B	20030	No	No	MP
2021-NE-N9	Canosia Road Substation 34 kV Expansion	2021/A	20032	No	No	MP
2021-NE-N11	Two Islands 115 kV Project	2022/A	20074	No	No	MP/ GRE
2021-NE-N12	Forbes 230 kV Modernization	2021/A	20075	No	No	MP
2021-NE-N13	Cloquet Substation Modernization	2021/B	20087	No	No	MP
2021-NE-N14	Mesaba Junction 137 Line Extension	2022/A	21686	No	Yes	MP
2021-NE-N15	137 Line Rebuild	2022/B	21762	No	No	MP
2021-NE-N17	West Cohasset Substation	2022/A	21606	No	No	MP
2021-NE-N19	56 Line Upgrade	2022/B	21764	No	Yes	MP
2021-NE-N20	105 & 106 Line Upgrade	2022/A	21608	No	Yes	MP
2021-NE-N21	230 kV STATCOM Project	2022/B	21765	No	Yes	MP
2021-NE-N22	126 Line Asset Renewal	2022/A	21766	No	No	MP
2021-NE-N23	13 Line Rebuild	2022/B	21767	No	No	MP
2021-NE-N27	Riverton - Wing River Storm Structures	2022/A	21824	No	No	GRE
2023-NE-N1	Northland Reliability Project	2021/A	23370	Yes	Yes	MP/ GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2023-NE-N2	40 Line Rebuild	2023/A	22909	No	No	MP
2023-NE-N3	Brainerd Crypto	2023/A	22885	No	No	MP
2023-NE-N4	Maturi Expansion	2023/A	23707	No	No	MP
2023-NE-N5	Mahtowa Expansion	2023/A	23708	No	No	MP
2023-NE-N6	158 Line Rebuild	2024/A	23076	No	No	MP
2023-NE-N7	Arrowhead Single Point of Failure	2024/A	25141	No	No	MP
2023-NE-N8	Forbes Single Point of Failure	2024/A	25142	No	No	MP
2023-NE-N9	Ridgeview 115/34 kV Transformer Addition	2024/A	25264	No	No	MP
2023-NE-N10	Wrenshall Substation Modernization	2024/A	25265	No	No	MP
2023-NE-N11	133 Line Rebuild	2024/B	22285	No	No	MP

Duluth 230 kV Project

MPUC Tracking Number: 2007-NE-N1

Utility: Minnesota Power (MP)

Project Description: Add a second 230/115 kV transformer at the Hilltop Substation and upgrade an existing line from 115 kV to 230 kV between the Arrowhead and Hilltop substations.

Need Driver: Reliability and load growth in the Duluth area. Retirement of local generators on the 115 kV system. Maintaining sufficient 230/115 kV transformer capacity for load serving in the Duluth area during a maintenance outage of one of the existing Arrowhead 230/115 kV transformers or following certain single contingency events.

Alternatives:
Transmission Alternatives

Build a new 230/115 kV substation in the Duluth area.

Non-Wires Alternatives

Install new dispatchable generation in the Duluth area. Non-wire alternatives must be dispatchable to respond when called upon and of sufficient duration to prevent or mitigate overloading. Minnesota Power will continue to consider non-wire alternatives alongside the Duluth 230 kV Project as the need and timing for the project develop.

Analysis: In 1993, Minnesota Power constructed a new 230 kV substation (the Hilltop Substation) in Duluth. This project involved the rebuilding of existing 115 kV lines for 230 kV operation in order to provide a single 230 kV source to the Hilltop Substation and upgrades of several unshielded 115 kV lines to improve reliability. As part of the application for the Hilltop Project

MP laid out long range plans which identified the future need for a second 230 kV source to the Hilltop Substation once Duluth load dictated its need. The Commission recognized this future need and approved rebuilding of portions of the unshielded 115 kV lines as part of the Hilltop Project for future 230 kV operation.

Because Minnesota Power anticipated this future need, a relatively minimal amount of transmission line and substation construction will be required to implement the Duluth 230 kV Project when it becomes needed. Due to the configuration of the existing Duluth area transmission system, the Duluth 230 kV Project is expected to be the most cost effective and least environmentally impactful solution to this pending inadequacy. Other transmission alternatives would require longer 230 kV line construction and the establishment of a new substation site, increasing social, environmental and economic impacts associated with construction of such a project. Operational changes that limit through-flow on the Duluth-area 115 kV system have proven helpful in delaying the need for this project, as discussed below. The Duluth Loop Reliability Project (2019-NE-N12) will include incremental improvements at the Arrowhead and Hilltop Substations, such as a larger 230/115 kV transformer and a 230 kV breaker at Hilltop and sectionalization of the Hilltop 230 kV line at Arrowhead. These incremental improvements are expected to further delay the need for the more significant expansion of Duluth-area 230/115 kV transformer capacity that would be achieved with the Duluth 230 kV Project.

Schedule: Slower than anticipated load growth, external system improvements such as the Arrowhead-Stone Lake-Gardner Park 345 kV Line, and operational flexibility provided by the phase shifting transformer at the Stinson Avenue Substation in Superior, Wisconsin, have delayed the need for the Duluth 230 kV Project for many years. Based on recent studies indicating a need for improved reliability and capacity of Duluth-area 230/115 kV transformers in the first half of the 2020s, Minnesota Power has included incremental improvements at the Arrowhead and Hilltop Substations as part of the Duluth Loop Reliability Project (2019-NE-N12). The underlying system drivers behind the timing of the incremental improvements included with the Duluth Loop Reliability Project are related to the impact of a number of transitional changes in the nearby North Shore Loop transmission system and changing regional transfers in and through the Minnesota Power system. These incremental improvements will shift the primary need drivers for the Duluth 230 kV Project back to local Duluth-area load growth or retirement of the dispatchable generators at the Hibbard Renewable Energy Center, likely delaying the need for the Duluth 230 kV Project to the late 2020s or even into the 2030s.

General Impacts: The Duluth 230 kV Project will make optimal use of an existing transmission line that was designed for future conversion for 230 kV operation and existing substations designed with space in or adjacent to the existing footprint to accommodate additional 230 kV connections. Since the Duluth 230 kV Project is using existing substations, transmission line corridors and rights-of-way, it is anticipated that no new landowners would be impacted by the project. The Duluth 230 kV Project is needed to maintain adequate power delivery capability from the transmission system to the Duluth area in light of local generator retirements, regional transfers, load growth, and economic development. Therefore, the project contributes to the realization of significant environmental, social, and economic benefits associated with these contributing factors. Minnesota Power's approach to this issue is intended to ensure that the most appropriate solution (in terms of cost and human and environmental impacts) is implemented at the most appropriate time to meet the reliability and capacity needs of Minnesota Power's customers.

HVDC Modernization Project

Formerly Square Butte – Arrowhead HVDC Valve Hall Replacement

MPUC Tracking Number: 2013-NE-N16

MPUC Docket Number: E015/CN-22-607, E015/TL-22-611

Utility: Minnesota Power (MP)

Project Description: Replace the existing Center (Square Butte) and Arrowhead high voltage direct current (HVDC) converter stations and associated assets with modern equipment. To modernize the terminals of the existing Square Butte HVDC Line and implement the latest VSC HVDC technology, new buildings and electrical infrastructure need to be constructed on a new site near the existing HVDC terminals. In Minnesota, to connect the new HVDC terminal to the existing AC system, the Project would require the construction of a new St. Louis County 345 kV/230 kV substation located less than one mile west of the current Arrowhead Substation. The new HVDC terminal would be connected to the St. Louis County Substation by less than one mile of 345 kV transmission line and the new St. Louis County Substation would be connected to the existing Arrowhead Substation by two parallel 230 kV transmission lines less than one mile in length. Additionally, a short portion of the existing ±250 kV HVDC Line in Minnesota will need to be reconfigured to terminate at the new HVDC terminal. Similar modifications will take place near the existing Center HVDC terminal in North Dakota.

Need Driver: The HVDC Modernization Project is needed to modernize aging HVDC assets, continue to position the transmission grid for clean energy transition, and improve the reliability of the transmission system. The existing HVDC terminal has operated for 45 years—15 years beyond its 30-year design life. 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 increase, which is of particular concern for the existing HVDC system because of limited parts availability. The orderly replacement of the HVDC terminal equipment is prudent to ensure continuous efficient delivery and 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 voltage source converter (VSC) HVDC technology implemented for the Project will be designed to provide key reliability attributes including voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability. These modernizations to the HVDC technology will enable Minnesota Power and the region to continue to support its clean energy transition.

Alternatives:

Transmission Alternatives

Alternatives to the HVDC Modernization Project discussed in the Certificate of Need application include not replacing the HVDC converter stations ("Do Nothing" – risk of extended outage due to equipment failure), retiring the HVDC system and replacing it with new AC transmission improvements ("AC Alternative"), and replacing the HVDC converters with older technology similar to the original stations ("Technology Alternative").

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Center and Arrowhead HVDC converter stations.

Analysis: The HVDC Modernization Project will modernize aging assets that are critical to the reliable delivery of renewable energy to Minnesota Power's customers, improve the reliability of the transmission system and thoughtfully position for continued clean energy system transformation. Under the "Do Nothing" alternative, failure rates of the existing HVDC Converter Station equipment are anticipated to increase, resulting in outages that impact the reliable and efficient delivery of Minnesota Power's North Dakota wind energy and result in direct cost impacts to Minnesota Power's customers and reliability impacts to the regional transmission system. As these outages increase in frequency and duration, the cost and reliability impacts will continue to grow. With no viable plan to modernize the existing HVDC converters, Minnesota Power would immediately need to determine if it were prudent to invest in relatively short-term fixes to keep the HVDC Line operating on a limited basis or to move on from the HVDC Line entirely and begin to develop alternative AC transmission solutions.

Under the "AC Alternative" the alternative AC transmission solutions required to facilitate continued delivery of Minnesota Power's zero fuel cost North Dakota wind energy, mitigate system impacts caused by the retirement of the HVDC Line, and replace the grid support provided by the VSC HVDC converters would come at a substantially higher cost and with greater human and environmental impacts than the HVDC Modernization Project. Given that the AC Alternative would need to include multiple regional-scale 345 kV transmission lines, there would likely be prolonged exposure to outages of the HVDC Line during the 10 or more years it would take to develop these projects. At some point during that time, it may become impossible to continue operating the HVDC Line at its full capacity, leading to extended outages and associated impacts to Minnesota Power's customers and regional reliability.

Were Minnesota Power to choose to invest in relatively short-term fixes to keep the HVDC Line operating on a limited basis, these fixes would result in significant risk of stranded investment as the regional transmission system develops. The "Technology Alternative" including targeted replacements of the existing control system, converter transformers, and thyristor valves could serve to keep the existing LCC HVDC system running for several more decades at its existing capacity. These replacements would not bring the additional grid-supporting attributes associated with VSC technology, and therefore additional investments in STATCOMs, synchronous condensers, or other solutions may become necessary as the clean energy transition continues to challenge the historical operating conditions of the grid. As MISO continues to advance proactive long-range transmission planning solutions to position the grid for the future of clean energy, VSC

HVDC solutions will inevitably begin to play a major role in the regional grid. At that point, Minnesota Power's short-term investments in keeping its existing LCC HVDC system may have to be replaced before the end of their useful asset life by a VSC HVDC upgrade similar to the Project in order to continue reliable operation of the Square Butte HVDC corridor and provide the best value for Minnesota Power's customers and the region.

The HVDC Modernization Project is the only prudent solution to limit cost impacts to Minnesota Power's customers in the near-term from increased exposure to HVDC outages, avoid substantial additional long-term cost for alternative projects to address reliability issues created by retirement of the HVDC Line, and align with opportunities to efficiently provide long-term bulk power transfer and grid support solutions for Minnesota Power and the region.

Schedule: Minnesota Power filed a combined Certificate of Need and Route Permit Application for the HVDC Modernization Project on June 1, 2023 [Docket Nos. E015/CN-22-607 and E015/TL-22-611]. It is anticipated that construction of the Project will begin in Q4 2024, with the expected Project in-service date between December 2028 – April 2030.

General Impacts: The modernization of Minnesota Power's HVDC converter stations is a prudent and necessary activity to ensure the ongoing operation of this critical piece of transmission infrastructure for Minnesota Power's customers, including the reliable delivery of Minnesota Power's substantial North Dakota wind generation assets.

The HVDC Modernization Project is also a critical component of Minnesota Power's efforts to leverage existing infrastructure to efficiently maintain the current load, gain additional access to renewable resources for customers, and keep momentum for reaching the state's goal of 100 percent carbon-free energy by 2040. The Project innovatively proposes flexible design options to allow for future expansion and additional renewable energy transfer capability, leveraging the unique attributes of VSC HVDC technology—the most efficient way to transfer power over long distances. In addition to the replacement of the existing HVDC terminals, the new Voltage Source Converter ("VSC") HVDC technology implemented for the 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 its clean energy transition reliably. All of this will be implemented in a relatively small geographic area near the existing Arrowhead 230 kV Substation, limiting human and environmental impacts by leveraging the existing site and contiguous lands to the greatest extent possible.

HVDC 900 MW Transmission Line Upgrades

Formerly Square Butte – Arrowhead HVDC Upgrade

MPUC Tracking Number: 2013-NE-N17

Utility: Minnesota Power (MP)

Project Description: Upgrade the capacity of the existing Square Butte – Arrowhead HVDC transmission line from 550 MW to 900 MW, generally by replacing existing structures with taller structures and reconductoring a short segment of line.

Need Driver: Transmission Service Requests (TSRs) have been filed with MISO for additional capacity to facilitate increased renewable energy transfers on the HVDC Line following the completion of the HVDC Modernization Project (Tracking No. 2013-NE-N16).

Alternatives:

Transmission Alternatives

Develop AC network upgrades necessary to facilitate the same amount of additional renewable energy interconnection and regional transfer capability.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot provide additional capacity for long-distance renewable energy transfers on the existing HVDC Line.

Analysis: 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 following completion of the HVDC Modernization Project (Tracking No. 2013-NE-N16). To achieve the higher capacity, upgrades would be needed at various locations along the length of the 465-mile HVDC transmission line. These upgrades are expected to include replacing existing structures with taller structures to increase conductor-to-ground clearance at a higher operating temperature, as well as replacement of a short segment of smaller conductor in North Dakota. Leveraging the opportunity to incrementally increase the capacity of the HVDC Line following completion of the HVDC Modernization Project provides an efficient solution for facilitating the interconnection and long-distance delivery of additional high-capacity renewable energy resources to Minnesota Power's customers.

Schedule: At the request of Minnesota Power, MISO updated Transmission Service Request ("TSR") System Impact Studies on varying levels of increased HVDC capacity in 2022-2023 and provided Facilities Studies documenting the costs assigned to the TSRs. Upon execution of a Facilities Construction Agreement ("FCA") for the upgrades necessary to provide the requested incremental transfer capability, Minnesota Power will begin to implement the HVDC transmission line upgrades. Construction is anticipated to take place in phases over 4-5 years to limit HVDC Line outage impacts. The earliest potential completion date for the project is 4Q 2028.

General Impacts: The additional capacity facilitated by the HVDC 900MW Transmission Line Upgrades Project will facilitate increased wind development in North Dakota, more efficient market operation, and system reliability enhancements for both North Dakota and Minnesota. Since the project is anticipated to take place within the existing transmission line right-of-way, it is anticipated that no new landowners would be impacted by the project.

Iron Range-Arrowhead 345 kV Line

MPUC Tracking Number: 2015-NE-N12

Utility: Minnesota Power (MP)

Project Description: Expand planned Iron Range 500 kV Substation to include two 1200 MVA 500/345 kV transformers and extend a double circuit 345 kV line from Iron Range to the existing Arrowhead 345 kV Substation.

Need Driver: When paired with the Great Northern Transmission Line (Tracking Number 2013-NE-N13), the Iron Range-Arrowhead 345 kV Line was found by MISO in the Manitoba Hydro Wind Synergy Study to facilitate significant regional benefits associated with the synergies between wind and hydroelectric generation resources. However, the near-term needs for incremental export capability from Manitoba to the United States were realized by the development of the Great Northern Transmission Line Project alone, without a 345 kV extension to Arrowhead. Because there were not sufficient transmission service requests to justify the 345 kV connection to Arrowhead at the time, Minnesota Power determined that it would not pursue construction of the Iron Range-Arrowhead 345 kV Project in the foreseeable future. Should the project become necessary in the future due to additional transmission service requests or other system reliability needs or regional transmission benefits – such as those currently being evaluated in the MISO Long Range Transmission Plan (LRTP) Study – it will be advanced at that time based on its own merits.

Alternatives:
Transmission Alternatives
No other alternatives are currently being considered.
Non-Wires Alternatives
None.

Analysis: Minnesota Power and Manitoba Hydro's analysis of the transmission necessary to enable 883 MW of incremental Manitoba-United States transfer capability identified that the Iron Range-Arrowhead 345 kV Line was not needed or economically justified at the time to achieve the desired level of Manitoba Hydro export.

Schedule: Minnesota Power has no current plans to construct the Iron Range-Arrowhead 345 kV Project.

General Impacts: The optimization of the new Manitoba to United States interconnection that allowed for deferral of the Iron Range-Arrowhead 345 kV Line provided benefit to Minnesota Power's ratepayers, local landowners, and the region by implementing a right-sized solution for the current need and avoiding extraneous transmission line construction. Should future additional transmission service requests or other regional transmission system needs justify construction of the Iron Range-Arrowhead 345 kV Line, the project could reasonably be expected to build upon the already-substantial social, economic, and environmental benefits provided by the Great Northern Transmission Line Project.

Little Falls Substation Modernization

MPUC Tracking Number: 2017-NE-N3

Utility: Minnesota Power (MP)

Project Description: The Little Falls Substation Modernization Project involves replacing aging equipment, structures, and civil works and correcting deficiencies at the existing Little Falls 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades and a reconfiguration of the existing 115 kV bus to move a line-connected transformer to a bus-connected configuration to make up the core of this project. This work at the Little Falls Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Little Falls Substation serves the City of Little Falls and the surrounding rural areas. The primary need driver for the Little Falls Substation Modernization is age and condition of existing transformers, distribution circuit breakers, disconnect switches, and site infrastructure. While transmission circuit breakers have been replaced in recent years, much of the remaining original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. In addition to these asset renewal concerns, the project will also address previously-identified low voltage concerns for the Little Falls area. Low voltage was identified at the Pepin Lake, Blanchard, Bellevue, and Little Falls Substations following contingency events involving the Little Falls 115 kV bus. These contingency events result in loss of the existing Little Falls capacitor bank plus all but one of the 115 kV lines serving the substation and will be resolved by transitioning a line-connected transformer to a bus-connected configuration.

Alternatives:

Transmission Alternatives

> Establish a replacement 115/34 kV distribution station in the Little Falls area. Add another 115 kV capacitor bank in the area or reconfigure the Little Falls 115 kV bus to include a bus tie breaker.

Non-Wires Alternatives

> Install new distribution-connected generation on Little Falls, Blanchard, or Pepin Lake 34.5 kV systems. Non-wire alternatives must be available when needed and have an output characteristic sufficient to reduce the effective peak load in the area. However, non-wire alternatives cannot address concerns related to age and condition at the Little Falls Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Little Falls Substation Modernization Project, Minnesota Power considered the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability. The resulting project involves significant improvements to equipment and infrastructure at the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

The low voltage issue was first identified in the MTEP15 assessment and has continued to show up in MTEP and Minnesota Power studies. The addition of a bus tie breaker at the Little Falls Substation was originally submitted as a potential Corrective Action Plan. However, further investigation of protective relaying and historical fault events in the area has proven that a more appropriate solution would be to change the connection point for one of the Little Falls 115/34.5 kV transformers so that it is not directly connected to the Little Falls – Blanchard 115 kV line. This reconfiguration will eliminate the potential low voltage concern at a reasonable cost and without degrading the reliability of the Little Falls Substation. The reconfiguration of the transformer connection will be packaged with the planned substation modernization project for the Little Falls Substation in order to realize efficiencies in engineering and construction.

Schedule: The project is currently planned as a multi-year project and has been prioritized behind nearer-term needs in the area, including Long Prairie and Verndale. Civil and site work is expected to begin in 2025, with above-grade construction taking place in stages for 1-2 years after that to manage outage and constructability constraints.

General Impacts: The Little Falls Substation Modernization Project will ensure a continuous and reliable power supply to the Little Falls area by replacing aging equipment before it fails and by resolving known post-contingent voltage issues. At present, it is expected that the impacts will be entirely contained within the existing Little Falls Substation yard and no expansion area will be necessary.

25 Line Rebuild

MPUC Tracking Number: 2019-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase rating of Hibbing – Virginia 115 kV Line (25 Line). The project also includes rebuild, reconductor, and switch replacements in the vicinity of the existing Minntac Tap.

Need Driver: Post-contingent overloads under higher transfer scenarios and multiple-circuit contingency events, as well as age and condition of existing 25 Line structures and hardware.

Alternatives:
Transmission Alternatives

> Reconductor existing line, build new parallel line.

Non-Wires Alternatives

> Install new dispatchable energy resource in the area. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate overloading. However, non-wire alternatives can only address the capacity needs and would not displace the need for asset renewal components of the project.

Analysis: This issue has been identified in MTEP and in several Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs along the length of the line and particularly at the Hibbing substation termination.

Schedule: The project is currently planned for phased construction beginning in 2021 and continuing through 2031.

General Impacts: The 25 Line Upgrade Project will provide necessary system improvements and asset renewal on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

Long Prairie Substation Modernization

MPUC Tracking Number: 2019-NE-N6

Utility: Minnesota Power (MP)

Project Description: The Long Prairie Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works, and correcting deficiencies at the Long Prairie 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades (replacing with higher-capacity load-tap changing transformers) to make up the core of this project. The work at the Long Prairie Substation was combined into one project to facilitate efficient coordination of engineering and construction.

Need Driver: The Long Prairie Substation serves Long Prairie and the surrounding rural area. The primary need driver for the Long Prairie Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many structures and foundations. In addition, these asset renewal concerns, the project will address previously-identified distribution reliability concerns including post-contingent overloading of the existing Long Prairie transformers and low post-contingent 34.5 kV bus voltage following 115 kV bus fault events.

Alternatives:

Transmission Alternatives

Develop area distribution system to shift load off Long Prairie.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Long Prairie Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Long Prairie Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability. The resulting project involves significant improvements to equipment and infrastructure at the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

The Long Prairie Substation Modernization Project will provide firm capacity and improved voltage regulation to the 34.5 kV distribution feeders out of Long Prairie. This will allow MP to take an outage on one of the two transformers to perform maintenance work without having to transfer load to another substation. Reconfiguring the line-connected distribution transformer would eliminate outages on the transmission line when a fault occurs on the distribution system. In considering whether or not non-wires solutions such as distribution-connected generation or demand side management presented a viable alternative to the project, Minnesota Power considered the fact that the assets involved in the replacement project would need to be replaced due to age and condition within the next 5-10 years anyway. Since the non-wires solutions would not eliminate the need for age and condition based replacements, the replacement project was ultimately determined to be the only viable long-term solution.

Schedule: The project is currently planned as a multi-year project with construction taking place in stages from 2021-2023 to manage outage and constructability constraints.

General Impacts: The Long Prairie Substation Modernization Project will ensure a continuous and reliable power supply to the Long Prairie area by increasing transformer capacity, improving voltage regulation, and replacing aging equipment before it fails. Per the scope discussed above, the impacts will be entirely contained within the existing Long Prairie Substation yard and no expansion area will be necessary.

Badoura Transformer Replacement

MPUC Tracking Number: 2019-NE-N8

Utility: Minnesota Power (MP)

Project Description: Replace existing 230/115 kV transformer at Badoura substation. Add 230 kV line breakers.

Need Driver: Age and condition of Badoura transformer. Transformer is also non-standard and there is no direct system spare. Post-contingent overloads following multiple-circuit contingency events in the surrounding area.

Alternatives:

Transmission Alternatives

Increase facility ratings to mitigate post-contingent overloads.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition and non-standard equipment at Badoura.

Analysis: The Badoura 230/115 kV transformer is non-standard for Minnesota Power's system, as it consists of an external 115 kV voltage regulating transformer rather than an internal load tap changer. The transformer is also nearly 60 years old. The project will replace it with a new standard-sized 230/115 kV transformer, for which Minnesota Power maintains a system spare. Studies have indicated that the voltage regulation from the transformer is not necessary and therefore the new transformer will be procured without load tap changers. Additionally, there are no breakers at the Badoura 230 kV Substation, which creates difficulties with relaying and contingencies that cause large parts of the area between Riverton and Park Rapids to lose critical transmission connections. Installing breakers will mitigate issues associated with these contingencies and provide for better protection of the transmission lines and transformer. Post-contingent overloads on the Badoura 230/115 kV Transformer were first identified in the MTEP18 2023 winter peak case.

Schedule: The project is currently targeted for an in-service date of 2027.

General Impacts: The Badoura Transformer Replacement Project will ensure a continuous and reliable power supply to a large area of the Minnesota Power transmission system between Riverton and Park Rapids by replacing aging, non-standard equipment before it fails and by improving system protection through the addition of breakers. The Project will make use of space available inside the existing Badoura 230/115 kV Substation, as all modifications associated with the project will take place within the existing substation fence-line.

Babbitt Area 115 kV Project

MPUC Tracking Number: 2019-NE-N10

Utility: Minnesota Power (MP)

Project Description: Establish a high capacity, networked connection between the Embarrass Substation and the Mesaba Junction Switching Station by either acquiring and rebuilding 6 miles of existing customer-owned 115 kV transmission or constructing approximately 4 miles of new 115 kV transmission south from the existing Babbitt Tap to the Mesaba Junction 137 Line Extension.

Need Driver: Reliability for important load-serving substations in the Babbitt Area, as well as redundancy, voltage support, and transmission capacity to the Hoyt Lakes area and the North Shore Loop to support existing customers and enable load growth.

Alternatives:
Transmission Alternatives

> Purchase and rebuild 6 miles of existing customer-owned 115 kV transmission through an active mining area to connect 137 Line from the Embarrass Substation to the 137 Line Extension from the Mesaba Junction Switching Station; or construct approximately 4 miles of new 115 kV transmission south from the Babbitt Tap to the 137 Line Extension to avoid acquiring the customer-owned segment through the mine.

Non-Wires Alternatives

> Non-wire alternatives involve new dispatchable energy resources, like reciprocating engines, combustion turbines, or possibly long-duration energy storage, in both the Hoyt Lakes and Babbitt areas. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at effective locations to prevent or mitigate overloading.

Analysis: The Babbitt Area 115 kV Project will connect two radially-operated transmission lines that are critical sources to the Babbitt area and provide an additional redundant connection to the North Shore Loop transmission system. The project will enhance the reliability of the Babbitt 115/46 kV Substation, which is a critical load-serving substation for Minnesota Power and Great River Energy customers in the Tower, Ely, and Babbitt areas, by networking the radial line that currently is the only source to the Babbitt Substation. The project will also build upon previous improvements from the Mesaba Junction 137 Line Extension (2021-NE-N14) to enhance redundancy and flexibility for the industrial load pocket in the Babbitt area, which requires near-constant availability of power. In doing so, the project makes optimal use of existing transmission line assets that are underutilized when operated as a radial system, taking advantage of the asset renewal improvements from the 137 Line Rebuild (2021-NE-N15) which are made possible by the Mesaba Junction 137 Line Extension Project (2021-NE-N14).

The Babbitt Area 115 kV Project also continues to support redundancy and power delivery enhancements for the Hoyt Lakes area and the North Shore Loop by establishing an additional transmission source to the Mesaba Junction Switching Station. Much has changed about how the North Shore Loop transmission system is operated following transition of local coal-fired baseload generators to retirement or idling over the last 5+ years. As the use of the system by existing customers in the Hoyt Lakes area and the North Shore Loop evolves over time, incremental long-term improvements like the Babbitt Area 115 kV Project will continue to become necessary to support the reliable operation of the system. The additional 115 kV source from Embarrass into the Mesaba Junction Switching Station established by this project prevents potential voltage collapse and transmission line overload concerns associated with loss of the Forbes – Mesaba Junction and Laskin – Mesaba Junction 115 kV lines, and therefore the project is crucial to enabling the long-term maintenance of these transmission lines in the area.

Schedule: The Babbitt Area 115 kV Project cannot be implemented until both the Mesaba Junction 137 Line Extension (2021-NE-N14) and the 137 Line Rebuild (2021-NE-N15) are constructed. Based on the anticipated schedule for those projects, preliminary plans are for project construction to take place in 2030-31.

General Impacts: The Babbitt 115 kV Project will ensure a continuous and reliable power supply to Minnesota Power and Great River Energy customers in the Tower, Ely, and Babbitt areas, as well as a nearby industrial load pocket. Establishing a high-capacity networked Embarrass – Mesaba Junction 115 kV Line (137 Line) enhances reliability to the local area and also allows for the continued reliable delivery of power into the North Shore Loop and the Hoyt Lakes area under a range of normal and maintenance conditions, effectively continuing to replace transmission system support previously provided by nearby baseload coal units as the system continues to evolve into the future. Utilizing most or all of existing 137 Line to complete this new connection makes optimal use of existing transmission assets while minimizing human and environmental impacts associated with establishing the new transmission connection.

Duluth Loop Reliability Project

MPUC Tracking Number: 2019-NE-N12

Utility: Minnesota Power (MP)

Project Description: Construct approximately 14 miles of new 115 kV transmission between the existing Hilltop, Haines Road, and Ridgeview substations. Some existing 115 kV transmission lines in the area will be reconfigured and upgraded. At the existing Ridgeview Substation, the substation yard will be expanded to accommodate a new 115 kV ring bus with 4 new 115 kV circuit breakers and a new transmission line entrance. At the existing Haines Road Substation, a 115 kV circuit breaker will be added to an existing transmission line entrance. At the existing Hilltop Substation, the substation yard till be expanded to accommodate a new 115 kV line entrance, the existing 230/115 kV transformer will be replaced with a larger-capacity transformer, a new 230 kV circuit breaker will be added, and four existing 115 kV circuit breakers will be replaced. At the existing Arrowhead Substation, a new 230 kV transmission line entrance will be constructed. The existing Hilltop 230 kV tap will be disconnected from the Arrowhead – Iron Range 230 kV Line (98 Line) and extended approximately 0.7 miles to the new line entrance at the Arrowhead Substation. The existing Hilltop 230 kV tap transmission line will be upgraded to a higher operating temperature and existing polymer insulators will be replaced. Additional substation and transmission line components will also be replaced as part of the project due to age and condition.

Need Driver: Following conversion, idling, or retirement of coal-fired baseload generators in the North Shore Loop, there is a risk of voltage collapse during maintenance outages of 115 kV lines between Arrowhead, Haines Road, Swan Lake Road, Ridgeview, and Colbyville Substations. Loss of a second transmission line during a maintenance outage would leave this part of Duluth on a single 140-mile transmission line originating in the Hoyt Lakes Area, and the transmission system is no longer able to support the load over that distance. The Duluth Loop Reliability Project will restore redundancy and load-serving capability to this area, mitigating the risk of voltage collapse. Duluth area 230/115 kV transformer loading also increases significantly without the local baseload generators online and connected to the 115 kV system. This causes a risk of severe overloads on the existing 230 kV line and the Hilltop 230/115 kV transformer during a maintenance outage of either of the Arrowhead 230/115 kV transformers. Upgrading the capacity of the existing Hilltop 230 kV tap line and Hilltop 230/115 kV transformer will mitigate these severe overloads. Extending the Hilltop 230 kV tap line into the new line entrance at the Arrowhead Substation will greatly improve the reliability of the 230 kV source at the Hilltop Substation by reducing over 64 miles of outage exposure to the sole source to the Hilltop Substation and eliminating a breaker failure event which could simultaneously disconnect two 230/115 kV transformers in the Duluth area. This reconfiguration will also allow significant relay protection improvements to the existing Iron Range – Arrowhead 230 kV Line (98 Line) and the newly established Arrowhead – Hilltop 230 kV Line (108 Line).

Alternatives:

Transmission Alternatives

New 115 kV or 230 kV line parallel to Arrowhead – Colbyville 115 kV path(s).

Non-Wires Alternatives

New dispatchable transmission- or distribution-connected generation in the Duluth 115 kV Loop; dynamic reactive support and transmission line capacity upgrades in the Duluth 115 kV Loop and the North Shore Loop. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate voltage concerns.

Analysis: The Duluth Loop is a network of 115 kV transmission lines and substations which form two parallel connections between the main Duluth-area transmission source of power and system support (the Arrowhead 230/115 kV Substation) and the North Shore Loop (beginning at the Colbyville Substation on the far eastern end of Duluth). Many of the customers in the Duluth area are served from substations connected to the Duluth Loop.

The Duluth Loop Reliability Project meets three critical needs for the Duluth area and the North Shore Loop, as discussed below.

First, the project addresses severe voltage stability concerns by providing another transmission source to the Duluth Loop and North Shore Loop. For most transmission outages in the Duluth Loop, the loss of a second Duluth Loop transmission line during the outage would leave all or part of the Duluth Loop and the North Shore Loop on a single 140-mile transmission line originating in the Hoyt Lakes area. Without the support previously provided by the local baseload generators on the North Shore Loop, the transmission system is no longer able to support the large amount of Duluth Loop load over such a long distance and the expected result would be a post-contingent voltage collapse in the Duluth Loop and extending up the North Shore toward Two Harbors. To manage the risk of voltage collapse in real-time operations, the Regional Transmission Operator (MISO) directs Minnesota Power to open the North Shore transmission connection at Colbyville, separating Duluth from the North Shore Loop during planned outages in the Duluth Loop. This causes Duluth Loop load to be served through a single transmission path from the Arrowhead substation and load along the North Shore to be served through a single transmission path from the Taconite Harbor substation. This operational solution serves mostly to contain the problem rather than resolve it, as the loss of a second Duluth Loop or North Shore Loop transmission line would still result in loss of power for many residential, commercial, and industrial customers. Constructing a new 115 kV transmission line between the Hilltop and Ridgeview substations will replace the redundancy once 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 without putting customers at risk.

Second, the project provides load serving capacity to the Duluth Loop and North Shore Loop. For most transmission outages impacting the Taconite Harbor Substation, a majority of load along the North Shore is served through the Duluth Loop. For this scenario, an outage along either connection between the Arrowhead and Colbyville substations could cause significant overloads along the remaining connection. Alternately, if the North Shore Loop is intact and an outage occurs on both transmission connections between the Arrowhead and Colbyville substations, significant overloads could occur on transmission lines between the Taconite Harbor, North Shore, and Big Rock substations. Constructing a new 115 kV transmission line between the Hilltop and Ridgeview substations will provide sufficient Duluth Loop and North Shore Loop transmission capacity to prevent transmission line overloads.

Third, the project improves the reliability of Duluth area transmission sources. Two 230/115 kV transformers at Arrowhead and one at Hilltop deliver power to 115 kV transmission lines in the Duluth area from the regional 230 kV transmission network. The reliance of the Duluth Loop and the North Shore Loop on these transformers has greatly increased with the idling of North Shore Loop coal generators. The Hilltop Substation is served by a single, 72-mile, 230 kV transmission line which also connects to the Arrowhead and Iron Range substations. Extending this 230 kV transmission line approximately 0.7 miles and adding a breaker at the Arrowhead Substation will reduce line mile exposure to Hilltop from 72 miles to 8 miles, greatly improving the reliability of the sole 230 kV source to the Hilltop substation at the same time an additional 115 kV line is being brought out of it to support the Duluth Loop. The additional breaker for this line connection at Arrowhead will eliminate a single point of failure which disconnects a 230/115 kV transformer at both Arrowhead and Hilltop, likely causing overloads on the remaining Arrowhead 230/115 kV transformer. Improving the reliability of Duluth Area 230/115 kV transformers will benefit customers in the Duluth Loop and along the North Shore as reliance on these transmission sources increases with the local baseload generators offline.

Schedule: Minnesota Power submitted a combined Certificate of Need and Route Permit application to the Commission in October 2021 [Docket Nos. E015/CN-21-140 and E015/TL-21-141], which was approved in February 2023. Following permitting and engineering activities, preliminary plans are for project construction to take place in 2023-26.

General Impacts: The Duluth Loop Reliability Project is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Replacing redundancy, voltage support, and power delivery capability previously provided by local baseload coal units in the area and improving the reliability of an increasingly-critical transmission connection for delivery of power into the North Shore Loop enables the realization of significant economic and environmental benefits from transitioning away from these units. The proposed project will require approximately 0.7 miles of new 230 kV transmission and 14 miles of new 115 kV transmission, some of which will be double circuited with an existing transmission line. New transmission line construction will be primarily along existing transmission line corridors and utilize existing rights-of-way to the greatest possible extent to help navigate areas of Duluth with varying land use and space constraints. Minnesota Power has taken into consideration all relevant human, environmental, and commercial interests in the area and has actively engaged impacted stakeholders in routing and siting of the project.

National Breaker Replacements

MPUC Tracking Number: 2019-NE-N13

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life circuit breakers and associated equipment at National Taconite 115 kV Substation.

Need Driver: Age and condition.

Alternatives:

Transmission Alternatives

There is no more economical or less impactful solution than replacing the existing circuit breakers.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the National Taconite Substation.

Analysis: Five 115 kV oil circuit breakers from 1966 will be replaced as part of this project.

Schedule: The project is presently planned for staged construction in 2021-24.

General Impacts: The National Breaker Replacements Project will replace end-of-life substation equipment, supporting continued transmission system reliability in the area. The project will take place entirely within the existing National Taconite Substation, which is located on mine property, making optimal use of the existing site infrastructure to minimize human and environmental impacts.

Portage Lake 115/69 kV Project

MPUC Tracking Number: 2019-NE-N15

Utility: Great River Energy (GRE)

Project Description: GRE will interconnect to Minnesota Power's (MP) 13 Line (Riverton – Cromwell 115 kV) with a 4 position, 115 kV ring bus, to be called Portage Lake, at or near the existing Mille Lacs Electric Cooperative (MLEC) Kimberly substation. The new 115 kV Portage Lake ring bus will have four positions; 115 kV line to Riverton (13 Line), 115 kV line to Cromwell (158 Line), 115/69 kV transformer with a 9.5-mile line to Palisade, and a 115-kV position for MLEC's Kimberly distribution substation.

Need Driver: This project is needed to address reliability concerns due to long radial line exposure, and thermal overloading during winter peak conditions.

Alternatives:

Transmission Alternatives

The following two transmission alternatives were considered but were not preferred:

Upgrade Four Corners Transformer

The Four Corners 115/69 kV transformer has a top rating of 28 MVA. An option that was evaluated was to add more transformation capacity at Four Corners. This option is relatively inexpensive, but it does nothing to alleviate the radial MW-mile exposure seen by the 4 substations served from the Palisade Radial 69 kV system.

Gowan 115/69 kV

The Gowan 115/69 kV concept utilizes the 156 Line (Cromwell – Savanna 115 kV) that passes by GRE's Gowan substation and interconnects to the existing 69 kV lines at Gowan via a 115/69 kV transformer. This project will alleviate the loading concerns on Four Corners transformer but falls short of alleviating the radial MW-mile exposure seen by the 4 substations served from the Palisade Radial 69 kV system.

Non-Wires Alternatives

A non-wires alternative (NWA) such as generation (solar, wind), demand response (load management), or energy storage (battery, plug-in hybrid vehicles) could be used to solve or partially solve the thermal overloads and voltage violations resulting from the loss of the Cromwell – Palisade Tap 69 kV line but it does not address the 32 miles of transmission line that the four Member substations are exposed to.

The system's peak loading is happening at night during winter months. The area is not wind rich and would have to rely on solar and since the peak is at night, it would have to be solar plus battery technology.

Analysis: The 69 kV Palisade Radial Line is made up of 3 Lake Country Power (LCP) delivery points (Wright, Round Lake and Big Sandy) and one MLEC delivery point, Palisade, with 32 miles of total line exposure. The Palisade Radial peaks at 25.9 MW in the winter and 15.3 MW. For the loss of the Cromwell – Palisade Tap 69 kV line during winter peak loading, the whole Cromwell-Four Corners 69 kV system is sourced from the Four Corners 115/69 kV transformer and the thermal loading reaches 110%.

Schedule: The project is planned to be in service by December 2024.

General Impacts: The project will require approximately 10 miles of new 69 kV transmission line from Portage Lake substation to Palisade substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 10 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

HVDC Line Hardening

MPUC Tracking Number: 2021-NE-N1

Utility: Minnesota Power (MP)

Project Description: Targeted structure replacements on the Square Butte – Arrowhead HVDC line to install more robust anti-cascade structures at major infrastructure crossings along the 465-mile length of the line.

Need Driver: Reduce the likelihood of structure failures at locations where failures would have a more significant impacts to the surrounding area or be more difficult to restore.

Alternatives:

Transmission Alternatives

> Due to the nature of the issue, the only other alternative is to "Do Nothing" – which would proliferate the risk of extended outages, difficult restoration, and adverse on-the-ground impacts from HVDC structure failures at high-profile or high-impact locations.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address the structural failure concerns.

Analysis: In coordination with the HVDC Modernization project (Tracking No. 213-NE-N16), Minnesota Power is also planning a transmission line "hardening" project. While the modernization of the converter stations will result in new state-of-the-art VSC HVDC components at the line terminals that should last for many years, the two converter stations will still be connected by a 40+ year old 465 mile transmission line. The existing original HVDC transmission line structures have proven to be susceptible to failure in extreme weather events. The transmission line hardening project planned for implementation in parallel with the HVDC Modernization Project will consist of targeted structure replacements at strategic locations – for example, near major infrastructure crossings – where anti-cascade structures that limit the impact of failures and allow for rapid line restoration would provide the most value. Executing the HVDC Line Hardening Project in coordination with the HVDC Modernization Project will limit on-the-ground impacts from structure failures near more heavily-trafficked areas and provide a more robust HVDC transmission line connection between the converter stations as the HVDC Line continues to be an important part of the transmission system for Minnesota Power and the region for many years following completion of the modernization project.

Schedule: The Project is expected to be constructed in phases over a 4-5 year period. To the extent it is possible to do so, construction of the Project will also be packaged with the modifications identified as part of the HVDC 900 MW Transmission Line Upgrades Project (2013-NE-N17). Engineering and construction on the first phase of the Project began in 2022-23. While additional phases are planned for construction through the end of the decade, execution on the second phase of the Project was temporarily put on hold in 2023 to enable the scope and timing of additional HVDC Line work, like the HVDC 900 MW Transmission Line Upgrades, to become clearer.

General Impacts: The hardening of the HVDC line structures at key locations is a prudent and necessary activity to reduce failure risks and impacts and ensure the ongoing operation of this critical piece of transmission for Minnesota Power's customers, including the reliable delivery of Minnesota Power's substantial North Dakota wind generation assets. Since the project is expected to take place at existing structure locations, it is anticipated that no new landowners would be impacted by the project.

Hibbing Substation Modernization

MPUC Tracking Number: 2021-NE-N3

Utility: Minnesota Power (MP)

Project Description: The Hibbing Substation is located west of Hibbing, Minnesota, south of the Hibbing Taconite mining operations. The Hibbing Substation Modernization project involves replacing aging equipment, structures, and civil works and correcting deficiencies at the substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs were combined with necessary capacity upgrade projects on 14 Line (Hibbing – 14 Line Tap) and 25 Line (Hibbing – Virginia) to make up the core of this project. Hibbing-Maturi will be renamed to 180 Line, a 180 Line project will be double circuiting to 44 Line tap. This work at the Hibbing Substation was coordinated around the same schedules in order to facilitate efficient coordination of engineering and construction. This project will begin after the majority of the load has been permanently transferred to a nearby substation (Maturi). This minimizes the invested needed for this substation while still serving as a backup for some distribution load.

Need Driver: The Hibbing Substation serves the City of Hibbing as well as Minnesota Power retail customers in the area surrounding Hibbing and Chisholm. The primary need driver for the Hibbing Substation Modernization project is the age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. The Hibbing 25L breaker is from 1976 and the 44L breaker is from 1988, both of which are historically problematic breaker models that are high on the breaker replacement priority list. Replacing these high-priority breakers in advance of failure is necessary to ensure safety and reliability, enhance long-term planning, and optimize lifecycle value. Although load will be shifted off the Hibbing Substation it is still part of the BES and needs to remain functional. The Distribution side will be needed to still serve some load and as a backup to Maturi and Nashwauk.

Alternatives:
<u>Transmission Alternatives</u>

Develop area distribution system to shift load off the Hibbing Substation to a new distribution substation.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Hibbing Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Hibbing Substation Modernization Project, Minnesota Power considered the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability. The resulting project involves a nearly complete overhaul of the site, which is expected to ensure the site remains viable and continues to reliably serve Minnesota Power's customers for many decades to come.

Schedule: The project is currently planned as a multi-year project. Civil and site work is expected to begin in fall 2026, with above-grade construction taking place in stages from 2026-27 to manage outage and constructability constraints.

General Impacts: The Hibbing Substation Modernization Project will ensure a continuous and reliable power supply to the Hibbing area by replacing aging equipment before it fails. While some minor fence expansion on Minnesota Power-owned property is necessary, the majority of impacts from the project will be entirely contained within the existing Hibbing Substation yard.

Verndale Substation Modernization

MPUC Tracking Number: 2021-NE-N4

Utility: Minnesota Power (MP)

Project Description: The Verndale Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works and correcting deficiencies at the existing Verndale 115/34 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Verndale Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Verndale Substation serves Verndale, Staples, Wadena and the surrounding area, including customers of Minnesota Power, Great River Energy, and Missouri River Energy Services. The primary need driver for the Verndale Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations. In addition to these asset renewal concerns, historical Verndale Substation loading exceeds firm capacity for loss of a single 115/34 kV transformer, and transformer load-tap changers are needed to provide more effective distribution system voltage regulation.

Alternatives:
Transmission Alternatives
Install new 115/34 kV transformers at nearby Wing River 230/115 kV Substation and reconfigure distribution system to enable retirement of Verndale Substation.
Non-Wires Alternatives
Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Verndale Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Verndale Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: The project is currently planned as a multi-year project with construction taking place in 2025-2026.

General Impacts: The Verndale Substation Modernization Project will ensure a continuous and reliable power supply to the Verndale, Staples, and Wadena areas by increasing transformer capacity, improving voltage regulation, and replacing aging equipment before it fails. At present, it is expected that the impacts will be entirely contained within the existing Verndale Substation yard and no expansion area will be necessary.

Badoura 115 kV Substation Modernization

MPUC Tracking Number: 2021-NE-N5

Utility: Minnesota Power (MP)

Project Description: Move existing 115 kV lines from straight bus in original Badoura 115 kV Substation into the open positions on the newer Badoura #2 Substation 115 kV ring bus. Build out bus work to connect existing cap bank. Demo original Badoura 115 kV Substation including removal of old 115 kV box structure and control house. Adding new alternate station service source to replace feed from 34.5 kV equipment at the Badoura site.

Need Driver: Age and condition of Badoura 40L and 48L 115 kV breakers and control house. Shifting capacitor bank position to mitigate post-contingent low voltage following loss of shared breaker with 230/115 kV transformer.

Alternatives:
Transmission Alternatives

Replace the breakers in current locations and modernize original Badoura 115 kV Substation yard to retain existing box structure.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of 115 kV equipment at Badoura.

Analysis: The existing breakers protecting the two 115 kV lines into the straight bus at Badoura are 1960s-vintage oil breakers connected to a box structure of the same vintage. A newer ring bus was constructed adjacent to the original Badoura Substation in the 2000s as part of the Badoura 115 kV Project. The transmission lines connected to the original Badoura Substation are being relocated to open positions on the newer Badoura 115 kV ring bus to retire the original circuit breakers, box structure, and control house as well as establish a more reliable configuration for the 115 kV lines connected to the Badoura Substation.

Schedule: The project is scheduled to be completed in 2025.

General Impacts: The Badoura 115 kV Modernization Project will improve safety and transmission system reliability around Badoura by relocating transmission lines from an aging 1960s era site and a straight bus configuration to a newer site in a ring bus configuration. The project will include small fence expansions to accommodate new line entrance equipment on the ring bus at the Badoura 115 kV site, but in general will make optimal use of the existing Badoura Substation site and enable retirement of most of the original Badoura Substation site.

15th Avenue West Transformer Addition

MPUC Tracking Number: 2021-NE-N6

Utility: Minnesota Power (MP)

Project Description: The 15th Avenue West Transformer Addition Project involves adding a new 115/34 kV transformer in an existing future transformer position at the 15th Avenue West Substation in downtown Duluth. Additional upgrades and reconfigurations will take place in the Duluth 34 kV system to integrate the new 34 kV source.

Need Driver: Load growth and reliability enhancements on Duluth 34 kV distribution system.

Alternatives:

Transmission Alternatives

Establish a new 115/34 kV substation near downtown Duluth; reinforce existing Duluth 34 kV system by building new feeders to existing sources at Swan Lake Road and LSPI substations.

Non-Wires Alternatives

Install new distribution-connected generation on Duluth 34 kV system. Non-wire alternatives must be available when needed, dispatchable to support reliable load-serving under contingency conditions, and have an output characteristic sufficient to reduce the effective peak load in the area.

Analysis: The Duluth 34 kV distribution system has sources at the Swan Lake Road and LSPI substations, but the majority of the load is located near the midpoint of the 34 kV system in downtown Duluth and the medical district – relatively far from the existing substation sources. The 34 kV system was originally developed due to the significant challenges associated with the development of additional transmission-distribution substations in central and downtown Duluth. The 34 kV system also provides enhanced reliability to critical loads such as the hospitals by placing them on a high-capacity backbone system with automated fault location, isolation, and system restoration (FLISR) implemented. As more load has transitioned onto the 34 kV system, backing up the entire system from either LSPI or Swan Lake Road has become more challenging due to the feeder distance from the sources to the load. Additional load growth following near-term expansion of one of the two major hospitals in the medical district will further impact backup capability for the Duluth 34 kV system. The addition of a new 115/34 kV transformer at the 15th Avenue West Substation, which is located much closer to the Duluth 34 kV system loads, and integration of the new source into the automated 34 kV feeder system will ensure that the Duluth 34 kV system continues to be a very reliable source with sufficient load-serving capability for critical loads in Duluth.

Schedule: The 15th Avenue West Transformer Addition Project is presently planned for construction in 2023.

General Impacts: The 15th Avenue West Transformer Addition Project will preserve and enhance the reliability of the Duluth 34 kV distribution system. Since the 15th Avenue West Substation was designed originally to accommodate the transformer addition, the majority of impacts from the substation expansion part of the project will be contained within the existing 15th Avenue West Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

LSPI Cap Bank Asset Renewal

MPUC Tracking Number: 2021-NE-N8

Utility: Minnesota Power (MP)

Project Description: LSPI Cap Bank Asset Renewal Project involves refurbishing the existing 115 kV capacitor bank at the LSPI Substation in West Duluth by replacing fuses, fuse holders, and other components.

Need Driver: The existing fuses are supposed to release on failure but are not working properly, resulting in capacitor bank outages that decrease the availability of the capacitor bank and increase maintenance costs for the site.

Alternatives:
<u>Transmission Alternatives</u>

Remove and replace the entire capacitor bank.

<u>Non-Wires Alternatives</u>

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing capacitor bank.

Analysis: The LSPI Substation capacitor bank provides important voltage support and regulation for the West Duluth area. This project involves low-cost targeted asset renewal improvements that will enhance the reliability and availability of this capacitor bank. There is no more economical or less impactful solution than replacing the existing fuses and fuse holders.

Schedule: The project is being targeted for implementation in 2024.

General Impacts: The LSPI Cap Bank Asset Renewal Project will ensure continued reliable voltage support for West Duluth by replacing failing components. The impacts of the project will be entirely contained within the existing LSPI Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Canosia Road Substation 34 kV Expansion

MPUC Tracking Number: 2021-NE-N9

Utility: Minnesota Power (MP)

Project Description: The Canosia Road Substation 34 kV Expansion Project involves expanding the existing Canosia Road Substation into a four position ring bus by adding two 115 kV breakers in order to interconnect a new 115/34 kV transformer. Additional upgrades and reconfigurations will take place in the Cloquet-area distribution system to integrate the new 34 kV source.

Need Driver: Establish a new 34 kV source for the Cloquet area to achieve asset renewal and distribution voltage standardization, increased system capacity and constructability for the Cloquet Substation Modernization Project (2021-NE-N13), improved reliability, and prepare for grid modernization project implementation.

Alternatives:

Transmission Alternatives

Establish a new 115/24 kV or 115/46 kV source from Canosia Rd to tie into existing non-standard voltages in the Cloquet area; build a new 115/34 kV substation at a different location.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition and voltage standardization for the Cloquet-area distribution system.

Analysis: The Canosia Road Substation 34 kV Expansion will be the first step and foundation in a multi-year plan to modernize and improve the Cloquet-area distribution system. There are several factors driving the need for improvements in the Cloquet area:

Asset Renewal & Standardization: Implementing a standard 34 kV backbone distribution network for the Duluth/Cloquet area. There are presently three different backbone distribution voltages between Duluth, Cloquet, and Hinckley. The Canosia Road Expansion and subsequent projects will convert existing 24 kV and 46 kV systems to 34 kV while addressing asset renewal needs for existing feeders and stepdowns associated with these systems

System Capacity & Asset Renewal Project Constructability: Enabling the Cloquet Substation Modernization Project (2021-NE-N13) to take place. Cloquet Substation is one of the highest-priority asset renewal sites in the Minnesota Power system, but the distribution system lacks sufficient capability to reliably support the Cloquet area during the extended outage of the Cloquet Substation that would be needed to implement the asset renewal project.

Reliability & Grid Modernization: Improving reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34/14 kV stepdowns, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration.

Schedule: The project at the Canosia Road Substation is currently under construction with work having started in 2022, with associated distribution system upgrades taking place in 2022 and 2023.

General Impacts: The Canosia Road Substation 34 kV Expansion Project will enhance the reliability of the Cloquet-area distributions system while also addressing significant age and condition and maintenance-related issues on the distribution system. Since the Canosia Road Substation was designed originally to accommodate the expansion, the majority of impacts from the substation expansion part of the project will be contained within the existing Canosia Road Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Two Islands 115 kV Project

MPUC Tracking Number: 2021-NE-N11

Utility: Minnesota Power (MP), Great River Energy (GRE)

Project Description: The Two Islands 115 kV Project involves the construction of a new switching station that will serve as the connecting point to replace the original Taconite Harbor Substation in the North Shore Loop transmission system. The new Two Islands Switching Station will be constructed across the highway from the original Taconite Harbor Substation and will consist of a 5-6 position ring bus and a new capacitor bank. Great River Energy hosts a 115/69 kV delivery point at the existing Taconite Harbor Substation that will be relocated to a new GRE Two Islands Substation adjacent to the MP Two Islands Switching Station. A second 115/69 kV transformer will be added at the GRE Two Islands Substation to provide redundancy for the GRE 69 kV system east of Taconite Harbor.

Need Driver: The new switching station will replace the original Taconite Harbor Substation, increasing reliability and safety by moving away from a compact original box structure in a straight bus configuration to a new ring bus configuration constructed according to modern standards for clearances, access, and maintainability. A major overhaul of the Taconite Harbor Substation would be required to extend the life of the existing site, but access and maintainability would still be limited due to the compact site layout. A complete overhaul of the Taconite Harbor Substation would require an extended outage that would leave the entire North Shore Loop on radial feeds for multiple weeks, which would increase risk of blackouts if any outage event should occur on the radial feeds.

Alternatives:

Transmission Alternatives

Complete overhaul of the Taconite Harbor Substation, including removal and reconstruction of foundations and steel structures and reconfiguration of bus work. This alternative results in unacceptable risk to the North Shore Loop with significant periods of radial feeds greatly reducing reliability in the region. GRE investigated the alternative to continue using Taconite Harbor and avoid building a 115/69 kV delivery point at the new GRE Two Islands Substation. This alternative was not embraced because MP couldn't commit to the duration that the existing Taconite Harbor Substation would continue to exist. The last remaining generators from the Taconite Harbor Energy Center recently completed Attachment Y studies with MISO to decommission.

Non-Wires Alternatives

Non-wire solutions are not viable as they would not address the aging condition and safety and reliability concerns associated with the existing Taconite Harbor Substation.

Analysis: The existing Tac Harbor Substation is a compact site originally purpose-built by a mine for the generators at the Taconite Harbor Energy Center. This compact style of substation creates safety concerns and outage constraints during maintenance with the condensed equipment locations. With the retirement of the generators, the substation now serves the primary purpose of providing reliable transmission support to the North Shore Loop. The Taconite Harbor Substation also provides a 115/69 kV step-down to source a 50 mile long radial 69 kV line that provides service to four of Arrowhead Electric Cooperative Incorporated's (AECI) distribution substations (Colvill, Maple Hill, Lutsen, and Cascade), one of Co-op Light & Power's distribution substations (Schroeder) and one of SMMPA's distribution substations (Grand Marais). GRE owns a generation station at the end of the line providing 18 MW of backup generation. The Taconite Harbor Substation is very critical to providing reliable power to a remote, radial system and is justified in rebuilding due to age and condition.

MP Schedule: The project is planned to be in service by the end of 2024, with civil work started in 2023.

GRE Schedule: The project is planned to be in service by the end of 2024.

General Impacts: The Two Islands 115 kV Project will improve reliability of the North Shore Loop with the new ring bus. A cap bank at this new facility will also improve voltage control on the North Shore Loop. The new ring bus will minimize outage concerns at the site with additional reliability and protection. As the Two Islands 115 kV Project will be a new facility, a new site location on Minnesota Power-owned property has been identified for all construction. The project will also require approximately 0.1 miles of new 69 kV transmission line from Two Islands Substation to the existing "SG" 69 kV line. The project is located in an area that is predominantly impacted by the historical utility usage of the nearby Taconite Harbor Energy Center. Prior to construction, MP and GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the 69 kV line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed over 18-24 months. During this time, MP and GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas and maximizes the use of existing utility-controlled lands and infrastructure.

Forbes 230 kV Modernization

MPUC Tracking Number: 2021-NE-N12

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life 230/115 kV transformer and 230 kV capacitor bank, circuit breakers, switches, relay panels, and associated equipment at the Forbes 230 kV Substation.

Need Driver: Age and condition.

Alternatives:

Transmission Alternatives

> There is no more economical or less impactful solution than replacing the existing substation equipment.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Forbes 230 kV Substation.

