Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

October 31, 2019

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: 2019 BIENNIAL TRANSMISSION PROJECTS REPORT
DOCKET NO. E999/M-19-205

Dear Mr. Wolf:

On behalf of the Minnesota Transmission Owners (MTO), we submit the enclosed 2019 Biennial Transmission Projects Report for approval by the Minnesota Public Utilities Commission. We submit this report in compliance with Minn. Stat. § 216B.2425.

The law firm of Fredrikson & Byron is serving paper and/or electronic copies of the 2019 Biennial Transmission Projects Report on the service list required by Minn. R. 7848.1800. Additionally, we are serving this report on the service list for the above referenced docket and the official service list of the last general rate cases for Xcel Energy, Minnesota Power, and Otter Tail Power Company. Given changes in technology and web accessibility, the MTO proposes that this will be the last year electronic copies of the report will be served by CD. In future years, 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.

Pursuant to Minn. R. 7829.0700, the MTOs request that the following persons be placed on the Commission's official service list for this matter:

Christina Brusven	Mara K. Ascheman
Attorney at Law	Senior Attorney
Fredrikson & Byron, P.A.	Xcel Energy
200 South Sixth Street, Suite 4000	414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55402-1425	Minneapolis, MN 55401
cbrusven@fredlaw.com	mara.k.ascheman@xcelenergy.com

Lynnette Sweet
Regulatory Administrator
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to regulatory.records@xcelenergy.com.

If you have any other questions about this filing, please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Enclosure
c: Service List

2019 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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1.0 Executive Summary

The 2019 Biennial Transmission Projects Report is the tenth 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 2019 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 2019 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	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

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

[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.

As required by the statute, the Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard deadlines.

In 2015, the Legislature established a new reporting requirement for certain utilities. Minn. Laws 2015, 1Sp2015, ch. 1, art 3, s 22, codified at Minn. Stat. § 216B.2425, subds. 2(e) and 8. 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.

The following is a summary of each subsequent chapter of the 2019 Biennial Report.

Chapter 2 describes the biennial reporting requirements. This includes a discussion of the specific information the Public Utilities Commission directed the utilities to include in the 2019 Biennial Report.

Chapter 3 is entitled 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 Midcontinent Independent Transmission System Operator (MISO) Transmission Expansion Plan (MTEP) Report is included since most planning is now conducted by MISO and the MTEP Reports are where most of the information about the pending projects can be found.

Chapter 4 is the Public Participation chapter. Several recent examples are provided regarding how 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 95 separate transmission inadequacies across the state, including 41 new ones identified in the 2019 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 2019 MTEP Report, for example, would be called MTEP19. In addition, information about each pending project, by Tracking Number, is provided. This information addresses issues like alternatives considered, a schedule, and the general impacts on the environment and the area if the project were 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 2017 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 that are 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 Renewable Energy Standards. Not all utilities that own transmission lines are subject to the state Renewable Energy Standards, 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.

For the past several reporting periods, and again this year at the direction of the MPUC, 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 through 2020, although demands of neighboring states for renewable energy will undoubtedly affect what resources will be required.

Chapter 8 also provides a brief summary of the information a number of the utilities just submitted to the MPUC pursuant to a statute that requires annual reporting regarding compliance with upcoming solar energy standards.

MPUC Process. Upon receipt of this Report, the Commission will solicit comments from the Department of Commerce, interested parties, and the general public about the Report. 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-19-205. The precise schedule for filing comments is established by Minn. Rule Chapter 7848 relating to the biennial reporting process. It is anticipated that the MPUC will make a final decision on the 2019 Biennial Transmission Projects Report in May 2020.

2.0 Biennial Report Requirements

2.1 Generally

Prior Reports
This is the tenth 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. Minn. Stat. § 216B.2425. 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 2019 Report will also be posted on that webpage.

Biennial Report	MPUC Docket Number	MPUC Order
2019	E999/M-19-205	
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 that expand and clarify what is expected to be in the report (Minn. Rules Chapter 7848). 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 what efforts were 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 done 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 publically 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 four biennial reports – 2011, 2013, 2015 and 2017 – the Commission has allowed the utilities to reference the latest MTEP Report to provide information about the identified inadequacies in Minnesota. The 2019 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 to addressing each inadequacy. The utilities explain in section 6.1 how 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 2019, 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.

In its June 12, 2018, Order accepting the 2017 Biennial Report, the Commission said that the MTO shall "shall include content similar to 2017 Report, and include an improved and expanded assessment of non-wire alternatives and a discussion of relevant actions by FERC, MISO, and the Commission related to distributed energy resources and distribution planning." Consequently, the 2019 Report closely tracks the 2017 Report but also includes discussions on non-wire alternatives and relevant actions by other agencies related to distributed energy resources and distribution planning.

Waiver Request for 2021 Report

The MTO requests that the Commission extend the rule variances granted in the June 12, 2018 Order accepting the 2017 Biennial Report (and previous orders) for the 2021 Biennial Report as well, such that the future report requirements will mirror the content, notice and participation requirements of this 2019 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. R. 7848.0900 and related to outreach in Minn. R. 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.

Additionally, given changes in technology and web accessibility, the MTO proposes that this will be the last year electronic copies of the report will be served by CD. In future years, 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" 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. Minn. Rule part 7848.0100, subp. 5. Each of the entities that is 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
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 31, 2019, the MTO filed a letter to the Commission in the instant docket that there would be no certification requests included with the 2019 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 found 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 that is several years in the future. The MPUC rules require the utilities to identify inadequacies that might affect reliability over the next ten years. Minn. Rule part 7848.1300, subpart D. A transmission planner is often unable to identify possible alternatives or the impacts of the alternatives, for projects that are ten years in the future. 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 user 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 that the utilities are to identify general economic, environmental, and social issues associated with each alternative. This is a recognition that it is not always possible to know during the planning stage what 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 95 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 where specific alternatives have been identified.

An in-depth analysis of potential impacts of a proposed project and the identified alternatives will be provided when 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 when the public generally begins to take notice of the need for a project and to participate in the analysis of alternatives. And this is when the utility must begin to pull together the information that is required to complete applications for a CON and for a permit. These applications, and any environmental review that is 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 that are 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. Minn. Stat. § 216B.2425, subd. 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 new reporting requirement is often referred to as the Grid Modernization Report. The PUC in May 2015 opened a separate docket for consideration of efforts related to modernization of the transmission and distribution grid. Docket Number 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.*

On October 30, 2015, Xcel Energy filed its 2015 Biennial Distribution-Grid Modernization Report under Minn. Stat. § 216B.2425. The MPUC assigned a separate docket number to the Report. Docket Number E002/M-15-962. On June 28, 2016, in that docket, the MPUC accepted the Grid Modernization part of the Report and directed Xcel Energy to file a separate Distribution System Study by December 1, 2016, which Xcel Energy did.

As mentioned above, 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. Accordingly, Xcel Energy has submitted its Grid Modernization Report and its Hosting Capacity/Distribution Study Report under separate cover for MPUC consideration in two separate dockets.

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 95 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 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 particular issue at hand.

Non-wires alternatives are electric utility system supply-and demand-side projects and/or 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 maximum demand in specific grid areas.[1] Examples of non-wires transmission alternatives may include: establishing new operating guides or procedures, demand side management (DSM), distributed generation (DG), and electricity and thermal storage.

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 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 solar and/or wind with storage offers the greatest impact to reduce loads regardless of season. Transmission planners continue to evaluate non-wire options that result in the avoidance of establishing new transmission corridors. 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

[1] www.nrri.org.

installations. There will be more points to monitor to ensure that 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 thus making it difficult to know how, when or where to reliably deliver the energy. Distribution automation likely will be needed to assist the operator in shifting load to other systems if the expected generation resource is 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 resource and increase its 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 is needed to ensure that reliability is equal to the availability of 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 is needed to ensure that reliability is equal to the availability of transmission options. Based on geographic locations, land constraints may be a challenge to installation of adequate wind generation to meet the new or expanding load. 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 flows 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 flows 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.

Non-Wire Alternatives			
Type of Trans-mission Project	**Solar/Storage**	**Wind/Storage**	**Demand Side Management**
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.

Conclusion

Non-Wire Alternatives are discussed in Chapter 6 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,[2] planning,[3] fact specific[4] and annual reporting dockets.[5]

Federal Energy Regulatory Commission (FERC)

FERC Order No. 841, which was issued in February 2018, amended FERC regulations to remove barriers to the participation of electric storage resources in the capacity, energy, and ancillary service markets operates by regional transmission organizations and independent

[2] For example, *In the Matter of Updating the Generic Standards for the Interconnection and Operation of Distributed Generation Facilities Established under Minn. Stat. §216B.1611*, Dockets No. E999/CI-16-521 and E999/CI-01-1023; *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 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 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 Possible Amendments to Rules Governing Cogeneration and Small Power Production, Minnesota Rules, Chapter 7835*, Docket No. E999/R-13-729; *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 Establishing a Distributed Solar Value Methodology under Minn. Stat. §216B.164, subd. 10(e) and (f)*, Docket No. E999/M-14-65; *In the Matter of the Commission Investigation on Grid Modernization*, Docket No. E999/CI-15-556.

[3] For example, *In the Matter of Xcel's 2017 Biennial Distribution Grid Modernization Report*, Docket No. E002/M-17-776; *In the Matter of Xcel Energy's 2018 Integrated Distribution Plan*, Docket No. E002/CI-18-251; *In the Matter of Xcel's 2017 Hosting Capacity Study*, Docket No. E002/M-17-777; *In the Matter of Xcel's 2018 Hosting Capacity Study*, Docket No. E002/M-18-684; *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.

[4] For example, *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 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 d/b/a Xcel Energy for Approval of Competitive Resource Acquisition Proposal and Certificate of Need*, Docket No. E002/CN-12-1240.

[5] For example, *In the Matter of Annual Cogeneration and Small Power Production Filings*, Docket No. E999/PR-19-9; *Distributed Generation Interconnection Report*, Docket No. E999/PR-19-10.

system operators by requiring RTOs and ISOs to revise its tariff to recognize the physical and operational characteristics of electric storage resources and facilitate their participation in markets. FERC has received requests to consider similar rules for DERs. In May 2018, FERC held a two day technical conference on DERs. There are two ongoing FERC dockets related to DERs. The first is Docket No. RM18-9, which relates to the Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, and is a continuation of the rulemaking FERC originally commenced in Docket No. RM16-23. The second is Docket No. AD18-10, which relates to Distributed Energy Resources – Technical Considerations for the Bulk Power System.

MISO

According to its website, MISO has noted that "[a] high penetration of Distributed Energy Resources (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." To that end, MISO has been hosting a series of workshops on DERs throughout the year. MISO is currently working with the Organization of MISO States (OMS) and other MISO stakeholders to develop a DER participation model that accounts for the distinctive characteristics of the MISO region and promotes reliability on a least cost basis.

Institute of Electrical and Electronics Engineers (IEEE)

While not specifically requested by Commission another important aspect is various entity's work on IEEE 1547-2018, which is a recently published distributed energy resources (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 with Xcel Energy's business practice decisions.

In terms of specifying DER response to abnormal grid conditions, IEEE 1547 indicates that 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 that 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 how local grid support functions are 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.

3.0 Transmission Studies

3.1 Introduction

The Commission requires that 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. Minn. Rules part 7848.1300, item F. 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 2019 Report.

Section 3.2 describes a number of studies that have been completed that either address expansion of the transmission network to provide for generation expansion, in particular renewable energy, 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 that are attempting to resolve 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" (MAPP). Minn. Rule part 7848.1300, item B. As the utilities reported in the 2011 Report, however, the Midcontinent Independent Transmission Operator (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 November 2017. 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
Grand Meadow 69 kV Transmission Study	2018	DPC	Study the 69 kV system in the Grand Meadow, MN area for serving a new distribution substation to serve Freeborn-Mower Cooperative Services Members
Huntley-Hayward Area Study	2019	DPC	This study reviewed the 69 kV system in the Albert Lea, MN area and impacts of a Hayward 69 kV bus-tie breaker failure.

Study Title	Year Completed	Utility Lead	Description
Grand Rapids Long-Term Analysis	2018	MP	Analysis of the Grand Rapids area in the post-2020 timeframe following shutdown of Boswell Units 1 & 2, interconnection of the Great Northern Transmission Line, potential mining expansion, and general load growth; 11 Line Upgrade (2019-NE-N1), Hibbing 14 Line Upgrade (2019-NE-N3), 25 Line Upgrade (2019-NE-N4), Duluth Area 230 kV (2007-NE-N1)
North Shore Loop Alternatives Analysis	2019	MP	Continued analysis of the North Shore Loop in the post-2020 timeframe following completion of the transition away from local baseload generators, potential mining expansion, and general load growth; Mesaba Junction 115 kV Project (2017-NE-N23), Forbes 37 Line Upgrade (2019-NE-N2), Babbitt Area 115 kV Project (2019-NE-N10), 38 Line Upgrade (2019-NE-N11), Duluth 115 kV Loop (2019-NE-N12), Duluth Area 230 kV (2007-NE-N1)
Western Minnesota Load Serving Study	2018	MRES (GRE/ OTP/ MPC)	A study of Western Minnesota reliability/load serving
Minnesota Transmission Assessment and Compliance Team 2018 Transmission Assessment (2018 – 2028)	2018	MTO	This report is an annual transmission assessment investigating near-term, mid-term, and long-term transmission conditions. This purpose of this study is to develop an understanding of the transmission system topology, behavior, and operations to determine if existing and planned facility improvements meet NERC Transmission Planning Standard TPL-001-4.
Cass Lake Casino	2018	OTP	The 69 kV system in Cass Lake, MN, was not strong enough to support a new casino load in the town. This study was performed to determine the reliability impacts of moving the town and casino load to the area 115 kV system.

Study Title	Year Completed	Utility Lead	Description
Otter Tail Power Company Ten Year Development Study	2018	OTP	This study was commissioned to determine areas of need on the Otter Tail Transmission system primarily consisting of non-Bulk Energy System (BES) facilities through a ten-year timeframe. Several different BES projects were identified as best-fit solutions to support the non-BES facilities.
Northwest Minnesota Study: Project Timing Analysis	2019	OTP	The MTEP18 study identified various near- and long-term performance concerns in the Northwest Minnesota area. A suite of projects was proposed to mitigate the concerns, and the timing of each project was determined in this study.

3.3 Regional Studies

While every study that is undertaken adds to the knowledge of the transmission engineers and helps to determine what transmission will be 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 that support multiple generation interconnect 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. 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."

MTEP18 Report
The MTEP18 report identified projects required to maintain reliability for the ten year period through the year 2027 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP18 Executive Summary, the MISO staff is recommending approval of approximately $3.3 billion in new transmission infrastructure investment. Of the $3.3 billion, $709 million is new Baseline Reliability Projects, $255 million is Generation Interconnection Projects, and the remainder falls into the Other category.

MTEP19 DRAFT Report
The MTEP19 DRAFT report identified projects required to maintain reliability for the ten year period through the year 2028 and provides a preliminary evaluation of projects that may be required for economic benefit up to twenty years in the future.

According to the MTEP19 DRAFT Executive Summary, the MISO staff is recommending approval of approximately $3.87 billion in new transmission infrastructure investment. Of the $3.87 billion, $824 million is new Baseline Reliability Projects, $246 million is Generation Interconnection Projects, and the remainder falls into the Other category.

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 load serving situations, 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 Long Range Plan (LRP)	2019	GRE	In 2018, Great River Energy embarked on an exhaustive study of the transmission system GRE owns and to some degree the transmission that serves GRE's membership. The LRP aims to uncover capacity deficiencies within the transmission system looking out approximately 10 years and identifying projects to address the weaknesses and build robustness for the long-term future. GRE will communicate the results through electronic displays to its members. This analysis is planned to be completed at the end of 2019.

Study Title	Anticipated completion	Utility lead for Study	Description
Duluth Area Study	2019	MP	Continued analysis of the Duluth-area issues identified in previous studies to identify preferred long-term solutions; Duluth 115 kV Loop (2019-NE-N12), Duluth Area 230 kV (2007-NE-N1)
Wendell Interconnection and Nashua Elevator Load Serving Study	2019	OTP	Load growth in the Western Minnesota area caused a need for system upgrades. Various transmission and non-transmission alternatives were investigated to determine a best-fit project for the new load.
Benson Area Study	2020	GRE	This study is in progress to identify and address reliability concerns in the transmission system that serves the Benson area.
Owatonna Area Study	2020	MISO	Owatonna Area Study. This study is to evaluate the need for more voltage support under contingency. The early results are indicating an additional 161 kV line into the Owatonna area. This study is still ongoing.
Barnesville Area	2020	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 2020.

Study Title	Anticipated completion	Utility lead for Study	Description
CapX2050 Transmission Vision Study	2020	GRE/XEL	The CapX2020 utilities plan to undertake a Transmission Vision Study to examine the transmission system that serves the Upper Midwest to identify system improvements and infrastructure upgrades that may be needed to achieve the ambitious 2050 carbon reduction goals established or proposed by utilities and policymakers. This holistic long-term study is critical to the eventual development of a comprehensive plan that will ensure the continued reliable delivery of low-cost electricity in a cost-effective manner as the Upper Midwest generation fleet transitions to use higher levels of carbon-free generation, distributed generation and new energy storage technologies. The study is targeted to be completed in January 2020. The CapX2020 is a joint initiative of 10 transmission-owning utilities consisting of: 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. For more information, visit www.capx2020.com

4.0 Public Participation

4.1 Public Involvement in Transmission Planning

Both the statute – Minn. Stat. § 216B.2425 – and the MPUC rules – Minn. Rule part 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 every time since, including in the June 12, 2018, 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 in a statewide newspaper of the webinar, 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 that 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 the 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. It 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, on which interested persons can obtain various information 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 detailing items of interest to the general public about transmission lines that are available on the webpage. 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 that are 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 that is 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.

In the 2015 Biennial Report, in Section 4.4, the utilities provided several examples of the steps the utilities take to involve local government and the general public in specific projects. A few additional examples are included below.

4.4.1 Plymouth-Area Power Upgrade MPUC Tracking Number 2017-TC-N6

On May 25, 2016, Xcel Energy held two public open houses, from 12 to 2 p.m. and from 4 to 7 p.m., at the Medina Ballroom in Medina, to gather public input on the three different electrical options that the Company studied to meet the electrical needs of the Plymouth area. Notice for these public open houses were sent to over 7,700 landowners and other stakeholders and notice was also published in the Minneapolis Star Tribune and in the local Sun Sailor newspaper on May 19, 2016. Approximately 80 people attended the two public open house sessions.

At these two public open houses, Xcel Energy presented information about the three electrical alternatives (Alternatives A-C) that Xcel Energy has identified to help solve Plymouth's identified electrical needs. A summary of these three alternatives is provided below:

- Alternative A: construct a new Pomerleau Lake Substation south of Schmidt Lake Road and west of I-494, construct two new 34.5 kV distribution feeders from this substation to the west, reinforce existing feeders and extend one existing 13.8 kV feeder from the Parkers Lake Substation, and install approximately 12 pad-mounted transformers.

- Alternative B: expand Parkers Substation near I-494 and County Road 6, construct two new 34.5 kV feeders from the Parkers Lake Substation to the west, reinforce existing feeders and extend one existing 13.8 kV feeders from the Parkers Lake Substation, and install approximately 12 pad-mounted transformers.

- Alternative C: expand existing Hollydale Substation and build three new 13.8 kV feeders from the Hollydale substation, construct new Pomerleau Lake Substation, extend the existing 69 kV line 0.7 miles from Hollydale to Pomerleau Lake and re-energize the Hollydale-Pomerleau Lake 69 kV line, keep the Medina-Hollydale 69 kV line energized, reinforce existing feeders and extend one existing 13. 8 kV feeder from Parkers Lake Substation.

All three of these options met the immediate, near-term, and long-term load-serving needs of Plymouth. Maps of each of these three alternatives were available to the public.

Additional information regarding these three alternatives was available in Xcel Energy's electrical study, "Plymouth-Area Engineering Study Report," a copy of which was available on the Company's website:
http://www.transmission.xcelenergy.com/Projects/Minnesota/Plymouth-Project.

In addition to presenting information about these three alternatives including maps and photos of typical facilities, the public open houses also featured stations with information about Xcel Energy's DSM programs, electricity 101, need for electrical improvements, vegetation management, construction, and right-of-way.

At the public open houses, Xcel Energy had comment forms available for landowners to submit comments. The Company website also included a comment form, as well as an email address and a telephone number for comments. The deadline for submitting comments was June 25, 2016. Xcel Energy spent many hours responding to the comments that were received and posted answers on its website to many of the questions that were received.

Transmission Project Public Involvement

During the past two years Great River Energy (GRE) has applied for permitting on several transmission and substation projects both with the Commission and at the local level. Regardless of the permitting authority, GRE follows the standard procedure of involving the public prior to the application and throughout the permitting process to keep the public informed. Some recent examples of public outreach are:

- Lebanon Hills 115 kV transmission and substation project – City of Eagan
  - GRE held a public open house informational meeting in November 2017, to provide information about the project to the public. GRE sent post card open house invitations to 90 landowners within the notice corridor. GRE also mailed notice of the Project and open house to 33 agencies, elected officials, and local governmental units. Newspaper notices announcing the open house were also placed approximately a week before the open house. Approximately 40 people attended the meeting.
- Swenoda 115 kV transmission and substation project – Swift County
  - Communication (letter, phone call, email) with landowners on the route.
- Cannon River Park 115 kV transmission and substation project - City of Faribault
  - Communication (letter, phone call, email) with landowners on the route.
- Ortonville to Johnson Junction & Morris to Johnson Junction 115 kV transmission rebuild project – Big Stone and Stevens Counties.
  - GRE held a public open house informational meeting in August 2019 to provide information about the project to the public. GRE sent post card open house invitations to 147 landowners within the notice corridor. GRE also mailed notice of the project and open house to 23 agencies, elected officials, and local governmental units. Newspaper notices announcing the open house were also placed approximately a week before the open house. Approximately 18 people attended the meetings over the two days.

As GRE continues to work on new transmission and substation projects, public participation will continue to be a focal point to a successful project.

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.

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 essentially 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 and/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 that have been 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 one 345 kV line 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 which delivers power to local loads.

The major change in the transmission system in the Northwest Zone since 2011 is the addition of a 230 kV line between Grand Rapids in the Northeast Zone and Bemidji in the Northwest Zone (a CapX2020 project). This line was energized in November 2012. This project has been referenced under Tracking Number 2005-NW-N2 and MPUC Docket No. E015,ET6,E017/TL-07-1327.

The MPC Center-Grand Forks 345 kV project was completed in early 2014 and will bring power from Center, North Dakota to Grand Forks, North Dakota. Also, the CapX Fargo-St. Cloud 345 kV project was completed in 2015 and will transfer power between Fargo, North Dakota and the St. Cloud area.

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. 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 between the Bemidji area in the Northwest Zone and the Grand Rapids area in the Northeast Zone (the CapX2020 Bemidji-Grand Rapids project) has been completed. 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.

The Great Northern Transmission Line Project consists of approximately 225 miles of new 500 kV coming from Manitoba Hydro to the Grand Rapids, Minnesota area. This project will increase the amount of hydro renewables that can be imported to the state of Minnesota. This line is reported under Tracking Number 2013-NE-N13.

