APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT

MPUC Docket No. E002, E017, ET2, E015, ET10/CN-22-538

September 29, 2023

Submitted by
Northern States Power Company
Great River Energy
Minnesota Power
Otter Tail Power Company
Western Minnesota Municipal Power Agency

TABLE OF CONTENTS

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

TABLE OF CONTENTS
(continued)

Page

List of Appendices

List of Tables

TABLE OF CONTENTS
(continued)

Page

List of Figures

TABLE OF CONTENTS
(continued)

Page

List of Maps

TABLE OF CONTENTS
(continued)

Page

1. EXECUTIVE SUMMARY

1.1 Introduction

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Missouri River Energy Services, on behalf of Western Minnesota Municipal Power Agency (Western Minnesota), (collectively, the Applicants) request a Certificate of Need from the Minnesota Public Utilities Commission (Commission) for the portion of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Project located within Minnesota (the Project). The Project consists of new 345 kV transmission facilities between Big Stone City, South Dakota, and Sherburne County, Minnesota which will be comprised of two segments:

- the western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- the eastern segment will continue from the existing Alexandria Substation to the Riverview Substation to a new Big Oaks Substation[1] in Sherburne County, Minnesota (Eastern Segment).

The Project was studied, reviewed, and approved as part of the Long-Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO)[2] Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.[3]

The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable

[1] The Big Oaks Substation was previously referred to as the Cassie's Crossing Substation.

[2] MISO is a member-based non-profit regional transmission organization (RTO) that is responsible for the planning and operation of transmission grid and wholesale energy market across 15 states and the Canadian province of Manitoba. MISO's members include 48 transmission owners with more than 65,800 miles of transmission lines and $34.5 billion in transmission assets that are under MISO's functional control.

[3] A copy of the MTEP21 Report Addendum that discusses the need for the LRTP Tranche 1 Portfolio, including the Project is provided as **Appendix E-1**. **Appendix E-1** was prepared from the version of the MTEP21 Report Addendum that was posted to MISO's website on August 10, 2023.

energy delivery. The Project, designated as LRTP2 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

The Applicants submit this Certificate of Need Application (Application) for the entire Minnesota portion of the Project pursuant to Minn. Stat. § 216B.243 and Minn. Rule Ch. 7849. To facilitate review of this Application, a completeness checklist is included as **Appendix A** which provides a roadmap identifying where in this Application information required by Minnesota statutes and rules can be found.

The Applicants will also apply for two separate Route Permits for the Project as required by Minn. Stat. § 216E.03, one for the Western Segment and one for the Eastern Segment. Xcel Energy is leading this Certificate of Need Application for the Minnesota portion of the Project on behalf of the Applicants. Xcel Energy is also leading the Route Permit application for the Eastern Segment on behalf of the Applicants and a Route Permit application for the Eastern Segment was submitted on the same day as this Certificate of Need Application. The Applicants request that the Commission order that the Certificate of Need and the Eastern Segment Route Permit proceedings be combined pursuant to Minn. Stat. § 216B.243, subd. 4 and Minn. R. 7849.1900, subp. 4.

Otter Tail will lead the Route Permit application for the Western Segment and plans to file the application on behalf of itself and Western Minnesota in the fourth quarter of 2024. Otter Tail and Western Minnesota are also expecting to file a Facility Permit application in South Dakota, along with any other applicable permits required within South Dakota, for the portion of the Western Segment that will be located in South Dakota.

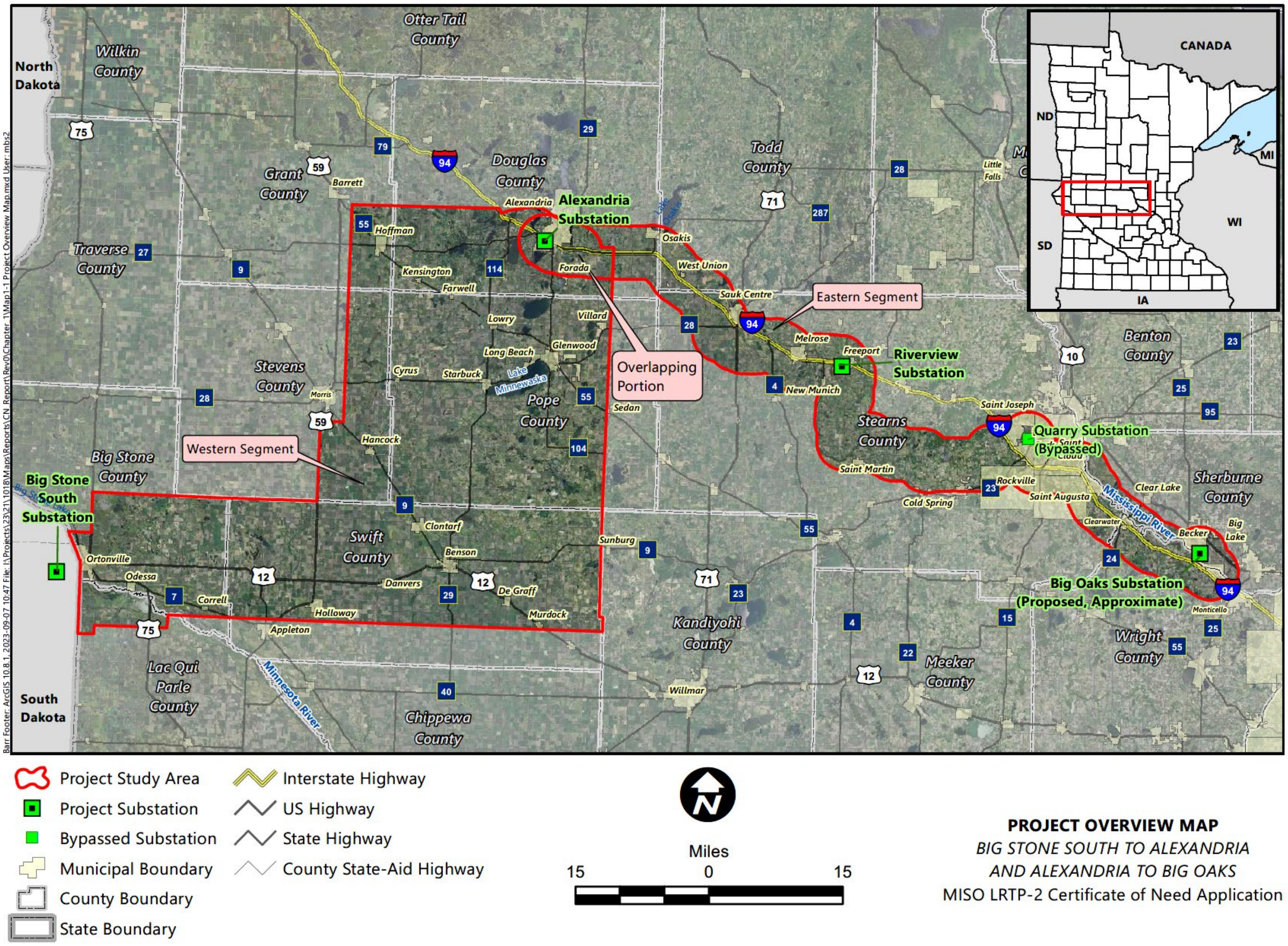
1.2 Project Description

The Western Segment of the Project consists of a new single-circuit 345 kV transmission line that will be placed on double-circuit capable structures from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota. The proposed 345 kV transmission facilities for the Western Segment could traverse Grant County in South Dakota and Big Stone, Lac Qui Parle, Swift, Stevens, Pope, Grant, and Douglas counties in Minnesota depending on the final route. The Eastern Segment of the Project involves stringing a second 345 kV transmission circuit on existing double-circuit capable[4] from the Alexandria Substation to the Riverview Substation and from the Riverview Substation to the Big Oaks Substation, with the exception of a short, approximately one- to four-mile, segment of new right-of-way that is required to connect to the new Big Oaks Substation in Sherburne County, Minnesota. The Eastern Segment could traverse Douglas, Todd, Stearns, Wright, and Sherburne counties in Minnesota depending on the final route.

The Project also includes necessary modifications to the existing Big Stone South Substation in South Dakota, the existing Alexandria Substation, the existing Riverview Substation, the existing Quarry Substation, and the construction of the new Big Oaks Substation in Minnesota. The proposed Project is shown in **Map 1-1**.

[4] These existing double-circuit capable structures were permitted and constructed as part of the Monticello to St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-246) and the Fargo to St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-1056).

Map 1-1
Project Study Area



1.3 Need for the Project

The electric system is currently undergoing significant changes. The generation resource mix is changing as more new renewable and variable energy, such as wind and solar, is added to the system and aging coal-fired generation plants are retired. This Project, along with the other LRTP Tranche 1 Portfolio of transmission projects, are needed to provide reliable, resilient, and cost-effective delivery of energy as the generation resource mix continues to evolve over the coming years.

Specifically, this Project, along with the Jamestown – Ellendale 345 kV Project (LRTP1), is needed to address reliability issues on the existing 230 kV system in eastern North Dakota and South Dakota and western and central Minnesota. This existing 230 kV system is at its capacity leading to thermal and voltage issues. This Project will help to resolve these issues by adding another 345 kV circuit to the system in this area. As part of its analysis in MTEP21, MISO concluded that this Project relieves 40 transmission elements with excessive thermal loading when one transmission element is out of service (N-1 contingency) and 70 transmission elements with excessive loading when one or more transmission elements are out of service (N-1-1 contingency). In addition to addressing the current capacity issues, the Project also provides additional transmission capacity to accommodate additional renewable energy resources in the future.

In addition to addressing system reliability needs, the Project will also provide economic benefits to offset a portion of its costs. Xcel Energy, on behalf of the Applicants, conducted additional economic analysis of the Project and determined that the Project will provide up to $2.1 billion in economic savings across MISO over the first 20 years that the Project is in service and up to $3.8 billion in economic savings across MISO over the first 40 years. These economic savings will help offset the capital cost of the Project.

Additional information on the need for the Project is provided in **Chapter 4**. The Applicants and MISO considered several alternatives to the Project including: (1) new generation; and, (2) different transmission solutions, including upgrading other existing transmission facilities, transmission lines with different endpoints, and transmission lines with different voltage levels. A complete discussion of the alternatives to the Project that were evaluated by MISO and the Applicants is provided in **Chapter 5**.

1.4 Project Schedule and Costs

Construction of the Eastern Segment of the Project is anticipated to commence in 2025 and be completed by the end of 2027. Construction of the Western Segment is anticipated to commence in 2027 or 2028 and be completed in either 2030 or 2031 dependent on a number of variables.

The estimated total capital costs for the Project is between $606.5 million and $699.4 million (2022$). Additional details regarding the schedule and cost for the Project are provided in **Chapter 2**.

1.5 Project Ownership

The Eastern Segment will be jointly owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail, and Western Minnesota. As the Project Manager for the Eastern Segment, Xcel Energy will be responsible for the construction of this portion of the proposed 345 kV transmission circuit. On the Eastern Segment, Great River Energy is expected to be responsible for the maintenance of the 345 kV transmission circuit from the Alexandria Substation to the Quarry Substation, located west of St. Cloud, and Xcel Energy is expected to be responsible for the maintenance of the 345 kV transmission circuit from the Quarry Substation to the Big Oaks Substation.

The Western Segment will be jointly owned by Otter Tail and Western Minnesota. As the Project Manager for the Western Segment, Otter Tail will be responsible for the construction and maintenance of this portion of the proposed 345 kV transmission circuit.

The equipment and improvements required inside the Big Stone South Substation in South Dakota will be owned solely by Otter Tail. The equipment and improvements required inside the Alexandria Substation will be owned solely by Western Minnesota. The equipment and improvements required inside the Riverview Substation will be owned solely by Great River Energy. The equipment and improvements required inside the Quarry Substation will be owned solely by Xcel Energy. The new Big Oaks Substation will be owned solely by Xcel Energy. Each party will be responsible for the construction and maintenance of its own substation.

Xcel Energy is a Minnesota corporation headquartered in Minneapolis, Minnesota, that is engaged in the business of generating, transmitting, distributing, and selling electric power and energy and related services in the states of Minnesota, North Dakota, and South Dakota. In Minnesota, Xcel Energy provides electric service to 1.5 million customers. Xcel Energy is a wholly-owned utility operating company subsidiary of Xcel Energy Inc. and operates its transmission and generation system as a single integrated system with its sister company, Northern States Power Company, a Wisconsin corporation, known together as the NSP Companies. The NSP Companies are vertically integrated transmission-owning members of MISO. Together, the NSP Companies have over 46,000 conductor miles of transmission lines and approximately 550 transmission and distribution substations.

Great River Energy is a not-for-profit wholesale electric power cooperative which provides electricity to approximately 1.7 million people through its 27 member-owner cooperatives and customers. Through its member-owners, Great River Energy serves two-thirds of Minnesota geographically and parts of Wisconsin. Great River Energy's transmission network is interconnected with the regional transmission grid to promote reliability, and Great River Energy is a transmission-owning member of MISO. Great River Energy is based in Maple Grove, Minnesota.

Minnesota Power is an investor-owned public utility headquartered in Duluth, Minnesota. Minnesota Power supplies retail electric service to 150,000 retail customers and wholesale electric service to 14 municipalities in a 26,000-square-mile electric service territory located in northeastern Minnesota. Minnesota Power generates and delivers electric energy through a network of transmission and distribution lines and substations throughout northeastern Minnesota. Minnesota Power's transmission network is interconnected with the regional transmission grid to promote reliability and Minnesota Power is a member of MISO.

Otter Tail Power Company is an investor-owned electric utility headquartered in Fergus Falls, Minnesota, that provides electricity and energy services to over 133,000 customers spanning 70,000 square miles in western Minnesota, eastern North Dakota and northeastern South Dakota. Otter Tail wholly or jointly owns approximately 6,000 miles of transmission lines and approximately 1,100 MW of generation capacity in these three states and is a transmission-owning member of MISO.

Western Minnesota is a municipal corporation and political subdivision of the State of Minnesota, headquartered in Ortonville, Minnesota. Western Minnesota owns generation and transmission facilities, the capacity and output of which are sold to Missouri River Energy Services (MRES). MRES, which is based in Sioux Falls, South Dakota, provides electricity, including conservation program services, to its 61-member municipal utilities in Iowa, Minnesota, North Dakota and South Dakota, who in turn serve approximately 174,000 customers.

1.6 Potential Environmental Impacts

The Applicants analyzed the potential environmental impacts of the Project and identified measures that can be implemented to avoid, minimize, or mitigate these impacts. **Chapter 8** of this application provides a general description of the environmental setting, land use and human settlement, land-based economies, archeological and historical resources, hydrological features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur in the Project Study Area. **Chapter 8** also identifies potential impacts to existing resources and identifies measures that can be implemented to avoid, minimize, or mitigate impacts. As discussed in **Chapter 8**, the Applicants have not identified any potential environmental impacts that would preclude construction of the Project.

1.7 Public Input and Involvement

The public can review this Application and submit comments on the Project to the Commission. A copy of the Application is available at the Commission's website: On the Commission's website, click on the eDockets link in the menu at the top of the page, click on "Go to eDockets" and then enter "22" for the Year and "538" for the Number in the "Basic Search" section, and then click "Search."

A copy of the Application is also available on the Project websites: www.BigStoneSouthtoAlexandria.com (for the Western Segment) and www.AlexandriatoBigOaks.com (for the Eastern Segment). This Application will also be available at the following locations for the public to review:

- Monticello Great River Regional Library, 200 W. 6th St. Monticello, MN
- Clearwater Great River Regional Library, 740 Clearwater Center, Clearwater, MN
- Douglas County Library, 720 Fillmore St., Alexandria, MN

- Glenwood Public Library, 108 1st Ave. SE, Glenwood, MN
- Benson Public Library, 200 13th St. N., Benson, MN
- Ortonville City Public Library, 412 2nd St. NW, Ortonville, MN

Persons interested in receiving notices and other filings about the Certificate of Need Application can subscribe to the Project's Certificate of Need docket by visiting the Commission's website: https://mn.gov/puc/, click on the eDockets link in the menu at the top of the page, then follow the instructions under "How to Use eDockets" and Subscribe.

If you would like to have your name added to the Certificate of Need mailing list send an email to docketing.puc@state.mn.us or call (651) 201-2204 or (800) 657-3782. If you send an email or leave a phone message, please include: (1) how you would like to receive mail (regular mail or email); and, (2) the docket number (CN-22-538), your name, and your complete mailing address or email address.

If you have questions about the state regulatory process, you may contact the Minnesota state regulatory staff listed below:

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Website: www.mn.gov/puc/

Minnesota Department of Commerce EERA
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1.8 Project Meets Certificate of Need Criteria

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a Certificate of Need. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Minnesota Rule 7849.0120 further provides that the Commission shall grant a Certificate of Need if the Commission determines that:

(A) The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;

(B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;

(C) By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and,

(D) The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

The Applicants' proposal satisfies these four criteria as discussed below.

(A) The probable result of denial of the Project would have an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, applicant's customers, or to the people of Minnesota and the neighboring states.

Denial of a Certificate of Need for this Project would result in adverse effects upon the present and future efficiency of energy supply to the Minnesota electric customers and other end users. This Project is one of 18 new transmission projects that comprise the LRTP Tranche 1 Portfolio identified by MISO that will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. Specifically, this Project is designed to provide additional transmission capacity to the current 230 kV transmission system in eastern North Dakota and South Dakota, which plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity and to maintain electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

> *(B) A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence.*

A more reasonable and prudent alternative was not demonstrated in MISO's MTEP21 analysis or as part of the additional study work conducted by the Applicants. As part of MTEP21, MISO considered multiple alternatives to each of the eighteen individual projects as well as to the aggregate LRTP Tranche 1 Portfolio. These alternatives were tested for their ability to relieve the identified congestion and to meet reliability needs. MISO evaluated five alternative transmission line configurations of the Project in combination with the Jamestown – Ellendale 345 kV line in North Dakota[5] to address these same issues, concluding that none of these alternatives is a more reasonable or prudent alternative to the Project. In addition to identifying the Project as a critical component of the LRTP Tranche 1 Portfolio, MISO concluded it is also the most cost-effective option to maintain reliability.

In addition to the study work conducted by MISO, Applicants considered multiple alternatives to the Project including: (i) size alternatives (different voltages); (ii) type alternatives (upgrades to existing lines, double-circuiting, direct current (DC) lines, underground lines, and alternative conductors); (iii) generation alternatives and consideration of conservation and demand-side management alternatives; and (iii) no build alternative. After reviewing these alternatives, the Applicants concluded that none is a more reasonable and prudent alternative to the Project.

> *(C) The proposed transmission lines will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments.*

The proposed Project will reduce congestion and allow the transmission system to operate more efficiently and more cost-effectively, and pursuant to the Commission's

[5] The Jamestown – Ellendale 345 kV transmission line project was approved by MISO in MTEP21 as LRTP1.

routing criteria will be routed in a manner compatible with protecting the natural and socioeconomic environments.

> *(D) The proposed transmission lines will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments*

Applicants will secure all necessary permits and authorizations prior to commencing construction on the portions of the Project requiring such approvals.

1.9 Request for Joint Proceeding

The Applicants are applying for a Route Permit for the Eastern Segment of the Project under the alternative review process (Docket No. TL-23-159) concurrently with this Certificate of Need Application. Minn. Rule 7849.1900, subp. 1 permits the Department of Commerce to elect to prepare an environmental assessment (EA) in lieu of an environmental report required under Minn. Rule 7849.1200 in certain circumstances. Further, Minn. Stat. § 216B.243, subd. 4 and Minn. Rule 7849.1900, subp. 4 permit the Commission to hold joint proceedings for the Certificate of Need and Route Permit in circumstances where a joint hearing is feasible, more efficient, and may further the public interest.

Applicants respectfully request that the Commission find that this Certificate of Need Application is complete, that the Department of Commerce prepare an Environmental Assessment rather than an Environmental Report and commence a joint regulatory review process for the Certificate of Need Application and the Route Permit Application for the Eastern Segment. A joint proceeding will further the public interest by allowing issues associated with the Certificate of Need and the Route Permit for the Eastern Segment to be fully examined in a single proceeding.

Otter Tail and Western Minnesota anticipate filing the Route Permit application for the portion of the Western Segment located in Minnesota in the fourth quarter of 2024 (Docket No. TL-23-160). As the Route Permit application for the Western Segment will not be filed until next year, the Applicants request that the Route Permit application for the Western Segment be processed separately from the Certificate of Need for the entire Project and the Route Permit for the Eastern Segment.

1.10 Applicants' Request and Contact Information

For the reasons discussed above and in the remainder of this Application and Appendices, the Applicants respectfully request that the Commission find this Application complete and, upon completion of its review, grant a Certificate of Need for the portions of the Project located in Minnesota. The Commission has established criteria in Minn. R. 7849.0120 to apply in determining whether a Certificate of Need should be granted for a proposed high-voltage transmission line.

The Applicants have demonstrated in this Application that the proposed Project meets all the requirements to obtain a Certificate of Need. The Project will provide additional transmission capacity that is needed to mitigate current capacity issues and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system. The proposed Project will support the State's goals to conserve resources, minimize environmental and human settlement impacts and land use conflicts by considering the use of existing corridors to the extent feasible, and ensure the State's electric energy security through the construction of efficient, cost-effective transmission infrastructure. All correspondence relating to this Application should be directed to:

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2. PROJECT DESCRIPTION

2.1 Project Description

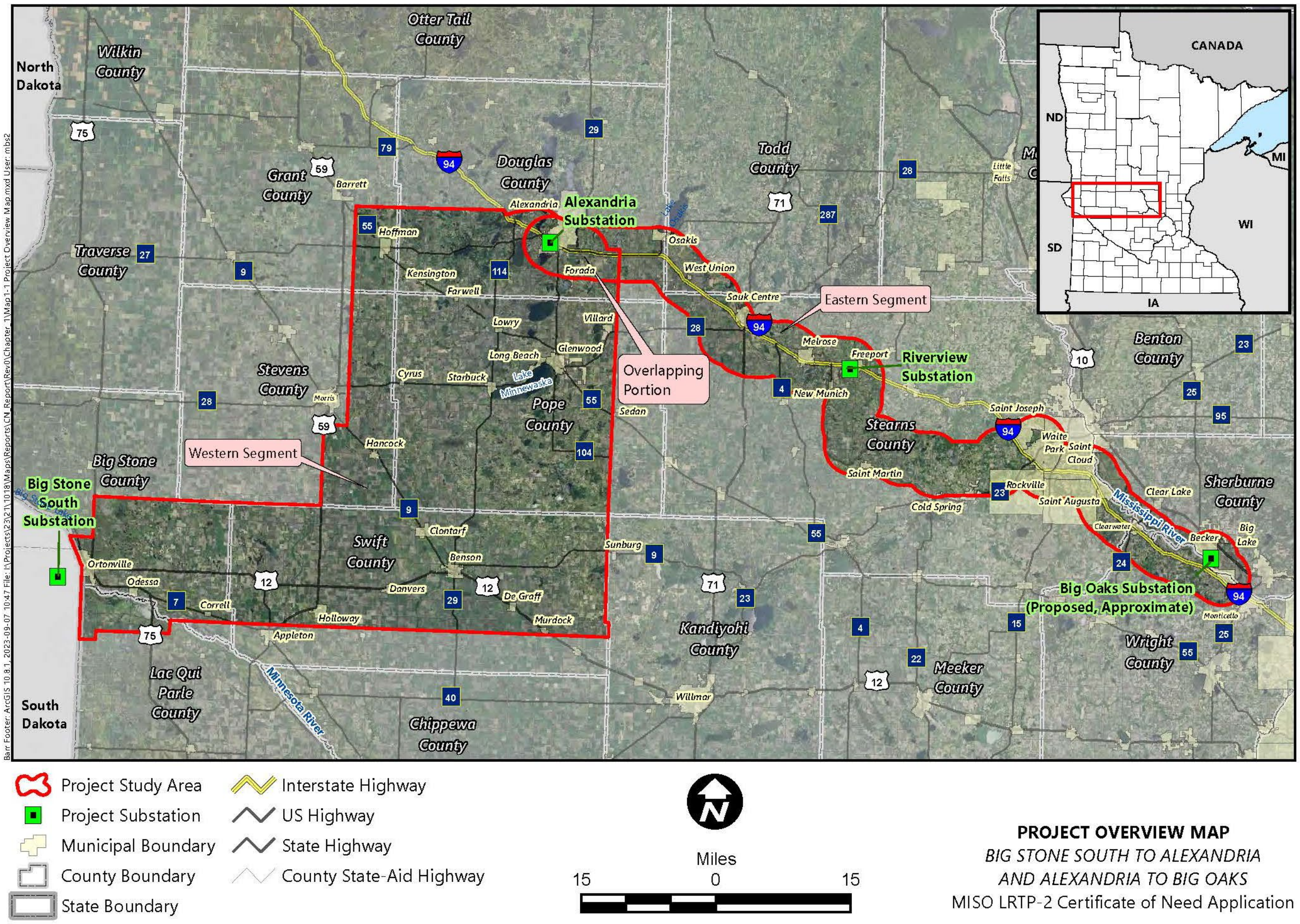
The Applicants propose to construct a new 345 kV transmission line between Grant County, South Dakota and Sherburne County, Minnesota, which will be comprised of two segments:

- the Western Segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota; and

- the Eastern Segment will continue from the existing Alexandria Substation to the Riverview Substation to a new Big Oaks Substation in Sherburne County, Minnesota.

An overview map of the Project is shown in **Map 2-1**. The two segments of the Project are also described separately below.

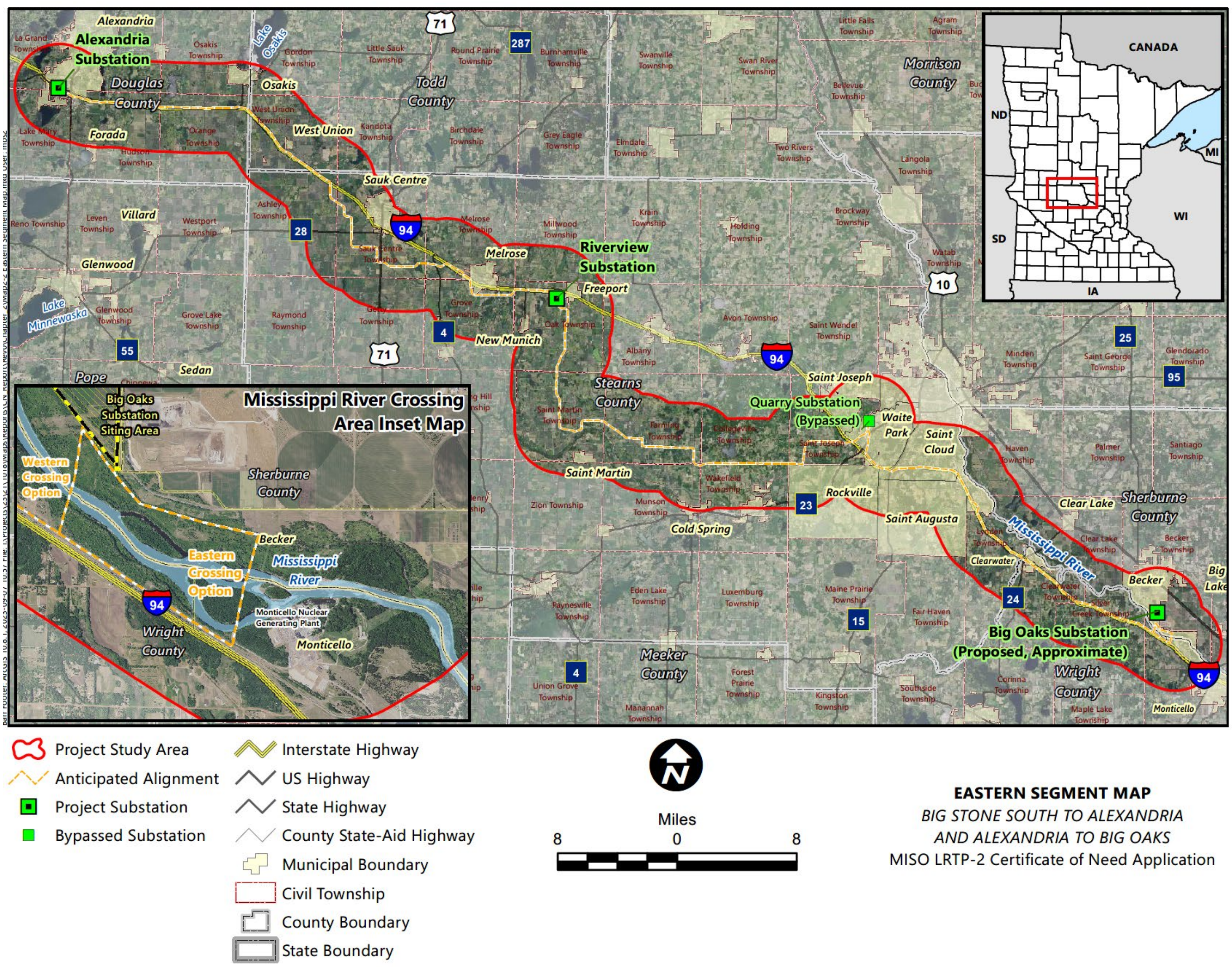
Map 2-1
Project Overview Map



The Western Segment will be jointly owned by Otter Tail and Western Minnesota and include construction of a new single-circuit 345 kV transmission line that will be placed on double-circuit capable structures along new right-of-way. Otter Tail will lead the Route Permit application for the portion of the Western Segment that will be located in Minnesota and will file an application on behalf of itself and Western Minnesota. Otter Tail and Western Minnesota will also file a Facility Permit application in South Dakota, along with any other applicable permits required within South Dakota, for the portion of the Western Segment that will be located in South Dakota.

The Eastern Segment of the Project will be jointly owned by Xcel Energy, Great River Energy, Minnesota Power, Otter Tail and Western Minnesota and involves the installation of a new 345 kV transmission circuit between the existing Alexandria Substation and the new Big Oaks Substation that will be strung on existing double-circuit capable structures, except for a short approximately one-to four-mile segment of new right-of-way that is required to connect the new 345 kV transmission line to the new Big Oaks Substation. The Eastern Segment will include a midpoint connection to the existing Riverview Substation. The Applicants filed a Route Permit application (Docket No. E002, E017, ET2, E015/TL-23-159) for the Eastern Segment of the Project on the same day as this Certificate of Need application. An overview map of the Eastern Segment is provided in **Map 2-2**.

Map 2-2
Eastern Segment Map



The Applicants also propose to make the necessary modifications to the Big Stone South Substation, located near Big Stone City, South Dakota, the Alexandria Substation, located near the city of Alexandria, the Riverview Substation, located near the city of Freeport, and the Quarry Substation, located near the city of Waite Park. The Applicants also propose to construct a new Big Oaks Substation in Sherburne County.

2.1.1 345 kV Transmission Line and Structures

The Western Segment of the 345 kV transmission line will be constructed on steel, single pole (monopole) double-circuit capable structures. Certain locations along the Western Segment may include multiple poles or other specialty structures, such as angles, along highways, or environmentally sensitive areas. These specialty and multiple pole structures (including H-frame or three-pole structures) may be used at any point along the route to accommodate large angles where the transmission line route changes direction or any other potential constraints that may be encountered along the route.

The majority of the Eastern Segment of the Project involves adding a second 345 kV circuit to existing double-circuit capable transmission structures within the existing 150-foot right-of-way. **Figure 2-1** provides a photo of the existing double-circuit capable 345 kV structures on the Eastern Segment with one of the 345 kV circuits strung.