Analysis: One circuit breaker is oil-filled from 1979 and one circuit breaker is an early generation SF6 model of concern. The existing capacitor bank has failed components and a larger replacement capacitor bank will provide additional voltage support to the transmission system. The 230/115 kV transformer is a critical transformer to the surrounding 115 kV system, including the East Range and the North Shore Loop. This transformer has many age and condition-related issues. An extended outage due to failure of this transformer would likely require running local peaking generation for the duration of the outage. There are concerns with moving the aging transformer from another site which has been identified as a spare in the event of a failure. It is prudent to proactively replace this transformer in the near-term future before it fails.

Schedule: The project is presently planned for construction in 2025-2026.

General Impacts: The Forbes 230 kV Modernization Project will ensure that the Forbes 230 kV Substation continues to provide safe and reliable transmission support for Minnesota Power's 230 kV and 115 kV transmission system. The impacts of the project will be entirely contained within the existing Forbes Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Cloquet Substation Modernization

MPUC Tracking Number: 2021-NE-N13

Utility: Minnesota Power (MP)

Project Description: The Cloquet Substation Modernization Project involves replacing aging electrical equipment, structures, and civil works and correcting deficiencies at the existing Cloquet 115/14 kV Substation in an effort to improve substation safety and reliability for the foreseeable future. Multiple substation asset renewal needs will be combined with necessary distribution transformer upgrades to make up the core of this project. This work at the Cloquet Substation was combined into one project in order to facilitate efficient coordination of engineering and construction.

Need Driver: The Cloquet Substation serves Cloquet, Esko, Scanlon, parts of the Fond Du Lac reservation and the surrounding area. The primary need driver for the Cloquet Substation Modernization Project is age and condition of existing transformers, circuit breakers, disconnect switches, and site infrastructure. Much of the original equipment in this substation is nearing or beyond the end of its useful life, including many of the structures and foundations.

Alternatives:

Transmission Alternatives

Establish a new 115/14 kV substation east of Cloquet and reconfigure distribution system to enable retirement of Cloquet Substation or expand Canosia Rd 34 kV system and establish new 34/14 kV stepdowns to enable retirement of Cloquet Substation.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Cloquet Substation.

Analysis: Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Substation Modernization (Asset Renewal) Program involves coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. The Program takes a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of many aging substations throughout Minnesota Power's system. In developing the scope for the Cloquet Substation Modernization Project, Minnesota Power is considering the near-term and long-term needs of the area transmission and distribution system as well as the age and condition of existing site infrastructure and modern design standards for safety, accessibility, and maintainability.

Schedule: The project is currently planned as a multi-year project with construction taking place in stages from 2027-2028 to manage outage and constructability constraints.

General Impacts: The Cloquet Substation Modernization Project will ensure a continuous and reliable power supply to the Cloquet area by replacing aging equipment before it fails. At present, it is expected that the impacts will be entirely contained within the existing Cloquet Substation yard, making optimal use of the existing infrastructure to reduce human and environmental impacts.

Mesaba Junction 137 Line Extension

MPUC Tracking Number: 2021-NE-N14

Utility: Minnesota Power (MP)

Project Description: Extend a new 115 kV line approximately 8 miles from the Mesaba Junction Switching Station to the end of a customer-owned segment of 115 kV line connecting back to the existing Embarrass – Babbitt 115 kV Line (137 Line). A normal open point will be established near the Argo Lake tap due to the relatively small existing conductor on 137 Line. At the Mesaba Junction Switching Station, a 115 kV line entrance will be constructed, including a circuit breaker and deadend structure, in an existing ring bus position at the substation.

Need Driver: Age and condition of existing 137 Line and redundancy of service to Babbitt-area customers served from 137 Line.

Alternatives:

Transmission Alternatives

Do nothing.

Non-Wires Alternatives

Install new dispatchable energy resource in the area. Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate overloading. In this case, the non-wire alternatives must also be able to continue to support and follow load when isolated from the transmission system due to outages on the only transmission source to the area (137 Line).

Analysis: The Mesaba Junction 137 Line Extension Project meets three critical needs for the Babbitt area:

1. Providing redundancy to an industrial load pocket that requires near-constant availability
2. Enabling asset renewal by allowing the 137 Line Rebuild Project (Project Number 2021-NE-N15) to be constructed
3. Improving reliability with two properly maintained 115 kV transmission sources to the area

For an outage affecting the Mesaba Junction end of 137 Line, the issue can be isolated and service can be restored from Embarrass end by closing the normal open point. For a planned outage affecting the Mesaba Junction end of 137 Line, the normal open point can be closed and a segment of the line can be isolated without a customer outage.

Schedule: Due to wetlands in the area traversed by the transmission line, transmission line construction is advantageous during frozen ground conditions. Below grade construction at the Mesaba Junction Switching Station is presently planned for the 2025 fall season. Transmission line construction and above grade construction at the substation is presently planned to be constructed in the 2025-2026 winter season.

General Impacts: The Mesaba Junction 137 Line Extension Project will preserve and enhance the reliable delivery of power to an important industrial load pocket in the Babbitt area. The project will also provide the opportunity to address significant age and condition and maintenance-related issues on the existing Embarrass – Babbitt 115 kV Line as part of the 137 Line Rebuild (2021-NE-N15). The project will require approximately 8 miles of new 115 kV transmission in a remote area of northern Minnesota that has been heavily impacted by historical mining operations.

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137 Line Rebuild

MPUC Tracking Number: 2021-NE-N15

Utility: Minnesota Power (MP)

Project Description: Rebuild existing Embarrass – Babbitt 115 kV Line (137 Line) from the Embarrass Substation to the North side of the Peter Mitchell Mine pit crossing with a larger conductor.

Need Driver: Age and condition.

Alternatives:
Transmission Alternatives
> There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line components on 137 Line.

Non-Wires Alternatives
> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come.

Schedule: Due to wetlands in the area traversed by the transmission line, construction is advantageous during frozen ground conditions. The 137 Line Rebuild is presently planned to be constructed in stages from 2027-2029, maximizing use of the winter construction season.

General Impacts: The 137 Line Rebuild Project will ensure that the existing Embarrass – Babbitt 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power's customers. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission line with little or no additional human or environmental impacts.

West Cohasset Substation

MPUC Tracking Number: 2021-NE-N17

Utility: Minnesota Power (MP)

Project Description: The West Cohasset Substation Project involves re-establishing a 115/23 kV transformer at the Boswell SES 115 kV Substation and extending new 23 kV feeders from the substation. The Boswell SES Substation will be renamed as part of the project to eliminate redundant naming with the adjacent Boswell 230/115 kV Substation.

Need Driver: The West Cohasset Substation Project is necessary to upgrade the reliability and capacity of the existing 23 kV distribution system in the Cohasset area.

Alternatives:
Transmission Alternatives

> Alternatives would be to rebuild the Lind-Greenway Substation for increased capacity as well as upgrading the feeder tie between Lind-Greenway and Zemple substations to facilitate better backup capability.

Non-Wires Alternatives

> Non-wire alternatives must be available when needed and dispatchable to support reliable load-serving under normal and contingency conditions.

Analysis: The West Cohasset Substation Project will enhance the existing Minnesota Power 23 kV distribution system while enabling new loads to be interconnected in the Cohasset area.

Schedule: The project is scheduled to be in service by the end of 2026.

General Impacts: The West Cohasset Substation Project will make optimal use of an existing substation site to preserve and enhance the reliability of the Cohasset-area distribution system. Since the Boswell SES 115 kV Substation was originally designed to accommodate a transmission-distribution transformer, the majority of impacts from the substation expansion part of the project will be contained within the existing substation yard, minimizing human and environmental impacts.

105 & 106 Line Upgrade

MPUC Tracking Number: 2021-NE-N20

Utility: Minnesota Power (MP)

Project Description: The 105 Line & 106 Line Upgrade Project involves reconductoring segments of the two existing Iron Range – Blackberry 230 kV lines and replacing limiting terminal equipment at the Blackberry Substation.

Need Driver: Post-contingent overloads for loss of parallel circuits.

Alternatives:
Transmission Alternatives
Build new parallel line; relocate one or more existing 230 kV line terminations from Blackberry to Iron Range to reduce post-contingent flows on the Iron Range – Blackberry 230 kV Lines.
Non-Wires Alternatives
Non-wire alternatives must be dispatchable to respond when called upon, of sufficient duration, and at an effective location to prevent or mitigate overloading.

Analysis: This issue has been identified in Minnesota Power internal and MISO MTEP studies, and is also discussed in Minnesota Power's Integrated Resource Plan as it relates to changes in operation of the Boswell Energy Center units. With at least one Boswell unit moving from baseload operation to economic dispatch, overloads on these transmission lines are expected to show up more frequently as they are critical outlets for the delivery of replacement energy from the Iron Range and Forbes 500/230 kV sources.

Schedule: The project is presently targeted for implementation in 2023-24.

General Impacts: The 105 Line & 106 Line Upgrade Project will provide necessary system improvements for Minnesota Power's 230 kV system without requiring the establishment of additional transmission line corridors. In addition to making optimal use of existing facilities, the project supports changes in operation at the Boswell Energy Center that have social, environmental, and economic benefits.

230 kV STATCOM Project

MPUC Tracking Number: 2021-NE-N21

Utility: Minnesota Power (MP)

Project Description: The 230 kV STATCOM Project involves the establishment of a new STATCOM at the existing Iron Range or Riverton 230 kV Substation.

Need Driver: The new STATCOM is needed to ensure a continuous and reliable source of steady state and dynamic voltage support during times when no large dispatchable generators are online in Northern Minnesota.

Alternatives:
Transmission Alternatives
    Must-run large dispatchable generators such as the Boswell Energy Center for reliability purposes. Retrofit one or more Boswell units with synchronous condenser capability.
Non-Wires Alternatives
    STATCOMs are a non-wire alternative. Other non-wire alternatives must be dispatchable to respond when called upon, able to provide sufficient magnitude, consistency, and availability of system support, and located at an effective location to replace the support previously provided by baseload generators.

Analysis: The Boswell Energy Center units are the last remaining baseload generators operating in Northern Minnesota. As the last remaining baseload generators, the Boswell units provide voltage support and system strength on a continuous basis that support consistent and predictable system operations and properly function 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 predictable voltages and fault currents historically and presently provided by the Boswell 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. Without the Boswell units online, the Northern Minnesota transmission system would operate for extended periods of time without any local generators online to provide 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 degraded operation in the transmission system and lower-voltage industrial, municipal and Minnesota Power distribution system connected to it.

As Minnesota Power has continued to evaluate the issue and potential solutions, studies have consistently demonstrated significant degradation of steady state and dynamic voltage regulation when the Boswell units are offline. Less predictable steady state voltages, lower transient voltage dips during and after fault events, slower transient voltage recovery after fault events, and greater susceptibility to impacts from far-away regional fault events have all been identified as concerns on Minnesota Power's system and propagating out on the regional 230 kV system. To address these concerns, a voltage support solution is needed to provide a continuous, predictable, and redundant source of steady state voltage regulation and dynamic voltage response on Minnesota Power's 230 kV system. Based on Minnesota Power's analysis and experience, a STATCOM is the ideal solution for meeting these steady state and dynamic voltage support needs. STATCOMs require no fuel for continuous operation and produce only reactive power. STATCOMs are capable of providing voltage regulation during normal system operations as well as dynamic voltage response during system disturbances. STATCOMs also provide inherently faster voltage response compared with Synchronous Condensers, and are less maintenance-intensive.

Schedule: Minnesota Power is presently in the late stages of identifying the preferred location on its 230 kV system to maximize the benefits of the proposed STATCOM solution. The STATCOM is anticipated to be sized between ±250 to ±350 MVAR and interconnected at either the existing Iron Range 230 kV Substation or the existing Riverton 230 kV Substation. Minnesota Power anticipates placing the STATCOM in service in 2027.

General Impacts: The establishment of one or more STATCOMs on Minnesota Power's transmission system will provide necessary voltage support for Minnesota Power's customers during times when no large dispatchable generators are online in Northern Minnesota. To the extent possible, new STATCOMs will be located at existing substation facilities. In addition to making optimal use of existing facilities, the establishment of one or more STATCOMs enables the transmission system to continue to operate reliably and predictably during and after changes in operation at the Boswell Energy Center that have social, environmental, and economic benefits.

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126 Line Asset Renewal

MPUC Tracking Number: 2021-NE-N22

Utility: Minnesota Power (MP)

Project Description: The 126 Line Asset Renewal Project involves replacement of transmission line components on the Little Fork – International Falls 115 kV Line (126 Line) due to age and condition. The project will also include age-related replacements of a 115 kV circuit breaker and relay panel at the Little Fork Substation and a relay panel at the International Falls Substation.

Need Driver: The project will address asset renewal needs on 126 Line related to the age and condition of existing structures and transmission line components, an oil-filled 115 kV circuit breaker, and older relay panels that have been found to be susceptible to component failures.

Alternatives:

Transmission Alternatives

> There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line and substation components associated with 126 Line.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line or substation equipment.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come.

Similarly, there are many transmission assets across Minnesota Power's system that require age-related upgrades. In developing the scope for the 126 Line Asset Renewal Project, Minnesota Power is also considering targeted replacements at the substations that will address age-related concerns and contribute to more reliable operation of the transmission system.

Schedule: The 126 Line Asset Renewal Project is presently targeted for construction in 2023.

General Impacts: The 126 Line Asset Renewal Project will ensure that the existing Little Fork – International Falls 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power's customers in the International Falls area and the region. The project involves replacement of existing assets on the existing transmission line right-of-way and within existing substations, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

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13 Line Rebuild

MPUC Tracking Number: 2021-NE-N23

Utility: Minnesota Power (MP)

Project Description: The 13 Line Rebuild Project involves replacement of transmission line structures and conductor on the Portage Lake – Riverton 115 kV Line (13 Line) due to age and condition. The project will also include the addition of shield wire and fiber-optic communications on the rebuilt transmission line.

Need Driver: The project will address asset renewal needs on 13 Line related to the age and condition of existing structures and transmission line components, add shield wire to improve reliability by reducing lightning-related outages that directly impact Minnesota Power and Great River Energy customers, and add fiber-optic communications to enhance transmission line protection systems.

Alternatives:
Transmission Alternatives

There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the scope for the 13 Line Rebuild Project, Minnesota Power also took into consideration reasonable enhancements that could be incorporated to improve operational performance and relaying for 13 Line.

Schedule: The 13 Line Rebuild Project is in early stages of project scoping and is presently targeted for 3-4 years of phased construction beginning at the earliest in 2025.

General Impacts: The 13 Line Rebuild Project will ensure that the existing Portage Lake – Riverton 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power and Great River Energy's customers and the region. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Riverton – Wing River Storm Structures

MPUC Tracking Number: 2021-NE-N27

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Riverton – Wing River 230 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5- to 10-mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:

Transmission Alternatives

Storm Structures were considered the most cost-effective solution to limit outages from line cascading.

Non-Wires Alternatives

This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by August 2024.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Riverton substation to Wing River substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Northland Reliability Project

MPUC Tracking Number: 2023-NE-N1

Utility: Minnesota Power (MP) & Great River Energy (GRE)

Project Description: Minnesota Power (MP) and Great River Energy (GRE) are jointly developing the Northland Reliability Project (Project), located in northern and central Minnesota. The Project consists of two major segments of transmission line construction:

1) Segment 1: construction of a new, approximately 140-mile long, double-circuit 345 kV transmission line connecting the existing Iron Range 500-230 kV Substation, a new Cuyuna 345 kV Series Compensation Station, and the existing Benton County 345 kV Substation, generally located near existing transmission line corridors; and
2) Segment 2: replacement of two existing 345 kV transmission lines
   a. Replace an approximately 20-mile 230 kV line with two 345 kV circuits from the Benton County Substation to the new Big Oaks Substation along existing transmission corridors on double-circuit 345 kV structures. Approximately 6 miles of this double circuit line will have 69 kV underbuild; and
   b. Replace an approximately 20-mile 345 kV line from the Benton County Substation to the existing Sherco Substation along existing transmission corridors using double-circuit capable 345 kV structures. Approximately 4 miles of this double circuit line will have a 69 kV circuit.

The Project will also involve the following new or modified substation and series compensation facilities:

- Expansion of the existing Iron Range Substation 500-230 kV Substation, located near Grand Rapids, Minnesota, to include new 500-345 kV transformers, 345 kV bus and breakers, and 345 kV line-end shunt reactors
- Construction of a new Cuyuna 345 kV Series Compensation Station located near Riverton, Minnesota, approximately at the midpoint of Segment 1
- Expansion of the existing Benton County 345 kV Substation, located near St. Cloud, Minnesota, to include new 345 kV bus and breakers, and 345 kV line-end shunt reactors

The proposed Big Oaks 345 kV Substation on the south end of Segment 2 is being permitted, engineered, and constructed by Xcel Energy as part of a separate project, and is not included in this scope of work.

Need Driver: The Northland Reliability Project is needed to address some of the most challenging transmission system reliability issues related to the transition away from fossil-fueled generation. These reliability issues include serious regional voltage and transient stability issues identified by MP and GRE and the Midcontinent Independent System Operator (MISO). The Project addresses these issues and also provides enhancements to voltage support and system strength, local sources of power delivery, and the ability to move power between regions. The Project was studied, reviewed, and ultimately approved as part of the MISO Long-Range Transmission Plan (LRTP) Tranche 1 Portfolio by MISO's Board of Directors in July 2022. The Project will ensure that the power grid in northern and central Minnesota continues to operate safely and reliably as energy resources in Minnesota and the regional power system continue to evolve.

Alternatives:
<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
None.

Analysis: New transmission lines are required for voltage stability in the northern Minnesota area.

Schedule: The project is planned to be in service by June 1, 2030.

General Impacts: The project will be constructed along the existing 230 kV transmission line from the Iron Range substation to the Benton County substation, with additional construction along the existing 230 kV transmission line from the Benton County substation to the Monticello substation, terminating at the new Big Oaks substation, and construction along the existing 345 kV transmission line from the Benton County substation to the Sherco substation. The project is located in both forested and agricultural lands across its length. Construction is expected to be completed over 3 years. During this time, MP/GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

40 Line Rebuild

MPUC Tracking Number: 2023-NE-N2

Utility: Minnesota Power (MP)

Project Description: Rebuilding the existing 40 Line, a 115 kV transmission line between the Badoura Substation and Dog Lake Substation. The project will upgrade conductors on the line and add OPGW for a communications path between the sites.

Need Driver: This project is primarily an age and condition rebuild project, replacing structures from the 1970s.

Alternatives:
Transmission Alternatives

This project is an age and condition rebuild project so no alternatives were evaluated.

Non-wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service in spring of 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from the Dog Lake substation to the Badoura substation. Construction is expected to be completed within 6 months starting in late summer 2023 and extending through the winter months into 2024. During this time, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Brainerd Crypto

MPUC Tracking Number: 2023-NE-N3

Utility: Minnesota Power (MP)

Project Description: Adding capacitor bank at Brainerd and rebuilding 12L.

Need Driver: New customers are connecting to the Brainerd 115 kV substation through the local 34.5 kV network. As the substation load grows, due to these customer connections, post-contingent overloads and low voltage violations were identified by MISO as part of the expedited project review process as part of MTEP.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
Minnesota Power enacting an operational guide for load shedding at Brainerd as a temporary mitigation.
Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is currently shown in MISO MTEP for in-service in 2025.

General Impacts: The rebuild of 12 Line would allow for additional load growth in Brainerd area. The rebuild would also replace an aging asset. The project would match new standards for conductor and structure designs. The cap bank would supply reactive sources to the Brainerd area to support the voltage during heavy load conditions.

Maturi Expansion

MPUC Tracking Number: 2023-NE-N4

Utility: Minnesota Power (MP)

Project Description: Expanding the Maturi Substation to accommodate new 23 kV lines to serve local MP loads, looping 25 Line in and out of the substation to replace the tap in 25 Line.

Need Driver: The Maturi Substation serves Minnesota Power retail customers in the area surrounding Hibbing and Chisholm. The primary need driver for the Maturi Substation Expansion project is to unload the Hibbing Substation and create a better source for the City of Chisholm and the surrounding area.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2026.

General Impacts: The Maturi Expansion Project will ensure a continuous and reliable power supply to the City of Chisholm and the surrounding area. The project involves looping 25 Line in and out of the substation on the existing transmission line right-of-way, therefore making optimal use of the existing transmission line with little or no additional human or environmental impacts.

Mahtowa Expansion

MPUC Tracking Number: 2023-NE-N5

Utility: Minnesota Power (MP)

Project Description: Substation expansion of the Mahtowa Substation to facilitate back-up of Cloquet feeder. Mahtowa is currently a tap located on 26 Line that spans from Thomson to GRE_Cromwell. This project will break this tap into two different lines so that the Mahtowa substation is no longer a radial tap.

Need Driver: Transformer age and condition.

Alternatives:
Transmission Alternatives

> There is no more economical or less impactful solution than replacing the existing substation equipment.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Mahtowa Substation.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2026.

General Impacts: The 115/23 kV transformer located at Mahtowa has reached its end of life and poses a reliability issue. This transformer and the 115/46 kV transformer also at this site will be replaced with a single 115/34 kV transformer. This will increase the reliability of this site and remove the last of the 23 kV voltage class in the Minnesota Power central area. This will help keep the distribution system consistent in the area for operation and maintenance. Second, this project will loop 26 Line in and out of the substation to remove Mahtowa as a radial tap.

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158 Line Rebuild

MPUC Tracking Number: 2023-NE-N6

Utility: Minnesota Power (MP)

Project Description: The 158 Line Rebuild Project involves replacement of transmission line structures and conductor on the Portage Lake – Cromwell 115 kV Line ("158 Line") due to age and condition. The project will also include the addition of shield wire and fiber-optic communications on the rebuilt transmission line.

Need Driver: The project will address asset renewal needs on 158 Line related to the age and condition of existing structures and transmission line components, add shield wire to improve reliability by reducing lightning-related outages that directly impact Minnesota Power and Great River Energy customers, and add fiber-optic communications to enhance transmission line protection systems.

Alternatives:
Transmission Alternatives

There are no reasonable alternatives that will address the asset renewal needs for the existing transmission line.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the existing transmission line.

Analysis: Across Minnesota Power's system there are many transmission lines that require age and condition-related upgrades. Many of the original wood pole structures and components on these transmission lines are nearing or beyond the end of their useful lives. As these transmission lines continue to age, the risk of structure and component failures – and therefore the risk of outages, property damage, and safety concerns – will increase. Minnesota Power's Transmission Line Asset Renewal Program involves identification, prioritization, and coordination of transmission line asset renewal projects to address end-of-life wood poles and other components while holistically considering long-term reliability, capacity, and communications needs. The program is designed to extend the lives of these transmission lines so they can continue to reliably serve Minnesota Power's customers and the region for many decades to come. In developing the scope for the 158 Line Rebuild Project, Minnesota Power also took into consideration reasonable enhancements that could be incorporated to improve operational performance and relaying for 158 Line.

Schedule: The 158 Line Rebuild Project is in early stages of project scoping and is presently targeted for 1-2 years of phased construction beginning at the earliest in 2025.

General Impacts: The 158 Line Rebuild Project will ensure that the existing Portage Lake – Riverton 115 kV Line continues to provide a safe and reliable transmission path for Minnesota Power and Great River Energy's customers and the region. The project involves replacement of existing assets on the existing transmission line right-of-way, therefore making optimal use of the existing transmission facilities with little or no additional human or environmental impacts.

Arrowhead Single Point of Failure

MPUC Tracking Number: 2023-NE-N7

Utility: Minnesota Power (MP)

Project Description: Adding monitoring and redundant controls to mitigate single point of failure concerns around DC supply systems.

Need Driver: Compliance.

Alternatives:
Transmission Alternatives

Significant existing transmission line rebuilt to a larger conductor to mitigate all violations present after the P5 contingency.

Non-Wires Alternatives

The P5 contingency can only be mitigated with extra monitoring and control redundancy.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2025.

General Impacts: This project will introduce redundant monitoring and controls at the Arrowhead 115 kV site. The specifics of the project and are still being determined. At the end of this project, the Arrowhead 115 kV P5 contingencies can be retired due to enough redundant monitoring at the site.

Forbes Single Point of Failure

MPUC Tracking Number: 2023-NE-N8

Utility: Minnesota Power (MP)

Project Description: Adding monitoring and redundant controls to mitigate single point of failure concerns around DC supply systems.

Need Driver: Compliance.

Alternatives:

Transmission Alternatives

Significant existing transmission line rebuilt to a larger conductor to mitigate all violations present after the P5 contingency.

Non-Wires Alternatives

The P5 contingency can only be mitigated with extra monitoring and control redundancy.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2025.

General Impacts: This project will introduce redundant monitoring and controls at the Forbes 115 kV site. The specifics of the project are still being determined. At the end of the project, the Forbes 115 kV P5 contingencies can be retired due to enough redundant monitoring at the site.

Ridgeview 115/34 kV Transformer Addition

MPUC Tracking Number: 2023-NE-N9

Utility: Minnesota Power (MP)

Project Description: Expanding the Ridgeview 115 kV Substation to add a new 115/34 kV transformer.

Need Driver: Distribution capacity and backup capability.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

Distribution project to address capacity need. This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2027.

General Impacts: This project will be the start of a series of projects that will shift the Duluth distribution network to allow more load addition while also increasing reliability. The Ridgeview 115/34 kV transformer addition will take over the stepdowns located on the Swan Lake 34 kV feeder so that the Miller Hill Mall can be added to Swan Lake. The Miller Hill Mall does not have and adequate backup source presently and shifting its feeder will mitigate the issue.

Wrenshall Substation Modernization

MPUC Tracking Number: 2023-NE-N10

Utility: Minnesota Power (MP)

Project Description: Adding monitoring and redundant controls to mitigate single point of failure concerns around DC supply systems.

Need Driver: The Wrenshall Substation is in need of asset replacement due to age and condition of the site.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
No alternatives for an age and condition project.

Analysis: This project will replace old equipment to strengthen reliability to the local loads.

Schedule: The project is planned to be in service by end of year 2027.

General Impacts: This project will ensure a continuous and reliable power supply to the Wrenshall area by replacing old assets prior to failure.

133 Line Rebuild

MPUC Tracking Number: 2023-NE-N11

Utility: Minnesota Power (MP)

Project Description: Rebuilding 115 kV Transmission Line between Verndale and Wing River Substations.

Need Driver: Age and condition replacement of transmission line structures.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by end of year 2026.

General Impacts: The project will be constructed on the existing 115 kV transmission line from the Verndale substation to the Wing River substation. During construction, MP and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

6.4.2 Completed Projects

The table below identifies those projects by Tracking Number in the Northeast Zone that were listed as ongoing projects in the 2021 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Minnesota Public Utilities Commission in October 2021. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2021 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-NE-N14	83 Line Upgrade	N/A	MP	CANCELED
2017-NE-N2	Laskin-Tac Harbor Voltage Conversion	N/A	MP	2023
2017-NE-N6	Forbes Tie Breaker Addition	N/A	MP	2022
2017-NE-N21	Laskin-Tac Harbor Transmission Line Upgrades	N/A	MP	2023
2017-NE-N23	Mesaba Junction 115 kV Project	N/A	MP	2022
2019-NE-N2	Forbes 37 Line Upgrade	N/A	MP	2022
2019-NE-N5	29 Line Upgrade	N/A	MP	CANCELED
2019-NE-N14	Laskin Breaker Replacements	N/A	MP	CANCELED
2021-NE-N2	8 Line Relocation	N/A	MP	2022
2021-NE-N7	98 Line Asset Renewal	N/A	MP	2021
2021-NE-N10	95 Line Asset Renewal	N/A	MP	CANCELED
2021-NE-N16	North Shore Transformer Addition	N/A	MP	2022
2021-NE-N18	Boise Breaker Addition	N/A	MP	CANCELED

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2021-NE-N24	Fond du Lac - Wrenshall	None	GRE	CANCELED
2021-NE-N25	Shamineau Lake	None	GRE	2/9/2023
2021-NE-N26	Wing River 230 kV Ring Bus	None	GRE	7/28/2022

6.5 West Central Zone

6.5.1 Needed Projects

The following table provides a list of transmission needs identified in the West Central Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2009-WC-N6	Elk River-Becker Area	2012/C	2691	No	Yes	GRE
2015-WC-N3	Ortonville 115/41.6 kV Transformer	2015/B	4236	No	No	OTP
2019-WC-N4	Westwood I 115 kV Conversion	2020/A	17971	No	No	GRE
2021-WC-N1	Black Oak – Sauk Centre 69 kV Rebuild	2021/A	19889	No	No	XEL
2021-WC-N4	Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild	2021/A	19913	No	No	XEL
2021-WC-N5	Panther – Big Swan Rebuild	2021/A	20135	No	No	XEL
2021-WC-N6	Appleton – Benson 115 kV Line	2021/A	20148	Yes	No	GRE/OTP/ MRES
2021-WC-N8	Big Swan Ring Bus and Capacitor Bank Addition	2022/A	20165 23803	No	No	GRE
2021-WC-N9	Kerkhoven 115 kV Breaker Additions	Future	TBD	No	No	GRE
2021-WC-N10	Walden 115 kV Breaker Addition	Future	TBD	No	No	GRE
2021-WC-N11	Benson – Morris Storm Structures	2022/A	21823	No	No	GRE
2023-WC-N1	Sauk Centre North Interconnection	2023/A	23514	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2023-WC-N2	Milbank, SD Area Upgrades	2023/A	25305	Yes	No	OTP
2023-WC-N3	Big Stone South – Alexandria – Big Oaks 345 kV	2021/A	23369	Yes	No	GRE, MP, MRES, OTP, XEL
2023-WC-N4	Big Swan – Wakefield Storm Structure Addition	2023/A	23849	No	No	GRE
2023-WC-N5	Willmar – Stockade – Hutchinson Rebuild and 115 kV Conversion	Future	TBD	Yes	No	GRE, MRES, SMMPA
2023-WC-N6	Lake Mary 115 kV Conversion	2022/A	17988	No	No	GRE
2023-WC-N7	Hodges Distribution Substation	Future	TBD	No	No	GRE
2023-WC-N8	I-94 Substation Expansion	Future	TBD	No	No	GRE
2023-WC-N9	Mud Lake – Riverton Line Upgrade	2024/A	25391	No	No	GRE
2023-WC-N10	Cedar Mountain Substation Upgrade	2023/A	23883	No	No	GRE
2023-WC-N11	Benton County Solar Farm (J1426)	2023/A	24285	No	No	GRE
2023-WC-N12	Morris to Grant County to East Fergus Falls 115 kV Line Upgrade	2023/A	23919	No	No	MRES
2023-WC-N13	Alexandria Light and Power Southeast Substation	2023/A	24232	No	No	MRES
2023-WC-N14	Alexandria Substation Expansion	2021/A	23369	Yes	No	MRES
2023-WC-N15	Inman – Miltona Upgrade	2024/A	25399	No	No	GRE
2023-WC-N16	Benton County Terminal Upgrade	2024/A	25399	No	No	GRE
2023-WC-N17	Johnson Junction Switch Upgrade	2024/A	25399	No	No	GRE

Elk River-Becker Area

MPUC Tracking Number: 2009-WC-N6

Utilities: Great River Energy (GRE)

Project Description: Build the Orrock 345/115 kV Substation northwest of Elk River. Build 115 kV lines from Orrock to Enterprise Park & Liberty.

Need Driver: This project is needed to address load growth and thermal overloading during a two overlapping single contingency event (NERC TPL-001-4 P6).

Alternatives:

Transmission Alternatives

> Reconductor the Crooked Lake-Parkwood line to ACSS conductor and add a second 345/115 kV transformer at Elm Creek.

Non-Wires Alternatives

> This project is still being studied. Non-transmission alternatives will be studied and considered prior to project initiation.

Analysis: The project is proposing a double circuit 115/69 kV line that would provide more capacity to a narrow transmission corridor than either a single circuit 115 or 69 kV line could offer. Furthermore, the Waco breaker station was designed to accept a 115/69 kV transformation and such a transformer would offload the Elk River 230/69 kV transformers. An Elk River Area 345/115 kV source would also offer a termination point for a 115 kV line going east towards the Crooked Lake Substation.

Schedule: This schedule for this project will be driven by the area load growth. Some portions of the 69 kV transmission will be converted to 115 kV design when needed due to age and condition.

General Impacts: The project will be constructed on an existing 69 kV transmission right-of-way that is located on residential and agricultural lands. The existing line will be upgraded from 69 kV to 115 kV construction and operation. A new substation will be built on approximately 22 acres near where the Xcel Energy 345 kV 0984 & 0992 transmission lines cross the GRE 69 kV EB line. No new landowners will be impacted by construction, although some additional temporary workspace may be required. GRE has completed a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction schedule and duration is uncertain at this time but will likely be spread out over several years. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Ortonville 115/41.6 kV Transformer

MPUC Tracking Number: 2015-WC-N3

Utility: Otter Tail Power Company (OTP)

Project Description: Replace existing Ortonville 115/41.6 kV transformer with a new 40 MVA 115/41.6 kV transformer.

Need Driver: This area is experiencing local load growth and continual growth may cause the current 115/41.6 kV Ortonville transformer to become overloaded and created reliability concerns.

Alternatives:

Transmission Alternatives

With the most recent load forecasts, this project is not presently planned for construction. Alternatives may be considered if or when loads drive the need for this project.

Non-Wires Alternatives

Non-wires alternatives may be considered if this project were to move forward in development; however, they would likely come with a higher cost than replacing this transformer.

Analysis: The replacement of the Ortonville 115/41.6 kV transformer with a larger transformer will address the local load growth that this area is experiencing and will provide reliable service to the customers in the area. This project is the most cost-effective and environmentally responsible project to address the local needs in the Ortonville area.

Schedule: While prior studies identified this need, current load growth projections show no need to replace this transformer based on OTP's *Ten Year Development Study*. However, faster load growth could create a need for this project, and continued studies will monitor this transformer's loading.

General Impacts: The new transformer would replace the existing transformer and would require no additional new land or expansion. Since it will replace the existing transformer, there likely would be no major environmental impacts. This project may require a temporary project crew. If so, this may bring some business to the area in the form of room and board. This is an existing substation and would likely not require any permits or fees from the local government. This project is the product of a reliability measure, and will probably not have a substantial or lasting impact on the community in terms of population or other social characteristics.

Westwood I 115 kV Conversion

MPUC Tracking Number: 2019-WC-N4

Utility: Great River Energy (GRE)

Project Description: Convert the Westwood I substation to 115 kV service and provide a loop feed to the LeSauk and Five Points distribution substations. The following will be accomplished as part of this project:

1. Install line dead-end, bus, and breaker at West St. Cloud substation.
2. Rebuild and convert existing 69 kV line (GRE's ST-WW line) to 115kV with 795 ACSS conductor
3. Conversion of Westwood I substation for 115 kV service.
4. Install a new FLB motor operated 3-way switch for the Five Points tap.
5. Install a new115 kV manual quick whip switch at Westwood I tap.
6. Install a FLB motor operator at the existing LeSauk Tap switch.
7. Keep the existing ST-WL de-energized in place for possible 115kV loop per Planning.

Need Driver: Improve service reliability to Westwood I, LeSauk and Five Points distribution substations. The West St. Cloud to Little Falls 115 kV line has been a congested interface. Removing Le Sauk and Five Points substations from this line will provide some relief to this congestion. The upgrade of Westwood I distribution substation to 115kV service will address current safety concerns arising from high current flow in the distribution system when switching between Westwood I and Westwood II, or vice versa.

Alternatives:

Transmission Alternatives

The alternative to abiding by existing guide with MP is to install a 115 kV breaker station at St. Stephen. While it is costly, it would not provide the redundancy that the project provides to Westwood I, LeSauk and Five Points substations. This alternative doesn't address the safety concern that exist when switching between the Weststood substations.

Non-Wires Alternatives

GRE is replacing existing wires to transition two substations from radial service to a looped service. An NWA was not deemed necessary for this project since the corridor exists and the objectives are to provide a loop feed and address existing safety concerns.

Analysis: The Westwood I conversion to 115 kV will be accomplished by upgrading existing 69kV transmission lines that serve the Westwood I substation. This is a project that is most economical and least impactful to landowners. This project addresses safety issues at the Westwood substations and the reliability improvement needs in the area.

Schedule: The project is planned to be in service by spring 2025.

General Impacts: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. The approximately 2.5 miles of existing line will be upgraded from 69 kV to 115 kV construction and operation. No new landowners will be impacted by construction, although some additional temporary workspace may be required. GRE has completed a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 3 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Black Oak – Sauk Center 69 kV Rebuild

MPUC Tracking Number: 2021-WC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild and upgrade conductor on approximately 6.64 miles from Black Oak to Sauk Center.

Need Driver: Structures exceed planned service life - built in 1951. 4/OA and 3/#6 CU line sections overloading on N-1 contingencies.

Alternatives:
Transmission Alternatives

The alternative option for this project is to perform maintenance and refurb on the line without upgrading the conductor. However, this option would still result in thermal overloads caused by N-1 contingencies.

Non-Wires Alternatives

None as this is an age and condition project of an existing line.

Analysis: Upgrading conductor on this line to current 69 kV standards will mitigate the thermal issues seen online as well as increase load serving capability in the area.

Schedule: The project is planned to be in service by June 1, 2024.

General Impacts: Line rebuild to take place along existing centerline in rural setting adjacent to roadways. Structure heights are likely to increase. Road lane closure may be required during some construction.

Howard Lake to Big Swan, Delano to Howard Lake, Cokato to Winstead Rebuild

MPUC Tracking Number: 2021-WC-N4

Utility: Xcel Energy (XEL)

Project Description: Howard Lake to Big Swan - Rebuild 16.0 miles, Delano to Howard Lake – Rebuild 19.7 miles, Cokato to Winstead – Rebuild 14.3 miles to current 69 kV standard for end of life asset renewal.

Need Driver: Re-occurring system reliability issues increase, public safety concerns
Inability to serve load in long term.

Alternatives:
Transmission Alternatives
Do nothing. Not replacing would result in more frequent and long term outages.
Non-Wires Alternatives
None, this is an age and condition replacement of existing lines.

Analysis: Upgrading the line to current 69 kV standards will reduce losses as well as improve load serving capability in the area.

Schedule: The project is planned to be in service by June 15, 2024.

General Impacts: Primarily rural/agricultural land use with scattered urban/ developed areas; main environmental concerns are storm water control, environmental reclamation, and bird flight diverters. DNR water crossing permits will be required, as necessary.

Panther – Big Swan Rebuild

MPUC Tracking Number: 2021-WC-N5

Utility: Xcel Energy (XEL)

Project Description: Rebuild 90% of line from Panther – Big Swan to current 69kV standard, replace Litchfield hard tap structure with double circuit structure, installation of a breaker station at Adams Wind Tap.

Need Driver: Panther – Big Swan 69 kV is one of NSP's worst performing lines with 60+ miles of line exposure. This project will cut the line exposure into thirds in addition to mitigating thermal issues, voltage issues, and 3-terminal relay issues.

Alternatives:
Transmission Alternatives
Partial rebuild of identified line segments or progressive end of life replacements as failures occur. These options would cause increased time, cost, and line outages as well as not address the system performance reliability.
Non-Wires Alternatives
None.

Analysis: Upgrading the line to current 69 kV standards will reduce losses as well as mitigate thermal, voltage, and 3-terminal issues seen in the area.

Schedule: The project is planned to be in service by December 31, 2026.

General Impacts: Project will be split into four stages and coordinated with other rebuilds occurring in that area within a similar timeframe. Line will be rebuilt using existing right-of-way.

Appleton – Benson 115 kV Line

MPUC Tracking Number: 2021-WC-N6

Utility: Great River Energy (GRE), Otter Tail Power (OTP), Missouri River Energy Services (MRES)

Project Description: Construct approximately 28 miles of 115 kV transmission line from the MRES Appleton substation to GRE Benson substation. Rebuild the Appleton Substation to a ring bus with four breakers and a 25 Mvar capacitor bank. Convert 2 GRE and 2 OTP 41.6 kV distribution substations to 115 kV service. Add 2 115 kV breakers to the Benson Municipal substation. Reconfigure line terminations at GRE Benson and Benson Municipal.

Need Driver: This project is needed to address load serving issues and make capacity available to serve future load growth in the area. Additionally, it will address low voltage concerns during N-2 contingencies that may otherwise result in voltage collapse within the project areas.

Alternatives:
Transmission Alternatives
The following alternatives were considered, but were not preferred:
Alexandria – Benson 115 kV ~47-mile line
MN Valley – Benson 115 kV ~44-mile line
Willmar – Benson 115 kV ~35-mile line
Six Mile Grove 230/115 kV substation

Non-Wires Alternatives

Both technical and economic analysis proves that the NWA is not viable for the area of study. In addition to that, the technical solution shows that NWA fails to address some of the issues which can be addressed by the proposed transmission solution, for example P6 contingency low voltage concerns in the Morris to Canby 115 kV system. A report is available upon request.

Analysis: The Appleton – Benson 115 kV line is the best value plan that addresses the load serving reliability issues in the area that in part was caused by generation retirement in the area. By in large, this project utilizes existing transmission line corridor and will upgrade existing 41.6 kV transmission lines to 115 kV. As such, among the alternatives considered, it is the most environmentally friendly project that addresses reliability issues and fosters economic development in wider area.

Schedule: The project is planned to be in service by December 2029.

General Impacts: The project will require approximately 28 miles of new 115 kV transmission line from Appleton substation to Benson substation. The project is located in predominantly agricultural lands. Prior to construction, GRE and/or OTP will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 24 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Big Swan 115 kV Ring Bus and Capacitor Bank Addition

MPUC Tracking Number: 2021-WC-N8

Utility: Great River Energy (GRE)

Project Description: Rebuild the Big Swan 115 kV side of the Big Swan substation in a ring bus configuration to accommodate installation of a new capacitor bank and to reterminate the Big Swan to Crow River 115 kV line into a breaker position. Upgrade 115 kV and 69 kV relaying to ensure all protection is redundant. Add a new 40 MVAr capacitor into a position in the ring bus.

Need Driver:
Ring bus addition:
The Big Swan 115 kV bus has an incomplete topology, missing a 115 kV breaker on the Big Swan 115 kV line. For 115 kV line faults between Big Swan and Crow River, three 115 kV lines (all BES) and Big Swan 115/69 kV TR1 need to be tripped to clear the fault. The addition of a 115 kV breaker and 115kV bus connected capacitor bank in the current configuration would create a five-position straight bus. GRE cannot add the new positions to the existing box structure and maintain required electrical clearances. A 115 kV ring bus will allow for safe clearances, higher system reliability/resilience, allow for future expansion, and aligns with GRE standards for a 115 kV facility.

Cap bank addition:
The Hutchinson area study identified low voltage concerns in the 115 kV system that is between Hutchinson, Wakefield and Crow River. NERC category P6 contingencies involving prior outages, such as McLeod – Hutchinson 115 kV line, Crow River – Brooks Lake 115 kV line and Wakefield – Stockade 115 kV line causes low voltage problems at 115 kV side of GRE member substations and Hutchinson Mun's substation.

The Hutchinson area study also identified low voltage and overload concerns in the 69 kV transmission system for the loss of the Hutchinson 115/69 kV transformer. Several options have been evaluated to address the voltage concerns and all the options involved installation of capacitor bank at Big Swan to improve the 115 kV system post contingent voltage profile and a second Hutchinson 115/69 kV transformer to address low voltage and overload concerns in the 69 kV system. Per discussion with the Xcel Energy and MRES, GRE will be responsible for the installation of the 40 MVAr capacitor bank at Big Swan and Hutchinson Municipal Commission will be responsible for the installation of a second 115/69 kV transformer at Hutchinson substation.

Alternatives:
<u>Transmission Alternatives</u>

Several transmission alternatives were considered, including installation of the capacitor bank at the Hutchinson substation. However, this option was not favored due to the proximity of Hutchinson substation to an industrial plant that could be highly sensitive to voltage transients. As for reterminating the 115 kV line from Crow River with a breaker at Big Swan, no other alternatives were considered.

<u>Non-Wires Alternatives</u>

NWA were not considered for this project. This project modifies existing substations that lack a breaker to re-termination of an existing line. The installation of the capacitor bank is contained within the existing substation fence, making the NWA unnecessary.

Analysis: The addition of capacitor bank at the existing Big Swan substation was found to be the best value and environmentally friendly plan that addresses reliability issues in the area. The Big Swan 115 kV side of the substation is deficient of a line termination breaker for the Crow River to Big Swan 115 kV line and is not up to GRE's current design standard. GRE plans to bring the Big Swan 115 kV side of the substation up to the current design standard while installing the capacitor bank and breaker at the Big Swan substation. This project is done with existing property of GRE's. Therefore, it would have minimal impact on landowners in the area.

Schedule: The project is planned to be in service by November 2024.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Kerkhoven 115 kV Breaker Addition

MPUC Tracking Number: 2021-WC-N9

Utility: Great River Energy (GRE)

Project Description: Add two 115 kV line breakers at the Kerkhoven substation

Need Driver: The installation of two 115 kV breakers is necessary to prevent tripping at the Kerkhoven substation in the event of faults on the 115 kV transmission system.

Alternatives:

Transmission Alternatives

The breaker addition was the only option considered to improve reliability due to cost effectiveness.

Non-Wires Alternatives

The project is for a reliability improvement to an existing substation that couldn't be addressed with a NWA. Therefore, NWA was not considered for this project.

Analysis: The Kerkhoven substation currently lacks breaker protection on the 115 kV side. In the event of a fault on the 115 kV line on either side of the Kerkhoven substation, it would trip offline. The most cost-effective plan to improve resilience in the area served by the Kerkhoven substation is to install breakers to terminate the 115 kV lines at Kerkhoven. This solution offers a cost-effective enhancement to the system's reliability.

Schedule: The project is planned to be in service after completion of the Appleton – Benson 115 kV project.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Walden 115 kV Breaker Addition

MPUC Tracking Number: 2021-WC-N10

Utility: Great River Energy (GRE)

Project Description: Add 2 115 kV line breakers at the Walden substation.

Need Driver: The installation of two 115 kV breakers is necessary to prevent outages at the Walden substation in the event of faults on the 115 kV transmission system.

Alternatives:

Transmission Alternatives

The breaker addition was the only option considered to improve reliability due to cost-effectiveness.

Non-Wires Alternatives

NWA was not considered as this project involves installation of breakers within the existing substation to prevent substation outages resulting from a 115 kV line fault.

Analysis: The Walden substation currently lacks breaker protection on the 115 kV side. In the event of a fault on the 115 kV line on either side of the Walden substation, it would trip offline. The most cost-effective plan to improve resilience in the area served by the Walden substation is to install breakers to terminate the 115 kV lines at Walden. This solution offers a cost-effective enhancement to the system's reliability.

Schedule: The project is planned to be in service after completion of the Appleton – Benson 115 kV project.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Benson – Morris Storm Structures

MPUC Tracking Number: 2021-WC-N11

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Benson – Morris 115 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:
Transmission Alternatives

Storm Structures were considered the most cost-effective solution to limit outages from line cascading.

Non-Wires Alternatives

This is a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by January 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Benson substation to Morris substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Sauk Centre North Interconnection

MPUC Tracking Number: 2023-WC-N1

Utility: Xcel Energy (XEL)

Project Description: Build three 1-way switches on line 0794 to accommodate new Sauk Centre Municipal distribution substation.

Need Driver: Interconnection request from Sauk Centre Municipal for a new substation to address reliability issues on the distribution system.

Alternatives:
Transmission Alternatives

None.

Non-Wires Alternatives

Load interconnection request, no alternatives considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by August 2024.

General Impacts: The project will install a new substation along existing 69 kV line. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Milbank, SD Area Upgrades

MPUC Tracking Number: 2023-WC-N2

Utility: Otter Tail Power Company (OTP)

Project Description: Phase 1 of the project will consist of constructing a new 12-mile 115 kV line from the Big Stone 230/115 kV substation (located near Big Stone City, SD) to a new 115/12.5 kV substation located near Milbank, SD. In addition, a portion of the town of Milbank, SD will be moved to the 115 kV system. Phase 1 of the project is located entirely within South Dakota. Phase 2 of the project will consist of construction a new 18.5-mile 115 kV line from the new 115/12.5 kV substation located near Milbank, SD to a new switching station on the Big Stone – Marietta 115 kV line located in Minnesota.

Need Driver: Planned load growth in Milbank, SD will bring the area's 41.6 kV transmission system beyond its capacity. Low voltages have been identified on the 41.6 kV transmission system in studies for the loss of the Highway 12 115 kV source. This project will move load to the 115 kV system and free up capacity on the area's 41.6 kV system.

Alternatives:

Transmission Alternatives

Several transmission alternatives were studied. The selected project is able to maintain system reliability at a low cost and is able to meet the timelines of the load expansion.

- New 230/41.6 kV substation on the Big Stone – Blair 230 kV line
- Big Stone 115 kV – Milbank 115 kV – New 230/115 kV substation on the Big Stone – Blair 230 kV line
- Radial-only 115 kV service for load expansion
- Highway 12 115 kV – Milbank 115 kV – new switching station on Big Stone – Marietta 115 kV line

Non-Wires Alternatives

This project is related to a load expansion, and non-wires alternatives would not provide sufficient availability or reliability to support the load.

Analysis: OTP performed a study to investigate projects to serve a load expansion in Milbank, SD. This analysis reviewed the selected project, as well as the transmission alternatives listed above. The analysis identified the selected project as the lowest-cost option while maintaining system reliability and meeting the timeline of the load expansion.

Schedule: The Minnesota portion of the project is expected to be completed by the end of 2026. A CON will be required due to the line crossing the South Dakota border. OTP expects to file the CON in Q2 of 2024.

General Impacts: This project will require approximately 30.5 miles of new 115 kV transmission line (approximately 4 miles in Minnesota) from the Big Stone 230/115 kV substation to a new 115/12.5 kV substation near Milbank, SD to a new switching station on the Big Stone – Marietta 115 kV line. The project is located in predominantly agricultural lands. Prior to construction OTP will acquire the necessary right-of-way and permits for construction of the project. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. During this time, OTP and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Big Stone South – Alexandria – Big Oaks 345 kV

MPUC Tracking Number: 2023-WC-N3

Utility: Great River Energy (GRE), Minnesota Power (MP), Missouri River Energy Services (MRES), Otter Tail Power Company (OTP), Xcel Energy (XEL)

Project Description: GRE, MP, MRES, OTP, and XEL are jointly developing the Big Stone South – Alexandria – Big Oaks 345 kV line, located in western and central Minnesota. The project consists of two major segments of transmission line construction:

1) Eastern Segment: Adding a second circuit to existing 345 kV structures originally built as part of the CapX2020 Fargo – St. Cloud and St. Cloud – Monticello projects between Alexandria and a new substation near the Sherco power plant in Becker.
2) Western Segment: Constructing a new 345 kV transmission line between the Big Stone South 345 kV substation in South Dakota to the Alexandria 345 kV substation in Minnesota.

Need Driver: With growth of wind energy projects in the Dakotas and Western Minnesota, there is not enough capacity on the transmission system to transfer that energy from the Dakotas and Western Minnesota to the Twin Cities load center.

Alternatives:

Transmission Alternatives

As part of MISO's LRTP Tranche 1 studies, numerous projects were studied and optimized into the full Tranche 1 project portfolio. Full details of the alternatives analysis are available in the LRTP Addendum to the MTEP21 report.

Non-Wires Alternatives

None.

Analysis: Full details of MISO's LRTP Tranche 1 analysis are available in the LRTP Addendum to the MTEP21 report.

Schedule: The Eastern Segment is expected to be completed in 2027. The Western Segment is planned to be completed by the end of 2030.

General Impacts: This project will require approximately new 115 kV transmission line from the Big Stone 345 kV substation to the Alexandria 345 kV substation. The project is located in predominantly agricultural lands. Prior to construction necessary right-of-way and permits will be acquired for construction of the project. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. During this time, GRE, MP, MRES, OTP, and XEL and/or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Big Swan – Wakefield Storm Structure Addition

MPUC Tracking Number: 2023-WC-N4

Utility: Great River Energy (GRE)

Project Description: Install (2) new storm structures every 5 miles along the ME-BW line between structures 306 and 415 as there are no full stop deadends in this section of line. Possible locations are structures 349 and 383.

Need Driver: Historical cascading failures on h-frame lines in ND as well as on the WB line for 19 miles. Majority of line is cross country, so would be difficult to re-construct in an emergency.

Alternatives:

Transmission Alternatives

Storm Structures were considered the most cost-effective solution to limit outages from line cascading.

Non-Wires Alternatives

This is a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: This project is planned to be in-service by fall 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Big Swan substation to Wakefield substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Willmar – Stockade – Hutchinson Rebuild and 115 kV Conversion

MPUC Tracking Number: 2023-WC-N5

Utility: Great River Energy (GRE), Missouri River Energy Services (MRES), Southern Minnesota Municipal Power Agency (SMMPA)

Project Description: Rebuild existing 69 kV transmission lines: Willmar to Litchfield Muni Tap, Litchfield to Litchfield Muni Tap, Hutchinson to Litchfield Muni Tap to 115 kV standard with high-capacity conductor for continued operation at 69 kV. Build a new 115 kV line from Litchfield Muni to Stockade substation. Convert upgraded facilities to 115 kV operation.

Need Driver: The lines between Willmar, Litchfield and Hutchinson have a need to be rebuilt due to age and condition concerns. These lines are some of the oldest 69 kV transmission lines in the area. The line rebuild projects will be done in such a way that it makes the load serving transmission system more resilient, creates opportunities for increased penetration of large loads and renewable resources, and solves existing or future reliability concerns in the transmission system.

Transmission system assessment studies have shown that the existing transmission system is not resilient and doesn't have margin to serve new or growing loads in the Hutchinson and Glencoe areas. The Hutchinson and Glencoe areas experience low voltage problems for NERC category P6 contingencies. To improve system, post contingent voltage, address reliability concerns due to the transmission line age and condition, and make capacity available to serve large loads in the system, GRE will coordinate with SMMPA and MRES to construct a 115 kV line between Willmar and Hutchinson substations, via Litchfield and Stockade. Most of this future 115 kV line will involve an upgrade of existing 69 kV lines to 115 kV voltage that will continue to operate at 69 kV until the line is permitted for 115 kV operation.

Operating the transmission at 115 kV would require double circuiting the line between Willmar and Svea (SH), rebuilding the line between Svea substation and Hutchinson (DS/HN), rebuilding the SMMPA operated line between Litchfield Municipal and the Willmar-Hutchinson line (LT) to a double circuit for an in-and-out configuration to Litchfield Municipal, rebuilding the GRE line between Litchfield Municipal and the Big Swan-Atwater line (LN) and construction of 8 miles of new 115 kV line from Litchfield Municipal North Tap to connect to the Stockade substation.

GRE, SMMPA and MRES would first complete the following projects to address age and condition concerns in the transmission system:

- Rebuild DS line to 115 kV standard with 795 ACSS conductor
- Rebuild SH line to double circuit 115 kV / 69 kV. Svea distribution substation will remain at 69 kV service.
- Rebuild LT line as a double circuit to 115 kV standard with 795 ACSS conductor
- Rebuild LN line to 115 kV standard with 795 ACSS conductor
- Rebuild HN line to 115 kV standard with 795 ACSS conductor

Following the completion of the above age and condition related line rebuild projects, GRE, SMMPA and MRES will work on the following projects to operate the transmission system at 115 kV:

- Rebuild the Litchfield Municipal breaker station and installation of 2x20 MVAr capacitor banks
- Construct a Stockade 115 kV breaker station
- Construct a new 8-mile 115 kV line from Litchfield Municipal North to the Stockade substation.
- Upgrade Litchfield Municipal distribution substation from 69 kV to 115 kV service

Alternatives:
Transmission Alternatives

The driver for the line rebuild is primarily age and condition of the transmission line. GRE could rebuild the transmission line to 69 kV standard, but this will limit the load serving capacity of the transmission system in the Litchfield area. In addition, rebuilding the line to 69 kV will not address low voltage problems in the Hutchinson and Glencoe areas.

Non-Wires Alternatives

Non-wires alternatives for this project are under review.

Analysis: The line rebuild projects bring efficiency improvement as there will be less power loss on the transmission line. It also provides better load serving reliability as it will be new, consist of larger conductor and be constructed to the 115 kV standard. The line rebuild makes capacity available in the transmission system for a new load that may come to the areas.

Schedule: This project is scheduled for spring 2030 completion.

General Impacts: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. While this project is at the end of the planning phase and although some additional temporary workspace may be required, no new landowners are expected to be impacted due to the line rebuild projects. Construction of a new 8-mile 115 kV line from Litchfield Municipal North to the Stockade substation require acquiring new route and easement and will impact new landowners along the transmission line.

Lake Mary 115 kV Conversion

MPUC Tracking Number: 2023-WC-N6

Utility: Great River Energy (GRE)

Project Description: Convert and relocate the Lake Mary substation from 41.6 kV to 115 kV service. Installing a 3-way 2000A load break switch and construct the new 115 kV tap line to the new Lake Mary substation location east of highway 29.

Need Driver: Lake Mary substation is reaching capacity, and REA has been monitoring the substation load to determined that upgrade is needed. In addition to the substation capacity increase that will be needed, the existing location is not preferred as it is difficult to build out new feeders to the growing area that is north of the Lake Mary distribution substation. A reliability improvement to the Lake Mary substation was also needed as it is served from on a 2 mile tap line is of 1968 vintage. With the robust 115 kV transmission system in the vicinity, the reliability improvement need would be accomplished by the conversion of the Lake Mary substation from 41.6 kV to 115 kV service. RE plans to retire and remove the existing 41.6 kV tap line to Lake Mary after the conversion of the Lake Mary substation for 115 kV service.

Alternatives:

Transmission Alternatives

> Replacing existing transformer with a larger transformer - this option is not preferred as Lake Mary would be served on a long radial line. The existing substation site is not a preferred site for REA to perform work around the substation.

Non-Wires Alternatives

> Non-wires alternatives cannot adequately accommodate load growth forecasts and reliability improvement needs.

Analysis: The relocation and conversion of the Lake Marion substation to 115 kV service was found to be the best value plan that results in a reliable and resilient service in the area that is served by the Lake Mary distribution substation. This project reduces system losses, reduces impacts landowners and fosters economic development in the area.

Schedule: The Lake Mary 115 kV Conversion project is planned to be in-service by August 2024.

General Impacts: The project will require approximately 0.2 miles of new 115 kV transmission line from the MRES-AA 115 kV line to new Lake Mary substation location. The project is located in predominantly industrial lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design minimizes impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Hodges Distribution Substation

MPUC Tracking Number: 2023-WC-N7

Utility: Great River Energy (GRE)

Project Description: Install a 3-way manual load break 115 kV, 2000 A switch on GRE's Walden – Morris 115 kV line and construct about 2 spans of 115 kV line with 477 ACSR conductor to the high side of Agralite's new Hodges area distribution substation. Install metering/telecom and a new EEE for the distribution substation.