North Shore Loop

A number of projects in the Northeast Zone are part of what is called the North Shore Loop. The North Shore Loop refers to an approximately 140-mile portion of 115 kV and 138 kV transmission lines in the northeastern Minnesota transmission system that is used by Minnesota Power and Great River Energy to serve customers along the North Shore of Lake Superior and in the Hoyt Lakes area. The following discussion about the North Shore Loop and the changes in generation that are taking place in the area is helpful in understanding the need for a number of projects in the Northeast Zone.

The North Shore Loop extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. Historically, the North Shore Loop was characterized by an abundance of coal-fired baseload generation, including Minnesota Power’s Laskin and Taconite Harbor Energy Centers and a large industrial cogeneration facility located in Silver Bay. A geographical representation of the North Shore Loop transmission system is shown in Figure 1 below.

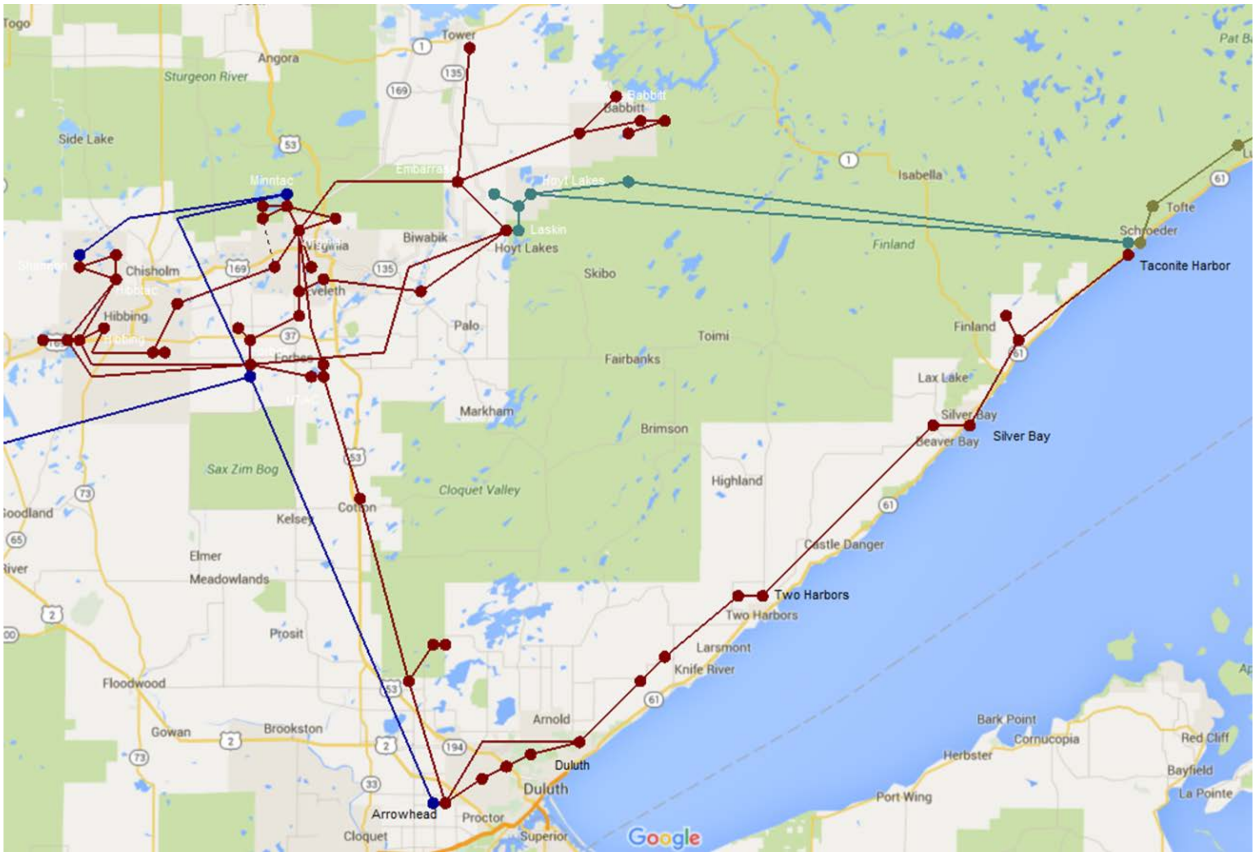

Figure 1: North Shore Loop Transmission System Geographical Representation

Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to natural gas peaking units. Also in 2015, Minnesota Power retired one of the units at Taconite Harbor. With Commission approval in the 2015 Integrated Resource Plan, Minnesota Power idled the other two Taconite Harbor units in the fall of 2016 with all coal-fired operations to cease at the facility by 2020. In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, near the end of September 2019 Silver Bay Power Company idled both of the Silver Bay units and began operating with no generators online. The cumulative impact of these operational changes leaves no baseload generators normally online in the North Shore Loop.

The local baseload generators at Laskin, Taconite Harbor, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing redundancy, voltage support, and power delivery capacity. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016. These projects are necessary to ensure the continued reliability of the transmission system in the area by restoring redundancy, addressing unacceptably low voltage and voltage stability concerns, and mitigating transmission line and transformer overloads. Projects located in the North Shore Loop or related to the transitional changes in the North Shore Loop include (MPUC tracking number and actual/planned year of completion listed in parenthesis):

- Minntac 230 kV Bus Reconfiguration (2015-NE-N10, Completed 2016),
- Forbes 230/115 kV Transformer Addition (2015-NE-N11, Completed 2016),
- North Shore Switching Station & Cap Banks (2017-NE-N7, Completed 2017),
- Babbitt Capacitor Bank (2017-NE-N8, Completed 2017),
- ETCO Capacitor Bank (2017-NE-N9, Completed 2017),
- Forbes 3T Breaker Replacement (2017-NE-N10, Completed 2017),
- 18 Line Upgrade (2017-NE-N17, Completed 2018),
- North Shore Transmission Line Upgrades (2017-NE-N19, Completed 2019),
- Two Harbors 115 kV Project (2017-NE-N20, Completed 2019),
- North Shore STATCOM (2017-NE-N15, Completed 2019),
- Laskin-Tac Harbor Transmission Line Upgrades (2017-NE-N21, Planned 2019-21),
- 38 Line Upgrade (2019-NE-N11, Planned 2020),
- Mesaba Junction 115 kV Project (2017-NE-N23, Planned 2020-21),
- Laskin-Taconite Harbor Voltage Conversion (2017-NE-N2, Planned 2021),
- Forbes 37 Line Upgrade (2019-NE-N2, Planned 2022),
- Forbes Tie Breaker Addition (2017-NE-N6, Planned 2022),
- Babbitt Area 115 kV Project (2019-NE-N10, Planned 2023),
- Duluth 115 kV Loop (2019-NE-N12, Planned 2024)

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:

- 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 are being considered to address the need for more power into this area. The new CapX Quarry substation will provide significant relief to the St. Cloud area system deficiencies. The CapX Fargo-St. Cloud 345 kV project was completed in 2015 and transfers power between Fargo, North Dakota and the St. Cloud area. The CapX Brookings, South Dakota-Twin Cities 345 kV project was also completed in 2015.

A new Riverside 345/115/69 kV substation is being installed in the St. Cloud Area along the CAPX Fargo-Monticello 345 kV line to address some of the area 69 kV issues. This is a Great River Energy substation connecting to the Xcel Energy’s 69 kV system.

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:

- Great River Energy
- 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 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 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 that is 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 CapX 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 CapX 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 that is occurring 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 will provide opportunities for new transmission substations to improve the load serving capability of the underlying transmission system.

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:

- Dairyland Power Cooperative
- Great River Energy
- ITC Midwest LLC
- Rochester Public Utilities
- Southern Minnesota Municipal Power Agency
- Xcel Energy

The major addition to the Southeast Planning Zone will be the addition of the Huntley-Wilmarth 345 kV line that will help improve renewable flow across the transmission system. This is an economic project that connects part of Southern Minnesota to the Mankato area. This project was identified through the MISO Economic Planning effort.

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 to the Southeast Planning Zone for lower voltage load service from generation stations outside of the area. The 345 kV system also allows the seasonal and economic exchange of power from Minnesota to the east and south from large generation stations that are 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.

6.0 Needs

6.1 Introduction

Chapter 6 contains information on each of the present and reasonably foreseeable future inadequacies that have been identified in the six transmission zones. For each zone, a table of present inadequacies is first presented, in order of when the inadequacy was first identified, so the older inadequacies are listed first. Then 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/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility

The following describes what information is 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 that 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 2007, on the other hand, was first identified in the 2007 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/App
The third column contains a reference to a MTEP Report and an Appendix in the report. The MTEP Report is prepared annually by the 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 MTEP19, 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 the 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 because even though Minnkota is not a MISO member. MISO performs some of Minnkota's transmission planning work.

Certificate Of Need
The MPUC rules (Minn. Rules part 7848.1300, item M) state that 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. 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 that could 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 that are 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 planning was being conducted by and through MISO.

In 2014, as part of its approval of the 2013 Biennial Report, the Commission determined that perhaps the MTEP Reports did not satisfy one requirement of the state statute to "identify [in the biennial report] general economic, environmental, and social issues associated with each alternative." Minn. Stat. §216B.2425, subd. 2(c)(3). 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 that are 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 as well, 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/App	MTEP Project Number	Utility	Date Completed

Most of the columns contain the same information that is 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 was required from the Commission, or both, 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 that was 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 of 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 that is prepared each year. Much of the information provided in this subsection was also available in the 2013, 2015 and 2017 Biennial Reports.

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 usually approves the report in December. The process continues with another report finalized the following December. The MTEP19 Report should be approved by the MISO Board of Directors in December of this year.

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

> Appendix A – Projects recommended for approval,
> Appendix B – Projects with documented need and effectiveness, and

Generally, when 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 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 more timely information. The Biennial Report is prepared every other year.
- The MISO planning process is comprehensive. MISO considers all regional transmission issues, not just Minnesota transmission issues.
- MISO conducts an independent 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 redo all the information that is found in the MTEP Report.

6.2.2 Finding a Project in a MTEP Report

For each zone, a table is included that describes certain information about each project by Tracking Number. The table looks like this (MPUC Tracking Number 2017-TC-N5 is used for illustrative purposes):

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-TC-N2	South Afton Substation	2019/A	15877	No	No	XEL

MPUC Tracking Number 2019-TC-N2is the South Afton Substation Project. The project can be found in Appendix A of the MTEP19 Report (the MTEP19 Report is not finalized until November) 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. Then click on the link on the left side of the page entitled "MISO Transmission Planning Expansion (MTEP)."

Step 3. Click on the link for the MTEP19 Report.

Step 4. Click on the "MTEP19 Appendices AB."

Step 5. Select the "Projects" tab at the bottom of the spreadsheet that was just 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 15877, 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, probably earlier than 2011, 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, which is "15877" 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 15877 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 D1 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 that 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 D1 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 South Afton Substation, Tracking Number 2019-TC-N2, which is an approved Appendix A project, this additional information can be found by going to Appendix D1 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 D1 West.
>
> Step 3. Once the desired Appendix D1 is downloaded, use the .pdf search tool to find Project Number 2019-TC-N2 and 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 that 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, from the Appendices ABC page, click on the down arrow located in the column C heading "Geographic Location by TO Member System," and then select the code for 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 Geographic Code
American Transmission Company, LLC	ATC LLC
Dairyland Power Cooperative	DPC
Great River Energy	GRE
ITC Midwest LLC	ITCM
Minnesota Power	MP
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	2014/B	4232	No	No	OTP/ MPC
2015-NW-N1	Clearbrook 115 kV-Bagley West 230 kV	2015/B	4813	No	No	OTP/ MPC
2015-NW-N5	Ulrich 115/69 kV Transformer Replacement	Non-MISO	9652	No	No	MPC
2015-NW-N7	Richwood-Oakland 69 kV (Load Transfers)	Non-MISO		No	No	MPC
2019-NW-N1	Hoot Lake 115 kV Capacitor Bank Addition	2019/A	15725	No	No	OTP
2019-NW-N2	Norcross Area Upgrades	2019/A	17225	No	No	OTP
2019-NW-N3	Erie-Frazee	2019/A	15344	No	No	GRE/ OTP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON ?	Non-Wire Alt.	Utility
2019-NW-N4	Lake Eunice	2019/C>A	15745	No	No	GRE
2019-NW-N5	Erie/Audubon Alternate Service	Non-MISO	17144	No	No	MPC

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 230/115 kV tap of Drayton-Prairie 230 kV (Lake Ardoch) and associated Oslo 115 kV substation in 2023, and depending on future load growth, a potential second Winger-Plummer 115 kV line and associated substation expansions sometime after 2028. 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.

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: 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 that the benefits of such a project are more robust and cost effective than the other options that were considered.

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 study efforts mentioned above determined that an upgrade to mitigate post-contingent service issues to the Northwest Minnesota area transmission is required by the winter of 2023. This date is a revised date from the initial draft of the "High Voltage Study" report, and the revised date came from the "Winger-Thief River Falls Timing Analysis." A refreshed study effort was completed in early 2019 to determine a more definitive mitigation plan and schedule. With the new planned set of projects, 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.

Clearbrook 115 kV-Bagley West 230 kV

MPUC Tracking Number: 2015-NW-N1

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

Project Description: This project is related to the new 115 kV ring bus to be installed at the existing Bagley Junction switch. (Tracking Number 2015-NW-N3). The option selected from the Coordinated Clearbrook Looped Service Study (performed primarily by OTP) was to develop a substation near Bagley (about 4.5 miles southwest) that taps the Winger to Wilton 230 kV line, as well as a 22 mile line from the newly developed substation to the Clearbrook 115 kV Substation.

Need Driver: The Clearbrook 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 two 230 kV sources at Wilton and Winger. Loss of any one source forces the load to be served from a single source that could result in low voltages or thermal overloads. Additionally, loss of any transmission between Bagley and Clearbrook threatens a substantial amount of existing and future load service. The proposed transmission facilities include a 22 mile transmission line and a new substation.

Alternatives: Several different transmission alternatives were developed as part of a Clearbrook Looped Service Study to assess the ability of the transmission system to serve the anticipated load increase for the Clearbrook area. These included:

- a new Clearbrook-Solway 115 kV line,
- a new Clearbrook-Plummer 115 kV line, or
- a capacitor bank / system rebuild alternative.

The options above have been considered and compared with a new 230 kV / 115 kV tap line, and it was determined that the benefits of such a project heavily out-weight the added investment (determined in coordinated efforts that followed the initial report).

Analysis: The option selected from the Coordinated Clearbrook Looped Service Study was to develop a substation near Bagley (about 4.5 miles southwest) that taps the Winger to Wilton 230 kV line, as well as a 26 mile line from the newly developed substation to the Clearbrook 115 kV Substation. The newly developed substation, referred to as Bagley West, has a 230/115 kV transformer, breakers for the high and low side of the transformer, switches, relaying, and all other associated bus work. The Bagley West 230/115 kV transformer was identified as an equivalent replacement for the previously repurposed Wilton transformer #1 (OTP), with the recognition that the Wilton 230/115 kV transformer would have needed to be replaced.

Looped service for the Clearbrook area loads was evaluated in the "Coordinated Clearbrook Looped Service Study." Of the options analyzed, the Clearbrook West 115 kV to Bagley West 230 kV option provided the best option to meet our transmission planning requirements.

Schedule: The project was listed as having an in-service date of 2026 in the previous report. This project has now been pushed out indefinitely because of the cancellation of proposed loads in the area. As the project is still included in MTEP Appendix B, it is not being removed from this report. A schedule would be developed if new loads were to drive the need for these upgrades.

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 814 acres, only 69 acres will actually be impacted.

The economic and social impacts will likely be minimal 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 importance of an improved system.

Ulrich 115/69 kV Transformer Replacement

MPUC Tracking Number: 2015-NW-N5

Utility: Minnkota Power Cooperative (MPC)

Project Description: A new 115/69 kV transformer is being proposed for installation at the Ulrich Substation. Capacitors mentioned in the 2015 Report as part of this project are no longer required due to the Lake Park 230/69 kV Substation (Tracking Number 2017-NW-N1) providing sufficient support during outage of the Ulrich transformer.

Need Driver: The Ulrich area load is approaching the thermal limitations of the existing transformer. In addition to the existing load topology, a couple of loads that are currently served by a neighboring utility will soon be transferred to the Ulrich source (2019-NW-N5).

Alternatives: There is a single transformer at Ulrich that serves two 69 kV transmission lines. These lines are well loaded under peak conditions, and alternate service is somewhat restricted to these transmission lines due to radial configuration or thermal limitations during peak conditions following a contingency. Ensuing load transfers also create some concerns during system intact conditions. A new 230/69 kV substation was built nearby (Lake Park, MN) to provide some alternate service, see Tracking Number 2017-NW-N1, but there are still some thermal limitations. An extensive uprate to the surrounding 69 kV system or 41.6 kV system, or further load transfers could serve as an alternative to the transformer replacement, but uprates would be a far more expensive approach. Load transfers are being investigated as another project is being studied (near White Earth, MN) (2015-NW-N7). The transformer replacement is a robust and energy efficient option, and is preferred for now.

Analysis: There are not any negative reliability impacts due to the transformer replacement. This is primarily a capacity uprate.

Schedule: The study efforts mentioned above determined that the transformer replacement must be completed by the winter of 2019-2020, however, the ultimate schedule and scope of this project will be determined by the outcome of Tracking Number 2009-NW-N2. Presently the project is planned to be completed in 2019; however, a schedule will be developed as that timeframe approaches.

General Impacts: This project is entirely at the existing Ulrich Substation location. There is no new transmission area for this project. No notable environmental, human, or health concerns exist.

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, little is expected as a result of the substation modifications.

This project is the result of update requirements and capacity needs, and it will probably not have an impact on the community in terms of the environment or health.

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. 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: There are several transmission alternatives being considered as part of these load transfers. In the 2015 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. 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.

Hoot Lake 115 kV Capacitor Bank Addition

MPUC Tracking Number: 2019-NW-N1

Utility: Otter Tail Power Company (OTP)

Project Description: A new 115 kV capacitor bank is proposed at the Fergus Falls Hoot Lake substation. A total of 50 MVAR in two 25 MVAR stages is proposed along with the necessary substation modifications.

Need Driver: The planned retirement of the Hoot Lake coal plant in 2021 leaves the transmission system in the Fergus Falls area with a lack of reactive support. This capacitor bank is being proposed to mitigate a variety of low voltage concerns on the area 41.6 kV system following the retirement of the plant.

Alternatives: These capacitor banks are a relatively low-cost improvement. Alternatives include a new 345 kV tie at Fergus Falls or other more complex and less reliable alternatives such as energy storage systems.

Analysis: These capacitors were recommended in the *Otter Tail Power Company Ten Year Development Study*. The study found a need for reactive support for the area 41.6 kV system for several different outages following the retirement of Hoot Lake. In addition to several distribution capacitor installations, the 115 kV Hoot Lake capacitor mitigates any low voltage concerns associated with the plant's retirement.

Schedule: The Hoot Lake capacitors are expected to go into service by the end of 2020 such that they will be available when the plant retires.

General Impacts: This project enables the retirement of aging fossil fuel generation. It is located entirely at the existing Hoot Lake substation. There is no new transmission included in this project. No notable sites or locations are near the site of this project. This project is still in its early stages of planning, but all of this information is relatively inconsequential to the nearby environment.

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, minimal impact is expected as a result of the substation modifications.

Norcross Area Upgrades

MPUC Tracking Number: 2019-NW-N2

Utility: Otter Tail Power Company (OTP)

Project Description: This project consists of a new 115/41.6 kV substation near Norcross, MN, as well as a new 7-mile 115 kV line from the existing Grant County substation to the new Norcross substation.

Need Driver: The existing 41.6 kV system in the Norcross area is not able to reliably support load growth. This project provides an additional 115 kV source to this 41.6 kV system to accommodate new planned loads.

Alternatives: Various alternatives were examined in the *Wendell Interconnection and Nashua Elevator Load Serving Study*, including 41.6 kV STATCOMs or a tie into the WAPA Moorhead – Morris 230 kV line.

Analysis: The *Wendell Interconnection and Nashua Elevator Load Serving Study* examined various projects that could mitigate the reliability concerns in the Norcross area. The recommended project as described above was found to be the most reliable and lowest-cost alternative. The STATCOM solution proved to be infeasible due to a low short-circuit ratio on the area 41.6 kV system. The WAPA 230 kV tie compared unfavorably to the preferred project due to some unmitigated N-1 concerns as well as additional ongoing SPP transmission service costs.

Schedule: In order to meet the schedule of new loads planned in the area, this project is planned for completion by the end of 2020.

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. There will 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 110 acres, only approximately 10 acres will actually be impacted.

The economic and social impacts will likely be minimal 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 importance of an improved system.

Erie – Frazee

MPUC Tracking Number: 2019-NW-N3

Utility: Great River Energy (GRE)

Project Description: Rebuild Frazee substation 115 kV side to a ring bus to accommodate a new 115 kV line from Erie. Construct about 2.5 miles of the Frazee to Erie Jct 115kV line. Install a 30 MVAr capacitor bank at Frazee substation

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

Alternatives: The following alternatives were considered in the study. These alternatives weren’t 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 – Pelican Rapids 115 kV double circuit line

Analysis: The Erie – Frazee project was determined to be the most reliable and least cost project.

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.

Lake Eunice 115 kV Conversion

MPUC Tracking Number: 2019-NW-N4

Utility: Great River Energy (GRE)

Project Description: This project is to convert Lake Region Electric Cooperate (LREC) owned Lake Eunice substation from 41.6 kV service to 115 kV service, retire existing Lake Eunice Tap 41.6 kV switches and retire portion of the LR-EC line.

Need Driver: Lake Eunice substation, which servers a relatively large load in the area, is served on a long radial 41.6 kV line from the Audubon 230/115/41.6 kV substation. The total radial 41.6 kV line exposure for the Lake Eunice substation is 20.5 mile, and the radial MW-Mile based on system peak load level is 195 MW-Mile. Based on GRE MW-mile criteria, this magnitude of exposure and radial MW-mile, in general, initiates a study for possible alternatives to either reduce the exposure, or provide a loop feed to the Lake Eunice substation. In addition, LREC have indicated that at system peak conditions, Lake Eunice substation can’t be back fed entirely from other substations. There are reliability problems that drive the conversion of the Lake Eunice substation from 41.6 kV service to 115 kV service.

Alternatives: Leave Lake Eunice substation on the long radial 41.6 kV line.

Analysis: The 115 kV system that will provide a reduced radial service to the Lake Eunice substation is located about 0.8 miles north of the Lake Eunice substation. This transmission system has historically had better reliability than the 41.6kV transmission system that currently serves the Lake Eunice substation.

Schedule: The project is planned to be in service by fall 2021.

General Impacts: The project will require approximately 1 mile of new 115 kV transmission line from the Lake Eunice substation to the tap in the GRE 115 kV LR-CF line. 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 and transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

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 3 mile line may be constructed from MPC's Audubon distribution substation to a tap on OTP's Audubon-Erie Jct. 41.6 kV line, with the remaining portion of OTP's 41.6 kV line 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: 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

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 2021 and 2022 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.

6.3.2 Completed Projects

The table below identifies one project in the Northwest Zone that was listed as an ongoing project in the 2015 Biennial Report but has since been determined to not be necessary. More information about Tracking Number 2015-NW-N6 can be found in the 2015 Report. Should the project once again become necessary, it will be assigned a new Tracking Number.