Figure 2-1
Existing 345 kV Structures on Eastern Segment

When these structures were originally installed, space was left for this future second circuit, allowing electrical capacity to be increased by the addition of a second circuit on the same structures. For the Eastern Segment of the Project, approximately 67 to 78 new structures are proposed depending on the route selected for the Mississippi River crossing. New structures are needed in select areas along the existing transmission line to accommodate angles (i.e., where the alignment turns), highway crossings, or where the anticipated alignment deviates from the existing infrastructure (e.g., substation bypasses, new substation taps, and the Mississippi River crossing). The angle structures were originally designed as 2-pole structures, typical for double-circuit 345/345 kV lines. When the first 345 kV circuit was installed, there was no need for the second monopole. Also, without wires attached for the second 345 kV circuit, the second monopole would have been more susceptible to damage from vibration. As part of the Eastern Segment of this Project, the second monopole will be installed. Where a second monopole structure is required next to an existing structure, it will be placed within the existing right-of-way, 40 to 60 feet from the existing structure. **Figure 2-2** shows two monopole structures constructed side-by-side.

Figure 2-2
Typical Monopole 345 kV Structures Side-by-Side

New structures on both the Western Segment and Eastern Segment will primarily be monopole structures; however, H-frame structures may be used at the Mississippi River crossing or other locations where longer spans are needed. Any new 345 kV line constructed along either the Western Segment or the Eastern Segment is anticipated to have a right-of-way of 150 feet wide. The existing and proposed structures typically range in height from approximately 75 feet to 160 feet tall. The typical span between structures will be about 1,000 feet. A monopole structure is typically installed on a concrete foundation while an H-frame structure can either be installed on two concrete foundations or directly embedded in the ground.

Figure 2-3 provides photos of typical 345 kV structures that the Applicants propose to use for the segments of the Project that require new structures. Technical diagrams of these proposed structure types are provided in **Appendix G**.

Figure 2-3
Typical 345 kV Structures

345 kV Steel Single-Circuit Monopole Structure	345 kV Steel Single-Circuit H-Frame Structure	345 kV/345 kV Steel Double-Circuit Monopole Structure

Table 2-1 summarizes the characteristics of typical 345 kV transmission structures. The structure size may change based on site conditions.

Table 2-1
Typical Structure Design Summary

Line Type	Structure Type	Structure Material	Typical Right-of-way Width (feet)	Typical Structure Height (feet)	Foundation Diameter (feet)	Average Span Between Structures (feet)
345 kV Double-Circuit	Monopole w/ Davit Arms	Galvanized or Self-Weathering Steel	150	90-160	7-12	1,000
345 kV Single-Circuit	Monopole w/ Davit Arms	Galvanized or Self-Weathering Steel	150	90-150	7-12	1,000
345 kV Single-Circuit	H-Frame	Self-Weathering Steel	150	75-150	5-8	1,000

A single-circuit transmission line carries three phases (conductors) and shield wire(s). A double-circuit transmission line carries six phases (conductors) and two shield wires. The Applicants are currently evaluating several different conductor types for the new 345 kV transmission line. The different conductors that the Applicants are evaluating include: a double bundled 2x636 kcmil 26/7 Twisted Pair ACSR "Grosbeak" conductor, a double bundled 2x397.5 kcmil 26/7 ZTACSR "Ibis" conductor, a double bundled round (non-twisted pair) ACSR conductor, a double bundled Round (non-twisted pair) ACSS conductor, and a triple bundled 2x336 kcmil 26/7 ACSR "Linnet" & 2x477 kcmil 26/4 ACSR "Hawk" conductor.

The proposed transmission line will be designed to meet or surpass relevant local and state codes including National Electric Safety Code (NESC) and Applicants' standards. Applicable standards will be met for construction and installation, and applicable safety procedures will be followed during design, construction, and after installation.

2.1.2 Associated Facilities

The Project will include modifications to the existing Alexandria Substation in Minnesota, the existing Riverview Substation in Minnesota, the existing Quarry

Substation in Minnesota, and the Big Stone South Substation in South Dakota. The Project will also include construction of a new Big Oaks Substation in Minnesota. Below is a description of the substation work associated with the Project.

2.1.2.1 Alexandria Substation

The existing Alexandria Substation, owned by Western Minnesota, is the midpoint between the Western Segment and Eastern Segment of the Project. This substation is located on the southern edge of the city of Alexandria just south of Interstate 94. New substation equipment necessary to accommodate the proposed 345 kV transmission line will be installed at the Alexandria Substation. Equipment will include new termination structures, circuit breakers, relays, and associated control equipment. Expansion of approximately 2 to 4 acres from the current fenced area will be required to accommodate the new substation equipment and will require the purchase of additional land.

2.1.2.2 Riverview Substation

The existing Riverview Substation, owned by Great River Energy, will provide a mid-point termination on the Eastern Segment of the Project between the Alexandria and Big Oaks substations. This substation is located in Stearns County, Minnesota. The existing 345 kV circuit from the Alexandria Substation to the Quarry Substation will be reconfigured to bypass the Riverview Substation and the new 345 kV circuit from the Alexandria Substation to the Big Oaks Substation will connect to the Riverview Substation. New substation equipment necessary to provide reactive power support will be installed at the Riverview Substation. The current fenced area of the Riverview Substation will be expanded by approximately 0.5 acres on Great River Energy owned property to accommodate this new substation equipment.

2.1.2.3 Quarry Substation

The existing Quarry Substation, owned by Xcel Energy, is located near the city of Waite Park in Stearns County, Minnesota. At this time, it is anticipated that new substation equipment will be necessary at the Quarry Substation to provide reactive power support. The current fenced area of the Quarry Substation will be expanded on Xcel Energy owned property to accommodate this new substation equipment.

2.1.2.4 Big Stone South Substation

The existing Big Stone South Substation, owned by Otter Tail, is located in Grant County, South Dakota and is the western endpoint for the Western Segment of the Project. The substation is located approximately 1 mile west of Big Stone City, South Dakota. The existing ring bus configuration will be modified to a breaker and half configuration by adding one additional row to the 345 kV portion of the substation. This new row will allow for new breaker positions added for the 345 kV line to the Alexandria Substation and additional reactive power equipment. The current fenced area of the Big Stone South Substation will be expanded on Otter Tail owned property to accommodate this new substation equipment. Otter Tail and Western Minnesota will seek all appropriate permits in South Dakota for the Big Stone South Substation and the portion of the Western Segment that will be located in South Dakota.

2.1.2.5 Big Oaks Substation and Interconnecting Transmission Lines

A new Big Oaks Substation, which will be owned by Xcel Energy, is the eastern endpoint for the Eastern Segment of the Project and will be constructed southwest of the city of Becker. The exact location of the substation has not yet been determined, but a 250-acre portion of land owned primarily by Xcel Energy has been identified as the location for the substation. The Big Oaks Substation will be a 345 kV switching station that will include 18, 345 kV circuit breakers configured to accommodate connection of up to 12, 345 kV transmission lines. The Big Oaks Substation will be located on a graded and fenced area of approximately 10 acres. The following transmission lines are proposed to connect to the Big Oaks Substation:

- Four existing 345 kV transmission lines originating at the Sherburne County Substation;

- The Eastern Segment of the Project, the 345 kV transmission line from Alexandria Substation to the Riverview Substation to the Big Oaks Substation; and

- Two 345 kV transmission lines proposed as part of LRTP3 (Benton County – Big Oaks Line #1, Benton County – Big Oaks Line #2).

2.2 Proposed Route

2.2.1 Western Segment

Otter Tail and Western Minnesota are currently assessing route alternatives for the Western Segment between the Big Stone South Substation in South Dakota and the Alexandria Substation in Minnesota (approximately 100 miles long). This assessment involves evaluating route alternatives, identifying opportunities and constraints, conducting stakeholder outreach including engaging applicable governmental, tribal, and regulatory agencies, developing engineering, design, and construction information and preparing the Route Permit application for the Western Segment. Otter Tail and Western Minnesota currently anticipate that a Route Permit application for the Western Segment will be filed in the fourth quarter of 2024.

2.2.2 Eastern Segment

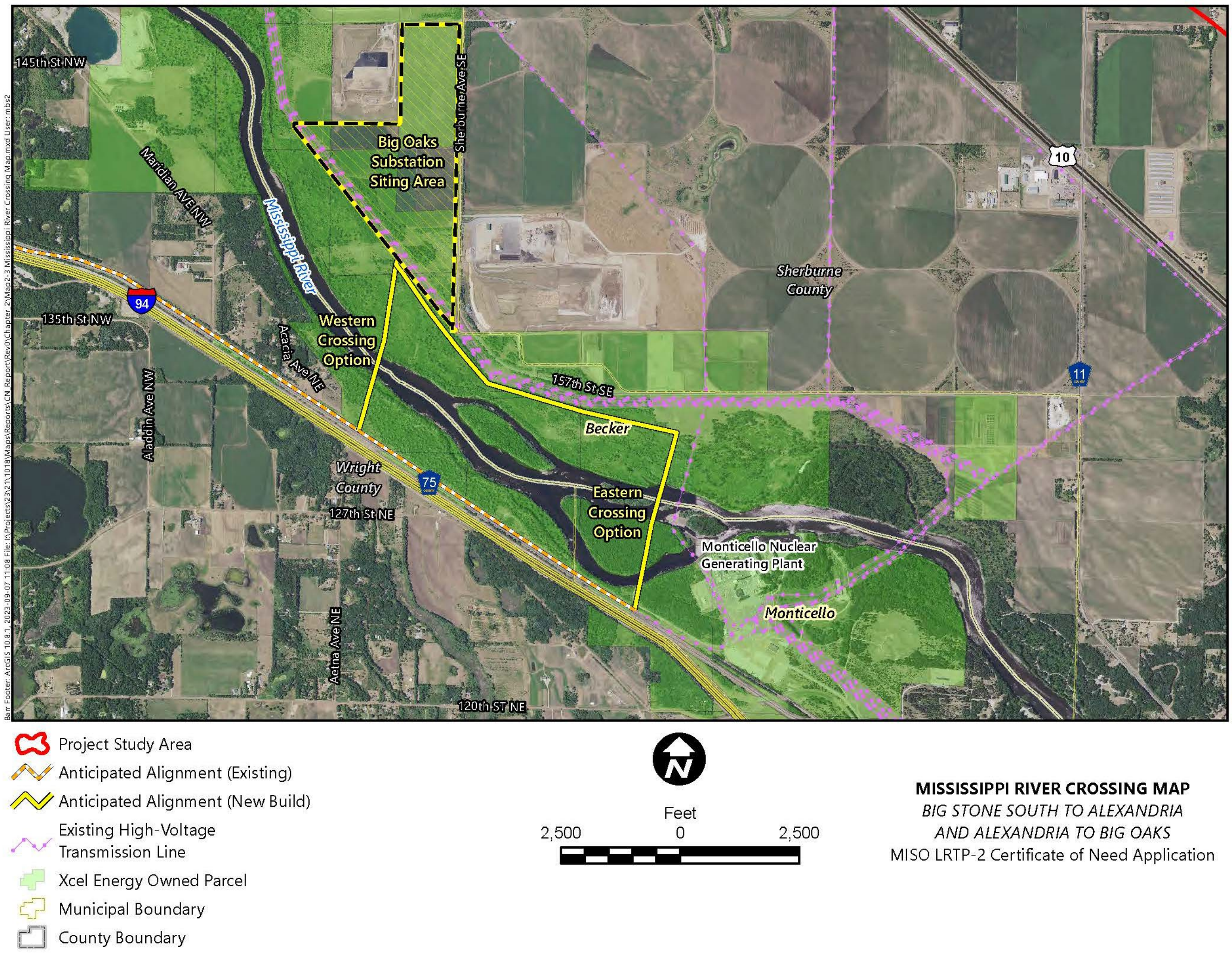
The majority of the Eastern Segment between the Alexandria Substation, Riverview Substation, and the new Big Oaks Substation (approximately 105 to 108 miles long) involves adding a second 345 kV circuit to existing transmission line structures that were constructed as double-circuit capable as part of the CapX2020 Monticello – St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-246) and the CapX2020 Fargo – St. Cloud 345 kV Transmission Project (Docket No. E002, ET2/TL-09-1056). As part of the Eastern Segment, approximately 67 to 78 additional foundations and steel structures will be installed at certain locations to accommodate the new 345 kV transmission line circuit. These locations are where the original line was designed for two-structure angles but only one structure was installed during construction of either the Monticello – St. Cloud or Fargo – St. Cloud transmission projects. These new structures will be installed within the existing transmission line right-of-way.

At four locations, the proposed route for the Eastern Segment deviates from the existing transmission line right-of-way. New right-of-way will be required for the new 345 kV transmission line to tap into the Alexandria Substation, a reconfiguration of the existing 345 kV circuit from the Alexandria Substation to the Quarry Substation to bypass the Riverview Substation near the city of Freeport, and the new 345 kV circuit from the Riverview Substation to the Big Oaks Substation to bypass the Quarry Substation near the city of Waite Park. The cumulative length of these three areas of new right-of-way is less than one mile total. Additionally, new right-of-way will be required for a new crossing over the Mississippi River to connect the new 345 kV transmission line near Monticello to the new Big Oaks Substation located northwest of the Monticello Nuclear Generating Plant in Becker. Two options are currently being considered by the Applicants for this river crossing:

- <u>Western Crossing Option:</u> The Western Crossing Option would construct a new crossing of the Mississippi River directly south of the proposed Big Oaks Substation and would be approximately 0.7 miles long (**Map 2-3**). This alignment would include new right-of-way located entirely on Xcel Energy-owned land.

- <u>Eastern Crossing Option:</u> The Eastern Crossing Option would construct a new crossing of the Mississippi River just west of the Monticello Nuclear Generating Plant. This option would be approximately 3.4 miles and would parallel an existing 115 kV transmission line (**Map 2-3**). This option would include 2.1 miles of new transmission line right-of-way and be located entirely on Xcel Energy-owned land; it would require two separate structures be placed on an island in the Mississippi River.

Map 2-3
Mississippi River Crossing Options



2.3 Project Costs

2.3.1 Estimated Construction Costs

There are several main components of the cost of constructing a new transmission project. These main components are the costs of: (1) transmission line structures and materials; (2) transmission line construction and restoration; (3) transmission line permitting and design; (4) transmission line right-of-way acquisition; and (5) substation materials, substation land acquisition, permitting, design, and construction. Each of these components also may include a risk reserve and financing expenses, such as

Allowance for Funds Used During Construction (AFUDC) or Construction Work in Progress (CWIP).

Table 2-2 below provides total Project costs. These costs include all transmission line costs (including materials, associated construction, permitting and design costs, and risk reserves), substation modification costs (including materials, construction, permitting and design costs, and risk reserve), AFUDC, and right-of-way costs.

To prepare a cost estimate for the transmission line portions of the Project, the Applicants relied in part upon the actual costs incurred for constructing prior similar transmission projects. The Applicants then updated this data based on current market conditions and included a risk reserve. The cost estimates are based on potential transmission line alignments. The introduction of additional corner structures or special structures for river or wetland crossings will increase the Project costs. Right-of-way cost estimates for the transmission line and substations were based on acquiring a 150-foot right-of-way for the transmission line and purchasing 40 acres of land for the Big Oaks Substation. The Applicants considered actual costs from prior project acquisitions and approximated the length of the line to estimate the overall land acquisition costs.

To estimate substation construction costs, the Applicants identified the necessary components for each substation. The Applicants then estimated land, material, construction, design, and permitting costs based on cost estimates for these items from prior substation improvement projects.

To calculate an appropriate risk reserve, the Applicants identified potential risks that could result in additional costs. These risks could include, for example: unexpected weather conditions, environmental sensitivities resulting in the need for mitigation measures, poor soil conditions in areas where no soil data was obtained, transmission line outage constraints, potential shallow rock, river crossings, labor shortages, and market fluctuations in material pricing and availability, and labor costs. The Applicants then developed an appropriate reserve amount for each of these risks and applied them to each of the cost categories.

Table 2-2 below provides both a low and high range of total Project costs.

Table 2-2
Construction Cost Estimates

Project Components	Low Capital Expenditures (2022$) ($Millions)	High Capital Expenditures (2022$) ($Millions)
Big Stone South – Alexandria 345 kV Transmission Line	$385.0	$441.2
Big Oaks – Alexandria 345 kV Transmission Line	$123.1	$130.9
Big Stone South Substation Modifications	$12.0	$20.0
Alexandria Substation Modifications	$20.0	$28.0
Riverview Substation Modifications	$3.0	$3.0
Quarry Substation Modifications	$3.0	$4.0
New Big Oaks Substation	$60.4	$72.3
Total Project Costs*	**$606.5**	**$699.4**

**There may be differences between the sum of the individual component amounts and Total Project Costs due to rounding*

The Applicants note that Table 2-2 includes cost estimates in 2022 dollars (2022$) to be consistent with MISO's cost estimates approved as part of MTEP21. These cost estimates will increase over time for any number of reasons such as, but not limited to escalation, inflation and commodity pricing, especially for these types of large-scale 345 kV transmission projects that have multi-year schedules. Therefore, the Applicants are also developing escalated cost estimates for each component of the Project in nominal dollars that will be provided during the course of this proceeding once they are available.

2.3.2 MISO's Estimated Project Costs

As part of developing the LRTP Tranche 1 Portfolio, MISO developed cost estimates for each of the 18 transmission projects. MISO's cost estimate for this Project was $574 million (2022$). The Applicants' cost estimate for the Project is higher than MISO's cost estimate for several reasons. The MISO cost estimate did not include the costs associated with the 67 to 78 new foundations and structures that will be required to string the second 345 kV transmission line circuit between the Alexandria Substation and the Big Oaks Substation. The MISO cost estimate also did not include the costs associated with adding reactive equipment and expanding the existing Riverview and

Quarry substations. The MISO cost estimate also did not include costs for adding remote end relays at the Big Oaks Substation. In addition, commodity prices in general (material and labor) have also increased since the MISO cost estimate was developed. Furthermore, the Applicants' cost estimates for both the labor and material for the Project's conductor is higher than the MISO estimate. The Applicants obtained multiple bids for the conductor to verify the accuracy of this cost estimate.

2.3.3 Effect on Rates

Minn. R. 7849.0270, subp. 2(E) requires an applicant for a Certificate of Need to provide the annual revenue requirement to recover the costs of the proposed Project. The Applicants requested an exemption from this rule requirement and instead committed to providing an explanation of how the costs for LRTP Tranche 1 Portfolio of projects will be shared across the MISO footprint. MISO's allocation of costs for the LRTP Tranche 1 Portfolio is discussed below. Minn. R. 7849.0260, subp. C(5), requires Applicants to provide an estimate of the Project's effect on rates system wide and in Minnesota. To fulfill this requirement, the Applicants are also providing the annual revenue requirement impact for the capital costs of the Project for a 20-year period for Xcel Energy customers starting with the MISO approved in-service date of June 1, 2030. While the rate impact for customers of other utilities would be different, this analysis provides an estimate of effect of the Project on rates. This analysis is provided in **Appendix H** and discussed further in Section 2.3.3.2 below.

2.3.3.1 Cost Allocation under MISO Tariff

The Project is part of the MISO LRTP Tranche 1 Portfolio, which has been determined by MISO to meet the criteria for being designated a Multi-Value Project (MVP) under the MISO tariff. As a result, the Project, along with the rest of the LRTP Tranche 1 Portfolio, qualifies for regional cost allocation. MISO has determined that the LRTP Tranche 1 Portfolio will be allocated to transmission customers in the MISO Midwest subregion,[6] where these projects are located and provide benefits. The allocation of the Project's costs to transmission customers is governed by Schedule 26-A, Multi-Value

[6] The MISO Midwest Subregion includes MISO transmission customers in Minnesota, Montana, North Dakota, South Dakota, Iowa, Wisconsin, Missouri, Illinois, Indiana, Michigan, and Kentucky. MISO South Subregion transmission customers are excluded in the allocation and recovery of Project costs.

Project Usage Rate, in MISO's tariff. The annual revenue requirement for the Project is determined by the formula rate in Attachment MM-MVP Charge in the MISO tariff. Withdrawing Transmission Owners in the MISO Midwest subregion pay the annual revenue requirement through Schedule 26-A charges assessed based on actual monthly energy consumption by customers. Minnesota customers' allocated share of the annual revenue requirement is determined by the percent of total MISO energy used by Minnesota utilities, which is estimated at approximately 15 to 20 percent based on MISO's posted 2021 energy withdrawal data. MISO provided an estimate of these MVP usage charges by pricing zone in Appendix A-4 of MTEP21.[7]

2.3.3.2 Xcel Energy Customer Rate Impact

Appendix H provides revenue requirement calculations for the NSP system (both Northern States Power Company, a Minnesota corporation (NSPM), and Northern States Power Company, a Wisconsin corporation (NSPW)), and are then adjusted to a Minnesota jurisdictional basis for NSPM. These revenue requirement calculations do not account for any future operation and maintenance costs for the Project or fuel impacts. These revenue requirement calculations also assume that the Project is jointly-owned with the other Applicants as discussed in Section 1.6. Applicants note the rate impacts for customers of other Minnesota utilities will be different than those provided for Xcel Energy customers in **Appendix H**.

2.4 Project Schedule

Table 2-3 and **Table 2-4** provide the permitting and construction schedule currently anticipated for the Eastern Segment and Western Segment of the Project. This schedule is based on information known as of the date of filing and may be subject to change as further information develops or if there are delays in obtaining the necessary federal, state, or local approvals that are required prior to construction.

[7] MISO LRTP Tranche 1 MTEP21 Appendix A-4 Schedule 26A *available at* https://cdn.misoenergy.org/LRTP Tranche 1 Appendix A-4 Schedule 26A Indcative625788.xlsx.

Table 2-3
Eastern Segment – Anticipated Project Schedule

Activity	Estimated Dates
Minnesota Certificate of Need and Route Permit for Eastern Segment Issued	Second/Third Quarter 2024
Land Acquisition Begins	Third Quarter 2024
Survey and Transmission Line Design Begins	Second Quarter 2024
Other Federal, State, and Local Permits Issued	First Quarter 2025
Start Right-of-Way Clearing	Second Quarter 2025
Start Project Construction	Second Quarter 2025
Project In-Service	Fourth Quarter 2027

Table 2-4
Western Segment – Anticipated Project Schedule

Activity	Estimated Dates
Minnesota Certificate of Need Issued	Second/Third Quarter 2024
Minnesota Route Permit for Western Segment Filed	Fourth Quarter 2024
Minnesota Route Permit for Western Segment Issued	Fourth Quarter 2026
Land Acquisition Begins	First Quarter 2026/First Quarter 2027
Survey and Transmission Line Design Begins	First Quarter 2027/First Quarter 2028
Other Federal, State, and Local Permits Issued	Second Quarter 2027/Second Quarter 2028
Start Right-of-Way Clearing	Third Quarter 2027/Third Quarter 2028
Start Project Construction	Third Quarter 2027/Third Quarter 2028
Project In-Service	Fourth Quarter 2030/Fourth Quarter 2031

Otter Tail and Western Minnesota are providing a range of estimated dates for the Western Segment because of the multiple variables involved in siting a new greenfield transmission line. Otter Tail, as project manager for the Western Segment, will use best efforts to manage the schedule to deliver a safe and reliable project by the end of 2030. However, challenges associated with land acquisition, material lead times, contractor availability and weather conditions are just some of the variables that could cause the in-service date of the Western Segment to be delayed into 2031. Additional clarity on the schedule for the Western Segment will be known once certain milestones are reached through the project development process and will be shared with interested stakeholders through various communication channels, including the project website.[8]

[8] The website for the Western Segment is: www.BigStoneSouthtoAlexandria.com.

3. ELECTRICAL SYSTEM AND CHANGING GENERATION PORTFOLIO OVERVIEW

3.1 Electrical System Overview

When a customer turns on a light switch, a circuit is completed that connects the light with the wires that serve the customer's building. The building wires are connected to a transformer that connects to a distribution line outside of the building. The distribution lines, in turn, are then connected to substations and then finally through larger transformers that connect to transmission lines that comprise the bulk power system. The bulk power system is comprised of large power transformers and high voltage transmission lines and can carry large amounts of electric power and energy (generally referred to below as electricity) from electric generating facilities to meet the demand for electricity at any given moment.

Electricity is produced at both large and small generating facilities. Electricity can be generated using a variety of sources or fuels, including solar, wind, and hydro; internal and external combustion of biomass, biofuels, natural gas, and coal; and heat and steam created through nuclear fission. Electric energy is generated at a specific voltage and frequency. For it to be useful, electricity must be transmitted from the generation source to substations with transformers and then to consumers at acceptable voltages. Unlike other consumables, where excess product can be easily and economically stored for future use, electricity must largely be generated simultaneously with its consumption. This means that generators connected to the bulk power system must instantaneously adjust their electric output to respond to changes in customer demand. However, energy storage technologies, including battery energy storage systems (BESS), are advancing which could help reduce the need for generators to adjust instantaneously with customer demand.

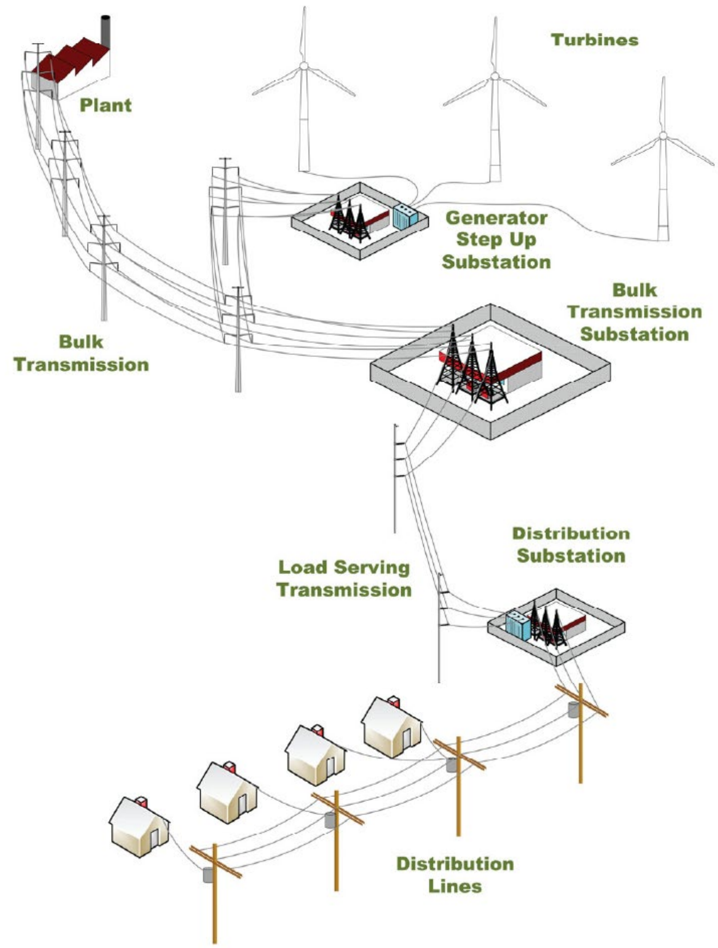
Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant. The electricity is then transported over high voltage transmission lines, often at voltages in excess of one hundred thousand volts (e.g., 115 kV, 230 kV, and 345 kV).[9] Voltage is stepped-up on

[9] One kV equals 1,000 Volts.

high voltage transmission lines because it is more efficient to move electricity over longer distances at higher voltages because the system experiences less electrical losses. Once the electricity reaches a location where it will be consumed, the transmission voltage (e.g., 115 kV and higher) is reduced (stepped-down) by substation transformers to a lower voltage, called a load serving transmission system, that is more appropriate to connect to a distribution substation. The electricity is further transformed at distribution substations where it is distributed at "primary" distribution voltages (e.g., 13.8 kV, 12.5 kV) within communities which delivers power for individual customer use to the end location where it is stepped-down further to, most commonly, 240 Volts or 120 Volts.

A diagram showing the transfer of electricity from a generator to a consumer is shown below in **Figure 3-1**. Note that this figure is an artistic portrayal of the electric system and is not an actual representation of all electric system components.

Figure 3-1
Electrical System



3.2 Transmission System Overview

The transmission system is made up of high-voltage transmission lines that can efficiently carry electricity long distances. The transmission system delivers power to distribution substations that serve distribution systems that meet customer needs in specific locations. The transmission system is designed to be an integrated system that is able to withstand the outage of a single transmission line without a major disruption to the overall power supply to consumers.

3.2.1 High-Voltage Transmission Lines

Transmission lines throughout this region are primarily made up of conductors which comprise a three-phase circuit and are usually accompanied by a shield wire that provides protection from lightning strikes. These conductors are several strands of wire grouped together, usually made from copper or aluminum and steel, and most commonly held up by poles or towers that are made from wood or steel.

High-voltage transmission lines carry electricity from the generation source to distribution systems where the power is needed. The rate at which electricity moves through a conductor is called current and is measured in Amperes (Amps). The force that moves the electricity through the conductor is called voltage (V). Voltage is measured in terms of Volts (or kV for 1,000 Volts). Conductors carrying the current have resistance that can hinder its ability to allow current to flow freely. This resistance is measured in a unit called Ohms. The wire conductors used by utilities on the high voltage transmission system conduct electricity with relatively little resistance.

3.2.2 Substations

Substations are a part of the system that contain high-voltage electric equipment to monitor, regulate, and distribute electricity. Generally, substations allow transmission lines to connect with one another, or allow electricity to be transformed from a higher transmission voltage to a lower transmission voltage or from a lower transmission voltage to a distribution voltage.

Substation property dimensions depend on the ultimate planned design that is planned for the specific substation and physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines. Substation sites need to be large enough to accommodate both the planned ultimate fenced area and the required surrounding areas. The required surrounding areas include applicable setbacks, stormwater ponds, wetlands, grading, access roads, and new transmission line rights-of-way. Depending on the timing of future load growth and electrical system needs, the configuration of a substation may change over time resulting in multiple construction stages over an extended period of years.

3.3 The Changing Energy Landscape

Over the course of the past 20 years, the generation mix in Minnesota and surrounding states has dramatically shifted from relying primarily on coal and nuclear generation resources to a more diverse generation mix that includes increasing amounts of renewable energy, including wind and solar generation. These changes in the generation portfolio in Minnesota and the surrounding states require additions and changes to the high-voltage transmission system in the region to ensure that generation can be efficiently and economically delivered to load centers.

The following sections discuss the federal and state policies on renewable energy, the growth in wind and solar energy in Minnesota and the Upper Midwest, and the likely continued expansion of wind and solar energy in this same region.

3.3.1 Federal Renewable Energy and Transmission Policies

Current federal energy policy promotes the expansion of renewable energy and the high-voltage transmission that will be necessary to interconnect that energy to the bulk power system. For example, the Inflation Reduction Act puts the United States on a path to approximately 40% emissions reduction by 2040 by supporting, among other things, continued development of domestic renewable energy. More specifically, the Inflation Reduction Act of 2022 extends the production tax credit (PTC) and investment tax credit (ITC) for renewable energy facilities through 2024, after which time the technology-neutral Clean Energy PTC and ITC begin in 2025.