Need Driver: Agralite desires to establish a new substation in the Hancock area to serve fast growing loads in the area around Hancock. Currently, this area is served from Hancock and Alberta substation. The fast-growing load in the area is loading up the transformer and a new substation is required to unload the existing Hancock and Alberta substations and serve new loads in the area.

Alternatives:

Transmission Alternatives

Continue serving growing loads from existing distribution substation, but this alternative is not desired due to concerns related to transformer loading, feeder loading, and voltage drop.

Non-Wires Alternatives

Non-wires alternatives cannot adequately accommodate load growth forecasts, assuming a cost of $500/kWh

Analysis: This project establishes a distribution substation to serve growing load in the area. Existing distribution substations are located far from the load center. Extending long feeders were found to be unreliable and lossy. This project was found to be the best value plan to reliably serve existing and growing load in the area.

Schedule: The Hodges Substation project is planned to be in-service by summer 2025.

General Impacts: The project will require approximately 0.05 miles of new 115 kV transmission line from the GRE AG-MB 115 kV line to the Hodges substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Mud Lake – Riverton Line Upgrade

MPUC Tracking Number: 2023-WC-N9

Utility: Great River Energy (GRE)

Project Description: The Mud Lake – Riverton (MR) 230 kV line is temperature rated at 189 degrees and is limited by seven spans. Make the necessary upgrades, six H-frame pole replacements, to get the Mud Lake – Riverton (MR) 230 kV line up to 212°F operating temperature and achieve a rating of 384.8/515.8 (summer/winter) MVA.

Need Driver: The Mud Lake – Riverton (MR) 230 kV line is temperature rated at 189 degrees which is limited by a couple of poles. This 212 degree F rating is needed post Boswell shutdown around 2029/2030.

Alternatives:
Transmission Alternatives
1.) Pole replacements to get the line to 212 degree F operating temperature.
2.) Complete rebuild of the transmission line.
3.) Build a new north to south connection to alleviate this flow.

Non-Wires Alternatives
This is an improvement to an existing line, so a non-wires alternative was not considered.

Analysis: Replacing a handful of poles will be able to get the line to 212 degree F operating temperature which will meet the loading needs in this part of the transmission system. An age and condition assessment suggests that a full rebuild isn't necessary and would be premature. Another transmission line is significantly more costly than to replace a handful of structures.

Schedule: The Mud Lake – Riverton Line Upgrade project is planned to be in-service by winter 2024.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Mud Lake substation to Riverton substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Cedar Mountain Substation Upgrade

MPUC Tracking Number: 2023-WC-N10

Utility: Great River Energy (GRE)

Project Description: Installation of (2) 75 MVar capacitor banks, installation of 3 new 345 kV breakers to complete the breaker and a half.

Need Driver: MISO required installation these capacitor banks for voltage regulation due to Generator Interconnections on the MISO system.

Alternatives:

Transmission Alternatives

Other forms of voltage regulation at this site, for example STATCOM would be unnecessary and more expensive.

Non-Wires Alternatives

Installation of reactive support devices is an alternative to transmission buildout. No other non-wires alternatives were considered.

Analysis: The need for the Cedar Mountain substation upgrades was evaluated as part of the MISO DPP system impact studies.

Schedule: The Cedar Mountain Substation Upgrade project is planned to be in-service by summer 2024.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Benton County Solar Farm (J1426)

MPUC Tracking Number: 2023-WC-N11

Utility: Great River Energy (GRE)

Project Description: A new 115 kV breaker and a half row and tap line would be built out to accommodate the interconnection of the 100 MW solar farm for J1426.

Need Driver: J1426 Solar facility has requested interconnection to the 115 kV bus at Benton County.

Alternatives:
Transmission Alternatives

> The interconnection was evaluated under the MISO's DPP system impact studies. No alternatives for the interconnections were identified.

Non-Wires Alternatives

> Non-wires alternatives are not considered for new generation interconnections as the POI is determined by the interconnection customer.

Analysis: The expansion of facilities at Benton County are required to provide a point of interconnection for project J1426.

Schedule: The Benton County Solar Farm project is planned to be in-service by spring 2025.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Morris to Grant County to East Fergus Falls 115 kV Line Upgrade

MPUC Tracking Number: 2023-WC-N12

Utility: Missouri River Energy Services (MRES)

Project Description: Increase the rating of 115 kV lines from Morris to Grant County to East Fergus Falls by installing phase raisers or structure replacements.

Need Driver: Market Participant requested that the line be upgraded due to local congestion.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
This would not have addressed the local congestion issue that the Market Participant was planning to mitigate.

Analysis: Market Participant requested upgrade.

Schedule: The project is planned to be in-service by Q2 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Morris to Grant County to East Fergus Falls substations. The project is located in predominantly agricultural lands. Construction is expected to be completed in 3 months. During this time, MRES and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Alexandria Light and Power Southeast Substation

MPUC Tracking Number: 2023-WC-N13

Utility: Missouri River Energy Services (MRES)

Project Description: Alexandria Light & and Power (ALP) will build a new distribution substation on the southeast part of town. The substation will tap and existing 115 kV line with an in and out substation. The substation will have a 115 kV to distribution transformer.

Need Driver: Distribution studies showed deficiencies present in the existing distribution system and to the need for a new distribution substation to support additional load growth within the City of Alexandria.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
This is a distribution system improvement, and no alternatives were considered.

Analysis: The need for a new distribution substation to support load growth was identified in Distribution System Planning Update report. The new distribution substation allows for more load growth within the City of Alexandria

Schedule: The project is planned to be in-service by Q4 2025.

General Impacts: This project is located at the outer edge of town not near residential homes. Construction is expected to be completed in 18 months. During this time the ALP, and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Alexandria Substation Expansion

MPUC Tracking Number: 2023-WC-N14

Utility: Missouri River Energy Services (MRES)

Project Description: Alexandria Substation will be expanded to add positions for new 345 kv transmission line to Big Oaks and Big Stone South substations.

Need Driver: The BSSA/ABP Project, along with the other LRTP Tranche 1 Portfolio of transmission projects, are needed to provide reliable, resilient, and cost-effective delivery of energy as the generation resource mix.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: The generation resource mix is changing as more renewable and variable energy, such as wind and solar, is added to the system and aging coal-fired generation plants are retired. The BSSA/ABP Project, along with the other LRTP Tranche 1 Portfolio of transmission projects, are needed to provide reliable, resilient, and cost-effective delivery of energy as the generation resource mix continues to evolve over the coming years.

Schedule: The project is planned to be in-service by Q4 2026/27.

General Impacts: The Alexandra Substation is located on the south end of Alexandria, MN. The substation will be expanded to accommodate the transmission lines to Big Oaks and Big Stone South . The project is located in predominantly agricultural lands. Construction is expected to be completed in 24 months. During this time, MRES and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Inman – Miltona Upgrade

MPUC Tracking Number: 2023-WC-N15

Utility: Great River Energy (GRE)

Project Description: Replace 10 structures to increase line rating.

Need Driver: This line has caused market congestion in the past and is projected to continue to cause market congestion into the future.

Alternatives:
Transmission Alternatives
Rebuilding the entire line is more expensive with more landowner impact.
Non-Wires Alternatives
No non-wires alternatives were considered.

Analysis: The structure replacements will increase the ratings of the line, reducing the likelihood of the lines causing congestion in the market. It is expected that the rating increase from the structure replacement will mitigate projected congestion in the near term, and a full rebuild is not required.

Schedule: The project is planned to be in service by summer 2024.

General Impacts: The project will be constructed on the existing 115 kV transmission line from Inman substation to Miltona substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Benton County Terminal Upgrade

MPUC Tracking Number: 2023-WC-N16

Utility: Great River Energy (GRE)

Project Description: Upgrade terminal equipment to 2000 A rating.

Need Driver: This terminal equipment has caused market congestion in the past and is projected to continue to cause market congestion into the future.

Alternatives:
<u>Transmission Alternatives</u>
No transmission alternatives were considered since this project is replacing equipment in an existing substation.
<u>Non-Wires Alternatives</u>
No non-wires alternatives were considered since this project is replacing equipment in an existing substation.

Analysis: The equipment upgrade will increase the ratings of the 230 kV lines out of Benton County, reducing the likelihood of these lines causing congestion in the market.

Schedule: The project is planned to be in service by winter 2024.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Johnson Junction Switch Upgrade

MPUC Tracking Number: 2023-WC-N17

Utility: Great River Energy (GRE)

Project Description: Upgrade line switch to 2000 A rating.

Need Driver: The line from Johnson Junction to Morris has caused market congestion in the past and is projected to continue to cause market congestion into the future.

Alternatives:
<u>Transmission Alternatives</u>
No transmission alternatives were considered since this project is replacing the most limiting equipment in an existing substation.
<u>Non-Wires Alternatives</u>
No non-wires alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Analysis: This upgrade will prevent switch from being the binding rating and allow for the line conductor capacity rating to be fully utilized, reducing the likelihood of the line causing congestion in the market.

Schedule: The project is planned to be in service by winter 2024.

General Impacts: This will be constructed on an existing 115 kV transmission line right of way. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

6.5.2 Completed Projects

The table below identifies those projects by Tracking Number in the West Central Zone that were listed as ongoing projects in the 2021 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Minnesota Public Utilities Commission in October 2021. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2021 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2019-WC-N3	Morris-Johnson Jct.-Ortonville J493/J526 Upgrade	None	GRE	2/1/2022
2021-WC-N3	Watkins – Kimball Line Rebuild	2021/A	XEL	11/14/2022
2021-WC-N7	Granite Falls - Willmar (WB) Line Upgrade	None	GRE	10/24/2022

6.6 Twin Cities Zone

6.6.1 Needed Projects

The following table provides a list of transmission needs identified in the Twin Cities Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2021-TC-N5	Lawndale – Bass Lake 115 kV Line	2015/A	7912	No	No	GRE
2021-TC-N6	Rush City 230 kV Ring Bus	2023/A	23718	No	No	GRE
2021-TC-N7	Bunker Lake 345 kV Ring Bus	Future	TBD	No	No	GRE
2021-TC-N8	Medina Breaker Addition and Replacement	Future	TBD	No	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2021-TC-N9	Parkwood 115 kV Ring Bus Expansion	2022/A	22025	No	No	GRE
2021-TC-N10	Bunker Lake – Elk River Storm Structures	2022/A	21826	No	No	GRE
2023-TC-N1	Blue Earth-South Bend Area Upgrades	2022/A	20505	No	No	XEL
2023-TC-N2	Elm Creek TR10	2022/A	21285	No	No	XEL
2023-TC-N3	NSPM Metro Steel Pole Replacement	2022/A	21845	No	No	XEL
2023-TC-N4	Hyland Lake TR1 and TR2 Upgrade	2022/A	21846	No	No	XEL
2023-TC-N5	Coon Creek Substation 345kV Breaker Additions	2022/A	21877	No	No	XEL
2023-TC-N6	Rogers Lake Breaker Addition	2022/A	21887	No	No	XEL
2023-TC-N7	Blue Lake Substation - FRM13	2023/A	23347	No	No	XEL
2023-TC-N8	West Shakopee Interconnection	2022/C	21892	No	No	XEL
2023-TC-N9	STY Install TR3 & 115kV Bus Tie	2023/A	23450	No	No	XEL
2023-TC-N10	Line 0811 - Riverside Substation - FRM13	2023/A	23453	No	No	XEL
2023-TC-N11	Line 0838 - Red Rock Substation - FRM13	2023/A	23454	No	No	XEL
2023-TC-N12	Parkers Lake TR09 ELR	2023/A	23455	No	No	XEL
2023-TC-N13	Line 0893 NSS-BCK Rebuild	2023/A	23458	No	No	XEL
2023-TC-N14	Line 0718 Arlington - Winthrop Rebuild	2023/A	23462	No	No	XEL
2023-TC-N15	Edina Switch Replacement	2023/A	24278	No	No	XEL
2023-TC-N16	Lyon County Substation - FRM13	2023/A	23712	No	No	XEL
2023-TC-N17	21829 - South Dayton Interconnection	2023/A	23547	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2023-TC-N18	Line 0859 Str 16 to Chemo lite Rebuild	2023/A	23467	No	No	XEL
2023-TC-N19	Chisago County Substation - FRM13	2023/A	23468	No	No	XEL
2023-TC-N20	Scott County Substation - FRM13	2023/A	23469	No	No	XEL
2023-TC-N21	Line 0771 Rebuild	2023/A	23502	No	No	XEL
2023-TC-N22	Line 0840 Elliot Park Pumping Plants	2023/A	23501	No	No	XEL
2023-TC-N23	Lake Pulaski TR05 ELR	2023/A	23497	No	No	XEL
2023-TC-N24	Inver Grove TR02 ELR	2023/A	23496	No	No	XEL
2023-TC-N25	Prairie Island TR10 ELR	2023/A	23494	No	No	XEL
2023-TC-N26	Monticello TR06 & TR10 ELR	2023/A	23493	No	No	XEL
2023-TC-N27	Line 0892 RRK-BCK Rebuild	2023/A	23473	No	No	XEL
2023-TC-N28	Line 0736 Arden Hills - Lawrence Creek Rebuild	2023/A	23475	No	No	XEL
2023-TC-N29	Line 0721 STR 71 to 476 Rebuild	2023/A	23475	No	No	XEL
2023-TC-N30	Line 0822 Empire to STR 107 Rebuild	2023/A	23476	No	No	XEL
2023-TC-N31	Inver Hills Substation - FRM13	2023/A	23486	No	No	XEL
2023-TC-N32	Parkers Lake TR10 ELR	2023/A	23491	No	No	XEL
2023-TC-N33	Kohlman Lake Substation - FRM13	2023/A	23487	No	No	XEL
2023-TC-N34	Wilmarth Substation - FRM13	2023/A	23489	No	No	XEL
2023-TC-N35	Eidswold Distribution Substation	2023/A	23819	No	No	GRE
2023-TC-N36	Arbor Lakes II Distribution Substation	Future	TBD	No	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2023-TC-N37	Pilot Knob to Deerwood Area Projects	2023/A	23921	No	No	GRE
2023-TC-N38	Laketown Distribution Substation	2023/A	23763	No	No	GRE
2023-TC-N39	Cedar Lake Tap Line Relocation	2023/A	22871	No	No	GRE
2023-TC-N40	Fischer Distribution Substation Rebuild	Future	TBD	No	No	GRE
2023-TC-N41	Lakeville Area Projects	2024/A	25405	No	No	GRE
2023-TC-N42	Burnsville Substation Upgrade	2024/A	25358	No	No	GRE

Lawndale – Bass Lake 115 kV Line

MPUC Tracking Number: 2021-TC-N5

Utility: Great River Energy (GRE)

Project Description: Construct approximately 2 miles of new 115 kV transmission line from the new Lawndale #2 115 kV distribution substation to an interconnection with the GRE Bass Lake – Cedar Island 115 kV transmission line on existing GRE 69 kV corridor.

Need Driver: This project is needed interconnect the Lawndale #2 distribution substation and establish a looped transmission service to the Corcoran and Lawndale distribution substations.

Alternatives:
Transmission Alternatives

The alternative plan is to build Lawndale #2 as 69 kV service. This alternative was not preferred as it would place both Lawndale I and II substations on radial service from the same source. Moreover, it would not improve reliability and is not aligned with the long-range plan for the area.

Non-Wires Alternatives

This project is still being studied. Non-transmission alternatives will be studied and considered prior to project initiation.

Analysis: Adding an alternate 115 kV source into the Lawndale Substation property will provide better diversity and overall reliability to the area as opposed to doubling the load and number of customers on a transmission line that does not have an alternate source in the case of damage.

Schedule: The project is planned to be in service by summer 2030.

General Impacts: The project will require approximately 2 miles of new 115 kV transmission line from Lawndale #2 substation to an interconnection with the GRE Bass Lake – Cedar Island 115 kV line. The project is located in existing GRE 69 kV right of way corridor. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 24 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Rush City 230 kV Ring Bus

MPUC Tracking Number: 2021-TC-N6

Utility: Great River Energy (GRE)

Project Description: Complete Rush City 230 kV ring bus. Build independent terminals for the Rock Creek – Rush City and Red Rock – Rush City 230 kV lines.

Need Driver: This project is needed to mitigate age and condition-related concerns and address overload issues associated with NERC TPL-001-4 P6 events.

Alternatives:
Transmission Alternatives

This project requires completing the existing substation ring bus. No alternatives were considered.

Non-Wires Alternatives

This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by spring 2025.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Bunker Lake 345 kV Ring Bus

MPUC Tracking Number: 2021-TC-N7

Utility: Great River Energy (GRE)

Project Description: Build Bunker Lake 345 kV ring bus.

Need Driver: The 345 kV transmission lines terminate with a switch at Bunker Lake substation. This project is needed to terminate the 345 kV lines in to a new 345 kV ring bus, improving system reliability.

Alternatives:

Transmission Alternatives

This project is the only option considered to address the reliability concerns.

Non-Wires Alternatives

This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by summer 2030.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Medina Breaker Addition and Replacement

MPUC Tracking Number: 2021-TC-N8

Utility: Great River Energy (GRE)

Project Description: Add a breaker at Medina substation on the Crow River – Medina 115 kV line. Add a breaker at the Medina substation on the 115/69 kV transformer. Replace breaker 55WB2.

Need Driver: The Crow River to Medina 115 kV line terminates with a switch at the Medina substation. A fault on the line would trip the entire substation. A fault on the Medina 115/69 kV transformer also trips the entire substation. The breaker installations are needed to limit equipment outage as a result of a fault. Breaker 55WB2 is Siemens BZO hydraulic breaker. There's limited parts availability. There have been past maintenance issues with this breaker, and it's the last oil breaker left at Medina.

Alternatives:
Transmission Alternatives

The need required installation of a breaker to protect the substation from tripping due to a fault. The project was the only alternative considered to address the problem.

Non-Wires Alternatives

This a reliability improvement at the substation and no alternatives were considered.

Analysis: Replacement of the 115 kV switch with a breaker improves the reliability and resiliency of service at the Medina substation. These replacement projects are done within the substation fence and have minimal impact on landowners in the area.

Schedule: The project is planned to be in service by summer 2033.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Parkwood 115 kV Ring Bus Expansion

MPUC Tracking Number: 2021-TC-N9

Utility: Great River Energy (GRE)

Project Description: The project will change the 115 kV bus topology from the current bus tie breaker topology to a ring bus topology, with alternating line and transformer connections in the ring. Consider space for a six-position ring bus topology with future expansion to a 1.5 bus topology. Breaker 12WB2 replacement is also in scope.

Need Driver:

- 115 kV line faults cause a trip of a Parkwood 115/69 kV transformer.
- Parkwood 12WB2 breaker failure causes overload of the Bunker Lake-Village Ten 69 kV line under peak loading conditions.

- A Parkwood 115/69 kV transformer differential protection activation causes transfer tripping to the remote substations. For the Crooked Lake 115 kV line, this causes the loss of Connexus' load service at Crooked Lake, which serves a major commercial development.

Alternatives:
Transmission Alternatives
This project reconfigures and updates existing topology to address reliability concerns at the Parkwood substation. No additional alternative was considered.
Non-Wires Alternatives
This a reliability improvement at the substation and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by June 2024.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Bunker Lake - Elk River Storm Structures

MPUC Tracking Number: 2021-TC-N10

Utility: Great River Energy (GRE)

Project Description: Install storm structures in the Bunker Lake - Elk River 230 kV line.

Need Driver: GRE is continuing to look at making the system more resilient. GRE has H-frame construction on multiple lines that have shown to be prone to line cascading (domino effect) resulting in long duration outages. One way is to limit the damage of cascading is to install stop structures, such as a storm structure. GRE is proposing to install storm structures that will limit damage from cascading to 5 to 10 mile sections rather than without storm structures, whereby significantly longer mileage of damage could occur.

Alternatives:
Transmission Alternatives
Storm Structures were considered the most cost-effective solution to limit outages from line cascading.
Non-Wires Alternatives
This a reliability improvement to an existing line to prevent cascading structure failure and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by fall 2024.

General Impacts: The project will be constructed on the existing 230 kV transmission line from Bunker Lake substation to the Elk River substation. The project is located in predominantly agricultural lands. Construction is expected to be completed in 2 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction.

Blue Earth-South Bend Area Upgrades

MPUC Tracking Number: 2023-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild approx. 30 miles of 161 kV line and upgrade South Bend TR6 to a 448 MVA transformer.

Need Driver: Address Thermal violations in multiple sensitivity cases.

Alternatives:
Transmission Alternatives

None.

Non-Wires Alternatives

This a reliability improvement to an existing line and transformer and no alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2026.

General Impacts: The project will be constructed on the existing 161 kV transmission line from Blue Lake substation to the South Bend substation and upgrading the existing South Bend TR6. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way will be restored at the end of the project.

Elm Creek TR10

MPUC Tracking Number: 2023-TC-N2

Utility: Xcel Energy (XEL)

Project Description: Install second 345/115 kV transformer at Elm Creek sub and route SherCo-Coon Creek #1 345 kV Line Into Elm Creek Sub

Need Driver: Additional load serving capability in the area. Removes need to shed load under contingency. Eliminates need for line rebuilds in the area, which would otherwise be required.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by November 2025.

General Impacts: Transmission addition of additional transformer and retermination of existing line are on existing footprint. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way will be restored at the end of the project.

NSPM Metro Steel Pole Replacement

MPUC Tracking Number: 2023-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Address painted poles concerns between Riverside Sub and Main Street Sub. Approximately 4-mile of triple circuit structure(35-structures) to be either replaced, painted or a combination of replace/paint.

Need Driver: The existing structures were installed in the 1980s and are experiencing paint peeling and steel deterioration.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2025.

General Impacts: Replacement and/or painting of existing structures. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right of way will be restored at the end of the project.

Hyland Lake TR1 and TR2 Upgrade

MPUC Tracking Number: 2023-TC-N4

Utility: Xcel Energy (XEL)

Project Description: Upgrade TR1 and TR2 to 115/13.8 kV 70 MVA transformers at Hyland Lake Substation. Install high-side line breaker. Install new feeder bay.

Need Driver: Hyland Lake TR1 and TR2 have distribution load at risk under contingency.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service March 17, 2023.

General Impacts: Upgrade of existing transformers and addition of additional reliability protection. Additional feeder bay to support providing reliable customer service. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Coon Creek Substation 345kV Breaker Additions

MPUC Tracking Number: 2023-TC-N5

Utility: Xcel Energy (XEL)

Project Description: Install three 345kV circuit breakers at the Coon Creek (CNC) substation to provide a better isolation between the Main Bus 1 & 2 to the line 1 & 2.

Need Driver: Three breakers needed to isolate the SHC-CNC "Line 1" and "Line 3" from the 345kV Main Bus 1 and 2, which will prevent loss of large portions of substation during existing breaker trip.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is expected to go into service December 31, 2023.

General Impacts: Additional breakers in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Rogers Lake Breaker Addition

MPUC Tracking Number: 2023-TC-N6

Utility: Xcel Energy (XEL)

Project Description: Install two breakers at Rogers Lake to separate Airport – Rogers Lake 115 kV line and Rogers Lake TR2

Need Driver: Eliminate single breaker failure and eliminate distribution exposure by terminating the line and TR2 into individual positions in the breaker and a half scheme at RLK.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service February 1, 2022.

General Impacts: Additional breakers in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Blue Lake Substation - FRM13

MPUC Tracking Number: 2023-TC-N7

Utility: Xcel Energy (XEL)

Project Description: Replace ammeter on Blue Lake 345 kV breaker 8M33 to increase rating on the Blue Lake - Scott County 345 kV line.

Need Driver: Blue Lake - Scott County 345 kV line is ratings limited by a single ammeter on the Blue Lake 345 kV breaker 8M33.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service September 2, 2022.

General Impacts: Ammeter replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

West Shakopee Interconnection

MPUC Tracking Number: 2023-TC-N8

Utility: Xcel Energy (XEL)

Project Description: City of Shakopee T-L Interconnection Request. In-and-out off NSP's Scott County - Dean Lake 115 kV transmission line. Joint substation, NSP will own the high side.

Need Driver: Needed to accommodate the rapidly developing load growth along the western edge of the City of Shakopee's territory.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
Load interconnection request, no alternatives considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by June 2023.

General Impacts: The project will install a new substation along existing 115 kV line. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

STY Install TR3 & 115kV Bus Tie

MPUC Tracking Number: 2023-TC-N9

Utility: Xcel Energy (XEL)

Project Description: Install new 115 kV bus tie and associated disconnect switches and bus work and re-terminate 0818/5529 at Rogers Lake Sub.

Need Driver: Needed to accommodate third distribution transformer due to capacity, location, and load.

Alternatives:
Transmission Alternatives
None.

Non-Wires Alternatives

None

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2024.

General Impacts: Additional bus tie and switches in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0811 - Riverside Substation - FRM13

MPUC Tracking Number: 2023-TC-N10

Utility: Xcel Energy (XEL)

Project Description: Replace switches 5M330B, 5M331B, 5M329A, 5M330A, 5M329B, 5M331A, aux current transformers on 5M304 and 5M305, and two sections of busbar.

Need Driver: FRM13 projects needed to address line derates caused by new split-path methodology.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service December 31, 2022.

General Impacts: Switch, busbar, and current transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0838 - Red Rock Substation - FRM13

MPUC Tracking Number: 2023-TC-N11

Utility: Xcel Energy (XEL)

Project Description: Replace bushing current transformers on breaker K2, switches K2B1, 946B, K2B2, 946A, and meters on 946 and K2.

Need Driver: FRM13 projects needed to address line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service December 31, 2022.

General Impacts: Switch, current transformer, and meter replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Parkers Lake TR09 ELR

MPUC Tracking Number: 2023-TC-N12

Utility: Xcel Energy (XEL)

Project Description: Replace Parkers Lake 345/115 kV TR09 (3 phases).

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2025.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0893 NSS-BCK Rebuild

MPUC Tracking Number: 2023-TC-N13

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.4 miles of 115 kV line between North Star Steel and Battle Creek substations. Portions of this line are double circuited with 0892, this project will separate the two circuits.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Verifying the secondary limit on the Farmington – Lake Marion 69 kV line, and limit may need to be replaced. No other immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 15, 2023.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0718 Arlington - Winthrop Rebuild

MPUC Tracking Number: 2023-TC-N14

Utility: Xcel Energy (XEL)

Project Description: Rebuild 15 miles line 0718 69 kV from Arlington - Winthrop.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by June 15, 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Edina Switch Replacement

MPUC Tracking Number: 2023-TC-N15

Utility: Xcel Energy (XEL)

Project Description: Replace 115 kV switch at Edina, which is limiting the rating of the Edina - St. Louis Park 115 kV line.

Need Driver: Remediates overloads on the Edina - St. Louis Park 115 kV line.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 31, 2023.

General Impacts: Switch replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Lyon County Substation - FRM13

MPUC Tracking Number: 2023-TC-N16

Utility: Xcel Energy (XEL)

Project Description: Replace 5N130 actuator secondary current limitation to increase TR9 rating to its transformer limits.

Need Driver: Remediates line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 15, 2023.

General Impacts: Actuator replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

21829 - South Dayton Interconnection

MPUC Tracking Number: 2023-TC-N17

Utility: Xcel Energy (XEL)

Project Description: New GRE interconnection (MTEP ID 21829). Xcel Energy will own high side of new sub with an in-and-out configuration on the Elm Creek - Champlin Tap 115 kV line.

Need Driver: Remediates line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
Interconnection request connecting to existing line. No alternatives considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by November 1, 2023.

General Impacts: The project will install a new substation along existing 115 kV line. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0859 Str 16 to Chemolite Rebuild

MPUC Tracking Number: 2023-TC-N18

Utility: Xcel Energy (XEL)

Project Description: Rebuild 6.9 miles of line 0859 115 kV from Chemolite substation to structure 16.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Chisago County Substation - FRM13

MPUC Tracking Number: 2023-TC-N19

Utility: Xcel Energy (XEL)

Project Description: Replace primary and secondary 115 kV bus 1 differential relays for TR05 and TR06.

Need Driver: Remediates line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service on August 1, 2022.

General Impacts: Relay replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Scott County Substation - FRM13

MPUC Tracking Number: 2023-TC-N20

Utility: Xcel Energy (XEL)

Project Description: Replace busbar.

Need Driver: Remediates line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service on December 31, 2022.

General Impacts: Busbar replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0771 Rebuild

MPUC Tracking Number: 2023-TC-N21

Utility: Xcel Energy (XEL)

Project Description: Rebuild 2 miles of line 0771 from Young America - Carver County 69 kV substations and add OPGW.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:
Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by March 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0840 Elliot Park Pumping Plants

MPUC Tracking Number: 2023-TC-N22

Utility: Xcel Energy (XEL)

Project Description: Upgrades to pumping station for HPFF.

Need Driver: Pumping plant is required to maintain electrical supply to the substation.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by May 2026.

General Impacts: No environmental issues have been identified. Equipment upgrades will have minimal impacts to existing system performance and footprint.

Lake Pulaski TR05 ELR

MPUC Tracking Number: 2023-TC-N23

Utility: Xcel Energy (XEL)

Project Description: Replace Lake Pulaski 115/69 kV TR05.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2026.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Inver Grove TR02 ELR

MPUC Tracking Number: 2023-TC-N24

Utility: Xcel Energy (XEL)

Project Description: Replace Inver Grove 115/69 kV TR02.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2025.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Prairie Island TR10 ELR

MPUC Tracking Number: 2023-TC-N25

Utility: Xcel Energy (XEL)

Project Description: Replace Prairie Island 345/161 kV TR10.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by June 2027.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Monticello TR06 & TR10 ELR

MPUC Tracking Number: 2023-TC-N26

Utility: Xcel Energy (XEL)

Project Description: Replace Monticello 345/230 kV TR06 and 345/115 kV TR10.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December, 2026.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0892 RRK-BCK Rebuild

MPUC Tracking Number: 2023-TC-N27

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.4 miles of 115 kV line between Red Rock and Battle Creek substations. Portions of this line are double circuited with 0893, this project will separate the two circuits.

Need Driver: Needed to increase reliability and performance of the line due to deterioration from age and wet environment.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 15, 2023

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0736 Arden Hills - Lawrence Creek Rebuild

MPUC Tracking Number: 2023-TC-N28

Utility: Xcel Energy (XEL)

Project Description: Rebuild 33 miles of line 0736 69 kV from Arden Hills - Lawrence Creek and add OPGW.

Need Driver: Needed for age and condition rebuild. Increasing the capacity of this circuit and potentially converting it to 115 kV in the future will reduce overloading of underground transmission cable at White Bear Lake.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2023

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0721 STR 71 to 476 Rebuild

MPUC Tracking Number: 2023-TC-N29

Utility: Xcel Energy (XEL)

Project Description: Rebuild 22 miles line 0721 69 kV from Structure 71 - Structure 476.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
> Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives
> This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2025

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0822 Empire to STR 107 Rebuild

MPUC Tracking Number: 2023-TC-N30

Utility: Xcel Energy (XEL)

Project Description: Rebuild 7 miles of line 0822 115 kV from Empire to Str 107 and add OPGW.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2024

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Inver Hills Substation - FRM13

MPUC Tracking Number: 2023-TC-N31

Utility: Xcel Energy (XEL)

Project Description: Replace busbar.

Need Driver: FRM13 projects needed to address line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service March 1, 2023.

General Impacts: Busbar replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Parkers Lake TR10 ELR

MPUC Tracking Number: 2023-TC-N32

Utility: Xcel Energy (XEL)

Project Description: Replace Parkers Lake 345/115 kV TR10 (3 phases).

Need Driver: The ELR transformer program is to proactively replace aging transformers that have past their operational service life and are showing increase signs of degradation.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service December 31, 2022.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Kohlman Lake Substation - FRM13

MPUC Tracking Number: 2023-TC-N33

Utility: Xcel Energy (XEL)

Project Description: Replace meter on breaker 5P106.

Need Driver: FRM13 projects needed to address line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service December 31, 2022.

General Impacts: Meter replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Wilmarth Substation - FRM13

MPUC Tracking Number: 2023-TC-N34

Utility: Xcel Energy (XEL)

Project Description: Replace bushing current transformer on breaker 5S11 as well as switches 8S26B1, 8S25B, 8S25A, 8S26B1.

Need Driver: FRM13 projects needed to address line derates caused by new split-path methodology.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project went into service December 31, 2022.

General Impacts: Switch and current transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Eidswold Distribution Substation

MPUC Tracking Number: 2023-TC-N35

Utility: Great River Energy (GRE)

Project Description: New 115/12.47 kV substation for Dakota Electric Association (DEA) in the Elko New Market area.

Need Driver: A new 115/12.47 kV distribution substation is required by DEA with provisions for future second 115/12/47 kV transformer. The need is based on a new industrial park load which is expected to increase load demand beyond what they can currently serve from existing substations.

The new industrial load is expected to be energized for 2024. This load is initially expected to be 7 MW but could expand with additional load growth.

The new substation is proposed in the Elko New Market area of Minnesota. The location will be east of Interstate 35 in the area highlighted in the system map. The only transmission line available for interconnection is Xcel Energy's 0832 115 kV line, approximately 2 miles south of Chub Lake substation.

Alternatives:

Transmission Alternatives

New 115 kV line from Chub Lake. This was not considered a viable alternative as there is an existing 115 kV line adjacent to the site with capacity.

Non-Wires Alternatives

Non-wires alternatives cannot adequately accommodate load growth forecasts, assuming a cost of $500/kWh.

Analysis: This project was needed from a capacity standpoint. The existing distribution infrastructure did not have the capacity to serve a new industrial load in this area.

Schedule: The Eidswold project is planned to be in-service by summer 2024.

General Impacts: The project will require approximately 0.10 miles of new 115 kV transmission line from the Xcel 0832 115 kV line to Eidswold substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Arbor Lakes II Distribution Substation

MPUC Tracking Number: 2023-TC-N36

Utility: Great River Energy (GRE)

Project Description: Wright-Hennepin Cooperative Electric Association (WHCEA) plans to double end the Arbor Lakes substation. GRE will need to provide a tap, switch, and metering/telecom. Sys. Ops has confirmed 2000A manual, three-way, full load break switch is required. GRE engineering requires a steel pole on a foundation for the switch. Added steel pole grading structure north of the existing switch.

Need Driver: WHCEA needs to support growing load that can't be served by existing distribution substations in the area.

Alternatives:

Transmission Alternatives

The existing substation was planned to accommodate a second transformer when needed. No additional alternative was considered.

Non-Wires Alternatives

Non-wires alternatives cannot adequately accommodate load growth forecasts.

Analysis: The Arbor Lake substation was planned to accommodate a second transformer when the need for capacity occurs. The extensive load growth that is seen and coming around the Arbor Lake I distribution substation requires a new distribution substation. It was found that adding a second transformer at the Arbor Lake substation is the least cost plan to address the capacity need and serve the area reliably. This project has no impact on landowners in the area as it will all be done within the property of GRE and its member owner.

Schedule: The Arbor Lakes II project is planned to be in-service by fall 2024.

General Impacts: The project will require approximately 0.10 miles of new 115 kV transmission line from the GRE WH-CA 115 kV line to the Arbor Lakes II substation. The project is located in predominantly industrial lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Pilot Knob to Deerwood Area Projects

MPUC Tracking Number: 2023-TC-N37

Utility: Great River Energy (GRE)

Project Description: Rebuild the Pilot Knob Substation to a breaker and a half configuration due to age and condition of the current equipment. Upgrade the DA-PD line from Deerwood to Pilot Knob substation to increase the capacity. Upgrade to be built to 115 kV standards but operated at 69 kV. Retire the underground portion of the DA-PLX at Pilot Knob and replace with overhead. Retire the DA-RE line from Pilot Knob Road to Black Hawk Road. Retire the DA-PKX from Pilot Knob to Cliff Road. Retire SS-2820 and replace with a turning structure. Retire SS-2819.

Need Driver: Pilot Knob substation age and condition require upgrade. DA-RE needs to be retired to allow for the county to upgrade the section of Pilot Knob Road. DA-PKX is no longer needed if the DA-RE is retired.

Alternatives:

Transmission Alternatives

Alternatives considered were rebuilding the line at 69 kV standards. For the following reasons GRE is rebuilding the line to 115 kV standard and operating at 69 kV until all associated 69 kV lines can be upgraded and the transformers at Pilot knob removed to create a 115 kV looped service between Pilot Knob and Burnsville:

- The metro area standard is 115 kV to allow for higher capacity transmission with increasing load due to electrification of load and possible large loads, e.g., data centers, that have been considered in the area. Electrification of load includes automobiles, water heating, and heat pumps per a zero-carbon society.

- Reduced Line Losses and improved voltage drop. The 69 kV system would have greater operating costs because of increased line losses. The greater line loss occurs because more electrical energy is lost as heat due to higher impedance of the 69 kV transmission line. The efficiency of the 115 kV conductor just based on voltage is estimated to be ~275% better than 69 kV.

Transformer Costs. The 69 kV system requires the 115/69 kV transformer at Pilot Knob Substation. Removing these high-cost transformers will result in cost savings to the consumer and remove the piece of equipment from creating reliability issues, which typically have long outage periods prior to replacing a failed unit.

Non-Wires Alternatives

Non-wires alternatives were not considered due to the replacement need for age and condition.

Analysis: An Analysis of the project was studied against the alternative of the system remaining at 69 kV, as described in the alternatives section.

Schedule: This project is planned to be in-service by summer 2027.

General Impacts: The project is located on existing property and exiting GRE 69 kV right of way corridor. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 24 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Laketown Distribution Substation

MPUC Tracking Number: 2023-TC-N38

Utility: Great River Energy (GRE)

Project Description: Construct about 3 to 5 miles 115 kV transmission line from GRE's 115 kV line near Victoria Tap. The interconnecting lines be constructed as an in-and-out design to accommodate a future double-ended sub.

Need Driver: MVEC is requiring the new Laketown substation because of the additional load planned in Laketown Township. The existing substations in this area will be at capacity and will not be able to serve the additional load in the future.

Alternatives:
Transmission Alternatives

Alternative 115 kV connections were considered but did not sectionalize the system as well as connecting to the MV-VTT line between Augusta and Victoria. This section provided the best reliability and resiliency.

Non-Wires Alternatives

Non-wires alternatives for this project are under review.

Analysis: A distribution analysis was performed. This showed the need for a new substation in the area due to lack of feeder redundancy, load growth in an area with no distribution substation, and future feeder overload and voltage issues on lines already with voltage regulators in use

Schedule: The Laketown Substation project is planned to be in-service by fall 2028.

General Impacts: The project will require approximately 3 to 5 miles of new 115 kV transmission line from the Xcel Energy 5557 115 kV line to Laketown substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Cedar Lake Tap Line Relocation

MPUC Tracking Number: 2023-TC-N39

Utility: Great River Energy (GRE)

Project Description: Design and construct a tap line approximately 6.5 miles and capable for 115 kV. Remove existing tap switch and line on the CapX line.

Need Driver: The Cedar Lake tap needs to be removed from the CapX to allow for the Helena – Hampton Corners 345 kV second circuit.

Alternatives:
Transmission Alternatives

A connection to the 69 kV lines to the west and to the south were considered. However, these Xcel Energy circuits to the west and south of the substation are not recommended for a new Cedar Lake tap due to concerns related age), reliability and limited capacity. Triple circuiting the CapX line was deemed not feasible as it would require new foundations and poles.

Non-Wires Alternatives

Transmission solution required due to existing distribution substation need to be connected to the transmission system.

Analysis: This project was needed due to the second Helena-Hampton 345 kV line project. This was a congestion reduction project submitted by Xcel Energy.

Schedule: The Cedar Lake Tap Line Relocation project is planned to be in-service by fall 2025.

General Impacts: The project will require approximately 6.5 miles of new 115 kV transmission line from the GRE MV-EVX 115 kV line to Cedar Lake substation. The project is located in predominantly agricultural lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, GRE will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 12 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Fischer Distribution Substation Rebuild

MPUC Tracking Number: 2023-TC-N40

Utility: Great River Energy (GRE)

Project Description: DEA plans to update their 115 kV Fisher in/out distribution substation (both east and west) on the same property to replace the aged substation equipment. GRE will need to move the meter and telecom equipment as part of this work. GRE will also be adding a breaker and associated controls to this site.

Need Driver: This project is needed due to aging infrastructure that needs replacements. The installation of a breaker is needed for improved reliability to areas served from Fisher distribution substation. This breaker will effectively prevent the tripping of both Fischer distribution substations in the event of a line fault.

Alternatives:
Transmission Alternatives

> This project was needed for age and condition and will not involve new transmission lines or substations; therefore, no other alternatives were considered.

Non-Wires Alternatives

> Non-wires alternatives were not considered due to the replacement need for age and condition.

Analysis: Distribution analysis determined the need for new equipment based on the age and condition of existing equipment at the substation. The need for a new breaker was determined based on reliability and outage data. A breaker at this site will improve reliability by reducing the line exposure Fischer distribution substations.

Schedule: The Fischer Distribution Substation Rebuild project is planned to be in-service by fall 2025.

General Impacts: This project is located on GRE-owned property and right-of-way. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Lakeville Distribution Substation

MPUC Tracking Number: 2023-TC-N41

Utility: Great River Energy (GRE)

Project Description: GRE will be adding a second radial circuit tap (double circuit) into Lakeville substation for the addition of a second transformer and switchgear to Lakeville substation. Dakota Electric Association (DEA) is responsible for the high side structures and associated transmission side substation equipment.

Need Driver: Dakota Electric Association needs a second transformer at the Lakeville site due to limited capacity of the existing distribution transformer.

Alternatives:
Transmission Alternatives

As this project is using existing transmission lines to connect to a new transformer, an alternative of building new transmission lines was not considered.

Non-Wires Alternatives

Non-wires alternatives cannot adequately accommodate load growth forecasts.

Analysis: Distribution analysis showed that a second transformer was required due to the limited capacity of the existing transformer and the load growth in the area.

Schedule: The Lakeville Area Projects are planned to be in-service by fall 2025.

General Impacts: This project is located on GRE-owned property and right-of-way. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Burnsville Substation Upgrade

MPUC Tracking Number: 2023-TC-N42

Utility: Great River Energy (GRE)

Project Description: This project involves the following at Burnsville substation: replace and relocate EEE (all new panels/relays/etc.), soil correction at new EEE site, northwest fence line expansion, replacement of 5M197, and add breakers with new 115 kV ring bus configuration on north end of substation.

Need Driver:

- EEE continues to sink into poor grading at site with flooding issues.
- Systematically replacing all electromechanical relays and first vintage microprocessor relays.
- Prepare site for future voltage conversion.
- Breaker Replacements (5M197): These are Siemens BZO breakers with a OA3 Hydraulic mechanism. These breakers have type U bushings with higher power factor test results. Limited spare parts availability. Higher risk scores of the oil breakers left for replacement.

Alternatives:

Transmission Alternatives

This is an equipment reliability improvement at the substation and no alternatives were considered.

Non-Wires Alternatives

This project involves equipment improvement at the substation and no alternatives were considered.

Analysis: An analysis determined that existing equipment was out-of-date and at a high risk of failure. Additionally, a future proposed project will bring in a new 115 kV connection into this substation, preparing for this connection now will reduce future outage time at this substation.
Schedule: The Burnsville Substation Upgrade project is planned to be in-service by summer 2028.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 18 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

6.6.2 Completed Projects

The table below identifies those projects by Tracking Number in the Twin Cities Zone that were listed as ongoing projects in the 2021 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Public Utilities Commission in October 2021. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2021 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	XEL	11/30/2021
2021-TC-N1	High Bridge-Rogers Lake Bifurcation to Double Circuit	2021/A	XEL	6/1/2023
2021-TC-N2	Elm Creek TR4	2021/A	XEL	6/15/2022
2021-TC-N3	Barnes Grove Interconnection	2021/A	XEL	5/1/2021
2021-TC-N4	South Dayton Substation	None	GRE	10/2/2023

6.7 Southwest Zone

6.7.1 Needed Projects

The following table provides a list of transmission needs identified in the Southwest Zone by MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2013-SW-N1	Heron Lake 161 kV Substation Rebuild	2012/A	3528	No	Yes	ITCM
2017-SW-N1	Summit to Dovray 69 kV Rebuild	2016/A	9907	No	No	ITCM
2017-SW-N2	Dovray to Fulda 69 kV Rebuild	2016/A	9908	No	No	ITCM
2017-SW-N3	Fulda to Heron Lake 69 kV Rebuild	2016/A	9910	No	No	ITCM
2021-SW-N1	Fieldon Retirement	2021/A	19165	No	No	XEL
2021-SW-N2	Worthington Area Projects	2022/A	GRE:22030/ ITCM:21929/ MRES:20608	No	No	GRE/ ITCM/ MRES
2023-SW-N1	J1164/J1325 Interconnection	2022/A	21999	No	No	ITCM
2023-SW-N2	Trosky to Pipestone 69 kV Rebuild	Non-MISO	NA	No	No	L&O
2023-SW-N3	Brookings - Lyon, Hampton - Helena 2nd 345 kV Circuits	2022/A	23452	No	No	XEL

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2023-SW-N4	Lake Yankton TR02 ELR	2023/A	23456	No	No	XEL
2023-SW-N5	Brookings - Lyon, Hampton - Helena OPGW Replacement	2023/A	24902	No	No	XEL
2023-SW-N6	Steep Bank Lake Line Swap	2023/A	24374	No	No	XEL
2023-SW-N7	Nighthawk Breaker Station	2023/A	23463	No	No	XEL
2023-SW-N8	Line 0719 Winthrop to STR 45 Rebuild	2023/A	23503	No	No	XEL
2023-SW-N9	Minnesota Valley TR11 ELR	2023/A	23498	No	No	XEL
2023-SW-N10	Fairmont, MN Area Transmission Expansion	2023/A	25252	Yes	No	SMP
2023-SW-N11	Fairmont, 10th St. Substation Modernization	2023/A	25199	No	No	SMP
2023-SW-N12	Lakefield Area Projects	Future	TBD	No	No	GRE

Heron Lake 161 kV Substation Rebuild

MPUC Tracking Number: 2013-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: Heron Lake 161 kV Substation Rebuild.

Need Driver: As part of a joint study with GRE and MRES, ITC Midwest has revised and reduced the scope of the Heron Lake 161 kV project. In the updated configuration, one of the capacitor banks is no longer needed and the 161 kV configuration changes from a breaker-and-a-half to a ring bus.

Alternatives:

Transmission Alternatives

The capacitor banks were re-evaluated during the ad hoc study and it was determined that one of them was no longer be needed with the addition of the ‘Worthington Area Projects.’

Non-Wires Alternatives

This project was first proposed in 2013, and system changes, like the Worthington area projects, have removed the initial need for capacitor banks. Substation age and condition issues remain, and a non-wires alternative would not resolve the need to address the age and condition of Heron Lake substation.

Analysis: Transmission studies revealed that voltage in the area is depressed by the relatively long 69 kV lines in the area and the lack of sources in the area. In addition, outages on either the 69 kV or 161 kV systems drove voltage below ITC Midwest's planning criteria. The Heron Lake 161 kV substation will be constructed as a three position ring but with a single 161/69 kV transformer.

Schedule: Due to outage constraints and the addition of the Worthington Area Projects, the new expected in-service date would be no later than December 2027.

General Impacts: The addition of the 'Worthington Area Projects' allowed ITC Midwest to reduce the scope and cost of the existing Heron Lake Capacitor Bank Addition and subsequent substation expansion. The new plan provides better electrical performance at a reduced cost, while adding the additional benefit of geographic diversity which significantly improves customer reliability.

Summit to Dovray 69 kV Rebuild

MPUC Tracking Number: 2017-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: The 12.9 miles-long Summit to Dovray 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line's age and condition and increased maintenance costs have required that this line be rebuilt. The existing line has galloping issues, and the line operates frequently.

Alternatives:

Transmission Alternatives

A rebuild of the line with T2-4/0 ACSR conductor is planned. The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

The Summit to Dovray 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the Summit to Dovray 69 kV line.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by the end of 2027.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

Dovray to Fulda Junction 69 kV Rebuild

MPUC Tracking Number: 2017-SW-N2

Utility: ITC Midwest (ITCM)

Project Description: The approximately 14.5 mile-long Dovray to Fulda 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line's age and condition and increased maintenance costs have required that this line be rebuilt. The existing line has galloping issues, and the line operates frequently.

Alternatives:
Transmission Alternatives

A rebuild of the line with T2-4/0 ACSR conductor is planned. The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

The Dovray to Fulda Junction 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the Dovray to Fulda Junction 69 kV line.

Analysis: The plan to replace the transmission line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line.

Schedule: Construction of the line is expected to be completed by the end of 2028.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

Fulda Junction to Heron Lake 69 kV Rebuild

MPUC Tracking Number: 2017-SW-N3

Utility: ITC Midwest (ITCM)

Project Description: The approximately 20.1 miles-long Fulda Junction to Heron Lake 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line's age and condition and increased maintenance costs have required that this line be rebuilt. The existing line has galloping issues, and the line operates frequently.

Alternatives:

Transmission Alternatives

A rebuild of the line with T2-4/0 ACSR conductor is planned. The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

The Fulda Junction to Heron Lake 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the Fulda Junction to Heron Lake 69 kV line.

Analysis: The plan to replace the line with new poles, conductor and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line. The line work is expected to be completed by the end of 2028.

Schedule: Construction of the line is expected to be completed by the end of 2028.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

Fieldon Retirement

MPUC Tracking Number: 2021-SW-N1

Utility: Xcel Energy (XEL)

Project Description: This project bypasses and retires the Fieldon series capacitor and removes the substation, whose only function is for the series capacitor.

Need Driver: System improvements in the area have removed the need for the Fieldon series capacitor which has had operational issues in the past and has a significant recurring maintenance cost.

Alternatives:
Transmission Alternatives
Leaving the series capacitor in service, with corresponding maintenance burden and cost.
Non-Wires Alternatives
Retirement of an existing asset no longer needed.

Analysis: Retiring this substation produces no adverse effects to the transmission system.

Schedule: This project is expected to be completed in March 2024.

General Impacts: Retirement of the Fieldon substation.

Worthington Area Projects

MPUC Tracking Number: 2021-SW-N2

Utility: Great River Energy (GRE), ITC Midwest (ITCM), Missouri River Energy Services (MRES) hereinafter referred to as "the Utilities."

Project Description: Construct the Forks substation interconnection in the Dickinson – Lakefield Junction 161 kV transmission line. Construct the Rost 161/69 kV substation interconnection in the Heron Lake – Round Lake 69 kV transmission line. Construct approximately 6.5 miles of 161 kV transmission line from the Forks substation to the Rost substation. Construct approximately 9 miles of 69 kV transmission line from the Lorain substation to the Rost substation.

Need Driver: Load growth at the Lorain 69 kV substation has exacerbated prior outage events in the area. Any outage on the 161 kV between Split Rock (Xcel) and Magnolia leaves the system susceptible to low voltages for faults anywhere between Lakefield Junction and Elk 161 kV.

Alternatives:
Transmission Alternatives
1. Nobles County to Worthington 115 kV Loop
2. Build a 69 kV line from Lakefield Junction to West Lakefield and from West Lakefield to Worthington (Lorain).
3. Rost 161/69 kV substation with Rost Located at intersection of ITCM's 161 kV and GRE's FE-RJ 69 kV line, along with 69 kV line from Worthington to GRE's FE-RH line.

Non-Wires Alternatives

Even though the hybrid solution identified in the NWA study addresses the issues based on the technical analysis, economic analysis reveals that this is not an economically feasible option for the Worthington area. Nonetheless, considering future zero carbon emission goals, the hybrid solution fails to fulfill those requirements as well. Compared to the traditional solution cost, the proposed hybrid solution cost is about 10 times higher than the traditional solution. This study verified that no non-wires alternatives or cost-effective environmentally friendly hybrid alternatives are available today to address the Worthington area's reliability issues in an economical manner. A report is available upon request.

Analysis: This new project will allow a strong new source to serve the growing Worthington load, address voltage collapse, and allow the existing 69 kV system to remain in a more system normal configuration during critical prior outages.

Schedule: The project is planned to be in service by November 2027.

General Impacts: The project will require approximately 6.5 miles of new 161 kV transmission line from Forks substation to Rost substation. The project is located in predominantly agricultural lands. Prior to construction, the Utilities will acquire the necessary right-of-way and permits for construction of the project. The Utilities anticipate acquiring a 100-foot easement to facilitate construction and operation of the line. The preliminary design follows existing road rights-of-way to minimize impacts to nearby residents and environmental features. Prior to construction, the Utilities will complete a desktop review of environmental features that may be present in the right of way and will work with the appropriate permitting agencies, as required, to minimize impacts during construction. Construction is expected to be completed in 60 months. During this time, the Utilities and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Trosky to Pipestone 69 kV Rebuild

MPUC Tracking Number: 2023-SW-N1

Utility: L&O Power Cooperative (L&O)

Project Description: The 9.2 miles-long Trosky to Pipestone 69 kV line will be reconstructed on the existing right of way.

Need Driver: The line’s age and condition and increased maintenance costs have required that this line be rebuilt. A portion of the line was rebuilt after a 2019 ice storm and this project will rebuild the remaining portions.

Alternatives:
Transmission Alternatives
The rebuild of the line on existing right of way was the sole alternative considered to solve the age and condition issue.
Non-Wires Alternatives
The referenced 69 kV line is being replaced due to age and condition. A non-wires alternative is not considered a viable alternative to address the need to replace the referenced 69 kV line.

Analysis: The plan to replace the transmission line with new poles and shield wire will solve the reliability concern caused by the age and condition of the 69 kV line. The existing 477 ACSR conductor is planned to be transferred.

Schedule: The line is expected to be constructed and in service by December 2023.

General Impacts: The rebuild will occur on existing right of way. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. L&O will work with the appropriate permitting agencies to receive necessary approvals. L&O contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild will increase the reliability of electric service in the area.

J1164 and J1325 Generator Interconnection to Magnolia 161 kV

MPUC Tracking Number: 2023-SW-N2

Utility: ITC Midwest (ITCM)

Project Description: To provide for interconnection of two 80 MW (160 MW total) solar-powered generating facility, MISO projects J1164 and J1325, the 161 kV bus at Magnolia will be reconfigured to form a ring bus at the location of the existing Magnolia substation.

Need Driver: MISO projects J1164 and J1325 was studied under the MISO business practices, and the expansion of the Magnolia 161 kV bus to connect projects J1164 and J1325 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:
Transmission Alternatives
The interconnections were evaluated under the MISO's DPP 2018 and 2019 system impact studies. No alternatives for the interconnections were identified.

Non-Wires Alternatives

Projects J1164 and J1325 will be interconnected under MISO Tariff requirements. A non-wires is not viable as this project is aiding in the interconnection of two 80 MW (160 MW total) solar-powered generating facilities.

Analysis: The interconnection of projects J1164 and J1325 were evaluated as part of the MISO DPP 2018 and 2019 system impact studies. The expansion of facilities at Magnolia are required to provide a point of interconnection for project J1164 and J1325.

The Magnolia substation is over 60 years old and the substation was not originally designed or constructed to accommodate additional bus positions on the 161 kV bus. The existing 161 kV substation bus will be rebuilt from a straight bus configuration to a ring bus configuration.

Schedule: The project will be placed in service in August of 2025.

General Impacts: The upgrades will occur within the existing Magnolia 161 kV Substation. Termination of the J1164 and J1325 generator tie-line will be coordinated with the interconnection customer and necessary authorities. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Brookings - Lyon, Hampton - Helena 2nd 345 kV Circuits

MPUC Tracking Number: 2023-SW-N3

Utility: Xcel Energy (XEL)

Project Description: Install approximately 60 mile second 345 kV circuit between the Brookings County and Lyon County substations. Install approximately 39 mile second 345 kV circuit between the Hampton Corner and Helena substations. Perform substation upgrades associated with installation of line.

Need Driver: Adds second circuit that eliminates current system conditions that impede deliverability of existing resources to demand centers in primarily off-peak periods of high renewable production which results in a reduction of available generation capacity at times of higher than average maintenance and construction outages.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

This new line installation uses existing double circuit structures on existing right of way. No alternatives were considered.

Analysis: This is a cost-effective system resiliency solution that reduces system congestion.

Schedule: The project is planned to be in service by September 2025.

General Impacts: The project will be constructed on the existing 345kV double circuit structures, using existing right of way. The second circuit will reduce congestion on the transmission system allowing for economical dispatch of renewable energy resources. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Lake Yankton TR02 ELR

MPUC Tracking Number: 2023-SW-N4

Utility: Xcel Energy (XEL)

Project Description: Replace Lake Yankton 115/69 kV TR02.

Need Driver: The ELR transformer program is to proactively replace aging transformers that have passed their operational service life and are showing increase signs of degradation.

Alternatives:

Transmission Alternatives

None.

Non-Wires Alternatives

None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by December 2025.

General Impacts: Transformer replacement in existing substation to support transmission reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Brookings - Lyon, Hampton - Helena OPGW Replacement

MPUC Tracking Number: 2023-SW-N5

Utility: Xcel Energy (XEL)

Project Description: This project will replace the aging OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines. This project will be performed in tandem with the installation of the Brookings - Lyon County and Hampton - Helena 2nd circuit installation project.

Need Driver: The existing OPGW on the Brookings - Lyon County and Hampton - Helena 345 kV lines are showing signs of degradation and have experienced failures. Replacement is needed to ensure reliable communications and controls on those circuits.

Alternatives:
Transmission Alternatives

None.

Non-Wires Alternatives

This project replaces existing end of life communications equipment. No alternatives were considered.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by September 2025.

General Impacts: The project will be replacing existing equipment at end of life. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Steep Bank Lake Line Swap

MPUC Tracking Number: 2023-SW-N6

Utility: Xcel Energy (XEL)

Project Description: This project will Move J460 Steep Bank Lake interconnection to new 345 kV second circuit being built between Brookings County - Lyon County (MTEP ID 23452).

Need Driver: Transferring Steep Bank Lake to the new Brookings County - Lyon County 345 kV line will avoid crossing lines going into the substation and provide additional operational flexibility.

Alternatives:
<u>Transmission Alternatives</u>
None.
<u>Non-Wires Alternatives</u>
None.

Analysis: This is a cost-effective system resiliency solution.

Schedule: The project is planned to be in service by September 2025.

General Impacts: The project will be swapping existing substation to new line on existing right of way eliminating line crossings which could impact reliability. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated. Existing right of way will be restored upon completion of project.