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2009-NW-N2	Frazee-Perham-Rush Lake Area	Not Required	GRE	2019
2015-NW-N3	Bagley North 115 kV Ring Bus	Not Required	MPC/OTP	2018
2015-NW-N4	Moranville 230/69 kV Transformer Replacement	Not Required	MPC	2018
2015-NW-N5	Ulrich 115/69 kV Transformer Replacement	Not Required	MPC	2019
2015-NW-N6	Anderson/Thief River Falls Tap-New Thief River Falls Substation 115 kV Line (Load Tap/Transfer)	Not Required	MPC	Withdrawn 2017
2015-NW-N8	Thief River Falls 115 kV Capacitor Bank Addition	Not Required	MPC	2019
2017-NW-N1	Lake Park Substation	Not Required	MPC	2018
2017-NW-N2	Itasca-MPL Laporte 115 kV Line (and Northwoods Circuit Breaker Addition)	Not Required	MPC	2018
2017-NW-N3	Thief River Falls-Plummer Pipe 115 kV Line Uprate	Not Required	MPC	2019
2017-NW-N4	Donaldson 115 kV Capacitor Bank Addition	Not Required	OTP	2019

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
2007-NE-N6	Onigum Area	2012/B	2632	No	Yes	GRE
2011-NE-N2	15 Line Upgrade	2016/A	7996	No	No	MP
2011-NE-N12	Wrenshall Substation	2013/B	3756	No	No	MP
2013-NE-N13	Great Northern Transmission Line	2014/A	3831	Yes	No	MP
2013-NE-N16	Square Butte—Arrowhead HVDC Valve Hall Replacement	2013/B	4295	No	No	MP
2013-NE-N17	Square Butte—Arrowhead HVDC Upgrade	2014/B	3856	No	No	MP
2013-NE-N22	Elisha 115/34.5 kV Project	2018/A	8920	No	No	GRE
2015-NE-N2	868 Line Upgrade	2019/A	7913	No	Yes	MP
2015-NE-N5	16 Line Relocation	2015/A	8000	No	No	MP
2015-NE-N12	Iron Range-Arrowhead 345 kV Project	2014/B	3832	Yes	No	MP
2015-NE-N14	83 Line Upgrade	2016/A	9622	No	Yes	MP
2015-NE-N16	Two Inlets Pumping Station (X1A)	2018/A	9200	No	No	GRE
2015-NE-N17	Backus Pumping Station (X2A)	2018/A	9201	No	No	GRE
2015-NE-N18	Swatara Pumping Station (X3A)	2018/A	9202	No	No	GRE/MP
2015-NE-N19	Hingley Pumping Station (X4A)	2018/A	9203	No	No	GRE
2017-NE-N2	Laskin-Tac Harbor Voltage Conversion	2016/A	10383	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON ?	Non-Wire Alt.	Utility
2017-NE-N3	Little Falls Voltage	2016/B	9643	No	Yes	MP
2017-NE-N4	Nashwauk 14 Line Upgrade	2018/A	9646	No	Yes	MP
2017-NE-N5	53 Line Upgrade	2018/A	9647	No	Yes	MP
2017-NE-N6	Forbes Tie Breaker Addition	2019/A	10285	No	No	MP
2017-NE-N15	North Shore STATCOM	2017/A	12644	No	Yes	MP
2017-NE-N16	51 Line Upgrade	2017/B	12564	No	Yes	MP
2017-NE-N21	Laskin-Tac Harbor Transmission Line Upgrades	2018/A	13504	No	Yes	MP
2017-NE-N22	Blackberry Breaker Replacements	2018/A	13527	No	No	MP
2017-NE-N23	Mesaba Junction 115 kV Project	2018/A	13485	No	Yes	MP
2017-NE-N25	Boswell 230 kV Fast-Switched Capacitor Bank	2017/B	12684	No	No	MP
2019-NE-N1	11 Line Upgrade	2019/A	15590	No	Yes	MP
2019-NE-N2	Forbes 37 Line Upgrade	2019/A	15591	No	Yes	MP
2019-NE-N3	Hibbing 14 Line Upgrade	2020/A	15592	No	Yes	MP
2019-NE-N4	25 Line Upgrade	2020/A	15593	No	Yes	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-N7	Savanna Transformer	2019/A	15597	No	No	MP
2019-NE-N8	Badoura Transformer Replacement	2020/A	15598	No	No	MP
2019-NE-N9	Midway Substation Retirement	2019/A	15601	No	No	MP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON ?	Non-Wire Alt.	Utility
2019-NE-N10	Babbitt Area 115 kV Project	2018/B 2018/B	16069 16070	No	Yes	MP
2019-NE-N11	38 Line Upgrade	2019/A	16804	No	Yes	MP
2019-NE-N12	Duluth 115 kV Loop	2020/B	17868	Yes	Yes	MP
2019-NE-N13	National Breaker Replacements	2020/A	17870	No	No	MP
2019-NE-N14	Laskin Breaker Replacements	2020/A	17871	No	No	MP
2019-NE-N15	Portage Lake 115/69 kV Project	2020/C>A	17664	No	No	GRE
2019-NE-N16	Forbes SVC Retirement	2020/A	14048 & 15544	No	No	XEL
2019-NE-N17	Running Cap Bank Retirement	2019/A	16145	No	No	XEL

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

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 increase social, environmental and economic impacts associated with construction of such a line. 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. Minnesota Power is currently evaluating both wires and non-wires solutions for several Duluth-area issues, including the 230/115 kV transformer loading issue and the Duluth 115 kV Loop issues (2019-NE-N12).

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. Studies continue to indicate that this project may become needed in the first half of the 2020s. The underlying system drivers behind the timing of the 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. The earliest that Minnesota Power currently anticipates initiating public outreach or permitting activities for this project would be in 2020. Further study is ongoing to determine if the Duluth 230 kV Project remains the best technical solution to the issues that have been identified, or if there is a more optimal wires or non-wires solution for the area.

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.

Onigum 115 kV Conversion

MPUC Tracking Number: 2007-NE-N6

Utility: Great River Energy (GRE)

Project Description: Construct a new, 115 kV line from Great River Energy's (GRE) existing Birch Lake Substation to Lake Country Power's (LCP) Onigum Substation. LCP will rebuild their substation adjacent to the existing site to receive 115 kV electric service.

Need Driver: LCP's Onigum Substation is served by a 34.5 kV system that is sourced by the 115/69/34.5 kV Birch Lake Substation and the 115/34.5 kV Akeley substation. Due to the aging condition and lack of capacity, GRE is planning to rebuild the existing 34.5 kV to 115 kV.

Alternatives: An alternative considered was rebuilding the 34.5 kV system with a like-for-like replacement.

Analysis: The 2008 GRE Long Range Plan indicated that the conversion of the Onigum Substation to 115 kV operation will unload the 34.5 kV service and extend the useful life of this system. MP and GRE will need to monitor the growth of the Walker area electric system to see when further conversion may be required.

Schedule: The timing of the Onigum conversion will be driven by the anticipated load growth in the area or if structural issues arise.

General Impacts: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. The approximately 9.5 miles of existing line will be upgraded from 34.5 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 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.

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15 Line Upgrade

MPUC Tracking Number: 2011-NE-N2

Utility: Minnesota Power (MP)

Project Description: Rebuild and reconductor existing Fond du Lac-Hibbard 115 kV Line (MP "15 Line").

Need Driver: The existing Fond du Lac-Hibbard 115 kV Line needs to be rebuilt with a larger conductor due to its age and condition, lack of shield wire resulting in elevated risk to nearby sensitive industrial loads, and identified pre- and post-contingent overloads on the line.

Alternatives: A previously-preferred alternative (MISO MTEP Project #2549) involved reconfiguring 15 Line with an existing 115 kV line and substation to allow for removal of approximately half of the 11-mile line. Further analysis of constructability, particularly with regard to the location where 15 Line would be reconfigured to interconnect with the existing 115 kV line, as well as further analysis of the long-term transmission system needs in the area identified that an in-place rebuild of 15 Line was a preferable solution. Non-wire alternatives are not viable because they cannot address concerns related to age and condition or lack of shield wire on 15 Line.

Analysis: Reconductoring 15 Line provides the best solution for maintaining the reliability of the Duluth-area 115 kV system in view of current needs (to deliver hydroelectric generation from Thomson and Fond du Lac, to support current load levels) and long-term needs (projected load growth and transmission system modifications such as the Duluth 230 kV Project). While recent analysis has shown that it would be prohibitively expensive to reconductor a portion of existing conductor on lattice towers, new line ratings will still be sufficient to mitigate identified overloads on the line.

Schedule: Execution of the project began in 2017 and was broken up into three phases. Phase 1, including rebuilding most of the line length between Fond Du Lac Substation and the City of Proctor, was completed in 2017. Phase 2, including replacing limiting equipment at the Fond Du Lac and Hibbard Substations, rebuilding transmission line crossings of Interstate Highway 35 and State Highway 210, and shielding several spans between Proctor and Duluth, was completed in 2018. Phase 3, including rebuilding the section of line through the City of Proctor, will be completed in 2019. Due to the multiple delays in construction of the project, an operating guide has been in place to mitigate overloading until the project is completed.

General Impacts: The 15 Line Upgrade project will provide necessary system improvements in the Duluth area without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Wrenshall Substation

MPUC Tracking Number: 2011-NE-N12

Utility: Minnesota Power (MP)

Project Description: Rebuild existing Wrenshall 115/14kV Distribution Substation and extend new feeder to Military Road.

Need Driver: Retirement of existing 46 kV line and equipment at Thomson Substation due to age and condition. Age and condition of existing Wrenshall Substation.

Alternatives: Rebuild existing radial 46 kV circuit from Thomson to Military Road. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Thomson and Wrenshall Substations.

Analysis: Rebuilding the existing Wrenshall Substation and extending a new feeder to the Military Road area will allow for continued service to Minnesota Power customers in the Wrenshall area and allow for Minnesota Power to retire 46 kV line assets and equipment at Thomson Substation.

Schedule: The Wrenshall Substation Project is expected to be in service in 2024.

General Impacts: The Wrenshall Substation Project will ensure a continuous and reliable power supply to Wrenshall and the surrounding area, while eliminating an aged segment of 46 kV line that is difficult and expensive to maintain due to its location and the surrounding terrain.

Great Northern Transmission Line

MPUC Tracking Number: 2013-NE-N13

MPUC Docket Numbers: E015/CN-12-1163 and E015/TL-14-21

Utility: Minnesota Power (MP)

Project Description: The Great Northern Transmission Line Project includes approximately 225 miles of 500 kV transmission line between a point on the Minnesota-Manitoba border northwest of Roseau, MN, and Minnesota Power's existing Blackberry Substation near Grand Rapids, MN. The project also includes the development of a new substation (Iron Range 500/230 kV Substation) located on the same site as the existing Blackberry Substation as well as a 500 kV midline series compensation station (Warroad River Series Compensation Station) located near Warroad, MN.

Need Driver: The purpose of the Great Northern Transmission Line Project is to efficiently provide Minnesota Power's customers and the Midwest region with clean, emission-free energy that will help meet the region's growing long-term energy demands, advance Minnesota Power's Energy*Forward* strategy to increase its generation diversity and renewable portfolio, strengthen system reliability, and fulfill Minnesota Power's obligations under its power purchase agreements with Manitoba Hydro, all in a manner that is consistent with Minnesota Power's commitment to making a positive impact on the communities where it does business.

Alternatives: Riel-Shannon 230 kV Line.

Analysis: The Great Northern Transmission Line provides the most effective and efficient long-term solution for supporting incremental power transfers on the Manitoba-United States interface.

Schedule: In anticipation of the Great Northern Transmission Line Project's aggressive schedule and needing to meet a June 1, 2020, in-service date, Minnesota Power initiated a proactive public outreach program to key agency stakeholders and the public that started in August 2012 and continued through May 2015. Through this program, thousands of landowners, the public, and federal, state, and local agency stakeholders were engaged through a variety of means, including five rounds of voluntary public open house meetings held throughout the project area.

On September 23, 2014, Minnesota Power, Manitoba Hydro, and the MISO executed a Facilities Construction Agreement (FCA) for the Great Northern Transmission Line Project, setting forth the ownership and financial responsibilities for the project, among other terms. Upon approval of the FCA by the Federal Energy Regulatory Commission (FERC) on November 25, 2014, MISO considered the project an approved project under the MISO tariff and moved the Great Northern Transmission Line Project to Appendix A of the MTEP14. Subsequently, the Commission granted Minnesota Power a Certificate of Need (MPUC Docket No. E015/CN-12-1163) and Route Permit (MPUC Docket No. E015/TL-14-21) for the Great Northern Transmission Line on May 14, 2015, and February 26, 2016, respectively. The final major approval – the United States Presidential Permit granting approval of the border crossing (DOE Docket No. PP-398) – was received from the United States Department of Energy on November 16, 2016. Following receipt of the Presidential Permit, Minnesota Power began construction of the project in early 2017 and is continuing to execute the project construction schedule in order to meet the required in-service date of June 1, 2020 in satisfaction of the contractual agreements between Minnesota Power and Manitoba Hydro.

General Impacts: The Manitoba Hydro hydropower purchases made possible by the Great Northern Transmission Line will provide Minnesota Power and other utilities in the Upper Midwest access to a predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements. Minnesota Power has maintained its commitment to making a positive impact in the communities throughout the project area through a multiyear proactive public outreach program and through designing its routes to utilize existing transmission line corridors to the greatest reasonable extent when considering all human, environmental, and engineering constraints. The project is also expected to have a significant impact on local property taxes in the counties where it will be located. An Environmental Impact Statement was prepared for the project and is available through eDockets in MPUC Docket No. E015/TL-14-21.

Square Butte – Arrowhead HVDC Valve Hall Replacement

MPUC Tracking Number: 2013-NE-N16

Utility: Minnesota Power (MP)

Project Description: Replace thyristor valve halls with modern equipment on Square Butte – Arrowhead HVDC line.

Need Driver: The Square Butte HVDC terminals were designed by General Electric (GE) for a 30 year operating lifetime and as of 2019 they have been operating reliably for over 40 years. The main components of the HVDC terminals include the thyristor valves and cooling, converter transformers, and smoothing reactors to complete the energy conversion. The original vendor, GE, left the HVDC business in the 1980s and in recent years it has been increasingly difficult to procure spare parts as the technology is becoming obsolete and the original designers are well into retirement. Minnesota Power has researched reverse engineering solutions to this technology issue, but has had limited results and thus spare and replacement parts for the HVDC system remain limited. By taking action to modernize the thyristor equipment, Minnesota Power will greatly reduce the likelihood of a line failure. Minnesota Power is planning a package of modernization activities for each of the major components of the HVDC system. Along with the thyristor valves, Minnesota Power can reduce the likelihood of forced outages of the 465 mile transmission line by planning replacement of transformers and smoothing reactors.

Alternatives: There are two alternatives. "Do Nothing" (risk of extended outage due to equipment failure) or implement the Square Butte – Arrowhead HVDC Upgrade (Tracking Number 2013-NE-N17). Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Square Butte and Arrowhead HVDC converter stations.

Analysis: Replacement of the existing thyristor valves with modern equipment is the minimum necessary project to maintain the reliability of Minnesota Power's HVDC line and reduce the risk of extended outages due to equipment failure.

Schedule: At this time, Minnesota Power is focused on developing the HVDC 750 MW Upgrade (Tracking Number 2013-NE-N17). Specification development for the HVDC 750 MW Upgrade Project will begin before the end of 2019, with a competitive bidding process for engineering and construction of the turnkey project expected to take place in 2020. The project will take approximately 3-4 years to engineer and construct, with a targeted in-service date in 2024.

General Impacts: The modernization of the HVDC equipment is a prudent and necessary activity to 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 anticipated to take place within the footprint of the existing converter terminal buildings and substations, it is anticipated that no new landowners would be impacted by the project.

Square Butte – Arrowhead HVDC Upgrade

MPUC Tracking Number: 2013-NE-N17

Utility: Minnesota Power (MP)

Project Description: Replace Square Butte – Arrowhead HVDC thyristor valve halls and outdoor equipment with modern equipment and upgrade existing line and terminal equipment to 750 MW or higher capacity.

Need Driver: The Square Butte HVDC terminals were designed by General Electric (GE) for a 30 year operating lifetime and as of 2019 they have been operating reliably for over 40 years. The main components of the HVDC terminals include the thyristor valves and cooling, converter transformers, and smoothing reactors to complete the energy conversion. The original vendor, GE, left the HVDC business in the 1980s and in recent years it has been increasingly difficult to procure spare parts as the technology is becoming obsolete and the original designers are well into retirement. Minnesota Power has researched reverse engineering solutions to this technology issue, but has had limited results and thus spare and replacement parts for the HVDC system remain limited. By taking action to modernize the thyristor equipment, Minnesota Power will greatly reduce the likelihood of a line failure. Minnesota Power is planning a package of modernization activities for each of the major components of the HVDC system. Along with the thyristor valves, Minnesota Power can reduce the likelihood of forced outages of the 465 mile transmission line by planning replacement of transformers and smoothing reactors.

With new equipment such as what would be necessary to complete the modernization of the HVDC system there is opportunity to consider new designs, technology capabilities and system enhancements. With the valve hall replacement, Minnesota Power has the opportunity to increase the power delivery capability of the entire Square Butte HVDC system from 550 MW to 750 MW or more while utilizing the existing transmission line, building and real estate. The new valves provide advantages of life extension (of at least 30 years) and the option to allow energy to flow in both west to east and east to west directions that would add a new and positive dynamic to the regional transmission system. Additional equipment upgrades beyond replacement of the thyristor valves will also be necessary to upgrade the capacity of the HVDC line to 750 MW or more. The converter transformers, AC filter banks, and transmission line capability would all be impacted. A final decision on the targeted capacity for the HVDC upgrade (750 MW or more) will be made and specification development for the upgraded HVDC system will begin before the end of 2019.

Alternatives: Square Butte – Arrowhead HVDC Valve Hall Replacement (Tracking Number 2013-NE-N16). Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Square Butte and Arrowhead HVDC converter stations.

Analysis: Replacement of the existing thyristor valves with modern equipment is the minimum necessary project to maintain the reliability of Minnesota Power's HVDC line and reduce the risk of extended outages due to equipment failure. Given the nature of the HVDC modernization project and the long life of the assets (30+ years anticipated), additional modifications to the HVDC system enabling higher transfer capability on the line will provide the most optimal value-added long-term solution for Minnesota Power at a reasonable incremental cost.

Schedule: Specification development for the Square Butte – Arrowhead HVDC Upgrade Project will begin before the end of 2019, with a competitive bidding process for engineering and construction of the turnkey project expected to take place in 2020. The project will take approximately 3-4 years to engineer and construct, with a targeted in-service date in 2024.

General Impacts: The modernization of the HVDC equipment is a prudent and necessary activity to 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. The additional capacity facilitated by the Square Butte – Arrowhead HVDC Upgrade Project has the potential to 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 footprint of the existing converter terminal buildings and substations and on the existing transmission line right-of-way, it is anticipated that no new landowners would be impacted by the project.

Elisha 115/34.5 kV Project

MPUC Tracking Number: 2013-NE-N22

Utility: Great River Energy (GRE)

Project Description: Construct a new 115/34.5 kV substation to be named Elisha, build approximately 2.0 miles of 115 kV transmission to interconnect Elisha to the Itasca Mantrap's Potato Lake Substation, and build approximately 12.0 miles of 69 kV transmission, to be operated at 34.5 kV, to interconnect to Itasca Mantrap's Pine Point Substation. The 230/115/34.5 kV Hubbard Substation will retire all of its 34.5 kV assets and the Elisha Substation will utilize the remaining 115/34.5 kV transformer at Hubbard. The newly established 34.5 kV loop served by Elisha and Long Lake will have a normally open point at the Osage Substation.

Need Driver: Provide a redundant, stronger source to the Osage load pocket to alleviate low voltage seen on the 12.47 kV end. Minimize the radial MW-Mile exposure on the Hubbard-Osage-Shell Lake-Pine Point 34.5 kV line.

Alternatives: Development of a 115/34.5 kV substation near Potato Lake and build a 34.5 kV line from the new substation to the Osage Substation.

Analysis: The Elisha Substation will serve the Osage, Pine Point, and Shell Lake substations system intact while Long Lake will act as a backup source to these loads. The voltage profile in the Osage area will increase significantly with the proposed Elisha Substation.

Schedule: The in-service date of this project will be determined by the Enbridge Pipeline permitting process.

General Impacts: The project will require approximately 11 miles of new 34.5 kV sub transmission between Pine Point and the double circuit 115 & 34.5 kV line; approximately 1.5 miles of new double circuit 115/34.5 kV transmission line to the Elisha substation; approximately 2 miles of new 115 kV transmission line from Elisha to the Potato Lake tap. The project is located in predominantly agricultural lands with approximately 3 miles along road right-of-way through the Two Inlets State Forest. 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 15 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 higher voltage transmission line through more sensitive areas.

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868 Line Upgrade

MPUC Tracking Number: 2015-NE-N2

Utility: Minnesota Power (MP)

Project Description: Reconductor existing Little Falls-Langola Tap-St. Stephen Tap 115 kV Line (MP "868 Line") and replace limiting substation terminal equipment.

Need Driver: Post contingent overload following loss of parallel 230 kV, 345 kV, or 500 kV lines.

Alternatives: Thermal upgrade of existing conductor paired with deployment of Smart Wires power flow control devices to reduce power flow to within capability of existing conductor; Build a new 115 kV or 230 kV line between Mud Lake and the St. Cloud area; 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.

Analysis: Following an evaluation of some of the alternatives listed above, Minnesota Power determined that the reconductor project was the most cost-effective long-term solution. Previous MTEP and Minnesota Power studies have indicated that this is a winter peak issue that becomes necessary as early as the 2019-20 winter ratings season.

Schedule: Construction of the project is planned for the 2020-21 winter construction season. Potential overloads prior to completion of the project are being managed with an operating guide.

General Impacts: The 868 Line Upgrade Project will provide necessary system improvements in the area between Little Falls and St. Cloud without requiring the establishment of additional transmission line corridors.

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16 Line Relocation

MPUC Tracking Number: 2015-NE-N5

MPUC Docket Numbers: E015/TL-14-977

Utility: Minnesota Power (MP)

Project Description: Reroute a segment of the existing Arrowhead-16 Line Tap 115 kV Line around a proposed United Taconite tailings basin expansion.

Need Driver: United Taconite tailings basin expansion.

Alternatives: Remove the segment of existing line without rebuilding it. Non-wire alternatives are not viable because they cannot address the need to remove the line off the impacted property.

Analysis: A fully-intact connection between Arrowhead and the 16 Line Tap is necessary for providing reliable electric service to the area between Duluth and Eveleth. Removal of the line off the proposed tailings basin expansion site without re-establishing this connection is not a viable solution.

Schedule: The 16 Line Relocation Project is expected to be completed by May of 2020 to meet United Taconite's schedule for the planned tailings basin expansion.

General Impacts: The 16 Line Relocation Project maintains an important source of power for the area between Virginia and Duluth while also enabling industrial expansion on the Iron Range.