Similarly, federal policy recognizes that additional high-voltage transmission infrastructure will be critical to expanding renewable energy and maintaining a resilient and reliable bulk power system. The Infrastructure Investment and Jobs Act of 2021 reflects a significant investment in transmission to facilitate the expansion of renewable energy, including the Department of Energy's (DOE) "Building a Better Grid" Initiative. The DOE explained, "… the number of generation and storage projects proposed for interconnection to the bulk-power system is growing, interconnection queue wait times are increasing and the percentage of projects reaching completion appears to be declining, particularly for wind and solar resources. Needed investments in transmission infrastructure include increasing the capacity of existing lines, using advanced technologies to minimize transmission losses and maximize the value of existing lines, and building new long-distance, high-voltage transmission lines."[10]

3.3.2 State of Minnesota Renewable Energy Policies

State energy policies have grown and evolved over the years. Minnesota's original Renewable Energy Objective, adopted in 2001, directed all electric utilities in the state to "make a good faith effort" to obtain one percent of their Minnesota retail energy sales from renewable energy resources by 2005, increasing to seven percent by 2010. In 2007, the Renewable Energy Objective was revised to require all utilities (except Xcel Energy) to generate 25% of their retail sales from renewable energy resources by 2025, with Xcel Energy required to generate 30% by 2020.[11]

Minnesota had previously set a goal to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 30 percent below 2005 levels by 2025 and to a level at least 80 percent below 2005 levels by 2050.[12] Similarly, Minnesota has recognized a "vital interest in providing for … the development and use of renewable energy resources wherever possible."[13] More recently, in February 2023, Minnesota Governor Tim Walz signed the "100 Percent by 2040" legislation into law, which, at a high level, directs electric utilities to transition to meeting the needs of Minnesota retail customers with 100% carbon-free electricity by the end of 2040.[14] Additional sources of emission-free electric energy – like wind and solar – will be necessary to meet these goals.

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[10] *See* Department of Energy Notice of Intent Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, at 4 (Jan. 11, 2022), available at https://www.energy.gov/sites/default/files/2022-01/Transmission%20NOI%20final%20for%20web_1.pdf

[11] Minn. Stat. § 216B.1691, subds. 2 and 2a.

[12] Minn. Stat. § 216H.02, subd. 1.

[13] Minn. Stat. § 216C.05, subd. 1.

[14] Minn. Stat. § 216B.1691, subd. 2g.

3.3.3 Overview of Growth of Renewable Generation in Minnesota

In 2005, about 65 percent of electricity generated in Minnesota came from coal and natural gas.[15] By 2022, renewable energy provided the largest share of electricity generation statewide.[16] Various factors that will continue to drive further expansion of renewable generation include the evolving federal and state renewable energy policies discussed above, the favorable wind conditions and solar suitability in Minnesota and neighboring states, and continued technological advancements resulting in improved economics of renewable generation.

The continuing growth of renewable energy generation in Minnesota is evident in utility resource planning processes. For example, the Commission approved Xcel Energy's most recent Integrated Resource Plan (IRP)[17] that is expected to reduce carbon dioxide emissions more than 85 percent from 2005 levels and deliver at least 80 percent of customers' electricity from carbon-free energy sources by 2030. Under the plan, which includes retirement of all of Xcel Energy's remaining Upper Midwest coal plants by the end of 2030 and extension of operations at Xcel Energy's Monticello Nuclear Generating Plant to 2040, Xcel Energy will add 2,150 MW of wind and 2,500 MW of solar by 2032, with another 1,100 MW of wind and solar capacity beyond 2032.

In its March 31, 2023, Great River Energy filed its IRP in Docket No. ET-2/RP-22-75, which is pending before the Commission. In its IRP, Great River Energy noted that by 2026, Great River Energy will add 866 MW of new wind generation to its existing 960 MW of wind generation and expects to serve the majority of its retail electric sales with renewable energy. By 2035, Great River Energy's retail electric sales will be 90 percent carbon-free and carbon emissions will be more than 90 percent reduced from 2005 base levels. Great River Energy's preferred expansion plan reflected in its IRP

[15] U.S. Energy Information Administration (EIA), *Electricity Data Browser,* available at https://www.eia.gov/electricity/data/browser/.

[16] EIA, *Minnesota State Profile and Energy Estimates,* available at https://www.eia.gov/state/?sid=MN.

[17] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a/ Xcel Energy*, Docket No. E002-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022).

builds on changes in its resource portfolio that have already significantly reduced carbon emissions and increased generation from carbon-free resources.

Minnesota Power was the first utility in Minnesota to reach 50 percent renewable energy in 2020. The Commission approved Minnesota Power's most recent IRP in January 2023 (Docket No. E015/RP-21-33) prior to the enactment of the "100 percent carbon free by 2040" legislation. Minnesota Power's approved IRP puts Minnesota Power on a path to reduce carbon emissions by 80 percent by 2035 and achieve more than 70 percent renewable energy in 2030. Minnesota Power's IRP also calls for the addition of up to 400 megawatts of wind energy, 300 megawatts of regional solar energy, and a significant investment in energy storage to support the expansion of renewables on Minnesota Power's system.

Otter Tail Power Company's goal is to reduce carbon dioxide emissions from owned generation resources 50 percent compared to 2005 levels by 2025 and 97 percent by 2050. In March 2023, Otter Tail filed its supplemental resource plan identifying the most cost-effective combination of resources for meeting customers' energy needs while reducing carbon dioxide emissions. In this plan, Otter Tail requested the addition of 200 MW of solar in the 2027-2028 timeframe and 200 MW of wind in 2029. With these resource additions, Otter Tail will be in position to comply with the "100 percent carbon free by 2040" legislation in Minnesota.

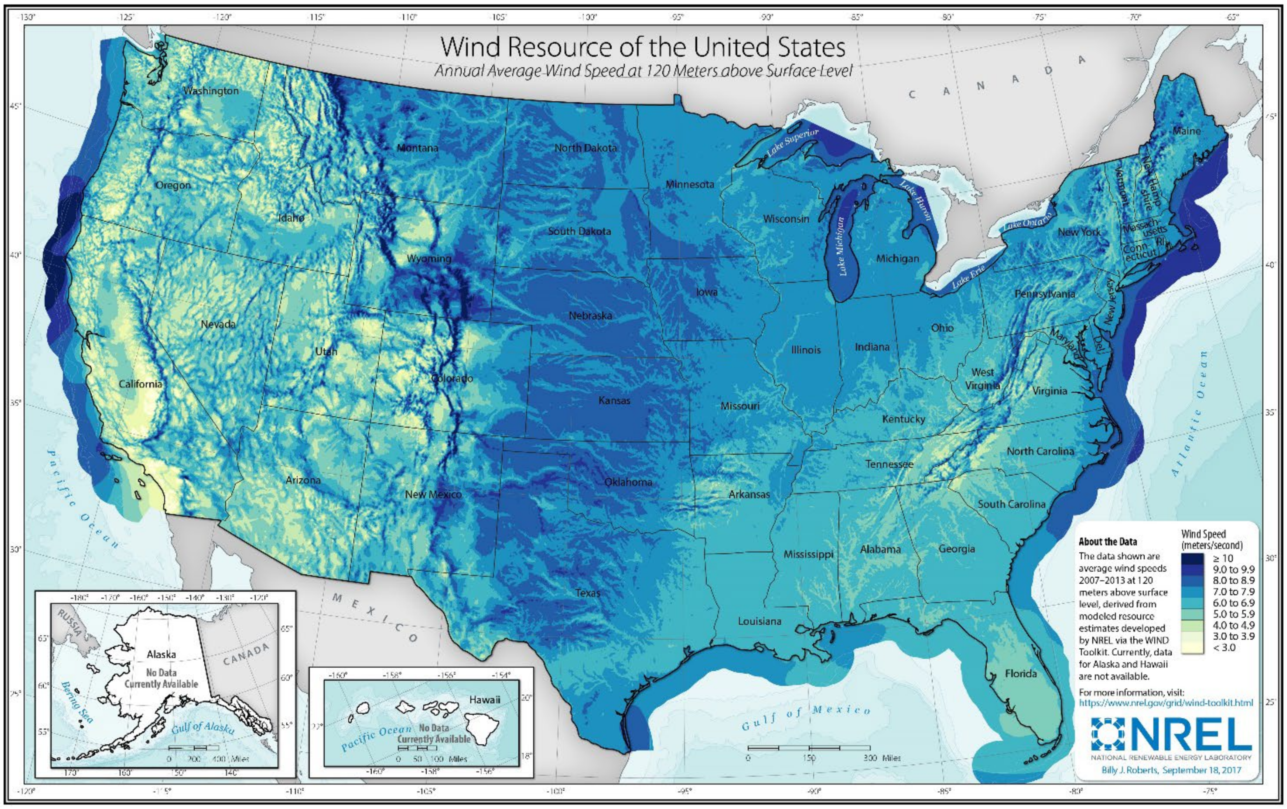
Western Minnesota Municipal Power Agency has been conscious to ensure that resource additions include low- or non-carbon dioxide emitting resources when possible. Since 2002, nearly all energy resource additions (both owned and those acquired under long-term contracts) have been from non-emitting resources or low-emitting natural gas, including over 85 MW of wind, over 33 MW of nuclear, 140 MW of natural gas generation, 55 MW of hydropower, and 1 MW of solar. Western Minnesota will continue to obtain renewable resources as needed to enhance the clean energy portion of its resource mix serving Minnesota consumers. These renewable resource additions will ensure that Western Minnesota and its members continue to meet new and expanding federal and state renewable energy policies.

While continuing expansion of renewable energy generation is planned, there is currently not enough transmission capacity on the high-voltage transmission system to accommodate all the renewable energy projects that wish to interconnect. Further, congestion on the high voltage transmission system has been increasing in the past several years due to the increased amount of new generation being added without a sufficient amount of additional transmission capacity. This Project will play a key role in providing additional transmission capacity, mitigating current capacity issues, and improving electric system reliability throughout the region as more renewable energy resources are added to the high voltage transmission system in and around the region.

3.3.3.1 Midwest's Favorable Conditions for Renewable Generation

The Midwest region has favorable conditions for renewable energy generation. Southwestern and southern parts of Minnesota as well as most of Iowa, North Dakota, and South Dakota have strong wind resources. As shown in **Map 3-1** below, these areas have higher than average wind speed as compared to the rest of the country and, as a result, wind turbines in these areas yield more energy than wind turbines in areas with lower average wind speeds.

Map 3-1
U.S. Annual Average Wind Speed at 120 Meters[18]



The majority of Minnesota's installed wind capacity is located in southwest Minnesota. In addition, there are wind facilities located throughout Iowa as well as in eastern South Dakota and in North Dakota.[19] The favorable wind conditions in these regions will continue to drive additional development of wind generation in this area.

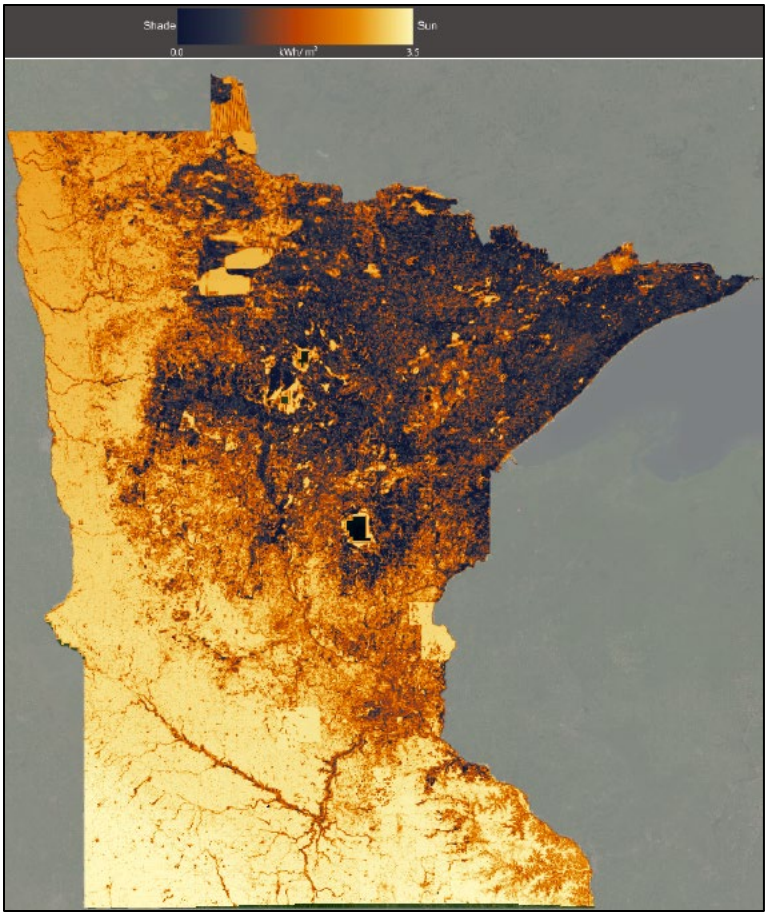
In addition, areas in the Midwest region are suitable for solar generation facilities. For example, in Minnesota the highest solar irradiance is located in the southwestern portion of the state where limited tree cover and expansive non-forested lands result in

[18] *See* NREL, *Wind Resource Maps and Data*, available at https://www.nrel.gov/gis/wind-resource-maps.html.

[19] *See* USGS, *The U.S. Wind Turbine Database*, available at https://eerscmap.usgs.gov/uswtdb/.

ample sun exposure at ground level.[20] A Minnesota map with solar suitability is shown in **Map 3-2**.

Map 3-2
Minnesota Solar Suitability Map



The southwestern portion of the state described above with the highest solar irradiance can be characterized as lightly populated rural areas with an abundance of agricultural and farmland.

The suitability for wind and solar generation combined with vast areas of land capable of accommodating new wind turbines or solar arrays makes this portion of the state ideal for future wind and solar generation. However, this generation needs to be transported from these resource rich areas in lightly populated rural areas to load centers

[20] *See* e.g., University of Minnesota, *Minnesota Solar Suitability Analysis*, available at https://solar.maps.umn.edu/index.php.

in more populated areas, which requires a more robust transmission system than what exists today.

The existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy to customers in Minnesota, but the existing 230 kV system is currently at its capacity. The Project is a key component of the LRTP Tranche 1 Portfolio by providing a new 345 kV transmission line, which is designed to provide additional transmission capacity to mitigate current capacity issues on the existing 230 kV transmission system and to improve electric system reliability as more renewable energy resources are added throughout the region.

3.3.3.2 MISO Interconnection Queue

While there is tremendous potential for future expansion of renewable generation in the region, it is currently challenging to interconnect new renewable resources onto the high voltage transmission system due in large part to significant constraints in the region. MISO's generator interconnection process is designed to allow generators non-discriminatory access to the electric transmission system and to ensure system reliability is maintained during certain operating conditions. MISO currently has one study cycle per year in which new generator requests are grouped into a common study group. MISO is currently running several interconnection studies for subsequent queue cycles in parallel in an attempt to address the backlog currently present in their generator interconnection process. Once a developer submits an application for a new generation project into MISO's Generator Interconnection Queue, their request enters MISO's queue on a first-ready, first-served basis. Once a developer gains preliminary information through either a feasibility study or the System Planning and Analysis (SPA) phase, the developer typically proceeds to the Definitive Planning Process (DPP) phase during which time MISO undertakes more detailed generation interconnection studies for their specific generation project(s).

In 2022, there were a record 956 interconnection requests during the application period, representing approximately 171 GW of new generation across the MISO footprint, with the vast majority of new generation requests comprised of wind and solar projects. By comparison, queue applications in the 2021 application period included 487 interconnection requests totaling 77 GW. **Table 3-1** below shows the nameplate capacity of the interconnection requests entering the DPP phase in the MISO footprint and the MISO West region, which primarily includes Minnesota, North Dakota and South Dakota.

Table 3-1
MISO DPP Cycle 22 Projects by Category

MISO DPP Cycle 22 (956 Projects)						
Fuel	Solar	Wind	Storage	Hybrid	Natural Gas	Other
GW	83.7	13.9	32.3	34.3	5	1.6
MISO DPP Cycle 22 West (136 Projects)						
Fuel	Solar	Wind	Storage	Hybrid	Natural Gas	Other
GW	6.8	8.2	6.5	2.2	1.7	0

The number of interconnection requests received for the 2022 DPP cycle exceeded the previous all-time high of interconnection requests in a single DPP cycle for the third year in a row. The volume of requests reflects an acceleration of the resource transition in the Midwest to include a larger percentage of renewables, a trend that was studied extensively in MISO's Renewable Integration Impact Assessment (RIIA).[21] Given the substantial volume of generation capacity currently in MISO's interconnection queue requesting study and interconnection approval, it is evident that the resource mix in the MISO region will include more renewables in the future.

The existing high voltage transmission system does not have sufficient capacity to interconnect new generation projects without substantial upgrades. Thus, the generation interconnection studies continue to indicate there will be costly upgrades assigned to new generators requesting to interconnect. For example, in the MISO West 2021 DPP cycle, the approximately 66 generation projects with a combined nameplate rating of 10534.4 MW were assigned approximately $1.6 billion in transmission upgrades (including Affected System Upgrades), if all of these generation projects were

[21] The full RIIA report is available at: https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/.

to interconnect to the transmission system.[22] This level of expense for transmission system upgrade requirements can sometimes render new generation projects uneconomic, forcing the developer to withdraw its new generation project from MISO's generator interconnection queue. This withdrawal then causes MISO to perform additional studies of the remaining projects in that same DPP cycle (and subsequent DPP cycles) to determine how the withdrawal of a generation project impacts the cost of transmission upgrades for the remaining generation projects in the same DPP cycle (and the subsequent DPP cycles).

3.3.3.3 Congestion Issues

Transmission congestion costs arise on the MISO network when a higher-cost generation resource is dispatched in place of a lower-cost one to avoid a reliability issue, such as overloading a transmission facility. Congestion costs are reflected in MISO's location-specific energy prices, which represent the marginal costs of serving load at each location on the transmission system. The energy price at each location is comprised of the marginal energy costs, network congestion costs, and losses.

Congestion on the transmission system has been increasing in the past several years due to the increased amount of new generation being added to the transmission system without an equivalent amount of new transmission capacity. One issue contributing to increased congestion costs is how MISO is dispatching existing and prior-queued generation projects when they add new generation projects to the models during their interconnection studies. In short, MISO is dispatching the new generation to 100% nameplate rating while existing and prior-queued generation located nearby is dispatched down to offset the new generation. This study assumption has resulted in significant amounts of new generation being added to the system without adding enough new transmission capacity to accommodate the full amount of new generation being added on the transmission system plus the existing and prior-queued generation on the transmission system. This study assumption leads to congestion on the

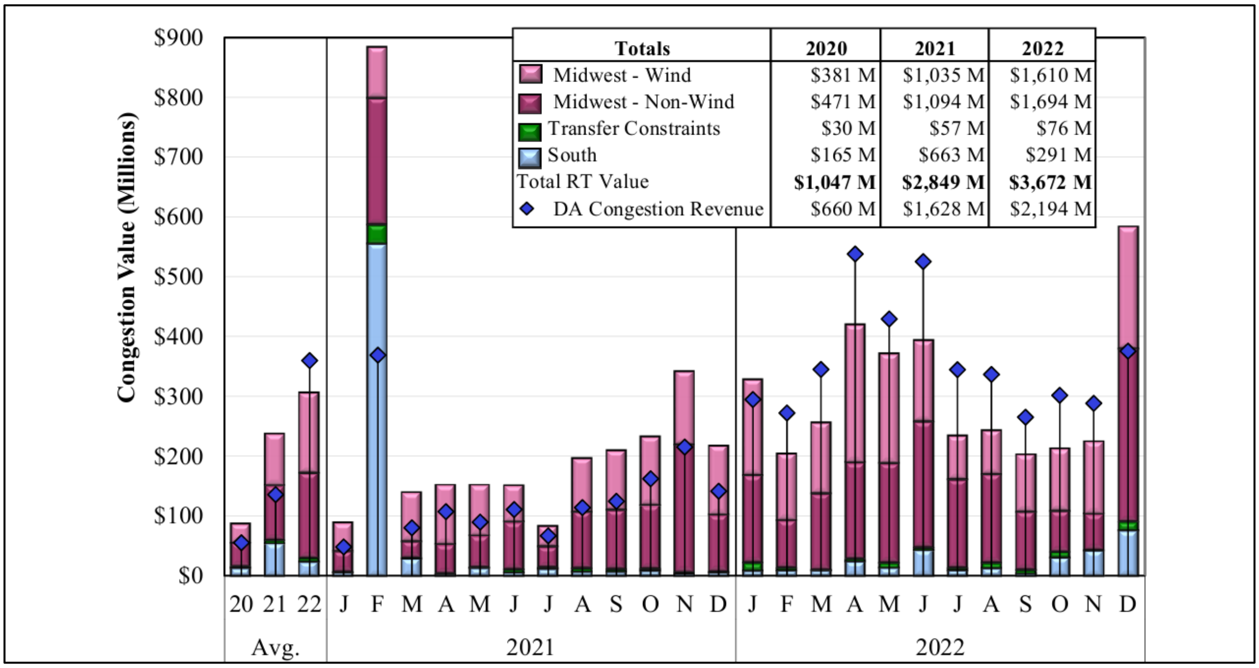
[22] A copy of the MISO DPP 2021 West Area Phase 1 Study (Aug. 30, 2023) is available at: https://cdn.misoenergy.org/GI-DPP-2021-West_Phase-1_SIS-Study-Results_FINAL_20230905%20-%20PUBLIC630260.pdf.

transmission system because there is not adequate transmission capacity to accommodate all of the generation on the transmission system.

Congestion leads to higher energy costs for Minnesota customers because more expensive generation must be dispatched when congestion occurs on the high-voltage transmission system. **Figure 3-2** below shows the monthly real-time congestion value over the past two years across the MISO footprint. Based on trends since 2020, the cost of real-time congestion continued to rise significantly in 2022 to total $3.7 billion across the MISO footprint. This increase in congestion was driven by increasing wind output without the addition of sufficient transmission capacity. Extreme weather events, like Winter Storm Elliot, also contributed to higher congestion costs during 2021.

Figure 3-2[23]

Monthly Congestion Values from 2020-2022 across MISO Footprint



The Project will play a key role in providing additional transmission capacity to reduce the severity of these current congestion issues.

3.3.3.4 Summary

The evolving energy landscape and ongoing changes to Minnesota's generation portfolio will require increasing the capacity of the existing high voltage transmission system in the region to ensure that existing generation and new generation projects can be efficiently and economically delivered to load centers. The next chapter discusses MISO's LRTP study that considered the changing energy landscape, reflecting upon the insights gained from MISO's Renewable Integration Impact Assessment that ultimately culminated in the identification of the Project as part of MISO's LRTP Tranche 1 Portfolio.

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[23] *2022 State of the Market Report for the MISO Electricity Markets* at 57, Independent Market Monitor for MISO (June 15, 2023) available at: https://www.potomaceconomics.com/wp-content/uploads/2023/06/2022-MISO-SOM_Report_Body-Final.pdf.

4. NEED ANALYSIS

4.1 Summary of Need Analysis

This Project is a key component of MISO's LRTP Tranche 1 Portfolio of 18 transmission projects. Overall, the LRTP Tranche 1 Portfolio is needed to address thermal and voltage reliability issues across the MISO transmission system to ensure that it can continue to reliably deliver energy to customers as aging coal-fired generators are retired and replaced with renewable resources. In addition to providing more reliable and resilient energy delivery, the LRTP Tranche 1 Portfolio will also provide congestion and fuel savings, avoid resource and transmission investment, improve transfer capability, avoid the risk of load shedding, and enable a reduction in carbon-dioxide (CO_2 or carbon) emissions by supporting a higher penetration of renewable resources. Overall, MISO concluded that the entire LRTP Tranche 1 Portfolio is expected to provide $23.2 billion in net economic savings over the first 20 years of service or more than two times the cost of the portfolio ($10.3 billion).

While the LRTP Tranche 1 Portfolio was developed as a collection of 18 projects that are designed to work together, each project was also individually studied and justified by MISO. In particular, this Project is needed to resolve regional reliability issues on the existing 230 kV system in western and central Minnesota and eastern North Dakota and South Dakota. This 230 kV transmission system plays a key role in transporting generation from North Dakota and South Dakota into Minnesota. As discussed in Chapter 3, the electric system is undergoing a transition as aging fossil-fueled baseload generation is retired and new renewable generation is being added to the system. This additional renewable generation is placing additional strain on the already constrained 230 kV transmission system in this area. The Project alleviates these constraints by providing additional capacity and additional outlet for the generation from North Dakota and South Dakota into and through Minnesota. As part of its analysis in MTEP21, MISO concluded that this Project relieves 40 transmission elements with excessive thermal loading when one transmission element is out of service (N-1 contingency) and relieves 70 transmission elements with excessive loading when one or more transmission elements are out of service (N-1-1 contingency).

In addition to meeting system reliability needs, the Project will also provide economic benefits to help offset its costs. Xcel Energy, on behalf of the Applicants, conducted additional economic analysis of the Project and determined that the Project will provide up to $2.1 billion in economic savings across the MISO footprint over the first 20 years that the Project is in service and up to $3.8 billion in economic savings across the MISO footprint over the first 40 years. These economic savings will help offset the capital cost of the Project.

Xcel Energy, on behalf of the Applicants, also analyzed the carbon reduction benefits of the Project. MISO's analysis demonstrated the implementation of the LRTP Tranche 1 Portfolio is estimated to reduce carbon emissions by 399 million metric tons over the first 20 years and 677 million metric tons over the first 40 years of LRTP Tranche 1 project life.[24] Xcel Energy, on behalf of the Applicants, estimated that the Project will reduce carbon emissions by 17.8 to 22.4 million metric tons over the first 20 years that the Project is in service and by 36.1 to 49.6 million metric tons over the first 40 years that the Project is in service.

This Project has been extensively studied by both MISO and the Applicants and this chapter summarizes this study work.

4.2 MISO's Analysis of Need for the Project

The Project is part of MISO's LRTP Tranche 1 Portfolio, a portfolio of 18 regionally beneficial transmission projects identified by MISO and approved by the MISO Board of Directors in July 2022. This section provides background on MISO's role in planning the regional transmission grid, the reliability implications of the Midwest's changing generation fleet, and MISO's LRTP study process. This section also includes a detailed discussion of MISO's analysis and justification of the LRTP Tranche 1 Portfolio, including its specific evaluation of the Project. Additional details on MISO's analysis and justification for the Project can be found in **Appendix E-1** which is MISO's MTEP21 Report Addendum that discusses the need for the LRTP Tranche 1 Portfolio and how MISO analyzed and evaluated these transmission projects.

[24] **Appendix E-1** at 79 (MTEP21 Report Addendum).

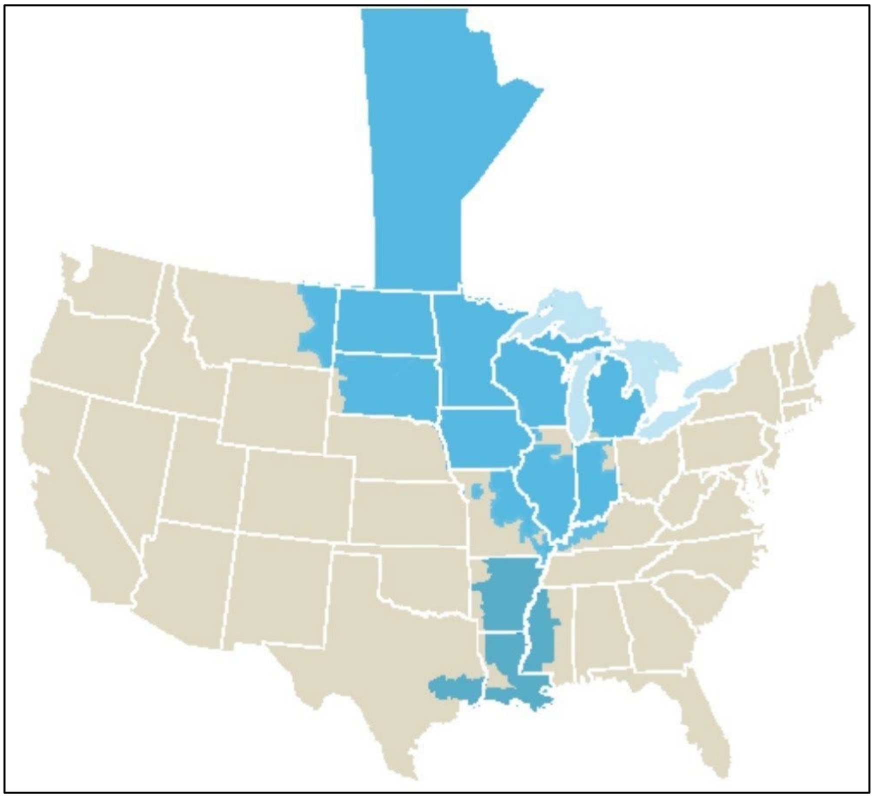
4.2.1 MISO Overview

MISO is an independent not-for-profit regional transmission organization (RTO) which operates the transmission system and energy market in parts of 15 states and the Canadian province of Manitoba. As an RTO, MISO is responsible for planning and operating the transmission system within its footprint in a reliable manner. MISO also provides operational oversight and control, market operations, and oversees planning of the transmission systems of its member Transmission Owners (TOs). MISO has 57 TO members, including Xcel Energy, Great River Energy, Minnesota Power, Otter Tail, and Missouri River Energy Services,[25] with more than 68,000 miles of transmission lines under MISO's functional control.[26] MISO members also include 135 non-TOs such as independent power producers and exempt wholesale generators, municipals, cooperatives, transmission dependent electric utilities, and power marketers and brokers. A map of MISO's geographic footprint is provided in **Map 4-1** below.

[25] Missouri River Energy Services is designated as the Transmission Owner of transmission facilities owned by Western Minnesota.

[26] Information from MISO fact sheet as of March 2023 available at: https://www.misoenergy.org/about/media-center/corporate-fact-sheet/.

Map 4-1
MISO's Reliability Footprint



4.2.2 MISO's Transmission Planning Process

MISO has a responsibility, established by the Federal Energy Regulatory Commission (FERC), to study the transmission system within its footprint to identify necessary transmission projects to address reliability issues. This study includes the development of the MISO MTEP in collaboration with TOs and other stakeholders. The MTEP is developed each year in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. MISO adheres to the planning principles outlined in FERC Order Nos. 890[27] and 1000[28] in developing the MTEP. These FERC Orders require an open and

[27] FERC Order No. 890, 18 C.F.R. parts 35, 36 (2007), available at https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

[28] FERC Order No. 1000, 18 C.F.R. part 35 (2011), available at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf.

transparent regional transmission planning process and include the requirement to plan for public policy objectives and for coordinated inter-regional planning and cost allocation. Each MTEP cycle, MISO undergoes a rigorous, open, and transparent stakeholder process that offers numerous opportunities for advice and input from a diverse stakeholder community, which includes utilities, state regulators, and public interest organizations including environmental and consumer groups.

4.2.3 MISO Energy Landscape Transformation

Like Minnesota, the MISO footprint is experiencing a fundamental change in the energy industry landscape – including shifts in generation resources, consumer demand for low-carbon resources, and decentralization of generation. MISO predicts as much industry change in the next five years as happened in the past 35 years. In 2001, generation across MISO was largely provided by coal generation and some natural gas, and customer demand was the largest source of day-to-day operating variation. In 2022, coal generation shrunk to approximately one-third of MISO's annual energy production and annual energy from wind and solar generation rose to 17 percent. Since 2001, over 40 GW of renewable resources have been installed across MISO.

Driven by a combination of state and federal policy, including Minnesota's carbon free by 2040 legislation,[29] customer preferences, economics, and utility goals, the retirement of legacy fossil fuel generators and the replacement with largely geographically dispersed wind and solar units is expected to continue and accelerate across the MISO footprint over the foreseeable future.

As an additional indicator of the regional energy transformation, in 2022 the MISO Generator Interconnection Queue set another record with 956 requests representing approximately 171 GW of new generation across the MISO footprint – 164 GW (or 96%) of which were renewable or storage from new generators – wanting to be built and to interconnect to the MISO transmission grid. Of this 171 GW of new generation, approximately 8 GW is requested to interconnect to the transmission system in Minnesota. The capacity associated with these new generation requests is significantly more than MISO's peak demand. Historically only a fraction of queued generation

[29] Minn. Stat. § 216B.1691, subd. 2g.