Nighthawk Breaker Station

MPUC Tracking Number: 2023-SW-N7

Utility: Xcel Energy (XEL)

Project Description: New 4-line terminal breaker station connecting to Minnesota Valley – Troy 69 kV transmission line (0724), Crook's substation, and the SMBSC plant.

Need Driver: Improve reliability of service to Southern Minnesota Beet Sugar Corporation (SMBSC), a business adversely impacted by power disruptions.

Alternatives:
<u>Transmission Alternatives</u>
New 230/69 kV substation north of the plant site to supply the two distribution substations supporting SMBS. No indicated load increase; the 69 kV line is capable of providing a well enough source of service to the existing customers. Not enough justification for an additional source in the area
<u>Non-Wires Alternatives</u>
None.

Analysis: Adding a breaker station to the existing 69 kV system will reduce outages and improve reliability for SMBSC. No other immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by June 1, 2024.

General Impacts: The project will install a new substation along existing 69 kV line. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Line 0719 Winthrop to STR 45 Rebuild

MPUC Tracking Number: 2023-SE-N8

Utility: Xcel Energy (XEL)

Project Description: Rebuild 1.5 miles of line 0719 69 kV from Winthrop - Structure 45.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 2025.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Minnesota Valley TR11 ELR

MPUC Tracking Number: 2023-SE-N9

Utility: Xcel Energy (XEL)

Project Description: Replace Minnesota Valley 115/69 kV TR11.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:
<u>Transmission Alternatives</u>

Transformer may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

<u>Non-Wires Alternatives</u>

This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 2027.

General Impacts: No environmental issues have been identified. Transformer replacement will have minimal impacts to existing system performance and footprint.

Fairmont, MN Area Transmission Expansion

MPUC Tracking Number: 2023-SW-N10

Utility: Southern Minnesota Municipal Power Agency

Project Description: Building of a new 69/12.5 kV distribution substation "West Industrial Park" (WIP) west of Fairmont, construction of a new 69 kV SMMPA breaker station and construction of two 69 kV transmission lines, one from WIP to the SMMPA's Fairmont Energy Station (FES) substation and one from WIP which will tap Great River Energy's 69 kV line between Rutland substation and the Fairmont 10th Street Substation.

Need Driver: This project was motivated by Fairmont Public Utilities (FPU) to address their need for a new distribution substation.

Alternatives:
<u>Transmission Alternatives</u>

A radial 69 kV transmission line was considered, but ultimately there was too much line exposure to Fairmont load.

<u>Non-Wires Alternatives</u>

Because Fairmont needs to be able to serve load from a new location non-wires alternatives were not considered.

Analysis: These additions will add a reliable 69 kV transmission loop through town. This increases the load serving capability in town as well as minimizes the possibility of transmission outages to area load.

Schedule: Expected in service date is late 2026

General Impacts: The new FPU substation is likely to be built on existing city owned land. The new SMMPA substation will be built on existing SMMPA owned land. Most of the line routing will be done on existing distribution right of way. Where needed right of way will be expanded or added to, environmental impacts will be minimized on the project. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Fairmont, 10th St. Substation Modernization

MPUC Tracking Number: 2023-SW-N11

Utility: Southern Minnesota Municipal Power Agency

Project Description: Current breakers were installed in 1985, and they have become unreliable and difficult to maintain with their age. Along with these breakers, the associated switches and relays will also be replaced with newer and more reliable equipment. The new equipment includes new PTs, arresters, and new solid-state relay panels.

Need Driver: Old breakers have become difficult to maintain with reoccurring problems and parts shortages, effectively driving maintenance costs up. Other equipment upgrades are being made to switch from electromechanical to the more reliable solid-state equipment.

Alternatives:
Transmission Alternatives
None.
Non-Wires Alternatives
None.

Analysis: N/A

Schedule: New equipment expected to be in service in 2025.

General Impacts: The 10th St. substation is on existing city owned land. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Lakefield Area Projects

MPUC Tracking Number: 2023-SW-N12

Utility: Great River Energy (GRE)

Project Description: Expansion of the 345 kV Gen tie bus at the Lakefield substation to accommodate the Three Waters Wind (340 MW) Wind Farm. Installation of new 345 kV breakers on the existing generator and installation of the GRE controlled EEE, 1500' of 345 kV Transmission to the interconnect 161 kV/345 kV step up substation.

Need Driver: Additional 345 kV interconnection required to connect the Three Waters wind farm.

Alternatives:

Transmission Alternatives

This project is necessary to facilitate the connection of a new wind farm. This is an existing generation site and was deemed the best interconnection point, therefore alternatives were not considered.

Non-Wires Alternatives

Non-wires alternatives are not considered for new generation interconnections as the POI is determined by the interconnection customer.

Analysis: The interconnection of the Three Waters Wind Farm at Lakefield was evaluated as part of the MISO DPP system impact studies.

Schedule: The Lakefield Area Projects are planned to be in-service by November 2026.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

6.7.2 Completed Projects

The table below identifies those projects by Tracking Number in the Southwest Zone that were listed as ongoing projects in the 2021 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Minnesota Public Utilities Commission in October 2021. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2021 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
No Projects Completed.				

6.8 Southeast Zone

6.8.1 Needed Projects

The following table provides a list of transmission needs identified in the Southeast Zone by MISO utilities. There were no projects identified in this zone by non-MISO utilities.

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-SE-N2	Adams to Stewartville 69 kV Rebuild	2012/A	3630	No	No	ITCM
2019-SE-N3	J523 Generator Interconnection to Adams 161 kV	2020/A	18113	No	No	ITCM
2019-SE-N5	Thisius 161/69 kV Substation	2020/A	17968	No	Yes	ITCM
2021-SE-N2	Northfield to Farmington Line Rebuild	2021/A	19888	No	No	XEL
2021-SE-N3	Hayward 161/69 kV Transformer Replacement	2022/A	21935	No	No	ITCM
2023-SE-N1	Line 0761 Rebuild	2022/A	21888	No	No	XEL
2023-SE-N2	Line 0749 Waseca - ITC Tap Rebuild	2023/A	23459	No	No	XEL
2023-SE-N3	Line 0714 Medelia - Watonwan Rebuild	2023/A	23460	No	No	XEL
2023-SE-N4	Line 0708 STR 78 to 476 Rebuild	2023/A	23461	No	No	XEL
2023-SE-N5	Gaiter Lake Substation	2023/A	23528	No	No	XEL
2023-SE-N6	Rock Dell to Pleasant Valley 69 kV Rebuild	N/A	N/A	No	No	DPC
2023-SE-N7	Genoa to Ringe 69 kV Rebuild	N/A	N/A	No	No	DPC
2023-SE-N8	J898 Interconnection at Beaver Creek	TBD	TBD	No	No	DPC
2023-SE-N9	Kellogg 161 kV Transmission Substation	2021/A	23371	No	No	DPC
2023-SE-N10	Loon Lake Substation Modernization	2023/A	25260	No	No	SMP
2023-SE-N11	Pleasant Valley Area Projects	2024/B	24297	No	No	GRE
2023-SE-N12	Pleasant Valley Terminal Upgrade	2024/A	25399	No	No	GRE

Adams to Stewartville 69 kV Rebuild

MPUC Tracking Number: 2019-SE-N2

Utility: ITC Midwest (ITCM)

Project Description: The approximately 35 miles-long Adams to Stewartville 69 kV line will be reconstructed on the existing right of way.

Need Driver: The Adams to Stewartville 69 kV line was built over 50 years ago, and increased maintenance costs will require the line to be reconstructed due to its age and condition.

Alternatives:
Transmission Alternatives

A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue.

Non-Wires Alternatives

Non-wire alternatives are not viable because they cannot address concerns related to age and condition on the Adams to Stewartville 69 kV circuit.

Analysis: The plan to replace the over 50-years-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the 69 kV line.

Schedule: Initial rebuild of the line is expected to commence in 2027.

General Impacts: The line is near the end of its useful life. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated. The right-of-way will be restored following construction. The rebuild of the line will increase the reliability of electric service in the area.

J523 Generator Interconnection to Adams 161 kV

MPUC Tracking Number: 2019-SE-N3

Utility: ITC Midwest (ITCM)

Project Description: To provide for interconnection of the 50 MW solar-powered generating facility, MISO project J523, the 161 kV bus at Adams will be reconfigured to form a breaker-and-1/2 terminal at the location of the existing Adams 161 kV bus-tie breaker. Also, as part of the work for the J523 generation, the 161 kV terminal to the 345/161 kV transformer will be re-terminated at a new terminal in the newly created breaker-and-1/2 row that will serve as the point of interconnection for project J523.

Need Driver: MISO project J523 was studied under the MISO business practices, and the expansion of the Adams 161 kV bus to connect project J523 is required to provide interconnection service to the project under the MISO tariff.

Alternatives:

Transmission Alternatives

The interconnection was evaluated under the MISO's DPP February 2016 system impact study. No alternatives for the interconnection were identified.

Non-Wires Alternatives

Project J523 will be interconnected under MISO Tariff requirements. A non-wires is not viable as this project is aiding in the interconnection of a 50 MW solar-powered generating facility.

Analysis: The interconnection of project J523 was evaluated as part of the MISO February 2016 system impact study. The expansion of facilities at Adams are required to provide a point of interconnection for project J523.

The Adams substation is approximately 55 years old, and the substation was originally designed to accommodate conversion to a breaker-and-1/2 bus configuration. In conjunction with the interconnection of project J523, a separate maintenance project will be developed to convert the remaining 161 kV substation bus from a straight bus configuration to a breaker-and-1/2 configuration.

Schedule: The project will be placed in service in March of 2024.

General Impacts: The upgrades will occur within the existing Adams 161 kV Substation. Termination of the J523 generator tie-line will be coordinated with the interconnection customer and necessary authorities. No new landowners will be impacted by construction, although some additional temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITCM will work with the appropriate permitting agencies to receive necessary approvals. ITCM contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Thisius 161/69 kV Substation

MPUC Tracking Number: 2019-SE-N5

Utility: ITC Midwest (ITCM)

Project Description: The project calls for the Huntley to Freeborn 161 kV line to be tapped approximately 6.1 miles west of Freeborn. A new 161/69 kV substation would be constructed to accommodate a 100 MVA, 161/69 kV transformer with load-tap changer.

Need Driver: The 69 kV system around Albert Lea, MN experiences low voltage and thermal loading issues under multiple NERC P2 contingencies. This area is primarily fed from the Huntley and Hayward substations and the line between them is approximately 50 miles long. This 69 kV system is operated radially, and the existing 161 kV sources are stretched on high impedance conductor over great distances.

Alternatives:

Transmission Alternatives

> Rebuilding Huntley 69 kV to a ring-bus configuration and re-terminating Corn Plus substation's load to a consolidated substation near Winnebago Local in conjunction with rebuilding the Hayward 161 kV Substation to a breaker-and-½ configuration were also considered.

Non-Wires Alternatives

> Non-wire alternatives are not viable because they cannot meet the duration requirements to alleviate the voltage concerns.

Analysis: The new substation at Thisius will help support future load growth on the 69 kV system and provide a much needed source between the Huntley and Hayward substations. The location of the Thisius 69 kV station can also accommodate future 161 kV expansion necessary to address future area needs.

Schedule: It is expected that the project would be placed in service by early June 2023.

General Impacts: Line routing and facilities siting will be coordinated with necessary local, state and federal authorities. ITC contractors and personnel will work with landowners to address their concerns during construction. Impacts to landowners will be minimized. Temporary workspace may be required. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITC will work with the appropriate permitting agencies. No significant traffic impacts are anticipated. ITC contractors and personnel will contribute positively to the local economy. The new facilities will increase the reliability of the electric system in the area.

Northfield to Farmington Line Rebuild

MPUC Tracking Number: 2021-SE-N2

Utility: Xcel Energy (XEL)

Project Description: This project involves the rebuilding of an approximately 1.6-mile portion of the 69 kV between Farmington substation (FRM) and Northfield substation (NOF). The intent of the rebuild is to increase reliability and performance of the line, reduce the likelihood of a forced outage occurring and increase the capacity for project future load growth.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:

Transmission Alternatives

Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.

Non-Wires Alternatives

This is replacing an existing asset.

Analysis: Verifying the secondary limit on the Farmington – Lake Marion 69 kV line, and limit may need to be replaced. No other immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 30, 2023.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Hayward 161/69 kV Transformer Replacement

MPUC Tracking Number: 2021-SE-N3

Utility: ITC Midwest (ITCM)

Project Description: Due to age and condition, ITC Midwest is replacing both 161/69 kV transformers at the Hayward substation near Hayward, MN, with a single larger unit.

Need Driver: Both transformers are nearing end of their life and are needing to be replaced.

Alternatives:

Transmission Alternatives

Replacing both existing units with a pair of larger/standard transformers. However, with the addition of *'2019-SE-N5 Thisius 161/69 kV Substation'* there was no longer a need to have two transformers in this substation.

Non-Wires Alternatives

Non wires alternative was not considered. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Hayward Substation.

Analysis: No other immediate overloads or voltage concerns were observed with the replacement of the two existing Hayward 161/69 kV transformers with a single unit.

Schedule: The in-service date for this project is by year end 2025.

General Impacts: The project is being completed within the existing Hayward substation property lines and minimal impacts to neighboring landowners is expected.

Line 0761 Rebuild

MPUC Tracking Number: 2023-SE-N1

Utility: Xcel Energy (XEL)

Project Description: This project involves the rebuilding of an approximately 19.7 miles of existing 69 kV on line 0761 from Zumbrota to the current 69 kV Standards.

Need Driver: Asset at end of life and at risk of imminent failures. Increased outage frequency and duration. Failure could provide risk to public safety.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by October 31, 2023.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0749 Rebuild

MPUC Tracking Number: 2023-SE-N2

Utility: Xcel Energy (XEL)

Project Description: Rebuild 6.7 miles of 69 kV line 0749 from Waseca - ITC Tap and add OPGW.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by June 15, 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0714 Medelia - Watonwan Rebuild

MPUC Tracking Number: 2023-SE-N3

Utility: Xcel Energy (XEL)

Project Description: Rebuild 22 miles of line 0714 69 kV from Medelia - Watonwan.

Need Driver: Needed for age and condition rebuild.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability and overloading issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Age and condition rebuild. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Line 0708 STR 78 to 476 Rebuild

MPUC Tracking Number: 2023-SE-N4

Utility: Xcel Energy (XEL)

Project Description: Rebuild 16 miles of line 0708 69 kV from Eagle Lake - Waterville and add OPGW.

Need Driver: Needed to address galloping issues on this line.

Alternatives:
Transmission Alternatives
Line may be used as is, but this runs the risk of reliability issues. No alternatives were considered.
Non-Wires Alternatives
This is replacing an existing asset.

Analysis: Rebuilding to address galloping concerns. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by December 31, 2024.

General Impacts: No environmental issues have been identified. Line rebuild will have minimal impacts to existing system performance and footprint.

Gaiter Lake Substation

MPUC Tracking Number: 2023-SE-N5

Utility: Xcel Energy (XEL)

Project Description: Build new Gaiter Lake substation in Waseca to pick up load off of Clarks Grove, Meridan, and Waseca substations. Retire Clarks Grove and Meridan substations.

Need Driver: Needed due to age and condition of Clarks Grove and Merdian substations, as well as capacity needs.

Alternatives:
<u>Transmission Alternatives</u>
Rebuild of existing substations would not increase load serving capability, leaving load at risk and would involve full rebuild of two substations opposed to construction of one new substation.
<u>Non-Wires Alternatives</u>
None.

Analysis: Transferring load from existing substations to new substation in same area. No immediate overloads or voltage concerns.

Schedule: The project is planned to be in service by February 2025.

General Impacts: The project will install a new substation along existing 69 kV line and retirement of two existing substations. During construction the company or contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Rock Dell to Pleasant Valley 69 kV Rebuild

MPUC Tracking Number: 2023-SE-N6

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 2.2 miles of DPC's Maple Leaf to Airport 69 kV line between the Rock Dell and Pleasant Valley distribution substations on existing and new right-of-way.

Need Driver: DPC purchased this line from People's Energy Cooperative in July of 2022. This line was identified for rebuild due to age and condition.

Alternatives:
<u>Transmission Alternatives</u>
A rebuild solely on existing right-of-way was considered. However, a portion of the existing right-of way runs through a lower lying area that is also in the Rock Dell Wildlife Management Area. For this reason, a mix of existing and new right-of way is also being considered.
<u>Non-Wires Alternatives</u>
None.

Analysis: The 2.2-mile section 69 kV transmission line rebuild will address the reliability concerns due to age and condition. The potentially relocated section of this rebuild will also improve accessibility for maintenance.

Schedule: Construction of the line is expected to be completed by early-2026.

General Impacts: The line is near the end of its useful life. Dairyland construction crews will rebuild this line in early-2026, requiring approximately three weeks to construct. The portion of the rebuild on existing right-of-way will have minimal impacts, while the portion being considered for new right-of-way will improve accessibility.

Genoa to Ringe 69 kV Rebuild

MPUC Tracking Number: 2023-SE-N7

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 8.9 miles of DPC's Maple Leaf to Rochester 69 kV line between the Genoa and Ringe distribution substations on existing and new right-of-way.

Need Driver: DPC purchased this line from People's Energy Cooperative in July of 2022. This line was identified for rebuild due to age and condition.

Alternatives:
Transmission Alternatives
A rebuild solely on existing right-of-way was considered. Relocating portions of the line has added reliability benefits.
Non-Wires Alternatives
None.

Analysis: The 8.9-mile section 69 kV transmission line rebuild will address the reliability concerns due to age and condition. The relocated section of this rebuild will also improve line exposure and reliability.

Schedule: Construction of the line is expected to be completed by late 2026.

General Impacts: The line is near the end of its useful life. Dairyland construction crews will rebuild this line in 2026, requiring approximately eleven weeks to construct.

J898 Interconnection at Beaver Creek 161 kV

MPUC Tracking Number: 2023-SE-N8

Utility: Dairyland Power Cooperative (DPC)

Project Description: Replace the 161 kV Beaver Creek Tap three-way switches with a 3-breaker substation approximately 6 miles south of the Beaver Creek Tap to allow for the interconnection of 100 MW of wind-powered generation with the potential for additional capacity in the future. A 6-mile portion of 161 kV transmission line on new right-of-way will be constructed to connect the new transmission substation back to the existing Harmony to Beaver Creek 161 kV transmission line. A 4-mile stretch of existing 161 kV transmission line between Harmony and the Beaver Creek Tap will be retired.

Need Driver: The new 3-breaker substation and 6-mile portion of 161 kV transmission line are required as part of the MISO Tariff for the interconnection of 100 MW of wind-powered generation for project J898.

Alternatives:
Transmission Alternatives

The interconnection for J898 was evaluated under MISO's DPP August 2017 West system impact study. An alternative of upgrading the 69 kV transmission to the south of SMMPA's Rice substation was considered.

Non-Wires Alternatives

None.

Analysis: The interconnection of project J898 was evaluated under MISO's DPP August 2017 West and 2020 West system impact study. Potential overloads of the underlying 69 kV system under contingent conditions were identified. The proposed project was determined to be the most reliable and cheapest mitigation for these overloads.

Schedule: The in-service date for the substation portion of the project is late-2026, while the new 161 kV transmission line portion of the project is mid-2027.

General Impacts: The 161 kV transmission line portion of this project will be built on new right-of-way, with approximately 4 miles of existing transmission line to be retired. The resulting configuration will replace the existing 3-terminal 161 kV transmission line between Harmony, Adams and Rice with three 2-terminal transmission lines, providing additional reliability benefits.

Kellogg 161 kV Transmission Substation

MPUC Tracking Number: 2023-SE-N9

Utility: Dairyland Power Cooperative (DPC)

Project Description: Construct a new 5-breaker 161/69 kV transmission substation, named Kellogg on DPC's Wabaco to Alma 161 kV transmission line. Construct 9 miles of 161 kV transmission line on new right-of-way, connecting between Wabaco and Kellogg from existing transmission into the Kellogg substation. Install a 112 MVA 161/69 kV transformer at Kellogg and reterminate DPC's Utica to Alma 69 kV transmission line into the Kellogg substation. Retire the remaining 2.5-mile Mississippi River crossing portion of the 69 kV transmission line between Alma and the Weaver distribution substation.

Need Driver: These projects are required by MISO's Long Range Transmission Plan (LRTP) and are included in the identified Tranche 1 projects to address needs associated with the changing resource mix across the MISO Midwest subregion. The new DPC facilities are required to replace the 69 kV Mississippi River crossing between Alma and the Weaver distribution substation with the North Rochester to Tremval 345 kV transmission line.

Alternatives:
<u>Transmission Alternatives</u>
The MISO LRTP planning efforts considered several alternatives to the recommended Tranche 1 projects.
<u>Non-Wires Alternatives</u>
None.

Analysis: The Kellogg substation, new 161 kV transmission line and 69 kV retermination frees up the Mississippi River crossing for the new North Rochester to Tremval 345 kV transmission line, without sacrificing local reliability.

Schedule: The in-service date for the project is mid-2027.

General Impacts: The new Kellogg substation and 69 kV retermination will have minimal need for new right-of-way, but will allow for new 345 kV Mississippi River crossing on existing right-of-way. The 9 miles of new 161 kV transmission will be constructed on new right-of-way. The LRTP Tranche 1 projects are renewable-enabling, allowing for reliable, green energy in the future.

Loon Lake Substation Modernization

MPUC Tracking Number: 2023-SE-N10

Utility: Southern Minnesota Municipal Power Agency

Project Description: Current breakers were installed in 1985, and they have become unreliable and difficult to maintain with their age. Along with these breakers, the associated switches and relays will also be replaced with newer and more reliable equipment. The new equipment includes new PTs, arresters, and new solid-state relay panels.

Need Driver: Old breakers have become difficult to maintain with reoccurring problems and parts shortages, effectively driving maintenance costs up. Other equipment upgrades are being made to switch from electromechanical to the more reliable solid-state equipment.

Alternatives:
Transmission Alternatives:
None.
Non-Wires Alternatives:
None

Analysis: N/A

Schedule: New equipment expected to be in service by 2025.

General Impacts: This project is located on SMMPA owned property. No significant traffic impacts are anticipated. Relevant permits and approvals will be received prior to construction. Contractors and personnel will contribute positively to the local economy.

Pleasant Valley Area Projects

MPUC Tracking Number: 2023-SE-N11

Utility: Great River Energy (GRE)

Project Description: Expansion of the 161 kV bus at the Pleasant Valley substation to accommodate the Phase 1 Wind (170 MW) and Phase 2 Wind (150 MW) Wind Farms. Expansion of the control house to accommodate the additional equipment.

Need Driver: Additional 161 kV transmission bays required to connect the Dodge County and Timberwolf Wind wind farms.

Alternatives:
Transmission Alternatives

Alternate design to install dead end and breakers in the existing opening between existing breakers 19QB6 and 19QB7. This would eliminate the need to expand the current yard. This would require extensive bus outages and limitations on generation at Pleasant Valley to allow for safe installation and maintenance of equipment. This alternative was decided against by the field service team and engineering due to the outage constraints for both maintenance and construction.

Non-Wires Alternatives

Non-wires alternatives are not considered for new generation interconnections as the POI is determined by the interconnection customer.

Analysis: The interconnection of the Dodge County and Timberwolf Wind wind farms was evaluated as part of the MISO DPP system impact studies.

Schedule: The Pleasant Valley Area Projects are planned to be in-service by spring 2024.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

Pleasant Valley Terminal Upgrade

MPUC Tracking Number: 2023-SE-N12

Utility: Great River Energy (GRE)

Project Description: Upgrade terminal equipment to 3000 A rating.

Need Driver: The line to Byron has caused market congestion in the past and is projected to continue to cause market congestion into the future.

Alternatives:
Transmission Alternatives

No transmission alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Non-Wires AlternativesNo non-wires alternatives were considered since this project is replacing the most limiting equipment in an existing substation.

Analysis: This upgrade will prevent terminal equipment from being the binding rating and allow for the line conductor capacity rating to be fully utilized, reducing the likelihood of the line causing congestion in the market.

Schedule: The project is planned to be in service by winter 2025.

General Impacts: This project is located on GRE owned property. Construction is expected to be completed in 6 months. During this time, GRE and/or their contractors will be working in the area and will contribute positively to the local economy. No significant traffic impacts are anticipated.

6.8.2 Completed Projects

The table below identifies those projects by Tracking Number in the Southeast Zone that were listed as ongoing projects in the 2021 Biennial Report but have been completed or withdrawn since the 2021 Report was filed with the Minnesota Public Utilities Commission in October 2021. Information about each of the completed projects is summarized briefly in the table below. More information about these projects and inadequacies can be found in earlier reports. Projects that were listed as being complete in the 2021 Report are not repeated here, but more information about those projects can be found in these earlier reports.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2015-SE-N6	Waseca Junction to Montgomery 69 kV Rebuild	N/A	ITCM	2/24/2023
2015-SE-N7	Ellendale to West Owatonna 69 kV Rebuild	N/A	ITCM	9/19/2022
2017-SE-N1	Huntley to Wilmarth 345 kV MEP Project	N/A	XEL/ITCM	5/15/2022
2017-SE-N3	Rochester-Wabaco 161 kV Rebuild	N/A	DPC	6/2/2022
2019-SE-N4	Adams 161 kV Maintenance	N/A	ITCM	8/25/2022
2021-SE-N1	Replace Green Isle Substation	N/A	XEL	7/29/2022

7.0 Transmission-Owning Utilities

7.1 Introduction

In this chapter of the 2023 Report, the utilities have provided the following information.

Background Information and Contact Person

For ease of reference, the utilities have provided much of the same background information provided in the 2021 Report. This information relates to the history of each utility and the extent of its service territory and operations. An Internet link is provided where additional information about each utility can be found. In addition, a contact person is identified for each utility.

Transmission Line Ownership

In the 2007 Biennial Report, the utilities reported on the miles of transmission lines each utility owned in Minnesota. The MTO updated that information in subsequent biennial reports in 2009, 2011, 2013, 2015, 2017, 2019, and 2021, and they are updating it again in this report. The table below is the latest information on the transmission lines in Minnesota owned by each utility. In addition, information specific to each utility is included in the discussion for that utility.

Miles of Transmission

Utility	<100 kV	100-199 kV	200-299 kV	> 300 kV	DC
American Transmission Company, LLC	0	0	0	12	0
Central Minnesota Municipal Power Agency	28	14	0	0	0
Dairyland Power Cooperative	423.8	152.75	0	8.88	0
East River Electric Power Cooperative	164	46	0	0	0
Great River Energy	3,086	642	524	146	0
ITC Midwest LLC	668	310	0	115	0
L&O Power Cooperative	43.17	8.32	0	0	0
Minnesota Power	0.22	1,310.02	617.65	265.52	231.56
Minnkota Power Cooperative	1,008.38	153.20	267.94	0	0
Missouri River Energy Services	32.16	239.32	24.02	47	0
Northern States Power Company d/b/a Xcel Energy	1,679.96	1,771.17	466.54	1,922.38	0
Otter Tail Power Company	1,295.2	584.6	186.2	564.8	0
Rochester Public Utilities	0	42.42	0	0	0
Southern Minnesota Municipal Power Agency	149.84	135.48	17.09	0	0
Totals:	8,578.73	5,409.28	2,103.44	3,081.58	231.56

7.2 American Transmission Company, LLC

Background information. American Transmission Company (ATC) began operations on January 1, 2001, the first multi-state electric transmission-only utility in the country. The company is head-quartered in Pewaukee, Wisconsin.

At least 28 utilities, municipalities, municipal electric companies, and electric cooperatives from Wisconsin, Michigan, and Illinois have invested transmission assets or money for an ownership stake in the company. ATC is responsible for operating and maintaining the transmission lines of its equity owners. It owns more than 9,921 circuit miles of transmission lines and 577 substations in Wisconsin, Michigan, Illinois, and Minnesota. ATC has $5.5 billion in total assets.

ATC is a transmission-owning member of the MISO, and its transmission system is located in both the Midwest Reliability Organization and ReliabilityFirst Corporation.

More information about the company is available on its website at:

http://www.atcllc.com

Contact Person: John Sealy
Transmission Planning Engineer
American Transmission Co.
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Waukesha, WI 53187-0047
Phone: (262) 506-6700
e-mail: jsealy@atcllc.com

Transmission lines. ATC owns more than 9,921 miles of transmission lines, including 12 miles in Minnesota. The transmission line segment in Minnesota extends from the Arrowhead Substation in the Duluth area to the St. Louis River and is part of the 220-mile 345-kV Arrowhead-Weston line that extends from the Arrowhead Substation to the Gardner Park Substation in Wausau, Wisconsin. The Arrowhead-Weston line, which cost $439 million to construct, was energized in January 2008. Arrowhead-Weston provides such benefits as improving reliability, enhancing transfer capability between Minnesota and Wisconsin, and providing ATC and other utilities greater opportunities to perform maintenance on other parts of the electric system, which reduces operating costs.

American Transmission Company Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0	0	0	12	0

7.3 Central Minnesota Municipal Power Agency

Background information. Central Minnesota Municipal Power Agency (CMMPA) is a municipal corporation and political subdivision of the State of Minnesota, headquartered in Eden Prairie, Minnesota. CMMPA was created in 1987 and has twelve municipally-owned utilities as members, located predominantly in south-central Minnesota. Central Municipal Power Agency/Services (CMPAS) serves as the utility services agent for CMMPA and provides energy management and consulting services to public power members and affiliates in Minnesota and Iowa. CMMPA has transmission assets that are part of MISO.

More information about the company is available on its website at:

http://www.cmpas.org

Contact Person:
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Policy Manager
Central Municipal
Power Agency/Services
7550 Corporate Way
Eden Prairie, MN 55344
Phone: (763) 710-3933
e-mail: warrenh@cmpas.org

Transmission lines. CMMPA is one of the eleven members of the CapX2020 group, and one of the five co-owners in the Brookings-Hampton 345 kV line. In addition, CMMPA is the transmission owner in MISO for the following transmission assets owned by its members.

Central Minnesota Municipal Power Agency

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
28	14	0	0	0

7.4 Dairyland Power Cooperative

Background Information. Dairyland Power Cooperative (DPC), a Touchstone Energy Cooperative, was formed in December 1941. A generation and transmission cooperative, Dairyland provides the wholesale electrical requirements to 24 member distribution cooperatives and 17 municipal utilities in Wisconsin, Minnesota, Iowa and Illinois. Today, the cooperative's generating resources include coal, hydro, solar, wind, natural gas, landfill gas and animal waste. Dairyland Power Cooperative joined MISO in 2010.

More information about Dairyland Power Cooperative is available at:

http://www.dairylandpower.com

Contact Person:

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Planning Engineer III
Dairyland Power
Cooperative 3200 East
Avenue South
La Crosse, WI
54601 Phone: (608)
787-1229
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e-mail: steve.porter@dairylandpower.com

Transmission Lines. Dairyland delivers electricity via more than 3,100 miles of transmission lines and nearly 300 substations located throughout the system's 44,500 square mile service area. Dairyland has the following transmission facilities in Minnesota:

Dairyland Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
423.80	152.75	0	8.88	0

7.5 East River Electric Power Cooperative

Background Information. East River Electric Power Cooperative (East River), headquartered in Madison, South Dakota, is a wholesale electric power supply and transmission cooperative serving 24 rural distribution electric cooperatives and one municipally-owned electric system, which in turn serve more than 250,000 member-owners. East River's 40,000 square mile service area covers the rural areas of 41 counties in eastern South Dakota and twenty-two counties in western Minnesota.

Six of East River's member systems have service areas entirely in western Minnesota and one member system has service areas in both eastern South Dakota and western Minnesota. The remaining eighteen member systems have service areas entirely in eastern South Dakota.

East River is a part of the Southwest Power Pool and has transmission facilities in MISO.

More information about East River Electric Power Cooperative is available at:

http://www.eastriver.coop

Contact Person:
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Transmission Policy Administrator
East River Electric Power Cooperative
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Madison, SD 57042
Phone: (605) 256-4536
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Transmission Lines. East River delivers electricity via approximately 3,000 miles of transmission lines and 240 substations located throughout the system's 40,000 square mile service area in eastern South Dakota and western Minnesota. East River has the following transmission facilities in Minnesota:

East River Electric Power Cooperative Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
164	46	0	0	0

7.6 Great River Energy

Background Information. Great River Energy (GRE) is a not-for-profit electric cooperative owned by 27 member distribution cooperatives. The organization generates and transmits electricity for those members, which are located from the outer-ring suburbs of the Twin Cities, up to the Arrowhead region of Minnesota and down to the farming communities in the southwest part of the state. GRE's largest distribution cooperative serves more than 112,000 member-consumers, while the smallest serves approximately 4,400. Collectively, GRE's member cooperatives distribute electricity to approximately 600,000 member accounts. GRE serves approximately 1.7 million people through its member-owned cooperatives and customers. The majority are served by 27 member-owners that collectively own GRE. In addition, GRE is part of MISO.

More information about Great River Energy is available at:

http://www.greatriverenergy.com

Contact Person: Gordon Pietsch
Director, Transmission Planning & Compliance Great River Energy
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Maple Grove, MN 55369-4718
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Fax: (763) 445-5050
e-mail: gpietsch@grenergy.com

Transmission Lines. Great River Energy has the following transmission lines:

GRE Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
3,086	642	524	146	0

7.7 ITC Midwest LLC

Background Information. ITC Midwest LLC (ITC Midwest) is an independent transmission company subsidiary of ITC Holdings Corp. ITC Midwest purchased the transmission assets of Interstate Power and Light, a subsidiary of Alliant Energy, in December 2007. The Commission approved the sale in an Order dated February 7, 2008 in MPUC Docket No. E001/PA-07-540.

ITC Midwest has headquarters in Cedar Rapids, Iowa, and ITC Holdings Corp. is headquartered in Novi, Michigan. ITC Midwest also has offices in Dubuque and Des Moines, Iowa, and in St. Paul, Minnesota. Minnesota warehouses are located in Albert Lea and Lakefield, Minnesota. In addition, ITC Midwest's transmission system is part of MISO.

More information about ITC Midwest and ITC Holdings Corp. can be found at:

http://www.itctransco.com

Contact Person:
Brian Drumm
Director, Regional Policy and RTO Engagement
ITC Holdings, LLC
27175 Energy Way
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e-mail: bdrumm@itctransco.com

Transmission Lines. The ITC Midwest system includes approximately 6,700 miles of transmission lines, operating at voltages from 34.5 kV to 345 kV in Minnesota, Iowa, Illinois, and Missouri.

ITC Midwest owns approximately 1,093 miles of transmission line in the state of Minnesota, operating at voltages of 345 kV, 161 kV and 69 kV. The total miles of these transmission lines are listed by voltage class in the table below.

ITC Midwest Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
668	310	0	115	0

7.8 L&O Power Cooperative

Background Information. L&O Power Cooperative (L&O), headquartered in Rock Rapids, Iowa, is a wholesale electric power supply and transmission cooperative serving three rural distribution electric cooperatives. These member cooperatives in turn serve more than 5,600 homes and businesses across Rock and Pipestone counties in southwest Minnesota, and Lyon and Osceola counties in northwest Iowa. Approximately 2,700 of the total 5,600 total consumers served are located in Minnesota.

Additional information about L&O is available at:

http://www.landopowercoop.com

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Engineering & Operations Manager
L&O Power Cooperative
P.O. Box 511
1302 S. Union Street Rock Rapids, IA 51246 Phone: (712) 472-2556
Fax: (712) 472-2710
e-mail: troy.metzger@dgr.com

Transmission Lines. L&O delivers wholesale electricity via approximately 183 miles of transmission lines and 16 substations located throughout the system's four county service area in southwestern Minnesota and northwestern Iowa. L&O has the following transmission facilities in Minnesota:

L&O Power Cooperative Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
43.17	8.32	0	0	0

7.9 Minnesota Power

Background Information. Minnesota Power (MP), a division of ALLETE, Inc., is an investor-owned utility headquartered in Duluth, Minnesota. Minnesota Power provides electricity in a 26,000 square-mile electric service area located in northeastern Minnesota. Minnesota Power serves approximately 150,000 residential and commercial customers, 15 municipalities, and some of the nation's largest industrial customers. Minnesota Power's transmission and distribution components include 8,742 miles of lines and 164 substations. Minnesota Power's transmission network is interconnected with the transmission grid to promote reliability and is part of MISO.

More information is available on the company's web page at:

http://www.mnpower.com

Contact Person: Christian Winter
Minnesota Power
30 West Superior Street Duluth, MN 55802
Phone: (218) 355-2908
e-mail: cwinter@mnpower.com

***Transmission Lines*.** The number of miles of transmission in Minnesota owned by Minnesota Power is shown in the following table.

Minnesota Power Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0.22	1,310.02	617.65	265.52	231.56

7.10 Minnkota Power Cooperative

Background Information. Minnkota Power Cooperative, Inc. (Minnkota or MPC) is a regional generation and transmission cooperative serving 11 member-owner distribution cooperatives in northwestern Minnesota and eastern North Dakota. Minnkota's service area is approximately 34,500 square miles over the two states. Minnkota is also the operating agent for the Northern Municipal Power Agency (NMPA), an association of 12 municipal utilities in the same service region. Together Minnkota and the NMPA comprise the Joint System and serve more than 151,000 consumers.

Additional information about Minnkota is available at:

http://www.minnkota.com

Contact Person:
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e-mail: kborboa@minnkota.com

Transmission Lines. The Joint System owns 1,429.52 miles of transmission line in Minnesota and 1,951.35 miles in North Dakota. The miles of Minnesota transmission lines are shown in the following table:

Joint System Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,008.38	153.20	267.94	0	0

7.11 Missouri River Energy Services

Background Information. Missouri River Energy Services (MRES) began in the early 1960s as an informal association of northwest Iowa municipalities with their own electric systems that decided to coordinate their efforts in negotiating the purchase of power and energy from the United States Bureau of Reclamation of the United States Department of the Interior (USBR). MRES was established as a body corporate and politic organized in 1965 under Chapter 28E of the Iowa Code and exists under the intergovernmental cooperation laws of the states of Iowa, Minnesota, North Dakota, and South Dakota. Municipalities in Minnesota, North Dakota and South Dakota subsequently joined MRES pursuant to compatible enabling legislation in each state.

MRES is comprised of 61 municipally owned electric utilities in the states of Iowa, Minnesota, North Dakota, and South Dakota. The MRES member cities' service territories roughly coincide with the boundaries of the respective incorporated cities. MRES has no retail load, and all of its firm sales are made to municipal or other wholesale utilities. MRES acts as an agent for the Western Minnesota Municipal Power Agency (WMMPA), which itself was incorporated as a municipal corporation and political subdivision of the State of Minnesota. WMMPA provides a means for its members to secure, by individual or joint action among themselves or by contract with other public or private entities within or outside the State of Minnesota, an adequate, economical and reliable supply of electric energy. Current membership in WMMPA consists of 24 municipalities located in Minnesota, each of which owns and operates a utility for the local distribution of electricity. In addition, MRES is part of MISO and the Southwest Power Pool (SPP).

More information about Missouri River Energy Services can be found at:

http://www.mrenergy.com

Contact Person:
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Missouri River Energy Services
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Sioux Falls, SD 57109-8920
Phone: (605) 330-6986
Fax: (605) 978-9396
e-mail: brian.zavesky@mrenergy.com

Transmission Lines. The number of miles of transmission in Minnesota owned by Missouri River Energy Services is shown in the following table.

Missouri River Energy Services Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
32.16	239.32	24.02	47	0

7.12 Northern States Power Company

Background Information. Northern States Power Company, a Minnesota corporation (NSP), is a public utility organized under the laws of the State of Minnesota and is a wholly-owned subsidiary of Xcel Energy Inc., a publicly-traded company listed on the Nasdaq Stock Market. NSP is headquartered in Minneapolis, Minnesota. Xcel Energy Inc.'s other utility subsidiaries are Northern States Power Company, a Wisconsin corporation (NSPW), headquartered in Eau Claire, Wisconsin, Public Service Company of Colorado, headquartered in Denver, Colorado, and Southwestern Public Service Company, headquartered in Amarillo, Texas. NSP provides electricity and natural gas to customers in a service territory that encompasses the Twin Cities, many mid-size and small towns throughout Minnesota, and also to portions of South Dakota and North Dakota. NSP and NSPW operate an integrated generation and transmission system (the NSP System). In addition, Northern States Power Company is part of MISO.

More information can be found on Xcel Energy's web page at:

0http://www.xcelenergy.com

Contact Person: Jason Standing
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414 Nicollet Mall
Minneapolis, MN 55401
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e-mail: jason.t.standing@xcelenergy.com

Transmission Lines. Northern States Power Company owns about 5,775 miles of transmission lines in Minnesota. The miles of Minnesota transmission lines are shown in the following table.

NSP Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,679.96	1,771.17	466.54	1,922.38	0

7.13 Otter Tail Power Company

Background Information. Otter Tail Power Company (OTP) is an investor-owned electric utility headquartered in Fergus Falls, Minnesota, and a subsidiary of Otter Tail Corporation (NASDAQ Global Select Market: OTTR). It provides electricity and energy services to more than 130,000 residential, commercial, and industrial customers in a service territory of 70,000 square miles that cover over 400 communities throughout Minnesota, South Dakota, and North Dakota, with approximately 61,100 customers in Minnesota. The company was originally incorporated in 1907, and first delivered electricity in 1909 from the Dayton Hollow Dam on the Otter Tail River. In addition, Otter Tail Power Company is part of MISO.

To learn more about Otter Tail Power Company visit www.otpco.com. To learn more about Otter Tail Corporation visit www.ottertail.com.

Contact Person:

Dylan Stupca
Manager, Delivery Planning
Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: (218) 739-8200
Fax: (218) 739-8442
e-mail: dstupca@otpco.com

Transmission Lines. OTP has the following transmission lines in Minnesota:

OTP Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
1,295.2	584.6	186.2	564.8	0

7.14 Rochester Public Utilities

Background Information. Rochester Public Utilities (RPU), a department of the City of Rochester, Minnesota, is the largest municipal utility in the state of Minnesota. RPU serves roughly 59,481 electric customers. In 1978, Rochester joined the Southern Minnesota Municipal Power Agency (SMMPA) with City Council approval. Initially, RPU was a full-requirements member with SMMPA controlling all of Rochester's electric power. Today, RPU is a partial requirements member of SMMPA and retains control over its own generating units. All of RPU's load and generation are serviced by MISO through its market function.

More information about Rochester Public Utilities is available at:

http://www.rpu.org/about

Contact Person: Scott Nickels
Director of Core Services
Rochester Public Utilities
4000 East River Road NE
Rochester, MN 55906
Phone: (507) 280-1585
Fax: (507) 280-1542
e-mail: snickels@rpu.org

Transmission Lines. RPU has the following transmission lines in Minnesota.

Rochester Public Utilities Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
0	42.42	0	0	0

7.15 Southern Minnesota Municipal Power Agency

Background Information. SMMPA is a not-for-profit municipal corporation and political subdivision of the State of Minnesota, headquartered in Rochester, Minnesota. SMMPA was created in 1977 and has seventeen municipally owned utilities as members, located predominantly in south-central and southeastern Minnesota. SMMPA serves approximately 112,000 retail customers. In addition, SMMPA is part of MISO.

More information about SMMPA is available at:

http://www.smmpa.com

Contact Person:
Seth Koneczny
Manager of Power Delivery
Southern Minnesota Municipal Power Agency
500 First Avenue Southwest
Rochester, MN 55902-6451
Phone: (507) 292-6456
e-mail: st.koneczny@smmpa.org

Transmission Lines. SMMPA has the following transmission lines in Minnesota:

SMMPA Transmission Lines

<100 kV	100-199 kV	200-299 kV	>300 kV	DC
149.84	135.48	17.09	0	0

8.0 Renewable Energy Standards

8.1 Introduction

Minn. Stat. § 216B.2425, subd. 7, states that in the Biennial Report the utilities shall address necessary transmission upgrades to support development of renewable energy resources required to meet the objectives set forth under Minn. Stat. § 216B.1691 (formerly the Renewable Energy Standards). In its May 30, 2008, Order approving the 2007 Biennial Report and Renewable Energy Standards Report, the Commission said, "Future biennial transmission projects reports shall incorporate and address transmission issues related to meeting the standards and milestones of the new renewable energy standards enacted at Minn. Laws 2007, ch. 3." By 2020, the utilities had largely met the then current Renewable Energy Standards and many had additionally announced voluntary renewable or clean energy standards that exceeded the statutory objectives. As a result, in its 2020 Order approving the 2019 Report, the Commission said the 2021 Report should include content similar to the 2019 Report, along with new information regarding additional clean-energy goals and related transmission needs. The 2021 Biennial Report included this information in Chapter 9 of that report.

In 2023, the Minnesota Legislature amended the objectives set forth in Minn. Stat. § 216B.1691 to include additional milestones for renewable energy as well as creating new carbon-free energy standards (CFES) (*see* Minn. Laws 2023, ch. 7). The statutory objectives now include:

	2025	2030	2035	2040
Renewable Energy	25%		55%	
Solar Energy*	1.5%	10%		
Carbon-free Energy		80% for public utilities; 60% for other electric utilities	90%	100%

**See* Minn. Stat. § 216B.1691, subd. 2f for additional detail relevant to the solar energy standards. For example, the 10% solar energy target by 2030 is established as a goal, rather than a requirement, and the legislation includes several other targets for smaller-scale solar energy.

In this Report, similar to prior reports, the utilities are reporting on their best estimates for the amounts of renewable generation required in future years and the efforts under way to ensure adequate transmission will be available to transmit that energy to the necessary market areas. A Gap Analysis is provided to illustrate the amount of renewable generation already available and the amounts required in the future to meet the standard. The narrative in this chapter is similar in many respects to the narrative and explanations provided in the 2021 Report, but all figures and charts and tables have been updated to reflect the 2023 legislation. As discussed more fully below, a gap analysis has not been provided for the carbon-free energy standards, as the Commission is continuing to evaluate and provide guidance on how this new standard will be implemented.

8.2 Reporting Utilities

It should be pointed out, as was done in previous reports, the utilities required to submit the Biennial Transmission Projects Report are not identical to those required to meet the Renewable Energy Standards. The information in this chapter reflects the work of all the utilities required to meet RES milestones, regardless of whether they own transmission lines and are required to participate in the Biennial Report. A list of those utilities participating in the Biennial Transmission Projects Report can be found in Chapter 2.0. The utilities participating in this part of the 2023 Biennial Report on renewable energy are the following.

Investor-owned Utilities
- Minnesota Power
- Northern States Power Company
- Otter Tail Power Company

Generation and Transmission Cooperative Electric Associations
- Basin Electric Power Cooperative
- Dairyland Power Cooperative
- East River Electric Power Cooperative
- Great River Energy
- L&O Power Cooperative
- Minnkota Power Cooperative

Municipal Power Agencies
- Central Minnesota Municipal Power Agency
- Minnesota Municipal Power Agency
- Southern Minnesota Municipal Power Agency
- Western Minnesota Municipal Power Agency/Missouri River Energy Services

Power District
- Heartland Consumers Power District

8.3 Compliance Summary

Minnesota utilities continue to increase the size and expand the diversity of their renewable portfolios. The table provided in the introduction details the RES and SES obligations Minnesota utilities are working to achieve. Overall, Minnesota utilities have a 2022 collective obligation of 24.5% RES and 1.5% SES, as a percent of retail sales. The most recent reporting is summarized by the Minnesota Department of Commerce in Docket Nos. E999/PR-22-12, E999/M-22-85, E999/PR-02-1240, filed 2/1/2023. All utilities have satisfied their respective compliance requirements and expect to continue to achieve and maintain all compliance requirements into the future. All utilities continue to plan for the addition of increased renewable generation. The utilities have provided a Gap Analysis regarding compliance with the upcoming 2025 Solar Energy Standard in Section 8.6 as well.

8.4 Gap Analysis

A Gap Analysis is an estimate of how many more megawatts of renewable generating capacity a utility expects it will require beyond that which is presently available to obtain the required amount of renewable energy. A Gap Analysis is not an exercise intended to verify the validity of forecasted energy sales and associated capacity needs. It is done for transmission planning purposes only. This is the ninth time the utilities have prepared a Gap Analysis; a Gap Analysis was also prepared for the 2007, 2009, 2011, 2013, 2015, 2017, 2019 and 2021 Biennial Reports.

8.5 Base Capacity and RES/REO Forecast

The chart below presents a system-wide overview of existing capacity in 2025 (used as a base figure throughout the various milestone periods) and forecasted renewable capacity requirements to meet Minnesota RES as well as non-Minnesota renewable energy standards or renewable energy objectives ("RES/REO"). Each utility provided its own forecast of Minnesota RES and non-Minnesota RES/REO renewable energy obligations and converted such estimates into capacity based on their own mix of renewable resources (e.g., wind, biomass, hydropower, solar) using the most appropriate capacity factors unique to their specific generating resources. It is important to note that the data presented in this Report represents MTO members' efforts to report on metrics that are part of a regulatory construct that is evolving as a result of the 2023 legislation. The Commission is currently in the process of issuing guidance to electric utilities on implementation of the RES and SES requirements in Docket No. E999-CI-23-151. The Commission reviewed this matter during its October 19, 2023, agenda meeting, focusing on initial guidance. The Commission's written order is forthcoming. Accordingly, MTO utilities remain in the planning stages related to compliance with the Minnesota Legislature's 2023 amendments.[21] To the extent that there are relevant updates informing implementation of these standards, MTO utilities are committed to coordinating with stakeholders if additional information is requested.

[21] Because MTO utilities are waiting for additional guidance for how to implement the carbon-free standard, this metric is not captured in this Report. MTO utilities will provide this information in the next Biennial report and will work with stakeholders if additional information in required in this proceeding.

The following Table 1 shows a more specific breakdown of each utility's Minnesota RES and non-Minnesota RES/REO needed capacity forecast.

Table 1. MN & Non-MN RES Forecast (MW)[1]

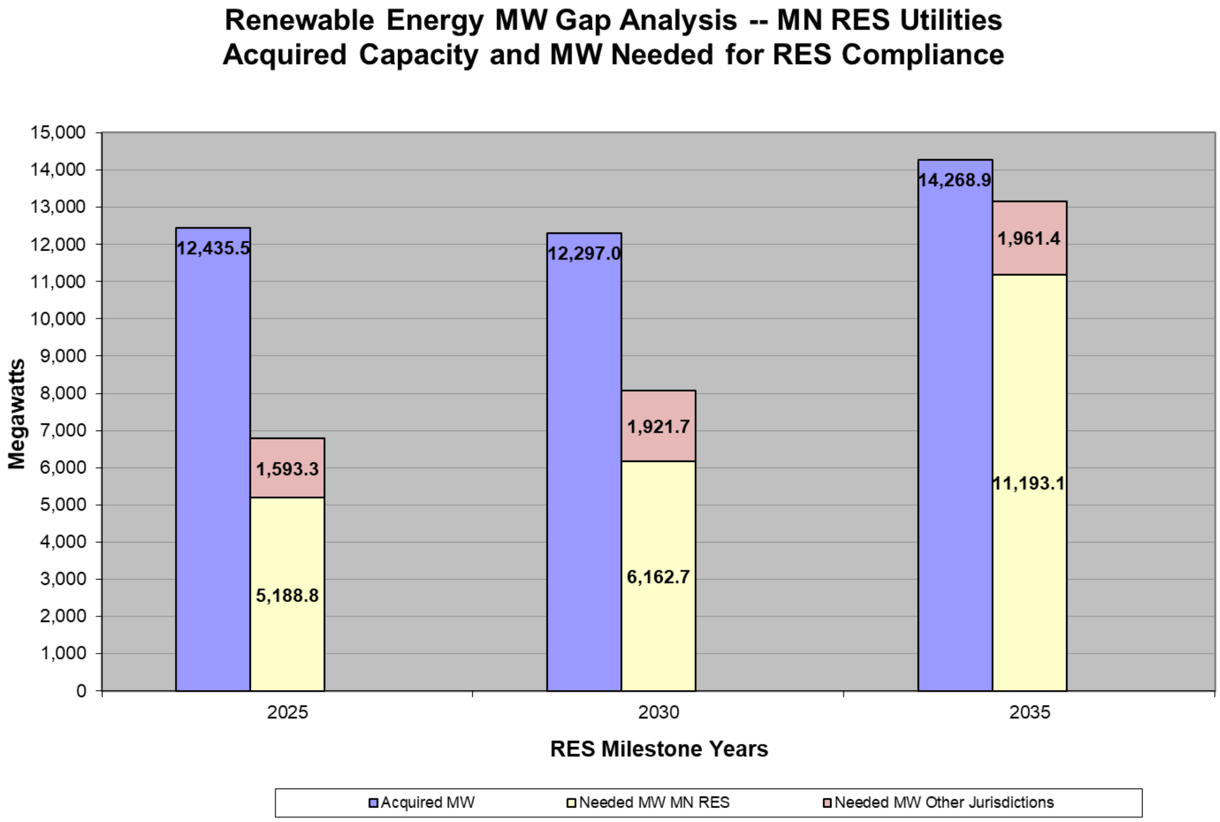
Utility	2025		2030		2035	
	MN RES	Non-MN RES	MN RES	Non-MN RES	MN RES	Non-MN RES
Basin Electric[2]	199.6	917.6	223.3	1,194.7	249.9	1,285.8
CMMPA	26.0	-	35.0	-	52.0	-
Dairyland	86.0	81.0	106.0	82.0	239.0	84.0
GRE	727.0	8.0	742.0	8.0	1,665.0	8.0
Heartland	9.2	5.5	5.3	4.9	10.0	5.1
Minnkota	42.5	-	44.0	-	99.6	-
MMPA	136.1	-	170.6	-	417.1	-
MN Power	482.4	24.0	622.1	25.4	1,366.6	26.9
Otter Tail	151.1	87.2	156.2	87.1	339.5	86.8
SMMPA	224.0	-	100.0	-	200.0	-
WMMPA/MRES	226.7	24.7	576.5	25.2	897.9	25.8
Xcel Energy	2,878.2	445.3	3,381.7	494.5	5,656.5	439.0
TOTAL	5,188.8	1,593.32	6,162.7	1,921.7	11,193.1	1,961.4

Note:

1. Capacity factor assumptions established by each utility
2. These quantities include Basin Electric Power Cooperative, L&O Power Cooperative, and East River Electric Power Cooperative.

8.5.1 RES Capacity Acquired and Net RES/REO Need

The following chart represents the total renewable capacity system-wide that will be acquired and lost between 2025 and 2035, as well as the total Minnesota RES and non-Minnesota RES/REO needs between 2025 and 2035. Capacity losses are attributable to the expiration of various power purchase agreements for renewable energy generation, and these losses are implicitly incorporated into the datasets provided.



As can be seen, the Minnesota RES utilities have sufficient capacity acquired to meet the Minnesota RES needs through 2035. When considering the RES needs, including other jurisdictions outside of Minnesota, the Minnesota RES utilities have enough capacity to meet RES/REO needs beyond 2025. In addition, some utilities with less than sufficient capacity to meet the Minnesota RES need may use renewable energy credits to fulfill their requirement.

Focusing back on just Minnesota RES needs, Table 2 below provides a more specific breakdown of each utility's forecast.

Table 2. RES Capacity Acquired & Net MN RES Capacity Need (MW)[1]

Utility	2025		2030		2035	
	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net
Basin Electric[2]	2,283.1	-	2,161.1	-	2,073.1	-
CMMPA	32.0	-	32.0	3.0	32.0	20.0
Dairyland	414.3	-	388.5	-	296.9	26.1
GRE	2,040.0	-	2,040.0	-	1,840.0	-
Heartland	41.0	-	41.0	-	41.0	-
Minnkota	192.4	-	192.4	-	192.4	-
MMPA[3]	451.8	-	827.0	-	1,142.4	-
MN Power	1,053.8	-	1,453.8	-	1,453.8	-
Otter Tail	400.0	-	600.0	-	600.0	-
SMMPA	224.0	-	107.0	-	107.0	93.0
WMMPA/MRES	540.8	-	540.8	55.4	503.4	433.3
Xcel Energy	4,762.4	-	3,913.4	-	5,986.9	108.5
TOTAL[4]	12,435.5	-	12,297.0	58.4	14,268.9	680.9

Note:
1. Capacity factor assumptions established by each utility
2. These quantities include Basin Electric Power Cooperative, L&O Power Cooperative, and East River Electric Power Cooperative.
3. RES Capacity Acquired includes banked inventory from previous years (banking allows for year of generation plus four years).
4. Some Utilities with less than sufficient capacity to meet the MN RES need may use renewable energy credits to fulfill their requirement.

Note that the "Needed MW MN RES" bar in the bar chart in this section represents the total level of RES megawatts required (or need) in Minnesota. Conversely, the column in Table 2 labeled "MN RES Net" represents the additional RES capacity presently identified to meet RES megawatts required. To the extent there is a shortfall, or "gap," between MN RES megawatts required and the additional RES capacity identified points to the likelihood that some utilities will seek additional renewable capacity. Alternatively, some utilities may use renewable energy credits to fulfill their RES requirements.

8.6 Solar Energy Standard

In 2013, the Minnesota Legislature established a separate solar standard for public utilities, effective by the end of 2020.[22] That statute requires public utilities subject to the SES to report to the Commission on July 1, 2014, and each July thereafter, on progress towards achieving the 1.5 percent solar energy standard.

Chapter 8 of the Biennial Report discusses utilities' compliance with Minnesota Renewable Energy Standards. Additionally, a brief summary regarding the status of compliance with the 2025 Solar Energy Standard (SES) is included below. Utilities file annual reports to demonstrate compliance with the SES on June 1 of each year as required by the statute and directed by the Commission.

[22] Minn. Laws 2013, Ch. 85, § 3, codified at Minn. Stat. § 216B.1691, subd. 2f (Solar Energy Standard or SES).

Table 3 shows a more specific breakdown of each utility's Minnesota SES and non-Minnesota SES megawatts required capacity forecast.

Table 3. MN & Non-MN SES Forecast (MW)						
Utility	2025		2030		2035	
	MN SES	Non-MN SES	MN SES	Non-MN SES	MN SES	Non-MN SES
MN Power	23.9	-	23.5	-	24.1	-
Otter Tail	22.7	-	23.4	-	23.2	-
Xcel Energy	238.0	-	256.4	-	278.2	-
TOTAL	284.6	-	303.4	-	325.4	-

Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES.

Additionally, Table 4 below provides SES Utilities' planned level of solar capacity additions.