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. This project was formerly coupled together with the Great

Northern Transmission Line (Tracking Number 2013-NE-N13) but the two projects have since been decoupled due to the lack of sufficient transmission service requests to justify the 345 kV connection to Arrowhead.

Need Driver: When paired with the Great Northern Transmission Line, 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 currently-desired incremental export capability from Manitoba to the United States and the majority of the benefits of wind and hydro synergy can be realized by the development of the Great Northern Transmission Line Project alone, without a 345 kV extension to Arrowhead. Because there are not sufficient transmission service requests to justify the 345 kV connection to Arrowhead at this time, Minnesota Power has determined that it will 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, it will be advanced at that time based on its own merits apart from the Great Northern Transmission Line Project.

Alternatives: No other alternatives are currently being considered.

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 is not needed or economically justified at this level of Manitoba Hydro export. MISO studies have confirmed this finding.

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 has 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.

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83 Line Upgrade

MPUC Tracking Number: 2015-NE-N14

Utility: Minnesota Power (MP)

Project Description: Replace limiting 230 kV terminal equipment at the Boswell and Blackberry substations to restore transmission line capacity.

Need Driver: The Boswell-Blackberry 230 kV lines (MP "83 Line" and "95 Line") were derated after a NERC-mandated equipment audit identified undersized terminal equipment at the Boswell and Blackberry substations. The 83 Line Upgrade Project restores the capacity of 83 Line, a critical outlet for Boswell generation, to its original capacity.

Alternatives: Build a third Boswell-Blackberry 230 kV Line. 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.

Analysis: There is no more economical or less impactful solution than replacing the limiting equipment to restore the capability of the existing line.

Schedule: This issue was first identified when 83 Line and 95 Line were derated; however, single contingency overloads on 83 Line following the derate have not been identified in any studies to date. Minnesota Power is monitoring MTEP reliability assessment results, as well as the results of Minnesota Power internal studies, to determine if and when a project is needed to restore 83 Line to its original capacity.

General Impacts: 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 address any issues caused by derating 83 Line.

Two Inlets Pumping Station (X1A)

MPUC Tracking Number: 2015-NE-N16

Utility: Great River Energy (GRE)

Project Description: Build approximately 5.5 miles of 115 kV transmission line from the GRE Elisha substation to the future Two Inlets Substation. The substation will supply power to the Enbridge Two Inlets pump station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 12 miles northwest of Park Rapids.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher voltage transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Potato Lake Substation. A short, radial tap from the Elisha Substation to the new Two Inlets Substation will be constructed to provide electric service.

Schedule: The in-service date of this project will be determined by the Enbridge Pipeline permitting process.

General Impacts: The project will require approximately 1.5 miles of double circuit new 115/34.5 kV transmission line from the Elisha substation to the 34.5 kV line to Pine Point; approximately 4 miles of new 115 kV transmission line from Elisha to the Two Inlets 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Backus Pumping Station (X2A)

MPUC Tracking Number: 2015-NE-N17

Utility: Great River Energy (GRE)

Project Description: Build an approximately 2.5 mile 115 kV transmission line from a new interconnection to the Minnesota Power 115 kV #142 line (Badoura to Pine River) to the Backus Pumping Station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 3 miles south of Backus.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Badoura-Pine River (142 Line) 115 kV line. A short, radial tap from the 142 Line to the new Backus Pumping Station Substation will be constructed to provide electric service.

Schedule: The in-service date of this project will be determined by the Enbridge Pipeline permitting process.

General Impacts: The project will require approximately 2.5 miles of new 115 kV transmission line from Backus Pumping Station to the interconnection with the Minnesota Power 115 kV 142

Line. The project is located along the Minnesota Power 250 kV DC line corridor through forested 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 transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Swatara 230 kV Station (X3A)

MPUC Tracking Number: 2015-NE-N18

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

Project Description: Construct a 3-way 230 kV motor-operated switch in MP's Riverton – Blackberry 230 kV Line ("92 Line") and extend a transmission tap <1500 feet to the Swatara Pumping Station. Also includes installation of a 230 kV breaker at the Riverton Substation to facilitate operation of the Swatara Tap switches. This project was previously named Palisade.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 2 miles south of the City of Swatara.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage such as 115 kV or higher. The nearest 115 kV or higher transmission line is the Riverton – Blackberry 230 kV line ("92 Line"). A radial tap from the 92 Line to the new Swatara Pumping Station Substation will be constructed to provide electric service. Due to the present breaker configuration at Riverton, breakers on the Blackberry end must always be opened first. In order to make use of the Swatara Tap switches, Minnesota Power is installing a new "92L" breaker at Riverton so that the line may be sectionalized on either side of the Swatara Tap without interrupting service to the Swatara Pumping Station. This breaker also has a broader system benefit as it provides better protection and control for Minnesota Power's backbone 230 kV system.

Schedule: The in-service date of this project will be determined by the Enbridge Pipeline permitting process. Minnesota Power is installing the Riverton 92L breaker in late 2019.

General Impacts: The project will require approximately 1000 feet of new 230 kV transmission line from Swatara Pumping Station to the interconnection with the Minnesota Power 230 kV 92 Line. The project is located near the Minnesota Power 230 kV 92 line and the 250 kV DC line corridor through forested lands. Prior to construction, GRE will acquire the necessary right-of-way and permits for construction of the project. GRE anticipates acquiring a 150-foot easement to facilitate construction and operation of the line. The preliminary design is adjacent to existing transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Hingley Pumping Station (X4A)

MPUC Tracking Number: 2015-NE-N19

Utility: Great River Energy (GRE)

Project Description: Build an approximately 0.2 mile 115 kV line from Cromwell City – Savanna (156 line) to the Hingley Pumping Station.

Need Driver: Enbridge Pipeline has proposed a new pumping station about 5.3 miles southeast of the City of Floodwood.

Alternatives: The nearby distribution systems would not support the large pumping station load. Other alternatives would require longer 115 kV or higher transmission lines.

Analysis: Large pumping stations with large electric motors require a robust voltage like 115 kV. The nearest 115 kV source is the Cromwell-Savanna (156 Line) 115 kV line. A short, radial tap from the 156 Line to the new Hingley Pumping Station Substation will be constructed to provide electric service.

Schedule: The in-service date of this project will be determined by the Enbridge Pipeline permitting process.

General Impacts: The project will require approximately 1000 feet of new 115 kV transmission line from Hingley Pumping Station to the interconnection with the Great River Energy 115 kV LC-CS Line. The project is located near the Great River Energy 115 kV LC-CS Line corridor on 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 adjacent to existing transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Laskin-Tac Harbor Voltage Conversion

MPUC Tracking Number: 2017-NE-N2

Utility: Minnesota Power (MP)

Project Description: The Laskin-Tac Harbor Voltage Conversion involves converting the legacy 138 kV system between the Laskin and Taconite Harbor substations to 115 kV operation. The work includes removing 138/115 kV transformers, replacing 138 kV equipment with 115 kV equipment, and replacing other aging equipment at the existing Laskin, Skibo, Hoyt Lakes and Tac Harbor substations. A previously-planned expansion of the existing Hoyt Lakes Substation has been eliminated from the scope of the project due to space limitations at the existing substation as well as constructability and maintainability concerns. Instead, a new switching station will be constructed on a nearby site as part of the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23).

Need Driver: Age and condition, removal of single points of failure, standardization of equipment, redundancy and voltage support concerns without local coal-fired generators online in the North Shore Loop.

Alternatives: Continue to operate at 138 kV. Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the 138 kV system assets or standardization of equipment.

Analysis: The Laskin-Tac Harbor 138 kV system was originally established by a mining company in the mid-1900s to connect its generating assets at Taconite Harbor to its plant operations in Hoyt Lakes. Over the years, improvements were made to provide redundancy to the area by connecting the 138 kV system to Minnesota Power's 115 kV system. Today, Minnesota Power owns the transmission in the Laskin-Tac Harbor 138 kV system and it provides a transmission connection that is critical for the reliability of service to all Minnesota Power and Great River Energy customers in the North Shore Loop.

The ongoing transition away from local baseload coal-fired generators in the North Shore Loop has served to increase the importance of the Laskin-Tac Harbor connection for the reliable delivery of power into the North Shore Loop from external sources, in addition to causing a need for additional voltage support in the area. The Laskin-Tac Harbor Voltage Conversion Project leads to the elimination of single points of failure with long replacement leadtimes (138/115 kV transformers), providing a more redundant and reliable transmission connection for the North Shore Loop. These reliability objectives are accomplished by the project in addition to the inherent benefits of replacing aging equipment, eliminating a non-standard voltage class from the Minnesota Power transmission system, and avoiding the cost of additional 138/115 kV transformers for redundancy, replacement, or the establishment of new transmission connections.

Beyond the benefits described above, the Voltage Conversion Project positions the northern end of the North Shore Loop for the establishment of other local redundancy and voltage support projects, including the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23) and the Babbitt Area 115 kV Project (Tracking Number 2019-NE-N10). Continued operation of the Laskin-Tac Harbor system at 138 kV would significantly increase the cost and complexity of making these transmission improvements in the area.

Schedule: The project will be coordinated with the construction of the Mesaba Junction 115 kV Project and is expected to be in service by the end of 2021.

General Impacts: The Laskin-Tac Harbor Voltage Conversion Project will eliminate a non-standard voltage class from the Minnesota Power system, mitigating single points of failure, replacing aging equipment, and avoiding the future cost of adding or replacing other equipment unique to the 138 kV system. It is the most efficient and least environmentally impactful solution for meeting the near-term and long-term needs of the North Shore Loop, making good use of the existing 138 kV facilities by converting them to 115 kV. The Voltage Conversion Project is also a critical component of maintaining a reliable system in the face of significant changes in the North Shore Loop. Replacing voltage support previously provided by baseload coal units in the area and improving the redundancy 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.

Little Falls Voltage

MPUC Tracking Number: 2017-NE-N3

Utility: Minnesota Power (MP)

Project Description: Reconfigure Little Falls 115 kV bus connections.

Need Driver: 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.

Alternatives: Add another 115 kV capacitor bank in the area or reconfigure the Little Falls 115 kV bus to include a bus tie breaker. 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.

Analysis: This 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 planned near-term asset renewal projects at the Little Falls Substation in order to realize efficiencies in engineering and construction.

Schedule: This issue was first identified in the MTEP15 2019 Winter Peak case. As described above, the reconfiguration of the transformer connection will be packaged with asset renewal projects at the Little Falls Substation. The earliest timeframe for implementation of these Little Falls Substation projects is 2021-22.

General Impacts: 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 address the issue first identified in the MTEP15 assessment. Per the scope discussed above, the impacts will be contained within the existing Little Falls Substation yard and no expansion area will be necessary.

Nashwauk 14 Line Upgrade

MPUC Tracking Number: 2017-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase capacity of Nashwauk-14 Line Tap 115 kV Line (MP "Nashwauk 14 Line") and replace associated capacity-limiting and end-of-life equipment at Nashwauk Substation.

Need Driver: Post-contingent overload following loss of parallel line.

Alternatives: Reconductor existing line, build new parallel line. 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.

Analysis: This issue was identified in several MTEP assessments and Minnesota Power studies going back to MTEP15. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs at the substation termination.

Schedule: This issue was first identified in the MTEP15 2020 Shoulder (off-peak) case, and subsequently showed up in a similar MTEP17 2022 Summer Peak case. Based on the MTEP15 results, the project is needed prior to May 1, 2020. Presently, the transmission line upgrade portion of the project – which provides most of the capacity increase – is expected to be completed in 2019 and the substation equipment replacements and remaining capacity increase are expected to be completed in 2020.

General Impacts: The Nashwauk 14 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

53 Line Upgrade

MPUC Tracking Number: 2017-NE-N5

Utility: Minnesota Power (MP)

Project Description: Increase capacity of Nashwauk-National 115 kV Line (MP "53 Line") and replace associated capacity-limiting and end-of-life equipment at Nashwauk and National Substations.

Need Driver: Post-contingent overload following loss of parallel line.

Alternatives: Reconductor existing line, build new parallel line. 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.

Analysis: This issue was identified in several MTEP assessments and Minnesota Power studies going back to MTEP15. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs at the substation termination.

Schedule: This issue was first identified in the MTEP15 2020 Shoulder (off-peak) case, and subsequently showed up in a similar MTEP17 2022 Summer Peak case. Based on the MTEP15 results, the project is needed prior to May 1, 2020. Presently, the transmission line upgrade portion of the project – which provides most of the capacity increase – is expected to be completed in 2019 and the substation equipment replacements and remaining capacity increase are expected to be completed in 2020.

General Impacts: The 53 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

Forbes Tie Breaker Addition

MPUC Tracking Number: 2017-NE-N6

Utility: Minnesota Power (MP)

Project Description: Reconfigure Forbes 115 kV bus to install a redundant bus tie breaker. One 115 kV transmission line entrance will be relocated to the end of the bus to make room for the redundant tie breaker.

Need Driver: Internal fault or failure of breaker to operate causes overloading on area transmission lines and low post-contingent voltages. Installation of a redundant bus tie breaker will eliminate the contingency causing these issues. Age and condition of existing Forbes 38-44 MW breaker and associated equipment.

Alternatives: Install breaker failure relay on existing Forbes 38-44MW 115 kV bus tie breaker, thermal upgrade overloaded transmission lines, and install additional voltage support in the area. Non-wire alternatives are not viable because they cannot address concerns related to age and condition of the breaker and associated equipment.

Analysis: This issue has been identified in MTEP assessments and Minnesota Power studies going back to MTEP15. Subsequent Minnesota Power studies have indicated that changes in the North Shore Loop which increase reliance on the Forbes 230/115 kV source for delivery of power once provided locally by baseload generators cause the Forbes tie breaker failure contingency to become more severe than initially anticipated in MTEP15. Therefore, Minnesota Power concluded that the addition of a redundant bus tie breaker is the most comprehensive long-term solution for the area, while also being cost-effective and limiting impact to the Forbes Substation and the immediately adjacent transmission line entrances.

Schedule: In coordination with the construction of other projects related to changes in the North Shore Loop, the Forbes Tie Breaker Addition is presently planned to be constructed in 2022.

General Impacts: Minnesota Power's approach to this issue is intended to ensure that the most appropriate solution (in terms of cost, human, and environmental impacts) is implemented at the most appropriate time to address the issue first identified in the MTEP15 assessment and any related issues that may be efficiently addressed with the same project. Per the scope discussed above, the impacts will be mostly contained within the existing Forbes Substation yard and no expansion area will be necessary. The only impacts outside the substation yard will be due to the relocation of a transmission line entrance to make room for the redundant tie breaker.

North Shore STATCOM

MPUC Tracking Number: 2017-NE-N15

Utility: Minnesota Power (MP)

Project Description: Install a new +/- 75 MVAR Static Synchronous Compensator (STATCOM) system at the North Shore Switching Station in Silver Bay, MN. The STATCOM will control local mechanically switched capacitors (MSCs) at the North Shore Switching Station as part of an integrated Static VAR System (SVS).

Need Driver: Voltage and transient stability concerns in the North Shore Loop transmission system following conversion, idling, or retirement of coal-fired generators.

Alternatives: Large new transmission line(s) from Duluth or the Iron Range into the Silver Bay area, replacement dispatchable baseload generation in the Silver Bay area. The North Shore STATCOM is a non-wire solution.

Analysis: Following transition of the last baseload coal-fired generator in the North Shore Loop, the dynamic reactive support formerly provided by local generators must be replaced to ensure continued reliable service to all customers in the North Shore Loop. Establishment of a new STATCOM system at the North Shore Switching Station is a low-impact, relatively low-cost dynamic reactive support solution when compared to the alternatives. The North Shore STATCOM will also build upon the establishment of the North Shore Switching Station and capacitor banks, making good use of the site and the assets located there.

Schedule: The North Shore STATCOM was energized and commissioned in August 2019, and will continue in trial operations until mid-December 2019 per the contract with the supplier. For all practical purposes, it is fully operational at the time of this filing.

General Impacts: The North Shore STATCOM is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. The addition of the STATCOM to the previously-installed capacitor banks at the North Shore Switching Station completes the replacement of voltage support previously provided by baseload coal units in the area, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. Locating the new STATCOM adjacent to the North Shore Switching Station within the boundaries of a large industrial facility greatly minimizes the human and environmental impacts from the project, especially compared to potentially routing large new transmission lines through highly-valued natural and recreational resources into the Silver Bay area or establishing new baseload generation in the area.

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51 Line Upgrade

MPUC Tracking Number: 2017-NE-N16

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade of the Riverton-Pequot Lakes 115 kV Line (MP "51 Line").

Need Driver: Post-contingent overload following loss of parallel 230 kV connections.

Alternatives: Reconductor, establish new transmission. 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.

Analysis: Post-contingent overloads on the Riverton-Pequot Lakes 115 kV Line were first identified in the MTEP16 2021 Winter Peak case and are being monitored. A modest thermal upgrade of the existing line to increase its capacity was submitted as a potential Corrective Action Plan based on the information available at the time. Depending on if and how the issue shows up in subsequent assessments, further analysis will be done to clarify the issue and determine what the most appropriate solution is.

Schedule: This issue was first identified in the MTEP16 2021 Winter Peak case. Minnesota Power is monitoring MTEP reliability assessment results to determine if and when a project is needed.

General Impacts: 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 address the issue first identified in the MTEP16 assessment.

Laskin-Tac Harbor Transmission Line Upgrades

MPUC Tracking Number: 2017-NE-N21

Utility: Minnesota Power (MP)

Project Description: Thermal upgrades of the existing Hoyt Lakes-Laskin line (MP "43 Line") and double circuit Hoyt Lakes-Taconite Harbor lines (MP "1 Line" and "2 Line"). Replace limiting equipment on 43 Line at Hoyt Lakes and Laskin.

Need Driver: Post-contingent overloading following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives: Build additional lines between Laskin and Taconite Harbor to relieve loading on existing transmission lines. 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.

Analysis: Following a transition away from baseload coal-fired generators in the North Shore Loop, the power formerly generated locally must be delivered from remote sources outside the North Shore Loop. This causes post-contingent overloading on several area transmission lines, including 43 Line, 1 Line, and 2 Line. The coordinated upgrade of these three transmission lines via thermal upgrades of existing conductors, minor modification of existing structures, and replacement of limiting substation equipment provides the needed capacity to ensure reliable delivery of power into the North Shore Loop following transition away from the local generation.

Schedule: The project will be completed in two stages. There is an initial need for increased capacity on the Laskin – Hoyt Lakes transmission line (43 Line) by the end of 2019. Therefore, a thermal upgrade and replacement of limiting terminal equipment at Laskin and Hoyt Lakes will be implemented in 2019. Additional capacity on 43 Line, as well as modifications to increase capacity on 1 Line and 2 Line, will be realized in 2021 following completion of the Mesaba Junction 115 kV Project (Tracking Number 2017-NE-N23) and the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2).

General Impacts: The Laskin-Tac Harbor Transmission Line Upgrades are a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the rating of these transmission lines allows for the reliable delivery of power to the area from remote sources following the transition away from local baseload coal units, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. The project will provide necessary system improvements to the North Shore Loop without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Blackberry Breaker Replacements

MPUC Tracking Number: 2017-NE-N22

Utility: Minnesota Power (MP)

Project Description: Replace three 115 kV circuit breakers at the Blackberry Substation due to age and condition and fault current projected to be over the breaker interrupting capability. Replace three additional 230 kV circuit breakers at the Blackberry Substation due to age and condition.

Need Driver: The six circuit breakers being replaced are older oil-filled circuit breakers. Three of those breakers will be over-dutied by increased fault currents in the 2020 timeframe. The other three will be replaced for asset renewal due to their age and condition.

Alternatives: There is no more economical or less impactful solution than replacing the existing circuit breakers. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Blackberry Substation.

The breakers were also identified to be replaced as part of MP's asset renewal program due to the age and maintenance required for the existing circuit breakers.

Analysis: Minnesota Power internal analysis identified that an increase in fault current in the 2020 timeframe, corresponding to the in-service date for the Great Northern Transmission Line (Tracking Number 2013-NE-N13), causes three 115 kV circuit breakers at the Blackberry Substation to exceed their interrupting capability. These three breakers are approximately 40-year old oil-filled circuit breakers that were scheduled to be replaced as part of Minnesota Power's ongoing asset renewal program. Three additional oil-filled 230 kV circuit breakers of a similar vintage will also be replaced at the same time to take advantage of the efficiencies of bundling the work at the Blackberry Substation.

Schedule: The project is planned to be in service by June 2020.

General Impacts: Replacing the circuit breakers will accommodate increased fault current due to changing system topology in the area. Accomplishing this within the footprint of an existing substation considerably limits human and environmental impacts from the project.

Mesaba Junction 115 kV Project

(formerly known as "Hoyt Lakes 115 kV Project")

MPUC Tracking Number: 2017-NE-N23

Utility: Minnesota Power (MP)

Project Description: The new Mesaba Junction Switching Station will be constructed and interconnected to the existing transmission lines in the area connecting to the Taconite Harbor, Hoyt Lakes, and Laskin substations. In addition to the transmission line connections, the new switching station will include two switched capacitor banks to provide voltage support. Approximately 5.4 miles of new 115 kV line will be constructed along the existing Laskin – Hoyt Lakes transmission line corridor to extend the existing Forbes – Laskin 115 kV Line ("38 Line") into Mesaba Junction. The existing connection to the Laskin Substation will be eliminated.

Need Driver: Redundancy, reliability, voltage support, and transmission capacity concerns following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives: Build a second Laskin-Hoyt Lakes transmission line and reconfigure (or rebuild) Laskin Substation to eliminate single points of failure; 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.
Analysis: The Mesaba Junction 115 kV Project meets four critical needs for the North Shore Loop, as discussed below.

First, the project supports redundancy by providing a third transmission source into the area, establishing a more robust substation configuration, and enabling a standardized network voltage. The Mesaba Junction 115 kV Project establishes a new 115 kV line parallel to the existing Laskin – Hoyt Lakes 115 kV Line and a new switching station that replaces the simple straight bus configuration of the existing Hoyt Lakes Substation with a more reliable ring bus configuration. The Project will be coordinated with the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2), greatly enhancing the constructability of that project and enabling Minnesota Power to realize all the benefits of a standardized network voltage.

Second, the project enhances reliability by providing a modern, utility-controlled path for power flow into the North Shore Loop. The Mesaba Junction 115 kV Project will place the customer-owned Hoyt Lakes Substation in a dedicated local network, relocating the regionally-important bulk electric system path into a new switching station that is designed, owned, operated and maintained by Minnesota Power. The modern design of the new switching station will also provide safer accessibility and maintainability. The result is improved personnel safety, enhanced system reliability, and reduced compliance risk associated with multiple NERC standards. This key benefit became possible when space constraints at the Hoyt Lakes Substation, as well as constructability and maintainability concerns with the facility, caused the previously-planned expansion of the Hoyt Lakes Substation to become infeasible.

Third and fourth, the project improves voltage support and provides transmission capacity to deliver power into the North Shore Loop. Previously, local baseload generators provided both voltage support on a continuous basis and a local source of power that met and, much of the time, exceeded the need for power in the North Shore Loop. New capacitor banks at the Mesaba Junction Switching Station will replace the voltage support that has been lost due to generator retirements. The extension of the existing Forbes – Laskin 115 kV Line into Mesaba Junction will increase power delivery capability into the North Shore Loop for 230/115 kV sources located west of the North Shore Loop to deliver the power no longer being produced by the retired generators.