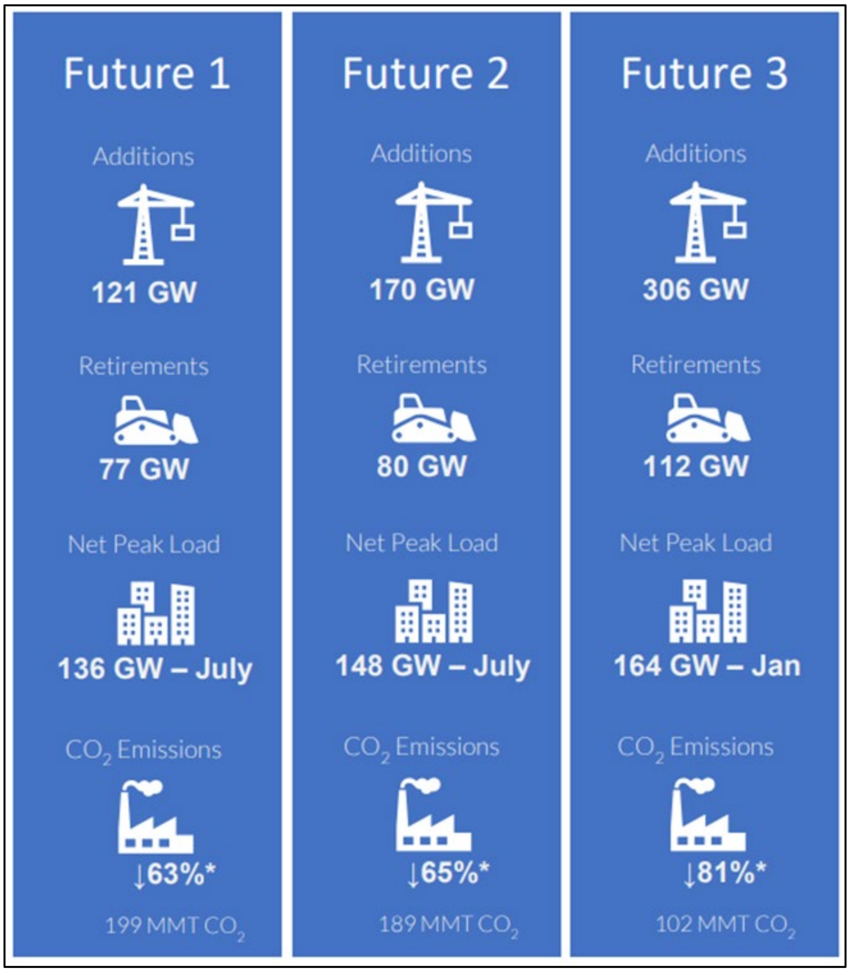
comes to fruition; however, additional generation interconnection requests are also made each year.

4.2.4 MISO Futures Development and Transmission Planning

As transmission grid expansions are long-term decisions, forecasts of the future generation mix and energy usage are necessary to plan the grid. As part of each MTEP cycle, MISO and its stakeholders engage in a robust process to develop a range of forward-looking scenarios, or Futures, which forecast multiple paths and timelines for states and utilities to meet their energy goals. The Futures are designed to "bookend" the potential range of future economic and policy outcomes, ensuring that the actual future is within the range of the Futures. These Futures, which envision system conditions 20 years into the future, are then used to assess and identify transmission needed to deliver the necessary energy reliably and efficiently from generation resources to customers.

In MTEP21, three Futures were developed by MISO. These three Futures incorporate varying assumptions about utility and state goals, retirements, distributed energy resources (DER) adoption, and electrification, among other factors. All of the MTEP21 Futures assume changes announced through September 2020 in utility Integrated Resource Plans (IRPs) (resource plans for upwards of 10-15 years into the future) are included in the MTEP21 Futures. A summary of the key assumptions for each MTEP21 Future is shown in **Figure 4-1** and **Figure 4-2**.

Figure 4-1
MTEP21 Futures Generation Assumptions[30]



[30] **Appendix E-3** at 3 (MISO Futures Report).

Figure 4-2
MTEP21 Futures Assumptions[31]

Future I	Future 2	Future 3
• The footprint develops in line with 100% of utility IRPs and 85% of utility announcements, state mandates, goals, or preferences • Emissions decline as an outcome of utility plans • Load growth consistent with current loads	• Companies/states meet their goals, mandates and announcements • Changing federal and state policies support footprint-wide carbon emissions reduction of 60% by 2040 • Energy increases 30% footprint-wide by 2040 driven by electrification	• Changing federal and state policies support footprint-wide carbon emissions reduction of 80% by 2040 • Increased electrification drives a footprint-wide 50% increase in energy by 2040

The magnitude of change considered in these three MTEP21 Futures is transformational. Future 1 alone, the "least transformational" of the MTEP21 Futures because it assumes only 85 percent of state decarbonization goals as of 2020 are met, anticipates 121 GW of resource additions[32] – roughly a 30 percent MISO-wide renewable penetration.

Given that Future 1 is the "least transformational" – in other words, the most conservative – of the MTEP21 Futures, MISO based its Long-Range Transmission Plan analyses for the LRTP Tranche 1 Portfolio on Future 1. This is because any benefits of transmission lines that are demonstrated under the Future 1 assumptions can be assumed to increase under Future 2 and Future 3, which both assume higher levels of decarbonization and renewable penetration, and higher load growth driven by increased electrification.

To understand the implications of the increased renewable penetrations, in 2021 MISO released a study called the Renewable Integration Impact Assessment (RIIA).[33] The RIIA found that up to 30 percent renewable penetration is manageable with incremental transmission; however, managing the system beyond 30 percent of system-wide

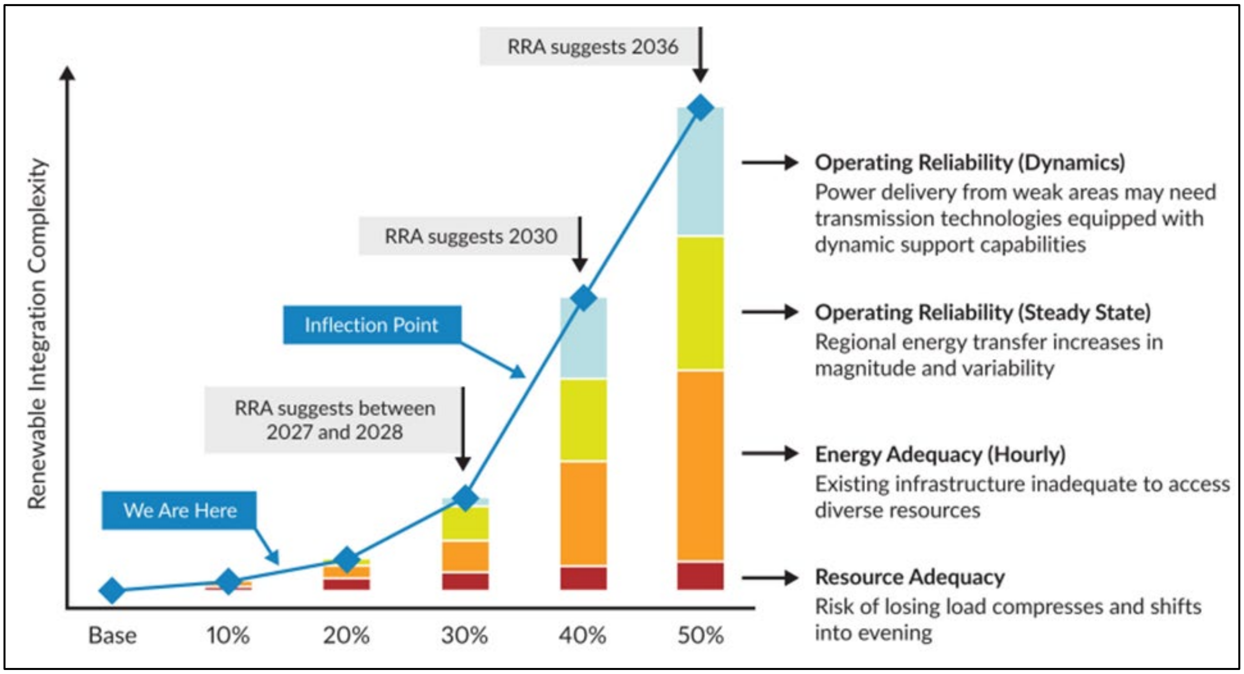
[31] **Appendix E-1** at 26 (MTEP21 Report Addendum).

[32] For reference MISO's total system market capacity as of March 2023 is 190 GW.

[33] The full RIIA report is available at: https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/.

renewable penetration will require transformational change in planning, markets, and operations, as shown in **Figure 4-3**.

Figure 4-3
Reliability Implications of Increasing Renewable Penetrations[34]



In 2022, MISO achieved a 19 percent renewable (wind, solar, and hydro) penetration throughout its footprint with many areas of MISO already experiencing more than 40 percent of its energy being generated from renewables.[35] While incremental transmission expansion has and continues to occur, the increased challenge to efficiently maintain reliability is evident in the increased congestion levels[36] and more frequent use of MISO emergency operating procedures.[37]

[34] MISO, 2022 Regional Resource Assessment ("RRA"), available at: https://www.misoenergy.org/planning/policy-studies/RRA/#t=10&p=0&s=FileName&sd=desc.

[35] MISO Corporate Fact Sheet – March 2023.

[36] Congestion trends are available via MISO's "Yearly Historical Real-Time Constraints" market reports at: https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/.

[37] From 2014 to 2016 MISO did not make a single emergency declaration. Since 2016, 41 emergency declarations have been required.

Recognizing that transformational changes in the generation fleet requires significant changes to the transmission grid to maintain reliability, MISO launched the LRTP effort in 2019. The LRTP is a multi-year multi-phase study to identify a regional "backbone" to cost-effectively maintain reliability and serve future needs. The objective of the MISO LRTP was to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply;
- **Cost Efficient** – enable access to lower-cost energy production;
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint; and
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice.

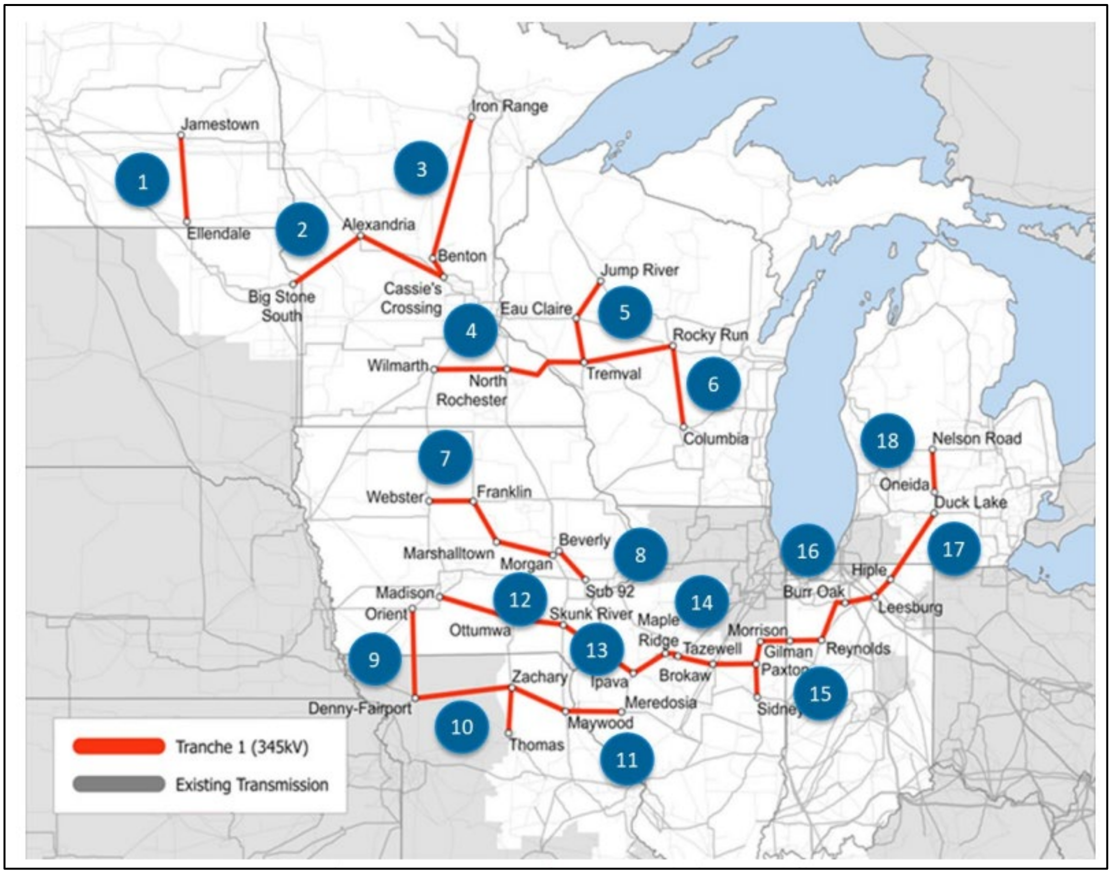
MISO evaluated the LRTP in accordance with MISO's federally approved tariff. For any transmission project to be deemed needed under MISO's tariff, it must meet defined criteria. In MISO's LRTP, MISO and stakeholders worked to identify a transmission plan that simultaneously addresses multiple regional needs – which under the MISO tariff is defined as a Multi-Value Project (MVP). For a project to be deemed needed by MISO as a MVP it must:

- **Reliability** – Address transmission issues associated with a projected violation of a reliability standard;
- **Economic** – Provide multiple types of economic value across multiple pricing zones with a benefit-to-cost ratio of 1.0 or higher, or
- **Policy** – Support the reliable and economic delivery of energy in support of documented energy policy mandates or laws.

4.2.5 LRTP Tranche 1 Portfolio

The Project is one part of a broader regional solution to maintain reliability in the most cost-effective manner. In July 2022, MISO approved the first phase or "tranche" of the LRTP. The MISO LRTP Tranche 1 Portfolio consists of 18 transmission projects, including the Project, identified in **Map 4-2** as project number two. The MISO LRTP Tranche 1 Portfolio includes approximately 2,000 miles of new and upgraded high voltage transmission equaling approximately $10 billion in investment, to enhance connectivity and maintain reliability for the Midwest by 2030 and beyond.

Map 4-2
MISO LRTP Tranche 1 Portfolio



The LRTP Tranche 1 Portfolio is needed to:

- Address reliability violations as defined by the North American Electric Reliability Corporation (NERC) at over 300 different sites across the Midwest.

In addition, increase transfer capability across the MISO Midwest subregion to allow reliability to be maintained for all hours under varying dispatch patterns driven by differences in weather conditions.

- Provide $23.2 billion to $52.2 billion in net economic savings over the first twenty to forty years (respectively) of the LRTP Tranche 1 Portfolio being in-service, which results in a benefit to cost ratio range of 2.6 to 3.8. This means MISO estimates the economic savings provided by the LRTP Tranche 1 Portfolio will more than pay for the costs of the portfolio over the first 20 years of service.

- Enable the reliable interconnection of approximately 43,431 MW of new, primarily renewable, generation capacity across the MISO Midwest subregion, 8,339 MW of which is in Minnesota and the surrounding region.

In the identification of the LRTP Tranche 1 Portfolio MISO considered multiple alternatives both to each of the eighteen individual projects and to the aggregate portfolio. The LRTP Tranche 1 Portfolio was developed through a robust, open, and transparent stakeholder process. The LRTP Tranche 1 Portfolio is the culmination of over 200 stakeholder meetings between 2020 and 2022. The average attendance at each of these stakeholder meetings was between 200 – 300 people.[38] A copy of MISO's MTEP21 Report Addendum can be found in **Appendix E-1**.

4.2.5.1 LRTP Tranche 1 Portfolio Reliability Need

MISO identified that the MISO LRTP Tranche 1 Portfolio is needed to prevent numerous thermal and voltage reliability issues – summarized in **Table 4-1** below. The MISO LRTP Tranche 1 Portfolio is needed to ensure the MISO transmission grid can continue to reliably deliver energy from future generation resources to load under a range of projected system conditions associated with the Future 1 scenario in the 10-year and 20-year time horizon.

[38] **Appendix E-1** at 9 (MTEP21 Report Addendum).

Table 4-1
LRTP Tranche 1 Portfolio Reliability Need Summary

LRTP Project ID(s)[39]	Summary of Reliability Need
LRTP 1 & 2 ***Proposed Project: LRTP2***	Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
LRTP 3	Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies
LRTP 4, 5, and 6	Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies
LRTP 7 and 8	Relieves 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies
LRTP 9, 10, and 11	Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
LRTP 12 through 18	Addresses 600 thermal reliability violations at 77 different sites.

4.2.5.2 LRTP Tranche 1 Portfolio Economic Need

While the LRTP Tranche 1 Portfolio was designed by MISO to primarily address reliability issues, MISO also optimized it to provide economic benefits to help offset the capital costs of the portfolio. As shown in **Figure 4-4**, MISO projects that the MISO LRTP Tranche 1 Portfolio will provide $23.2 billion to $52.2 billion in net economic savings over the first 20 to 40 years (respectively) of the portfolio being in-service – a benefit to cost ratio range of 2.6 to 3.8.[40] This means MISO projects the LRTP Tranche 1 Portfolio will more than pay for itself in less than twenty years of service. MISO used six different metrics to calculate the projected economic savings of the portfolio: (1) congestion and fuel savings, (2) avoided capital cost of local resource investment, (3) avoided transmission investment, (4) resource adequacy savings, (5) avoided risk of load shedding, and (6) reduced carbon emissions. Additional details on the definition and valuation of each of MISO's six benefit metrics can be found in **Appendix E-1**.

[39] LRTP Tranche 1 Project IDs reference **Map 4-2**.

[40] The 2.6 to 3.8 benefit to cost ratio is for the entire MISO Midwest subregion. MISO projects that Minnesota and the surrounding region ("MISO Cost Allocation Zone 1") will realize a 2.8 to 4.0 benefit to cost ratio – slightly better than the broader MISO Midwest subregion.

Figure 4-4
LRTP Tranche 1 Economic Benefits[41]

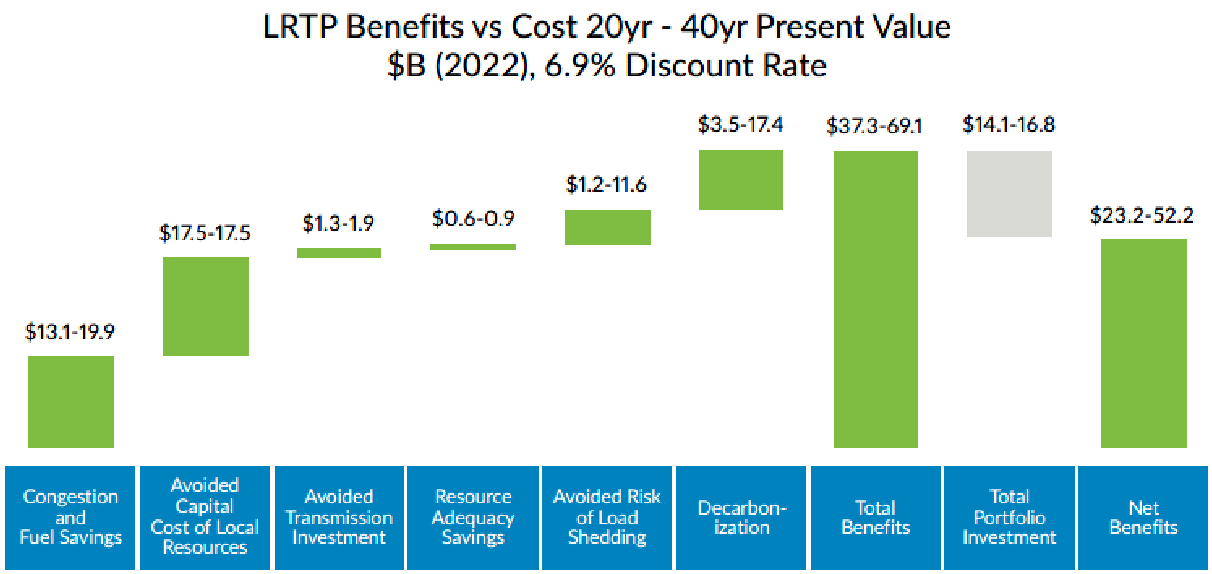


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

4.2.5.3 LRTP Tranche 1 Portfolio Enabled Generation

MISO's analysis shows the LRTP Tranche 1 Portfolio accommodates the reliable interconnection of approximately 43,431 MW of new generation needed to serve the forecasted customer demand and replace energy currently provided by retiring fossil-fuel generation with newer lower carbon emitting generation resources – primarily renewable generation.[42] Of the capacity enabled by the LRTP Tranche 1 Portfolio, 8,339 MW is in Minnesota and the surrounding region (MISO Local Resource Zone 1 or LRZ1). The generation enabled by the LRTP Tranche 1 Portfolio is expected to reduce carbon-dioxide emissions by upwards of 20 million metric tons annually across the MISO footprint or 399 million metric tons over the first 20 years of the LRTP Tranche 1 Portfolio being in-service and 677 million metric tons over the first 40 years

[41] **Appendix E-1** at 4 (MTEP21 Report Addendum).

[42] **Appendix E-1** at 66 (MTEP21 Report Addendum).

of service.[43] Using the Minnesota Public Utilities Commission's valuation of carbon-dioxide emission reduction of $12.55/metric ton[44] the LRTP Tranche 1 Portfolio is expected result in $3.5 billion to $4.8 billion in carbon reduction benefits across the MISO footprint over the first 20 years that the LRTP Tranche 1 Portfolio is in service.[45]

4.2.5.4 LRTP Tranche 1 Portfolio Transfer Capability

MISO found that the LRTP Tranche 1 Portfolio is needed to increase the transfer capability across the MISO footprint. As the generation fleet transitions to more wind and solar generation resources whose output is dependent on weather conditions, the ability to transfer energy across the MISO system is critical to serving demand when wind or solar are not available in a particular area. As weather patterns regularly change, the MISO Tranche 1 Portfolio provides flexibility to transfer more energy where it is needed and when. In addition, the increased transfer capability provided by the LRTP Tranche 1 Portfolio enables more geographic diversity which allows grid operators to better manage generation dispatch volatility and uncertainty.

4.2.5.5 LRTP Tranche 1 Portfolio Other Qualitative Benefits

The LRTP Tranche 1 Portfolio also provides multiple other qualitative benefits. MISO expects the addition of the Tranche 1 Portfolio to increase the operational flexibility to better allow timely outage scheduling to maintain the reliability of the system and to reduce the economic impacts due to congestion caused by outages.[46] The operational flexibility also helps reduce the economic impacts of natural gas fuel price changes by providing access to a broader pool of generation resources.

The LRTP Tranche 1 Portfolio also gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing

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[43] **Appendix E-1** at 79 (MTEP21 Report Addendum).

[44] **Appendix E-1** at 79 (MTEP21 Report Addendum). The Commission recently updated its cost of future carbon-dioxide regulation for 2023-2024 in Docket No. E999/CI-07-1199 but a written order is currently pending.

[45] **Appendix E-1** at 80 (MTEP21 Report Addendum).

[46] **Appendix E-2** at 47 (LRTP Tranche 1 Portfolio Detailed Business Case).

uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

4.2.6 MISO's Summary of Need for the Project

The MISO LRTP Tranche 1 Portfolio was developed as a portfolio of projects designed to work together; however, each of the 18 projects in the MISO LRTP Tranche 1 Portfolio was also individually justified by MISO based on regional and local needs. MISO identified that the Project is a critical component of the LRTP Tranche 1 Portfolio and also the most effective option to maintain regional reliability in western and central Minnesota and eastern North Dakota and South Dakota. MISO summarized the need for the Project, along with the LRTP1 project (Jamestown – Ellendale 345 kV transmission line) as follows:

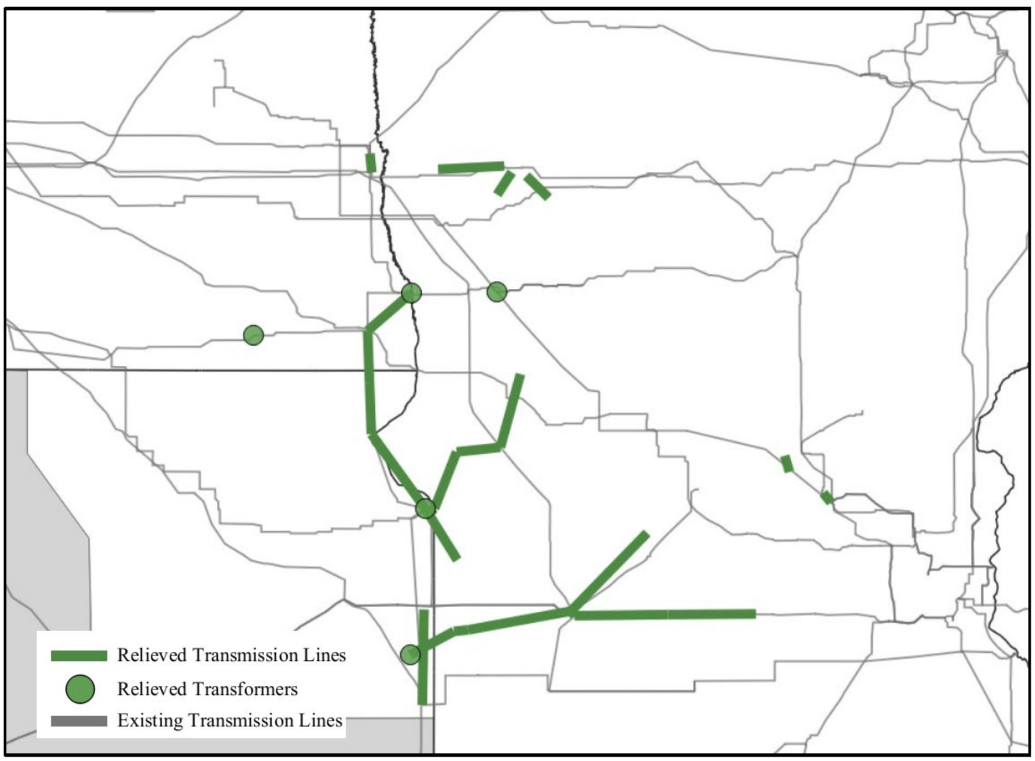
> The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.[47]

MISO's analysis identified that the Project and the LRTP1 project address many of the thermal and voltage issues identified in western Minnesota and eastern North Dakota and South Dakota as shown in **Map 4-3** below. The solid green lines in **Map 4-3** depict

[47] **Appendix E-1** at 23 (MTEP21 Report Addendum).

the transmission lines that no longer have overloads and the circles depict transformers that no longer have overloads following construction of the Project and the LRTP1 project. Most notably, the 230 kV system from Ellendale to Fergus Falls and from Big Stone to Hankinson is relieved during numerous N-1 and N-1-1 contingencies. An N-1 contingency is an event that involves the loss of a single generator or transmission component. An N-1-1 contingency is an event that involves the initial loss of a single generator or transmission component, followed by system adjustments, and then another loss of a single generator or transmission component.

Map 4-3[48]
Reliability Issues Addressed by the Project and LRTP1



As shown in **Table 4-2** and **Table 4-3** below, MISO determined that the Project and the LRTP1 project relieved 40 thermal overloads and 97 voltage violations under N-1

[48] **Appendix E-1** at 24 (MTEP21 Report Addendum).

contingencies and 70 thermal overloads and 91 voltage violations under N-1-1 contingencies.[49]

Table 4-2
Elements with Thermal Issues Relieved by LRTP2 and LRTP1 in Future 1[50]

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
		Max % Loading		Max % Loading
	Count Elements	Pre-Project	Count Elements	Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 4-3
Elements with Voltage Issues Relieved by LRTP2 and LRTP1 in Future 1[51]

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
		Minimum p.u. voltage		Minimum p.u. voltage
	Count Elements	Pre-Project	Count Elements	Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

In its analysis of the Project and the LRTP1 project, MISO considered five alternatives:

- **Alternative 1:** Big Stone South – Alexandria 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;
- **Alternative 2:** Big Stone South – Hankinson – Fergus Falls 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;

[49] MISO considered a constraint relieved if its worse pre-project loading was greater than 95% of its monitored Emergency rating, its worst pre-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

[50] **Appendix E-1** at 39 (MTEP21 Report Addendum).

[51] **Appendix E-1** at 39 (MTEP21 Report Addendum).

- **Alternative 3:** Big Stone South – Hazel Creek – Blue Lake 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line;

- **Alternative 4:** Big Stone South – Alexandria 345 kV transmission line, Big Stone South – Hazel Creek – Blue Lake 345 kV transmission line, and Jamestown – Ellendale 345 kV transmission line; and

- **Alternative 5:** Big Stone South – Breckenridge – Barnesville 345 kV transmission line and Jamestown – Ellendale 345 kV transmission line.

MISO compared the performance of the Project and the LRTP1 project to these five alternatives and concluded that the Project and the LRTP1 project performed the best of all the alternatives. A summary of MISO's conclusions related to each alternative is provided in **Table 4-4** below. A more detailed discussion of each of these alternatives is provided in **Chapter 5**.

Table 4-4
Summary of MISO's Alternatives Conclusion[52]

MISO Alternative	MISO's Conclusion
Alternative 1	"Without double circuit to [Big Oaks] there are new N-1 issues around Alexandria."[53]
Alternative 2	"Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls."[54]
Alternative 3	"Reduces nearly all overloads of concern but not to the extent of the preferred project."[55]
Alternative 4	"Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake

[52] **Appendix E-1** at 39 (MTEP21 Report Addendum).

[53] **Appendix E-1** at 39 (MTEP21 Report Addendum).

[54] *Id.*

[55] *Id.*

MISO Alternative	MISO's Conclusion
	(Alternative 3) does not add enough additional value over the preferred project."[56]
Alternative 5	"Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative."[57]

Based on its evaluation, MISO determined that the Project was an important component of the overall LRTP Tranche 1 Portfolio to ensure a reliable, resilient, and cost-effective transmission system as the generation mix within the MISO footprint continues to evolve to include more renewables. The Project, along with the entire LRTP Tranche 1 Portfolio, was approved by the MISO Board of Directors in July 2022.

4.3 Applicants' Analysis of Need

In addition to MISO's need analysis, Xcel Energy, on behalf of the Applicants, further examined system reliability improvements related to the Project and conducted additional economic analyses. These analyses, described in the following sections, focused on the Project under a variety of modeling assumptions to further illustrate the incremental benefits of the Project.

4.3.1 Applicants' Reliability Need Analysis

As discussed in Section 4.2.6, MISO's reliability analysis concluded that construction of the Project and LRTP1 addressed many of the thermal and voltage issues in western/central Minnesota and eastern North Dakota and South Dakota by providing additional capacity to relieve the currently constrained 230 kV system.

In addition to the reliability analysis conducted by MISO, the Applicants further examined system reliability improvements yielded by the Project based on the most current assumptions on transmission topology and generation retirements and additions contained in MISO's most current transmission system model (MTEP22). As demonstrated in the following sections, the Applicants' analysis further confirms

[56] *Id.*

[57] *Id.*

MISO's reliability analysis that the Project is needed to uphold reliability in western and central Minnesota and eastern North Dakota and South Dakota.