Table 4. SES Capacity Acquired & Net MN SES Capacity Need (MW)						
Utility	2025		2030		2035	
	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net
Dairyland	176.3	-	176.3	-	176.3	-
MN Power	33.4	-	333.4	-	333.4	-
Otter Tail	49.9	-	249.9	-	249.9	-
SMMPA	5.0	-	5.0	-	5.0	-
Xcel Energy	1,245.3	-	3,315.1	-	4,881.3	-
TOTAL	1,509.9	-	4,079.7	-	5,645.8	-

Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES.

8.7 Gap Analysis Summary

As demonstrated by the data provided in this section, MTO utilities continue to make tangible progress to satisfy RES and SES requirements. Though generally encouraged by this progress, MTO utilities emphasize that continuing progress is also closely linked to the ability to procure the necessary transmission resources, which is analyzed throughout this Report. Further, MTO utilities continue to analyze how compliance with the CFES may impact transmission needs and anticipate providing additional information in the next biennial report in 2025.

9.0 Outages & Congestion

9.1 Introduction

In the Commission's June 29, 2022 Order Accepting Report, the MTO was ordered to include the information required to be filed in the 2021 Report in their 2023 Report as well as the following:

1) *Expected sustained HVTL or generation planned outages;*
2) *Whether those outages are anticipated to have new or incremental congestion; and*
3) *Whether those outages are anticipated to contribute to sustained incremental congestion.*

9.2 System Changes and Upcoming Projects Addressing Congestion Relief

MTO is cognizant of congestion issues, and MTO utilities have taken numerous actions to alleviate congestion throughout the state. MTO utilities' efforts include the following:

- NSP System Upgrades: Xcel Energy conducted an internal analysis to determine projects designed to remove system limiters on congested lines in southwest Minnesota. These projects typically addressed substation equipment and sag limits.[23]
- Xcel Energy initiated an out-of-cycle request for MISO for completing the second 345 kV circuit from Brookings Co-Lyon Co and Helena-Hampton for the existing CAPX Brookings-TC facility.
- Market congestion projects including the:
    - Forman 230/115 kV transformer upgrade;
    - High Bridge-Rogers Lake 115 kV line upgrade;
    - Fergus Falls-Morris 115 kV line upgrades;
    - Hoot Lake 115 kV substation upgrades;
    - Canby-Granite Falls 115 kV upgrade;
    - Huntley-Wilmarth 345 kV (Market Efficiency Project);
    - CapX 2020 Brookings 2nd 345 kV addition;
    - CapX 2020 Helena 2nd 345 kV addition;
    - Hoot Lake-Fergus Falls 115 kV upgrades;
    - Morris-Grant County 115 kV upgrades;
    - Franklin-Ft Ridgely-Swan Lake 115 kV upgrades;
    - Swan Lake-Wilmarth 115 kV upgrade;
    - Red Rock-Raptor 115 kV upgrade;
    - Johnson Jct.-Morris 115 kV Ambient Adjusted Rating (AAR);
    - Inman-Elmo-Parkers Prairie-Miltona-Alexandria 115 kV (AAR);

[23] For additional information on MTO utilities' congestion initiatives, *see* MTO Response to Commission Staff Information Request No. 4 (May 12, 2023) (eDocket No. 20236-197008-02). In addition to the Commission's directive to further analyze outages and congestion, Commission Staff also sought information on MTO's work to alleviate current congestion issues in southwest Minnesota which are resulting in curtailment of certain resources. MTO's response is public and available on eDockets.

- Mud Lake-Benton 230 kV (AAR);
- Wakefield-St. Cloud 115 kV upgrade;
- Pleasant Valley-Byron 161 kV upgrade;
- Big Stone-Blair 230 kV upgrade;
- Coon Creek-Terminal 345 kV upgrade;
- Coon Creek-Kohlman Lake 345 kV upgrade;
- Forbes-Iron Range 230 kV (AAR);
- Blackberry-Riverton 230 kV (AAR).[24]

- Transmission System Reconfiguration: Xcel Energy implemented a process to study reconfiguration requests from outside entities. These requests are looked at to determine effectiveness, duration, and impact to the transmission system. Reliability is the primary determinant of whether a reconfiguration request is approved.
- MTO worked with MISO and other stakeholders to change how ERIS impacts are identified in the MISO DPP process. The current distribution factor (DF) is 20% and the proposal is to reduce the DF to 10% to ensure that more generation is not interconnected without necessary transmission facilities being built to deliver the energy to the system.
- Xcel Energy initiated two projects, MN Energy Connection and King Connection, which are designed to utilize existing transmission access rights. The MISO interconnection queue has a significant number of new interconnection requests currently seeking to connect to a system that is already very congested. Reusing existing transmission rights through the MN Energy Connection and King Connection Projects allows Xcel Energy to interconnect additional MWs through its existing transmission rights, avoiding long delays often related to MISO queue interconnection studies.
- Grid North Partners' Tech Team is working with MTO to identify simple system upgrades (less than $1 million cost) to improve transmission line ratings.
- MISO LRTP Tranche 1 projects in Minnesota utilize existing 345 kV second circuit capabilities where possible, which will increase the overall ability to transfer power across the system.
- Xcel Energy initiated an internal study process to determine any transmission system reconfigurations on the underlying transmission system able to have a positive impact on the bulk transmission system and congestion. Xcel Energy Transmission Operations factor both system reliability, curtailment, and congestion when considering/scheduling transmission outages.
- Xcel Energy monitors congestion and curtailment on a weekly basis to find new issues as they arise and determine whether a permanent solution is warranted or if the congestion is related to temporary system conditions.
- GRE is examining factors that have led to increased market congestion, where congestion is occurring, and what can be done to address congestion. GRE is undertaking this congestion effort with the goal of positioning the grid for operational reliability and market efficiency.

[24] For more information, *see* Congestion-projects-press-release-Grid-North-Partners-2023.pdf (gridnorthpartners.com).

These examples represent MTO members' commitment to actively addressing congestion issues impacting the grid statewide. Going forward, MTO will continue collaborating with other stakeholders to address congestion issues.

9.3 Planned Outages

As part of the 2021 Biennial Plan, the Commission ordered MTO to include a congestion study in future biennial plans. In compliance with the Commission's directive, MTO prepared the Biennial Transmission Project Report – Congestion Study (attached as Appendix B). The Congestion Study includes information on the following: (1) expected or sustained HVTL or generation planned outages; (2) whether those outages are anticipated to have new or incremental congestion; and (3) whether those outages are anticipated to contribute to sustained or incremental congestion. The Congestion Study analyzed congestion and outages over the next four quarters (Q4 2023 to Q3 2024), comparing market prices and congestion between a benchmark simulation and planned outages simulations using the Control Room Operating Window (CROW). The Congestion Study reveals that there are outages in each quarter that significantly impact average Locational Marginal Prices (LMPs) in the simulations. Additional details can be found in the attached Congestion Study.

9.4 Potential Congestion Based on Future Facility Additions

Notwithstanding the MTO's efforts described in Section 9.2, MTO believes that there is the potential for continued congestion issues over the next decade. The grid continues to evolve. As detailed in previous sections of this Report, Minnesota (and other states in MISO) is in the midst of transitioning to carbon-free/renewable energy, and the addition of new renewable generation requires additional transmission resources. Efforts to bring new transmission resources are underway; however, the planning, approval, and construction processes take time. For example, in 2022, MISO's Board of Directors approved Tranche 1 of the LRTP. Tranche 1 includes $10.3 billion in new transmission projects, and it is the first of four tranches designed to provide reliable and economic energy delivery to address future reliability needs.[25] While LRTP Tranche 1 encompasses 18 new transmission projects and more than 2,000 miles of transmission lines, the expected in-service dates are not until the 2028-2030 timeframe. Because the availability of these resources is years away, there is the potential for continued congestion issues. MTO continues to look for creative solutions to minimize system congestion while waiting for additional transmission resources to come online.

[25] MISO Long Range Transmission Planning – Reliability Imperative available at https://www.misoenergy.org/planning/transmission-planning/long-range-transmission-planning/#:~:text=Long%20Range%20Transmission%20Planning%20%28LRTP%29%20is%20a%20key,-%20reliably%20and%20at%20the%20lowest%20possible%20cost.

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Appendix A

Appendix A contains the pertinent pages from the 2022 NERC Long Term Reliability Assessment. The entire assessment along with previous assessments can be found here:

Reliability Assessments (nerc.com)

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2022 Long-Term Reliability Assessment

December 2022

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.

MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area (see **Regional Assessments**) basis to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee, at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2022 about known system changes with updates incorporated prior to publication. This *2022 LTRA* assessment period includes projections for 2023–2032; however, some figures and tables examine data and information for the 2022 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories**. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

Assumptions

In this *2022 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2022. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

Introduction

This *2022 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. This *2022 LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

The findings in this 2022 LTRA are vitally important to understand the reliability risks to the North American BPS as it is currently planned and as it is being shaped by government policies, regulations, consumer preferences, and economic factors. Energy systems and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee—and design for—their future states. This report contains future energy sufficiency metrics that serve as guideposts for the reliability of the North American electric grid on its current trajectory. It also describes the relevant trends that are propelling the grid's transformation and have the potential to alter the ability of the BPS to service the energy needs of communities and industries in North America.

Projected Area Supply Shortfalls

The **Resource Capacity and Energy Risk Assessment** section of this report identifies potential electricity supply shortfalls under normal and more severe conditions. NERC's assessment assumes the latest demand forecasts, resource levels, and area transfer commitments as well as accounts for expected generator retirements, resource additions, and demand-side resources.

High Risk Areas[7]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, areas shown in red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10 year load-loss metric during periods of the assessment horizon. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. The following is a summary of the high-risk areas (details are discussed in later sections of this *2022 LTRA*):

- **In the Midcontinent Independent System Operator (MISO)** area, the previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.
- **NPCC-Ontario** also continues to project a reserve margin shortfall in 2025 and beyond. The capacity deficit of 1,700 MW is driven by generation retirements and lengthy planned outages at nuclear units undergoing refurbishment.
- Resource additions in the **California/Mexico (CA/MX) part of WECC** are alleviating capacity risks, but energy risks persist. Planned reserve margins meet annual reserve margin targets for the duration of the 10-year horizon. However, overall variability in both the resource mix and demand profile contributes to shortfall risk periods, mainly in summer months around sunset, when expected supplies are not sufficient to meet the demand.

Elevated Risk Areas[8]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme weather impacts the system by increasing electricity demand and forcing generation and other resources off-line. While a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, **long-duration weather events increase the risk of electricity supply shortfalls**.

In many parts of North America, peak electricity demand is increasing, and forecasting demand and its response to extreme temperatures and abnormal weather is increasingly uncertain. Electrification and distributed energy resource (DER) trends can be expected to further contribute to demand growth and sensitivity to weather patterns. Specifically, electrification of residential heating requires the system to serve especially high demand on especially cold days.

[7] An assessment area is deemed to be "high risk" by failing to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1 day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[8] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

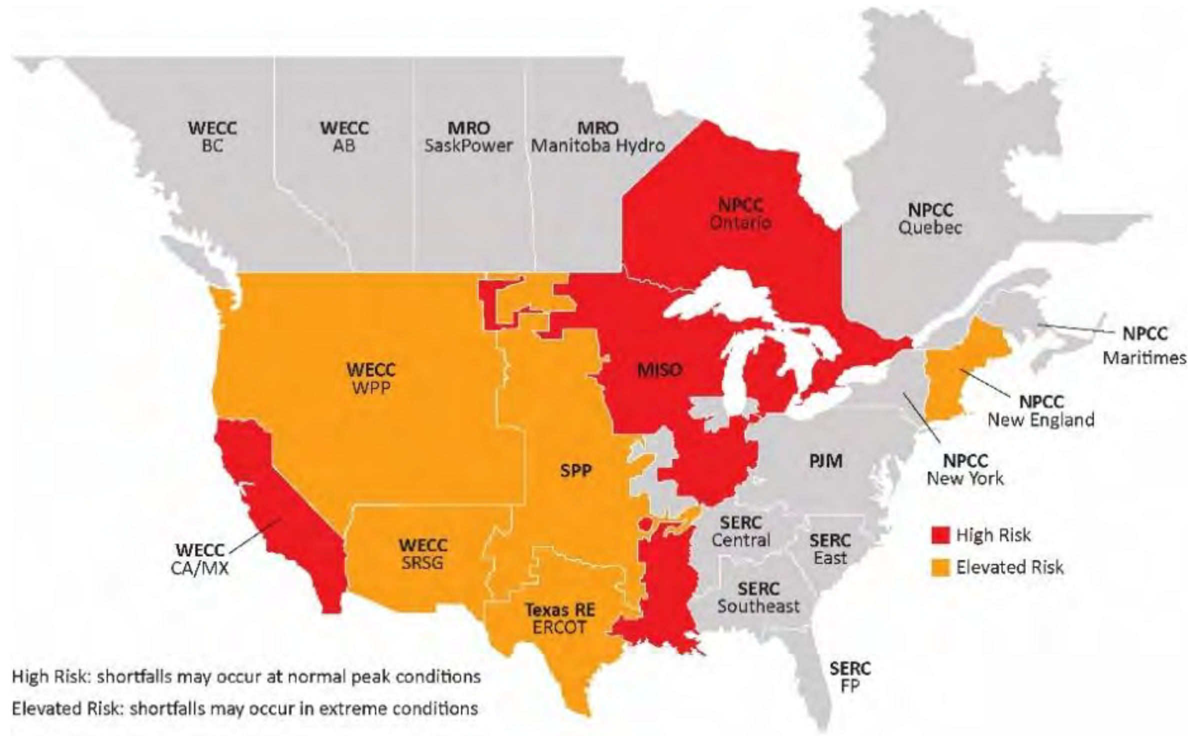

Figure 1: Risk Area Summary 2023–2027

Areas in orange (elevated risk) in Figure 1 meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- All three assessment areas in the **U.S. West—CA/MX, Western Power Pool (WPP), and the Southwest Reserve Sharing Group (SRSG)—**have increasing demand and resource mix variability. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.
- Reliability during extreme winter weather remains a concern in **Texas**. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. A high number of forced outages of the thermal and wind generation fleet have been an issue in severe winter weather. Improved generator availability resulting from winter preparedness programs and reforms implemented by Texas regulators, ERCOT, and Generator Owners since February 2021 are expected to reduce the risk that electricity supplies will be insufficient during a severe winter storm.
- **SPP** is exposed to energy risks in ways that are similar to both Texas and the U.S. West. Severe weather in SPP is likely to cause high generator outages and poses a risk to natural gas fuel supplies. In addition, the penetration of wind generation makes the resource mix variable and exposed to insufficient energy during low wind periods.
- In **New England**, limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions to generators. Liquefied natural gas facilities and sufficient generators with stored backup fuels are critical to electric reliability.

Continuing Resource Mix Changes and Implications for Reliability

This *2022 LTRA* contains the latest industry projections for generation and other resources, including DR, DERs, and the resulting **Continuing Resource Mix Changes and Implications for Reliability** found at this link. Highlights of these trends and the implications for reliability include the following:

- **Reliable Interconnection of Inverter-Based Resources:** Reliably integrating inverter-based resources (IBR), which include most solar and wind generation, onto the grid is paramount. Over 70% of the new generation in development for connecting to the BPS over the next 10 years is solar, wind, and hybrid (a generating source combined with a battery).
- **Accommodating Large Amounts of Distributed Energy Resources:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Solar photovoltaic (PV) DERs are projected to reach over 80 GW by the end of this 10-year assessment, a 25% increase in projection since the *2021 LTRA*; a total of 12 assessment areas project to double the amount of DERs in their areas by 2032.

- **Managing the Pace of Generation Retirements:** As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.
- **Maintaining Essential Reliability Services:** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.[9] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services. As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

Trends and Implications for Reliability

Demand Trends and Implications as well as **Transmission Development Trends and Implications** found at these links affect long-term reliability and the sufficiency of electricity supplies. Several key insights emerge from the latest industry data:

- **Peak Demand and Energy Growth:** Projected growth rates of electricity peak demand and energy in North America are increasing for the first time in recent years. Government policies for the adoption of electric vehicles (EVs) and other energy transition programs have the potential to significantly influence demand. Demand-side management programs, including conservation, EE, and DR continue to offset demand and contribute to load management. Where rapid transition is proposed, early alignment and coordination on energy and infrastructure are needed.
- **Insufficient Transmission for Large Power Transfers:** Transmission development projections remain near the averages of the past five NERC LTRAs. There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the *2021 LTRA* projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources.
- **Emerging Electrification Challenges:** Several emerging issues and trends have the potential to impact future long-term projections of demand and resources. In addition to EV and electrification issues, cryptocurrency mining may have a notable impact on demand and resources in some areas. Resource development may be significantly altered by supply chain issues and differ from projections used in this *2022 LTRA*. Notable emerging issues and their potential implications are discussed in this report.

Conclusions and Recommendations

The energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues. General actions for industry and policymakers to address the reliability risks described in this *2022 LTRA* include the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services
- Include extreme weather scenarios in resource and system planning
- Address IBR performance and grid integration issues
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure

Specific *LTRA* recommendations are provided on the following page and in the appropriate sections of this report.

[9] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Reducing the Risk of Insufficient Energy

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios for resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. In areas with a high dependence on VERs and natural-gas-fired generation, Prospective Reserve Margins (PRM) are not sufficient for measuring resource adequacy:

- Industry and regulators should conduct all-hours energy availability analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs.
- The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons.
- State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
- Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.
- Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections.

Planning and Adapting for IBRs and DERs

IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused a sudden loss of generation resources over wide areas in some cases. As areas become more reliant on IBRs for their electricity generation, it is critically important to reduce risks from IBR performance issues. Likewise, explosive growth in DERs underscores the need to incorporate them into system planning:

- The ERO and Industry should take steps to ensure that IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document to address IBR performance issues that illustrates current and future work to mitigate emerging risks in this area.[10] Regulators, industry-standards-setting organizations, trade forums, and manufacturers each have a role to play to address IBR performance issues.
- Industry should increase its focus on the technical needs for the BPS to reliably operate with increased amounts of DERs. Growth promises both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures

Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure:

- ERO and Industry planners should enhance guidelines for assessing and reducing risks through system and resource planning studies and develop appropriate Reliability Standards requirements to ensure corrective actions are put in place.
- Regulators and other energy stakeholders must also take steps to promote coordination on interdependencies. The forum convened by the North American Energy Standards Board is one such important action that should be broadly supported.[11]

[10] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

[11] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

Capacity and Energy Assessment

Resource Capacity and Energy Risk Assessment

NERC is using two approaches in this *LTRA* to assess future resource capacity and energy risk:

- Comparing the margin between projected resources and peak demand, or reserve margin, to a reference margin level (RML) that represents the accepted level of risk based on a probability-based loss of load analysis
- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over *all* hours to identify high risk periods and energy constraints. Loss-of-load hours (LOLH) and expected unserved energy (EUE) from NERC's biennial Probabilistic Assessment (ProbA) are used to identify risk levels. LOLH greater than two hours and EUE greater than 0.2% of total energy is considered high risk for the purposes of this LTRA.

See the **Demand Assumptions and Resource Categories** for further details on these approaches. Supplemental tables and figures throughout this *LTRA* as well as assessment area dashboards (see **Regional Assessments**) provide resource capacity and energy risk assessment results for all areas.

Finding: Parts of the North American BPS face resource capacity or energy risks as early as the summer of 2023 (**Figure 1**). Capacity deficits, where they are projected, are largely the result of generator retirements that have yet to be replaced. While some areas have sufficient capacity resources, energy limitations and unavailable generation during certain conditions (e.g., low wind, extreme and prolonged cold weather) can result in the inability to serve all firm demand.

Future Capacity Shortfall in MISO

Anticipated reserves fall below the RML in the MISO assessment area beginning in the summer of 2023—one year earlier than reported in the *2021 LTRA* and two years earlier than reported in the *2020 LTRA*. Resources below the RML indicate that the area lacks adequate resources to limit load loss events to less than 1-day-in-10 years, an established resource planning criterion. The 1,300 MW shortfall that is projected for next summer follows the retirement of 5,900 MW of coal-fired and natural gas generation since 2021. Anticipated resources for the 2023 summer include 6,600 MW of planned (Tier 1) resources made up of 56% solar, 37% natural gas, and 7% wind. MISO's anticipated reserve margins (ARM) and PRMs for the next five years are in **Figure 2**.

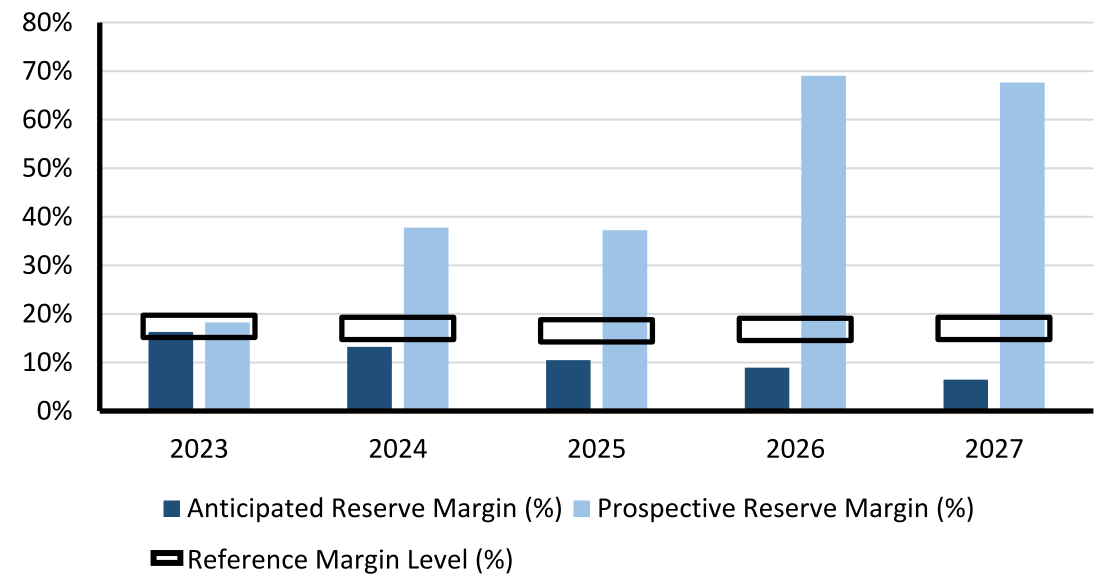

Figure 2: MISO Five-Year Projected Reserves (ARM and PRM)

Future Energy Risks in MISO

Results of the biennial ProbA conducted as part of this year's *LTRA* (2022 ProbA) confirm LOLH for 2024 are expected to increase from less than 0.1 hours per year to approaching one hour per year. Most risk occurs in June through August, corresponding to the months during which demand in MISO peaks. The ProbA also reveals risk periods in September and October when seasonal planned outages overlap with high demand. Another risk period is associated with winter, when extreme cold temperatures can push demand higher than normal in the morning and evening hours.

Future Capacity Shortfall in NPCC-Ontario

The ARMs in NPCC-Ontario fall below the RML in 2025 and beyond (see **Figure 3**). Anticipated shortfalls of about 1,700 MW are forecast for 2025 and 2026. As reported in the *2021 LTRA*, the main drivers for Ontario's projected shortfall are planned retirements and lengthy outages for nuclear units undergoing refurbishment. In September 2022, Ontario's Ministry of Energy announced that it was supporting a plan by Ontario Power Generation to extend operation of Pickering Nuclear Generating Station beyond its planned retirement in 2025 through September 2026. If approval is received from the Canadian Nuclear Safety Commission, this extension would reduce the potential capacity shortfall in 2026 described in the *2021 LTRA*. The ARM in **Figure 3** is calculated with an assumed retirement of Pickering units in late 2026.

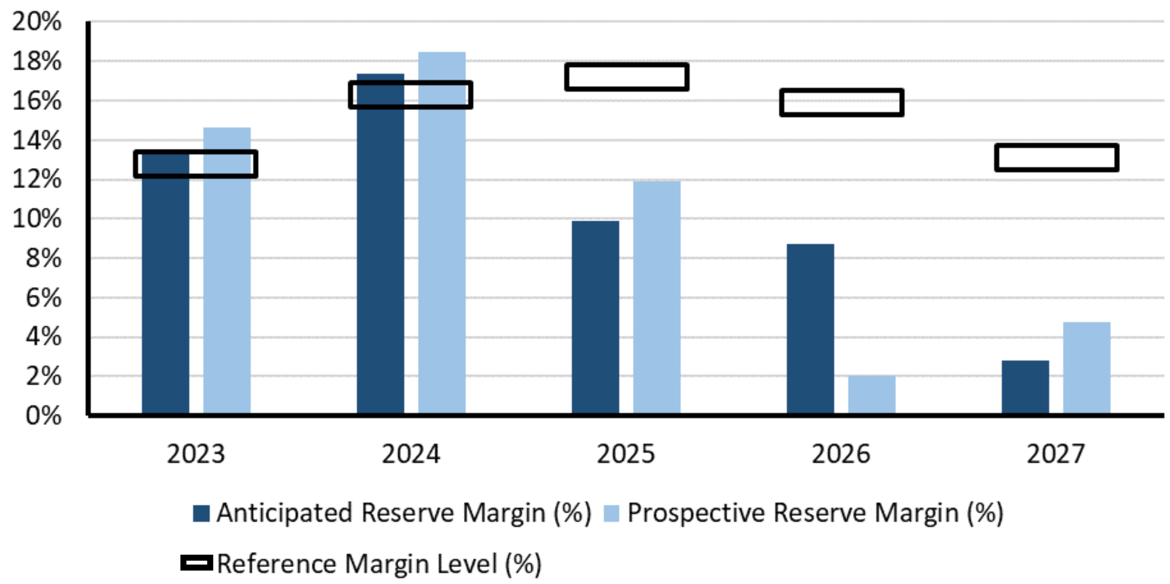

Figure 3: NPCC-Ontario Five-year Projected Reserves (ARM and PRM)

In order to address these emerging resource adequacy needs, the Independent Electricity System Operator's (IESO) established a Resource Adequacy Framework in 2021 to provide a flexible and cost-effective approach for competitively securing resources.[12] The Resource Adequacy Framework sets out a multi-pronged approach to cumulatively address needs over varying time frames with the annual acquisition report specifying the mechanisms and targets that will be used to meet the needs. In addition to supporting the Pickering Nuclear Generating Station extension, Ontario's Ministry of Energy also directed the IESO to obtain 4,000 MW of new capacity through three separate procurements. The IESO also announced new energy efficiency programs targeting needs in 2025–2027.

Energy Risks in U.S. Western Interconnection

Throughout the U.S. assessment areas in WECC, both demand and resource variability are increasing, and the challenges they present are accelerating. CA/MX, SRSG, and WPP show hours at risk of load loss over the next five years despite having adequate capacity for the peak demand hour.

Energy Risks in WECC-CA/MX

Resource additions in WECC-CA/MX are alleviating capacity risks, but energy risks persist. In the *2021 LTRA*, a capacity shortfall was projected beginning in 2026. Now the ARM in 2026 has risen to over 22% and is above the RML throughout the 2023–2027 period (see **Figure 4**). This indicates that the anticipated resources are sufficient to meet peak demand of a normal summer. However, the area remains dependent on electricity imports to manage periods of extreme electricity demand or low resource output. Heat events spanning a wide area that reduce the availability of electricity imports into California are likely to continue to raise concerns and be an area of risk that could induce energy shortfalls in the near term.

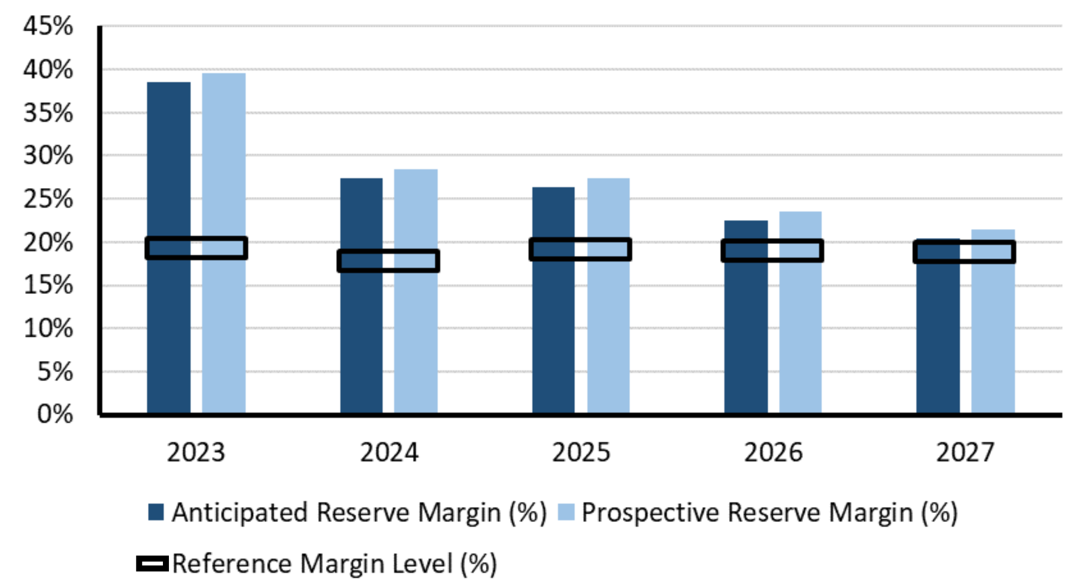

Figure 4: WECC-CA/MX Five-Year Projected Reserves (ARM and PRM)

[12] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Resource-Adequacy-Framework

Added capacity in California has resulted in improved ProbA metrics and reduced energy risks; however, calculated load loss hours and unserved energy risks remain high. Since the 2020 ProbA, LOLH for 2024 has decreased from 56 hours per year to less than 1 hour per year, but projections for 2026 increase to nearly 10 hours per year. **Figure 5** shows a summary of CA/MX monthly energy shortfall risks for 2024 from the ProbA. Risk periods are spread across the months of July–September, coinciding with some of the warmest temperatures and potentially volatile electricity demand. Output from solar begins to fall off earlier in the day during the late summer months as well, and hydro output is lower from seasonal water flow patterns.

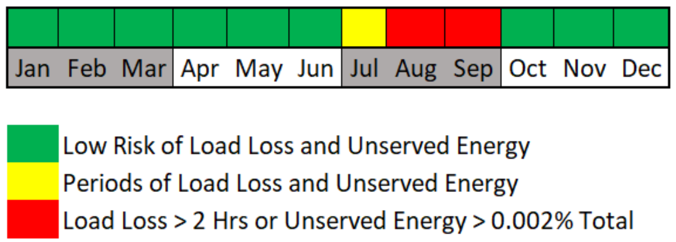

Figure 5: 2024 Monthly Energy Risk Summary for WECC-CA/MX

Examining the projected resource performance for the full 24 hours of the day that the peak risk hour occurs demonstrates the drivers of the energy risk in California. The bars in **Figure 6** show the variation in capacity resource output over the day. Each curve represents a demand forecast that ranges from a normal year forecast (e.g., Demand 50 indicates levels are equally likely to be above or below the actual demand on that day) to an extreme year forecast with higher demand levels that are unlikely to be exceeded by actual demand (e.g., Demand 05 indicates that statistically only 5 in 100 years are likely to have a day in which actual demand exceeds this forecast). As solar decreases as sunset approaches, the total of all available resources can fall short of the demand, especially for the higher demand levels represented in the load forecast. Imports are limited and cannot satisfy the increased demand levels in the CA/MX area, resulting in significant EUE.

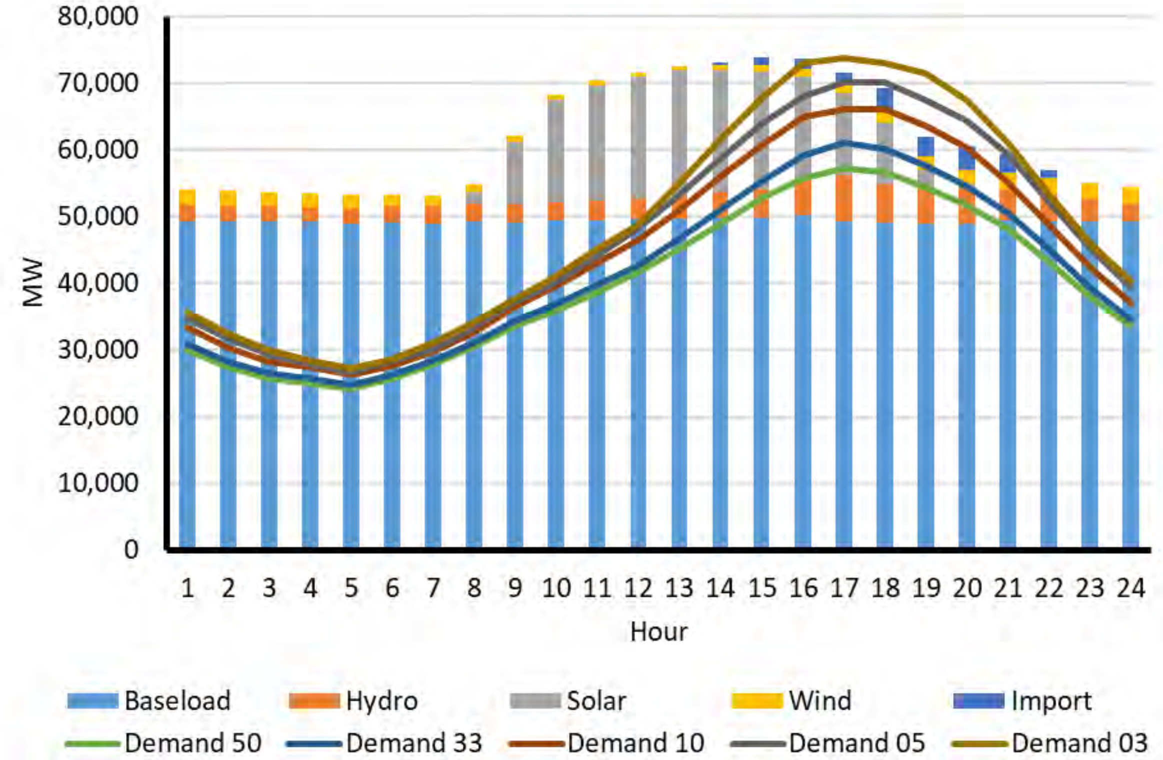

Figure 6: Hourly Demand and Resources for 2024 Summer Peak in WECC-CA/MX

Energy Risks in WECC-SRSG and WECC-WPP

Assessment areas in the U.S. Southwest and Northwest are also projecting summer periods of energy shortfall risks in the next five years. Risk months for WECC-SRSG and WECC-WPP are summarized in **Figure 7** and **Figure 8**. These areas have an increasingly variable generation resource mix and peak summer demand profile. Like CA/MX, late summer periods in the Southwest have the greatest risk of energy shortfalls due to the hot temperatures and potential for volatile electricity demand along with drop-off in solar that begins to occur earlier each day. In the Northwest, risk is spread across all summer months; this is driven primarily by declining on-peak capacity as coal-fired generators retire and less generation capacity is in the interconnection queue to replace it. ProbA results indicate that the risk of energy shortfall is increasing from 2024 to 2026 study years in both assessment areas.

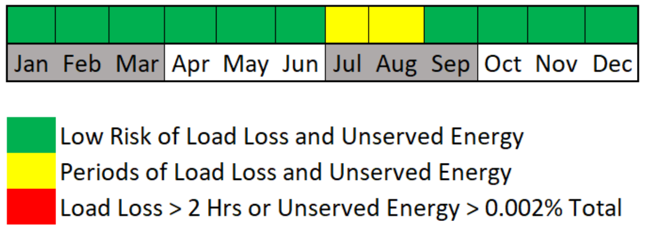

Figure 7: 2026 Monthly Energy Risk Summary for WECC-SRSG

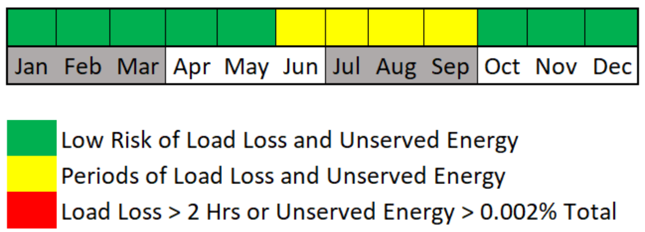

Figure 8: 2026 Monthly Energy Risk Summary for WECC-WPP

ERCOT Energy Risks

Generation resources, primarily solar and wind, continue to be added to the grid in Texas in large quantities, increasing on-peak planning reserve margins but also elevating concerns of energy risks that result from the variability of these resources and the potential for delays in implementation.

The summer on-peak ARM is projected to stay above the RML of 13.75% through 2027 (see **Figure 9**). The ARM increases significantly for the summers of 2023 and 2024 due to the expected addition of over 22,000 MW of summer Tier 1 capacity, most of which is solar.

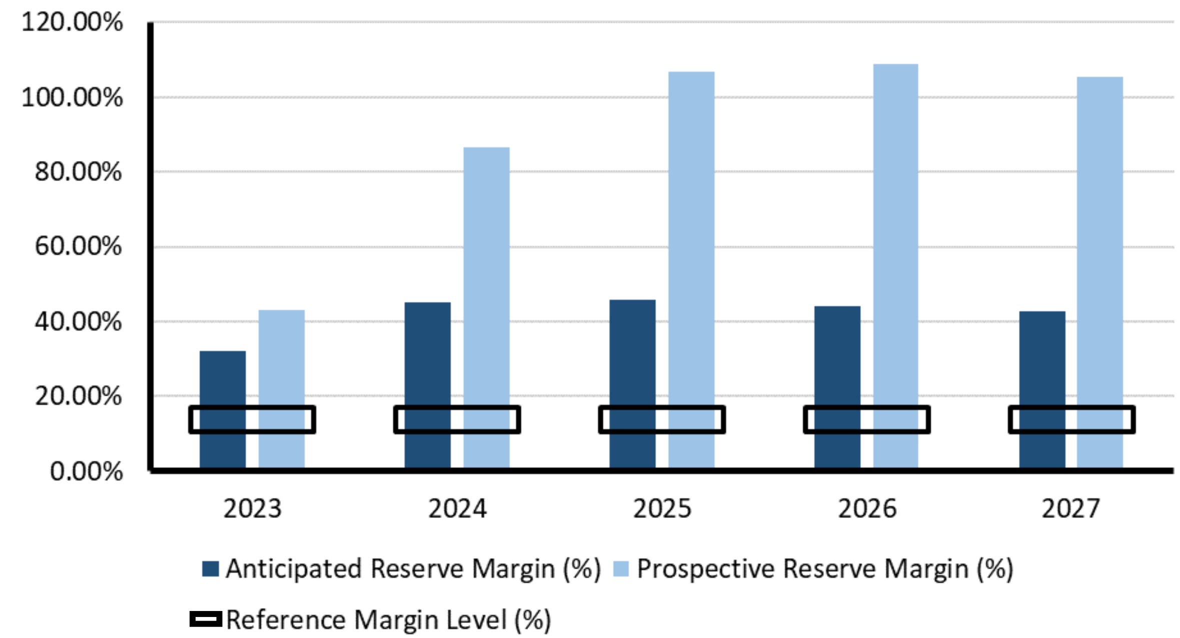

Figure 9: Texas RE-ERCOT Five-Year Projected Reserves (ARM and PRM)

The growing penetration of solar in ERCOT is increasing the risk of tight operating reserves during hours after the daily peak load hour when planning reserve margins are measured. Like California, this issue is most acute for the summer season when solar generation ramps down during the early evening hours while load is still relatively high. Studies by ERCOT show that the highest risk of energy emergencies occurs during summer months from early afternoon through early evening hours, peaking during the 7:00–8:00 p.m. hour. See **Texas RE-ERCOT** in the assessment area pages. ERCOT's summer LOLH and EUE are relatively small; however, these results are contingent upon completion of nearly 20 GW of Tier 1 solar resources by 2024.

Finding: Parts of North America are exposed to energy shortfall risks in the near-term assessment period from wide-area and long duration extreme weather events like the 2020–2021 U.S. Western area heat wave and the South Central Winter Storm Uri in 2021.

Extreme Winter Weather Risks in Texas

Though typical winters in Texas are mild and pose little risk of energy shortfalls, extreme winter weather similar to Winter Storm Uri in February 2021 are likely to challenge grid operators to maintain reliability in the near-term. ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. This is in contrast to the relative stability of ERCOT's summer peak demand, which does not vary by more than a few percentage points between an average year and an extremely hot year. With such demand variability, long-range weather and demand forecasting becomes more important to ensuring sufficient resources are available and ready to operate.

In winter, demand in Texas peaks during cold early morning hours before ERCOT's vast solar resources are producing electrical output. Demand must be met primarily with the fleet of thermal and wind generators. In Texas and other parts of the South that do not experience harsh winters each year, high forced outages of the thermal and wind generation fleet has been a common issue when extreme weather events have led to energy emergencies, causing generator component freezing, fuel supply disruption to natural gas and coal-fired plants, and wind generator protection cut-outs.[13] ERCOT's analysis for the 2022 ProbA included forced outage risk modeling for extreme winter conditions, and most risk of load loss occurs in winter, not summer, months. A summary of monthly energy risk is in **Figure 10**.

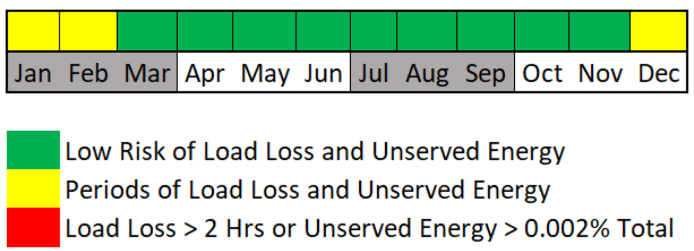

Figure 10: 2024 and 2026 Monthly Energy Risk Summary for ERCOT

These winter energy risks in the ProbA results are significantly influenced generator outage modeling like the effects from Winter Storm Uri. Since February 2021, Texas regulators, ERCOT, and Generator Owners have implemented winter preparedness programs and other reforms aimed at improving generator performance in extreme winter weather. The ProbA results do not consider these changes and are likely to be pessimistic for similar extreme weather as a result.

Energy Risks in NPCC-New England

Studies performed by NPCC and ISO New England have identified energy risks for the area. Although there is sufficient capacity to meet the resource adequacy criterion, a previously identified and persistent concern is whether there will be sufficient fuel available to satisfy electrical energy and operating reserve demands during an extended cold spell or a series of cold spells given the existing resource mix and regional fuel delivery infrastructure. See the **NPCC New England** assessment area pages.

Energy Risks in SPP

While the SPP PRM shows a significant amount of capacity, ARMs do not account for planned, forced, or maintenance generator outages. Instead, they reflect the full availability of accredited capacity. Additionally, anticipated resources do not reflect derates based on real-time operational impacts. Capacity and energy shortfalls can occur in SPP when high demand coincides with low wind or above-normal generator outages. See the **SPP** assessment area pages.

Recommendation for Reducing Resource Capacity and Energy Risk

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios in resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. Industry and regulators should conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs. In areas with high dependence on VERs and natural-gas-fired generation, PRMs are not sufficient for measuring resource adequacy.

The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons. State and provincial regulators and ISO/ RTO) should have mechanisms they can employ to prevent retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.

[13] See the findings and recommendations of the Joint FERC/NERC/Regional Entity inquiry into the February 2021 cold weather event: https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and

Resource Mix Changes

Finding: The vast amounts of wind, solar, and now hybrid generation resources in interconnection processes will enable continued transition in the generation resource mix as traditional resources retire. VERs (resources with output dependent upon weather and hourly conditions) will increase and the fleet of thermal resources will shrink and have less fuel diversity.

The addition of VERs (primarily wind and solar) and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Maintaining reliability will require the pace of change to be carefully managed by industry and regulators and steps to be taken to ensure that essential reliability services (ERS) continue to be provided as generators retire.

Generation Resource Mix in 2022

Figure 11 shows the fuel mix composition of all generation resources connected to the North American BPS in 2022. The installed resource mix (left) is based on the design ratings of the generators. On-peak resource capacity (right), in contrast, reflects the expected capacity that the resource type will provide at the hour of peak demand. Because the electrical output of wind and solar VERs depends on weather and light conditions, on-peak capacity contributions are less than nameplate installed capacity. The wind on-peak capacity contribution ranges from a low of 10% of installed capacity in Saskatchewan to 26.2% in ERCOT. Solar on-peak contributions are 0% in most areas during winter when the peak occurs in low light. In summer, some areas, such as ERCOT and parts of the U.S. West, can expect solar contribution to reach over 80% of installed capacity at peak demand hour. High expected capacity contributions from VERs help increase Planning Reserve Margins but also increase the exposure of the system to energy risks from weather or environmental conditions that impact VER output. Supplementary tables on NERC's Reliability Assessments web page provide on-peak capacity contributions of existing wind and solar resources in each assessment area.[14]

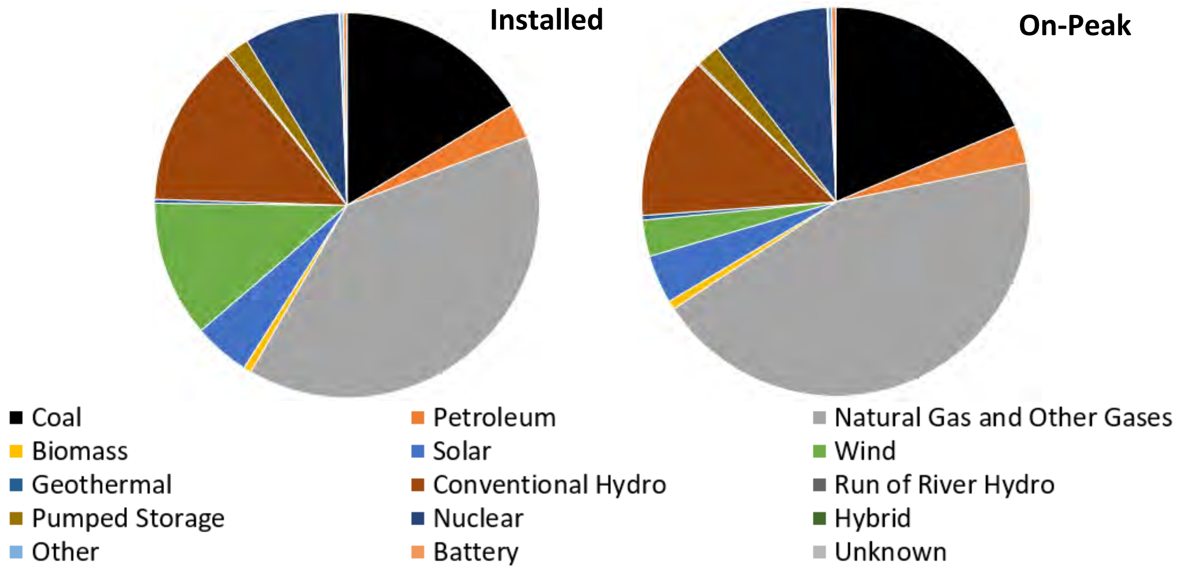

Figure 11: 2022 BPS Generation Capacity by Fuel Type

Total on-peak capacity by generation type is summarized in **Table 1** below. The capacity of several traditional baseload generation fuel-types is in decline. Since the *2021 LTRA*, coal-fired generation has fallen by 17 GW and nuclear generation has fallen by 2 GW.

Table 1: 2022 Capacity at Peak Demand

Type	Capacity (GW)	Change since 2021 (GW)
Natural Gas	477	+14
Coal	202	-18
Nuclear	106	-2
Solar and Wind	70	+19
All others	189	+2
Contributions at hour of peak demand. VER (solar, wind, and some hydro) typically count less than installed nameplate capacity.		

[14] https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

Capacity Additions

New generation is added to the BPS through area interconnection planning processes. Wind, solar, and natural-gas-fired generation are the overwhelmingly predominant generation types in the planning horizon for addition to the BPS. A summary of generation resources in the interconnection planning queues is shown in **Figure 12**. See supplemental tables for greater detail by fuel type.

In general, Tier 1 resources are in final stages for connection while Tier 2 resources are further from completion and some may, in fact, not be completed. Supply chain issues, planning and siting challenges, and business or economic factors can cause projects to be delayed or withdrawn.

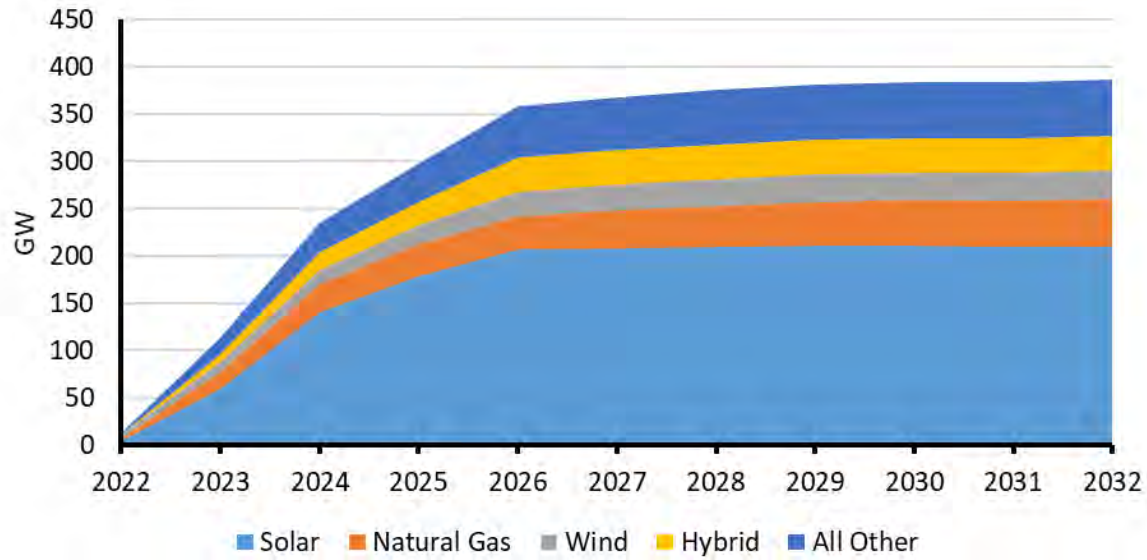

Figure 12: Tier 1 and 2 Planned Resources Projected Through 2032

Solar and wind capacity, both existing and planned, vary widely by area. **Figure 13** and **Figure 14** show current solar and wind installed capacities and capacity in the planning process through 2032 for assessment areas with significant amounts. In addition, hybrid generation resources, which combine energy storage with a generating plant (e.g., a wind or solar farm) are connecting to the grid in parts of North America, and many more projects are in BPS planning processes. A complete listing for all assessment areas is available in the supplemental tables.

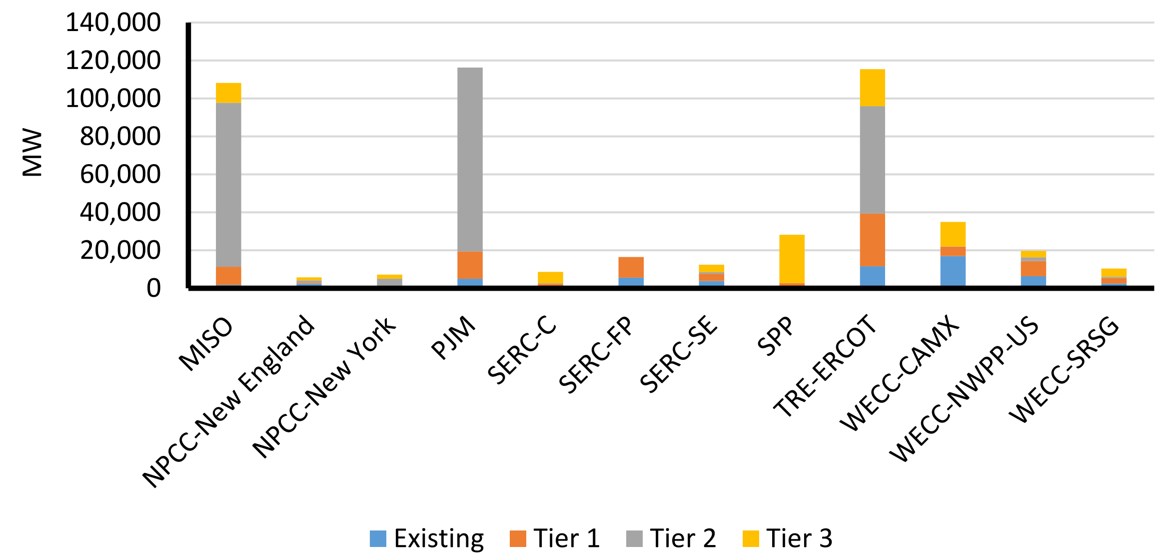

Figure 13: Solar Capacity Planned and Existing

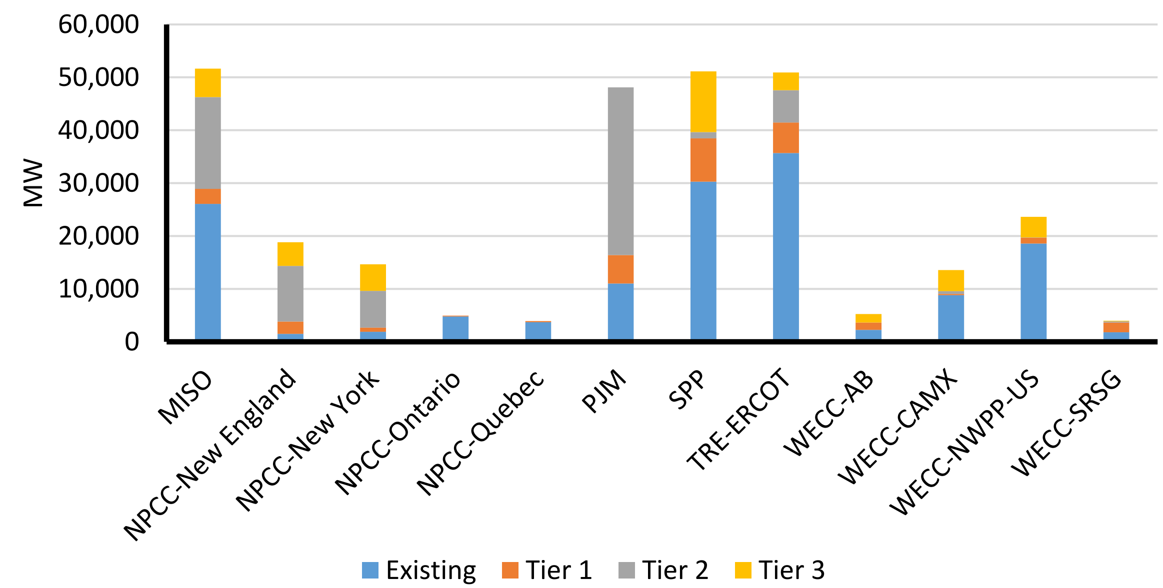

Figure 14: Wind Capacity Planned and Existing

Solar Distributed Energy Resource Growth

Behind the meter (BTM) solar PV generators are solar resources connected directly to the distribution system, such as residential rooftop solar systems. Rapid growth of BTM solar PV continues with cumulative levels expected to reach over 80 GW by the end of this 10-year assessment period (an increase of 25% since publication of the *2021 LTRA*). BTM solar PV generators, like grid-connected solar, are also VERs. In large penetrations, their predictable change in output from the time of day contributes to steep ramps in demand. As the sun sets and output diminishes, grid resources must make up for the decrease in solar generation and increase in demand that was being served. The opposite ramp occurs during morning hours and may be less impactful to reliability but can be challenging for grid-connected generator scheduling and dispatch. Supplemental tables show the current and projected BTM solar PV by area.

Generation Retirements

The total capacity of traditional baseload generation fuel-types will continue to decline as older generators retire. The resource mix changes as these retirements are coinciding with the addition of new generation of different types with different capacity characteristics. **Figure 15** shows how the current resource mix (on-peak capacity) compares to the projection of the future on-peak capacity in 2032 if confirmed retirements occur and all projected Tier 1 resources are added. Across the entire BPS, the on-peak capacity contribution of solar and wind will grow modestly from the current 7% to 12%. The change in specific Interconnections varies. ERCOT and the Western Interconnection are projected to have more significant increases in the share of on-peak generation that is coming from VERs while the Eastern Interconnection and Québec Interconnection would change little in the 10-year period.

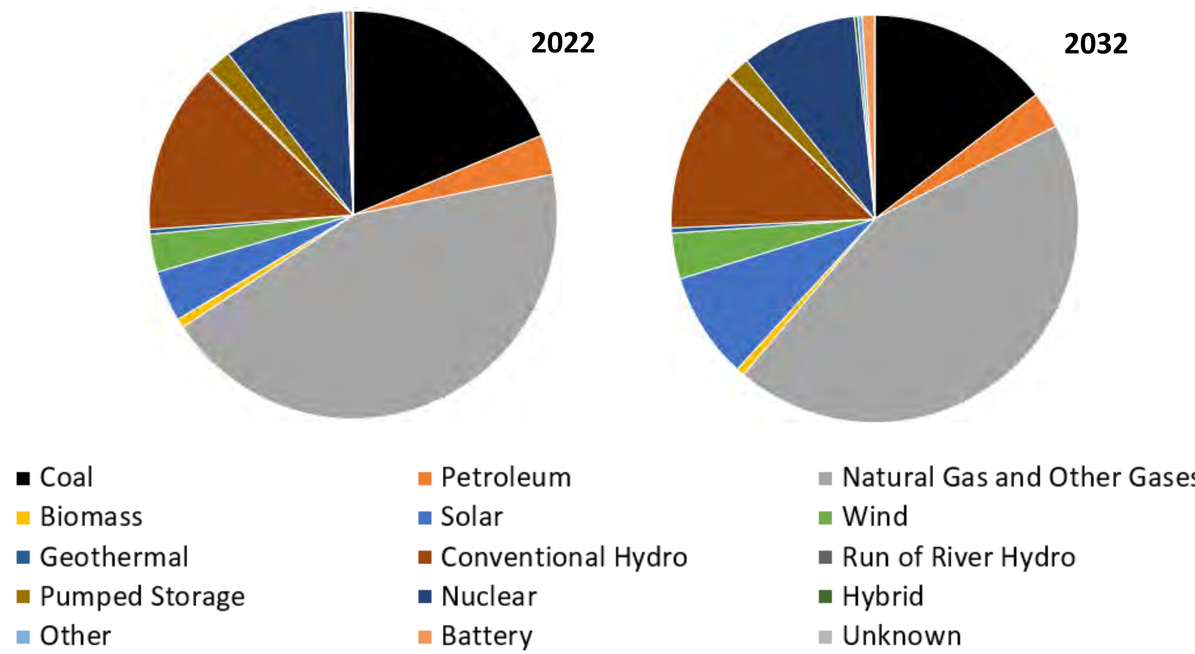

Figure 15: 2022–2032 BPS On-Peak Capacity by Fuel Type with Tier 1 Resources

Generators become confirmed for retirement according to various processes in place in the Interconnections, such as regional planning tariffs in the wholesale electricity market areas or integrated resource planning process in vertically-integrated states. Properly designed mechanisms can prevent generators from retiring before planners can study and address reliability issues that could occur.