Schedule: The Mesaba Junction Switching Station is planned for 2020 construction. Extension of the Forbes – Laskin 115 kV Line into Mesaba Junction is planned during the winter 2020-21 construction season, with first energization of Mesaba Junction from Forbes sometime in early second quarter 2021. Subsequently, the remaining transmission line interconnections to Mesaba Junction will be completed as the Laskin-Tac Harbor Voltage Conversion (Tracking Number 2017-NE-N2) is constructed in 2021. Both projects are planned for completion by the end of 2021.

General Impacts: The Mesaba Junction 115 kV 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 project will require approximately 5 miles of new 115 kV transmission in a remote area of northern Minnesota that has been heavily impacted by historical mining operations.

Boswell 230 kV Fast-Switched Capacitor Bank

MPUC Tracking Number: 2017-NE-N25

Utility: Minnesota Power (MP)

Project Description: Add fast-switched capacitor bank at Boswell 230 kV Substation in a size to be determined.

Need Driver: Transient voltage violations following local three-phase fault events.

Alternatives: No alternatives are currently being considered.

Analysis: Transient voltage violations in the Boswell 230 kV Substation area were first identified in the MTEP16 stability assessment and are being monitored. A conceptual fast-switched capacitor bank was submitted as a potential Corrective Action Plan based on the limited information about the issue known at the time. Depending on if and how the issue shows up in subsequent assessments, further analysis will be done to clarify the issue and determine what the most appropriate solution is.

Schedule: This issue was first identified in the MTEP16 stability assessment. Minnesota Power is monitoring MTEP reliability assessment results to determine if and when a project is needed.

General Impacts: 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 address the issue first identified in the MTEP16 assessment.

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11 Line Upgrade

MPUC Tracking Number: 2019-NE-N1

Utility: Minnesota Power (MP)

Project Description: Thermal upgrade of Grand Rapids – Riverton 115 kV Line ("11 Line").

Need Driver: Post-contingent overloading following loss of parallel 230 kV and 500 kV lines.

Alternatives: Normal Open Switch, Smart Wires Power Flow Control, Rebuild/Reconductor. 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.

Analysis: Thermal overloads of the Grand Rapids – Riverton 115 kV Line have been identified in MTEP assessments and Minnesota Power studies for many years, in part because it is one of the oldest, lowest-capacity, and longest 115 kV lines in the Minnesota Power system. In the past, an operating guide has been an effective strategy for preventing potential overloads, deferring significant investment in the 70-mile transmission line for many years. Recent MTEP and Minnesota Power studies have indicated that this operating guide is becoming less effective, and a more permanent mitigation solution needs to be implemented in the early 2020s. While rebuilding and reconductoring the 70-mile transmission line would be a very expensive project, several lower-cost solutions are possible. Establishing a normally-open switch in the transmission line would preserve electric service to existing load-serving taps while preventing adverse through-flows from overloading the line. However, evaluation of this low-cost and relatively easy-to-implement solution showed that it would aggravate loading issues on adjacent transmission lines and contribute to noticeably degraded post-contingent voltages in the Grand Rapids area. Another alternative solution would involve the installation of Smart Wires power flow control devices at the Grand Rapids Substation. This solution would preserve the power flow path while limiting the flow on 11 Line to within its capability and reducing the loading impact on adjacent transmission lines. In this instance, economic evaluation of the Smart Wires solution versus a thermal upgrade of 11 Line proved that the thermal upgrade was the more optimal solution. Therefore, the proposed project involves targeted structure replacements to achieve a higher capacity with the existing transmission line conductor.

Schedule: Due to extensive wetlands in the area traversed by the transmission line, the project requires construction during frozen ground conditions. The project is currently planned for construction in the 2019-20 winter season.

General Impacts: The 11 Line Upgrade Project will provide necessary system improvements in the area between Grand Rapids and Riverton without requiring the establishment of additional transmission line corridors.

Forbes 37 Line Upgrade

MPUC Tracking Number: 2019-NE-N2

Utility: Minnesota Power (MP)

Project Description: Increase rating of Forbes – 37 Line Tap 115 kV Line.

Need Driver: Post-contingent overloads for loss of various parallel circuits following conversion, idling, or retirement of North Shore Loop coal-fired generators and anticipated load growth in the Hoyt Lakes area.

Alternatives: Reconductor existing line, build new parallel line. 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.

Analysis: Following a transition away from baseload coal-fired generators in the North Shore Loop, the power formerly generated locally must be delivered from remote sources outside the North Shore Loop. This causes post-contingent overloading on several area transmission lines, including the Forbes – 37 Line Tap 115 kV Line. The upgrade project provides the needed capacity to ensure reliable delivery of power to the East Range and into the North Shore Loop following transition away from the local generation.

Schedule: Due to wetlands in the area traversed by the transmission line, construction is advantageous during frozen ground conditions. In coordination with the construction of other projects related to changes in the North Shore Loop, the Forbes 37 Line Upgrade is presently planned to be constructed in the 2021-22 winter season.

General Impacts: The Forbes 37 Line Upgrade is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the rating of this transmission line allows for the reliable delivery of power to the area from remote sources following the transition away from local baseload coal units, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. The project will provide necessary system improvements to the North Shore Loop without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Hibbing 14 Line Upgrade

MPUC Tracking Number: 2019-NE-N3

Utility: Minnesota Power (MP)

Project Description: Increase rating of Hibbing – 14 Line Tap 115 kV Line.

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

Alternatives: Reconductor existing line, build new parallel line. 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.

Analysis: This issue was identified in the MTEP18 assessment and Minnesota Power studies. The upgrade project provides the needed capacity increase as identified in the studies while also efficiently addressing asset renewal needs at the substation termination.

Schedule: Due to wetlands in the area traversed by the transmission line, line construction is advantageous during frozen ground conditions. The transmission line upgrade is currently planned for construction in the 2020-21 winter season.

General Impacts: The Hibbing 14 Line Upgrade Project will provide necessary system improvements on Minnesota Power's 115 kV system without requiring the establishment of additional transmission line corridors.

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25 Line Upgrade

MPUC Tracking Number: 2019-NE-N4

Utility: Minnesota Power (MP)

Project Description: Increase rating of Hibbing **–** Virginia 115 kV Line ("25 Line").

Need Driver: Post-contingent overloads under higher transfer scenarios and multiple-circuit contingency events

Alternatives: Reconductor existing line, build new parallel line. 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.

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 at the substation termination.

Schedule: The project is currently planned for construction in 2021.

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

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29 Line Upgrade

MPUC Tracking Number: 2019-NE-N5

Utility: Minnesota Power (MP)

Project Description: Increase rating of Boswell – Grand Rapids 115 kV Line (“29 Line”).

Need Driver: Overloads following multiple-circuit contingency events in the surrounding area.

Alternatives: Reconductor, establish new transmission. 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.

Analysis: Post-contingent overloads on the Boswell – Grand Rapids 115 kV Line were first identified in the MTEP18 2020 and 2023 summer off-peak cases and are being monitored. A thermal upgrade of the existing line to increase its capacity was submitted as a potential Corrective Action Plan based on the information available at the time. Depending on if and how the issue shows up in subsequent assessments, further analysis will be done to clarify the issue and determine what the most appropriate solution is.

Schedule: This issue was first identified in the MTEP18 2020 and 2023 summer off-peak cases and is related to multiple-circuit contingency events. Minnesota Power is monitoring MTEP reliability assessment results to determine if and when a project is needed.

General Impacts: 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 address the issue first identified in the MTEP18 assessment.

Long Prairie Substation Modernization

MPUC Tracking Number: 2019-NE-N6

Utility: Minnesota Power (MP)

Project Description: Replace existing Long Prairie 115/34.5 kV transformers with higher-capacity transformers including load-tap changers. Bundled with planned asset renewal projects including replacement of 115 kV and 34.5 kV circuit breakers and disconnect switches. Also includes reconfiguration of transformer bus connection to eliminate line-connected distribution transformer.

Need Driver: Age and condition of existing transformers, circuit breakers, and disconnect switches. Post-contingent overloading of existing Long Prairie transformers for loss of parallel transformer, including bus faults and line faults due to line-connected transformer configuration. Low post-contingent 34.5 kV bus voltage following 115 kV bus fault event mitigated by including LTCs on new transformers.

Alternatives: Develop area distribution system to shift load off Long Prairie; Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Long Prairie Substation.

Analysis: The Long Prairie Transformer Replacement 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. The project would also replace other substation equipment due to their age and condition. Eliminating 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: Transformer replacements and associated planned asset renewal work will take place at the Long Prairie substation in summer of 2021.

General Impacts: The Long Prairie Transformer Replacement 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.

Savanna Transformer

MPUC Tracking Number: 2019-NE-N7

Utility: Minnesota Power (MP)

Project Description: Add one 115 kV breaker in the existing Savanna Substation ring bus to accommodate a new 115/13.8 kV transformer. Retire existing 90-year old Floodwood Distribution Substation. Project also includes rebuild of existing Meadowlands Substation nearby.

Need Driver: Age and condition of existing Floodwood and Meadowlands transformers. Enhance backup capability between Floodwood area and Meadowlands area to improve customer reliability and limit need to deploy mobile substation.

Alternatives: Rebuild & replace Floodwood Distribution Substation. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Long Prairie Substation.

Analysis: The current Floodwood and Meadowlands distribution substations are well beyond end-of-life (Floodwood is 90 years old). The distribution transformer capacity at both substations is not sufficient to support backing up one substation from the other in the event of an outage. In addition to replacing the aging assets, the project will improve backup capability, eliminating the need to deploy a mobile substation during outages or construction and greatly reducing the amount of potential downtime experienced by customers in the Floodwood and Meadowlands areas.

Schedule: Work in the Savanna Substation to add a 115 kV breaker and a transformer will be completed by the end of 2020. After completion of this addition at the Savanna Substation the old Floodwood Distribution Substation will be removed. Rebuilding the existing Meadowlands Substation will take place and be completed by the end of 2021.

General Impacts: The Savanna Transformer Project will ensure a continuous and reliable power supply to the Floodwood and Meadowlands areas by enhancing backup and restoration capability and replacing aging equipment before it fails. The Project will make use of space available inside the existing Savanna Substation to enable the retirement of the existing Floodwood Distribution Substation site.

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 and 115 kV transformer breaker.
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: Increase facility ratings to mitigate post-contingent overloads. 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 with load tap changers, for which Minnesota Power maintains a system spare. 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 2022.
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 fenceline.

Midway Substation Retirement

MPUC Tracking Number: 2019-NE-N9

Utility: Minnesota Power (MP)

Project Description: The existing Midway 115/13.8 kV Substation in the Duluth area will be retired and removed following construction of a new feeder from Canosia Road Substation.

Need Driver: Age and condition and maintenance issues with Midway Substation. Lack of full backup capability for Midway Substation feeders.

Alternatives: Rebuild Midway Substation and modify feeders to provide backup capability. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Midway Substation.

Analysis: The existing Midway Substation is near the end of its useful life. There have been a number of maintenance concerns surrounding the site in the past few years. Bog shoes have been used to stabilize leaning wood pole structures that have been causing tension on substation conductor and transformer bushings. Similar situations in the recent past have led to bushing failures. The transformer is also well beyond end-of-life and has an increased risk of failure. If the substation were to fail, there is not currently a straightforward way to backfeed the entire load reliably. It is estimated that adding a distribution breaker and building out the new feeder from Canosia Road will be more cost-effective and a better long-term solution for the area, rather than rebuilding the existing Midway Substation.

Schedule: The new feeder buildout from Canosia Road Substation will happen by the end of 2019. Once this is completed the Midway Substation will be retired and removed.

General Impacts: The Midway Substation Retirement will ensure a continuous and reliable power supply to areas west of Duluth by enhancing backup capability and replacing aging equipment before it fails. The Project will make use of space available inside the existing Canosia Road Substation to enable the retirement of the existing Midway Substation site.

Babbitt Area 115 kV Project

MPUC Tracking Number: 2019-NE-N10

Utility: Minnesota Power (MP)

Project Description: Extend the existing Embarrass – Babbitt 115 kV Line ("137 Line") to the Hoyt Lakes area. The final Hoyt Lakes area endpoint for the project is yet-to-be determined. The project will also include a new capacitor bank in the area to provide voltage support and rebuilding the existing segment of Embarrass – Babbitt 115 kV Line to accommodate increased power flows.

Need Driver: Redundancy, reliability, voltage support, and transmission capacity concerns following conversion, idling, or retirement of North Shore Loop coal-fired generators and anticipated load growth in the Hoyt Lakes area. Age and condition of existing 137 Line, and redundancy of service to Babbitt-area customers served from 137 Line.

Alternatives: Hoyt Lakes – Babbitt 115 kV Project, Dunka Road – Babbitt 115 kV Project, New dispatchable peaking generation in the North Shore Loop. 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. Non-wire alternatives will not, however, resolve age and condition issues associated with 137 Line.

Analysis: The Babbitt Area 115 kV Project meets four critical needs for the North Shore Loop and the Babbitt area, as discussed below.

First, the project supports redundancy by providing an additional transmission source into the North Shore Loop. This additional transmission source is crucial to enabling the long-term maintenance of existing transmission lines serving the North Shore Loop after future projected load growth in the area.

Second, the project supports reliability and redundancy for existing customers in the Babbitt area by connecting the existing radial 137 Line to a second 115 kV source. This will allow for maintenance outages on 137 Line while tapped load on this line remains energized. Redundancy on 137 Line is critical as it is extremely challenging to take a lengthy transmission line outage necessary to perform maintenance or make improvements on this aging infrastructure. The project will also allow for an overall improvement in outage restoration time for customers served from tapped substations on 137 Line.

Third and fourth, the project improves voltage support and provides transmission capacity to deliver power into the North Shore Loop. Previously, local baseload generators provided both voltage support on a continuous basis and a local source of power that met and, much of the time, exceeded the need for power in the North Shore Loop. A new capacitor bank would provide additional voltage support to replace the voltage support that has been lost due to generator retirements. The extension of the existing Embarrass – Babbitt 115 kV Line into the Hoyt Lakes area will increase power delivery capability into the North Shore Loop for 230/115 kV sources located west of the North Shore Loop to deliver the power no longer being produced by the retired generators.

Schedule: The substation portion of the Babbitt 115 kV Project is planned for 2023 construction. Extension of the Embarrass – Babbitt 115 kV Line into the North Shore Loop is planned to take place in 2023. A rebuild of the existing 115 kV Line currently scheduled to begin in 2023 and be completed in 2024.

General Impacts: The Babbitt 115 kV 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 project also facilitates significant reliability improvements for existing customers in the Babbitt area. The project will require approximately 5-8 miles of new 115 kV transmission in a remote area of northern Minnesota located adjacent to current and potential future mining operations. Minnesota Power will take into consideration all relevant human, environmental, and commercial interests in the area and actively engage impacted stakeholders as routing and siting of the project progresses.

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38 Line Upgrade

MPUC Tracking Number: 2019-NE-N11

Utility: Minnesota Power (MP)

Project Description: Replace approximately 31.5 miles of 636 ACSR on the Forbes – Laskin 115 kV Line with a higher-capacity conductor.

Need Driver: Post-contingent overloads for single- and multiple-contingency events following conversion, idling, or retirement of North Shore Loop coal-fired generators.

Alternatives: Thermal upgrade/replace structures on existing line, build new parallel line. 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.

Analysis: Following a transition away from baseload coal-fired generators in the North Shore Loop, the power formerly generated locally must be delivered from remote sources outside the North Shore Loop. This causes post-contingent overloading on several area transmission lines, including 38 Line. These overloads become more significant during construction staging of the Mesaba Junction 115 kV Project (Tracking 2017-NE-N23) and the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2) and following their completion. Ultimately, after completion of these two projects, 38 Line will extend from Forbes to Mesaba Junction and become a critical source of redundancy for the North Shore Loop. The 38 Line Upgrade project provides the needed capacity to ensure reliable delivery of power to the East Range and into the North Shore Loop following transition away from the local generation.

Schedule: Due to extensive wetlands in the area traversed by the transmission line, the project requires construction during frozen ground conditions. The project is currently planned for construction in the 2019-20 winter season. This will enable the subsequent construction of the Mesaba Junction 115 kV Project (Tracking 2017-NE-N23) and the Laskin-Tac Harbor Voltage Conversion Project (Tracking Number 2017-NE-N2) in 2020-21.

General Impacts: The 38 Line Upgrade is a critical component to maintaining a reliable system in the face of significant changes in the North Shore Loop. Increasing the rating of this transmission line allows for the reliable delivery of power to the area from remote sources following the transition away from local baseload coal units, enabling the full realization of significant economic and environmental benefits from transitioning away from these units. The project will provide necessary system improvements to the North Shore Loop without requiring the establishment of additional transmission line corridors, which will minimize any potential environmental impacts.

Duluth 115 kV Loop

MPUC Tracking Number: 2019-NE-N12

Utility: Minnesota Power (MP)

Project Description: Add redundancy and load-serving capacity to 115 kV system serving northern and eastern Duluth. Project scope to be determined.

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 115 kV Loop Project will restore redundancy and load-serving capability to this area, mitigating the risk of voltage collapse.

Alternatives: New 115 kV or 230 kV line parallel to Arrowhead – Colbyville 115 kV path(s); 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 115 kV Loop Project meets two critical needs for the Duluth area and the North Shore Loop, as discussed below.

First, the project supports redundancy by providing another transmission source, additional power supply, or additional reactive power support with transmission upgrades to a large part of Duluth and the North Shore Loop. When there is a risk of voltage collapse during maintenance outages, system operators are directed to create a normal open in the Colbyville – Two Harbors 115 kV Line. A significant portion of Duluth area load is then being served through a radial transmission path and is at risk of an outage for a fault along the transmission path serving this load. The Duluth 115 kV Loop project will reduce or mitigate the risk of a voltage collapse scenario and allow the Colbyville – Two Harbors 115 kV Line to remain a continuous path during maintenance outages.

Second, the project provides load serving capacity to the North Shore Loop. Previously, local baseload generators provided both voltage support on a continuous basis and a local source of power that met and, much of the time, exceeded the need for power in the North Shore Loop. The Duluth 115 kV Loop Project will either provide increased power delivery capability on an improved transmission system or allow new local generation to reduce the amount of power that must be delivered on the existing transmission system.

Schedule: Presently, studies are ongoing to determine the most appropriate solution for this issue. These studies are expected to be complete by the end of 2019. The earliest that Minnesota Power would begin public outreach and permitting activities for the recommended solution is 2020. If a Certificate of Need and/or Route Permit are required, those applications would be submitted in the second half of 2020 or in 2021. Following permitting and engineering activities, preliminary plans are for project construction to take place in 2023-24.

General Impacts: The Duluth 115 kV Loop 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. If the transmission line alternative is selected, the project will require approximately 15-20 miles of new or rebuilt 115 kV transmission, primarily along existing transmission line corridors and utilizing existing rights-of-way to the greatest possible extent to help navigate areas of Duluth with varying land use and space constraints. Minnesota Power will take into consideration all relevant human, environmental, and commercial interests in the area and actively engage impacted stakeholders when routing and siting of the project progresses.

National Breaker Replacements

MPUC Tracking Number: 2019-NE-N12

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: There is no more economical or less impactful solution than replacing the existing circuit breakers. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Nashwauk Substation.

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

Schedule: The project is currently planned for construction in 2021.

General Impacts: 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 address this age and condition replacement.

Laskin Breaker Replacements

MPUC Tracking Number: 2019-NE-N12

Utility: Minnesota Power (MP)

Project Description: Replace end-of-life circuit breakers and associated equipment at Laskin Substation.

Need Driver: Age and condition.

Alternatives: There is no more economical or less impactful solution than replacing the existing circuit breakers. Non-wire alternatives are not viable because they cannot address concerns related to age and condition at the Laskin Substation.

Analysis: Three 115 kV oil circuit breakers from 1962-69 will be replaced as part of this project.

Schedule: The project is currently planned for below grade construction in 2020 and above grade construction in 2021.

General Impacts: 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 address this age and condition replacement.

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: Long radial line exposure. Thermal overloading during winter peak.

Alternatives:

Transmission Solutions

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-Transmission Alternatives

A non-transmission alternative (NTA) 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 4 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 November 2023.

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.

Forbes SVC Retirement

MPUC Tracking Number: 2019-NE-N16

Utility: Xcel Energy, Inc. (XEL)

Project Description: Retire the active portion of the Static VAR Compensation (SVC) and convert the existing 2x300 MVAR capacitors to 2x160 MVAR capacitors.

Need Driver: Age and condition.

Alternatives: Replacing the old SVC with a new comparable unit.

Analysis: This SVC was originally installed as part of the MMTU facilities to ship power south from Manitoba Hydro into the Twin Cities metro area in summer times and ship power north in the winter. It was installed in the early 90’s and is one of the first SVC units ever installed. The SVC is reaching the end of useful life and obtaining replacement parts is getting difficult. Based on the analysis in today’s system it showed there is no need to have an SVC to maintain power transfers in the MISO market.

Schedule: The project is currently planned for retirement in coordination with the in-service date of the Great Northern Transmission Line (Tracking Number 2013-NE-N13).

General Impacts: Xcel Energy'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 address this age and condition retirement.

This is an existing asset that has reached the end of its useful life. It involves no new permits or land requirements as it will all be done on the existing Forbes Substation site. Since it is a retirement of an existing asset there is no alternative non-wire solution.

Running Cap Bank Retirement

MPUC Tracking Number: 2019-NE-N17

Utility: Xcel Energy, Inc. (XEL)

Project Description: Retire one of the five existing 30.5 MVAR cap banks at the Running Substation.

Need Driver: Age and condition.

Alternatives: Replacing existing cap bank.

Analysis: These capacitor banks were originally installed as part of the MMTU facilities to ship power south from Manitoba Hydro into the Twin Cities metro area in summer times and ship power north in the winter. They were installed in the 90's. This capacitor bank has failed and based on the analysis in today's system it showed there is no need to have this capacitor bank to maintain power transfers in the MISO market.

Schedule: The capacitor bank has already failed and this project is to remove the failed parts.

General Impacts: Xcel Energy'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 address this age and condition retirement.

This is an existing asset that has reached the end of its useful life. It involves no new permits or land requirements as it will all be done on the existing Running Substation site. Since it is a retirement of an existing asset there is no alternative non-wire solution.