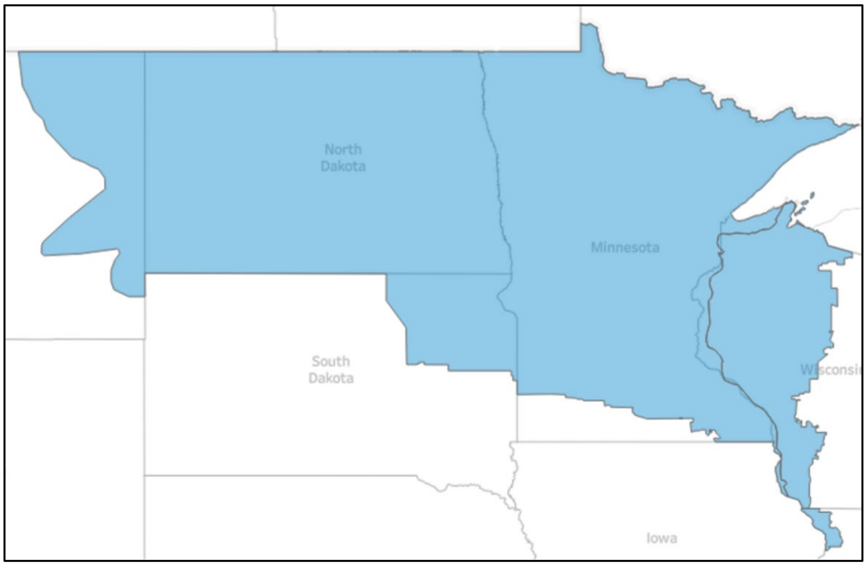
The Applicants conducted two separate analyses:

- First, Applicants conducted an analysis based on the most current MISO transmission system model (MTEP22) assuming no additional generation is added to the system. This analysis looked at the year 2027, which was the most readily available MTEP model that is nearest to the Project's MISO approved in-service date (June 1, 2030), to show improvements to system reliability related to the Project. The MISO MTEP22 model reflects the current transmission system, which includes limited additional transmission facilities in-service compared to the MTEP21 model used for the LRTP Tranche 1 Portfolio analysis.

- Second, Applicants conducted an analysis based on the MTEP21 Future 1 (at year 20) to show improvements to system reliability related to the Project in the future when additional generation is online.

For both analyses, Applicants studied reliability in the MISO Local Resource Zone 1 (LRZ1) area, which is shown in **Map 4-4** below.

Map 4-4
MISO Local Resource Zone 1



The analyses looked at transmission system performance using Summer Shoulder – High Wind models, which represent the most stressed conditions for this portion of the transmission system. The Project is designed to alleviate constraints on the existing 230 kV and 115 kV transmission systems in eastern North Dakota and South Dakota as well as western Minnesota, which play a key role in delivering energy into Minnesota and is currently at capacity. This system is particularly stressed under Summer Shoulder load conditions, generally defined as 70 to 80 percent of Peak Summer load, combined with high wind conditions. When there is high wind generation available without peak demand to consume that energy, considerable stress is placed on certain elements of the transmission system.

Reliability analyses studied all NERC contingency categories (P1-P7) and looked at facility overloads under a variety of transmission system modeling assumptions, including the following:

- Base Model – assuming no additional transmission projects are constructed (*i.e.*, the current base transmission system remains in place);
- Only LRTP2 – assuming the Project is constructed, but no other LRTP Tranche 1 projects are constructed;

- All LRTP Tranche 1 projects except LRTP2 – assuming construction of all LRTP Tranche 1 projects except the Project; and

- LRTP Tranche 1 – assuming construction of all LRTP Tranche 1 projects.

While LRTP Tranche 1 is a portfolio of 18 individual projects designed to work together to provide benefits, the Applicants' reliability analyses provides an alternative way to look at the reliability improvements resulting from the Project. The results of the reliability studies are provided in the following sections and illustrate which overloads are remedied with implementation of the Project.

4.3.1.1 MTEP22 2027 – Reliability Results

Applicants conducted an analysis for the LRZ1 area based on the MISO MTEP22 transmission system model assuming no additional generation is added to the system. This analysis looked at the year 2027, which is nearest to MISO's approved in-service date for the Project, to show improvements to system reliability related to the construction of the Project.

The results of this analysis are provided in **Table 4-5** below. The table lists the "Overloaded Facilities" and provides the number of different contingencies that cause thermal issues on the facility listed for each transmission model studied. The table also includes the "Fixed By LRTP2" column showing the number of thermal issues that are resolved with implementation of the Project.

The number of thermal issues resolved by the Project reflects issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model. A thermal overload was considered to be resolved by the Project if it showed up in the "Base Model" but not the "LRTP2" model or full "Tranche 1" model. Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.

Table 4-5
Reliability Results
MTEP22 2027 Summer Shoulder – High Wind

Totals			MTEP22 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	8956	4503	7	0	4480
Helena - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	5042	4508	13	0	559
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4453	2	0	0	4451
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1, N-1-1	4394	0	0	0	4394
Big Stone - Highway 12 115 kV Ckt 1	SD	N-1, N-1-1	582	0	2	0	582
Highway 12 - Ortonville 115 kV Ckt 1	SD, MN	N-1, N-1-1	301	0	1	0	301
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	270	2	0	0	268
Ortonville - Ortonville Quarry 115 kV Ckt 1	MN West	N-1, N-1-1	259	0	0	0	259
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	182	0	58	0	182
Hoot Lake - Fergus Falls 115 kV Ckt 1	MN West	N-1, N-1-1	171	0	1	0	171
Sheyenne - Lake Park 230 kV Ckt 1	ND	N-1, N-1-1	167	0	167	0	167
Audubon - Lake Park 230 kV Ckt 1	MN West	N-1, N-1-1	167	0	167	0	167
Inman - Wing River 230 kV Ckt 1	MN West	N-1, N-1-1	139	0	0	0	139
Big Stone - Big Stone South 230 kV Ckt 2	SD	N-1, N-1-1	85	0	83	0	85
Wahpeton - Fergus Falls 230 kV Ckt 1	MN West	N-1, N-1-1	83	0	0	0	83
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	55	0	0	0	55
Big Stone - Big Stone South 230 kV Ckt 1	SD	N-1, N-1-1	27	0	27	0	27
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	5	0	0	0	5

As shown in the last column of **Table 4-5**, the major reliability benefits of the Project can be seen on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in western Minnesota and eastern North Dakota and South Dakota. For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Scott County – Blue Lake and from Helena – Chub Lake has a large number of thermal issues that are mitigated with the addition of the Project. There are several areas on the underlying 230 kV and 115 kV systems that also see reliability benefits, such as the areas around the Big Stone, Wahpeton, Morris, Sheyenne, and Audubon substations.

4.3.1.2 MTEP21 Future 1 Year 20 – Reliability Results

Applicants conducted an analysis for the LRZ1 area based on the MISO MTEP21 Future 1 (at year 20) to show improvements to system reliability related to the construction of the Project in the future when additional generation is online. This analysis shows the impact that the Project has under a high wind model with the added generation that the LRTP Tranche 1 Portfolio will enable.

The results of this analysis are provided in **Table 4-6** below. The table lists the overloaded facilities and provides the number of different contingencies that cause thermal issues on the overloaded facility for each transmission model studied. The table also includes the "Fixed By LRTP2" column showing the number of thermal issues that are resolved by the Project.

The number of thermal issues resolved by the Project reflects thermal issues resolved from both the "Base Model" and the "Tranche 1 Without LRTP2" model. A thermal overload was considered to be resolved by the Project if the overload showed up in the "Base Model" but not the "LRTP 2" model or full "Tranche 1" model. Similarly, a thermal overload was considered resolved by the Project if it showed up in the "Tranche 1 Without LRTP 2" model but not the full "Tranche 1" model.

Table 4-6
Reliability Results
MTEP21 Future 1 Year 20, Summer Shoulder – High Wind

Totals			F1Y20 Shoulder High Wind Overload Count				
Overloaded Facility	Area	Contingency Type	Base Model	LRTP 2	Tranche 1 Without LRTP 2	Tranche 1	Fixed By LRTP 2
Tamarac - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36957	46967	54054	43711	17092
Cormorant Junction - Cormorant 115 kV Ckt 1	MN West	N-1, N-1-1	36867	46349	54151	2006	22945
Wilmarth - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6740	7	0	0	6736
Helena - Sheas Lake 345 kV Ckt 1	MN South	N-1, N-1-1	6685	7	0	0	6681
Blue Lake - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	3758	0	2	0	3760
North Rochester - Scott County 345 kV Ckt 1	MN South	N-1, N-1-1	1498	1552	43845	7622	36133
Tamarac - Pelican Rapids 115 kV Ckt 1	MN West	N-1, N-1-1	309	139	275	99	184
Southwest (MMU) - Southeast (MMU) 115 kV Ckt 1	MN SW	N-1, N-1-1	233	116	175	126	121
Morris - Grant County 115 kV Ckt 1	MN West	N-1, N-1-1	123	0	0	0	123
Big Stone - Browns Valley 230 kV Ckt 1	SD	N-1, N-1-1	98	0	0	0	98
Browns Valley - New Effington 230 kV Ckt 1	SD	N-1, N-1-1	74	0	0	0	74
Helena - Chub Lake 345 kV Ckt 1	MN South	N-1-1	16	0	2	0	18
Johnson Junction - Morris 115 kV Ckt 1	MN West	N-1	6	0	0	0	6

The major reliability benefits of the Project can be seen on the 345 kV system in southern Minnesota as well as the underlying 230 kV and 115 kV systems in western Minnesota and eastern South Dakota. For example, the 345 kV system from Wilmarth – Sheas Lake – Helena – Chub Lake and Blue Lake – Scott County – North Rochester has a large number of thermal issues mitigated with the addition of the Project. There are also several areas on the underlying 230 kV and 115 kV systems that see reliability benefits, such as the areas around the Big Stone, Browns Valley, Tamarac, Cormorant, and Morris substations.

4.3.2 Applicants' Economic Need Analysis

As discussed in Section 4.2.5.2, the entire LRTP Tranche 1 Portfolio is expected to provide economic savings that are more than two times the cost of these transmission projects. As discussed below, the Project alone is projected to provide up to $2.1 billion in economic savings across the MISO footprint over the first 20 years that the Project is in service and up to $3.8 billion in economic savings across the MISO footprint over the first 40 years that the Project is in service. These economic savings will help offset the capital cost of the Project.

On behalf of the Applicants, Xcel Energy conducted economic analyses using PROMOD software, short for PROduction MODeling (PROMOD), which is used to support economic transmission planning. The PROMOD software simulates the electric market on an hourly constrained-dispatch basis using models containing generation unit locations and operating characteristics, transmission grid topology, and market system operations. The PROMOD software can calculate the future cost of producing electricity, market congestion, and energy losses based on these assumptions.

The economic analysis was performed in a manner consistent with MISO's analysis of the entire LRTP Tranche 1 Portfolio but focused on identifying the economic benefits specifically for the Project. Xcel Energy, on behalf of the Applicants, conducted three economic analyses, each comparing PROMOD results under various scenarios to show the incremental benefit of Project to the entire MISO footprint and LRZ1.

The first analysis evaluated the adjusted production cost (APC) savings[58] benefit of the Project to the MISO footprint and LRZ1. The second analysis evaluated the carbon reduction benefits of the Project for the MISO footprint and LRZ1 under two different cost of carbon assumptions. The third analysis evaluated the congestion cost saving benefits of the Project. Each of these three analyses is described in detail in the separate subsections below.

Xcel Energy's analyses used various models and assumptions to provide a robust assessment of the benefits of the Project under different potential scenarios. A summary of these three models and assumptions are as follows:

[58] APC savings are utilized to measure the economic benefits of proposed transmission projects. These savings are calculated as the difference in total production costs of energy for a generation fleet adjusted for import costs and export revenues with and without the proposed transmission project.

- *MISO's MTEP21 Future 1 model.* This model reflects assumed generation additions and retirements shown in **Figure 4-1**, based on the assumptions described in Section 4.2.4 above.

- *MISO's MTEP Future 1 with the addition of Xcel Energy's Upper Midwest Integrated Resource Plan (IRP) generation model.* This model includes additional generation based on Xcel Energy's 2020-2034 Upper Midwest IRP that was approved by the Minnesota Public Utilities Commission in April 2022,[59] after MISO completed the development of its Future scenarios for MTEP21. Under Xcel Energy's approved Upper Midwest IRP, which includes retirement of all Xcel Energy's remaining Upper Midwest coal plants by the end of 2030 and extension of operations at Xcel Energy's Monticello Nuclear Generating Plant to 2040, Xcel Energy will add 2,150 MW of wind and 2,500 MW of solar by 2032, with another 1,100 MW of wind and solar capacity beyond 2032. A comparison of the resource additions assumed by MISO's MTEP21 Future 1 and Xcel Energy's Upper Midwest IRP is provided below in **Table 4-7** and **Table 4-8**.

Table 4-7
Generation Additions in MISO's MTEP21 Future 1

MISO MTEP21 Future 1 Types of Generation Additions by Year (MW)					
	2025	**2030**	**2035**	**2040**	**Total**
Combined-Cycle (CC)	749.7	1,725	-	90	2,565
Combustion Turbine (CT)	-	1,725	2,568		4,293
Wind	233.7*	198*	724.45*	828.32*	-
Solar	1,442	1,213	2,914	374	5,943
					13,257

repower

[59] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a/ Xcel Energy*, Docket No. E002-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022).

Table 4-8
Generation Additions in Xcel Energy's Approved Upper Midwest IRP

Xcel Energy's Upper Midwest IRP Types of Generation Additions by Year (MW)					
	2025	**2030**	**2035**	**2040**	**Total**
Standalone Storage	-	200	50	850	1,100
Wind	-	1,350	1,900	1,650	4,900
Solar	1,300	1,250	600	1,300	4,450
Firm Peaking	60	1,381	1,496	374	3,311
CC	-	-	-	-	-
Sherco CC	-	-	-	-	-
Demand Response (DR)	382	77	111	15	720
Energy Efficiency (EE)	781	743	493	(585)	1,433
Distributed Solar	440	75	74	72	662
					16,575

- *MISO's MTEP21 Future 2.* This model reflects assumed generation additions and retirements shown in **Figure 4-1**, based on the assumptions described in Section 4.2.4 above.

4.3.2.1 Adjusted Production Cost Savings of the Project

Xcel Energy used the PROMOD software to calculate the APC savings benefit of the Project using the MTEP21 Future 1, MTEP21 Future 1 with generation additions from Xcel Energy's approved Upper Midwest IRP, and Future 2 models. **Table 4-9** through **Table 4-11** below show the APC savings benefit, on a present value basis over 20 years and 40 years of the Project using these models. As shown in these tables, the APC savings benefit of the Project to the MISO footprint is up to $2.1 billion over the first 20 years of the Project being in-service.

In addition, the Future 1 and Future 2 models likely understate the Project's APC savings benefit because these futures do not include the generation enabled by the other LRTP Tranche 1 transmission projects. Rather, the Future 1 and Future 2 models are based on the generation additions and retirements announced in utility Integrated Resource Plans at the time the MISO MTEP21 Futures were developed in the first quarter of 2021. As a result, once the entire LRTP Tranche 1 Portfolio is constructed, the APC savings benefit of the Project will likely increase as greater amounts of lower cost renewable generation will be enabled across the entire MISO footprint.

In addition, the APC savings benefit shown in **Table 4-9** below, which is Future 1 with the generation additions from Xcel Energy's Upper Midwest IRP included, is likely a more accurate representation of the future generation mix than Future 1 which was developed before Xcel Energy's Upper Midwest IRP was approved by the Commission. Notably, the APC savings benefit under this Future is the highest among the three Future scenarios evaluated by Xcel Energy.

Table 4-9
APC Savings Benefits of the Project under MTEP21 Future 1 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$509.05	$684.8
40 Year Present Value	APC Benefits ($Millions)	$806.8	$1,083.5

Table 4-10
APC Savings Benefits of the Project under MTEP21 Future 1 Model With Xcel Energy's Upper Midwest IRP Generation Added

Timeline	APC Benefit	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$2,061.8	$2,316.7
40 Year Present Value	APC Benefits ($Millions)	$3,758.6	$4,185.1

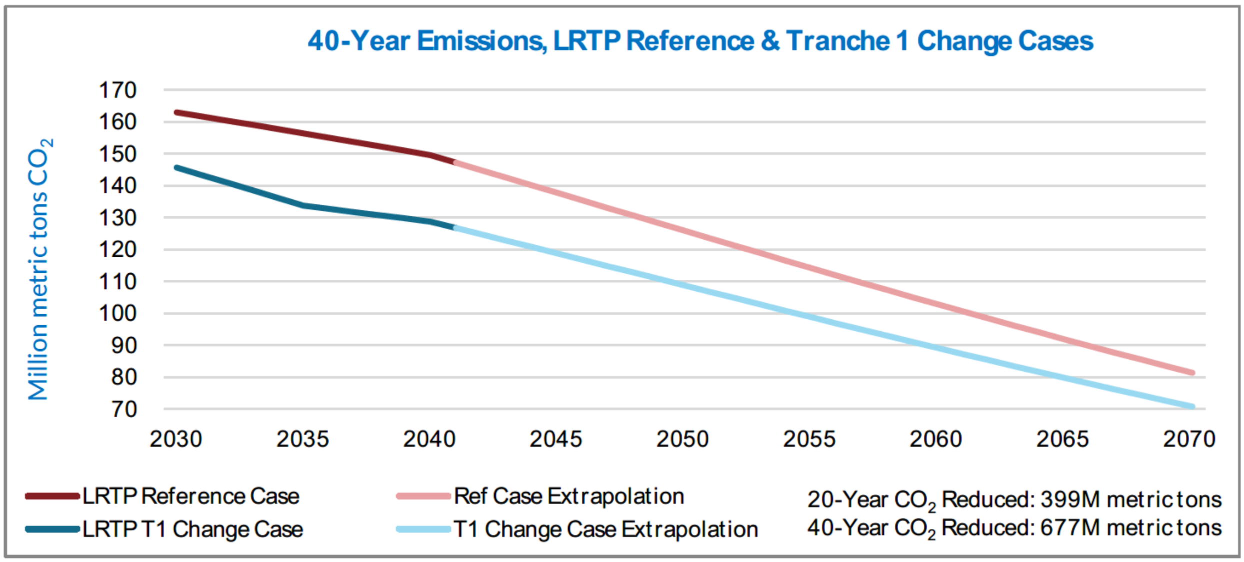
Table 4-11
APC Benefits of the Project under MTEP21 Future 2 Model

Timeline	APC Benefits	MISO	LRZ1
20 Year Present Value	APC Benefits ($Millions)	$796.3	$654.2
40 Year Present Value	APC Benefits ($Millions)	$1,218.3	$912.9

4.3.3 Applicants' Carbon Reduction Analysis

As discussed above in Section 4.2, one of the benefits of the LRTP Tranche 1 Portfolio is a reduction in carbon emissions across the MISO footprint. MISO's PROMOD analysis demonstrated the implementation of the LRTP Tranche 1 Portfolio is estimated to reduce carbon emissions by 399 million metric tons over the first 20 years of the LRTP Tranche 1 Portfolio being in-service and 677 million metric tons over the first 40 years of LRTP Tranche 1 projects being in-service (**Figure 4-5**).[60]

Figure 4-5
40-Year CO_2 Emissions Reductions under LRTP Reference and Tranche 1 Change Cases[61]



MISO also calculated the economic benefit of the carbon reduction or decarbonization enabled by LRTP Tranche 1 Portfolio. MISO conducted research to develop a price range to express the value of decarbonization. MISO chose sources within the U.S., at state and federal levels, both within and outside of the MISO footprint. MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons. Second, MISO converted prices from nominal dollar-years of

[60] **Appendix E-1** at 79 (MTEP21 Report Addendum).

[61] **Appendix E-1** at 79 (MTEP21 Report Addendum).

origin into 2022 dollars using the Consumer Price Index Inflation Calculator. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean) price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.

- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement price of $28.26/metric ton is $28.59 in 2022 dollars.

- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon. The 45Q Tax Credit follows a prescribed price schedule starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

MISO then calculated the decarbonization benefits of the LRTP Tranche 1 Portfolio using the following methods:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case.

- Convert the reduced emissions to metric tons.

- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable.

- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits.

- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits.

This resulted in MISO's decarbonization benefit values as shown in **Table 4-12**.

Table 4-12
MISO's Analysis of LRTP Tranche 1 Decarbonization Benefits[62]

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Xcel Energy, on behalf of the Applicants, also evaluated the carbon reduction benefits of the Project using PROMOD. Xcel Energy's analysis estimated that the Project will reduce CO_2 emissions within MISO by 17.8 to 22.4 million metric tons over the first 20 years that the Project is in service and by 36.1 to 49.6 million metric tons over the first 40 years that the Project is in service.

While there is no cost of carbon that is applicable to the entire MISO footprint currently, Xcel Energy used two different carbon costs to determine a range of potential carbon reduction benefits of the Project. Xcel Energy used the same lower and upper bookend prices used by MISO, i.e., the Minnesota Public Utilities Commission approved CO_2 costs of $12.55/metric tons ($2022) and a federal cost of carbon of $47.80/metric ton ($2022).[63]

The next series of tables show the carbon reduction benefits of the Project to the MISO footprint and LRZ1 under the MISO MTEP21 Future 1, the MTEP21 Future 1 with

[62] **Appendix E-1** at 80 (MTEP21 Report Addendum).

[63] The federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon. This is the same federal price used by MISO in MTEP21 and is discussed in **Appendix E-1** at 80 (MTEP21 Report Addendum).

the generation additions from Xcel Energy's Upper Midwest IRP included, and the MTEP21 Future 2 models.

Table 4-13
Carbon Reduction PV Benefits of the Project under MTEP21 Future 1 Model

MISO	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$93.9	$357.7
40-Year Benefit ($Millions)	$123.0	$468.6

LRZ1	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$85.6	$326.0
40-Year Benefit ($Millions)	$98.3	$374.5

Table 4-14
Carbon Reduction PV Benefits of the Project under MTEP21 Future 1 Model With Xcel Energy's Upper Midwest IRP Generation Added

MISO	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$77.4	$294.7
40-Year Benefit ($Millions)	$ 99.7	$379.8

LRZ1	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$53.6	$204.0
40-Year Benefit ($Millions)	$44.8	$170.5

Table 4-15
Carbon Reduction PV Benefits of the Project under MTEP21 Future 2 Model

MISO	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$115.2	$438.8
40-Year Benefit ($Millions)	$157.8	$600.9

LRZ1	MN PUC	Federal
2022 $/metric ton	*$12.6*	*$47.8*
20-Year Benefit ($Millions)	$129.7	$494.2
40-Year Benefit ($Millions)	$163.3	$621.9

As shown in the tables above, the carbon reduction benefits of the Project to the MISO footprint range from approximately $77.4 million to $438.8 million for the first 20 years the Project is in service. Likewise, the carbon reduction benefits of the Project to LRZ1 range from approximately $53.6 million to $494.2 million for the first 20 years the Project is in service.

4.4 Estimated System Losses

Energy losses on the transmission system can result in increased costs for utilities and ratepayers due to the need to generate enough energy to adequately serve loads while also accounting for the losses incurred during the transmission of this energy. Each new transmission line that is added to the electric system affects the losses of the system. If a new transmission line reduces transmission losses, utilities will not have to generate as much energy to meet customer demands. Thus, if a new transmission line reduces system losses, then the costs to end-use consumers to provide that energy will also be reduced.

Lower voltage lines tend to have higher losses than higher voltage lines. This is because when the voltage of a line is lowered, the current must be increased to achieve similar power flow. This increases losses because of the correlation between the physical requirements of the transmission line conductor and the amount of current flowing on that conductor.

Applicants compared the loss savings achieved by the Project across LRZ1 using the Summer Shoulder - High Wind cases for both the Future 1, Year 20 (F1Y20) and the MTEP22 model sets. The Summer Shoulder - High Wind cases were used to compare line losses because these cases feature the highest losses due to high wind transfers. Line loss data was pulled for transmission lines within the LRZ1 area (Xcel Energy, Minnesota Power, Southern Minnesota Municipal Power Agency, Great River Energy, Otter Tail, Montana-Dakota Utilities, and Dairyland Power Cooperative). To determine the amount of line losses, the base model with no changes to today's transmission system was compared to the model with the Project added to see the benefits that the Project alone has on line losses. A similar comparison was made with the full LRTP Tranche 1 model and the Tranche 1 without LRTP2 model. These comparisons were done for both the F1Y20 and MTEP22 model sets and the results are provided in **Table 4-16** below. In conclusion, the Project reduces line losses by an average of 80.75 MW and 340.80 MegaVolt Ampere of reactive power (MVAr) as shown in **Table 4-17**.

Table 4-16
Estimated Line Losses

MTEP22 2027 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 2	Delta	Tranche 1 Without LRTP 2	Tranche 1	Delta
MW Losses	1031.8	930.5	101.3	923.7	849.4	74.3
MVAr Losses	9628.6	9237.1	391.5	9062.9	8770.1	292.8
Future 1 Year 20 Shoulder High Wind Line Losses for LRZ1						
Model	Base Model	LRTP 2	Delta	Tranche 1 Without LRTP 2	Tranche 1	Delta
MW Losses	1220.5	1139.5	81	1093.4	1027	66.4
MVAr Losses	10834.4	10495.5	338.9	10122.6	9782.6	340

Table 4-17
Average Line Losses

	Average SH Losses
MW losses	80.75
MVAr Losses	340.80

4.5 Development of Future Renewable Generation Enabled by the Project

The unprecedented level of interconnection requests for renewable generators in MISO has continued since the approval of the LRTP Tranche 1 Portfolio. Moreover, and in accordance with MISO model development practices, the Project has been included in all economic, reliability, and interconnection models that have been developed since the Project's approval as part of MTEP21. Interconnection of these new generators will be conditioned on the completion of the Project.

Starting with the 2022 DPP cycle, the Project will be considered in-service at the beginning of 2031. The 2021 DPP cycle can utilize the LRTP Tranche 1 Portfolio as mitigation to identified issues, but any cycles before the 2021 DPP cycle would not be able to rely on the Project. Based on the studies conducted to date, up to 198 interconnection requests amounting to over 35,000 MW will be conditioned on, but not necessarily dependent on, the Project. These generators can be subject to quarterly operating studies that can restrict the output. Even if these quarterly studies allow the maximum output of the generators, the MISO real-time and day-ahead market could constrain the output of these units because of system limits that will be addressed by the Project. Once the Project and the other conditional facilities are constructed and put into operation, the quarterly operating studies will no longer be performed for conditional generators.

4.6 MISO Load Forecast Data

The Project is needed to support the reliability of the regional transmission system as it undergoes significant changes to its generation portfolio. In analyzing the need for the LRTP Tranche 1 Portfolio of projects, MISO developed load forecasts to ensure that these projects could meet both current and future demand. MISO's base demand forecast was developed by aggregating each MISO member's forecast. To evaluate a broad range of potential outcomes, MISO created multiple demand and energy forecasts from the base forecast. The load forecasts used in MISO's Futures consider different adoption rates for demand response, energy efficiency, distributed generation, and beneficial electrification. MISO's demand and energy forecasts are developed for each of MISO's ten Local Resource Zones to consider regional differences. MISO's ten Local Resource Zone forecasts are then aggregated to a MISO-wide forecast. The gross peak demand and annual energy forecast for the MISO footprint that were used for the MTEP21 Futures is provided in **Appendix E-3**.[64]

[64] **Appendix E-3** at 21-30 (MISO Futures Report).

4.7 Effect of Promotional Practices

The Applicants have not conducted any promotional activities or events that have triggered the need for the Project. As discussed above, the Project is needed to address regional reliability issues across MISO's Midwest subregion.

4.8 Effect of Inducing Future Development

The Project is not necessarily intended to induce future development, but it will support future economic development (for example, additional renewable generation).

4.9 Socially Beneficial Uses of Facility Output

The Project is needed to maintain reliability of the transmission system for the Applicants' customers and the MISO Midwest subregion as aging coal-fired generation resources are retired and replaced with renewable generation. As discussed in Sections 4.2.5 and 4.3.2.3, by enabling greater renewable generation, the LRTP Tranche 1 Portfolio will provide societal benefits such as a reduction in carbon emissions. MISO estimated that the LRTP Tranche 1 Portfolio will reduce CO_2 emissions by 399 million metric tons over the first 20 years that these projects are in service and 677 million metric tons over the first 40 years.[65] Using the Minnesota Public Utilities Commission's valuation of carbon-dioxide emission reduction of $12.55/metric ton,[66] the LRTP Tranche 1 Portfolio is expected to result in $3.5 billion to $4.8 billion in carbon reduction benefits over the first 20 years across the MISO footprint.[67] Using this same cost of carbon ($12.55/metric ton), the Applicants estimate that the carbon reduction benefits of the Project alone to the MISO footprint range from $77.4 million to $438.8 million over the first 20 years. In addition, the Project will relieve transmission congestion, increase market access to lower cost renewable generation, and provide economic benefits in the form of reduced wholesale energy costs.

[65] **Appendix E-1** at 79 (MTEP21 Report Addendum).

[66] **Appendix E-1** at 79 (MTEP21 Report Addendum).

[67] **Appendix E-1** at 81 (MTEP21 Report Addendum).

5. ALTERNATIVE ANALYSIS

Both MISO and the Applicants analyzed a number of different alternatives considered to solve the need identified in the previous chapter. Minnesota Certificate of Need statutes and rules require analysis of transmission and non-transmission alternatives. This includes examining size alternatives (different transmission line voltages), type alternatives (including different transmission line configurations as well as generation and non-wires alternatives), demand-side management, and a "no build" alternative to solve the identified need. As explained in **Chapter 4**, as part of its analysis in MTEP21, MISO also evaluated six specific transmission line alternatives, including the proposed Project, for North Dakota, South Dakota, and Western Minnesota of the LRTP Tranche 1 Portfolio. As discussed in more detail below, both MISO's and Applicants' analysis of these alternatives determined that none of these alternatives alone or in combination with other alternatives is a more reasonable and prudent alternative to the proposed Project.

5.1 Size Alternatives

5.1.1 Different Voltages

The Applicants evaluated the feasibility of different line voltages (both higher and lower) to relieve current capacity issues and to improve electric system reliability throughout the region as more renewable energy resources are added to the transmission system in and around the region. As additional renewable generation is constructed in the region, the existing congestion problem will only worsen if there is not sufficient capacity available to transmit this generation to load centers such as the Twin Cities. As of June 2023, for the West MISO DPP cycle 22, there is approximately 22,500 MW of renewable generation in the MISO queue that has requested to be placed in-service through 2030.

In examining transmission alternatives to relieve congestion, the capacity of a single transmission line is an important consideration, as the amount of congestion present on the transmission system, in part, is a function of the amount of available transmission capacity on a single transmission line. Generally speaking, the higher the voltage of a transmission line, the higher capacity the line has to carry power, assuming the same current. The correlation between voltage level and the capacity of a transmission line is shown by the following equation:

$$\text{Three Phase AC Power (MVA, capacity)} = \text{Volts (V)} \times \text{Amperes (I)} \times \sqrt{3}$$

The following table provides a general comparison of the capacity of transmission lines operated at different voltages assuming the same current of 3000 Amps.

Table 5-1
Comparison of Capacity by Voltage Level

Voltage Level	Capacity (MVA)
69 kV	358.5
115 kV	597.6
230 kV	1195.1
345 kV	1792.7
Double-Circuit 345/345 kV	3585.4
500 kV	2598.1

Given the increasing amounts of renewable generation in Minnesota and the surrounding states, it is important that sufficient transmission capacity be in place to deliver this renewable generation reliably, efficiently, and economically to load centers.

In Minnesota, 345 kV is the standard high voltage that is utilized to transfer large amounts of power long distances. The 345 kV voltage is the standard because it provides sufficient capacity to accommodate large power transfers, can be easily incorporated into the existing transmission system, and minimizes line losses. Voltages higher than 345 kV are currently less utilized in Minnesota and are reserved for long distance point-to-point power transfers (i.e., moving power from Manitoba's hydro generation facilities into Minnesota). Voltages lower than 345 kV are used primarily for load serving support. Following an evaluation, the Applicants concluded that the proposed 345 kV voltage is the appropriate voltage level to address reliability issues, relieve congestion, and to efficiently transfer generation currently projected to be developed in Minnesota and surrounding states.