Additional retirements beyond what is reported as confirmed in this *2022 LTRA* are expected. Often Generator Owners announce plans to retire generator units before initiating the interconnection planning process, and the announced plans or timing may be subject to change before the retirement is confirmed. **Figure 16** shows the total capacity of confirmed and announced as well as unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next five years.[15]

[15] Confirmed generator retirements are reported to NERC by each assessment area in the LTRA development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

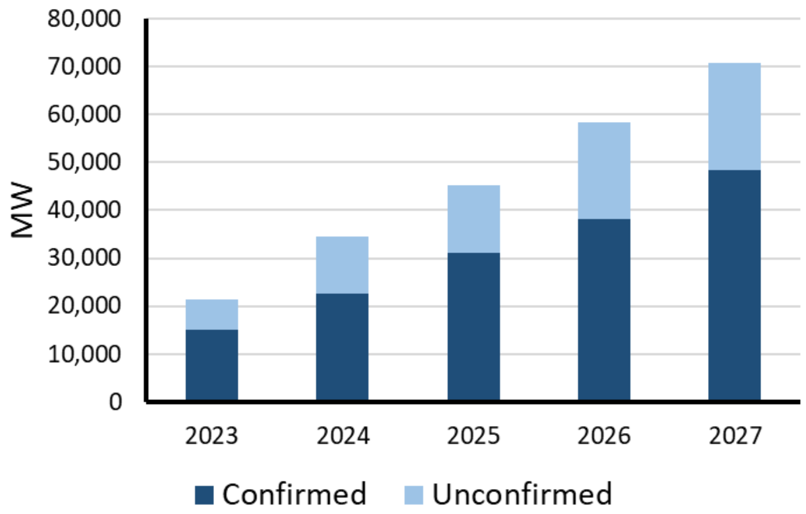

Figure 16: Projected Generation Retirement Capacity Through 2027

Throughout this *2022 LTRA*, all confirmed generation retirements have been removed from each assessment area's anticipated and prospective resources while unconfirmed, announced generator retirements have been removed from prospective resources only. In some risk areas identified in the **Resource Capacity and Energy Risk Assessment** section of this *2022 LTRA*, the announced, unconfirmed generator retirements are likely to exacerbate currently-projected energy shortfalls. **Figure 17** shows a comparison of the 2027 (Year 5) ARMs for the assessment areas at risk of shortfall as well as the potential 2027 reserve margins for a scenario with both confirmed and announced generator retirements. In MISO, where 10.2 GW of generation is expected to retire by 2027, another 5.4 GW of generation capacity is at risk of retirement based on retirement plan announcements. Loss of this additional capacity could lower the reserve margins from 6.5% in the current year to below 2% for the 2027 capacity assessment. The Maritimes provinces in Canada could also face a capacity shortfall if 550 MW of unconfirmed retirements were to exit the system without replacement resources.

In SPP, Texas RE-ERCOT, CA/MX, WPP, and SRSG, where energy limitations are contributing to projected load-loss risk in the **Resource Capacity and Energy Risk Assessment** section of this LTRA, additional thermal generator retirements could also be detrimental to reliability. Loss of these traditional baseload resources would lead to a more variable generation resource mix unless they are replaced by resources that are dispatchable, flexible, and able to counter variations in generation and demand. Consequently, the risk of insufficient energy and loss-of-load during periods of high demand and low resource output will rise.

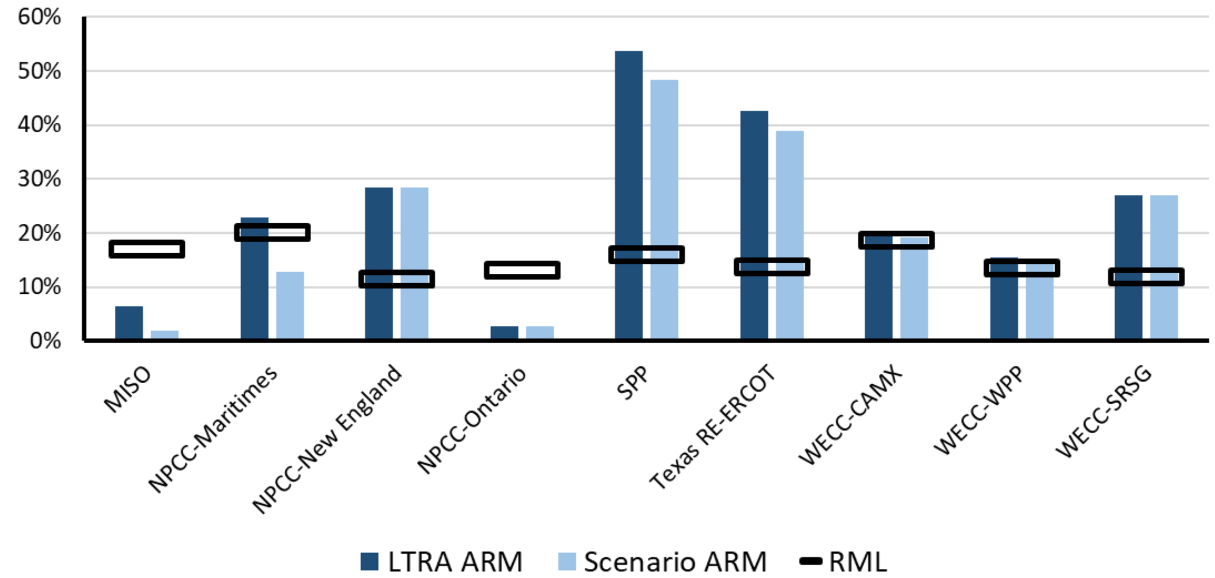

Figure 17: Year 2027 Reserve Margins Including a Scenario with Announced/Unconfirmed Retirements

These scenarios illustrate the potential impacts that significant generation retirements can have on resource adequacy, and they underscore the important role of ISO/RTO and integrated system planning processes that are necessary to maintain reliability.

Reliability Implications

The addition of variable resources, primarily wind and solar, and the retirement of conventional generation are fundamentally changing how the BPS is planned and operated. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources. Important reliability implications include the following:

- **Flexible Resources:** In order to maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, some operators are seeing the need to have more system ramping capability. As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.[16] Maintaining ERSs is critically important, and resources must be made available in the long-range resource portfolio as part of the planning process; market and other mechanisms need to be in place to deliver resources with ERS-capabilities to the operators.

- **Fuel-related Risks to Electricity Generation (Fuel Assurance):** Natural gas for electricity generation is an essential fuel that bridges the rapid development of VERs. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[17] Disruptions to the fuel delivery can result from adverse events that may occur, such as line breaks, well freeze-offs, and/or storage facility outages. The pipeline system can be impacted by events that occur on the electric system (e.g., loss of electric motor-driven compressors) that are compounded when multiple plants are connected through the same pipeline or storage facility. Furthermore, additional pipeline infrastructure is needed to reliably serve electric load.
- **Inverter-based Resources:** IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred as recently as the summer of 2022.[18] A common thread with these events is the lack of IBR ride-through capability causing a minor system disturbance to become a major disturbance. To address systemic issues with IBRs, NERC continues to urge industry's adoption of the recommended practices set forth in NERC guidelines even as NERC begins the process of developing mandatory Reliability Standards based on those guidelines. High priority items include incorporating electromagnetic transient modeling into the NERC Reliability Standards and developing a comprehensive ride-through requirement that focuses specifically on generator protections and controls.
- **BES Protective Relay Systems:** The changing resource mix presents unique risks and challenges to the vast network of protective relay systems that are critical to the safe and reliable operation of the Bulk Electric System (BES). Protection systems are meticulously planned and maintained to rapidly respond to dynamic grid conditions in a coordinated manner that isolates faults from spreading throughout the system and minimizes risks to grid equipment and personnel. With more IBRs and fewer synchronous generators on the grid, there is growing concern in the industry that protection systems will no longer function properly during system faults without redesign. Unlike synchronous generators, which produce high currents with unbalanced characteristics during faults that enable existing protections systems to function properly due to their physical properties, IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation. Protection engineers need to have better tools to analyze periods of low synchronous generation and ensure protection systems will still function properly.
- **Tools and Models for Assessing Capacity and Energy Risks:** Planners and operators are updating processes, tools, and techniques to keep pace with the changing resource mix. The explosive growth of battery and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, battery duration, and battery operating mode. Additionally, resource planners and wholesale market designers in most areas with growing wind and solar resources are considering or developing new processes for assigning the contribution of resources to meeting demand. Some are investigating the use of effective load-carrying capacity (ELCC) methods that involve probabilistic study to assign the capacity contribution of resources. These ELCC methods should address the risks and shortcomings in present modeling described in this report. Specifically, the statistical representation of capacity that has variable and uncertain fuel can

[16] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS_Measure_6_Forward_Tech_Brief_03292018_Final.pdf
[17] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
[18] See *May/June 2021 Odessa Disturbance Report*, *June-August 2021 CAISO Solar PV Disturbance Report*, and other relevant IBR event reports here: https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx

be problematic when combined in a reserve margin evaluation with capacity that has firm fuel and highly reliable. Finally, planners are finding it necessary to have improved tools and methods to study wide-area, long duration extreme weather risks and other low-likelihood, extreme events. Scenario planning is needed to ensure that the industry is ready to take actions needed to preserve the reliable operation of the BPS for many potential system conditions. Traditional models and approaches rooted in a loss-of-load expectation of 1 day-in-10-years do not account for the essential role that electricity plays in modern society, and normal demand distributions appear to be ill-suited for describing the extremes of a changing weather patterns.

- **Essential Reliability Services:** Conventional units, such as coal and nuclear power plants, provide frequency support services as a function of their large spinning mass and governor control settings, along with voltage regulation. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. The reliability of the BPS depends on the operating characteristics of the replacement resources. Merely having available generation capacity does not equate to having the necessary reliability services or ramping capability to balance generation and load. It is essential for the BPS to have resources not only with the capability to respond to frequency and voltage changes, but to actively provide those services.[19]

Recommendations for Reducing Risks as the Resource Mix Changes

In addition to the recommendations found elsewhere in the report, the following will reduce risks that can occur during the resource mix transition:

- Resource planners and policymakers must give careful attention to the pace of change in the resource mix and update capacity and energy risk studies, including all-hours probabilistic analysis, with accurate resource projections.
- The ERO and Industry should take steps to ensure IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document for addressing inverter-based resource performance issues that illustrates current and future work to mitigate emerging risks in this area.[20] Regulators, industry standards-setting organizations, trade forums, and manufacturers also have a role to play addressing IBR performance issues.
- Industry should increase its focus on technical needs for reliably operating with increased amounts of DER. Growth promises both opportunity and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role to BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.
- Industry, regulators, and energy stakeholders must urgently act to solve reliability challenges arising from interdependent natural gas and electricity infrastructure. For industry, this entails enhancing guidelines for assessing and reducing risks and developing appropriate Reliability Standards requirements to ensure corrective actions are put in place. Regulators and other energy stakeholders must also take steps. The forum convened by the North American Energy Standards Board is an example of one such important action.[21]

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[19] Essential reliability services are measured periodically using evaluations developed by the Essential Reliability Service Task Force: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERSTF%20Framework%20Report%20-%20Final.pdf Forward-looking frequency response evaluations are conducted every three years and included in the Long-Term Reliability Assessment. Historical evaluations are reported in the State of Reliability report: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf

[20] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

[21] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth rates in North America are both increasing. The 10-year summer and winter peak demand growth projections show the largest percentage increase in recent years. Electrification and projections for growth in EV over the 10-year horizon are a component of the demand and energy estimates provided by each assessment area. Growth rate increases in winter peak demand are being influenced by electrification of space-heating systems. Summer peak demand growth rates are lower compared to winter; growth in DERs and some EE contributing to lower summer demand growth. See the **Figure 18** for seasonal peak demand growth over the current and prior assessment periods and **Figure 19** for net energy growth. Area demand growth rates are provided in the supplemental tables, and more information is available in the **Regional Assessments** pages.

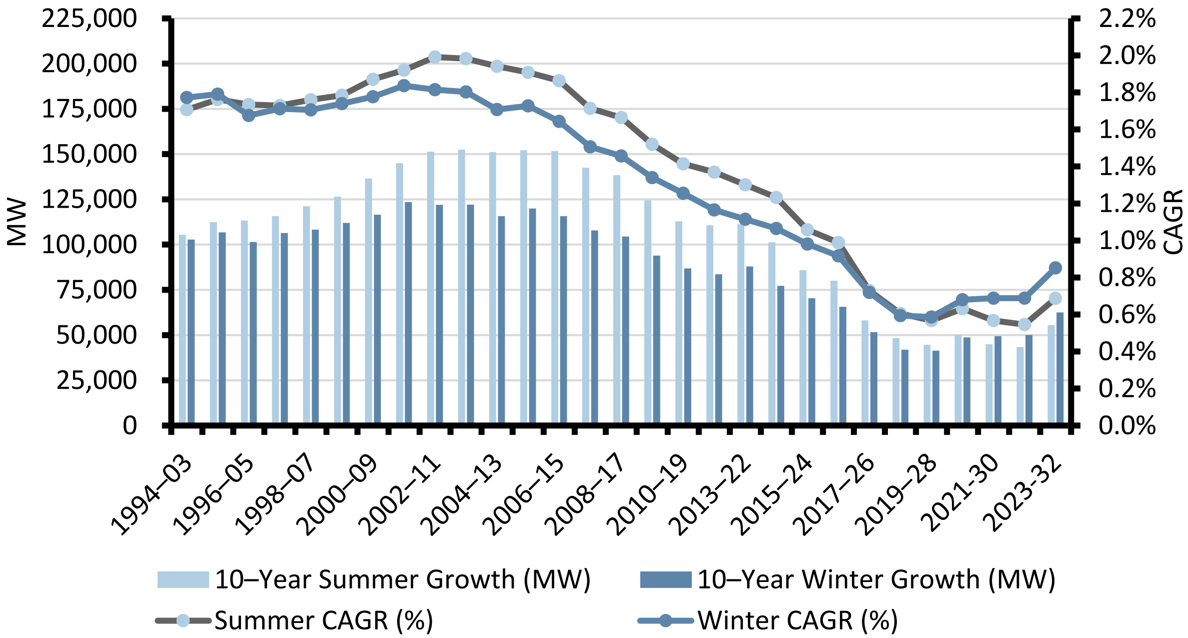

Figure 18: The 10-Year Summer and Winter Peak Demand Growth and Rate Trends

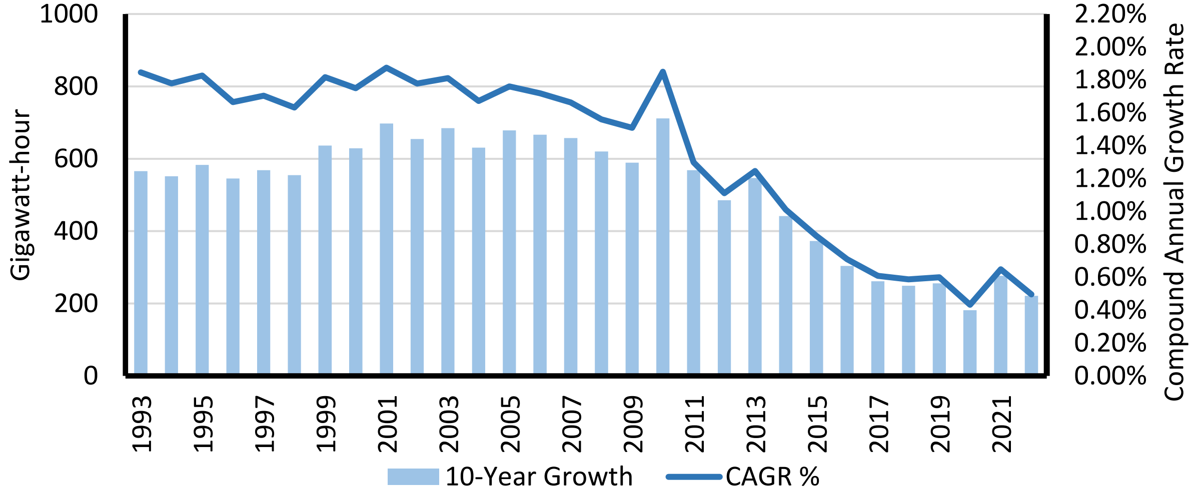

Figure 19: The 10-Year Net Energy to Load Growth and Rate Projection Trends

Demand-Side Management

Conservation, EE, and DR programs contribute to an assessment area's ability to manage load. DR describes a number of load-reducing programs that are available to system operators under specific conditions. NERC collects forecasts of the amount in MW that is expected to respond when called upon to reduce peak load for each assessment area. **Figure 20** shows the total system DR forecasted to be available for the first and fifth year's summer and winter peaks (Year 1 and Year 5) from each of the past five LTRAs.

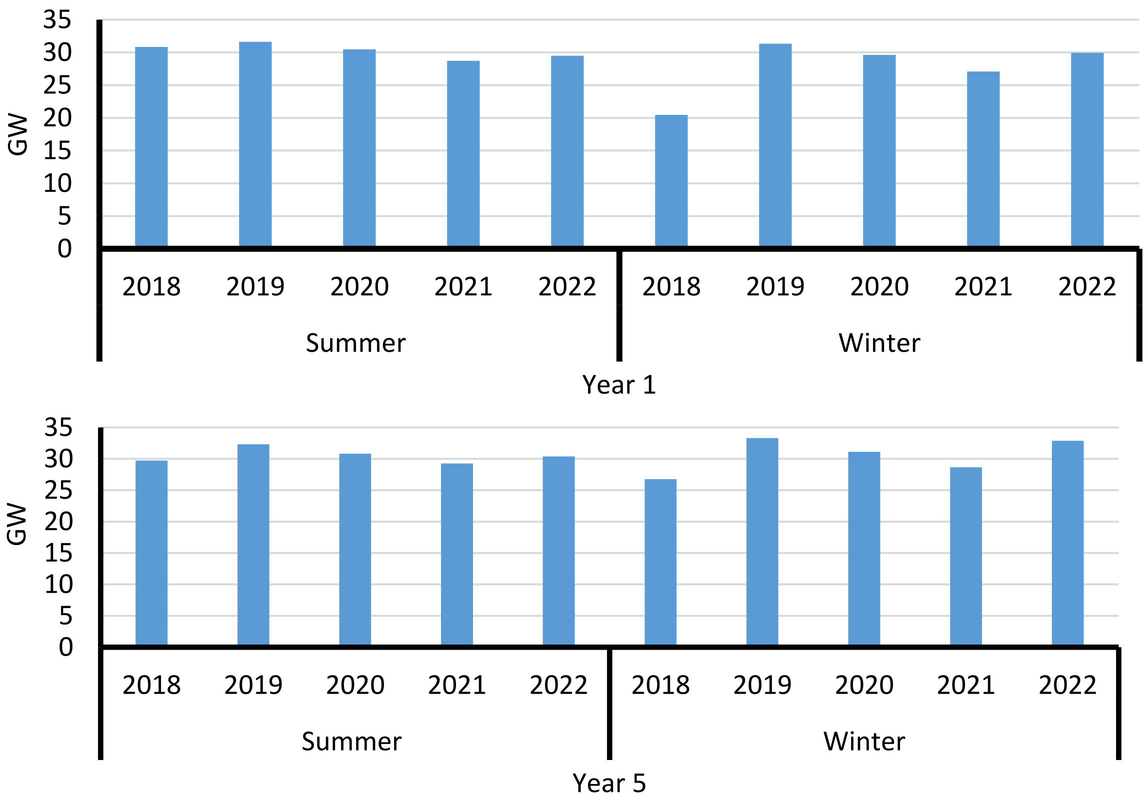

Figure 20: Demand Response Available in Year 1 and Year 5 of 2018–2022 LTRA

Reliability Implications

Demand projections are influenced by a variety of factors, including the economy, energy policies, technology development, and consumer preferences. Projections are increasing in complexity with more uncertainty in the impacts of the changing resource and demand characteristics, especially with their variability. DR, EE, BTM generation, energy storage, electrification and consumer behavior all impact the demand and energy projections. To ensure reliability, grid and resource planners must manage short- and long-term load forecasts to account for this complexity and uncertainty.

Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Such changes have wide-ranging implications to how the grid and resources are planned and operated.

Transmission Development Trends and Implications

Trends

There is relatively little change in cumulative miles of BPS transmission under construction or in planning for the next 10-year horizon; however, projects for renewable integration are increasing. The current cumulative level of 15,495 miles of transmission (>100 kV) in construction or stages of development for the next 10-years (**Figure 21**) is running near averages of the past five years.

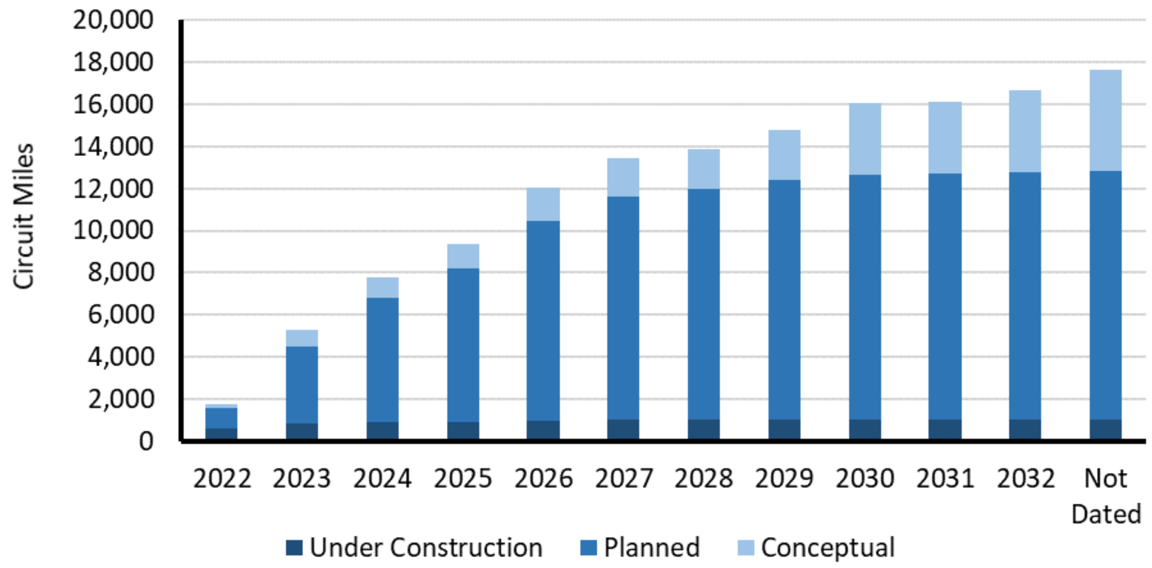

Figure 21: Future Transmission Circuit Miles >100 kV by Project Status

New transmission projects are being driven to support new generation and enhance reliability. **Figure 22** shows the percentage of future transmission circuit miles by primary driver. Most project miles are initiated to support grid reliability. Projects under construction or in planning to integrate renewables have grown from 1,589 miles reported in the *2021 LTRA* to 2,376 miles currently.

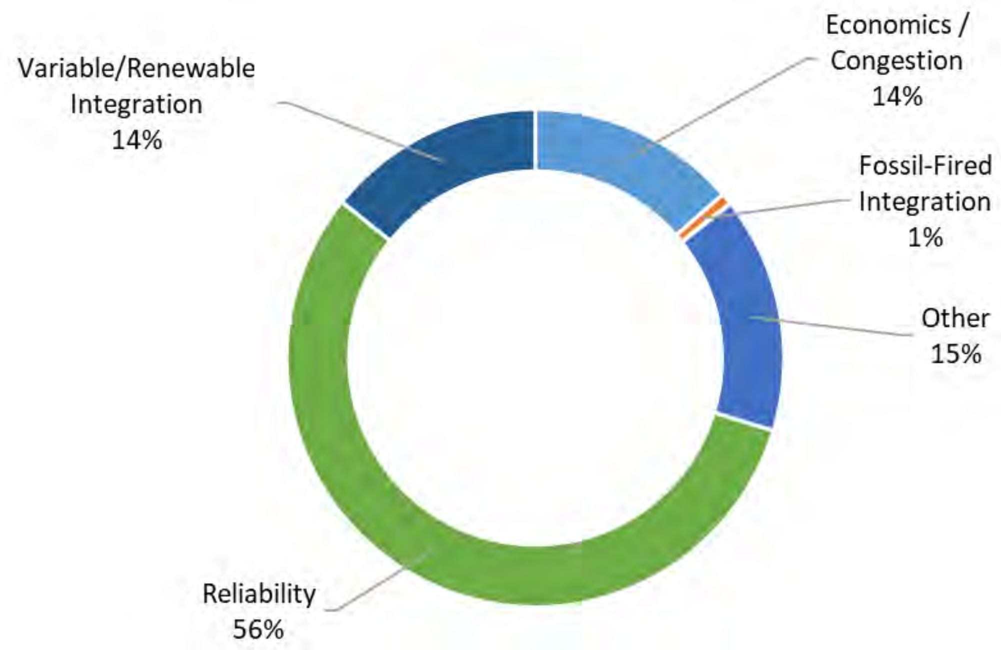

Figure 22: Future Transmission Circuit Miles by Primary Driver

Reliability Implications

Decarbonization goals must be developed with due consideration for transmission needs. Meeting the siting and grid development needs for new generation involves transmission development. Monitoring and managing transmission planning processes is a necessary part of maintaining reliability as the resource mix evolves.

Emerging Issues

In developing this *LTRA*, NERC and the industry considered trends and developments that have the potential to impact the future reliability of the BPS in the next 10-years and beyond. Discussed below are emerging issues and trends not previously covered in this report that have the potential to impact future long-term projections or resource availability and operations.

Electrification and Electric Vehicle Growth

Government policies for the adoption of EVs and other energy transition programs have the potential to significantly influence future demand and energy needs. For example, estimates from the California Energy Commission staff of the added electrical load from plug-in EV charging by 2030, under the state's zero-emission vehicle targets, indicate an additional 5,500 MW of demand at midnight and 4,600 MW of demand at 10:00 a.m. on a typical weekday. This is an increase of 25 and 20%, respectively at those times.[22] State and local policies for transitioning appliances and heating systems can also affect projections of electricity demand and daily load shapes, and these policies also have many ramifications for infrastructures other than the BPS. Industry demand forecasters have differing methods for projecting how EV adoption will impact future demand and many have not directly applied government policy targets to demand forecasts.

Cryptocurrency Impacts on Load and Resources

Due to unique characteristics of the operations associated with cryptocurrency mining, potential growth can have a significant effect on demand and resource projections. Computer operations for cryptocurrency mining are energy intensive, and mining operators can interrupt or scale operations in response to energy costs. ERCOT and their stakeholders and Texas regulators are working on resolving various policy, market, operational, and planning issues associated with interconnecting these large flexible loads and potentially using them as reliability resources.

Supply Chain and Other Factors Affecting Projections

Projections of future resources and transmission in this *LTRA* are based on industry data from the interconnection queues, representing only some of the myriad factors that will ultimately determine when and what gets completed. For resources to materialize and connect to the grid, substantial supply chain, planning, and commissioning processes must be completed. Timing is only an estimate, and some projects can be expected to be withdrawn from the interconnection process by developers. Having ample generating capacity in the interconnection queues to replace the nearly 60 GW of confirmed generation retirements projected over the 10-year assessment period (already a low indicator of future retirements) does not provide assurance that new capacity will be connected and available to meet future resource needs.

6 GHz Frequency Band Interference

The ability of grid owners and operators to monitor and control BPS equipment and respond to grid events may impact future changes in the allocation of the frequency spectrum, constituting an emerging risk to BPS reliability. Growth in demand for wireless connectivity and the need to improve rural internet connectivity prompted the U.S. Federal Communications Commission (FCC) to issue a ruling in 2020 and propose further access changes that impact frequencies that was once restricted to licensed users, including many electric grid owners and operators.

Recent changes to U.S. communications regulations and pending future rules are increasing the risk that electric grid owners and operators will experience harmful interference on communications channels that are important for the reliable operation of the BPS. In April 2020, the FCC issued a report and order that partially opened spectrum in the 6 GHz band for unlicensed use.[23] Prior to this ruling, the 6 GHz band was restricted to use by an array of industries responsible for critical infrastructure, such as electric, natural gas and water utilities, railroads, and wireless carriers as well as by public safety and law enforcement officials. Electric utilities in the United States use communications systems operating in this frequency band as primary or alternate means for monitoring and controlling BPS equipment (via SCADA systems) and for voice communications with operators and field personnel. Subsequently, the FCC gave notice of further proposed rulemaking to fully open the 6 GHz band to unlicensed users with the removal of current restrictions on mobile device outdoor usage. Many electric grid owners and operators that use the 6 GHz band are anticipating impacts to their communications networks and are developing mitigation plans. Following an initial review and an industry survey conducted by a task force established by the NERC RSTC, NERC has identified that many grid operators continue to use the 6 GHz band for their critical communications and many have not identified remediation plans to mitigate potential interference impacts.[24] Because of the expected growth of users in the 6GHz band and potential for increased interference, NERC is taking action to determine the level of impact that the regulation changes have on BPS reliability and develop mitigation to reduce the risks.

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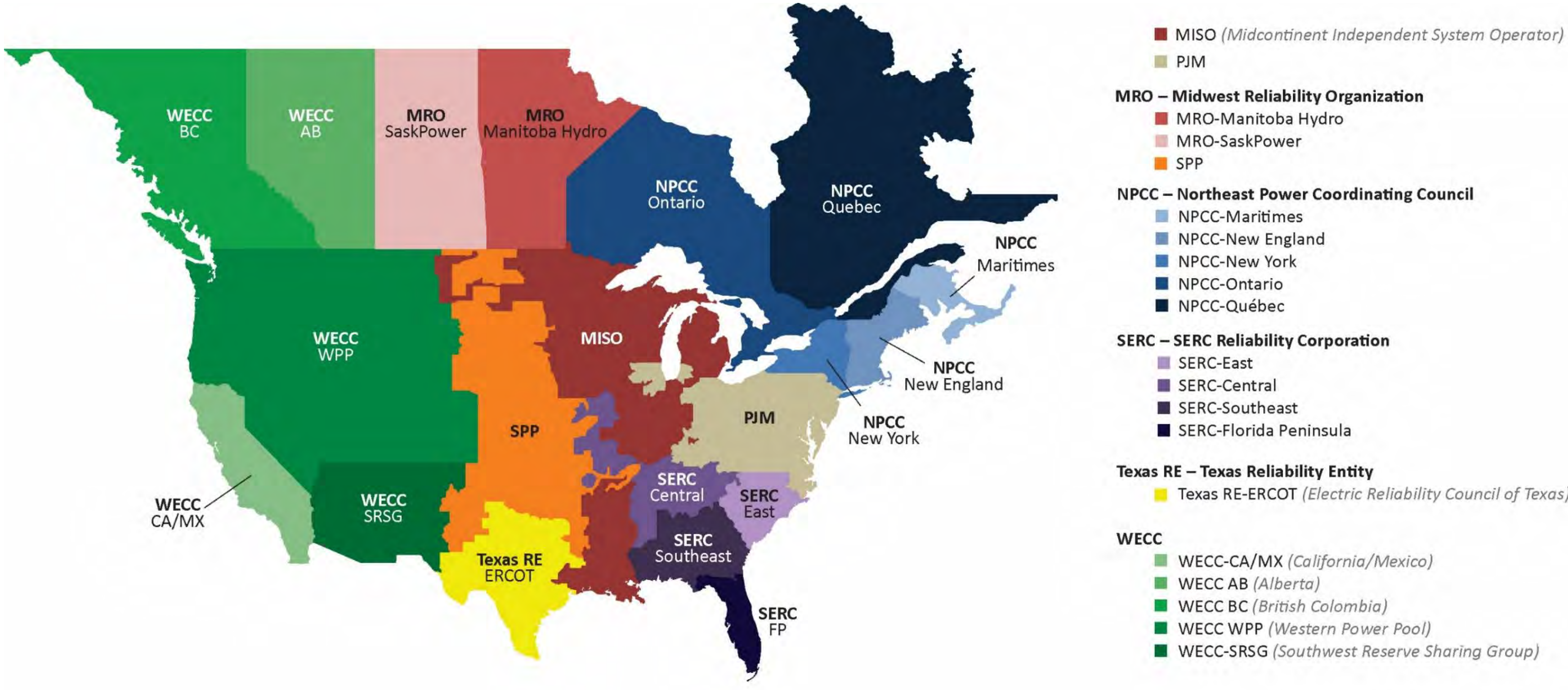
[22] See, for example, California Energy Commission Revised Staff Report *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment*: https://efiling.energy.ca.gov/getdocument.aspx?tn=238032

[23] https://www.fcc.gov/document/fcc-opens-6-ghz-band-wi-fi-and-other-unlicensed-uses-0

[24] https://www.nerc.com/comm/RSTC/6GHTZF/6GHZ%20Communication%20Network%20Extent%20of%20Condition%20White%20Paper.pdf

Regional Assessments

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. In addition, NERC published additional *2022 LTRA* assessment area data in supplemental tables on the Reliability Assessments web page.[25] The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



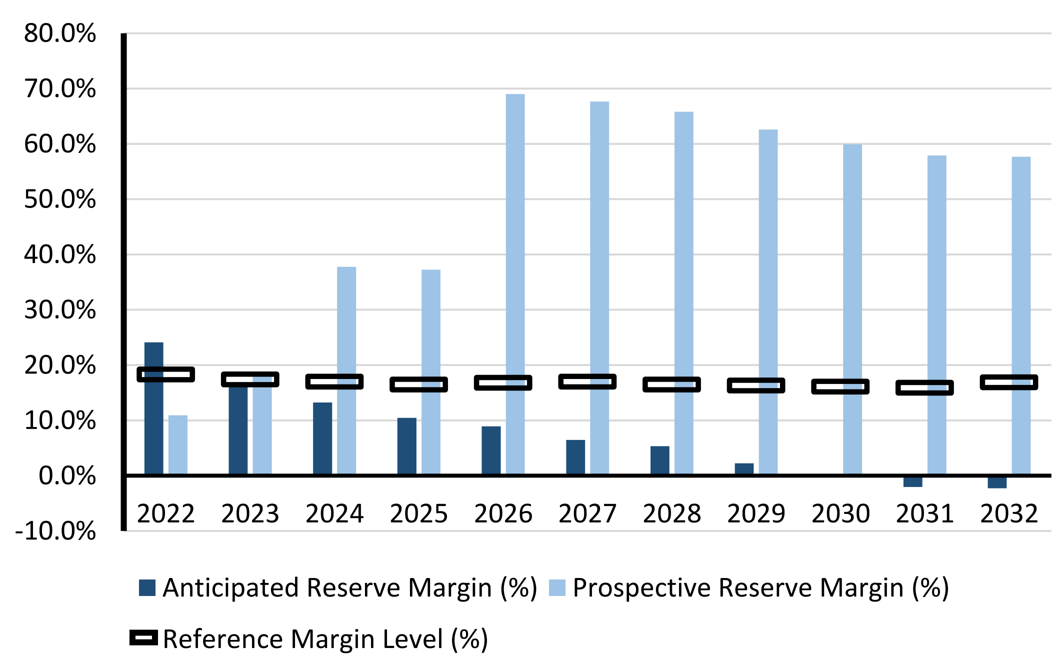
[25] See the NERC Reliability Assessments page here: https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx

MISO

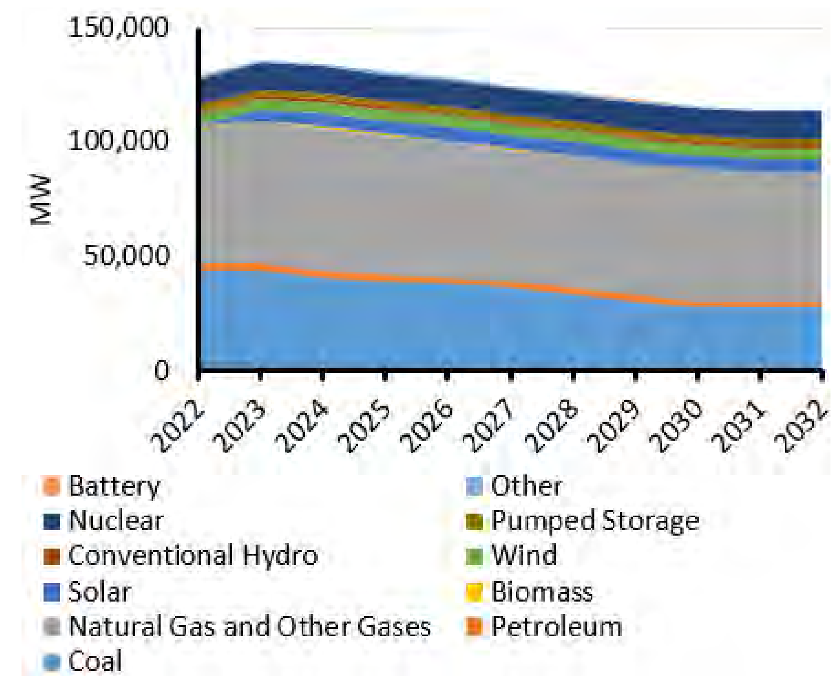
The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency.

MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Demand, Resources, and Reserve Margins (MW)										
Quantity	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Total Internal Demand	124,950	126,091	126,212	126,298	126,631	126,965	127,240	127,652	128,320	128,317
Demand Response	6,158	6,189	6,116	6,130	6,131	6,051	6,052	6,054	6,050	6,017
Net Internal Demand	118,792	119,902	120,096	120,168	120,500	120,914	121,188	121,599	122,269	122,300
Additions: Tier 1	6,605	8,253	8,311	8,311	8,311	8,311	8,311	8,311	8,311	8,311
Additions: Tier 2	2,322	30,796	35,517	76,576	78,071	78,096	78,096	78,096	78,096	78,096
Additions: Tier 3	2,193	3,504	5,501	6,055	8,581	9,331	10,538	11,621	12,226	12,409
Net Firm Capacity Transfers	1,593	1,598	767	767	663	593	598	493	493	155
Existing-Certain and Net Firm Transfers	131,538	127,506	124,353	122,572	119,986	119,034	115,593	112,865	111,440	111,204
Anticipated Reserve Margin (%)	16.3%	13.2%	10.5%	8.9%	6.5%	5.3%	2.2%	-0.3%	-2.1%	-2.3%
Prospective Reserve Margin (%)	18.2%	38.9%	40.0%	72.6%	71.3%	69.9%	66.7%	63.9%	61.8%	61.6%
Reference Margin Level (%)	17.4%	17.0%	16.5%	16.8%	17.0%	16.5%	16.3%	16.1%	15.9%	16.9%



Planning Reserve Margins



Existing and Tier 1 Resources

Highlights

- MISO is facing resource shortfalls across this entire assessment period. Since the *2021 LTRA*, 5,900 MW of generation has retired (mostly coal-fired generators) and 1,700 MW of new generation has been added (approximately 700 MW natural-gas-fired, 400 MW Solar, 100 MW wind, and 300 MW pumped storage. In the summer of 2023, MISO's capacity shortfall is projected to be 1,395 MW even after adding over 6.5 GW of new generation with signed interconnection agreements. More additions from the planning queue are not likely to be completed in sufficient quantity to make up for the capacity shortfall.
- MISO's Reliability Imperative Initiative is designed to lead the shared responsibility that utilities, states, and MISO have in addressing the ongoing generation fleet changes and the challenges of more frequent extreme weather events.

MISO Fuel Composition (MW)

Fuel	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Coal	44,102	40,951	39,159	38,066	36,351	33,846	30,415	28,133	28,133	28,133
Petroleum	2,800	2,800	2,707	2,707	2,697	2,697	2,697	2,524	2,451	2,451
Natural Gas	62,087	62,514	61,096	59,606	57,647	57,647	57,644	57,521	56,310	56,310
Biomass	375	375	375	375	304	273	273	240	240	240
Solar	4,753	5,852	5,829	5,828	5,828	5,827	5,827	5,826	5,826	5,826
Wind	4,645	4,689	4,741	4,739	4,730	4,682	4,670	4,660	4,654	4,654
Conventional Hydro	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,280	1,280
Pumped Storage	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617	2,617
Nuclear	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711	11,711
Other	1,280	1,280	1,257	1,224	1,224	1,224	1,224	1,224	1,224	1,224
Battery	20	20	20	20	20	20	20	20	20	20
Total MW	135,805	134,224	130,927	128,308	124,544	121,959	118,513	115,891	114,465	114,465

MISO Assessment

Planning Reserve Margins

MISO is projecting a decrease from last year's reserve margins with planned reserves falling below reference margin levels beginning in 2023. The reserve decline is driven mainly by lower capacity contribution from weather dependent new generation additions that are replacing retiring units with higher contributions. Increasing demand projections also contribute to lower reserve margins. Increased coordination and continued action with MISO members will be critical to ensuring resource adequacy into the future. In most of the MISO area, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Seasonal resource assessments evaluate unit availability, outage rates, and forecasted load varies across all four seasons. MISO has also initiated a change to a seasonal capacity construct that promotes energy adequacy by evaluating how each resource and resource type helps to serve load at periods of peak risk in each season.

Probabilistic Assessment

In the Base Case results, most of the LOLHs occur in June–August, corresponding to the typical MISO peak time frame. There are some instances of LOLHs occurring in September–October when seasonal planned outages overlap with high demand. The winter also experiences a small amount LOLH when cold temperatures push demand higher than normal.

Non-peak risk drivers tend to be unique to the season. In the fall, the risk of unseasonably high demand overlapping with seasonal planned outages increases the loss of load risk. Extreme cold weather, particularly in MISO South, increases demand and causes the risk of loss of load to increase

The ProbA analyzes all hours of the year; whereas, the LTRA is only looking at 10-year summer/winter peak forecasts. As a result, the ProbA provides more insight into intra-yearly system risks that may occur during non-peak periods, and the LTRA highlights longer-term resource adequacy planning concerns.

Base Case Summary of Results			
	2024*	2024	2026
EUE (MWh)	14.3	193.6	68.8
EUE (ppm)	0.02	0.304	0.108
LOLH (Hours per Year)	0.085	0.808	0.393
Operable On-peak Margin	13.7%	8.1%	13.9%

* Provides the 2020 ProbA results for comparison

For the 2022 ProbA Risk Scenario, MISO is investigating how the risk changes as a result of modeling seasonal average, rather than annual average, outage rates along with correlated cold weather outages.

Demand

The peak demand forecast increased from last year by approximately 1.1 GW, largely due to a rebound from COVID-related decline. The five-year regional demand growth remained stable at a relatively flat 0.2%. It is unclear how electrification of transportation and other sectors will drive future growth, but anticipated electrification is considered in the MISO Transmission Expansion Plan (MTEP) process.

Demand Side Management

DR programs continue to play an important role in providing capacity. While DR projections are shown to be decreasing over this assessment period, this trend may change following the 2022 resource auction, OMS-Survey, and in the transition to seasonal capacity auctions.

Distributed Energy Resources

MISO estimates that there is a total of 860 MW of installed solar PV distribution resource capacity. While DERs are anticipated to play a larger role into the future, MISO is still working with stakeholders on adequate methods for aggregating, reporting, and allowing DER participation in MISO markets.

Generation

Since the *2021 LTRA*, MISO has retired 5,000 MW of generation and added 1,700 MW of new generation for a net change of 3,300 MW (on-peak capacity).

The MISO generator interconnection queue continues to show steadily increasing levels of VERs, including battery storage and hybrid resources, in the future generation fleet mix. Currently 300 MW of grid-connected batteries are installed with another 15 GW in the interconnection planning queue and 16 GW of hybrid battery-renewable generation in queue. This transition of the generation fleet, along with the observed impacts from extreme weather events, such as Hurricane Laura in 2020 and Winter Storm Uri in February 2021, continue to stress the importance of the MISO Resource Adequacy construct. Appropriate planning and operating signals must be sent to prompt investment (or system enhancements) when needed to ensure that the BPS continues to perform reliably.

Capacity Transfers

Net firm transfers with neighboring areas declined from the prior *LTRA* and continue to decline as reported in this year's *LTRA*; for the summer of 2023, firm transfer commitments have fallen by nearly 25%. Non-firm transfers have played a critical role in maintaining reliability during extreme weather events. A growing reliance on non-firm imports increases the risk of energy emergencies when external transfer assistance is not available.

Transmission

Approved transmission projects increased since the *2021 LTRA*. In the latest MTEP (MTEP21), 33% of projects are classified as "reliability" projects that are needed to maintain system reliability in accordance with NERC Reliability Standards. Another 47% are for replacing aging equipment, and the remaining 20% are for the integration of new resources and to accommodate load growth. In addition, MISO's Long Range Transmission Plan introduced a $10.3 billion transmission project portfolio in the upper-Midwest that was appended to MTEP21 transmission projects in summer of 2022. These lines are expected to support 53 GW of renewable energy and provide $23–52 billion in benefits to MISO utilities.

Reliability Issues

MISO's planning, markets and operations continue to evolve in response to the changing resource fleet and the increased frequency of extreme weather events. Managing the increasing uncertainty is a key component of the market redefinition effort and includes transitioning to a seasonal resource adequacy construct, reforming accreditation, and enhancing scarcity pricing to better align system needs and capabilities during tight operating conditions. The seasonal resource adequacy construct has been filed at FERC and will be effective in September 2022 ahead of the 2023/2024 Planning Resource Auction. MISO is awaiting FERC approval of the updated tariff provisions.

Appendix B

Appendix B contains the Congestion Study.

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Biennial Transmission Project Report – Congestion Study

Executive Summary

This congestion study is included in compliance with the Minnesota Public Utilities Commission's June 29, 2022 order which instructed the Minnesota Transmission Owners (MTO) to include a congestion study in future Biennial Transmission Project Reports.

Per the order, this Congestion Study which includes information on the following: 1) expected sustained HVTL or generation planned outages; 2) whether those outages are anticipated to have new or incremental congestion; and 3) whether those outages are anticipated to contribute to sustained incremental congestion. The MTOs shall include this information in Biennial Transmission Projects Reports. The goal is to understand the dynamic nature that outages (both planned and forced) have on congestion.

The study looked at congestion and outages the next four quarters, Q4 2023 through Q3 of 2024. Analysis compared market prices and congestion between a benchmark "System Intact" simulation without outages, a simulation with "Planned" outages taken from the Control Room Operating Window (CROW) as known at the time of the study, and a "Planned+Forced" outages simulation adding a proxy for future unknown forced outages (forced outages from 2021-2022 time-shifted to the study period).

The analysis found that in each quarter there were outages that significantly impacted average Locational Marginal Prices (LMPs) in the simulations. Specific outages contributing to the congestion are identified. The simulations do not include operating guides or system reconfigurations which may be planned to mitigate the congestion identified in this study.

Average LMP for Local Resource Zone 1 (LRZ1) areas during each quarter are shown in the tables below. Relatively small price differences ($0 to $2) do not indicate concern for any specific outages in the area.

DPC – Dairyland Power Cooperative
GRE – Great River Energy
MP - Minnesota Power
NSP – Northern States Power (Xcel)
OTP – Otter Tail Power
SMP – Southern Minnesota Municipal Power Agency

Table: Average LMPs

	2023 Q4				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$32.03	$35.36	+$3.33	$34.73	-$0.63
GRE	$29.00	$29.51	+$0.51	$28.14	-$1.37
MP	$29.19	$27.86	-$1.33	$26.65	-$1.21
NSP	$29.62	$31.82	+$2.20	$31.00	-$0.82
OTP	$28.70	$92.32	+$63.62	$90.28	-$2.04
SMP	$28.19	$27.64	-$0.55	$26.48	-$1.16

The LMP difference for OTP is driven by two outages: Donaldson to Drayton October 2-6, 2023, and Winger 115 kV outage November 13-24, 2023.

Table: Average LMPs

	2024 Q1				
Area	System Intact	Planned	Difference vs System Intact	Planned+Forced	Difference vs Planned
DPC	$32.92	$33.35	+$0.43	$32.28	-$1.07
GRE	$30.52	$32.15	+$1.63	$31.08	-$1.07
MP	$32.36	$63.43	+$31.08	$62.54	-$0.90
NSP	$30.77	$33.59	+$2.81	$33.62	+$0.04
OTP	$28.82	$28.75	-$0.07	$26.78	-$1.97
SMP	$26.72	$26.47	-$0.25	$24.69	-$1.78

The LMP difference for MP is driven by the outage of Ortman to Little Fork 230 kV January 1- March 9, 2024.

Table: Average LMPs

	2024 Q2				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$34.21	$34.83	+$0.62	$33.16	-$1.67
GRE	$28.47	$29.34	+$0.88	$28.34	-$1.00
MP	$30.45	$30.84	+$0.38	$29.08	-$1.75
NSP	$29.53	$30.33	+$0.81	$29.33	-$1.01
OTP	$27.98	$41.44	+$13.46	$48.65	+$7.21
SMP	$27.60	$27.88	+$0.28	$26.52	-$1.36

The LMP difference for OTP is driven by the outage of Forman 230/115 kV transformer and related outages May 1- August 30, 2024.

Table: Average LMPs

	2024 Q3				
Area	System Intact	Planned	Difference vs System Intact	Planned+ Forced	Difference vs Planned
DPC	$46.34	$45.58	-$0.76	$44.91	-$0.68
GRE	$42.70	$41.30	-$1.40	$42.61	+$1.30
MP	$43.42	$41.83	-$1.59	$39.87	-$1.96
NSP	$42.22	$40.84	-$1.39	$40.81	-$0.03
OTP	$48.95	$56.11	+$7.15	$63.28	+$7.17
SMP	$40.32	$38.56	-$1.76	$38.72	+$0.16

The LMP difference for OTP is driven by the outage of Forman 230/115 kV transformer and related outages May 1 - August 30, 2024.

Observations

- Congestion is typically highest in times with high wind around the morning or evening peak load.
- The system intact operating state has significant baseline congestion.
- The operating state with CROW outages increases congestion moderately.
  - Most outages have minimal impact, a few specific outages show potential for greater congestion impact.
- The operating state with CROW and a selected set of forced outages also increases congestion moderately.
- Patterns in all of the operating states show congestion between:
  - Wind generation areas in southwest Minnesota and the Twin Cities metro;
  - Minnesota and Wisconsin;
  - Twin Cities and northern Minnesota; and
  - Dakotas/far western Minnesota and the rest of Minnesota.

Model

Future congestion was simulated using PROMOD production cost modeling software. The source model for the simulation was MISO MTEP21 Future 1 2025 model adjusted to represent the system conditions for the four quarters from Q4 2023 through Q3 2024. The source model uses 2018 weather data for wind and solar output profiles representing a typical year and does not forecast 2022 weather, so a direct hour-by-hour comparison of results to actual congestion will be different due to weather patterns and other assumptions such as fuel price forecasts. The simulation calculates results on hourly timesteps.

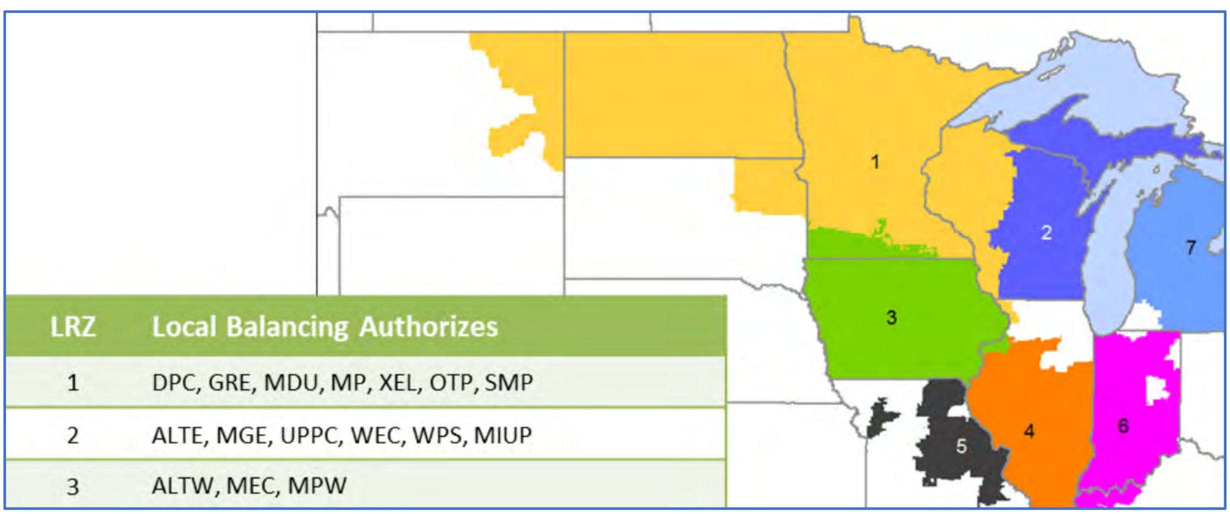
Three operating states of the electric grid were simulated:

- System Intact – Baseline with all transmission available.
- Control Room Operating Window (CROW) – Planned outages added.
- Forced Outages – Planned outages plus historical outages from 2021-2022 time-shifted forward to the study period.

Future forced outages are characteristically unpredictable, so the past events modeled are a proxy for unknown future forces outages and should not be viewed as a specific forecast of events, but as demonstration of wider scale trends due to forced outages.

Shadow price sums reported are a measure of the relative impact of constraints and do not represent to cost savings of fixing the constraint. Fuel mix and load is reported for MISO North in MWh. Constraints are reported for the LRZ1 (footprint as shown below).

The model may be overly sensitive to 69 kV constraints like Cleveland-Le Center and Spring Creek compared to recent historical constraints. Simulations with those constraints unenforced show similar impact in the results due to planned and forced outages.



LRZ	Local Balancing Authorizes
1	DPC, GRE, MDU, MP, XEL, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS, MIUP
3	ALTW, MEC, MPW

System Intact Congestion

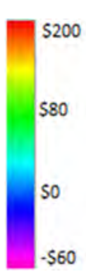
Similar congestion patterns appear in many hours throughout the simulation. Representative hours from the simulation were selected to show the typical conditions causing congestion. This section shows a map of LMPs and constraints for each representative hour and a pie chart of the MISO north generation fuel mix each hour. The table below shows the percent of time the facility is a constraint in the market and a sum of the Shadow Price, which is a measure of the marginal value of the constraint, not the savings if it were to be mitigated.