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 2017 Biennial Report but have been completed or withdrawn since the 2017 Report was filed with the Minnesota Public Utilities Commission in November

2017. 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 2017 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
2011-NE-N5	Dunka Road Substation	Not Required	MP	Cancelled due to change in customer requirements
2015-NE-N1	5 Line Upgrade	Not Required	MP	2018
2015-NE-N4	15th Avenue West Modernization	Not Required	MP	2018
2015-NE-N13	Bear Creek 69/46 kV Transformer	Not Required	MP	2017
2015-NE-N15	95 Line Upgrade	Not Required	MP	2017
2017-NE-N1	28 Line Upgrade	Not Required	MP	2017
2017-NE-N7	North Shore Switching Station & Cap Banks	Not Required	MP	2017
2017-NE-N8	Babbitt Capacitor Bank	Not Required	MP	2017
2017-NE-N9	ETCO Capacitor Bank	Not Required	MP	2017
2017-NE-N10	Forbes 3T Breaker Replacement	Not Required	MP	2017
2017-NE-N11	LSPI 10K Breaker Addition	Not Required	MP	2017
2017-NE-N12	93 Line Upgrade	Not Required	MP	2019
2017-NE-N13	Boswell 230/115 kV Transformer	Not Required	MP	2019
2017-NE-N14	76 Line Upgrade	Not Required	MP	2018
2017-NE-N17	18 Line Upgrade	Not Required	MP	2018
2017-NE-N18	Tioga 115/23 kV Substation	Not Required	MP	2018

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2017-NE-N19	North Shore Transmission Line Upgrades	Not Required	MP	2019
2017-NE-N20	Two Harbors 115 kV Project	Not Required	MP	2019
2017-NE-N24	Knife Falls Distribution Substation	Not Required	GRE	November 2018

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
2017-WC-N5	DS Line Rebuild Project	2019/C>A	14366	No	No	GRE
2019-WC-N1	Litchfield 69kV LT Tap Line	NA	NA	No	No	SMP
2019-WC-N2	Howard Lake-Maple Lake 115 kV Rebuild	2020/C>A	17970	Yes	No	GRE
2019-WC-N3	Morris-Johnson Jct.-Ortonville J493/J526 Upgrade	2019/C>A	17006	No	No	MRES/GRE/OTP

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-WC-N4	Westwood 1 115 kV Conversion	TBD	TBD	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: Reconductor the Crooked Lake-Parkwood line to ACSS conductor and add a second 345/115 kV transformer at Elm Creek.

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: Due to the small size of the project, little impact and low cost no alternatives were considered.

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.

DS Line Rebuild Project

MPUC Tracking Number: 2017-WC-N5

Utility: Great River Energy (GRE)

Project Description: Rebuild GRE's existing 69 kV transmission line from Willmar to Litchfield Muni Tap to 115 kV standard with high capacity conductor for continued operation at 69 kV.

Need Driver: GRE's Svea to Litchfield Muni Tap 69 kV line (DS line) is one of the oldest 69 kV transmission lines in the area. It is in need of a replacement due its age and condition. In addition, this transmission line provides support to a large load center at Litchfield Muni. System analysis shows the existing transmission system doesn't have margin to serve new or growing loads in the Litchfield area within the required voltage criteria. In order to improve system voltage, and address reliability concerns due to the transmission line age and condition, GRE will rebuild the transmission line. Better system reliability and load serving performance will be gained in this area with 115 kV transmission line that extends between Willmar and Big Swan area. As a result, GRE will rebuild the DS line to 115 kV standard but will continue to operate the line at 69 kV until the need to operate the transmission line at 115 kV is justifiable in the future.

Alternative: The driver for the line rebuild is mostly 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. Rebuilding the line to 115 kV at a later date will also be costly.

Analysis: The DS Line Rebuild Project brings 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, and construction of the line will be done 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 that are served from the DS line.

Schedule: This project is scheduled for spring 2024 completion.

General Impact: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. 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 25 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.

Litchfield 69 kV LT Tap Line

MPUC Tracking Number: 2019-WC-N1

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: Rebuild SMMPA's existing 69 kV LT tap line from the GRE DS Line to the Litchfield Substation to 115 kV standard with 795 ACSR conductor for continued operation at 69 kV.

Need Driver: This project is motivated by the GRE rebuild of the DS line to a 115kV standard. See project 2017-WC-N5 for more information.

Alternative: No alternatives.

Analysis: The line rebuild will provide increased load serving capability to Litchfield as well as increased reliability in the area.

Schedule: The schedule is currently unknown. See project 2017-WC-N5.

General Impact: The line will be rebuilt on existing right-of-way and will have little impact on land owners.

Howard Lake-Maple Lake 115 kV Rebuild

MPUC Tracking Number: 2019-WC-N2

Utility: Great River Energy (GRE)

Project Description: Rebuild the AC line from the Maple Lake sub dead-end to the Howard Lake substation tap switch SS2940.

Need Driver: Reduce momentary outages.

Alternatives: Rebuild to 69 kV standard.

Analysis: Rebuilding to 115 kV standard brings efficiency improvements by reducing loss on the transmission line. It also provides better load serving reliability of the new 115 kV design standard. Rebuilding the line to 115 kV at a later date would be costly.

Schedule: The project is planned to be in service by fall 2023.

General Impacts: The project will be constructed on an existing 70-foot right-of-way that is largely located on agricultural lands. 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 17 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.

Morris-Johnson Jct.-Ortonville J493/J526 Upgrade

MPUC Tracking Number: 2019-WC-N3

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

Project Description: This project consists of upgrades to the GRE/MRES/OTP owned Ortonville to Morris 115 kV transmission line to accommodate the interconnection of wind generators, J493/J526. These facilities consist of:

1. Ortonville to Johnson Jct. 115 kV line
2. Ortonville Substation
3. Morris to Johnson Jct. 115 kV line

Need Driver: Network Upgrades to the Transmission Owner's transmission line required for the interconnection of the Interconnection Customers' Project J493/J526.

Alternatives: Building additional 345 kV lines at a higher cost.

Analysis: The Morris – Johnson Jct. – Ortonville 115 kV line upgrade is needed to accommodate the wind generation outlet of the MISO J493 & J526 projects.

Schedule: The project is planned to be in service by winter 2021.

General Impacts: The project will be constructed on an existing 100-foot right-of-way that is largely located on agricultural lands. No new landowners will be impacted by construction, although some additional temporary workspace may be required. GRE/MRES/OTP have 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 24 months. During this time, GRE/MRES/OTP 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.

Westwood 1 115 kV Conversion

MPUC Tracking Number: 2019-WC-N4

Utility: Great River Energy (GRE)

Project Description: Convert the Westwood 1 substation to 115 kV service.

Need Driver: Improve service reliability to Westwood 1, LeSauk and Five Points distribution substations. Abide by existing agreement with MP to limit the number of substations between breaker stations at a maximum of three. 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.

Alternatives: The alternative to abiding by existing agreement with MP is to install a 115-kV breaker station at St. Stephen. While it is costly, it wouldn't provide the redundancy that the project provides to Westwood 1, LeSauk and Five Points substations.

Analysis: Westwood 1 conversion will also utilize the 115kV transmission line that Westwood 2 is connected to this could result in losing both Westwood 1 and Westwood 2 substations at the same time. Therefore, the project described in the description is the best value plan for the system.

Schedule: The project is planned to be in service by spring 2023.

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.

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 2015 Biennial Report but have been completed or withdrawn since the 2015 Report was filed with the Minnesota Public Utilities Commission in November 2015. 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 2015 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
2003-WC-N7	Panther Area	Not Required	GRE	Withdrawn

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2013-WC-N3	Priam Substation	Not Required	WMU/ GRE	2019
2015-WC-N4	Riverview 345/115/69 kV Project	Not Required	GRE	2019
2017-WC-N1	Benson 14.4 MVAR Capacitor Bank	Not Required	GRE	2018
2017-WC-N2	Brooks Lake Distribution Substation	Not Required	GRE	2019
2017-WC-N3	Swenoda 115 kV Distribution Substation (previously Cashel West)	Not Required	GRE	2019
2017-WC-N4	Dublin 115 kV Distribution Substation (previously Cashel East)	Not Required	GRE	2019

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
2017-TC-N1	Airport-Rogers Lake 115 kV Rebuild	2016/B>A	10074	No	No	XEL
2017-TC-N4	Black Dog-Wilson 115 kV Uprate	2017/C>A	11993	No	No	XEL
2017-TC-N5	Wilson Substation	2017/C>A	4695	No	No	XEL
2017-TC-N6	Plymouth-Area Power Upgrade	2018/C>A	14054	No	Yes	XEL
2017-TC-N7	Lebanon Hills 115 kV	2018/A	12211	No	No	GRE

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wires Alt.	Utility
2019-TC-N1	Red Rock Transformer Uprate	2018/A	14844	No	No	XEL
2019-TC-N2	South Afton Substation	2019/A	15730	No	No	XEL
2019-TC-N3	East Metro Area Upgrades	2019/A	15877	No	No	XEL

Airport-Rogers Lake 115 kV Rebuild

MPUC Tracking Number: 2017-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Rebuild the existing Airport to Rogers Lake 115 kV line due to age and condition.

Need Driver: The existing Airport to Rogers Lake 115 kV line structures have reached end of life and need to be replaced. The line will be rebuilt using the same right of way.

Alternatives: An alternative to rebuilding the existing 115 kV line would be to construct a new 115 kV line in the area to replace the existing line. However, this line needs to connect to substations in a congested metro area and connects directly to the Minneapolis-St. Paul International Airport. It was determined that rebuilding the line in place was the best alternative.

Analysis: Nearly 70% of the existing structures are overloaded and in failure mode.

Schedule: The project is planned to be in-service by December 2021.

General Impacts: This project will be constructed on ~3.2 miles of existing right of way that is located in the Twin Cities metro area. No new land owners will be impacted by this project. Xcel Energy performed a preliminary review of the route shows that the existing line crossed the Mississippi River, close to multiple lakes, two cemeteries, three highways, and an interstate crossing. The company will work with all appropriate agencies during the permitting phase of the project. 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.

Black Dog-Wilson 115 kV Uprates

MPUC Tracking Number: 2017-TC-N4

Utility: Xcel Energy (XEL)

Project Description: This project is to uprate the existing 115 kV lines from the Black Dog Substation to the Wilson Substation.

Need Driver: Load has continued to grow in the southern metro area putting additional pressure on the existing facilities to continue to serve the load reliably. Under certain conditions the existing 115 kV lines from Black Dog-Wilson #1 and #3 are likely to be overloaded in the 2020 summer peak cases.

Alternatives: Alternative 1 was to build a 4th 115 kV line from Black Dog-Wilson. This option was shown infeasible due to a new river crossing and the difficulty in getting into the Wilson Substation due to the line congestion and the location of the substation.

Alternative 2 was to convert the Black Dog Substation to breaker-and-½. This option was shown to be a very expensive solution as most of the existing Black Dog Substation would have to be rebuilt to accommodate this solution.

Analysis: This project is needed due to the load growth in the area under certain contingencies causing thermal overloads. Under certain contingencies Black Dog generation would have to be reduced to prevent overloading the 115 kV lines feeding the Bloomington/494 area.

Schedule: The work will take approximately two years to complete and use Xcel Energy employees. This project will be completed in coordination with the Wilson Substation conversion project.

General Impacts: This project will use existing right of way and substation land. The cost estimate is approximately $4.2M and has a targeted in-service date of summer 2020.

Wilson Substation

MPUC Tracking Number: 2017-TC-N5

Utility: Xcel Energy (XEL)

Project Description: Convert the existing Wilson Substation from a straight bus configuration to a breaker-and-½ configuration.

Need Driver: This project is needed to interconnect a fourth distribution transformer at Wilson Substation, remove a three terminal line, and add flexibility for real time operations and maintenance.

Alternatives: An alternative to this project is a new substation in the area and new transmission lines to the new substation. This area is already very congested and routing new transmission lines would be very difficult.

Analysis: This project is needed due to the load growth in the area and to address the lack of load serving flexibility in the area. This substation is one of the largest substations on the Xcel Energy system with a straight bus design; the breaker-and-½ design will address load serving concerns in this area.

Schedule: The work will take approximately two years to complete and use Xcel Energy employees. The expected in service date for this project is June 2020.

General Impacts: This project will use existing substation land and has an estimated cost of approximately $17M.

Plymouth-Area Power Upgrade

MPUC Tracking Number: 2017-TC-N6

Utility: Xcel Energy (XEL)

Project Description: This project includes the rebuild of the existing Parkers Lake to Gleason Lake 115 kV double circuit line into two single circuit lines in the same right of way and installation of a 40 MVAR capacitor bank at Gleason Lake. Additionally, this project constructs a new substation called Pomerleau Lake, located on the Parkers Lake to Plymouth 115 kV line, re-energizes the existing Hollydale to Plymouth 69 kV line, and re-terminate that 69 kV line into Pomerleau Lake Substation. Finally, the Hollydale Substation will be expanded to accommodate serving load from 69 kV on a permanent basis.

Need Driver: Regular load growth in the area in and around Plymouth has required the need for the project. The City of Plymouth asked for a long term solution in this area after extensive public input. This set of projects was the result of this public input.

Alternatives: This project has gone through many years of public involvement and included many alternatives. The project listed above is the project that came out of all of this public involvement.

Analysis: This project is needed due to the load growth in the area under certain contingencies causing voltage and thermal violations. Assuming normal load growth in the Plymouth area, the project as listed above should mitigate these load serving violations for at least the next 20 years.

Schedule: This project will occur in phases and the majority of the phases will be completed in 2019. The final project phase, expanding Hollydale substation, is planned to be in-service in 2021.

General Impacts: This project involved several public meetings to determine what the best fit project for the area would be. Various options were considered as part of this process. The public input was a valuable part of the process when determining the final project.

Lebanon Hills 115 kV

MPUC Tracking Number: 2017-TC-N7

Utility: Great River Energy (GRE)

Project Description: Build 1.25 miles of double circuit 115 kV transmission line to the Dakota Electric Association Lebanon Hills Substation.

Need Driver: The Lebanon Hills Distribution Substation is served on the 69 kV system from Inver Grove source with a contingency back up from the Pilot Knob Substation. The future plan of the area involves reconfiguration of the Pilot Knob Substation and the transmission system in the area. The Pilot Knob Substation will be reconfigured in such a way that the 115 kV side will have a breaker-and-½ design and the 69 kV side is a simpler straight bus configuration. The transmission system reconfiguration involves overheading the underground cables towards Deerwood and Lemay Lake and retirements of the DA-PKX, DA-RE, DA-LE, DA-LEX and DA-LK lines. With this future plan, the Lebanon Hills Substation will be better served from the 115 kV system in the area.

The Pilot Knob Substation consists of breakers and transformers that are old and have been failing. Breaker and underground cable pot head replacement projects were done in the past. Remaining breakers and pot heads will continue to be sources of failure that could cause outages in area. In additions, the transformers are old and are likely to fail causing extended outage at the substation. Replacements of these equipment at Pilot Knob Substation are efficient as the substation can be reconfigured in to a more reliable configuration that is up to GRE’s current substation design standard. This proposed Pilot Knob reconfiguration project, in a long run, saves on cost of equipment replacement and frequent maintenance while resulting in a more reliable transmission system in the area. The Lebanon Hills Substation conversion to the 115 kV system is among few projects that need to be completed before the start of Pilot Knob reconfiguration project.

Alternative: Continued 69 kV service for Lebanon Hills-this option makes service to Lebanon Hills unreliable after the proposed configuration of the Pilot Knob Substation. The proposed configuration will retire the underground 69 kV line out of Pilot Knob to Pilot Knob Tap and the line from Pilot Knob Tap that connects to Lebanon Hills. Therefore, Lebanon Hills will depend on service from Chub Lake during contingencies along the Inver Grove to Lebanon Hills 69 kV line. This causes low voltage at Lebanon Hills.

Keep the underground 69 kV line from Pilot Knob to Pilot Knob Tap and use it for contingency backup for Lebanon Hills. The underground 69 kV lines out of Pilot Knob that connects to Pilot Knob Tap have had historical reliability concerns related to the underground cable pot head failures. The line termination breakers are also old and there is not much service life left in them. In addition, part of Pilot Knob Substation reconfiguration plan involves elimination of these underground cables and line termination breakers. Therefore this option wasn't considered further as these lines won't be available when the Pilot Knob area is reconfigured. This is also inefficient and costly in a long run in terms of reliability and replacement cost of pot heads.

Analysis: The 69 kV transmission system that serves the Lebanon Hills Substation consists of high impedance conductors. As a result, power loss on the 69 kV system is significant with Lebanon Hills served from the 69 kV system. In addition to the added reliability improvement from serving Lebanon Hills on the stronger 115 kV system, conversion of the Lebanon Hills to the 115 kV system will have financial benefit in relation to loss saving in a long run.

Schedule: The Lebanon Hills 115 kV Project is scheduled to be in service by summer 2020.

General Impact: The project will require approximately 0.5 miles of new 115 kV transmission and approximately 1 mile of 69 kV upgraded to 115 kV transmission line. The project is located in predominantly residential area with approximately 1 mile along road and transmission right-of-way. 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. Most of the preliminary design follows existing road and transmission 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Red Rock Transformer Upgrade

MPUC Tracking Number: 2019-TC-N1

Utility: Xcel Energy (XEL)

Project Description: Upgrade the existing Red Rock 448 MVA transformers to 672 MVA.

Need Driver: This project is needed to accommodate the area load growth primarily in the Woodbury area under certain contingencies.

Alternatives: An alternative to this project is a new substation in the area and new transmission lines to the new substation. This area is already very congested and routing new transmission lines would be very difficult.

Analysis: This project is needed due to the load growth in the area and to address the lack of load serving flexibility in the area. The Red Rock substation is a very important bulk load serving substation to the east metro area. Continued load growth in the Woodbury area will put pressure on the area load serving capabilities.

Schedule: The work will take approximately two years to complete and use Xcel Energy employees.

General Impacts: This project will use existing substation land. The cost estimate is approximately $31M and has a targeted in-service date in 2022.

South Afton Substation

MPUC Tracking Number: 2019-TC-N2

Utility: Xcel Energy (XEL)

Project Description: Add a new load serving substation in the south Afton/Woodbury area.

Need Driver: This project is needed to accommodate the area load growth primarily in the Woodbury area. Current distribution substation capacity is reaching the limit and a new source is needed closer to the new load development.

Alternatives: Expand existing facilities to accommodate new load growth.

Analysis: This project is needed due to the load growth in the area and to address the lack of load serving flexibility in the area. The current load serving substations are located in the northern area of Woodbury away from the expanding growth.

Schedule: The work will take approximately one year to complete and use Xcel Energy employees.

General Impacts: This project will require land for a new distribution substation. The cost estimate is approximately $5M and has a targeted in-service date in 2021.

East Metro Area Upgrades

MPUC Tracking Number: 2019-TC-N3

Utility: Xcel Energy (XEL)

Project Description: Upgrade existing 115 kV line from Long Lake-Baytown.

Need Driver: This project is needed to prevent a thermal overload for the summer peak times under certain contingencies.

Alternatives: Bring new line into the area.

Analysis: As load continues to grow in the east metro it will put more pressure on the existing facilities to serve the load reliably. Some of these facilities are very old with limited emergency ratings.

Schedule: The work will take approximately one to two years to complete and use Xcel Energy employees.

General Impacts: This project will require land for a new distribution substation. The cost estimate is approximately $12M and has a targeted in-service date in 2023.

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 2017 Biennial Report but have been completed or withdrawn since the 2017 Report was filed with the Public Utilities Commission in November 2017. 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 2017 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-N3	Southtown Area Upgrades	Not Required	XEL	2016
2017-TC-N2	City of Chaska Interconnection	Not Required	XEL	2018

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. 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
2013-SW-N1	Heron Lake Capacitors	2012/A	3528	No	Yes	ITCM
2015-SW-N3	Buffalo Ridge Cutover	2015/A	8017	No	No	XEL
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
2019-SW-N1	Lismore 115 kV Interconnection	2019/B>A	15764	No	No	GRE
2019-SW-N2	Rutland Substation 161kV Ring Bus Addition	2018/A	14484	No	No	SMP

Heron Lake Capacitors

MPUC Tracking Number: 2013-SW-N1

Utility: ITC Midwest (ITCM)

Project Description: Heron Lake 161 kV Capacitor Banks.

Need Driver: Low voltage in the Heron Lake area requires the addition of a 42 MVAR capacitor bank at the Heron Lake 161 kV Substation. The addition of the capacitor bank will require rebuild of Heron Lake Substation to a breaker-and-½ configuration.

Alternatives Considered: The capacitor bank was the only alternative evaluated. Expansion of the transmission system in the area would have been a more costly alternative.

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. The capacitor bank will help support system voltage. The existing facility is not able to accommodate the capacitor bank. The 161 kV substation will be constructed in a breaker-and-½ configuration, which will require expansion of the existing facility.

Schedule: It is expected that the project would be complete by December 2022.

General Impacts: The capacitor bank addition will increase reliability by adding voltage support for the area. Site expansion will be coordinated with local authorities and landowners to minimize impacts. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. ITC contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Summit to Dovray 69 kV Rebuild

MPUC Tracking Number: 2017-SE-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: 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.

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 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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-SE-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: 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.

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 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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-SE-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: 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.

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 2019.

Schedule: Construction of the line is expected to be completed by the end of 2024.

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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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.

Lismore 115 kV Interconnection

MPUC Tracking Number: 2019-SW-N1

Utility: Great River Energy (GRE)

Project Description: Move the Nobles Cooperative Electric's Lismore substation load from the 24 kV line between Fulda and Magnolia to the Fenton-Nobles 115 kV line and provide support to remaining 24 kV system with 115 kV interconnection.

Need Driver: The Nobles Cooperative Electric requires 115 kV service for their Lismore substation.

Alternatives: Convert the existing 24 kV line to 115 kV.

Analysis: Converting Lismore substation is much cheaper than converting the entire 24 kV line to 115 kV.

Schedule: The project is planned to be in service by fall 2020.

General Impacts: The project will require approximately 500 feet of new 115 kV in-and-out transmission line from the interconnection with the Xcel Energy 115 kV 5545 line to the Lismore 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 adjacent to existing transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

Rutland Substation 161kV Bus Addition

MPUC Tracking Number: 2019-SW-N1

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: The existing substation is being expanded and reconfigured to a 161 kV ring bus.

Need Driver: Baseline reliability is the primary driver for this project. MISO identified a breaker failure contingency that resulted in a potential voltage collapse in the area.

Alternatives A new line into the area was considered, along with reconfiguring to serve the local load radially.

Analysis: The MISO analysis found that under contingency a potential voltage collapse existed.

Schedule: This project will be completed year end 2019.

General Impacts: This project is being constructed on the existing property. It will provide increased reliability and voltage support in the area.

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 2017 Biennial Report but have been completed or withdrawn since the 2017 Report was filed with the Minnesota Public Utilities Commission in November 2017. 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 2017 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-SW-N3	Buffalo Ridge Cutover	Not Required	XEL	Withdrawn

MPUC Tracking Number	Description	MPUC Docket	Utility	Date Completed
2013-SW-N4	MVP #3	ET-6675/CN-12-1053	ITCM	2018

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
2011-SE-N5	Arlington-Green Isle 69 kV	2012/A		No	No	XEL
2015-SE-N4	Line 0714 Rebuild	2015/A	8079	No	No	XEL
2015-SE-N5	Alden-Mansfield 69 kV Rebuild	N/A	N/A	No	No	DPC
2015-SE-N6	Waseca Junction to Montgomery 69 kV rebuild	2013/A	4101	No	No	ITCM
2015-SE-N7	Ellendale to Owatonna 69 kV Rebuild	2013/A	4108	No	No	ITCM
2017-SE-N1	Huntley to Wilmarth 345 kV MEP Project	2016/A	11883	Yes	Yes	XEL/ITCM
2017-SE-N6	J407 Interconnection at Glenworth 161 kV	2018/A	14030	No	No	ITCM
2019-SE-N1	Cannon River Park Tap Line	2020/C>A	18025	No	No	GRE
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	TBD	No	No	ITCM

MPUC Tracking Number	MISO Project Name	MTEP Year/App	MTEP Project Number	CON?	Non-Wire Alt.	Utility
2019-SE-N4	Adams 161 kV Maintenance	2020/A	13879	No	No	ITCM
2019-SE-N5	Thisius 161/69kV Substation	2020/A	17968	No	Yes	ITCM
2019-SE-N6	Grand Meadow 69 kV Tap	N/A	N/A	No	No	DPC
2019-SE-N7	Glenworth-Exol Tap 69 kV Line	N/A	N/A	No	No	DPC
2019-SE-N8	Blooming Prairie N86 69 kV Line Rebuild	NA	NA	No	No	SMP
2019-SE-N9	Preston N-22 69kV Line Rebuild	NA	NA	No	No	SMP
2019-SE-N10	West Owatonna 161kV Ring Bus Addition and Load Interconnection	2019/A	16065	No	No	SMP

Arlington-Green Isle 69 kV

MPUC Tracking Number: 2011-SE-N5

Utility: Xcel Energy (XEL)

Project Description: Re-build 13 miles of 69 kV line from Arlington-Green Isle-Carver County in existing right of way.