5.1.1.1 Higher Voltage

The Applicants considered higher voltage 765 kV and 500 kV transmission lines as alternatives to the proposed 345 kV transmission lines. There are currently no 765 kV transmission lines in Minnesota and, although there are two 500 kV transmission lines in Minnesota, neither 500 kV line is located in the Project area. As a result, constructing a new 765 kV or 500 kV transmission line would require additional substation transformers to accommodate these higher voltage transmission lines. Specifically, connecting higher voltage lines to the existing electric system, mainly comprised of 345 kV, 230 kV, 115 kV, 69 kV, and 41.6 kV lines in the Project area, would require installation of additional transformers at the existing Big Stone South Substation, the existing Alexandria Substation, the existing Riverview Substation, and at the new Big Oaks Substation.

In addition to the costs of these substation transformers, 765 kV and 500 kV lines are, in general, more costly to construct than 345 kV transmission lines and are meant for long distance power transfer. For comparison, a single-circuit 500 kV line would generally cost approximately $4.1 million per mile and would require, at a minimum, a 500 kV/345 kV transformer at each substation connection at a cost of approximately $20 million per transformer. In contrast, the indicative cost estimate for a double-circuit 345 kV line is approximately $3.5 million per mile. Further, the majority of the Eastern Segment of the Project involves stringing an additional 345 kV circuit on the existing CapX2020 transmission line structures, which were constructed as 345/345 kV double-circuit capable as part of the Monticello to St. Cloud 345 kV Transmission Project (Docket No. ET2/TL-09-246) and the Fargo to St. Cloud 345 kV Transmission Project (Docket No. E002, ET/TL-09-1056). These existing double-circuit structures were not built to accommodate a 500 kV or 765 kV circuit and would need to be removed and replaced if a 500 kV of 765 kV circuit were to be installed, resulting in significant additional costs and environmental impacts compared to the currently proposed 345 kV Project.

A 500 kV or 765 kV transmission line would also require a wider right-of-way than the proposed 345 kV transmission line. A 500 kV or a 765 kV transmission line would require at least 200 feet of right-of-way while a 345 kV transmission line only requires

150 feet of right-of-way. In addition, the typical construction for a 500 kV or 765 kV transmission line would likely be a two-pole structure or a four-legged latticed type structure that would result in greater environmental impacts along the route (two or four foundations per structure as opposed to one foundation for a double-circuit 345 kV structures).

Based on Applicants' analysis, higher voltage transmission lines above 345 kV are not a more reasonable or prudent alternative to the proposed Project.

5.1.1.2 Lower Voltage

The Applicants also analyzed lower voltage alternatives to the Project. Transmission line voltages lower than 345 kV include: 230 kV, 161 kV, 138 kV, 115 kV, 69 kV, and 41.6 kV. As there are existing 230 kV, 115 kV, 69 kV, and 41.6 kV transmission lines in the Project area, the Applicants examined these lower voltages as alternatives to the proposed 345 kV Project.

The Project is designed to address issues on the heavily constrained 230 kV system in eastern North Dakota and South Dakota and western and central Minnesota. The existing 230 kV system is congested during periods of high renewable generation which results in higher energy prices for Minnesota customers. This is because lower cost renewable energy is unable to reach customers. Because of congestion, higher cost resources must be dispatched and renewable generation is curtailed. Given the lower capacity of 115 kV, 69 kV, and 41.6 kV transmission lines, the Applicants eliminated these lower voltage alternatives from further study as these voltages would not have sufficient capacity to address the congestion issues on the existing 230 kV system and would not offer the capacity needed to support future renewable generation. As a result, installing these lower voltage alternatives would require more transmission facilities to be constructed in the future to provide additional capacity to support this future generation. With regard to a lower voltage 230 kV alternative, the 230 kV system in the Project area is currently heavily congested, so it is beneficial to install transmission facilities with voltages greater than 230 kV to unload the existing 230 kV system. In addition, the cost of a 345 kV is similar to 230 kV but allows for significantly greater capacity to support future generation in the Project area.

Another consideration in determining the appropriate voltage for a new transmission line is whether the voltage of the new line is present on the existing system in the Project area. The majority of the transmission system in the Project area is at the 345 kV voltage level such that integrating a new line at the 345 kV voltage fits into the existing system without requiring the need to construct additional substation facilities. For instance, a lower voltage line would require additional costs associated with substation upgrades to accommodate the introduction of new voltage to the system. The existing Big Stone South and Alexandria substations already have 345 kV infrastructure such that additional transformation is not required. If a lower voltage alternative such as 230 kV or 115 kV is selected, additional transformers might be needed at these substations resulting in increased costs.

Another drawback of lower voltage alternatives is that lower voltage lines tend to have higher losses than higher voltage lines. This is because when the voltage of a line is lowered, the line rating must be increased to achieve similar levels of power transfer. To achieve a comparable line rating on a lower voltage line, larger conductor and thus larger structures, foundations and associated hardware would also be required leading to higher costs.

Based on the analysis discussed above, the Applicants determined that lower voltages are not a more reasonable or prudent alternative to the Project.

5.1.2 Common Tower

The Western Segment of the Project involves construction of a single-circuit 345 kV transmission line on double-circuit capable structures from the Big Stone South Substation to the Alexandria Substation. There is an existing 115 kV transmission path between Big Stone and Alexandria that includes the following transmission line segments:

- Big Stone – Highway 12
- Highway 12 – Ortonville
- Ortonville – Johnson Junction
- Johnson Junction – Morris
- Morris – Grant County

- Grant County – Elbow Lake
- Elbow Lake – Brandon
- Brandon – Lake Mina
- Lake Mina – Alexandria

The Applicant's evaluated a common tower alternative for the Western Segment and concluded that it is not a preferred alternative. MISO's approval of the Project specified that the Western Segment will be built with double-circuit capable structures for a future 345 kV circuit. Therefore, a common tower alternative for the Western Segment would require a triple-circuit line. As further discussed below, triple-circuiting is not desired because it can increase cost due to removing the existing facilities that have not yet reached the end of their useful life and lead to operational and maintenance challenges.

The Eastern Segment of the Project involves stringing a second single-circuit 345 kV circuit on existing double-circuit capable structures from the Alexandria Substation to near the Big Oaks Substation. For this portion of the Project, the Applicants evaluated triple-circuiting. Triple-circuiting the Eastern Segment of the Project would require removal of the existing double-circuit capable structures that were installed between 2012 and 2014 and replacing those structures with new triple-circuit structures. Transmission structures like these generally have useful lives of approximately 60 years, thus replacing these structures that are far from the end of their useful lives would add significant costs to the Project. In addition, while triple-circuiting a line may be technically feasible, there are operational and maintenance concerns with this design. Generally, all three lines must be taken out of service to work on a single line. Triple-circuit structures are taller than double-circuit structures, would likely require two poles rather than one pole, and would require a wider right-of-way of 175 to 200 feet as compared to the typical 150 foot right-of-way for a single-circuit and double-circuit 345 kV transmission line.

5.2 Type Alternatives

5.2.1 Transmission with Different Terminals/Substations

Both MISO and the Applicants evaluated transmission lines with different substation endpoints to relieve the identified congestion and to meet reliability needs. As part of

MTEP21, MISO evaluated alternative LRTP Tranche 1 projects on a regional basis. For eastern North Dakota and South Dakota and western and central Minnesota, MISO tested system solutions against its approved projects, comprised of the Jamestown – Ellendale 345 kV line in North Dakota[68] and the Big Stone South – Alexandria – Big Oaks 345 kV line (the Project in this Application). These two LRTP projects address issues on the heavily constrained 230 kV system in eastern North Dakota and South Dakota and western and central Minnesota, relieving many thermal and voltage issues for this region. MISO evaluated five alternative transmission line configurations to address these same issues. Because the Jamestown – Ellendale 345 kV transmission project is necessary in each instance, MISO's evaluation assessed five alternatives to the Big Stone South – Alexandria – Big Oaks 345 kV transmission line. Provided below are the five alternatives MISO considered and a summary of the results of MISO's reliability studies. Based on this analysis, MISO determined that none of these alternatives is a more reasonable or prudent alternative to the Project.

5.2.1.1 Alternative 1: Big Stone South – Alexandria 345 kV and Jamestown – Ellendale 345 kV

The first alternative that MISO examined was construction of the Jamestown – Ellendale 345 kV transmission line along with a 345 kV transmission line between Big Stone South and Alexandria (Alternative 1). Alternative 1 is depicted in **Map 5-1** below.

[68] The Jamestown – Ellendale 345 kV transmission project was approved by MISO in MTEP21 as LRTP1.

Map 5-1
MISO Alternative 1

Alternative 1 differs from the proposed Project in that it does not include adding a new 345 kV connection between the existing Alexandria Substation and the new Big Oaks Substation. Without the proposed 345 kV transmission line between the Alexandria to Big Oaks substations, construction of Alternative 1 results in new, unmitigated thermal overloads on certain transmission lines near the Alexandria Substation when there are outages of other transmission facilities. **Table 5-2** below lists the transmission lines that would experience reliability issues if Alternative 1 is constructed. These thermal issues do not exist if the proposed Project is constructed. The proposed Alexandria – Big Oaks 345 kV transmission line is needed to mitigate congestion around the Alexandria Substation area. By not completing the Alexandria – Big Oaks 345 kV transmission line, the resulting system configuration would have two 345 kV lines (i.e., the Big Stone South – Alexandria 345 kV line and the Bison – Alexandria 345 kV line) that could be delivering power into the Alexandria Substation with only one 345 kV outlet (i.e., the existing Alexandria to Monticello 345 kV transmission line) to the Twin Cities.

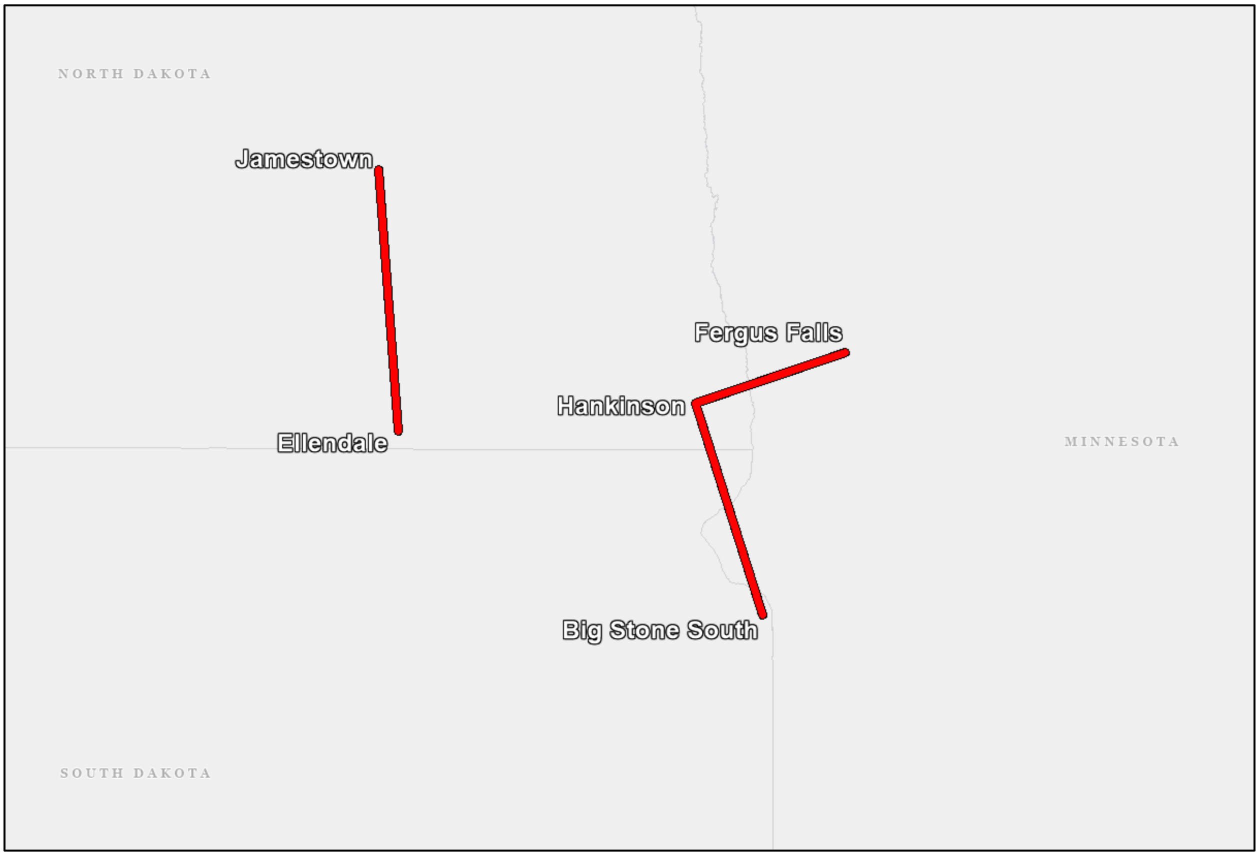
Table 5-2
Thermal Reliability Issues Resulting From Alternative 1

Alternative 1 - Big Stone South-Alexandria & Jamestown-Ellendale Reliability Issues
St. Cloud - Wakefield 115 kV
Minnesota Pipeline - Aldrich 115 kV
Verndale - Aldrich 115 kV
Long Prairie - Little Sauk 115 kV
Inman - Wing River 230 kV

5.2.1.2 Alternative 2: Big Stone South – Hankinson – Fergus Falls 345 kV and Jamestown – Ellendale 345 kV

The second alternative that MISO examined was construction of the Jamestown – Ellendale 345 kV transmission line along with a 345 kV transmission line between the Big Stone South, Hankinson, and Fergus Falls substations (Alternative 2). Alternative 2 is depicted in **Map 5-2** below.

Map 5-2
MISO Alternative 2



Alternative 2 solves overloads of concern on the 230 kV system around Wahpeton, North Dakota but creates new issues on the 230 kV and 115 kV system around Fergus Falls, Minnesota. **Table 5-3** lists the transmission lines that would experience thermal issues if Alternative 2 is constructed instead of the proposed Project. Alternative 2 would result in thermal issues because this alternative would not provide sufficient transmission outlet from the Fergus Falls Substation to the Twin Cities area. By not constructing the new Alexandria – Big Oaks 345 kV transmission line, the resulting system configuration would have two 345 kV lines that could be delivering power to the Fergus Falls area (i.e., Big Stone South – Hankinson – Fergus Falls and Bison – Fergus Falls) without sufficient transmission outlet to the Twin Cities.

Table 5-3
Thermal Reliability Issues Resulting From Alternative 2

Alternative 2 - Big Stone South-Hankinson-Fergus Falls & Jamestown-Ellendale Reliability Issues
St. Cloud - Wakefield 115 kV
Minnesota Pipeline - Thomastown 115 kV
Minnesota Pipeline - Aldrich 115 kV
Verndale - Wing River 115 kV
Verndale - Aldrich 115 kV
Long Prairie - Little Sauk 115 kV
Inman - Wing River 230 kV
Inman - Henning 230 kV
Silver Lake - Henning 230 kV
Silver Lake - Fergus Falls 230 kV
Hoot Lake - Fergus Falls 115 kV
Fergus Falls 230/115 kV TR1

5.2.1.3 Alternative 3: Big Stone South – Hazel Creek – Blue Lake 345 kV and Jamestown – Ellendale 345 kV

The third alternative examined by MISO was construction of the Jamestown – Ellendale 345 kV transmission line along with a 345 kV transmission line between the Big Stone South, Hazel Creek, and Blue Lake substations (Alternative 3). Alternative 3 is depicted in **Map 5-3** below.

Map 5-3
MISO Alternative 3

Alternative 3 reduces nearly all of the same overloads of concern as the proposed Project but, as shown in **Table 5-4**, results in a thermal issue on the Long Prairie – Little Sauk 115 kV line that does not occur if the proposed Project is constructed. The Big Stone South – Hazel Creek – Blue Lake 345 kV alternative provides similar system benefits to the proposed Project but did not fully address congestion issues in western and central Minnesota. Even if the performance of the transmission system is similar with Alternative 3, the proposed Project would be expected to have fewer environmental impacts and can be constructed at a lower cost than Alternative 3 because it involves less miles.

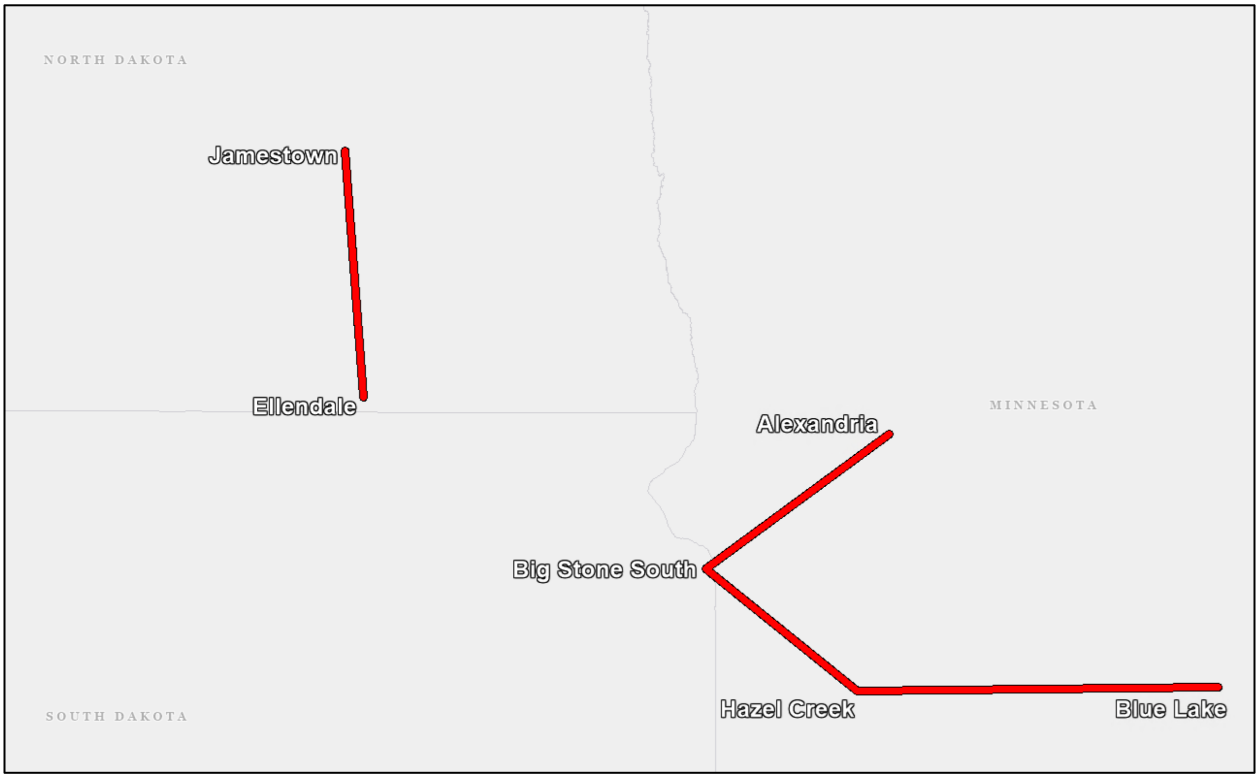
Table 5-4
Thermal Reliability Issues Resulting From Alternative 3

Alternative 3 - Big Stone South-Hazel Creek-Blue Lake & Jamestown-Ellendale Reliability Issues
Long Prairie - Little Sauk 115 kV

5.2.1.4 Alternative 4: Big Stone South – Alexandria 345 kV, Big Stone South – Hazel Creek – Blue Lake 345 kV, and Jamestown – Ellendale 345 kV

The fourth alternative considered by MISO involved construction of the Jamestown – Ellendale 345 kV transmission line and a combination of Alternative 1 and Alternative 3. Specifically, this alternative involves the construction of the Jamestown – Ellendale 345 kV transmission line along with a Big Stone South – Alexandria 345 kV transmission line and a 345 kV transmission line between the Big Stone South, Hazel Creek, and Blue Lake substations (Alternative 4). Alternative 4 is depicted in **Map 5-4** below.

Map 5-4
MISO Alternative 4



Alternative 4 reduces nearly all of the same overloads of concern as the proposed Project but, as shown in **Table 5-5**, results in a thermal issue on the Long Prairie – Little Sauk 115 kV line that does not occur if the proposed Project is constructed. In addition, on a straight-line mileage basis, Alternative 4 is longer than the proposed Project. The proposed Project is approximately 200 miles long whereas the Big Stone South – Alexandria 345 kV transmission line and the Big Stone South – Hazel Creek – Blue Lake 345 kV transmission line are together, approximately 234 miles long. The additional transmission line miles of Alternative 4 would result in increased costs and greater environmental impacts as compared to the proposed Project and still only achieve a similar performance as the proposed Project.

Table 5-5
Thermal Reliability Issues Resulting From Alternative 4

Alternative 4 - Big Stone South-Alexandria & Big Stone South-Hazel Creek-Blue Lake & Jamestown-Ellendale Reliability Issues
Long Prairie - Little Sauk 115 kV

5.2.1.5 Alternative 5: Big Stone South – Breckenridge – Barnesville 345 kV and Jamestown – Ellendale 345 kV

The fifth alternative considered by MISO involves construction of the Jamestown – Ellendale 345 kV transmission line and a new 345 kV transmission line connecting the Big Stone South, Breckenridge, and Barnesville substations (Alternative 5). Alternative 5 is depicted in **Map 5-5** below.

Map 5-5
MISO Alternative 5

Table 5-6 lists the transmission lines that would experience thermal issues if Alternative 5 is constructed instead of the proposed Project. Similar to the prior alternatives, Alternative 5 would result in thermal issues because this alternative would result in a system configuration that would have two 345 kV lines that could be delivering power to the Barnesville area (i.e., Big Stone South – Breckenridge – Barnesville and Bison – Barnesville) without sufficient transmission outlet to the Twin Cities area.

Table 5-6
Thermal Reliability Issues Resulting From Alternative 5

Alternative 5 - Big Stone South-Breckenridge-Barnesville & Jamestown-Ellendale Reliability Issues
St. Cloud - Wakefield 115 kV
West St. Cloud - Le Sauk 115 kV
Audubon - Lake Park 230 kV
Lake Park - Barnesville 230 kV
Fergus Falls - Breckenridge 230 kV

In addition to evaluating these five alternative transmission lines with different substation endpoints to relieve the identified congestion and reliability issues, both MISO and the Applicants also considered the ability to use existing corridors and/or existing infrastructure to meet the identified need.

5.2.1.6 Monticello Substation Termination

MISO and the Applicants also analyzed terminating the new 345 kV transmission at the existing Monticello Substation rather than constructing a new substation (i.e., the Big Oaks Substation). Both MISO and the Applicants determined that there was not sufficient space at the existing Monticello Substation to add the additional 345 kV line termination required for the Project and the Iron Range – Benton County – Big Oaks 345 kV Project (LRTP3 or the Northland Reliability Project, Docket No. ET015, ET2/CN-22-416). In addition, constructing a new substation would provide room for additional transmission line terminations that may be needed in the future as the system expands.

5.2.2 Upgrading Existing Transmission Lines

The Applicants considered upgrading existing transmission facilities as an alternative to the Project. For the Eastern Segment, the majority of the length of this segment already involves upgrading an existing 345 kV transmission circuit on double-circuit capable structures to add an additional 345 kV transmission circuit.

For the Western Segment, the Applicants considered the existing 115 kV transmission line segments between Big Stone, South Dakota, and Alexandria, Minnesota, as an opportunity to upgrade existing transmission lines to implement the Western Segment of the proposed Project.

The Applicants concluded that it is not cost effective to upgrade this existing 115 kV transmission line to 345 kV because it would be necessary to add new step-down transformers along this existing transmission line at nine separate locations to interconnect to the existing transmission system.[69] These step-down transformers would be needed to interconnect the proposed Project into the lower voltage facilities that exist at each of these locations to maintain reliability of this lower voltage transmission system.

5.2.3 Double-Circuiting of Existing Transmission Lines

Double-circuiting is the construction of two separate circuits on the same structures to reduce the overall amount of right-of-way required. Double-circuiting transmission lines minimizes the need for new right-of-way and expansion of the overall footprint of the transmission system.

The Eastern Segment of the Project is already proposed to be double-circuited with an existing 345 kV transmission line for over 90 percent of its length. The proposed Project deviates from the existing 345 kV transmission line to terminate at the Big Oaks Substation because the existing Monticello Substation where the existing 345 kV transmission line terminates is at capacity and cannot accommodate an additional 345 kV line termination. The Applicants examined double-circuiting the remaining portion of the Eastern Segment of the Project from where the transmission line leaves the existing CapX2020 345 kV transmission line structures to cross the Mississippi River into the Big Oaks Substation. The Applicants determined that there was no additional capacity or reliability benefit to constructing this short one-mile segment as a 345/345 kV double-circuit transmission line at the time of initial construction.

[69] New step-down transformers would be needed at Big Stone, Highway 12, Ortonville, Johnson Junction, Morris, Grant County, Elbow Lake, Brandon and Lake Mina because the 345 kV voltage level does not currently exist at these substations.

The Applicants considered double-circuiting the Western Segment of the proposed Project with the existing 115 kV transmission line segments between Big Stone, South Dakota, and Alexandria, Minnesota. The Applicants determined that double-circuiting this existing 115 kV transmission line was not prudent because many of these 115 kV transmission segments have recently been upgraded. Replacing these existing 115 kV transmission line segments with double-circuit 345/115 kV transmission lines would result in removing the existing transmission line structures and replacing them with double-circuit structures. As mentioned previously, transmission lines generally have useful lives of approximately 60 years, thus replacing these existing transmission lines that are far from the end of their useful lives would add significant costs to the Project. In addition, while double-circuiting the Western Segment of the proposed Project with the existing 115 kV line segments may be technically feasible, there are operational and maintenance concerns. Generally, both lines must be taken out of service to work on a single line that would cause increased congestion and reliability concerns when maintenance is underway. Furthermore, with MISO's approval specifying that the Western Segment will be built with double-circuit capable structures for a future 345 kV circuit, it is less desirable to leverage the existing 115 kV transmission line segments because it would result in the need for a triple-circuit line which was not preferred for the reasons stated above in Section 5.1.2.

5.2.4 Direct Current Line

Applicants considered a High Voltage Direct Current (HVDC) line in place of the proposed AC facilities. An HVDC transmission system consists primarily of a converter station, in which the AC voltage of the conventional power grid is converted to HVDC voltage, a transmission line, and another converter station at the other end, where the voltage is converted back into AC.

An HVDC transmission line is generally employed to deliver generation over a considerable distance, more than 300 miles, to a load center. HVDC systems typically do not allow for cost-effective interconnections along the line.

While line losses and conductor costs associated with HVDC lines are generally less than those associated with high voltage AC lines, HVDC lines also require expensive converter stations at each end point of the line to convert power from AC to DC and

DC to AC. It should be noted that HVDC converter stations do not eliminate the need for AC substation facilities that would be required after the power is converted back to AC. There are also extended lead times (6 years or more) for HVDC systems.

Converter stations for 500 to 600 kV HVDC lines can range from approximately $400 million to $500 million.[70] Given the substantial additional cost imposed by the required HVDC converter stations, the costs associated with a HVDC design would exceed the benefits and therefore HVDC is not a more prudent or reasonable alternative to the proposed Project.

5.2.5 Underground Transmission Lines

Applicants evaluated underground transmission, both AC and DC, and concluded that an underground design would not be a feasible or reasonable alternative to the proposed overhead design due to the significantly higher cost of undergrounding a line of this length and voltage.

High voltage AC underground cable systems at 345 kV are generally limited in length to approximately 50 miles or less because of its impact on reactive power. While longer installations can be constructed with the addition of shunt reactors along the line, this is an atypical design and practical applications of underground high voltage AC lines for more than 50 miles are cost prohibitive due to the technical requirements required for a line of this length. As the proposed Project is approximately 200 miles in length, an underground high voltage AC design was deemed to be cost prohibitive.

High voltage DC cable systems are used for underground lines of approximately 100 miles or more. High voltage DC systems do not have the same reactive power limitations and line losses as high voltage AC underground cable systems. High voltage DC cable systems require converter stations on each end of the line to convert the voltage from DC to AC and AC to DC. Because of the need for conversion from overhead to underground and conversion of voltage through converter stations, high

[70] MISO's Transmission Cost Estimation Guide for MTEP21 at 39 available at: https://cdn.misoenergy.org/20210209%20PSC%20Item%2006a%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP21519525.pdf.

voltage DC lines do not readily accommodate interconnections at midpoints along the lines.

Both underground AC and DC designs are infeasible due to costs. Indicative estimates for underground high voltage DC over 100 miles are $25 million or more per mile, depending on the ultimate design. As with any high voltage DC option, the costs of two converter stations would be approximately $800 million to $1 billion.

Construction costs for AC underground transmission are anticipated to be similar to underground high voltage DC but would not require converter stations. Specifically, Applicants developed a cost estimate to underground two miles of a 345 kV line using an open trench construction method. Applicants determined that this open trench underground installation would cost at least $20 million per mile (2023$). This compares to an indicative cost estimate of $3.5 million per mile for Applicants' overhead designs. If underground is considered, the specific location must be studied as certain installations, for example a deep burial under a river, would result in additional costs. In addition, all underground cable installations behave differently, electrically, than overhead lines and therefore a study would be required to determine if reactive compensation is required. If reactive compensation is required, this would add several million dollars to the underground costs stated above. Based on this cost analysis, the Applicants determined that the underground design is not a reasonable alternative.

In addition, the majority of the Eastern Segment of the Project involves stringing a second 345 kV transmission line circuit on existing transmission structures that were initially constructed as double-circuit capable. An underground design for the Eastern Segment would mean that the cost savings associated with using these existing double-circuit structures would not be realized – in addition, reconstruction for an underground alternative would result in significantly more environmental impacts.

5.2.6 Alternative Conductors

The conductor for the Project will be determined during the final design of the Project based on the results of a conductor optimization study. This conductor optimization study will identify the optimal conductor configuration or configurations for the Project based on a technical and economic analysis of different conductor sizes and configurations.

For the Eastern Segment, the Applicants are currently evaluating several different conductor types for the new 345 kV transmission circuit. The different conductors that the Applicants are evaluating include: a double bundled 2x397.5 kcmil 26/7 ZTACSR "Ibis" conductor and a double bundled round (non-twisted pair) 954 kcmil 20/7 ACSS/TW "Cardinal" conductor.

For the Western Segment, the Applicants are considering twisted pair conductor using either double bundled 2 x 636 kcmil 26/7 ACSR "Grosbeak" or double bundled 2 x 795 45/7 ACSR "Tern".

5.2.7 Generation and Non-Wires Alternatives

5.2.7.1 Generation Alternatives

In evaluating alternatives to the proposed Project, Applicants considered the addition of new generation resources rather than the proposed transmission line facilities to resolve the congestion currently present. Fundamentally, however, adding new generation resources to resolve congestion is not a reasonable alternative given that generation alternatives will not add transmission capacity. Transmission congestion occurs when there is not enough transmission capacity to support all generation output at a particular time. Thus, regardless of the type of the generation facility evaluated, construction of additional generation facilities is not a feasible and prudent alternative to the Project because such generation would: (1) further exacerbate the congestion already present on the system; (2) result in underutilization of existing generation resources; and (3) likely be more costly than the proposed Project. In addition, the LRTP Tranche 1 Portfolio was designed to address the needs of the MISO Midwest subregion and it is not likely or cost effective that a generation alternative would be able to provide the regional benefits needed in the MISO Midwest subregion.

5.2.7.1.1 Peaking Generation

The Applicants considered peaking generation as an alternative to the Project. Peaking generation refers to flexible generation resources – typically natural gas or diesel generators – that can be quickly dispatched to supplement other generation resources. One of the purposes of this Project and the entire LRTP Tranche 1 Portfolio is to enable greater generation deliverability across the MISO Midwest subregion. Construction of additional peaking generation will not create the needed transmission capacity across the MISO Midwest subregion but rather worsen the existing congestion and curtailment issues and increase customer costs.