Table: Top Constraints Shadow Price Sum and Percent of Quarter Binding

Constraint	Map	Q4 2023	Q1 2024	Q2 2024	Q3 2024
ABDNJCT7 to ELLENDL7 #1	AE	$12253 (7%)	$3850 (2%)	$8843 (5%)	$2687 (2%)
ADAMS 5 to BVR CRK5 #1	AB			-$30586 (10%)	-$9711 (4%)
BIGSTON4 to BROWNSV4 #1	BB	-$13890 (3%)		-$35039 (9%)	-$81030 (12%)
BROWNSV4 to NEW EFFNGTN4 #1	BN	-$1563 (1%)	-$6576 (4%)		
BLCKBRY4 to GRE-SWTRX3A4 #1	BS			-$14277 (8%)	-$27859 (6%)
FORMN 7 to FORMAN 7 #1	FT	-$150111 (15%)	-$675665 (46%)	-$167422 (19%)	-$242468 (21%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	CT	$10682 (4%)	$39810 (18%)	$5429 (3%)	$2755 (2%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	CT	-$3119 (1%)	-$3788 (2%)	-$1175 (0%)	-$203 (0%)
GRE-CLVLAND8 to LECENTR8 #1	CL	-$138514 (10%)	-$465853 (31%)	-$172296 (16%)	-$199207 (11%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	SC	-$136419 (5%)	-$111942 (7%)	-$39143 (1%)	-$45459 (1%)
HELENA 3 to SCOTTCO3 #1	HS	-$2002 (4%)	-$1153 (4%)		-$9 (0%)
HIBBARD7 to WNTR ST7 #1	HW	-$9383 (5%)	-$10831 (5%)	-$116555 (39%)	-$155900 (27%)
MINVALT4 to GRANITF4 #1	MG	$11635 (3%)	$1103 (0%)	$1702 (1%)	$2373 (1%)
RVT1BUS7 to GRE-MERRFLD7 #1	RM			-$251 (0%)	-$212686 (2%)
WILMART7 to SWAN LK7 #1	WS			-$9675 (2%)	-$12994 (3%)

Map Legend:

LMP in $/MWH



Pink Lines:

Constraints labeled with two letter code in table above

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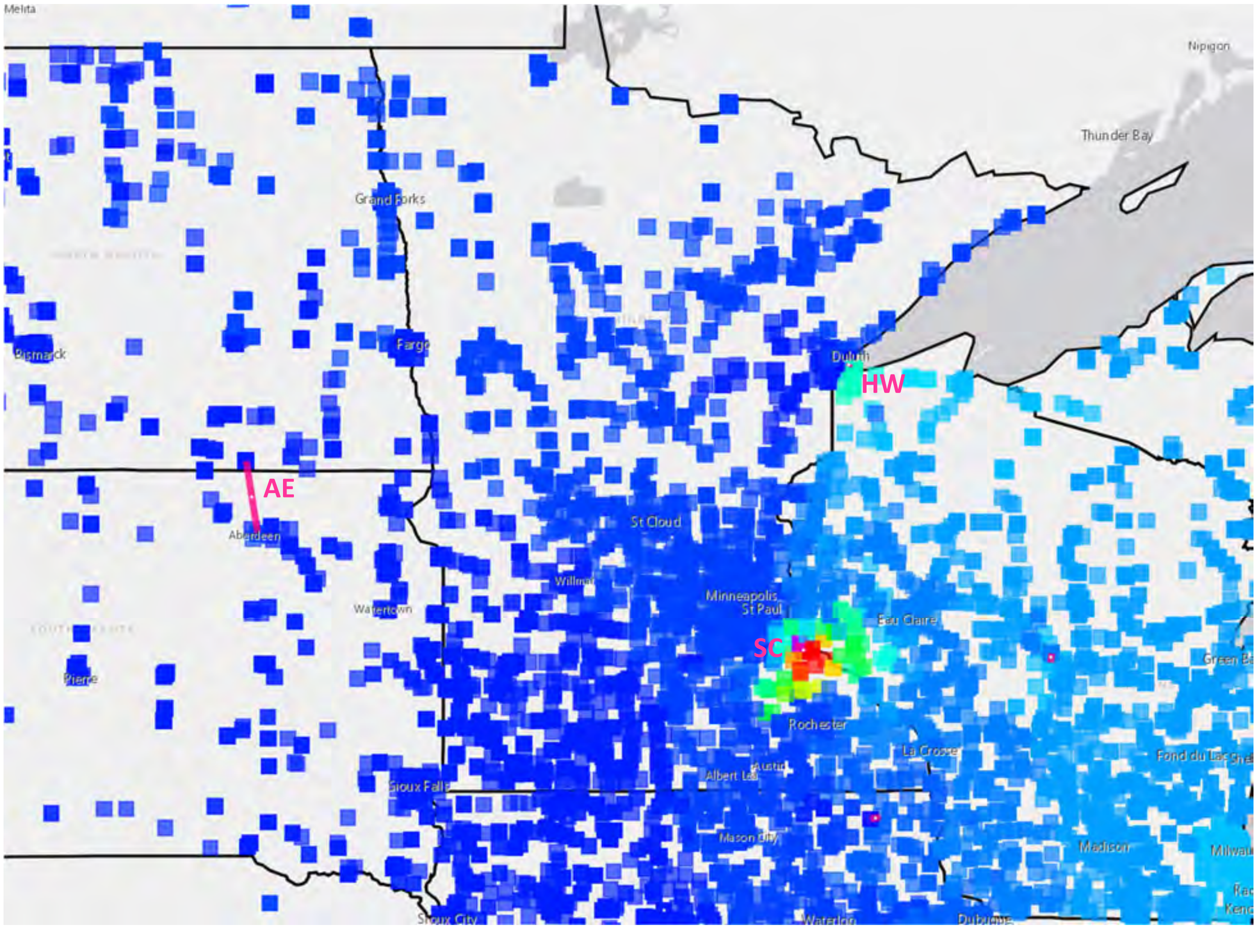

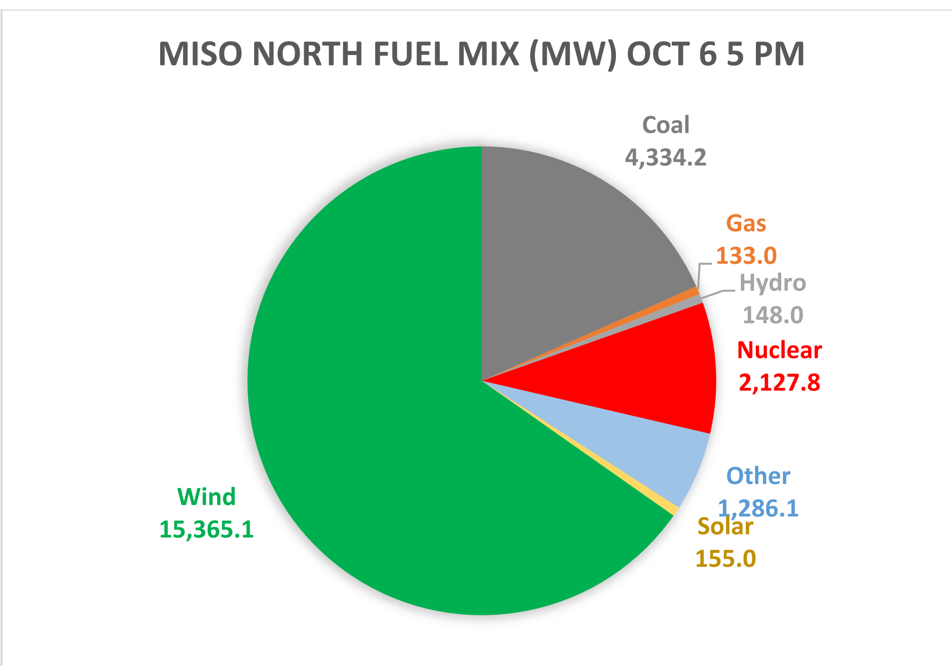

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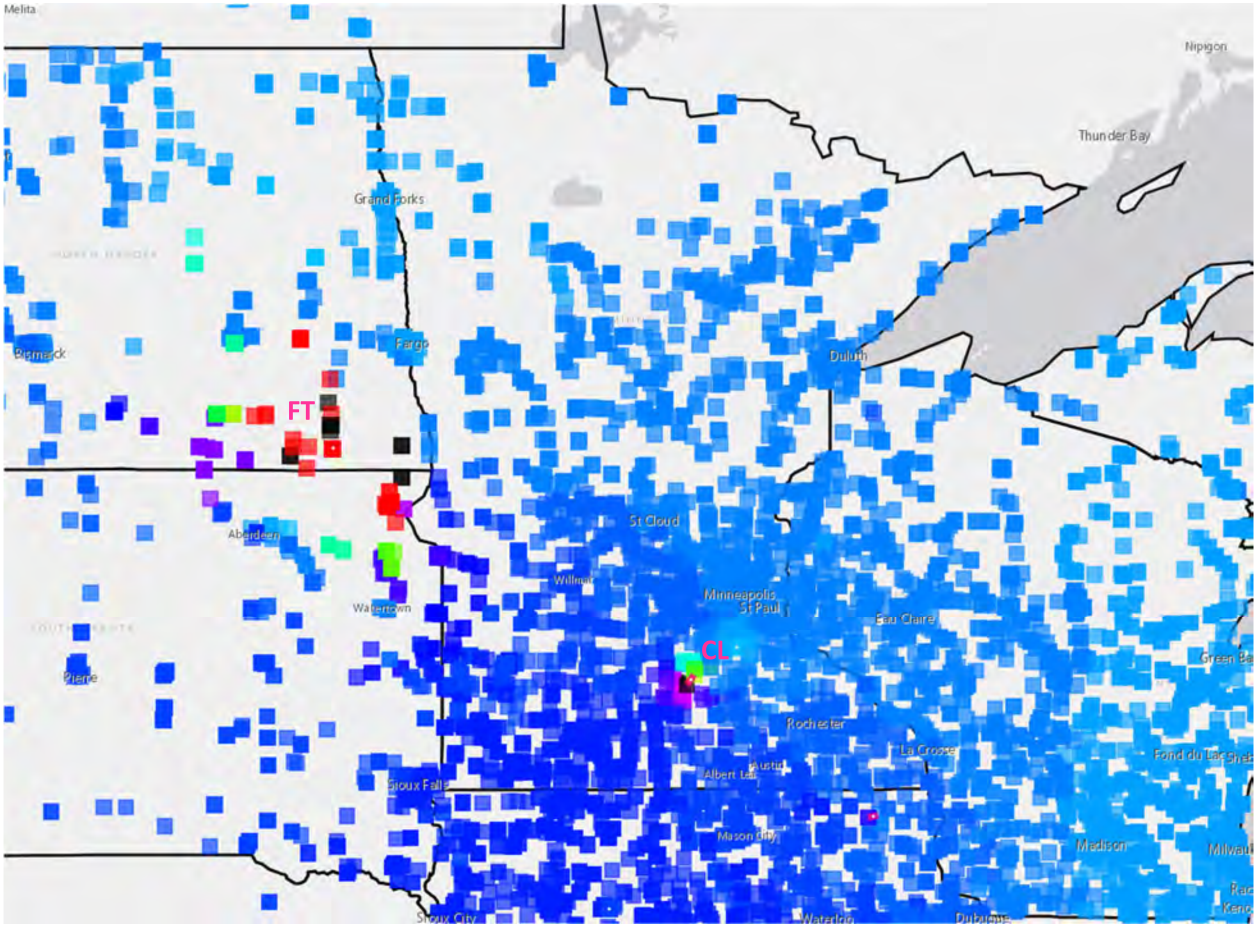

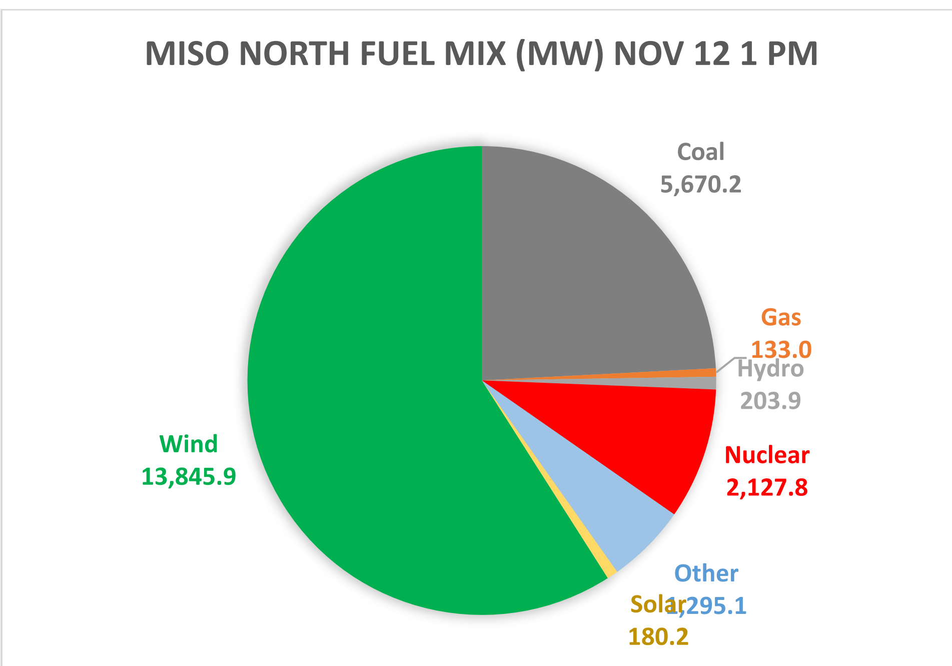

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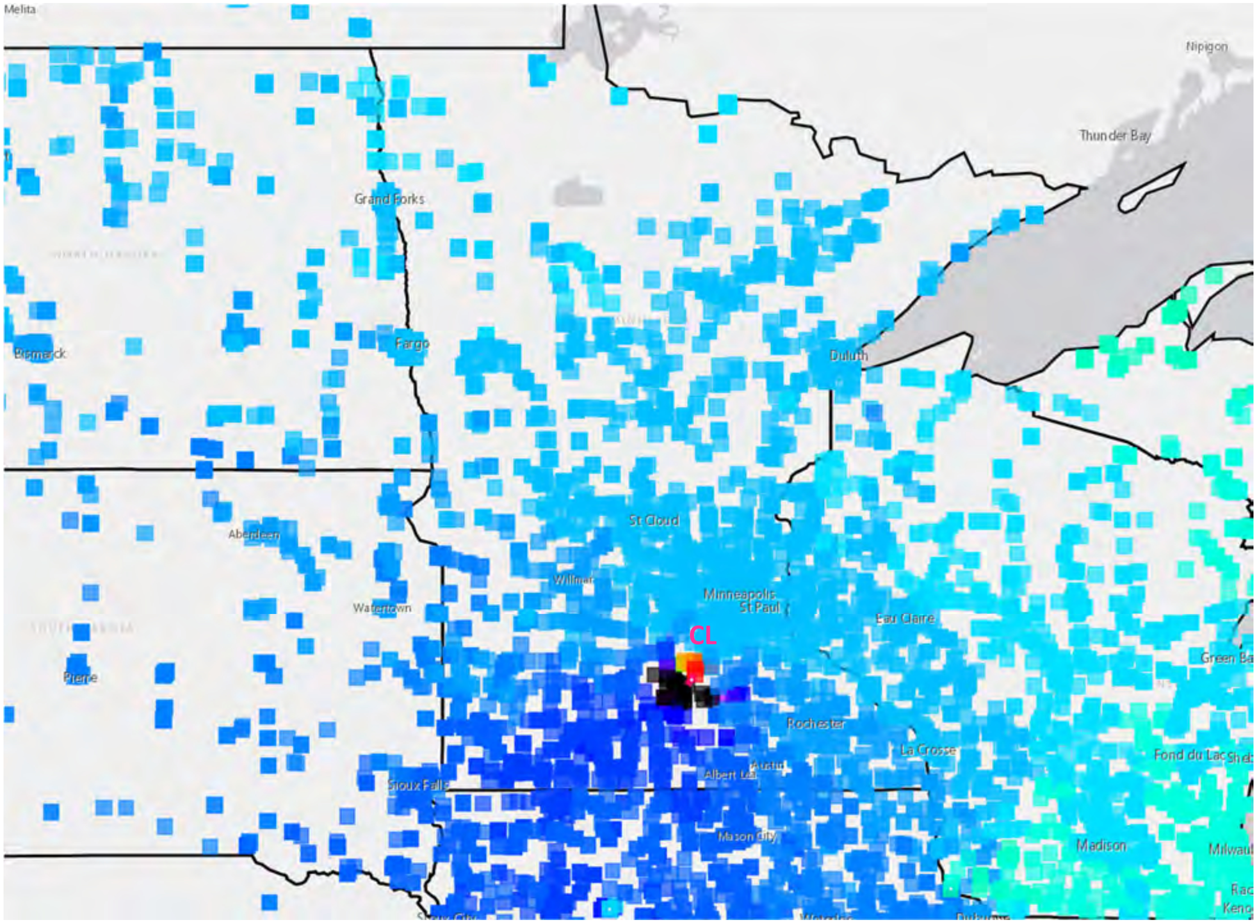

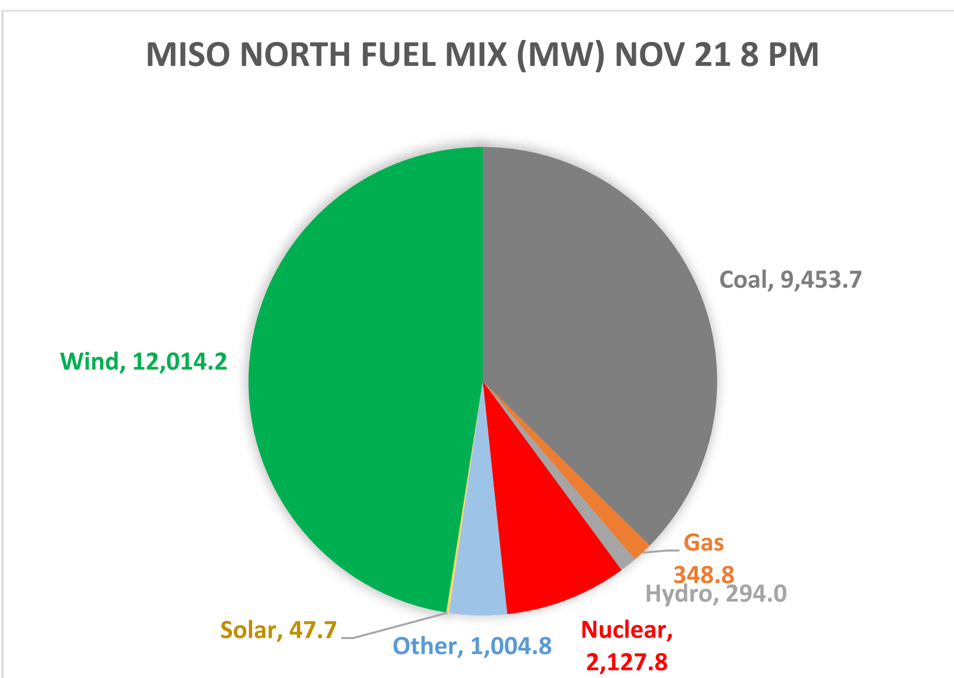

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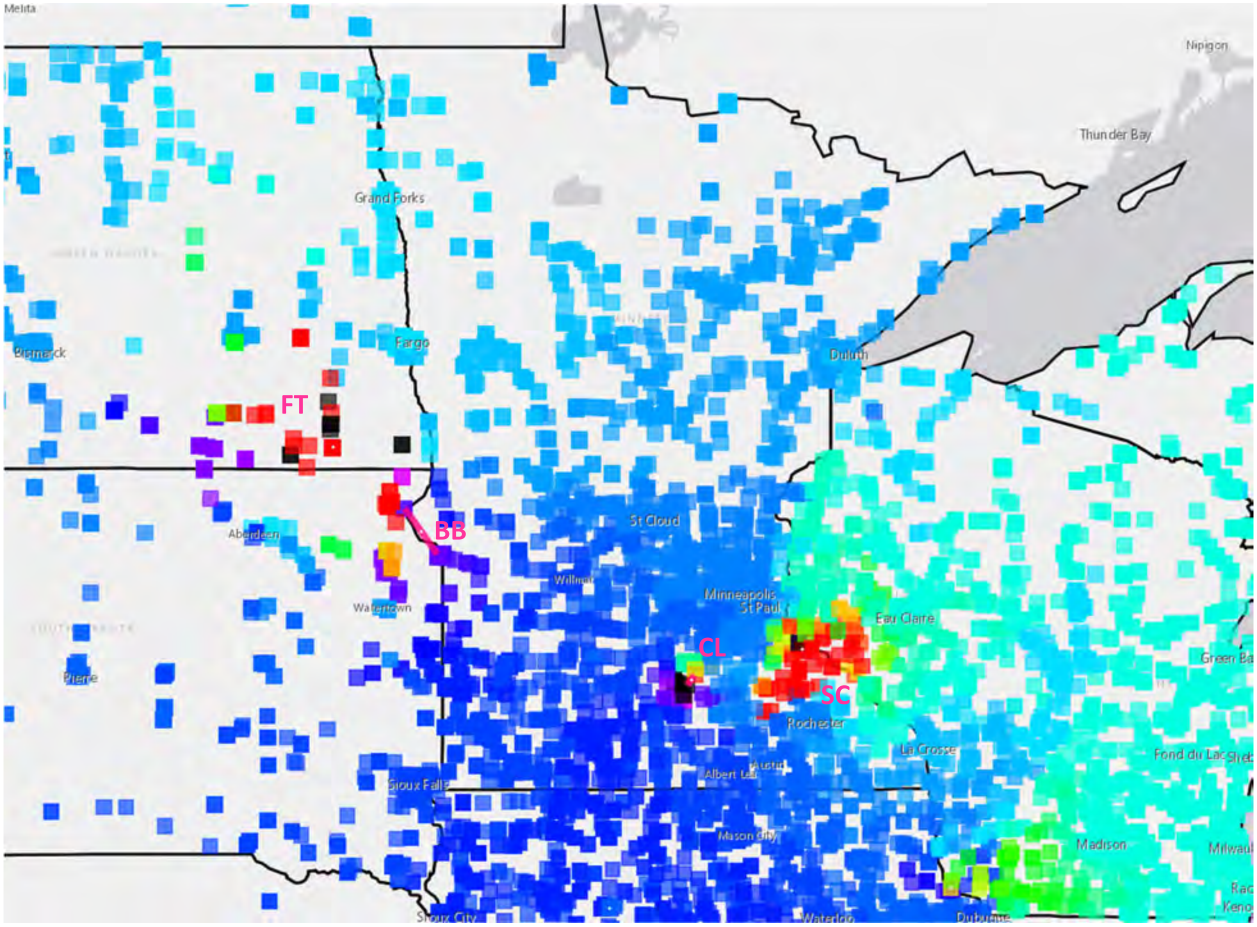

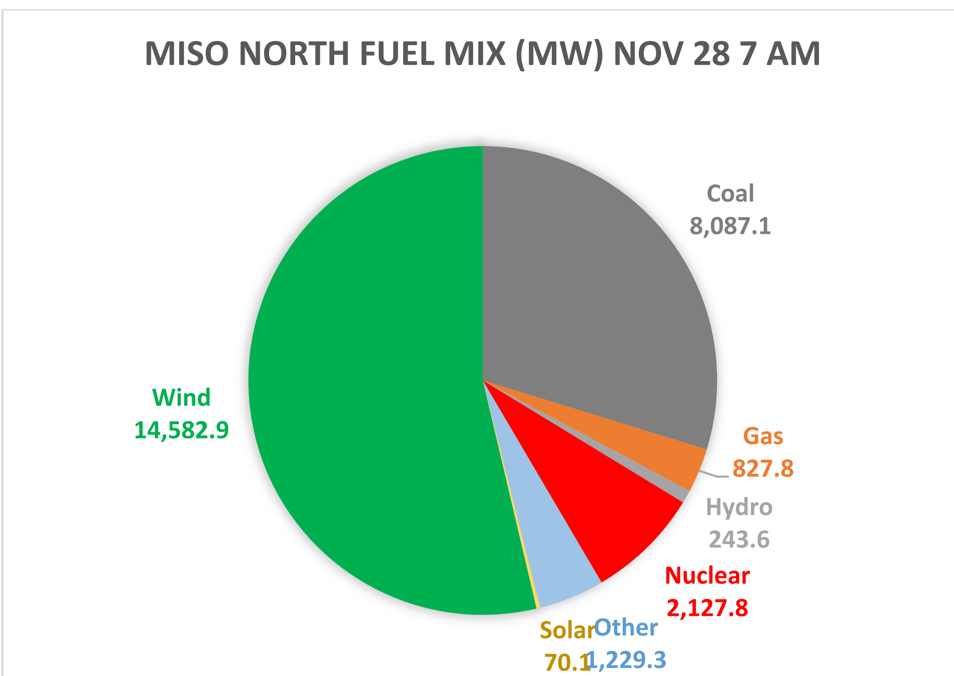

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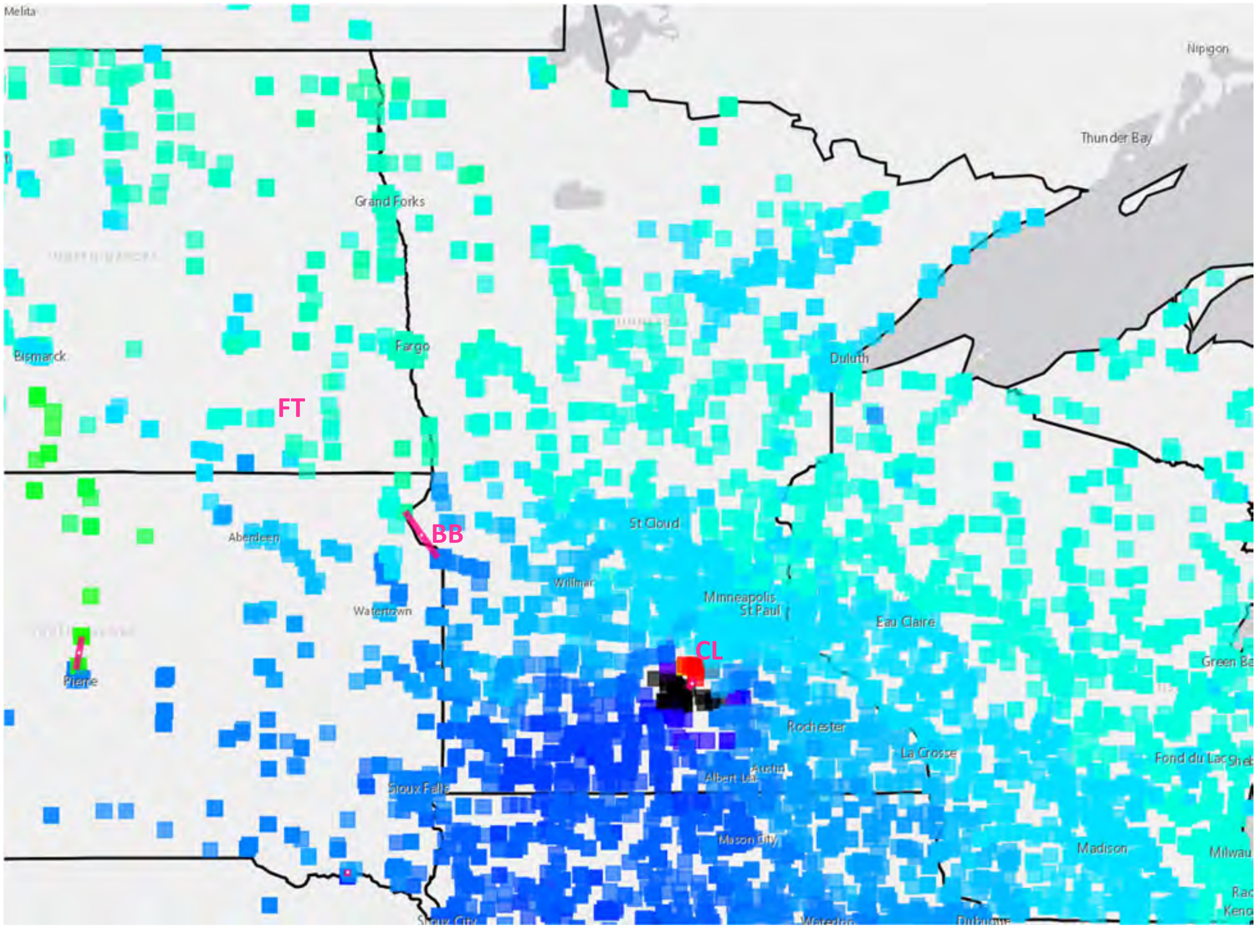

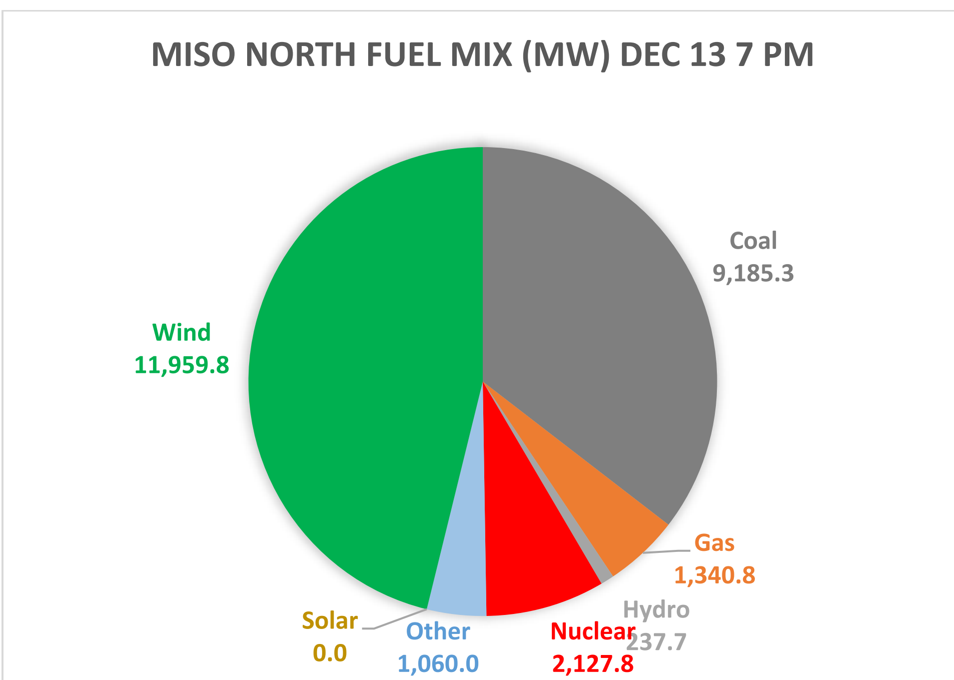

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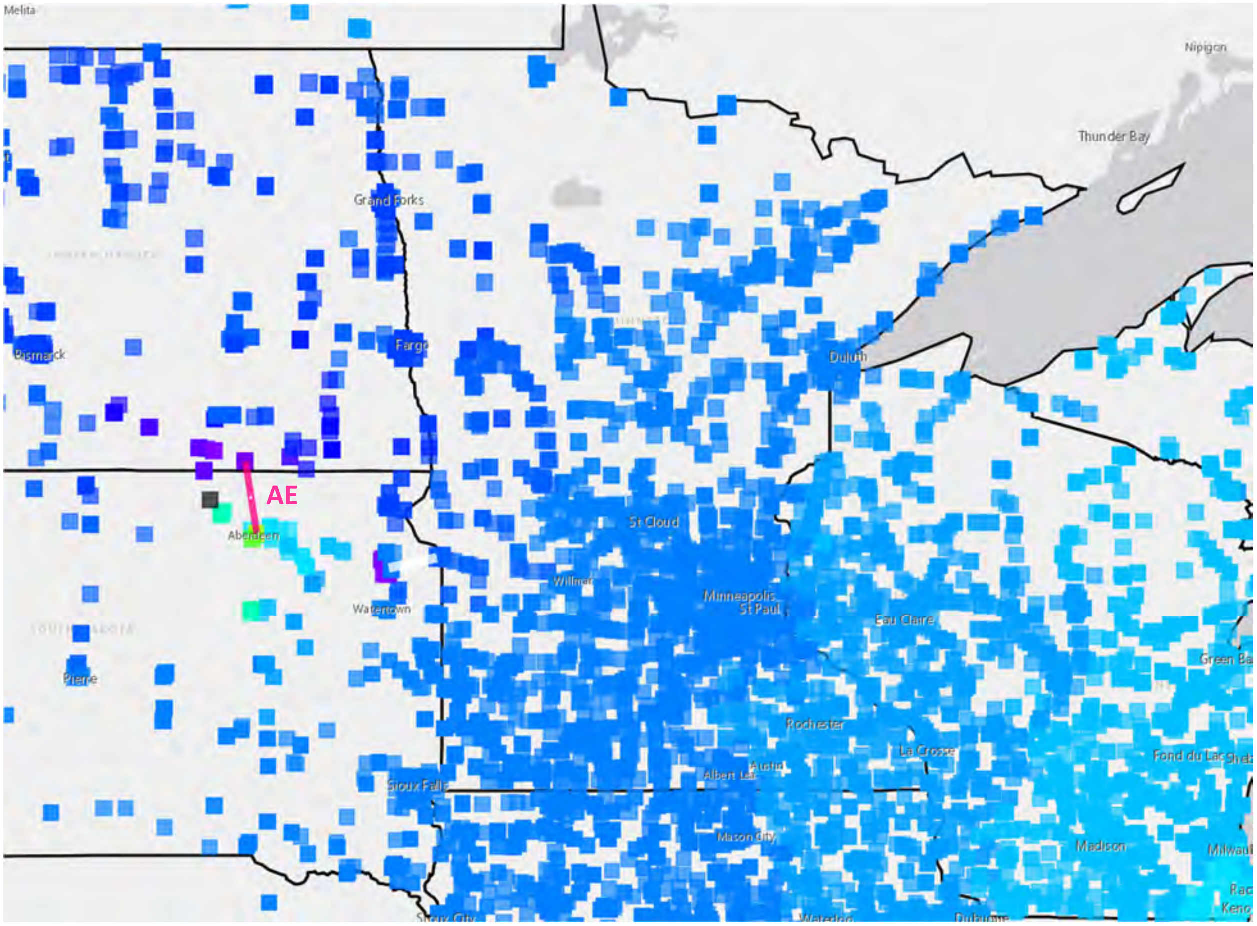
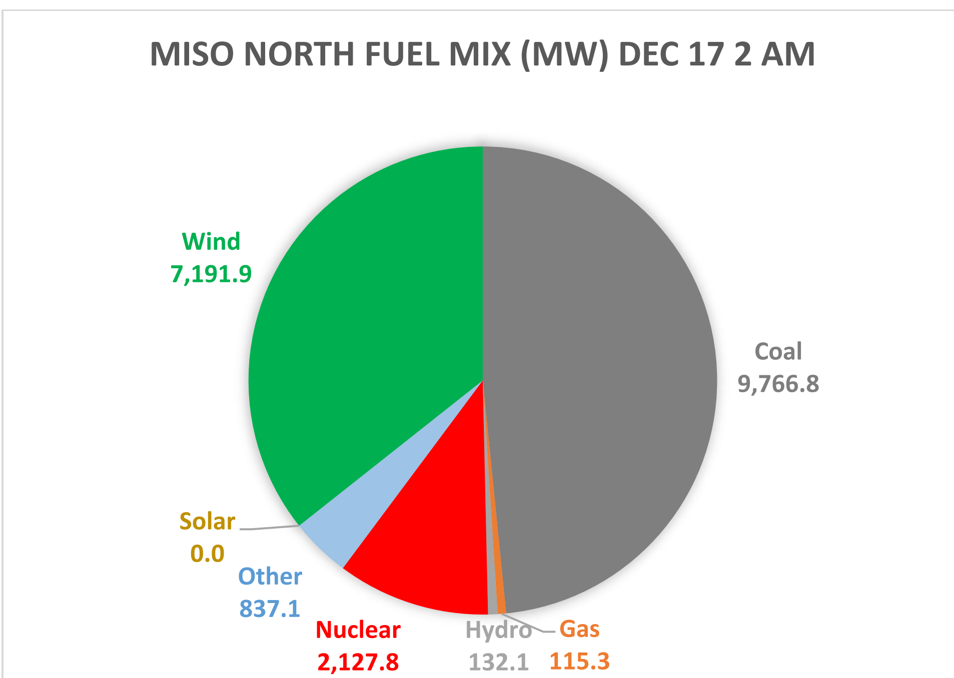
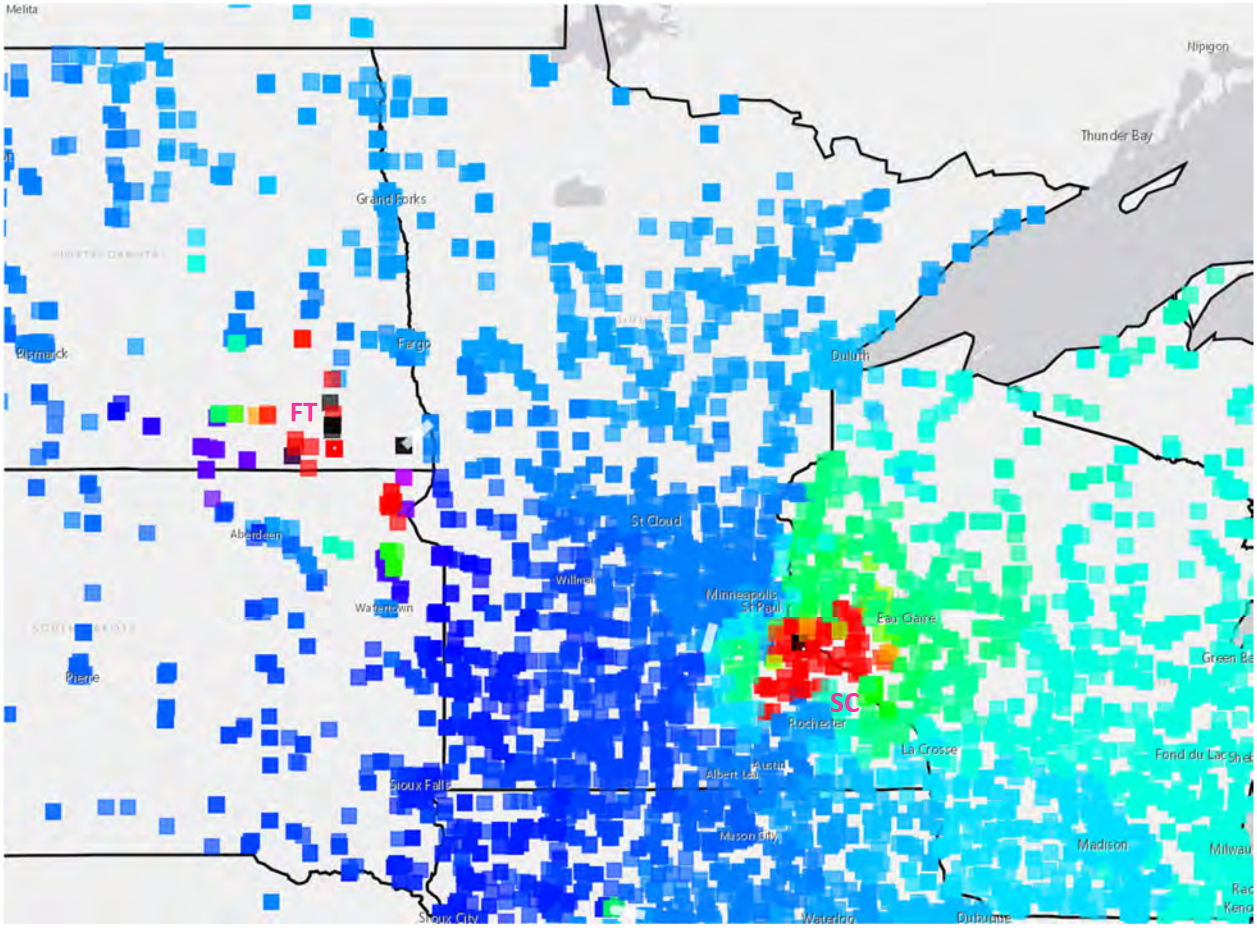
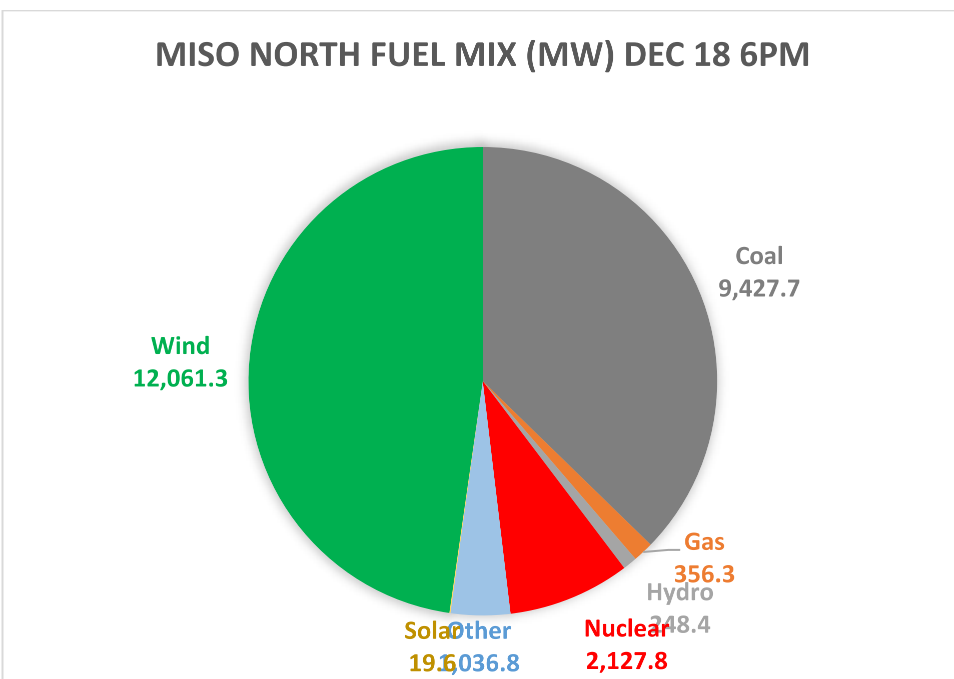




December 18, 2023, 6:00 P.M.





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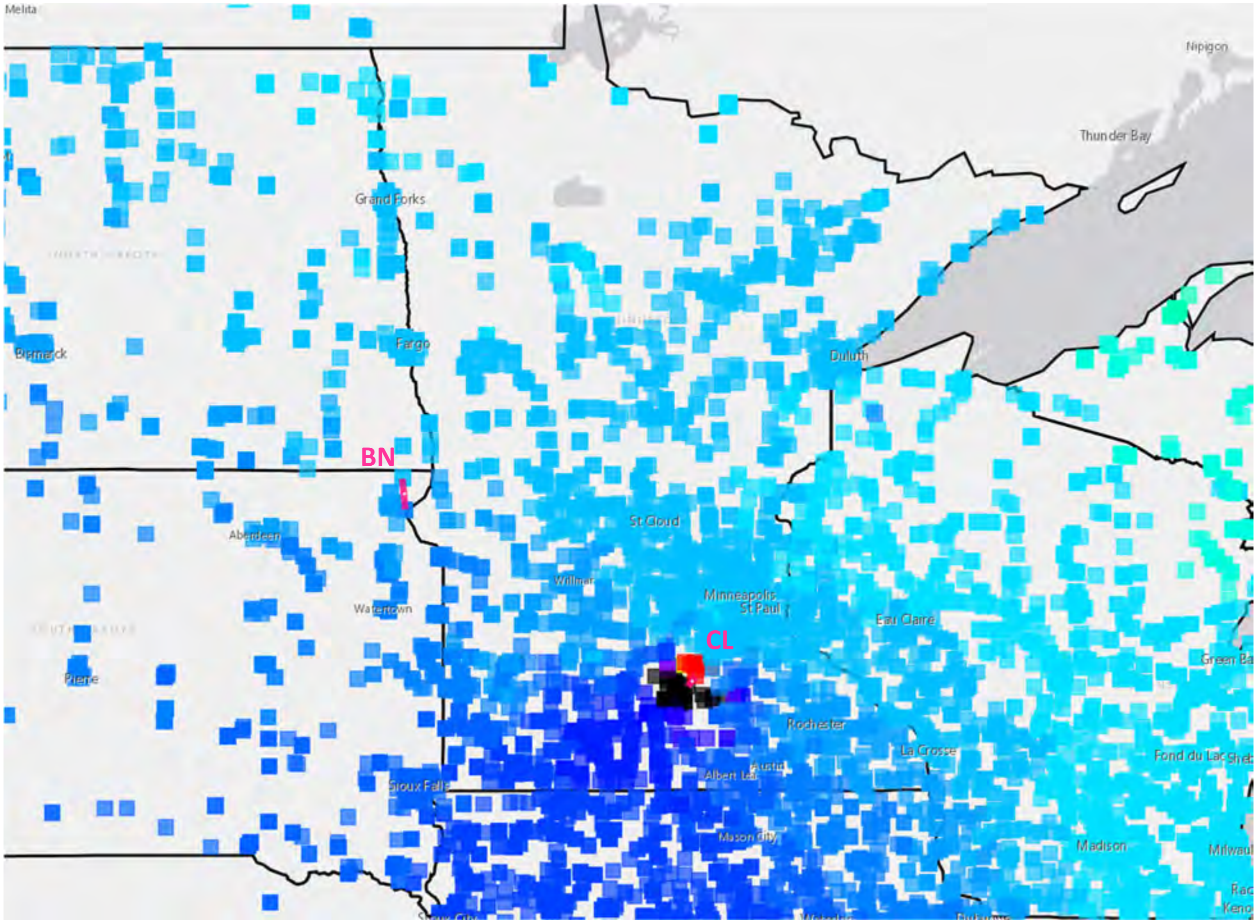

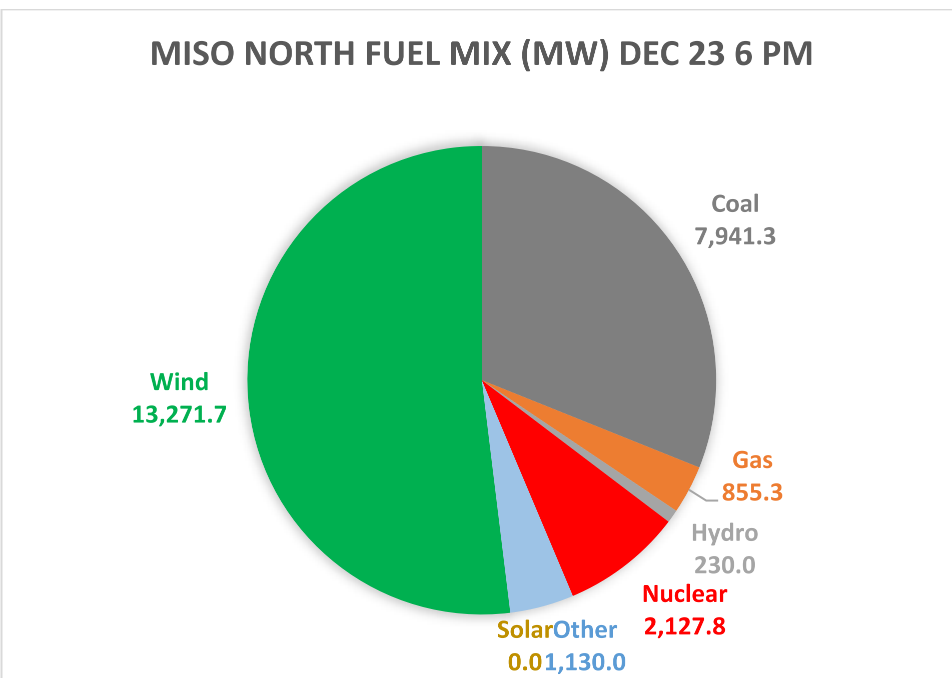

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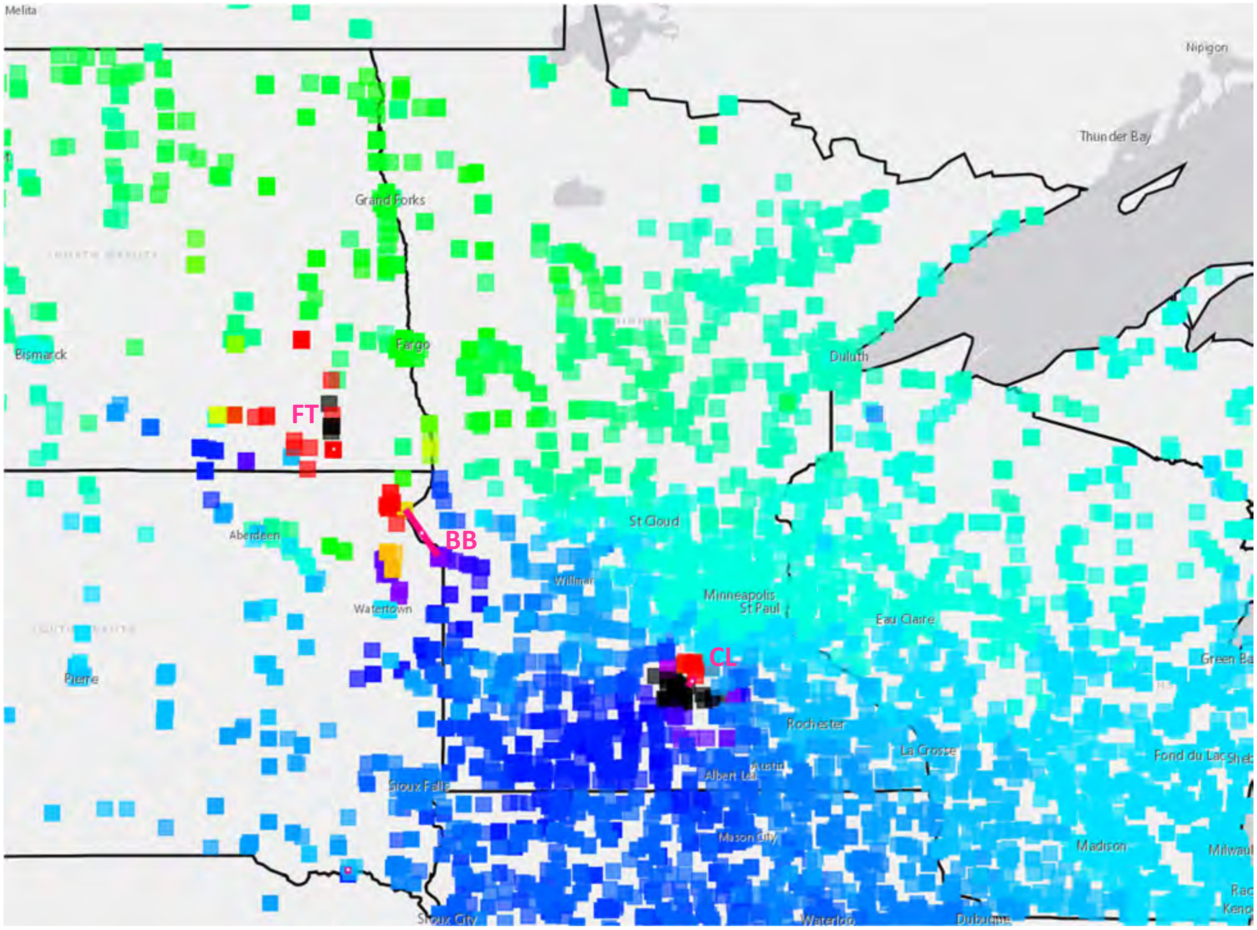
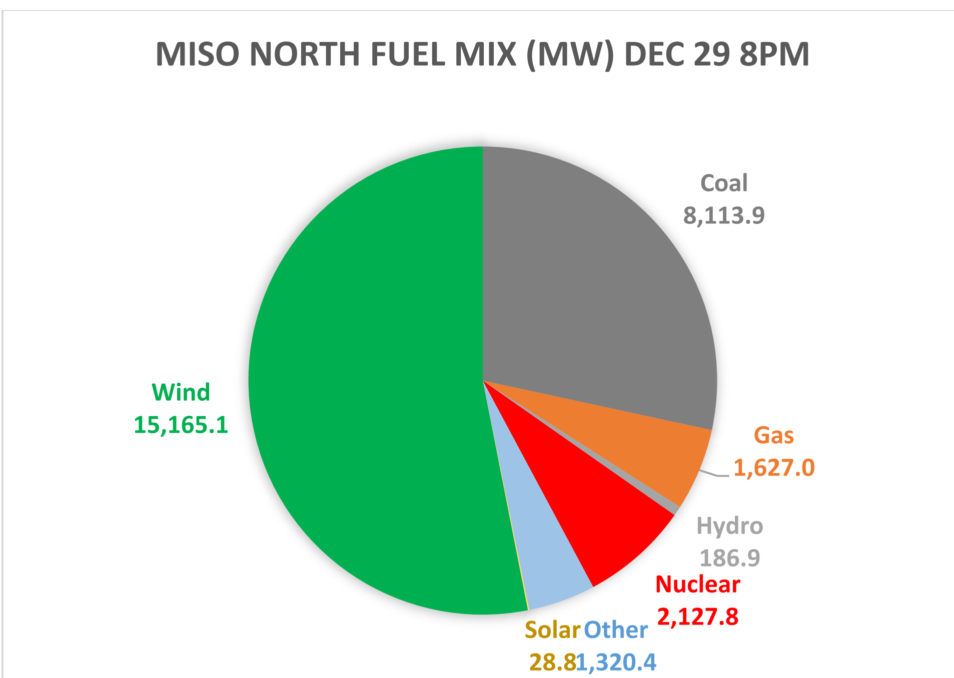
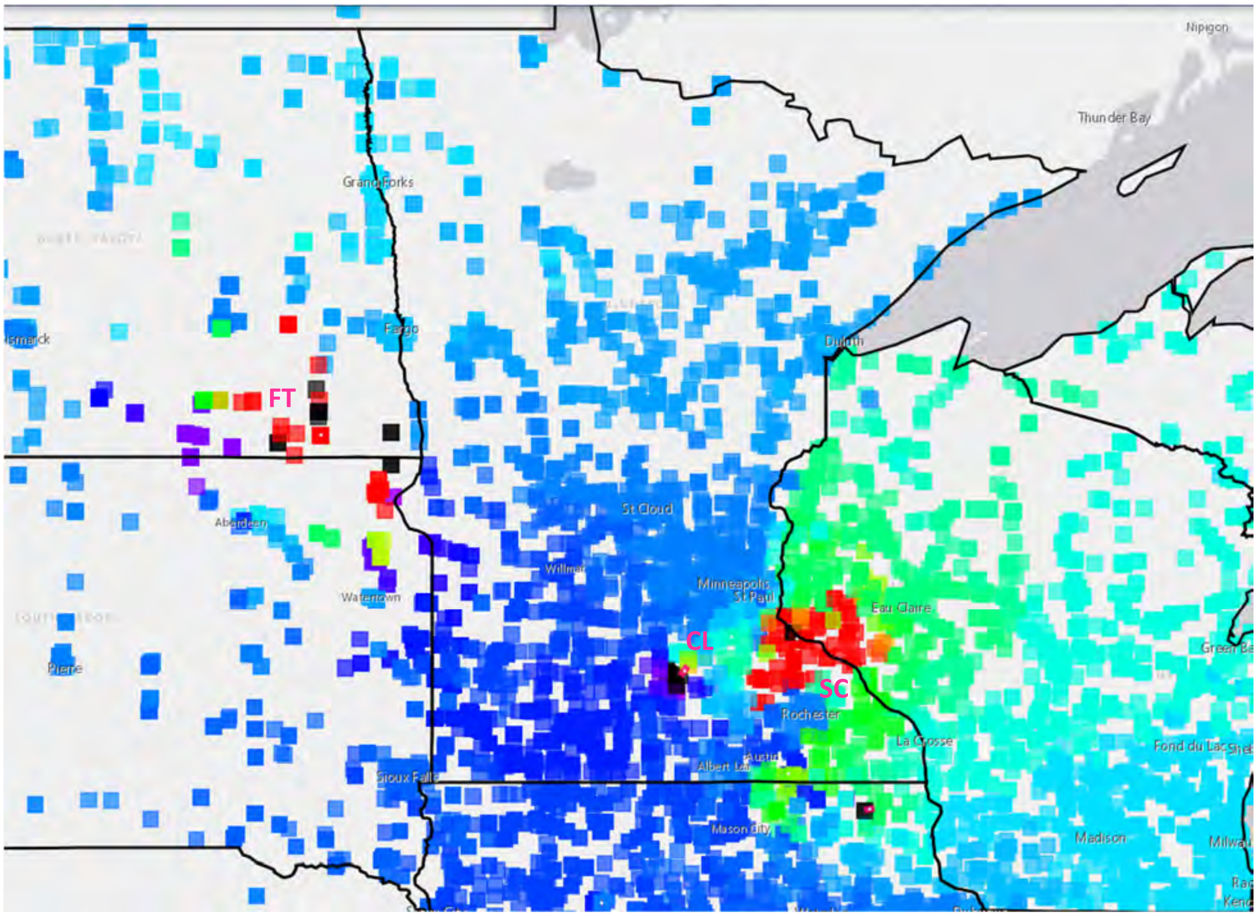
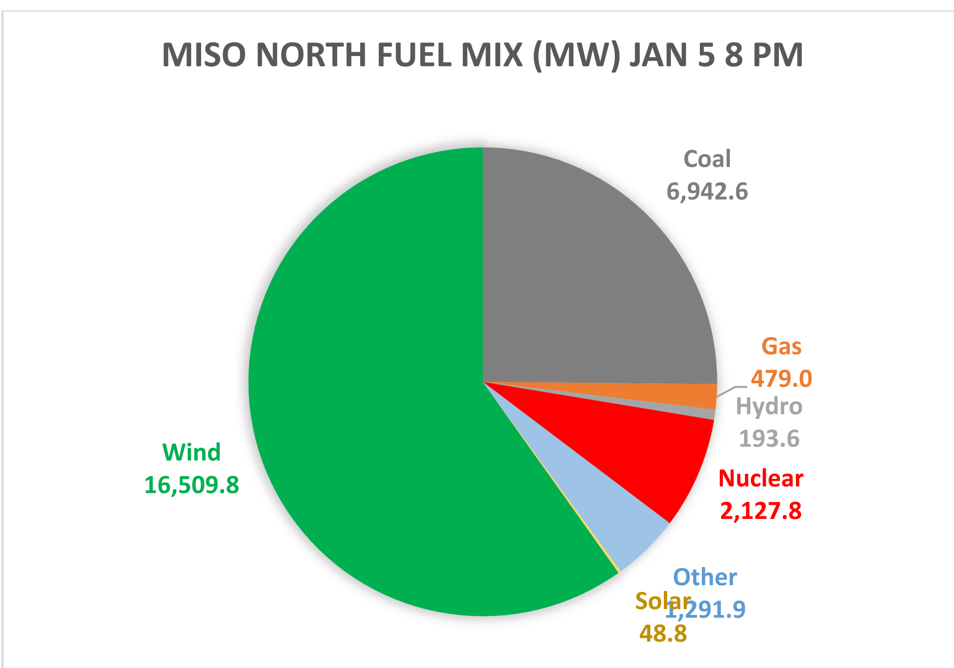


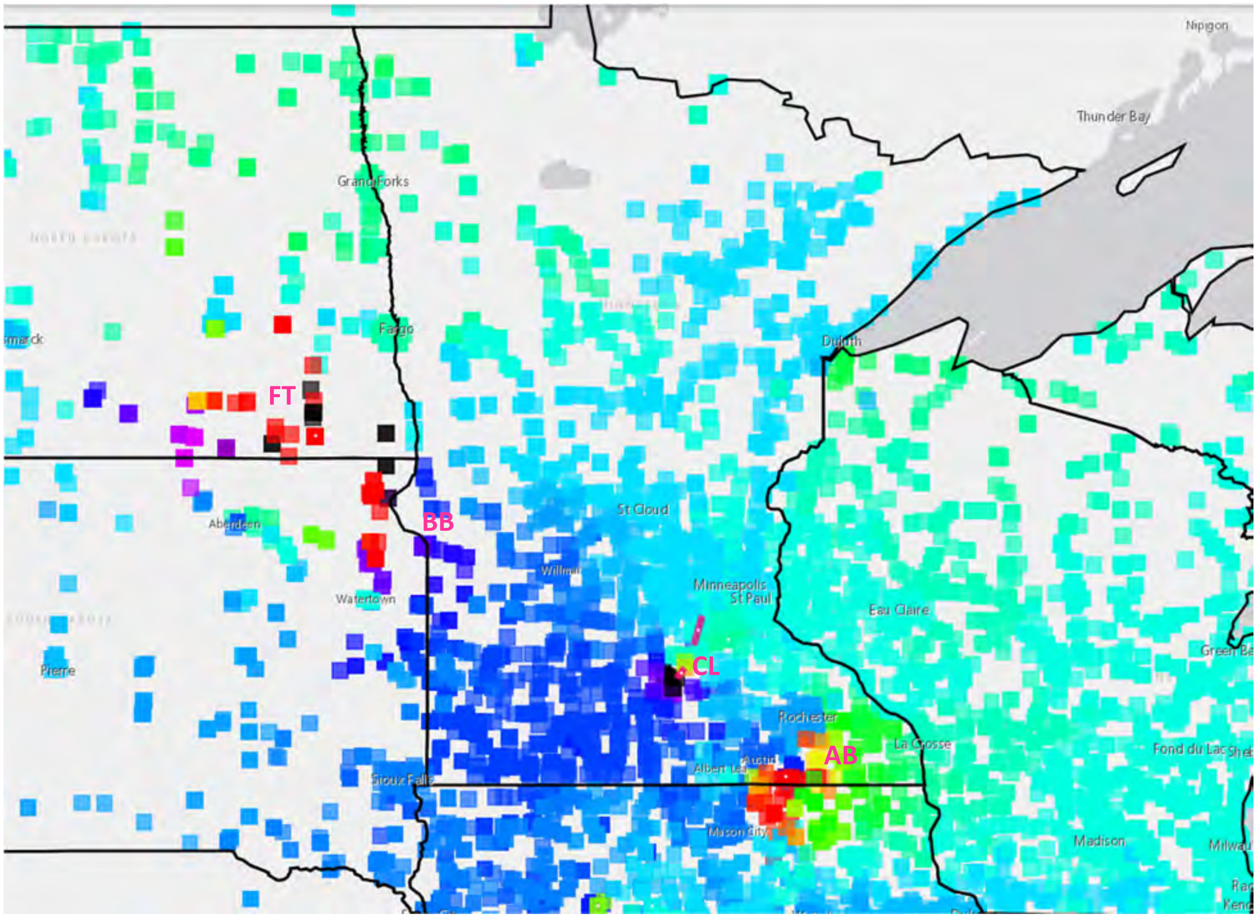


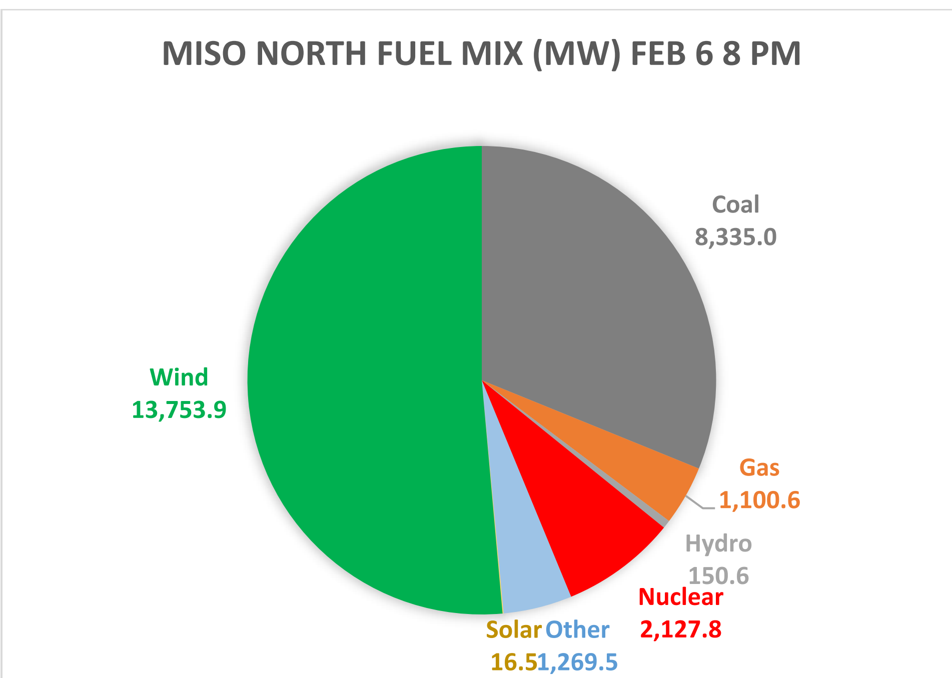
January 5, 2024, 8:00 P.M.