Need Driver: This line was flagged during the CapX study as an underlying facility that needed upgrading. With the loss of the CapX lines under high transfers this 69 kV line will overload.

Alternatives: Adding additional transmission lines would mitigate this issue but would require far greater cost and land usage.

Analysis: This project will have the associated construction projects by Xcel Energy employees. This project will help maintain local reliability and uses existing right of way to minimize impact.

Schedule: This project got delayed due to distribution work at Green Isle substation. The line rebuild is expected to take 2 years to construct and has an expected in-service date in 2022.

General Impacts: The project will be constructed on 13 miles of existing right of way that mostly consists of agricultural lands. No new landowners will be impacted by the construction. Xcel Energy has completed a desktop review of the transmission line right of way and will work with the appropriate agencies, as required, to minimize impacts to the area. Construction is expected to take 2 years. No significant traffic impacts are anticipated. The existing right of way will be restored when the project is completed.

0714 Line Rebuild

MPUC Tracking Number: 2015-SE-N4

Utility: Xcel Energy (XEL)

Project Description: Rebuild 3.6 miles of 0714 69 kV line from Madelia Switching Station to Village of Madelia to 336 ACSR.

Need Driver: With the loss of both 345 kV lines heading into Wilmarth, this line will overload. Rebuilding it to a higher ampacity mitigates the issue.

Alternatives: Alternatives would have been more costly and environmentally impactful. Such alternatives include construction of a new transmission line which would have required additional land and right of way.

Analysis: This project will have associated construction jobs. This project will help maintain local reliability and uses existing right of way to minimize impact.

Schedule: This project should be completed by 2022.

General Impacts: The project will be constructed on 3.6 miles of existing right of way that mostly consists of agricultural lands. No new landowners will be impacted by the construction. Xcel Energy has completed a desktop review of the transmission line right of way and will work with the appropriate agencies, as required, to minimize impacts to the area. Construction is expected to take 1 year. No significant traffic impacts are anticipated. The existing right of way will be restored when the project is completed.

Alden-Mansfield 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N5

Utility: Dairyland Power Cooperative (DPC)

Project Description: Rebuild 5.3 miles of DPC's Twin Lakes-Freeborn 69 kV line between DPC's Alden and Mansfield distribution substations, improving reliability to all three distribution substations on this line which was originally constructed in 1951.

Need Driver: This 69 kV line was built in 1951 and increased maintenance costs have required that this line be rebuilt due to age and condition. The line also has some long spans that can be prone to galloping due to high winds.

Alternatives: The primary need driver is age and condition issues resulting in reliability concerns. Because of this need, the only alternative that was considered is a rebuild of the existing line. An alternative on new right-of-way was not considered as this line serves several distribution substations and new right-of-way would present routing difficulties and a higher cost.

Analysis: The plan to replace the existing 64-year-old transmission line with new poles, conductor and shield wire will solve the reliability concern caused be the age and condition of the existing transmission line serving Mansfield, Alden and Freeborn distribution substations. The estimated cost is approximately $1.5M and has a targeted in-service date of 2018.

Schedule: Construction would occur October 2019 – January 2020.

General Impacts: Dairyland construction crews will rebuild this line at the end of 2019 requiring approximately eleven weeks to construct. This 69 kV line follows a road, resulting in minimal impacts to the local right-of-way.

Waseca Junction to Montgomery 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N6

Utility: ITC Midwest (ITCM)

Project Description: The 29.6 mile-long Waseca Junction to Montgomery 69 kV line will be reconstructed on the existing right of way.

Need Driver: This 69 kV line was built in 1946 and increased maintenance costs have required that this line be rebuilt due to age and condition.

Alternatives: A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue.

Analysis: The plan to replace the approximately 70-year-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: Construction of the line is expected to be completed by the end of 2021.

General Impacts: The line is near the end of its useful life. The line will be reconstructed on the 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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 line rebuild will increase the reliability of the electric system in the area.

Ellendale to West Owatonna 69 kV Rebuild

MPUC Tracking Number: 2015-SE-N7

Utility: ITC Midwest (ITCM)

Project Description: The 13.2 miles-long Ellendale to West Owatonna 69 kV line will be reconstructed on the existing right of way.

Need Driver: This 69 kV line is a known, real-time system constraint. The line is also nearing the end of its useful life.

Alternatives: Rebuilding the line to a greater capacity on existing ROW was the sole alternative considered to alleviate the system capacity constraint.

Analysis: Replacement of the 69 kV transmission line with new poles, conductor and shield wire addresses a capacity constraint and provides for needed upgrade of the 50-year-old 69 kV line.

Additional analysis is ongoing. The Ellendale to West Owatonna 69 kV has also been a source of system congestion due to area wind energy, and evaluation of s possible voltage conversion from 69 kV to 161 kV along a corridor from the Hayward or Freeborn 161 kV substations to Owatonna and other alternatives are also being evaluated in effort to better address possible future generation outlet and load-serving needs.

Schedule: The rebuild of the line is expected to occur within approximately 5-6 years.

General Impacts: Replacement of the line will provide for additional system capacity and reduce maintenance cost on the existing, aging infrastructure. It is expected that the line will be reconstructed 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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 the electric system in the area.

Huntley to Wilmarth 345 kV MEP Project

MPUC Tracking Number: 2017-SE-N1

Utilities: Xcel Energy (XEL) & ITC Midwest (ITCM)

Project Description: Construct new 345 kV circuit from the Wilmarth Substation to the Huntley Substation.

Need Driver: This is a market efficiency project to relieve congestion on the Huntley to Blue Earth 161 kV line.

Alternatives: Several solutions such as rebuilding the South Bend to Blue Earth to Huntley 161 kV, a new Freeborn to West Owatonna 161 kV circuit, and a new Wilmarth to North Rochester 345 kV circuit were also studies to relieve the congestion observed.

Analysis: The Huntley to Wilmarth 345 kV project was found to alleviate the observed congestion at the Minnesota/Iowa border. The proposed project met the MISO present value cost to benefit ratio required for Market Efficiency projects.

Schedule: Planned in service date is end of 2021. A certificate of need and route permit were granted for this project in 2019.

General Impacts: This project will utilize the existing Wilmarth and Huntley substations. Some additional new right-of-way will need to be acquired to construct the new 345 kV circuit on the approved route, but approximately 40% of the line will be constructed as a double circuit with the existing Wilmarth-Lakefield Jct. 345 kV line. An Environmental Impact Statement was prepared for the project and is available on eDockets in MPUC Docket Nos. E002,ET-6675/CN-17-184 and TL-17-185. Unique environmental features will be addressed to minimize environmental impacts that could occur during construction. Xcel will work with the appropriate permitting agencies to receive necessary approvals. Xcel contractors and personnel will contribute positively to the local economies. No significant traffic impacts are anticipated.

J407 Interconnection at Glenworth 161 kV

MPUC Tracking Number: 2017-SE-N6

Utility: ITC Midwest (ITCM)

Project Description: Expand the 161 kV ring bus at Glenworth by adding a 161 kV breaker and new terminal for the interconnection of a 200 MW wind-powered generating facility and replace the existing 100 MVA, 161/69 kV transformer with an 150 MVA unit.

Need Driver: The expansion of Glenworth and the replacement of the existing 100 MVA transformer with a 150 MVA unit are required for the Interconnection Service for project J407 under the MISO Tariff.

Alternatives: The interconnection was evaluated under the MISO's DPP February 2015 system impact study. No alternatives for the interconnection or the overload of the transformer were identified.

Analysis: The interconnection of project J407 was evaluated as part of the MISO February 2015 system impact study. The expansion of facilities at Glenworth are required to provide a point of interconnection for project J407, and the transformer was shown to overload under contingency with the interconnection of project J407 to Glenworth.

Schedule: The in service date for the project is August 2020.

General Impacts: The upgrades will occur within the existing Glenworth 161 kV Substation. Termination of the J407 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Cannon River Park Tap line

MPUC Tracking Number: 2019-SE-N1

Utility: Great River Energy (GRE)

Project Description: Construct a 115 kV line from the Xcel 0832 line to the new Cannon River Park substation.

Need Driver: A 6 MW air-processing facility is planned for construction directly east of Faribault Energy Park. Steele-Waseca requires a 115/4160 source for this load. Additionally, Steele-Waseca plans to install a 115/12.47 kV transformer at the same substation to serve future load growth in the area.

Alternatives: Provide service to the new load from the 115 kV Airtech substation.

Analysis: The Airtech substation configuration and existing sensitive load customer requires the new load to be located at a new substation.

Schedule: The project is planned to be in service by fall 2020.

General Impacts: The project will require approximately 0.5 mile of new 115 kV transmission line from the interconnection with the Xcel Energy 115 kV 0832 line to the Cannon River Park substation. The project is located in predominantly industrial park 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 adjacent to existing transmission line 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 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. As compared to available alternatives, the project minimizes the length of transmission line through sensitive areas.

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: A rebuild on existing ROW was the sole alternative considered to solve the age and condition issue.

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 2023.

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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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 reterminated 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: The interconnection was evaluated under the MISO's DPP February 2016 system impact study. No alternatives for the interconnection were identified.

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 September of 2021.

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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC contractors and personnel will contribute positively to the local economy. No significant traffic impacts are anticipated.

Adams 161 kV Maintenance

MPUC Tracking Number: 2019-SE-N4

Utility: ITC Midwest (ITCM)

Project Description: The Adams 161 kV currently has 2 generating facilities, 5-161 kV lines, a 161/69 kV transformer and a 345/161 kV transformer connected to the 161 kV bus in a straight bus configuration. The greater than 55 years old substation was initially designed with capability for the 161 kV bus to be converted to a breaker-and-1/2 configuration, and in conjunction with the interconnection of project J523, additional circuit breakers will be installed, and the 161 kV bus will be converted to a breaker-and-1/2 configuration.

Need Driver: The breaker-and-1/2 configuration will provide greater operational flexibility by avoiding generating facility outages and line outages otherwise required for maintenance, and it will increase system reliability by avoiding loss of multiple system elements in the event of a fault. The Adams 161 kV bus reconfiguration will also eliminate the overload of the Adams to Rose Wind 69 kV line for a breaker failure contingency of bus L2 at Adams 161 kV.

Alternatives: Rebuilding the Adams 161 kV substation near the existing facility would require significant line relocation and new equipment, and it was considered a too costly alternative.

Analysis: Reconfiguring the substation to a breaker-and-1/2 configuration in conjunction with the interconnection of project J523 will provide operational flexibility if performing system maintenance while also providing for increased system reliability. The operational flexibility also removes the need to reduce area generation in the event of a bus fault or breaker failure event at Adams 161 kV.

Schedule: The project work will be coordinated with the work to interconnect project J523, which has a September 2021 in service date.

General Impacts: Coordination with generating facilities' owners, Xcel Energy and Dairyland Power Cooperative will be required for outages facilities construction. The upgrades will occur within the existing Adams 161 kV Substation. 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. ITC will work with the appropriate permitting agencies to receive necessary approvals. ITC 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 161/69kV 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: 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.

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 the end of December 2027.

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.

Grand Meadow 69 kV Tap

MPUC Tracking Number: 2019-SE-N6

Utility: Dairyland Power Cooperative (DPC)

Project Description: Build a new eight-mile 69 kV tap line from DPC's Harmony-Adams 69 kV line to new Grand Meadow distribution substation.

Need Driver: The main need drivers are local load serving issues, the inability to back up the Sargeant substation, and aging distribution.

Alternatives: Five alternatives were considered, with the substation tapping into various lines to the north, south, and east. Alternatives involving tapping into westward lines were not considered, as the tap lines would become quite lengthy. Alternatives were analyzed and compared based on transmission reliability, exposure, cost, and power flow. Electrical engineering and protection concerns were also considered.

Analysis: The plan to tap the Harmony-Adams 69 kV line three miles east of the Taopi Tap will satisfy the main need drivers mentioned prior. This alternative proved reliable and was among the alternatives with the lowest costs. It also avoided the concerns of related to electrical engineering and protection.

Schedule: Construction would occur April-July 2020.

General Impacts: Dairyland construction crews will build this line in 2020, requiring approximately fourteen weeks to construct.

Glenworth-Exol Tap 69 kV Line

MPUC Tracking Number: 2019-SE-N7

Utility: Dairyland Power Cooperative (DPC)

Project Description: Build a 1.5 mile 69 kV line from Glenworth to Exol Tap and add a new circuit breaker at the Glenworth 161/69 kV transmission substation south of Albert Lea, Minnesota creating a new looped transmission facility between Glenworth and ITC's Albert Lea West Side 69 kV substation.

Need Driver: The primary need driver is voltage concerns for breaker failure of the Hayward 69 kV bus-tie breaker resulting in low voltages in the Albert Lea, Minnesota area.

Alternatives: MISO led the analysis with DPC, GRE and ITCM of nine alternatives in the area to address the contingent voltage concerns. Alternatives like capacitor additions, new 161/69 kV substations located north of Albert Lea and a combination of those projects were considered. Alternatives were analyzed and compared based on their post contingent performance and cost.

Analysis: MISO's recommended plan included a capacitor addition as well as DPC's project to add a new line into Glenworth from the Exol area creating a Glenworth-Albert Lea West Side 69 kV line. A switch at the South Shore station will be operated Normally Open to prevent three terminal operation. This plan will improve the ability for the Glenworth 161/69 kV source to help post contingent voltages in the Albert Lea area for a contingency at the Hayward station. It was also the least cost plan.

Schedule: The construction timing is being developed for potentially the 2022/2023 timeframe.

General Impacts: Dairyland construction crews will build this line requiring approximately five to six weeks to construct.

Blooming Prairie N86 69 kV Tap Line Rebuild

MPUC Tracking Number: 2019-SE-N8

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: Rebuild and reconductor 7.95 miles of SMP's Blooming Prairie 69 kV N86 line between Corning tap and Blooming Prairie substation. This existing line will be upgraded from a 1/0 ACSR to a 4/0 ACSR conductor for increased capacity and reliability.

Need Driver: This existing 69 kV line was built in 1965 and has sustained considerable damage from the April 2019 storm in the area.

Alternatives: There were no alternatives considered.

Analysis: The rebuild of this existing line will provide increased reliability in the area.

Schedule: This project is scheduled for completion in the fourth quarter of 2020.

General Impacts: This project will require this existing line to be out of service for the duration of the project. Existing right-of-way is being utilized. This will result in a quicker project and shorter downtime.

Preston N22 69kV Line Rebuild

MPUC Tracking Number: 2019-SE-N9

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: Rebuild 2.3 miles of SMP's N22 Preston 69 kV line between the Preston north tap and the Preston south substation.

Need Driver: This 69kV line was built in 1960 and the rebuilding of this line will increase the reliability in the area.

Alternatives: There were no alternatives considered.

Analysis: The rebuilding of this existing line will decrease operational costs associated with the aging line, along with providing increased reliability.

Schedule: The project is scheduled for completion in the first quarter of 2020.

General Impacts: The line is being rebuilt on existing right-of-way and will have little impact on surrounding land owners. The biggest positive impact will be to the reliability in the area.

West Owatonna 161kV Ring Bus Expansion and Load Interconnection

MPUC Tracking Number: 2019-SE-N10

Utility: Southern Minnesota Municipal Power Agency (SMP)

Project Description: Owatonna Public Utilities (OPU) is acquiring existing load from the Steele-Waseca Co-op. This load is currently being served from the 69 kV bus at West Owatonna substation, but will now be served from the 161 kV bus as a part of this project.

Need Driver: The primary driver for the expansion is the interconnection of new load to the Owatonna Public Utilities system. However, considerations have been given to both increased reliability and voltage support in the area.

Alternatives: A new connection point was required for the acquisition. No alternatives were explored.

Analysis: The interconnection and substation expansion was studied and approved by MISO through their expediated project process.

Schedule: The in-service date for this project is by year end 2019.

General Impacts: The project is being completed within the existing West Owatonna substation property lines. It will provide additional space for future connection, increase reliability, and increase voltage support on the 69 kV system in the Owatonna area.

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 2017 Biennial Report but have been completed or withdrawn since the 2017 Report was filed with the Minnesota Public Utilities Commission in November 2017. 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 2017 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-N1	Lake Bavaria	Not Required	XEL	2018
2015-SE-N2	Vesili Substation	Not Required	XEL	2015
2015-SE-N3	Jordan Substation	Not Required	XEL	2015
2015-SE-N2	Bluff Siding Area Reconfiguration	Not Required	XEL	2019
2017-SE-N5	Huntley 69 kV Maintenance	Not Required	ITCM	2018

7.0 Transmission-Owning Utilities

7.1 Introduction

In this chapter in the 2019 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 that was provided in the 2017 Report. This information relates to the history of the 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, and 2017, 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	18	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	3,073	574	524	145	436
ITC Midwest LLC	688.6	307.9	0	92.6	0
L&O Power Cooperative	44.52	8.32	0	0	0
Minnesota Power	0.22	1,326.72	617.01	43.34	231.6
Minnkota Power Cooperative	998.67	153.2	268.09	0	0
Missouri River Energy Services	32.61	239.32	24.02	47	0
Northern States Power Company d/b/a Xcel Energy	1,675.49	1,726.12	461.59	1,839.29	0
Otter Tail Power Company	1,300.99	540.95	181.18	619.02	0
Rochester Public Utilities	0	42.42	0	0	0
Southern Minnesota Municipal Power Agency	149.84	135.48	17.09	0	0
Totals:	8,569.74	5,267.18	2,092.98	2,807.13	667.6

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, with more than 600 employees working in Wisconsin and Michigan.

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 9,890 circuit miles of transmission lines and 568 substations in Wisconsin, Michigan, Illinois, and Minnesota. ATC has $3.5 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: Joel Berry
Transmission Planning Engineer
American Transmission Co.
P.O. Box 47
Waukesha, WI 53187-0047
Phone: (262) 506-6700
e-mail: jberry@atcllc.com

Transmission lines. ATC owns more than 9,890 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 Blue Earth, 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 MN and IA. CMMPA transmission assets are part of MISO.

More information about the company is available on its website at:

http://www.cmpas.org

Contact Person: Sayan Roy
Transmission Planning Engineer
Central Municipal Power Agency/Services
459 S Grove Street
Blue Earth, MN 56013
Phone: (763) 710-3954
e-mail: sayanr@cmpas.org

Transmission lines. CMMPA is one of the eleven members of the CapX group, and one of the five investors 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
18	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: Steve Porter
Planning Engineer III
Dairyland Power Cooperative
3200 East Avenue South
La Crosse, WI 54601
Phone: (608) 787-1229
Fax: (608) 787-1475
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: John Knofczynski
System Planning Manager
East River Electric Power Cooperative
P.O. Box 227
211 South Harth Avenue
Madison, SD 57042
Phone: (605) 256-4536
Fax: (605) 256-8058
e-mail: jknofczynski@eastriver.coop

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 28 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. Great River Energy's largest distribution cooperative serves more than 125,000 member-consumers, while the smallest serves approximately 2,500. Collectively, Great River Energy's member cooperatives distribute electricity to approximately 655,000 member accounts, or about 1.7 million people. In addition, Great River Energy 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
12300 Elm Creek Blvd
Maple Grove, MN 55369-4718
Ph: (888) 521-0130, ext. (763) 445-5050
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
3,073	574	524	145	436

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. 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: David Grover
Director, RTO Affairs
ITC Midwest, LLC
100 South 5th Street, Suite 1925
Minneapolis, MN 55402
Phone: 612-332-2511
Fax: 612-332-2544
e-mail: DGrover@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 1,089 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
688.6	307.9	0	92.6	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

Contact Person: Curt Dieren
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: CDieren@dgrnet.com

Transmission Lines. L&O delivers wholesale electricity via approximately 193 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
44.52	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 about 145,000 residential and commercial customers, 16 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	1,326.72	617.01	43.34	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: Brenden Kennelly
Senior Manager Power Delivery Engineering
Minnkota Power Cooperative, Inc.
5301 32nd Avenue South
Grand Forks, ND 58208-3201
Phone: (701) 795-4442
Fax: (701) 795-4333
e-mail: bkennelly@minnkota.com

Transmission Lines. The Joint System owns 1,420.02 miles of transmission line in Minnesota and 1930.06 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
998.67	153.2	268.09	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 existing 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 60 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 23 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 Minnesota River Energy can be found at:

http://www.mrenergy.com

Contact Person: Brian Zavesky
Missouri River Energy Services
3724 West Avera Drive
P.O. Box 88920
Sioux Falls, SD 57108-8920
Phone: (605) 330-6986
Fax: (605) 978-9396
e-mail: brianz@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**
32.61	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:

http://www.xcelenergy.com

Contact Person: Jason Standing
Principal Engineer
414 Nicollet Mall
Minneapolis, MN 55401
Phone: (612) 330-7768
Fax: (612) 330-6357
e-mail: jason.t.standing@xcelenergy.com

Transmission Lines. Northern States Power Company owns about 5,700 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
1,675.49	1,726.12	461.59	1,839.29	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:
Jesse Tomford
Supervisor, Delivery Studies
Otter Tail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: (218) 739-8200
Fax: (218) 739-8442
e-mail: JTomford@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
1,300.99	540.9	181.18	619.02	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 48,219 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
Manager of System Operations/Reliability
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. Rochester Public Utilities owns 42.42 miles of 161 kV transmission line in Minnesota. Rochester Public Utilities is one of the eleven members of the CapX group, and is one of the five investors in the Hampton-Rochester-La Crosse CapX project. Beyond this CapX project, Rochester Public Utilities has no immediate plans for future transmission expansion.

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. Southern Minnesota Municipal Power Agency (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 eighteen 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
Power Delivery Engineer
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 upcoming Renewable Energy Standard milestones. 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." In its June 12, 2018, Order approving the 2017 Report, the Commission said that the 2019 Report should include content similar to the 2017 Report.

Accordingly, in this Report, as in past years, the utilities are reporting on their best estimates for how much renewable generation will be required in future years and what efforts are underway to ensure that 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 that is already available and how much will be 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 2017 Report but all figures and charts and tables have been updated since those provided two years ago.