5.2.7.1.2 Distributed Generation

The Applicants considered distributed generation as an alternative to the Project. Distributed generation refers to generation that is located near load centers, is connected to the local distribution system, and is able to run continuously when called upon, most likely on natural gas or other fossil fuels. Renewable distributed generation and battery energy storage were also considered as alternatives and are discussed below. Fossil-fueled distributed generation has the same drawbacks as peaking generation. The Project is needed to provide additional transmission capacity to provide greater generation deliverability across the MISO Midwest subregion. As a result, adding additional distributed generation will not provide this additional transmission capacity and instead will only worsen the existing congestion and curtailment issues on the system. Construction of new distributed generation resources will also result in the underutilization of existing generation resources due to the congestion and curtailment issues.

5.2.7.1.3 Renewable Generation

The Applicants considered renewable generation as an alternative to the Project. Renewable generation refers to energy that is produced from the sun or the wind and that is either connected to the transmission system at a single transmission interconnection point or at multiple locations on the transmission and distribution system. As discussed in **Chapter 3**, western Minnesota, North Dakota, and South Dakota have abundant wind resources and, as a result, a number of large-scale wind facilities have already been constructed in these areas. The Project is needed to provide additional transmission capacity to provide greater generation deliverability for these existing renewable generation resources. The addition of new renewable generation resources in lieu of adding transmission capacity would only worsen the existing congestion and curtailment issues on the system and require further build-out of the transmission system.

5.2.7.2 Energy Storage

The Applicants considered energy storage as an alternative to the Project. Energy storage refers to the ability to capture energy produced at one point in time for use at a later time. Current energy storage technologies include battery storage systems and pumped hydro facilities. Energy storage was determined to not be a reasonable alternative to the proposed Project because in order to provide the same amount of congestion relief as the proposed Project, an energy storage solution would need to be a large and costly facility. The cost for utility-scale energy storage depends on a variety of factors but the levelized cost of energy storage has been estimated to range from $99/MWh to $253/MWh for an energy storage system with the capability to store 100 MW for up to 4 hours.[71] Utilizing the MTEP21 PROMOD models the average energy per year on the Western Segment of the Project is 3.5 Million MWh. Assuming the life of the transmission line to be 63 years, this results in a levelized cost of energy at $2.24/MWh. By way of comparison, the levelized cost of onshore wind ranges from $24/MWh to $75/MWh for 175 MW facility and the levelized cost of utility-scale solar ranges from $24/MWh to $96/MWh for 150 MW facility.[72]

5.2.7.3 Reactive Power Additions

The Applicants considered reactive power additions as an alternative to the Project. Reactive power additions refer to capacitor or reactor banks for voltage control. These devices generally maintain local voltage stability on the system. These devices are not effective at enabling large power transfers across a broad region such as those needed to relieve the existing congestion on the system. As a result, reactive power additions are not a reasonable alternative to the proposed Project. While reactive power additions are not by themselves able to accommodate large scale power transfers, these reactive power additions will likely be needed for ancillary support.

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[71] Lazard's Levelized Cost of Energy Analysis – Version 16.0 at 35. Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf.

[72] *Id.* at 37-38.

5.2.7.4 Flow Control Devices

The Applicants evaluated flow control devices as an alternative to the Project. Flow control devices refers to devices that divert power flows from constrained areas, but do not provide system stability or additional transmission capacity. Flow control devices are generally used to address more localized overloads where there is already sufficient capacity on the system. As discussed, the primary purpose of this Project is to provide additional transmission capacity across the MISO Midwest subregion. As flow control devices would not provide any additional transmission capacity to support generation outlet, these devices are not a viable alternative to the proposed Project.

5.2.7.5 Conservation and Demand-Side Management

The Applicants analyzed conservation and demand-side management as an alternative to the Project. Specifically, the Applicants analyzed conservation and demand-side management tools that reduce overall demand as well as tools that reduce peak demand. This included interruptible load programs and energy efficiency programs. Since the need for the Project is driven in part by the need for additional transmission capacity to deliver increasing amounts of renewable generation on the system across the MISO Midwest subregion rather than a localized increase in demand, conservation and demand-side management are not effective alternatives to meet the identified need. The Applicants provide information on their conservation and energy efficiency programs in **Appendix F**. **Appendix F** also provides discussion of how conservation and energy efficiency was considered by MISO in its evaluation and approval of the Project.

5.3 Any Reasonable Combination of Alternatives

As the only feasible alternative to meet the identified need is a transmission alternative and the proposed Project is the best performing alternative, there is no reasonable combination of alternatives that would be a more reasonable and prudent alternative to the Project.

5.4 No Build Alternative/Consequences of Delay

Applicants also considered the no build alternative, i.e., no new transmission facilities constructed to meet the identified need. If the Project is not constructed, Minnesota customers will be denied the reliability and economic benefits of this Project.

With regard to economic benefits, this Project relieves existing congestion on the system and provides provide up to $2.1 billion in economic savings across the MISO footprint over the first 20 years that it is in service and up to $3.8 billion in economic savings across the MISO footprint over the first 40 years that it is in service. Relieving the congestion on the transmission system is also important to enabling the state's ability to achieve its goal of 100 percent carbon-free generation by 2040. As discussed in **Chapter 3**, additional carbon-free generation will need to be added to the system to achieve this 2040 goal. This new generation will require the additional transmission capacity provided by the Project to deliver this power to customers.

As discussed in **Chapter 4**, MISO found that this Project also provides reliability benefits by relieving 40 elements with excessive thermal loading during N-1 contingencies and 70 elements with excessive loadings for N-1-1 contingencies.

6. TRANSMISSION LINE OPERATING CHARACTERISTICS

6.1 Transmission Line Operating Characteristics Overview

The major components of an overhead transmission line include: (1) an above-ground structure typically made from wood or steel, often referred to as a pole or tower; (2) the wires attached to the structure and carrying the electricity, called conductors; (3) insulators connecting the conductors to the structures to provide electrical insulation; (4) shield wires which protect the line from direct lightning strikes along with providing a fiber optic communications path between substations; and (5) ground rods located below ground and connected at each structure.

During operation, transmission lines are, for the most part, passive elements of the environment as they are stationary in nature with few, if any, moving parts. Their primary impact is aesthetic, i.e., a man-made structure in the landscape. Due to the physics of how electricity works, some chemical reactions occur around conductors in the air due to the electrical and magnetic fields created around the conductors. As a result, noise can occur in some circumstances as well as the potential for interference with electromagnetic signals. All of these operating characteristics are considered when designing the transmission line to prevent any significant impacts to its operation and to the overall environment.

6.2 Ozone and Nitrogen Oxide Emissions

Corona consists of the breakdown or ionization of air within a few centimeters of energized conductors. Usually some imperfection, such as a scratch on the conductor or a water droplet, is necessary to induce corona because transmission lines are designed to be corona free under typical operating conditions. Corona can produce ozone and oxides of nitrogen (NO_x) in the air surrounding the conductor. Ozone also forms in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants, such as hydrocarbons from auto emissions. The natural production rate of ozone is directly proportional to temperature and sunlight, and inversely proportional to humidity. Thus, humidity or moisture, the same factor that increases corona discharges from transmission lines, inhibits the production of ozone. Ozone is a very reactive form of an oxygen molecule and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short-lived.

Currently, both state and federal governments have regulations regarding permissible concentrations of ozone and oxides of nitrogen. The state and national ambient air quality standards for ozone are similarly restrictive. The National Ambient Air Quality Standard (NAAQS) for ozone is 0.070 parts per million (ppm) on an eight-hour averaging period. The state standard is 0.070 ppm based on the fourth highest eight-hour daily maximum average in one year.[73] The ozone created by the Project will be below these standards.

The national standard for nitrogen dioxide (NO_2), one of several oxides of nitrogen, is 100 parts per billion (ppb) and the annual standard is 53 ppb. The State of Minnesota is currently in compliance with the national standards for NO_2. The operation of the proposed Project will not create any potential for the concentration of these pollutants to exceed the nearby (ambient) air standards.

Sulfur hexafluoride (SF6) will be used in equipment that is installed at the substations. Small releases will occur as part of regular breaker operation and maintenance. Applicants will minimize sulfur hexafluoride emissions through operational best management practices (BMPs) and will monitor equipment for leaks. Applicants will comply with Environmental Protection Agency reporting requirements in the event a leak is detected.

6.3 Audible Noise

Noise is defined as unwanted sound. Noise may include a variety of sounds of different intensities across the entire frequency spectrum. Noise is measured in units of decibels (dB) on a logarithmic scale. Because human hearing is not equally sensitive to all frequencies of sound, certain frequencies are given more "weight." The A-weighted decibel (dBA) scale corresponds to the sensitivity range for human hearing. Noise levels capable of being heard by humans are measured in dBA. A noise level change of three dBA is barely perceptible to average human hearing. A five dBA change in noise level,

[73] Minn. R. 7009.0080.

however, is clearly noticeable. A 10 dBA change in noise levels is perceived as a doubling or halving of noise loudness, while a 20 dBA change is considered a dramatic change in loudness.

6.3.1 Noise Related to Construction of the Project

Construction activities will generate noise that is short-term and intermittent. Construction activities will be limited to daytime hours. As such, the Project will have temporary and localized noise impacts during construction, but overall will not have significant noise effects on the surrounding area. Residents living in close proximity to the construction of the Project would be temporarily affected by noise generated from construction activities. Construction activities are estimated to last 18 to 20 months for the Eastern Segment and between two and four years for the Western Segment, however noise would dissipate at a single location as construction crews progress along the Project's route.

6.3.2 Transmission Line Noise

Generally, activity-related noise levels during the operation and maintenance of transmission lines are minimal. Transmission conductors can produce noise under certain conditions. The level of noise depends on conductor conditions, voltage level, and weather conditions. In foggy, damp, or rainy weather, power lines can create a crackling sound due to the small amount of electricity ionizing the moist air near the conductors. During heavy rain, the background noise level of the rain is usually greater than the noise from the transmission line. As a result, people do not normally hear noise from a transmission line during heavy rain. During light rain, dense fog, snow, and other times when there is moisture in the air, transmission lines will produce audible noise equal to approximately household background levels. During dry weather, audible noise from transmission lines is barely perceptible by humans.

The MPCA has established standards for the regulation of noise levels. The land use activities associated with residential, commercial and industrial land have been grouped together into Noise Area Classifications (NACs).[74] Each NAC is then assigned both daytime (7 a.m. to 10 p.m.) and nighttime (10 p.m. to 7 a.m.) limits for land use activities within the NAC.[75] **Table 6-1** shows the MPCA daytime and nighttime limits in dBA for each NAC. The limits are expressed as a range of permissible dBA within a one-hour period; L50 is the dBA that may be exceeded 50 percent (30 minutes) of the time within an hour, while L10 is the dBA that may be exceeded 10 percent (six minutes) of the time within an hour. Residences, which are typically considered sensitive to noise, are classified as NAC-1.

Table 6-1
Minnesota Pollution Control Agency Noise Limits by Noise Area Classification (dBA)

Noise Area Classification (NAC)	Land Use Activities	Daytime		Nighttime	
		L_{50}	L_{10}	L_{50}	L_{10}
1	residential housing, religious activities, camping and picnicking areas, health services, hotels, educational services	60	65	50	55
2	retail, business and government services, recreational activities, transit passenger terminals.	65	70	65	70
3	highways, utilities, manufacturing, fairgrounds and amusement parks, agricultural and forestry activities.	75	80	75	80

The Applicants performed a noise analysis by assuming that the noise levels generated by the Project will be the same at night as those generated during the daytime. Using this assumption, compliance with the nighttime levels (more restrictive) will also demonstrate compliance with the daytime noise standards due to greater noise sensitivity of humans at night.

The Applicants anticipate that NAC-1 is likely to apply to the large majority of the Project. NAC-1 has a daytime L50 limit of 60 dBA and a nighttime L50 limit of 50 dBA. As shown in **Figure 6-1** to **Figure 6-3** the proposed 345 kV lines will be below the MPCA noise limits for NAC-1 which are the most stringent MPCA noise limits.

[74] Minn. R. 7030.0050.

[75] Minn. R. 7030.0040.

Figure 6-1
Calculated Audible Noise for Double-Circuit 345 kV for Eastern Segment at Nominal System Voltage

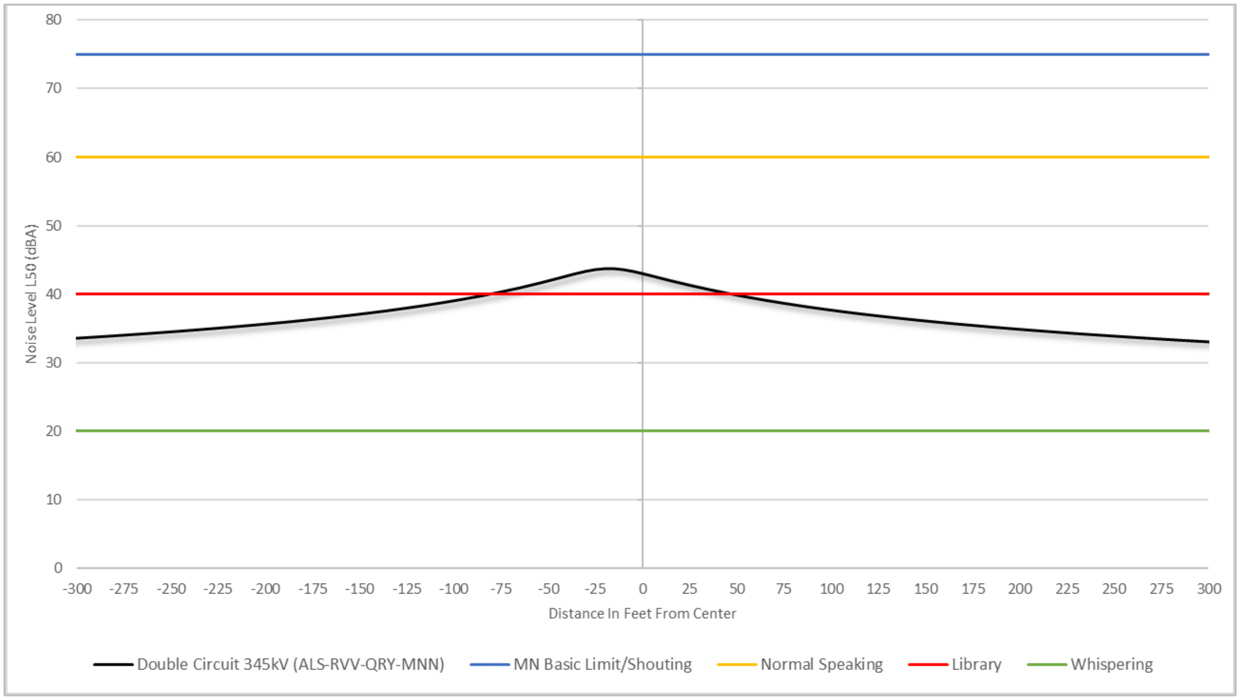


Figure 6-2
Calculated Audible Noise for Single-Circuit 345 kV for Eastern Segment at Nominal System Voltage

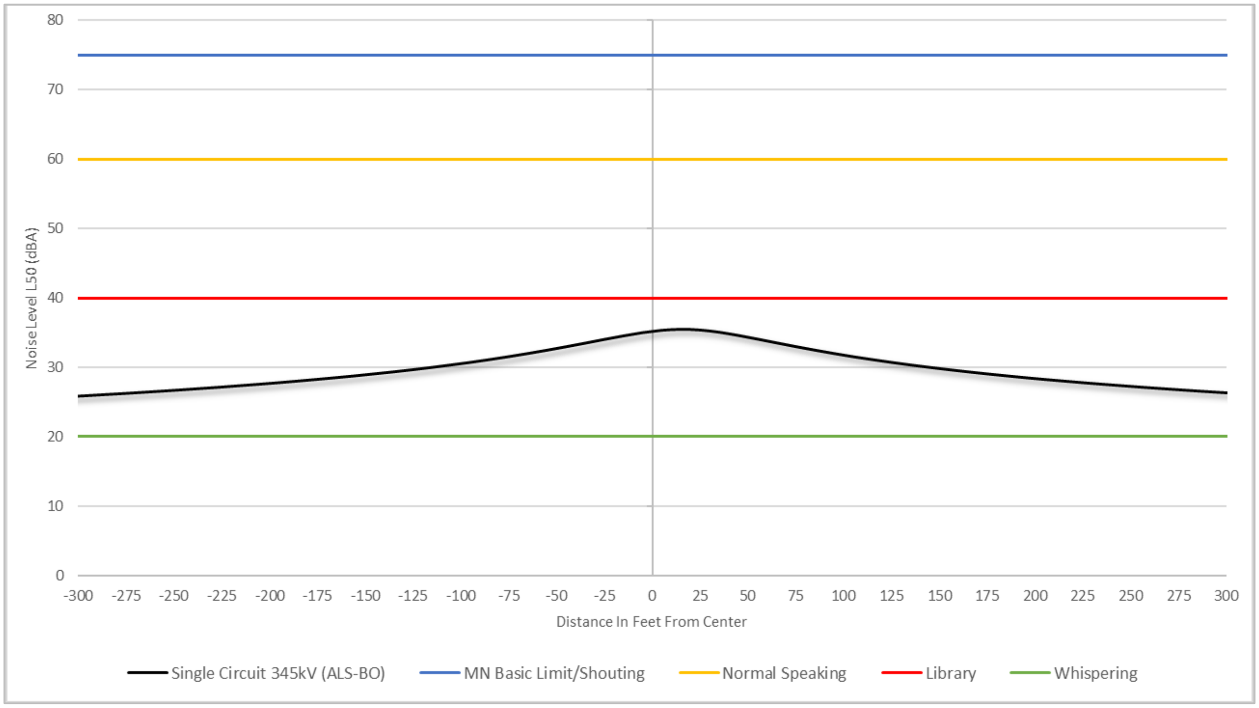
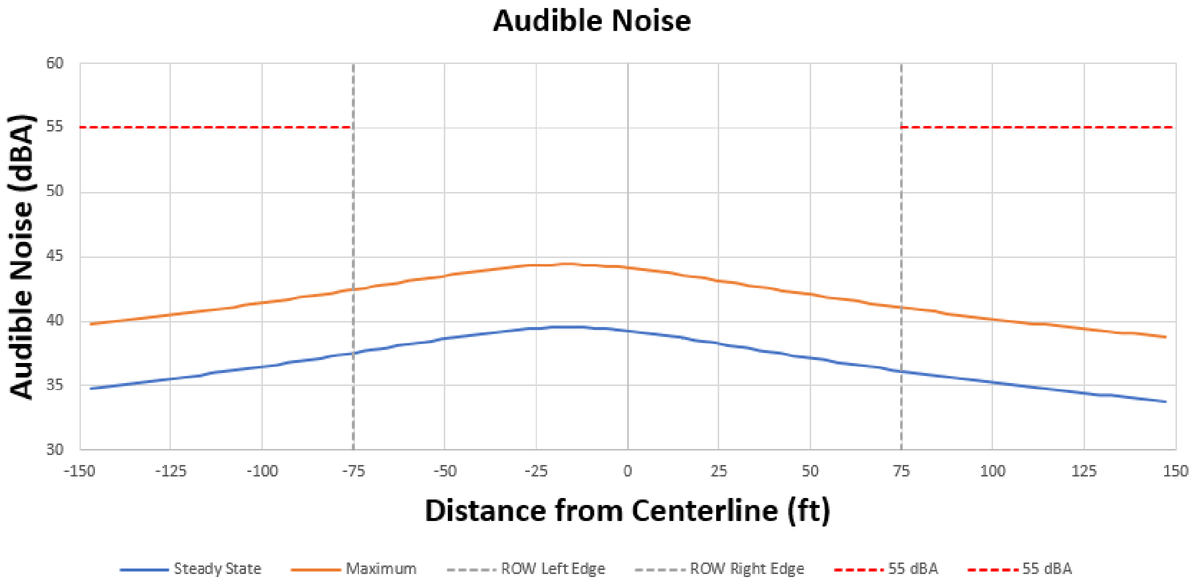


Figure 6-3
Calculated Audible Noise for Single-Circuit 345 kV for Western Segment at Nominal and Maximum System Voltage



6.3.3 Substation Noise

Substations may also contribute noise. Transformer or shunt reactor "hum" is the dominant noise source at substations if such equipment exists. At substations without transformers or shunt reactors, only infrequent noise sources would exist such as the opening and closing of circuit breakers or the operation of an emergency generator. Typical substation design is such that noise produced by these sources does not reach beyond the substation property. In the rare cases that space is limited around substations such that noise reduction cannot be accomplished, noise reduction designs are applied such as sound walls placed around transformers, or shelter belts planted around substations to reduce the distance the sound can travel. Like the transmission lines themselves, Project substations will comply with the MPCA noise standards as set forth in Minn. Rule 7030.0040.

6.4 Radio, Television, and GPS Interference

Overhead transmission lines are designed to not cause radio or television interference under typical operating conditions. Corona, as well as spark discharge, from transmission line conductors can generate electromagnetic "noise" at the same frequencies that some radio and analog television signals are transmitted.[76] This noise can cause interference with the reception of these signals depending on the frequency and strength of the radio and television signal. Interference from a spark discharge source can be found and corrected.

If radio interference from transmission line corona does occur, satisfactory reception from AM radio stations previously providing good reception can be restored by the appropriate modification of (or addition to) the receiving antenna system. AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly within the right-of-way to the edge of the right-of-way on either side of the line.

FM radio receivers usually do not pick up interference from transmission lines because:

- Corona-generated radio frequency noise currents decrease in magnitude with increasing frequency and are quite small in the FM broadcast band (88-108 Megahertz); and

- The excellent interference rejection properties inherent in FM radio systems make them virtually immune to amplitude-type disturbances.

A two-way mobile radio located immediately adjacent to and behind a large metallic structure (such as a steel tower) may experience interference because of signal-blocking effects. Movement of either mobile unit so that the metallic structure is not immediately between the two units should restore communications. This would generally require a movement of less than 50 feet by the mobile unit adjacent to a metallic tower.

Television interference is rare but may occur when a large transmission structure is aligned very close to the receiver and between the receiver and a weak distant signal, creating a shadow effect. If television or radio interference is caused by or from the operation of the proposed facilities in areas where good reception is presently obtained,

[76] Full power television stations were required by the DTV Delay Act, Public Law No: 111-4, to cease broadcasting signals by June 12, 2009.

Applicants will take necessary action to restore reception to the present level, including the appropriate modification of receiving antenna systems if deemed necessary.

Transmission lines typically do not cause interference with Global Positioning Systems (GPS). Utilities regularly use GPS-based surveying methods under and around transmission lines and have not experienced interference.

6.5 Safety

The Project will be designed in compliance with local, state, and NESC standards regarding clearance to ground, clearance to crossing utilities, clearance to buildings, strength of materials, and right-of-way widths. Appropriate standards will be met for construction and installation, and all applicable safety procedures will be followed during and after installation of the Project.

The proposed transmission lines will be equipped with protective devices to safeguard the public from the transmission lines if an accident occurs, such as a structure or conductor falling to the ground. The protective devices include breakers and relays located where the line connects to the substations. The protective equipment will de-energize the line should such an event occur.

6.6 Electric and Magnetic Fields

"EMF" is an acronym for the phrase electric and magnetic fields. For the lower frequencies associated with power lines (referred to as Extremely Low Frequency (ELF), EMF should be considered separately – electric fields and magnetic fields, measured in kilovolt per meter (kV/m) and milliGauss (mG), respectively. Electric fields are dependent on the voltage of a transmission line, and magnetic fields are dependent on the current carried by a transmission line. The strength of the electric field is proportional to the voltage of the line, and the intensity of the magnetic field is proportional to the current flow through the conductors. Transmission lines operate at a power frequency of 60 Hertz (cycles per second).

6.6.1 Electric Fields

There is no federal standard for transmission line electric fields. The Commission, however, has imposed a maximum electric field limit of 8 kV/m measured at one meter above the ground.[77] The standard was designed to prevent serious hazards from shocks when touching large objects parked under AC transmission lines of 500 kV or greater. **Figure 6-4** and **Figure 6-5** provides the electric fields at maximum conductor voltage for the proposed 345 kV transmission lines. Maximum conductor voltage is defined as the nominal voltage plus five to ten percent depending on the facility owner. The maximum electric field generated by the Project, measured at one meter (3.28 feet) above ground is calculated to be 5.7 kV/m. As shown in **Figure 6-4** and **Figure 6-5**, the strength of electric fields diminish rapidly as the distance from the conductor increases. The electric field values of all of the design options at the edge of the transmission line right-of-way and sample points beyond are shown in **Table 6-2**.[78] The Western Segment of the Project involves constructing a new single-circuit 345 kV transmission circuit that will be placed on new double-circuit capable structures from the Big Stone South Substation in South Dakota to the Alexandria Substation in Minnesota. The Eastern Segment of the Project involves stringing a new 345 kV transmission circuit on existing 345 kV structures to form a double-circuit 345/345 kV transmission line from the Alexandria Substation to the Riverview Substation to just outside the Big Oaks Substation. From just outside the Big Oaks Substation to the Big Oaks Substation, the Project will be constructed as a single-circuit transmission line.

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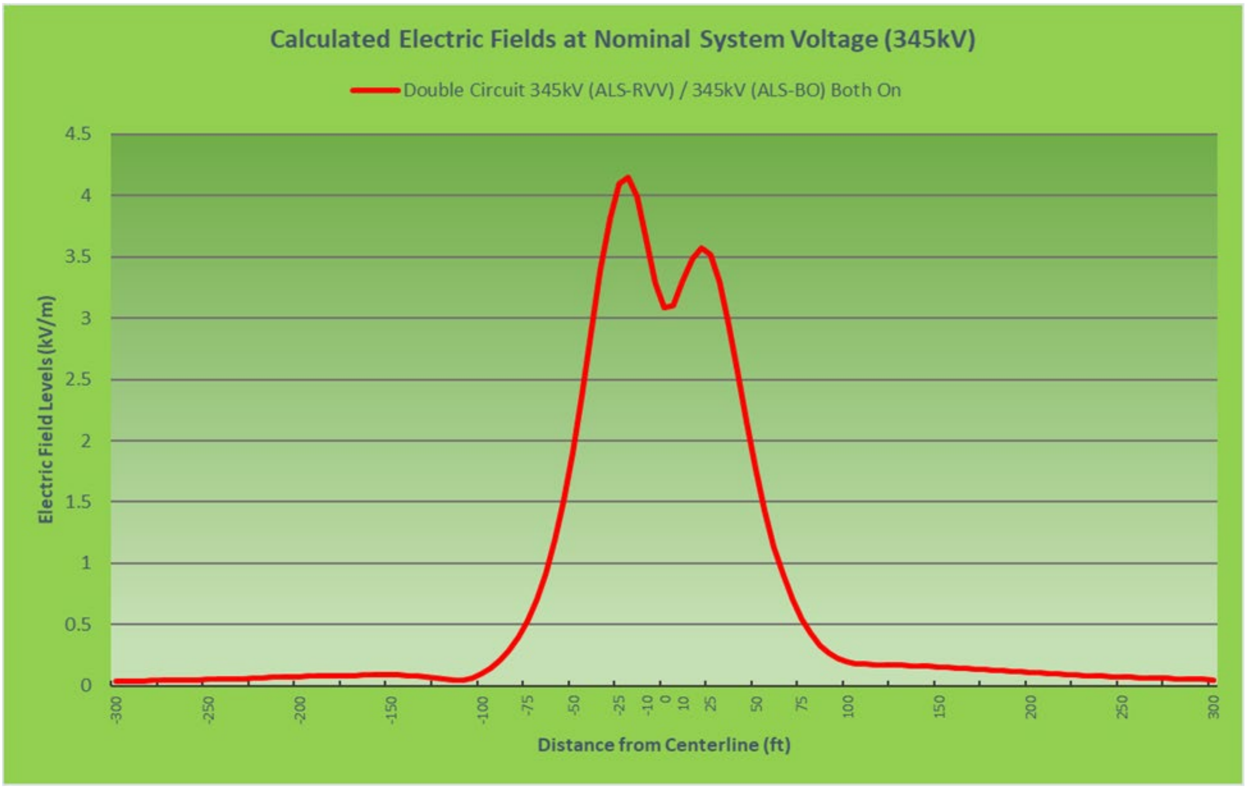
[77] *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton, Minn.*, Docket No. ET2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (Sept. 14, 2010) (adopting the Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation at Finding 194).

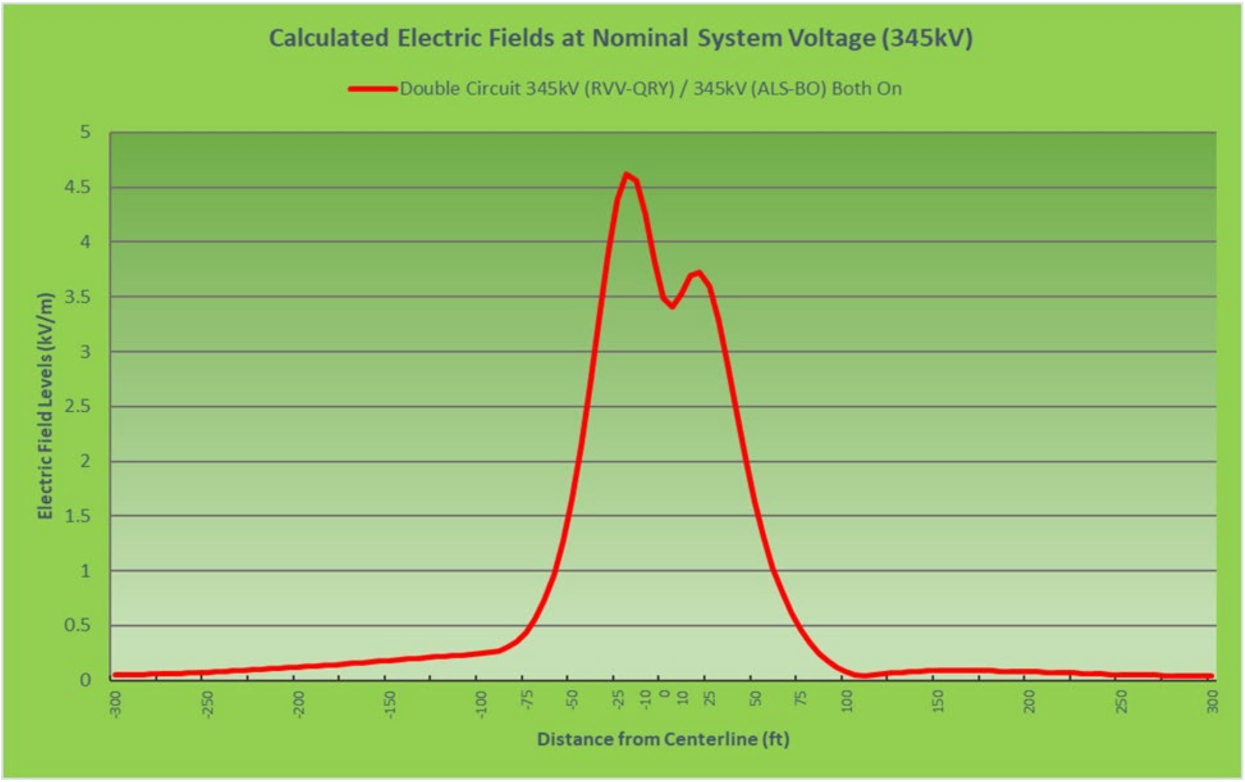
[78] Electric field calculations are not provided for Project substations because Project substations will not be accessible to the public, and electric fields associated with the substations are anticipated to be similar to the 345 kV lines and thus, well below the Commission's electric field limit.