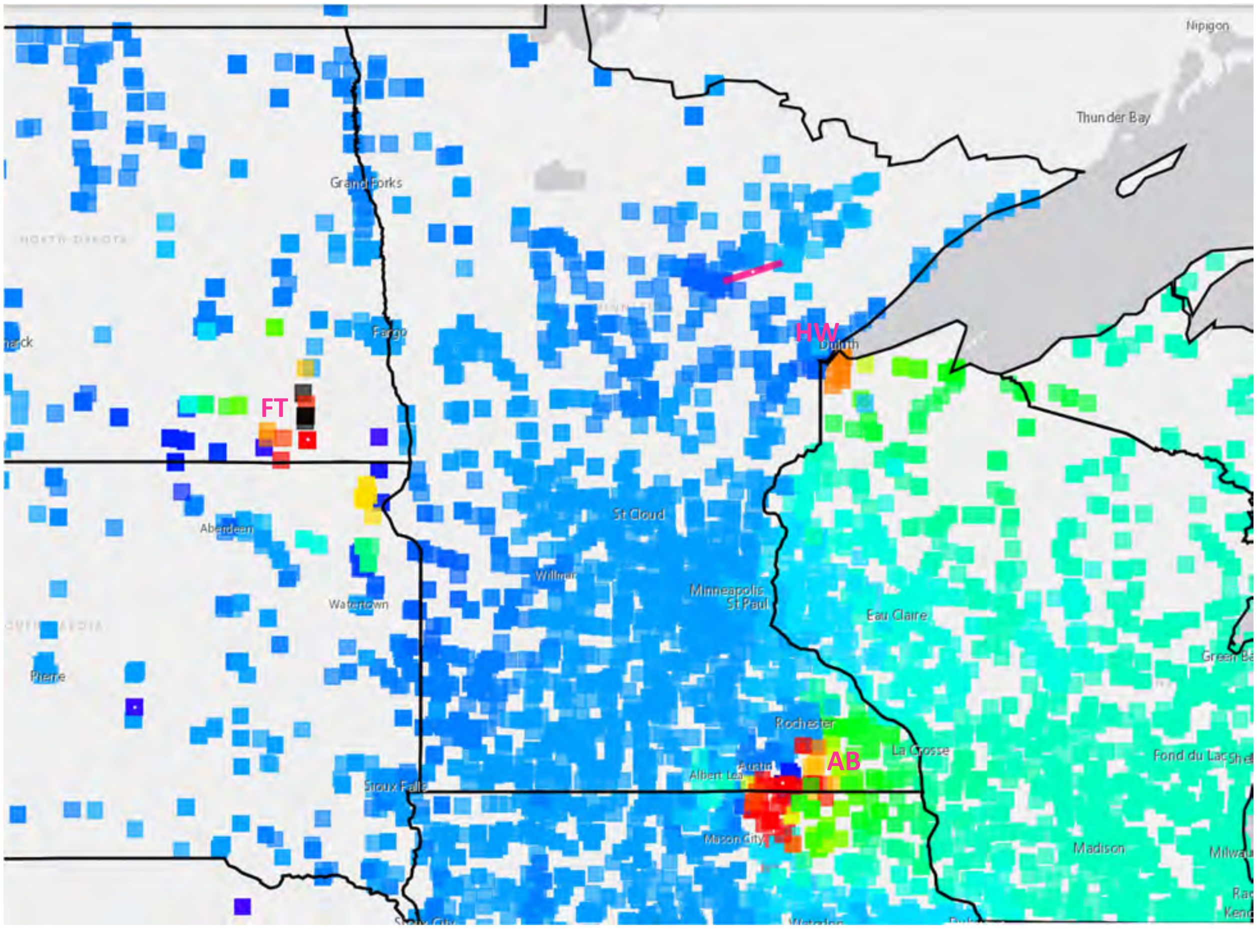


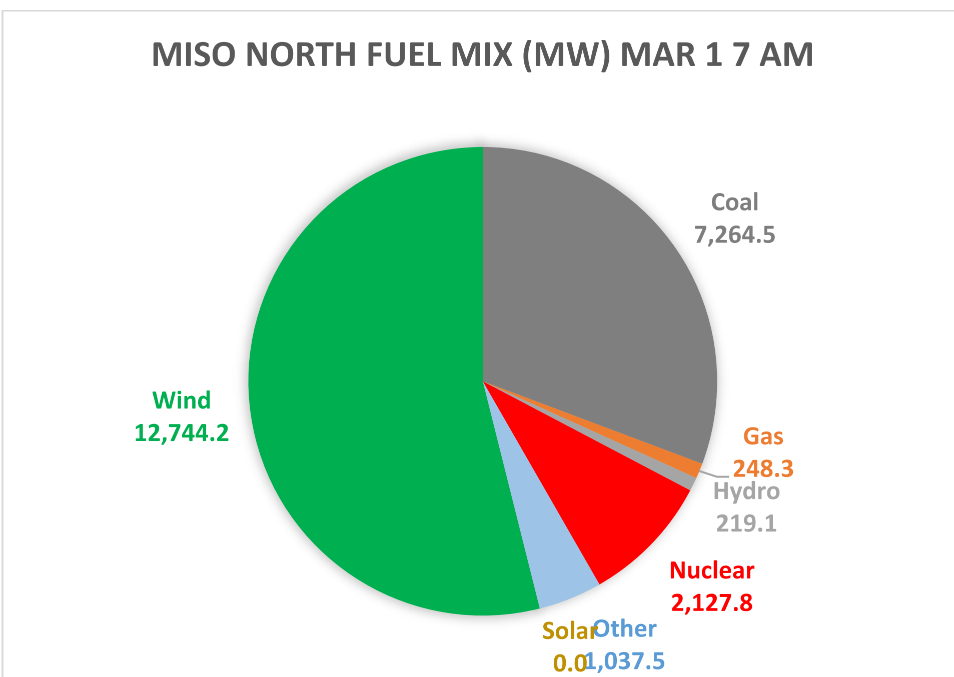
February 6, 2024, 8:00 P.M.



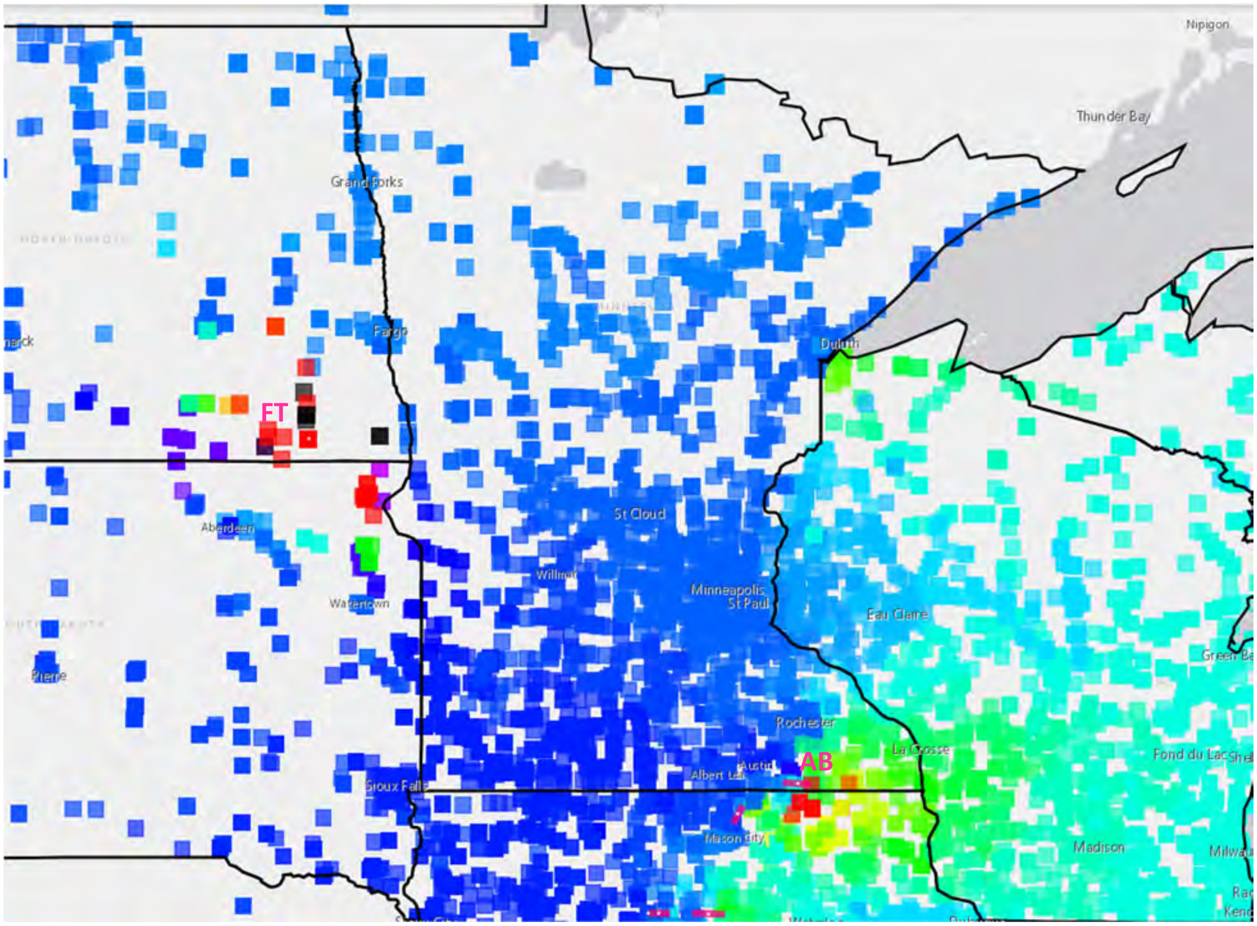


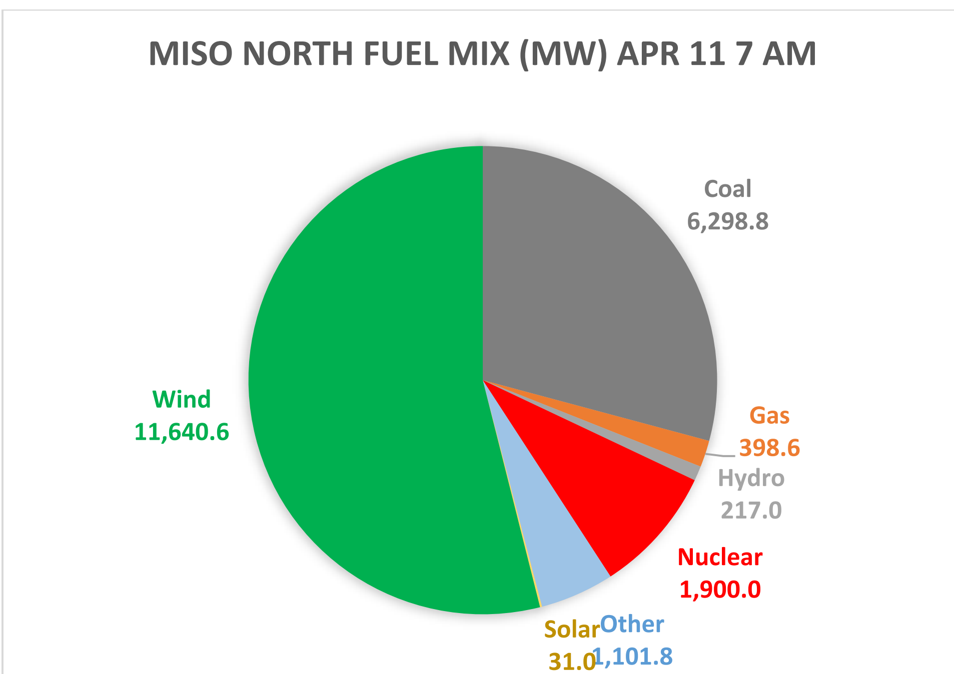
March 1, 2024, 7:00 A.M.



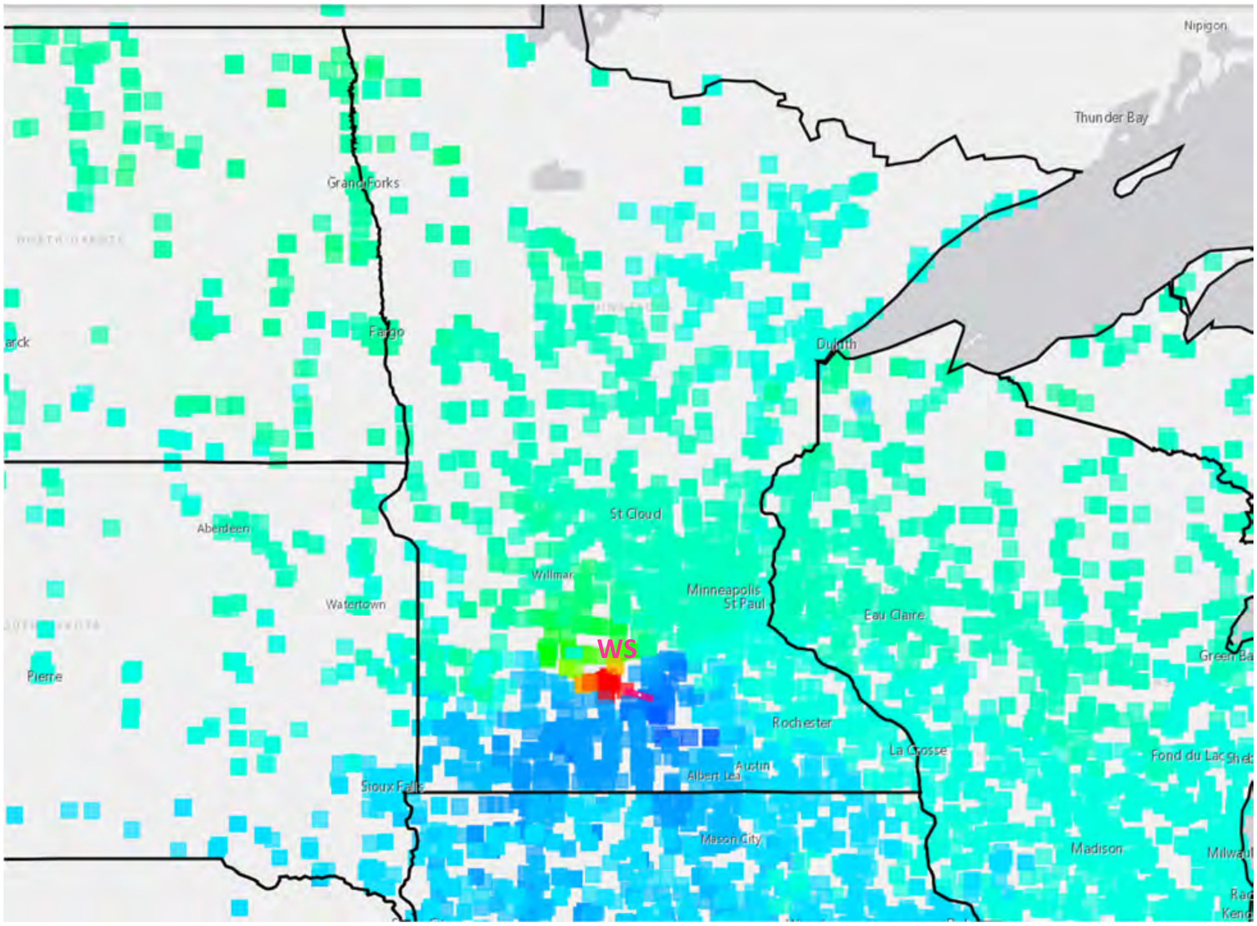


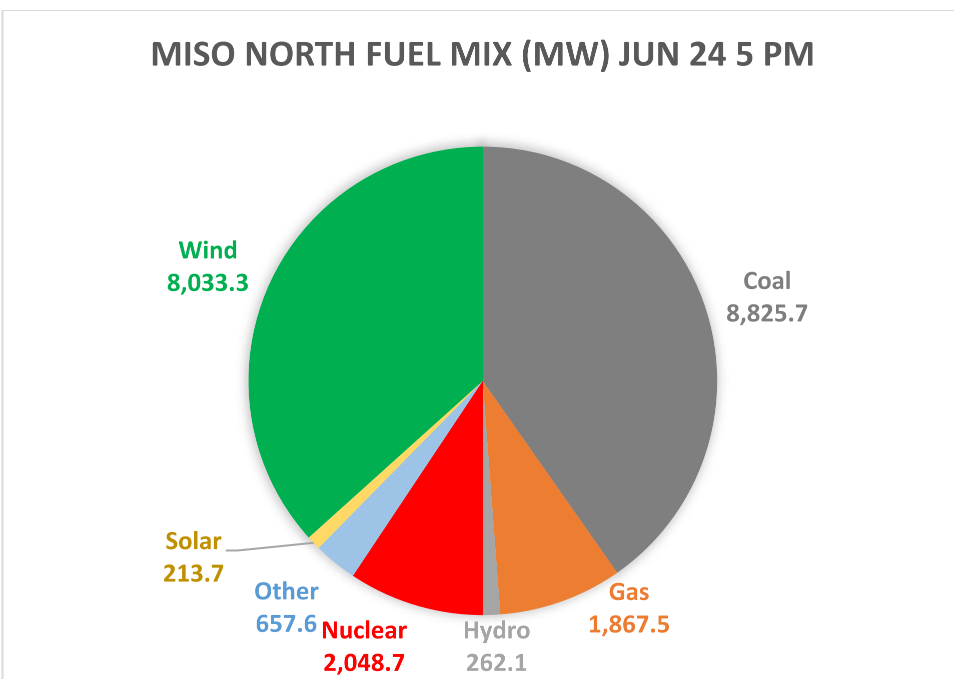
April 11, 2024, 7:00 A.M.



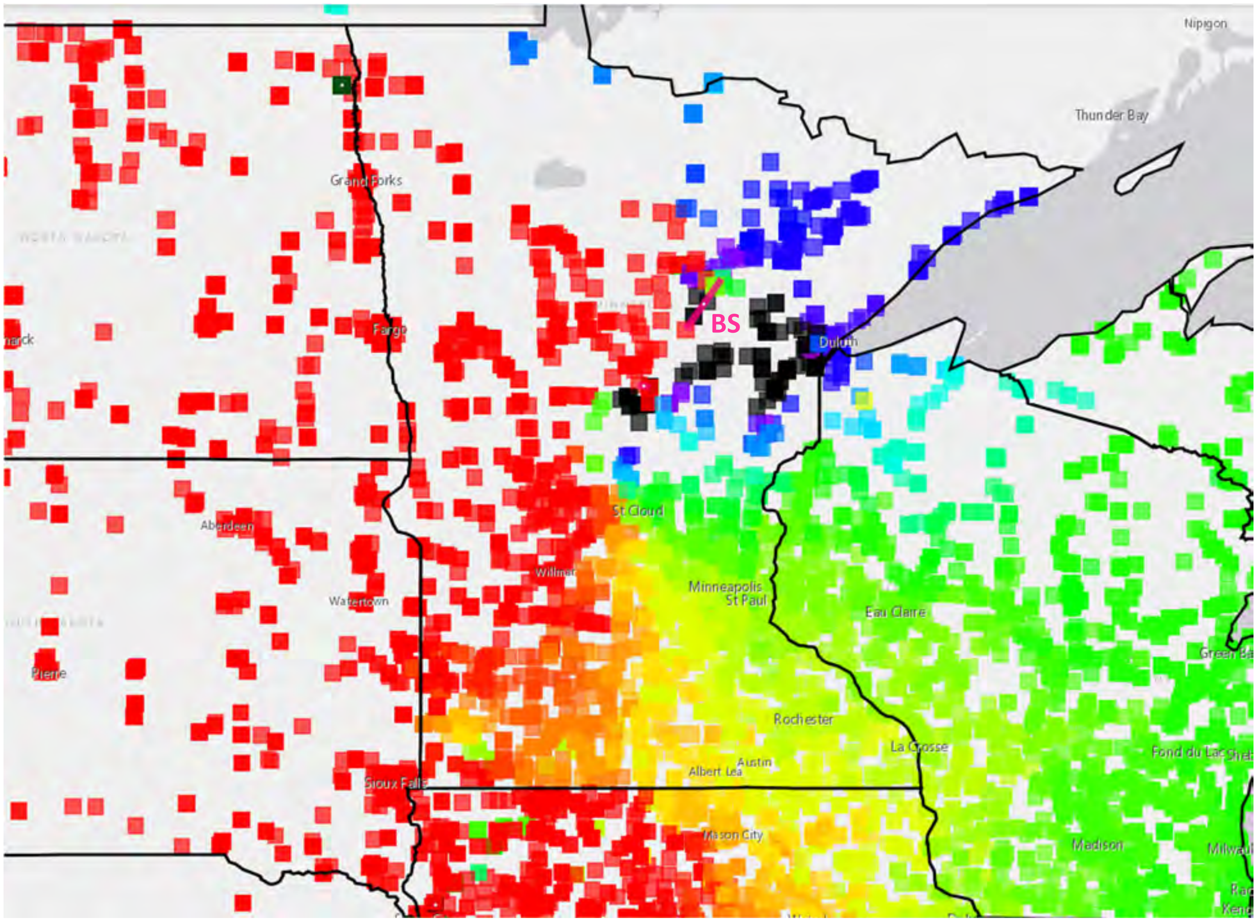


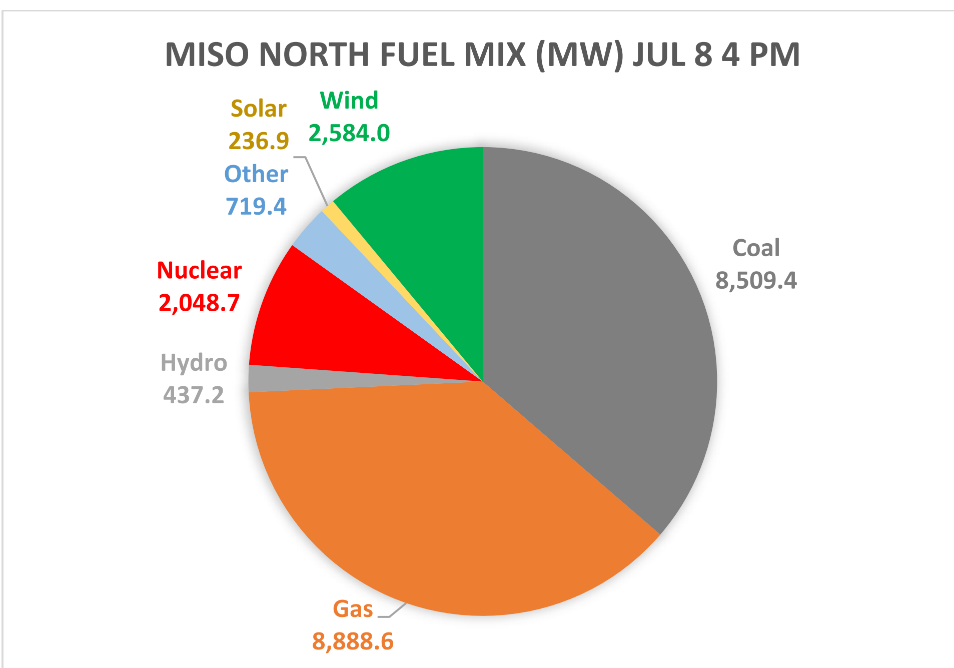
June 24, 2024, 5:00 P.M.



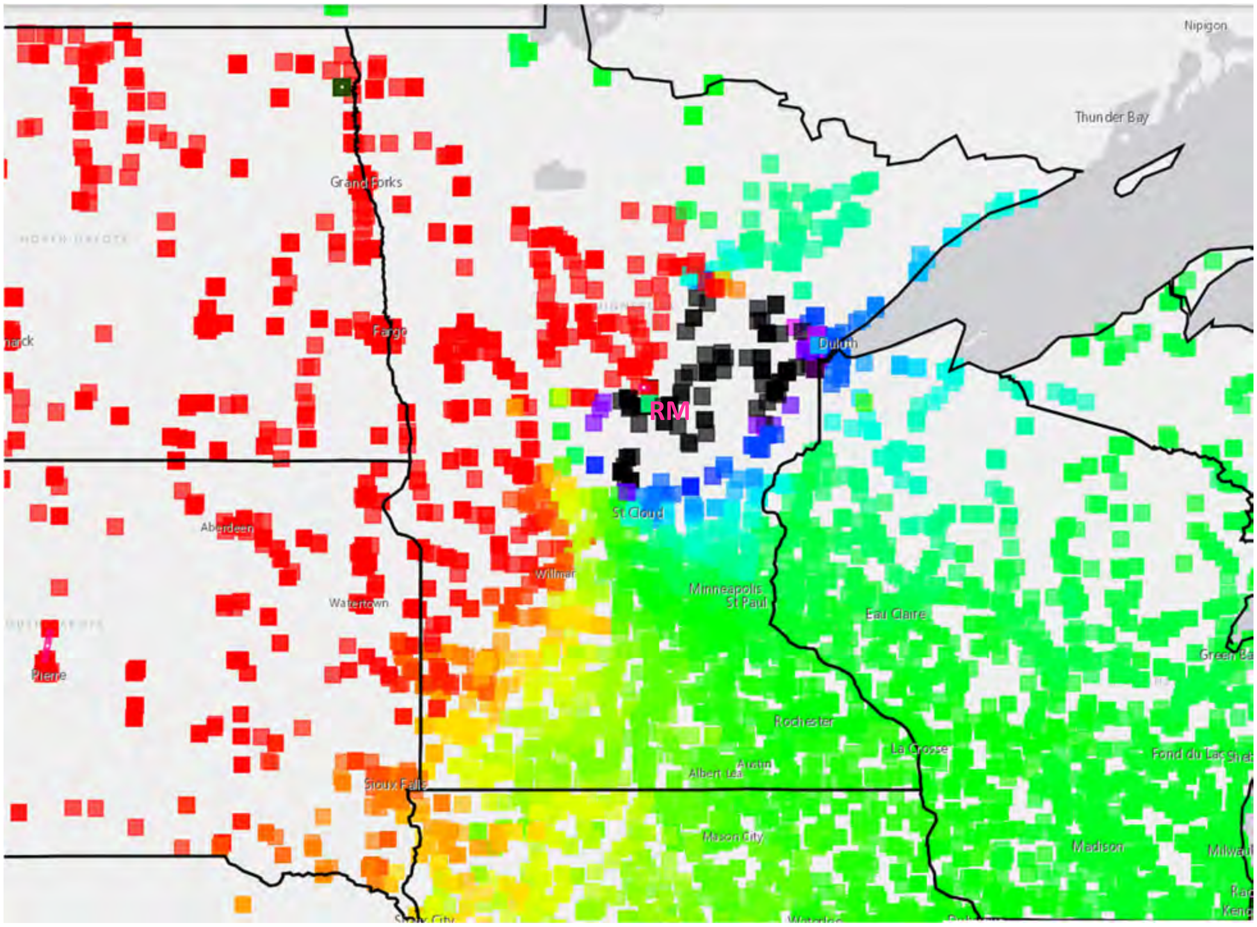


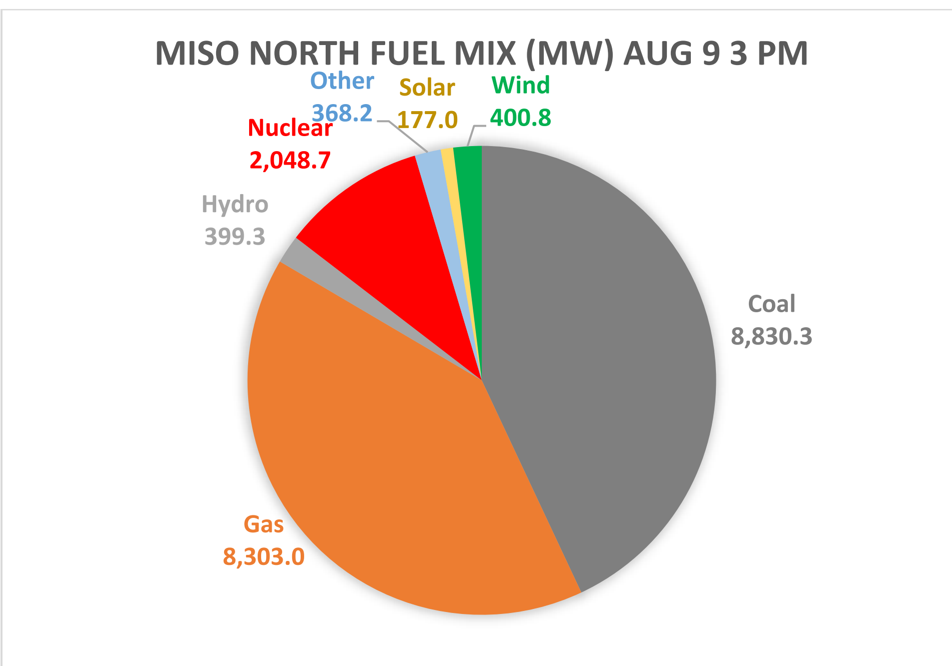
July 8, 2024, 4:00 P.M.



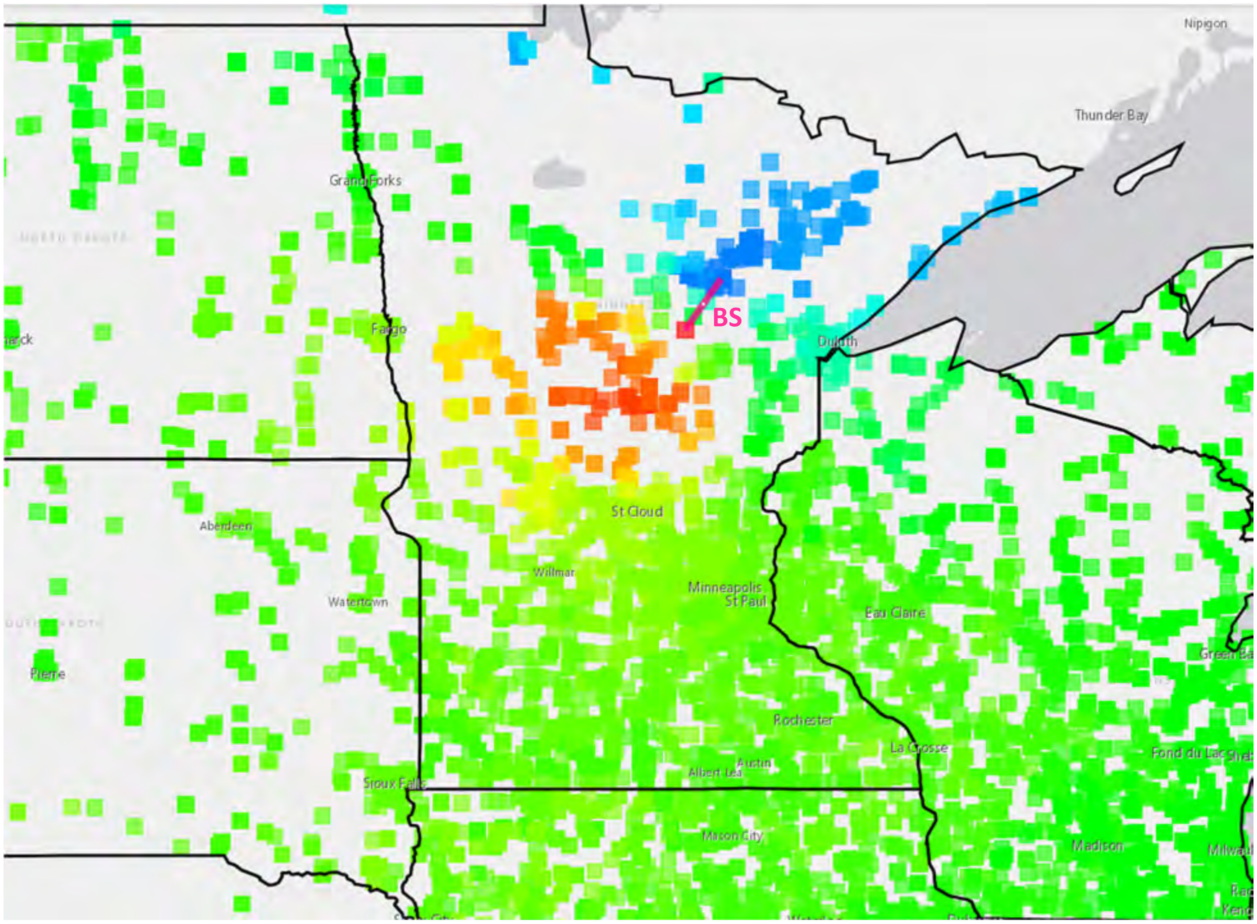


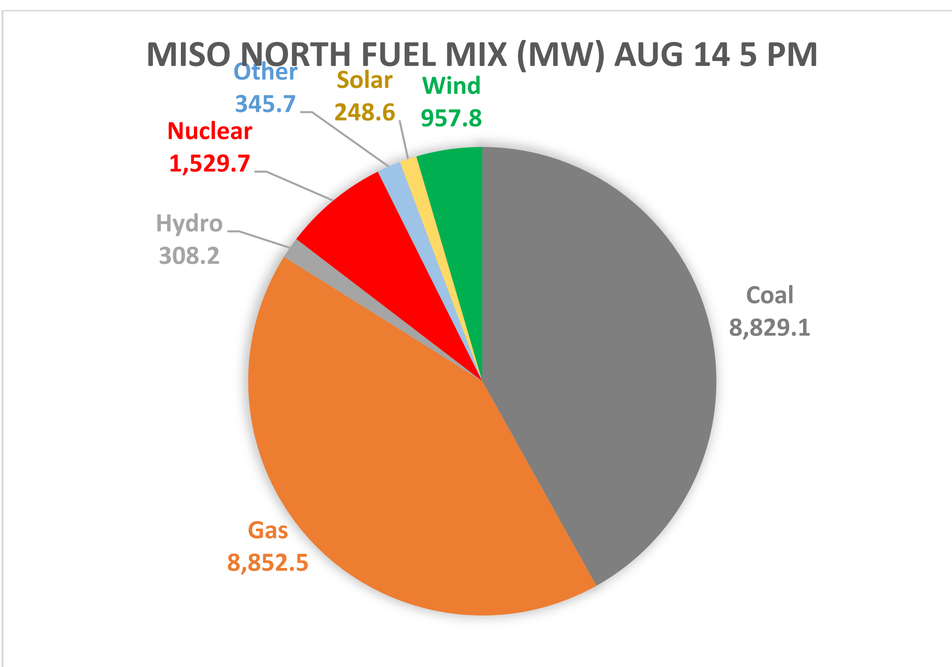
August 9, 2024, 3:00 P.M.





August 14, 2024, 5:00 P.M.





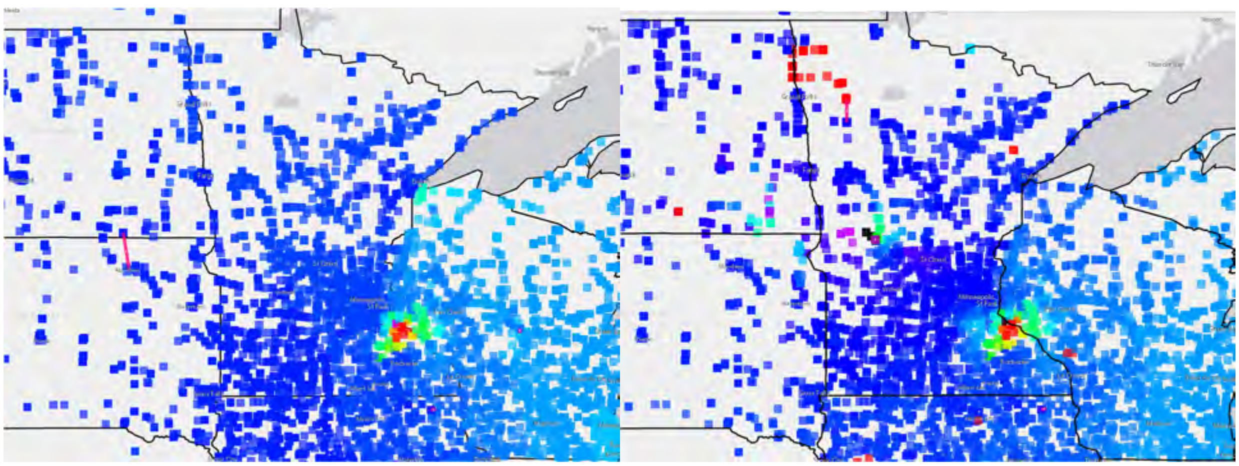
Impact of Planned and Forced Outages

The purpose of this study is to understand how planned and forced outages impact congestion. Outages can reduce congestion on one facility because it is masked by increased congestion on another facility, and not an indication of an overall reduction in congestion. In some cases, congestion due to outages can lower prices and appear favorable for Minnesota customers, while other customers in the MISO market have higher prices (see November 21, 2023, 8:00 p.m.).   In general, the outage-congestion increase results in a reduction of MISO North generation, especially wind, replaced by imports from other regions.

Planned Outages

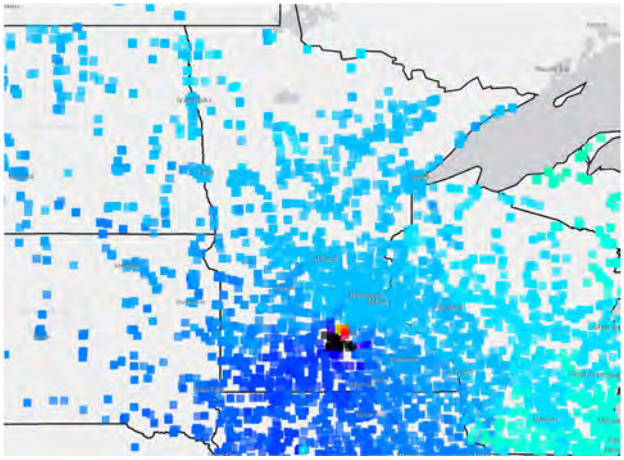
The following maps show side-by-side comparisons of LMPs from simulations before (left) and after (right) planned outages are included. Table show the impact on fuel mix for the representative hour.

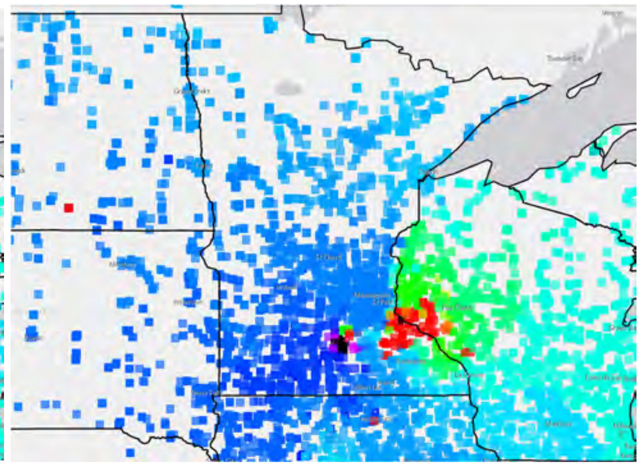
October 6, 2023, 5:00 p.m. - Most Impactful Outage: Donaldson-Drayton



	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	4,334.2	133.0	148.0	2,127.8	1,286.1	155.0	15,365.1	23,549.2
Planned	4,646.9	133.0	148.0	2,127.8	1,288.3	112.5	13,423.0	21,879.6
Difference	+312.7	0.0	0.0	0.0	+2.2	-42.4	-1,942.1	-1,669.7

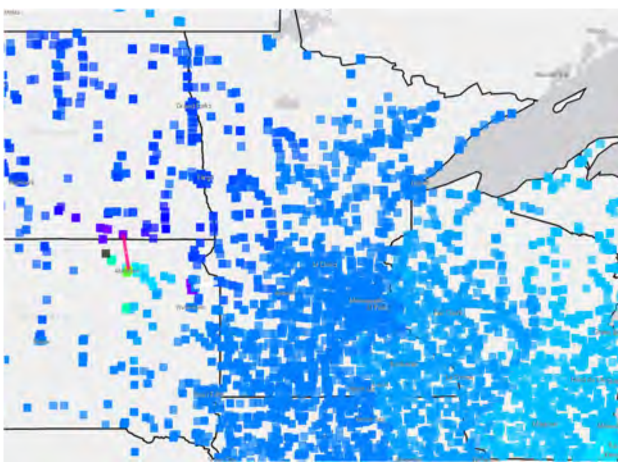
November 21, 2023, 8:00 P.M. – Most Impactful Outage: Winger

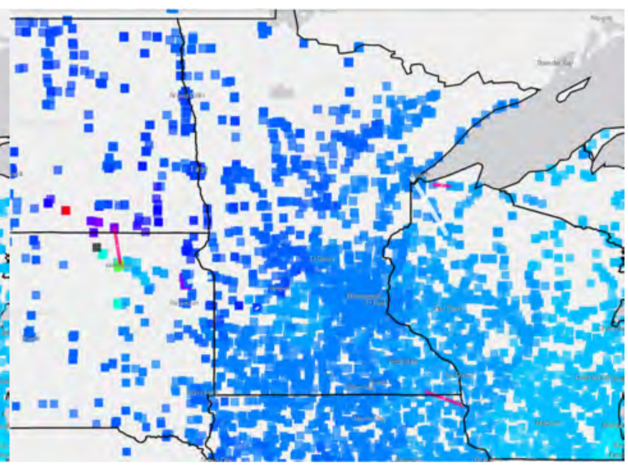




	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	9,453.7	348.8	294.0	2,127.8	1,004.8	47.7	12,014.2	25,290.9
Planned	9,389.9	248.3	317.8	2,127.8	1,008.1	47.7	11,659.8	24,799.3
Difference	-63.8	-100.5	+23.7	0.0	+3.4	0.0	-354.4	-491.6

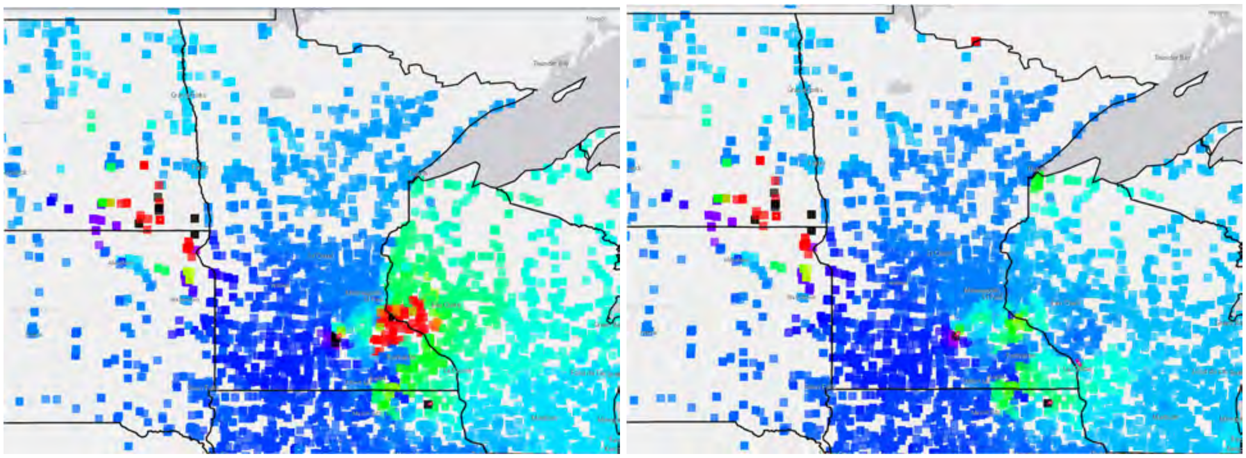
December 17, 2023, 2:00 A.M. – Most Impactful Outage: Wishek





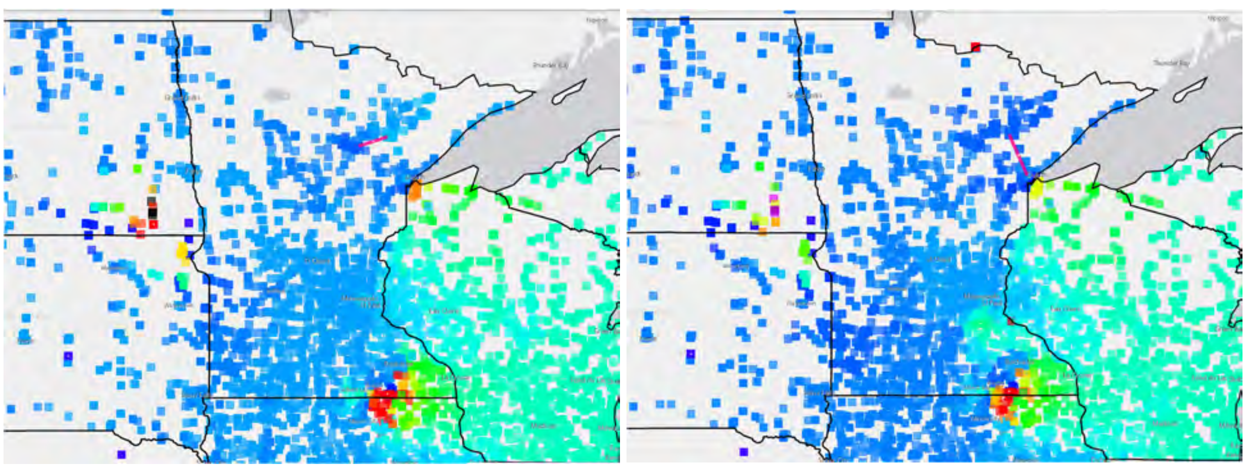
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	9,766.8	115.3	132.1	2,127.8	837.1	0.0	7,191.9	20,170.9
Planned	8,768.0	115.3	132.1	2,127.8	842.6	0.0	7,180.9	19,166.6
Difference	-998.8	0.0	0.0	0.0	+5.5	0.0	-11.0	-1,004.3

January 5, 2024, 8:00 P.M. – Most Impactful Outage: Ortman-Little Fork



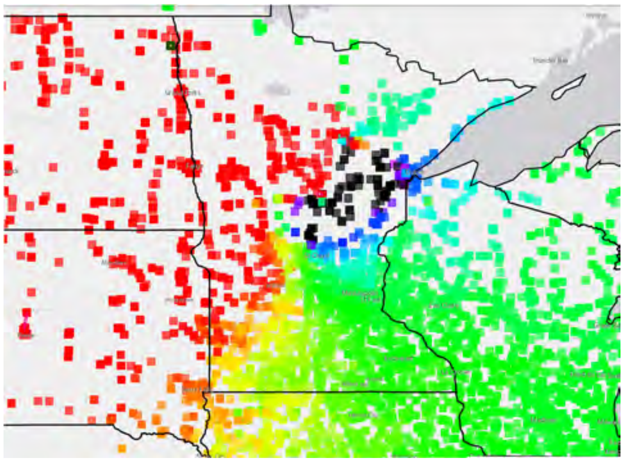
	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	6,942.6	479.0	193.6	2,127.8	1,291.9	48.8	16,509.8	27,593.4
Planned	6,817.4	449.4	172.1	2,127.8	1,291.9	48.8	15,537.8	26,445.0
Difference	-125.3	-29.6	-21.5	0.0	0.0	0.0	-972.1	-1,148.4

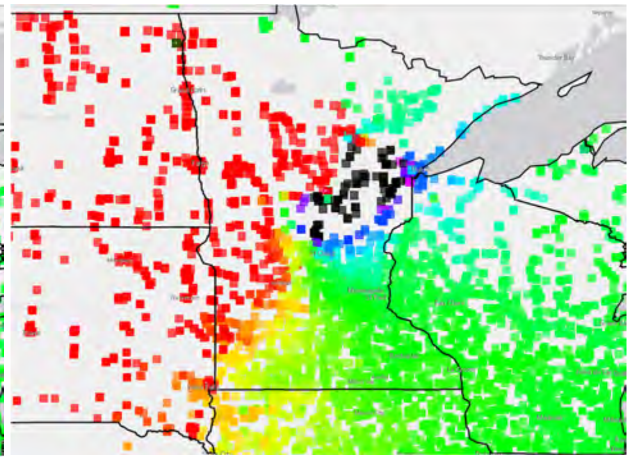
March 1, 2024, 7:00 A.M. – Most Impactful Outage: Ortman-Little Fork



	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	7,264.5	248.3	219.1	2,127.8	1,037.5	0.0	12,744.2	23,641.4
Planned	7,410.2	331.4	222.0	2,127.8	1,030.2	0.0	12,660.6	23,782.1
Difference	+145.6	+83.1	+2.8	0.0	-7.2	0.0	-83.6	140.7

August 9, 2024, 3:00 P.M. - Most Impactful Outage: Forman





	Coal	Gas	Hydro	Nuclear	Other	Solar	Wind	Total
System Intact	8,830.3	8,303.0	399.3	2,048.7	368.2	177.0	400.8	20,527.3
Planned	8,833.8	8,287.0	399.3	2,048.7	368.2	177.0	400.8	20,514.8
Difference	+3.5	-16.0	0.0	0.0	0.0	0.0	0.0	-12.5

Planned + Forged Outages

	Q4 2023		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$12253 (7%)	$14336 (6%)	$8388 (4%)
ADAMS 5 to BVR CRK5 #1			
ALEXMRES7 to ALEXSWM7 #1		-$90013 (30%)	-$77053 (25%)
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$13890 (3%)	-$16189 (4%)	-$15147 (3%)
BROWNSV4 to NEW EFFNGTN4 #1	-$1563 (1%)	-$1771 (1%)	-$2576 (1%)
BLCKBRY4 to GRE-SWTRX3A4 #1		-$123 (0%)	-$92 (0%)
FORMN 7 to FORMAN 7 #1	-$150111 (15%)	-$178626 (21%)	-$154597 (21%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$10682 (4%)	$14522 (5%)	$9734 (3%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$3119 (1%)	-$7547 (3%)	-$7231 (3%)
GRE-CLVLAND8 to LECENTR8 #1	-$138514 (10%)	-$220483 (15%)	-$368025 (20%)
GRE-JOHNJCT7 to MORRIS 7 #1			
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$136419 (5%)	-$286554 (10%)	-$285925 (9%)
HELENA 3 to SCOTTCO3 #1	-$2002 (4%)		-$37 (0%)
HIBBARD7 to WNTR ST7 #1	-$9383 (5%)	-$7580 (4%)	-$6051 (4%)
LANSING L2 5 to HARMONY5 #1		-$4038 (14%)	-$3861 (14%)
MINVALT4 to GRANITF4 #1	$11635 (3%)	$17830 (8%)	$52904 (20%)
RVT1BUS7 to GRE-MERRFLD7 #1			
WILMART7 to SWAN LK7 #1		-$724 (0%)	-$3707 (1%)

	Q1 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$3850 (2%)	$3940 (2%)	$4224 (3%)
ADAMS 5 to BVR CRK5 #1			
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1		-$10491 (8%)	
BIGSTON4 to BROWNSV4 #1			
BROWNSV4 to NEW EFFNGTN4 #1	-$6576 (4%)	-$7262 (5%)	-$5725 (4%)
BLCKBRY4 to GRE-SWTRX3A4 #1			
FORMN 7 to FORMAN 7 #1	-$675665 (46%)	-$669031 (46%)	-$631877 (48%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$39810 (18%)	$30587 (13%)	$31942 (12%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$3788 (2%)	-$20225 (8%)	-$14853 (6%)
GRE-CLVLAND8 to LECENTR8 #1	-$465853 (31%)	-$414142 (32%)	-$715819 (38%)
GRE-JOHNJCT7 to MORRIS 7 #1			
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$111942 (7%)	-$35398 (3%)	-$47758 (3%)
HELENA 3 to SCOTTCO3 #1	-$1153 (4%)	-$1005 (3%)	-$302 (1%)
HIBBARD7 to WNTR ST7 #1	-$10831 (5%)	-$20086 (10%)	-$7311 (4%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$1103 (0%)	$1843 (1%)	$23710 (7%)
RVT1BUS7 to GRE-MERRFLD7 #1			
WILMART7 to SWAN LK7 #1			

	Q2 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$8843 (5%)	$18897 (8%)	$13158 (7%)
ADAMS 5 to BVR CRK5 #1	-$30586 (10%)	-$21519 (7%)	-$9355 (2%)
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$35039 (9%)	-$29059 (9%)	-$35056 (10%)
BROWNSV4 to NEW EFFNGTN4 #1			
BLCKBRY4 to GRE-SWTRX3A4 #1	-$14277 (8%)	-$14784 (9%)	-$14697 (9%)
FORMN 7 to FORMAN 7 #1	-$167422 (19%)	-$99569 (10%)	-$93178 (10%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$5429 (3%)	$2095 (1%)	$2049 (1%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$1175 (0%)	-$1778 (1%)	-$1944 (1%)
GRE-CLVLAND8 to LECENTR8 #1	-$172296 (16%)	-$223586 (18%)	-$268606 (20%)
GRE-JOHNJCT7 to MORRIS 7 #1		-$14598 (2%)	-$26641 (3%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$39143 (1%)	-$30891 (1%)	-$27621 (1%)
HELENA 3 to SCOTTCO3 #1			
HIBBARD7 to WNTR ST7 #1	-$116555 (39%)	-$152511 (42%)	-$118074 (35%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$1702 (1%)	$42514 (13%)	$33477 (10%)
RVT1BUS7 to GRE-MERRFLD7 #1	-$251 (0%)		-$297 (0%)
WILMART7 to SWAN LK7 #1	-$9675 (2%)	-$10807 (3%)	-$11907 (3%)

	Q3 2024		
Constraint	System Intact	Planned	Planned+Forced
ABDNJCT7 to ELLENDL7 #1	$2687 (2%)	$39746 (20%)	$45379 (27%)
ADAMS 5 to BVR CRK5 #1	-$9711 (4%)	-$8681 (3%)	-$8126 (3%)
ALEXMRES7 to ALEXSWM7 #1			
BRIGGS RD 5 to LAC TAP5 #1			
BIGSTON4 to BROWNSV4 #1	-$81030 (12%)	-$192813 (36%)	-$184256 (34%)
BROWNSV4 to NEW EFFNGTN4 #1			
BLCKBRY4 to GRE-SWTRX3A4 #1	-$27859 (6%)	-$30712 (6%)	-$36453 (8%)
FORMN 7 to FORMAN 7 #1	-$242468 (21%)	-$154458 (15%)	-$156740 (15%)
GRE-CHUBLAK3 to YBUS(GRE-CHUBLAK7_GRE-CHUBLAKT) #1	$2755 (2%)	$891 (1%)	$1047 (1%)
GRE-CHUBLAK7 to YBUS(GRE-CHUBLAK3_GRE-CHUBLAKT) #1	-$203 (0%)	-$1461 (1%)	-$1203 (1%)
GRE-CLVLAND8 to LECENTR8 #1	-$199207 (11%)	-$244317 (13%)	-$267809 (13%)
GRE-JOHNJCT7 to MORRIS 7 #1			-$252 (0%)
GRE-SPRGCK15 to YBUS(GRE-SPRNGCK8_GRE-SPRNGC1T) #1	-$45459 (1%)	-$75445 (2%)	-$68538 (3%)
HELENA 3 to SCOTTCO3 #1	-$9 (0%)		
HIBBARD7 to WNTR ST7 #1	-$155900 (27%)	-$141372 (27%)	-$109368 (23%)
LANSING L2 5 to HARMONY5 #1			
MINVALT4 to GRANITF4 #1	$2373 (1%)		$171 (0%)
RVT1BUS7 to GRE-MERRFLD7 #1	-$212686 (2%)	-$243067 (2%)	-$526918 (6%)
WILMART7 to SWAN LK7 #1	-$12994 (3%)	-$20287 (4%)	-$18400 (5%)