8.2 Reporting Utilities

It should be pointed out, as was done in previous reports, that the utilities that are required to submit the Biennial Transmission Projects Report are not identical to those that are required to meet the Renewable Energy Standards. The information in this chapter reflects the work of all the utilities that are 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 2019 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

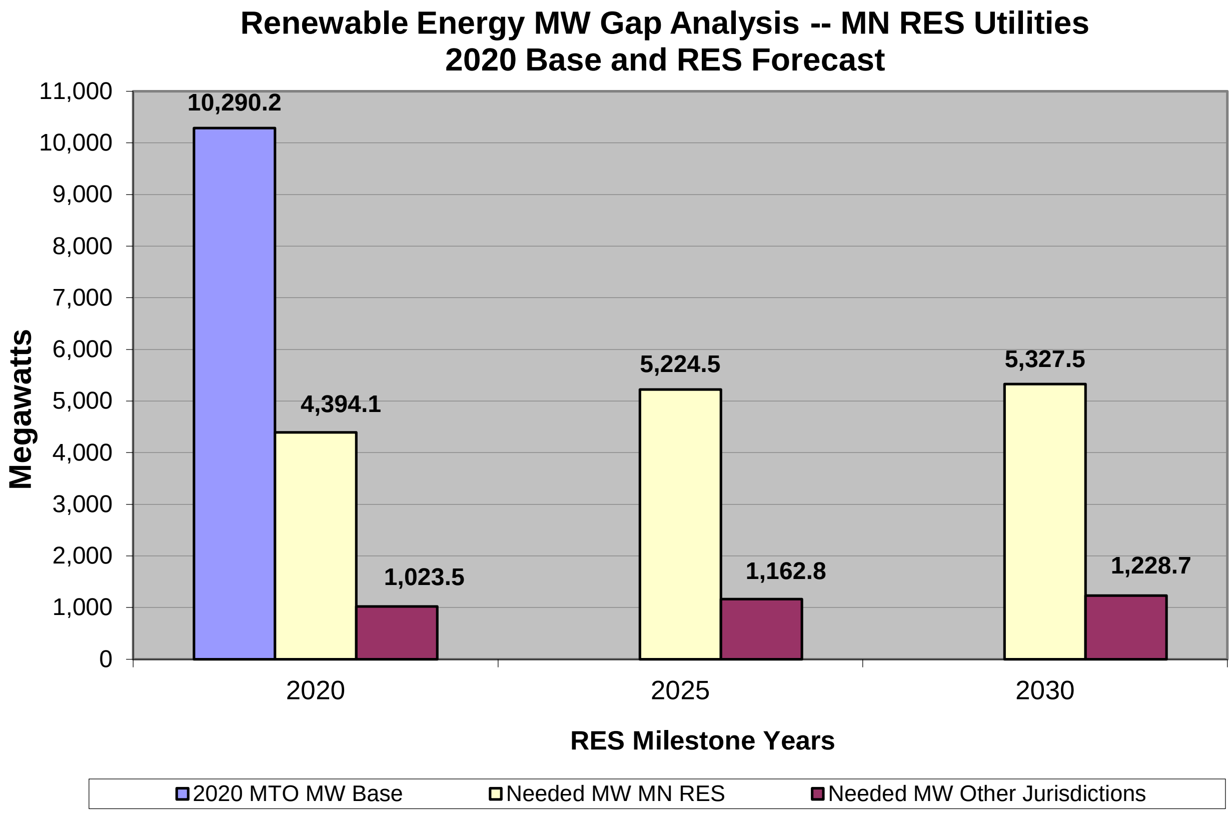
The utilities have continued to make substantial progress with respect to meeting future RES milestones. The RES milestone for 2018 – 17% renewables for all utilities except Xcel Energy, for which the standard is 25% - was achieved and is presently being achieved. The CapX Group 1 projects were crucial to meeting the 2018 Minnesota RES and non-Minnesota RES milestones. In addition, the utilities have provided a Gap Analysis regarding compliance with the upcoming 2020 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 to need beyond what is presently available to obtain the required amount of renewable energy that must come from renewable sources at a particular time in the future. 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 seventh time the utilities have prepared a Gap Analysis; a Gap Analysis was prepared for the 2007, 2009, 2011, 2013, 2015, and 2017 Biennial Reports also.

8.5 Base Capacity and RES/REO Forecast

The chart below presents a system-wide overview of existing capacity in 2019 (used as a base figure throughout the various milestone periods) and forecasted renewable capacity requirements to meet Minnesota RES as well as non-Minnesota RES/REO needs. Each utility provided its own forecast of Minnesota RES and non-Minnesota RES/REO renewable energy needs, and converted such estimates into capacity based on their own mix of renewable resources (wind, biomass, hydropower, solar) using the most appropriate capacity factors unique to their specific generating resources.



2020 MTO MW Base: RES capacity acquired, actually installed and operational ("in the ground and running") regardless of geographic location. Does not include projects under contract but not yet under construction, and it does not include projects under construction but not yet completed.

Needed MW MN RES: Renewable capacity required to meet the RES energy goals for each utility serving customers in Minnesota.

Needed MW Other Jurisdictions: Gross non-MN renewable capacity required to meet RES requirements or REO goals in states served by the reporting utility other than Minnesota.

Table 1 on the following page 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	**2020**		**2025**		**2030**	
	MN RES	Non-MN RES	MN RES	Non-MN RES	MN RES	Non-MN RES
Basin Electric[2]	86.2	455.6	129.5	541.0	144.7	570.8
CMMPA	18.0	-	26.0	-	35.0	-
Dairyland	54.0	90.0	101.0	104.0	117.0	121.0
GRE	612.6	4.3	824.9	5.7	824.9	7.1
Heartland	4.9	7.9	6.6	8.4	6.8	8.8
Minnkota	107.9	-	143.1	-	148.1	-
MMPA	106.2	-	139.9	-	148.4	-
MN Power	577.4	19.8	718.5	22.6	727.5	23.4
Otter Tail	155.0	67.0	222.0	69.0	222.0	69.0
SMMPA	173.0	-	224.0	-	100.0	-
WMMPA/MRES	118.5	23.0	152.9	23.4	168.2	24.5
Xcel Energy	2,380.5	355.8	2,536.1	388.6	2,684.8	404.1
TOTAL	4,394.1	1,023.46	5,224.5	1,162.8	5,327.5	1,228.7

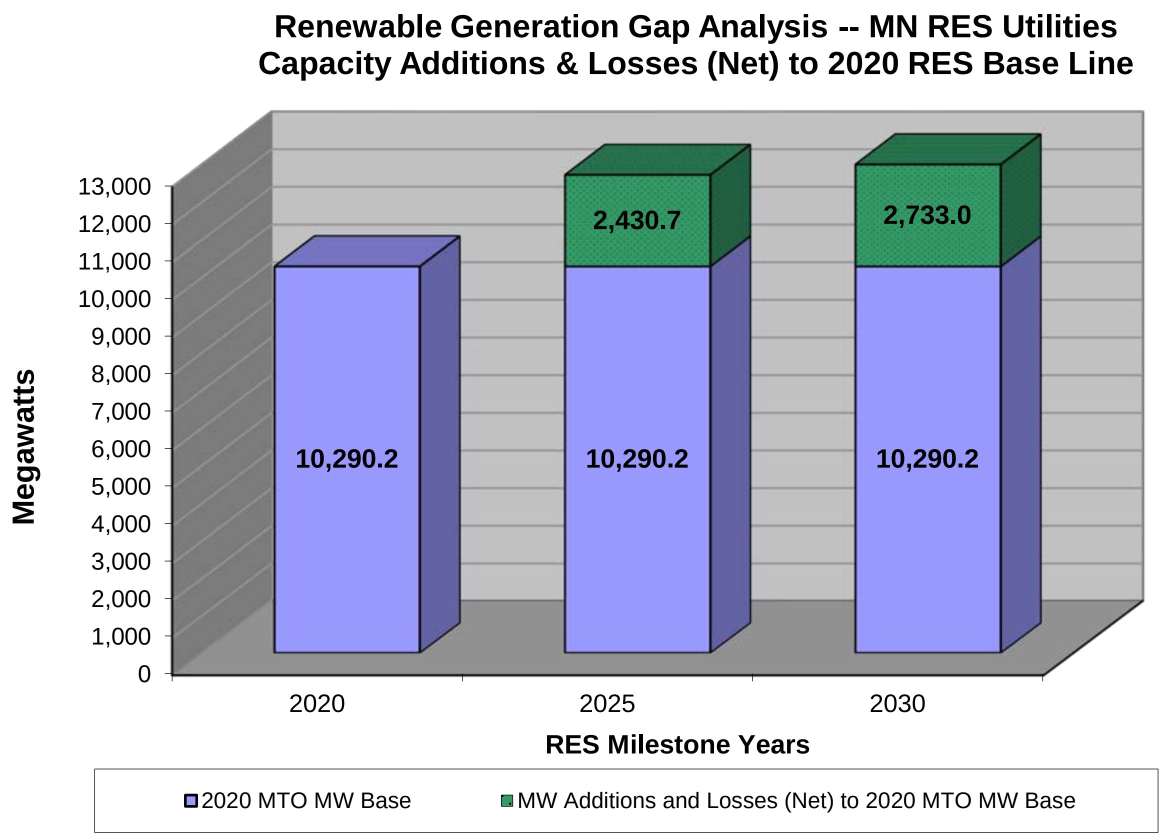
Note:

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

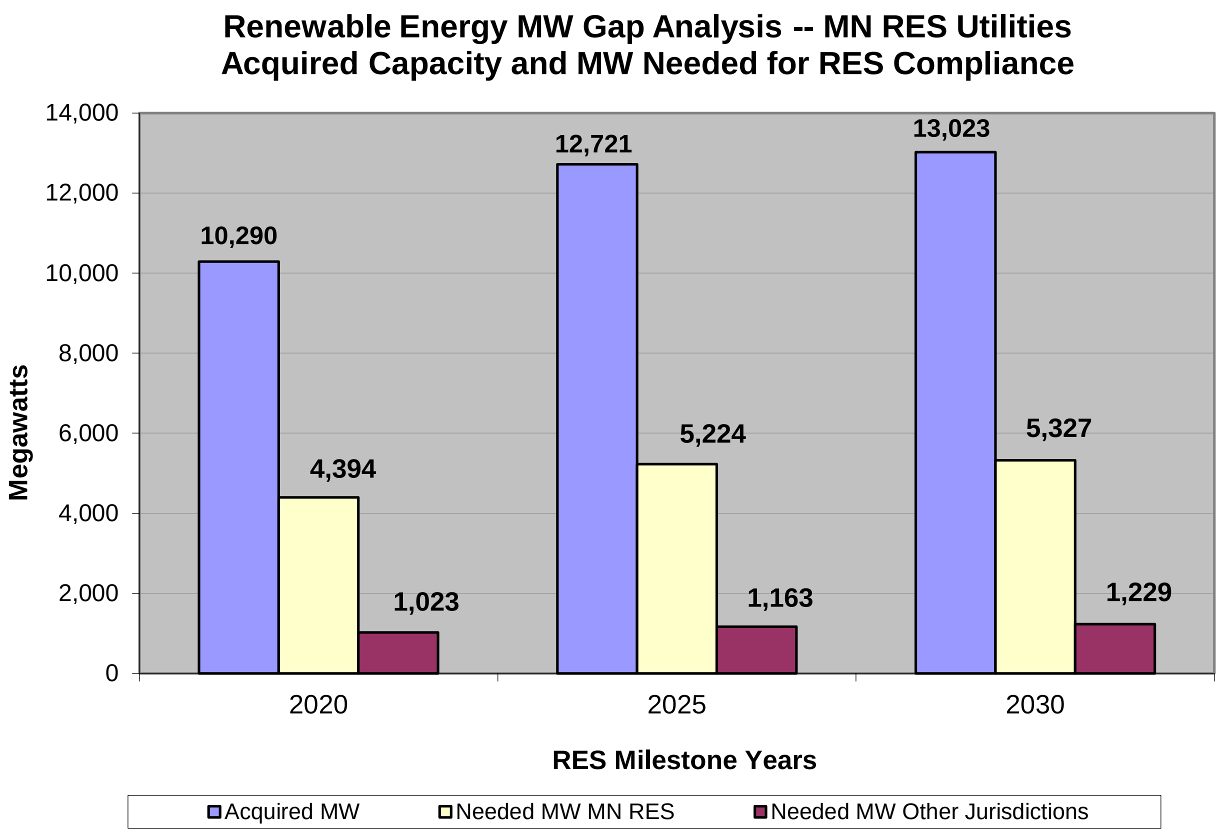
8.5.1 Capacity Acquisitions & Expirations

This chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning in 2020 and capacity that will expire between 2020 and 2030. Such losses are attributable primarily to the expiration of various power purchase agreements for renewable energy generation.



8.5.2 RES Capacity Acquired and Net RES/REO Need

This chart represents the total renewable capacity system-wide that will be acquired and lost between 2020 and 2030, as well as the total Minnesota RES and non-Minnesota RES/REO needs between 2020 and 2030.



As can be seen, the Minnesota RES utilities have sufficient capacity acquired to meet the Minnesota RES needs through 2030. When considering the RES needs, including other jurisdictions outside of Minnesota, the Minnesota RES utilities have enough capacity to meet RES needs beyond 2020. 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	2020		2025		2030	
	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net	RES Cap Acq.	MN RES Net
Basin Electric[2]	1,760.6	-	1,731.6	-	1,623.5	-
CMMPA	32.0	-	32.0	-	26.0	9.0
Dairyland	301.0	-	409.0	-	462.0	-
GRE	751.0	-	1,210.0	-	1,210.0	-
Heartland	30.0	-	30.0	-	41.0	-
Minnkota	458.1	-	458.1	-	458.1	-
MMPA	315.7	-	345.7	-	226.8	-
MN Power	864.6	-	1,052.1	-	1,052.1	-
Otter Tail	254.0	-	404.0	-	404.0	-
SMMPA	224.0	-	224.0	-	224.0	-
WMMPA/MRES	141.7	0.5	141.7	27.7	141.7	42.3
Xcel Energy	5,157.6	-	6,682.7	-	7,154.1	-
TOTAL[3]	10,290.2	0.5	12,720.9	27.7	13,023.3	51.3
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. 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 need in Minnesota. Conversely, the column in Table 2 that is labeled "MN RES Net" represents the additional RES capacity that is presently identified to meet RES need. The shortfall, or "gap", between MN RES need and the additional RES capacity identified points to the need for some utilities to seek additional renewable capacity and when they need to do so. 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. Minn. Laws 2013, Ch. 85, § 3, codified at Minn. Stat. § 216B.1691, subd. 2f (Solar Energy Standard or SES). That statute requires public utilities subject to the SES to report to the Commission on July 1, 2014, and each July thereafter, on progress in achieving the standard. In the 2013 Biennial Report, even though the first report was not due until 2014, Northern States Power Company provided a brief analysis of its anticipated needs for solar energy in future years.

The first solar energy reports required under the statute were filed in May or June 2014 and the Commission accepted these filings in an Order dated October 23, 2014. MPUC Docket No. E999/M-14-321. The second reports were filed in summer 2015 and were approved by the Commission on October 28, 2015. MPUC Docket No. E999/M-15-462. Readers are referred to those dockets for more information about the utilities' progress in meeting the upcoming SES.

Because this Chapter 8 of the Biennial Report discusses utilities' compliance with Minnesota Renewable Energy Standards, however, a brief summary regarding the status of compliance with the 2020 Solar Energy Standard is included below. Utilities will continue to file annual reports until 2020 as required by the statute and directed by the Commission.

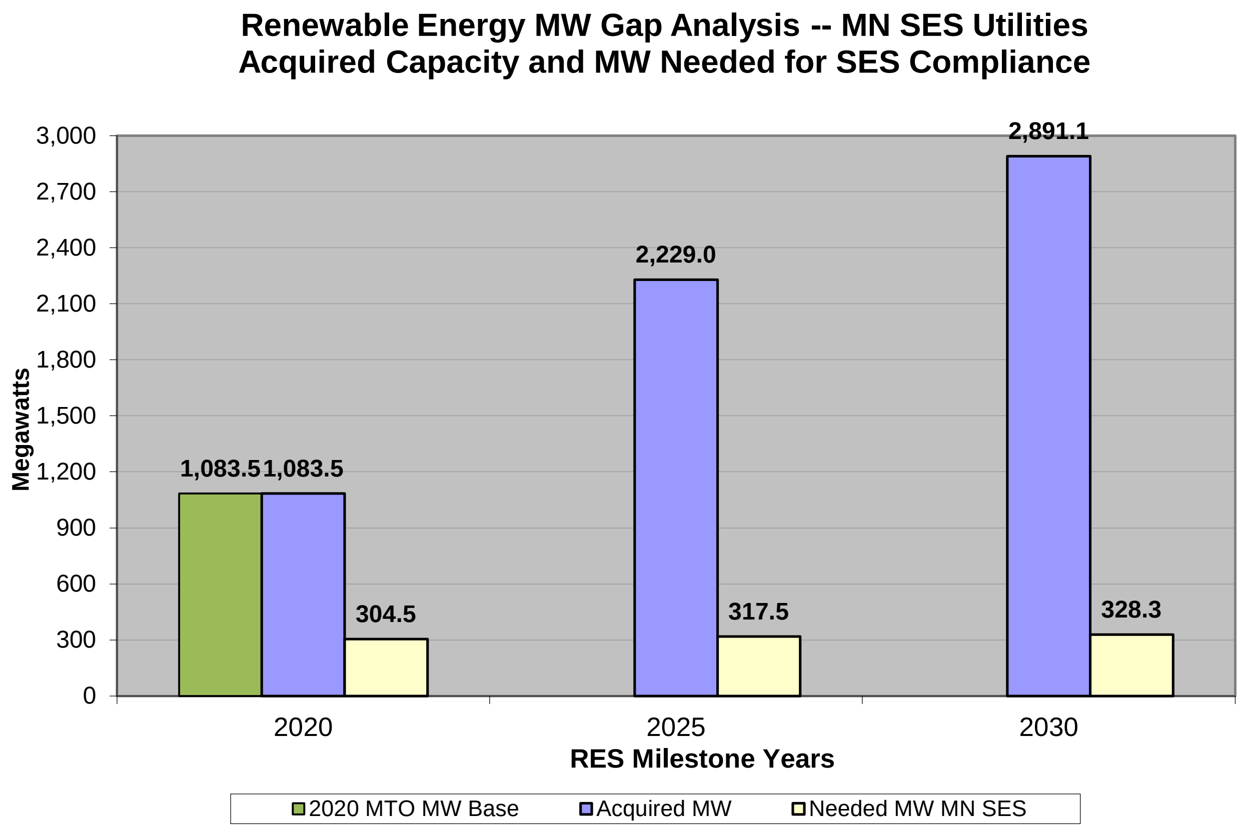


Table 3 shows a more specific breakdown of each utility's Minnesota SES and non-Minnesota SES needed capacity forecast.

Table 3. MN & Non-MN SES Forecast (MW)						
Utility	**2020**		**2025**		**2030**	
	MN SES	Non-MN SES	MN SES	Non-MN SES	MN SES	Non-MN SES
Heartland	0.3	-	0.3	-	0.3	-
MN Power	29.9	-	31.7	-	33.1	-
Otter Tail	30.0	-	30.0	-	30.0	-
Xcel Energy	244.3	-	255.4	-	264.9	-
TOTAL	304.5	-	317.5	-	328.3	-
Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES						

This chart presents a system-wide overview of additional renewable capacity that will be acquired by individual utilities beginning in 2020 and capacity that will expire between 2020 and 2030. Such losses are attributable primarily to the expiration of various power purchase agreements for renewable energy generation.

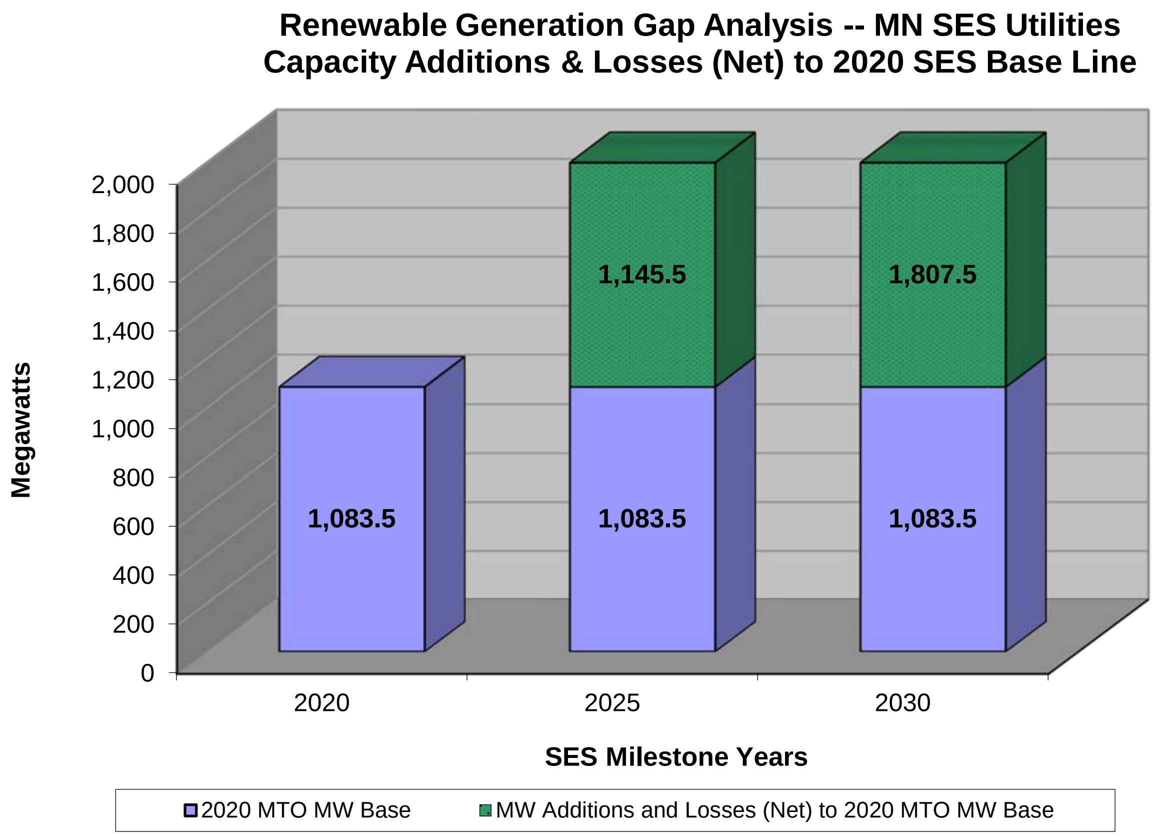


Table 4 below provides SES Utilities' planned level of solar capacity additions.

Table 4. SES Capacity Acquired & Net MN SES Capacity Need (MW)

Utility	2020		2025		2030	
	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net	SES Cap Acq.	MN SES Net
Dairyland	25.0	-	175.0	-	225.0	-
Heartland	-	0.3	-	0.3	-	0.3
MN Power	13.5	16.4	33.0	-	33.0	0.1
Otter Tail	-	30.0	-	30.0	-	30.0
SMMPA	5.0	-	5.0	-	5.0	-
WMMPA/MRES	1.0	-	1.0	-	1.0	-
Xcel Energy	1,039.0	-	2,015.0	-	2,627.1	-
TOTAL	1,083.5	46.7	2,229.0	30.3	2,891.1	30.4

Note: SES is the MN Solar Energy Standard which will require additional solar beyond the MN RES