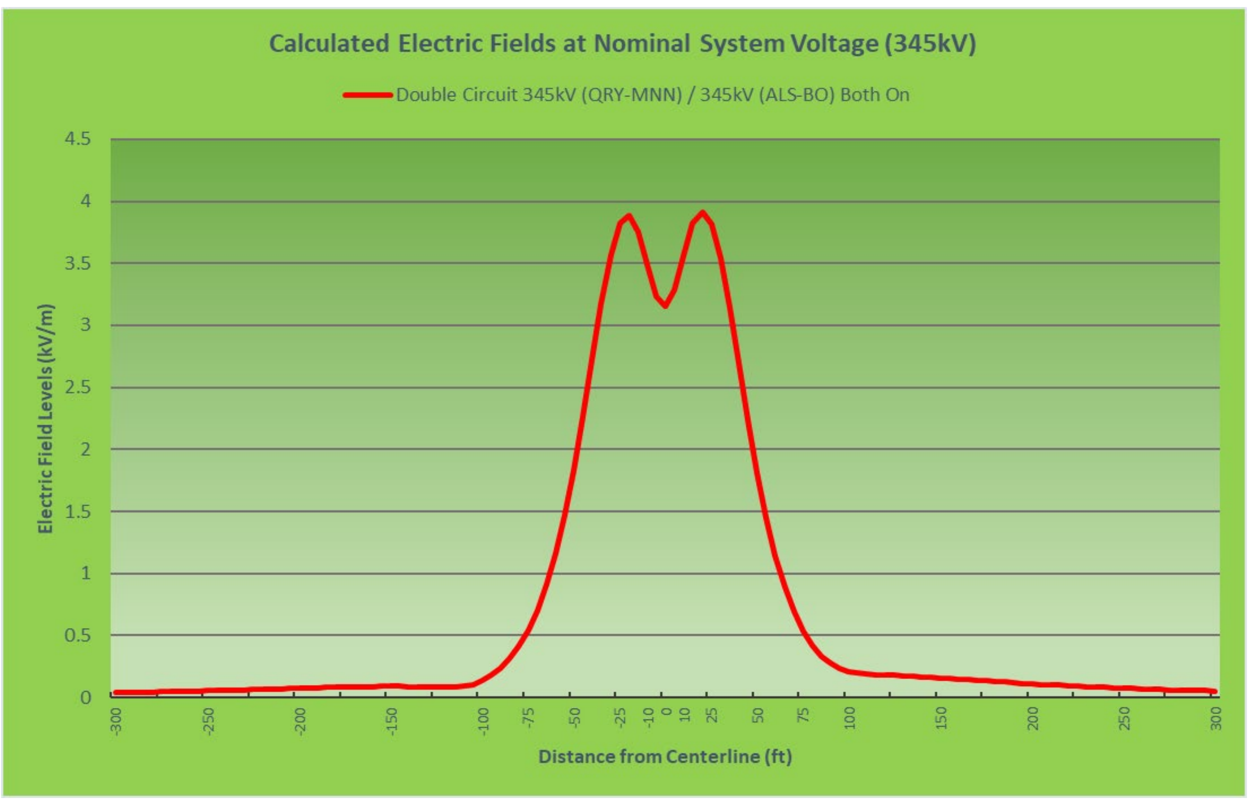
Table 6-2
Electric Field Calculations Summary

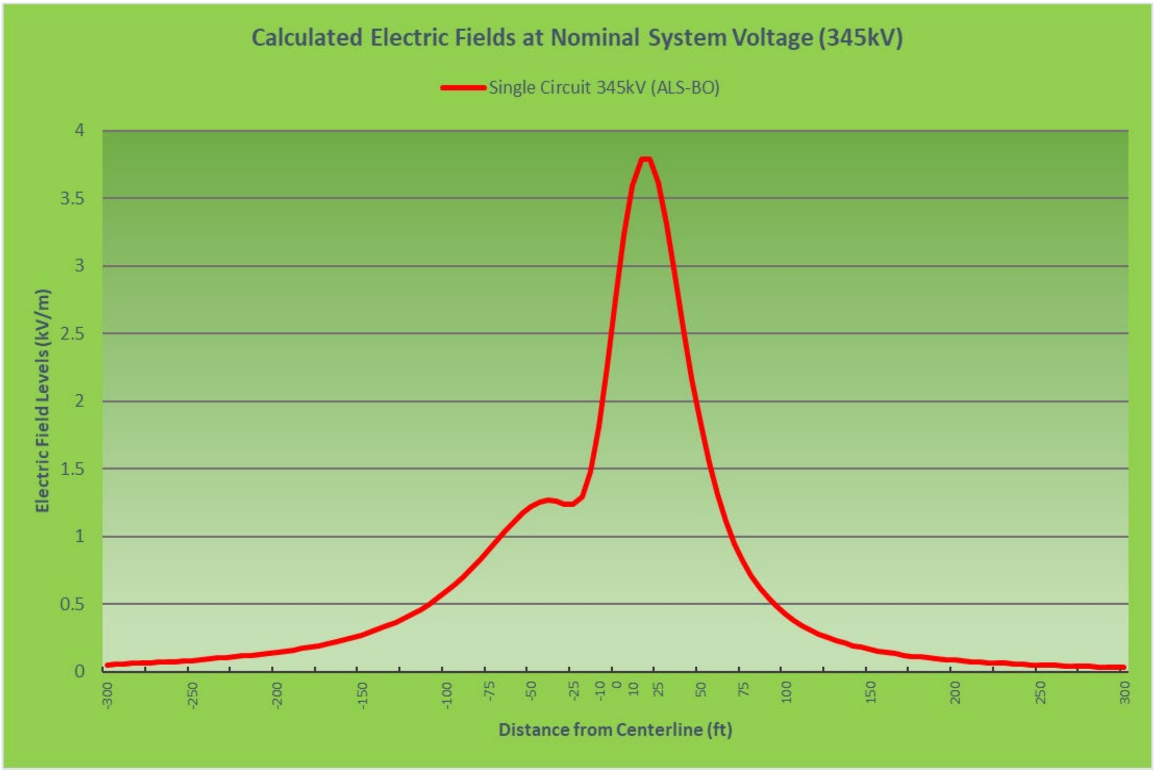
Structure Type	Circuits Present	Maximum Voltage	Distance to Proposed Centerline (feet)												
			-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit on Double-Circuit Capable Monopole	Big Stone South – Alexandria	379.5 kV	0.07	0.15	0.21	0.33	1.8	5.7	4.6	1.2	0.12	0.16	0.19	0.10	0.06
345 kV/345 kV Double-Circuit Monopole	Alexandria (ALS) – Riverview (RVV) Alexandria (ALS) – Big Oaks	362 kV	0.04	0.08	0.10	0.53	1.91	4.10	3.08	3.52	1.77	0.54	0.20	0.11	0.05
345 kV/345 kV Double-Circuit Monopole	Riverview (RVV) – Quarry (QRY) Alexandria (ALS) – Big Oaks	362 kV	0.05	0.12	0.24	0.44	1.66	4.39	3.49	3.59	1.64	0.46	0.08	0.08	0.04
345 kV/345 kV Double-Circuit Monopole	Quarry (QRY) – Monticello (MNN) Alexandria (ALS) – Big Oaks	362 kV	0.04	0.07	0.14	0.54	1.83	3.82	3.15	3.82	1.82	0.54	0.21	0.11	0.05
345 kV Single-Circuit Monopole	Alexandria (ALS) – Big Oaks	362 kV	0.05	0.14	0.59	0.90	1.22	1.23	2.76	3.61	1.83	0.82	0.43	0.08	0.03
345 kV Single-Circuit H-Frame	Alexandria (ALS) – Big Oaks	362 kV	0.07	0.20	1.11	1.76	2.30	1.74	0.82	1.82	2.08	1.51	0.95	0.18	0.06

Figure 6-4
Calculated Electric Fields (kV/m) for Proposed 345 kV Transmission Line Designs for Eastern Segment
(3.28 feet above ground)*




Calculated Electric Fields at Nominal System Voltage (345kV)
Double Circuit 345kV (RVV-QRY) / 345kV (ALS-BO) Both On
Electric Field Levels (kV/m)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
-300
-250
-200
-150
-100
-75
-50
-25
-10
0
10
25
50
75
100
150
200
250
300
Distance from Centerline (ft)


Calculated Electric Fields at Nominal System Voltage (345kV)
Double Circuit 345kV (QRY-MNN) / 345kV (ALS-BO) Both On
Electric Field Levels (kV/m)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
-300
-250
-200
-150
-100
-75
-50
-25
-10
0
10
25
50
75
100
150
200
250
300
Distance from Centerline (ft)


Calculated Electric Fields at Nominal System Voltage (345kV)
Single Circuit 345kV (ALS-BO)
Electric Field Levels (kV/m)
Distance from Centerline (ft)

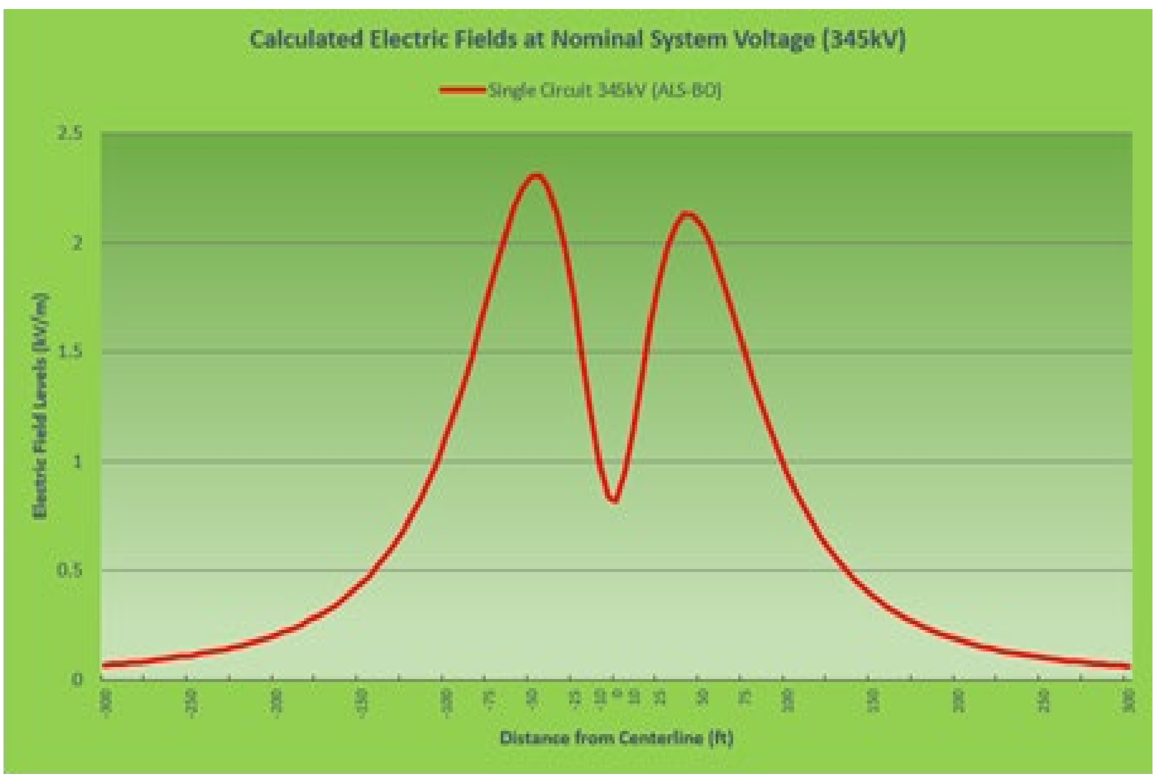
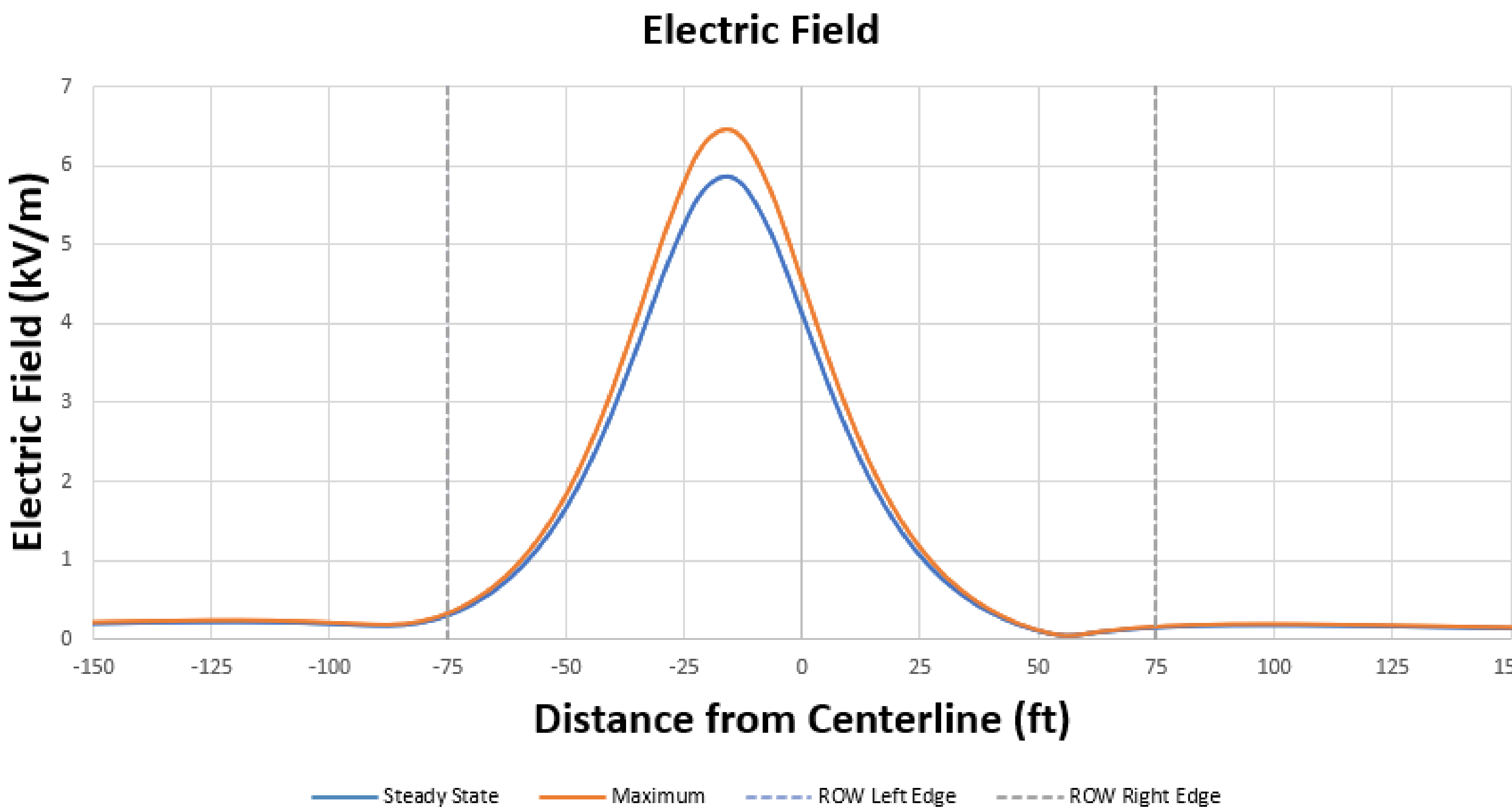

Calculated Electric Fields at Nominal System Voltage (345kV)
Single Circuit 345kV (ALS-BO)
Electric Field Levels (kV/m)
Distance from Centerline (ft)

Figure 6-5
Calculated Electric Fields (kV/m) for Proposed 345 kV Single-Circuit Transmission Line on Double-Circuit Capable Structures for Western Segment
(3.28 feet above ground)*



6.6.2 Magnetic Fields

The projected magnetic fields for different structure and conductor configurations for the Project are provided in **Table 6-3** and **Figure 6-6** and **Figure 6-7**. Since magnetic fields are dependent on the current flowing on the line, magnetic fields were calculated for two different typical system conditions: (1) System Peak Energy Demand and (2) System Average Energy Demand. The "System Peak Energy Demand" (estimated loading of 857 MVA on the Western Segment and 580 MVA on the Eastern Segment) represents the current flow on the line during the peak hour of system-wide energy demand. The "System Average Energy Demand" (estimated loading of 421 MVA on the Western Segment and 185 MVA on the Eastern Segment) represents the current flow on the line during the non-peak time times of the year.

The magnetic field values for the two scenarios were calculated at a point where the conductor is closest to the ground. The magnetic field data shows that magnetic field levels decrease rapidly as the distance from the centerline increases (proportional to the inverse square of the distance from source). In addition, since the magnetic field produced by the transmission line is dependent on the current flow, the actual magnetic fields when the Project is placed in service will vary as the current flow on the line changes throughout the day and time of year.

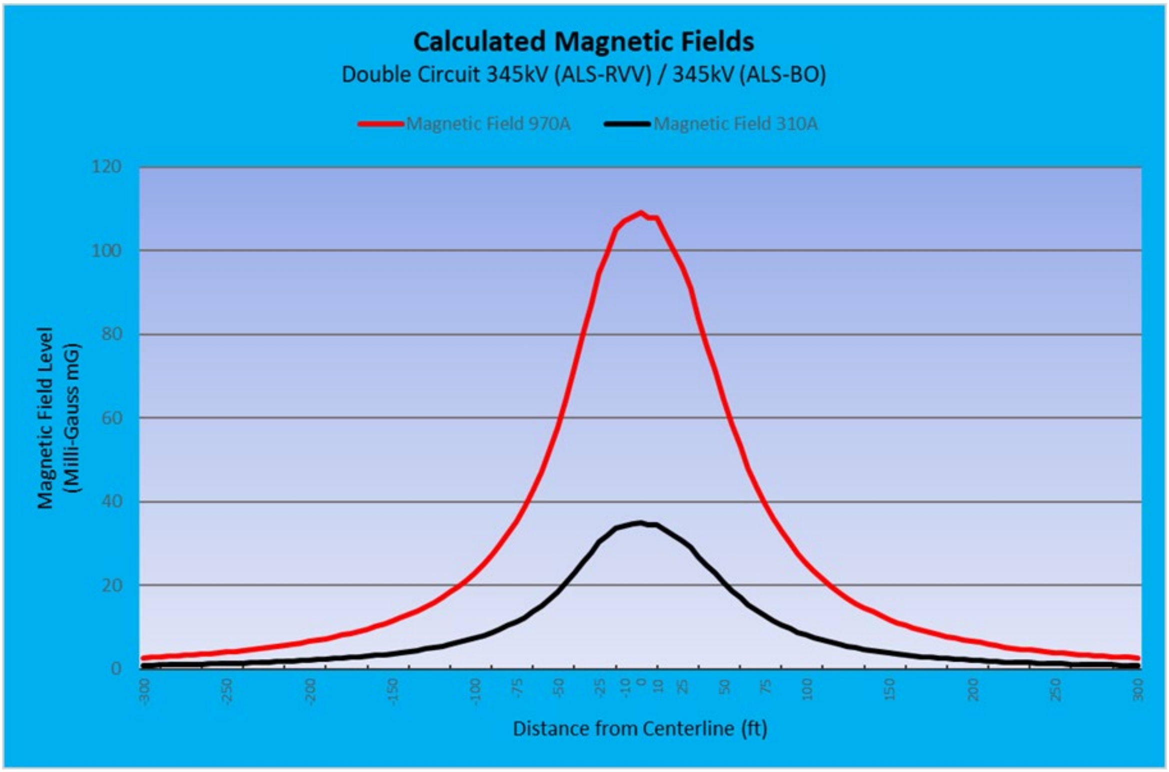
Magnetic field calculations for the Project substations are not provided here because the specific physical design of a substation is required to calculate representative magnetic fields, and that level of design is not yet available for the Project substations. Magnetic fields associated with the Project's substations are anticipated to be similar to other existing 345 kV substations in Minnesota.

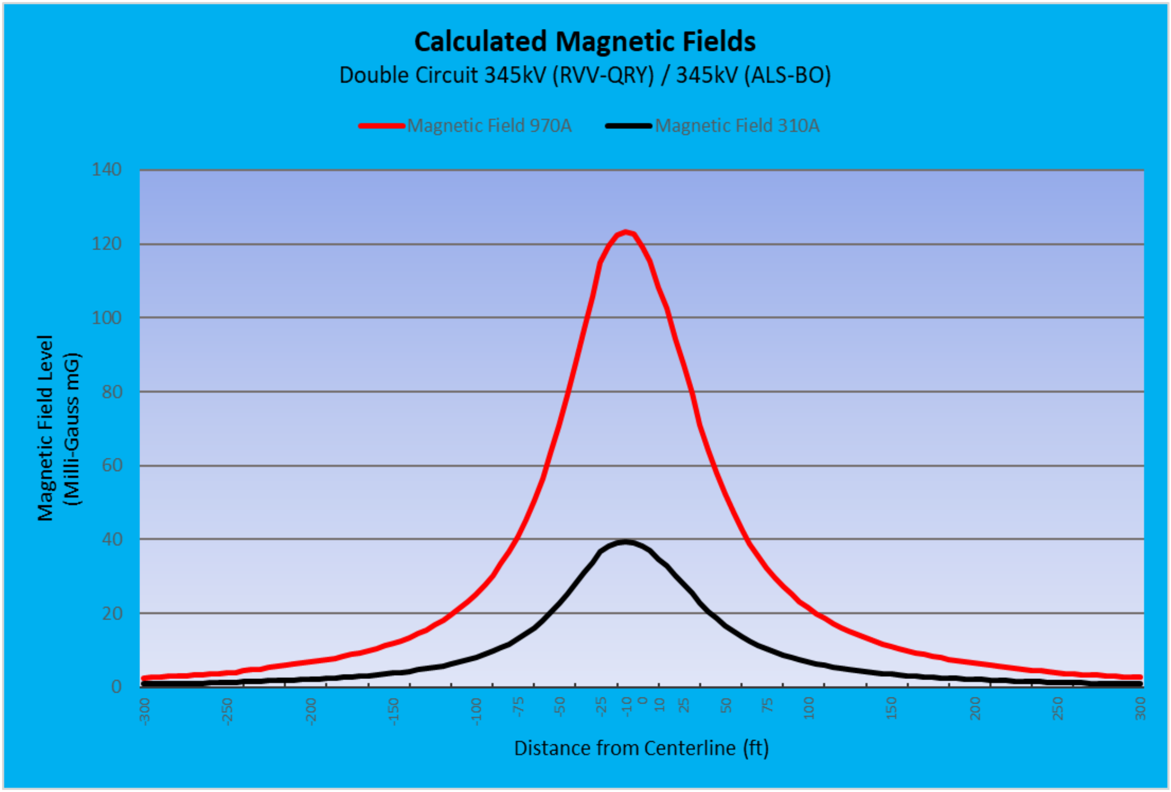
Table 6-3
Magnetic Field Calculations Summary

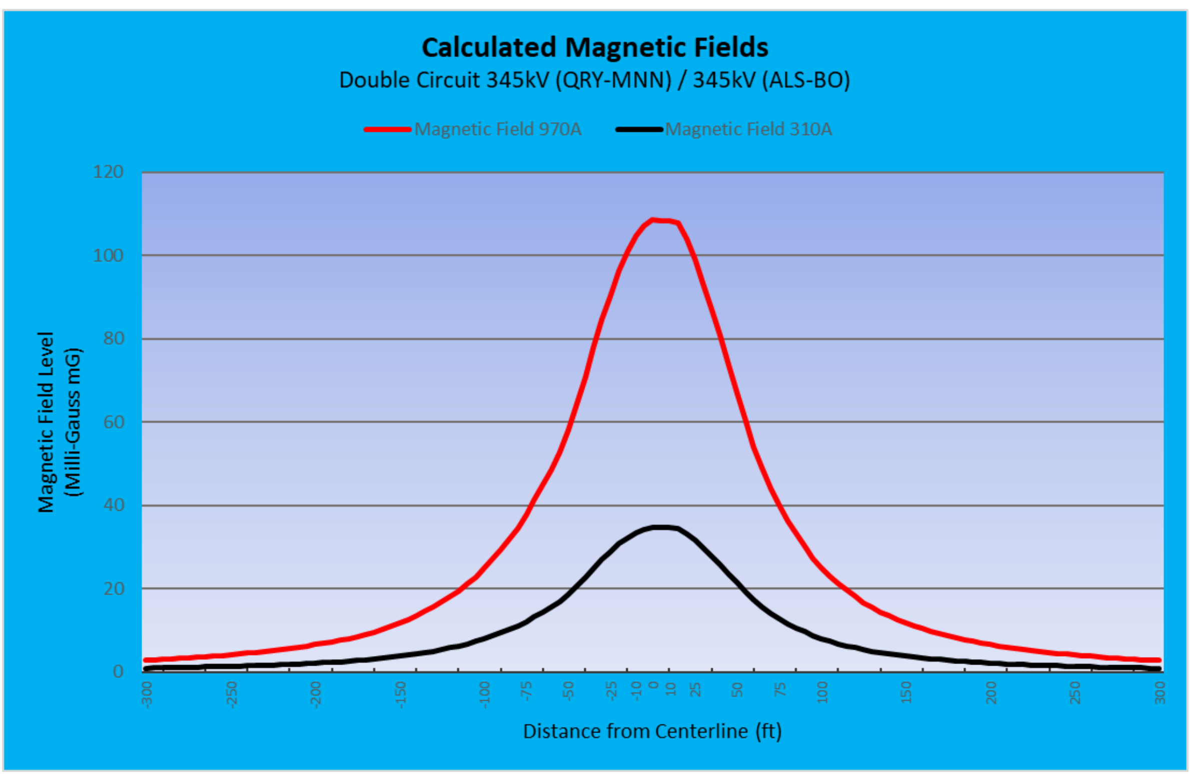
Structure Type	Circuits Present	System Condition	Current (Amps)	Distance to Proposed Centerline (feet)												
				-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit on Double-Circuit Capable Monopole	Big Stone South – Alexandria	Peak System Energy Demand	1,434/1,434	5	11	41	65	112	182	163	95	56	36	25	8	4
	Big Stone South – Alexandria	Average System Energy Demand	705/705	2	6	20	32	5 5	89	80	47	28	18	12	4	2
345 kV/345 kV Double-Circuit Monopole	Alexandria (ALS) – Riverview (RVV) Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580 MVA/580 MVA)	970/970	2.7	6.6	23	35	58	95	109	96	65	40	25	6.6	2.6
	Alexandria (ALS) – Riverview (RVV) Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA/185 MVA)	310/310	0.9	2.1	7.3	11	18	30	35	31	21	13	8.1	2.1	0.8
345 kV/345 kV Double-Circuit Monopole	Riverview (RVV) – Quarry (QRY) Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580 MVA/580 MVA)	970/970	2.6	6.7	25	40	71	115	119	87	52	32	21	6.5	2.6
	Riverview (RVV) – Quarry (QRY) Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA/185 MVA)	310/310	0.8	2.2	8.0	13	23	37	38	28	17	10	6.9	2.1	0.8
345 kV/345 kV Double-Circuit Monopole	Quarry (QRY) – Monticello (MNN) Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580 MVA/580 MVA)	970/970	2.8	6.5	25	38	58	90	109	99	67	40	25	6.6	2.7
	Quarry (QRY) – Monticello (MNN) Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA/185 MVA)	310/310	0.9	2.1	7.9	12	19	29	35	32	21	13	8.0	2.1	0.9

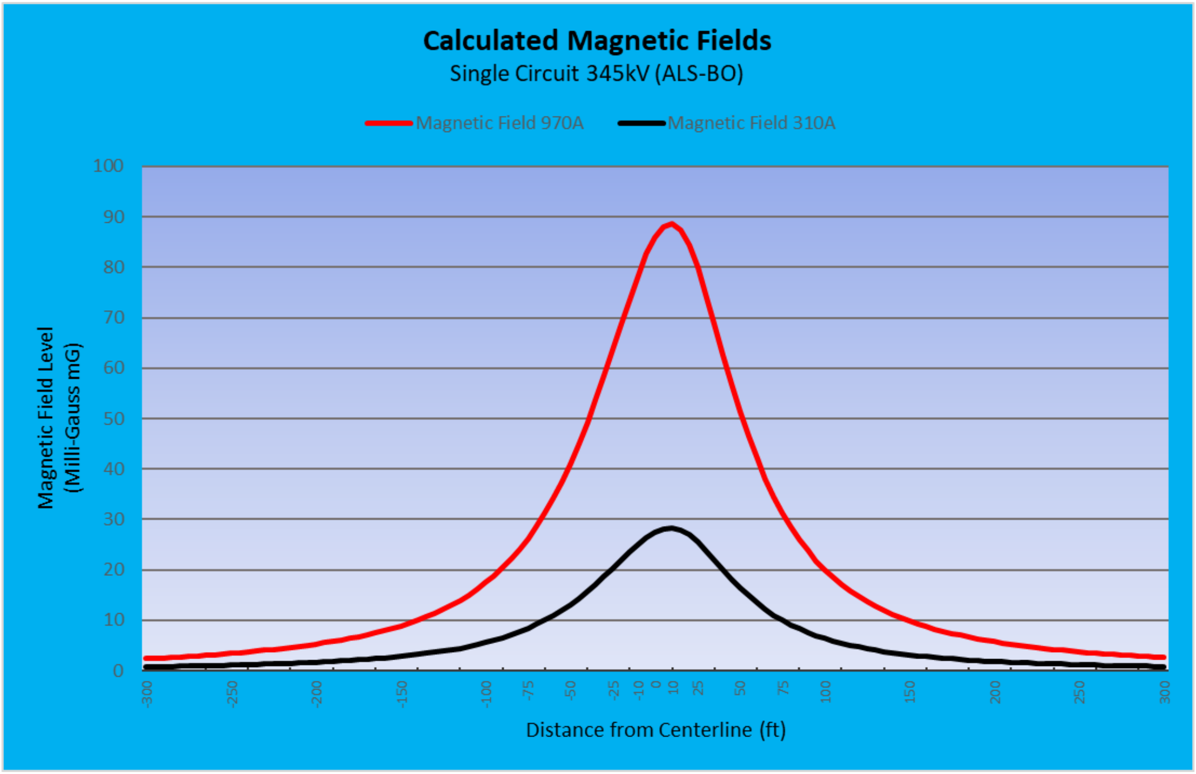
345 kV Single-Circuit Monopole	Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580 MVA)	970	2.4	5.3	17	26	41	64	86	80	51	31	20	5.8	2.6
	Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA)	310	0.8	1.7	5.6	8.4	13	20	27	26	16	10	6.4	1.8	0.8
345 kV Single-Circuit H-Frame	Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580MVA)	970	3.9	8.5	29	43	61	79	82	73	54	37	25	7.9	3.8
	Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA)	310	1.3	2.7	9.2	14	19	25	26	23	17	12	8.0	2.5	1.2

Figure 6-6
Calculated Magnetic Flux density (mG) for Proposed 345/345 kV Transmission Line Designs For Eastern Segment (3.28 feet above ground)




Calculated Magnetic Fields
Double Circuit 345kV (RVV-QRY) / 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
140
120
100
80
60
40
20
0
-300 -250 -200 -150 -100 -75 -50 -25 -10 0 10 25 50 75 100 150 200 250 300
Distance from Centerline (ft)


Calculated Magnetic Fields
Double Circuit 345kV (QRY-MNN) / 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
120
100
80
60
40
20
0
-300 -250 -200 -150 -100 -75 -50 -25 -10 0 10 25 50 75 100 150 200 250 300
Distance from Centerline (ft)


Calculated Magnetic Fields
Single Circuit 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
100
90
80
70
60
50
40
30
20
10
0
-300
-250
-200
-150
-100
-75
-50
-25
-10
0
10
25
50
75
100
150
200
250
300
Distance from Centerline (ft)

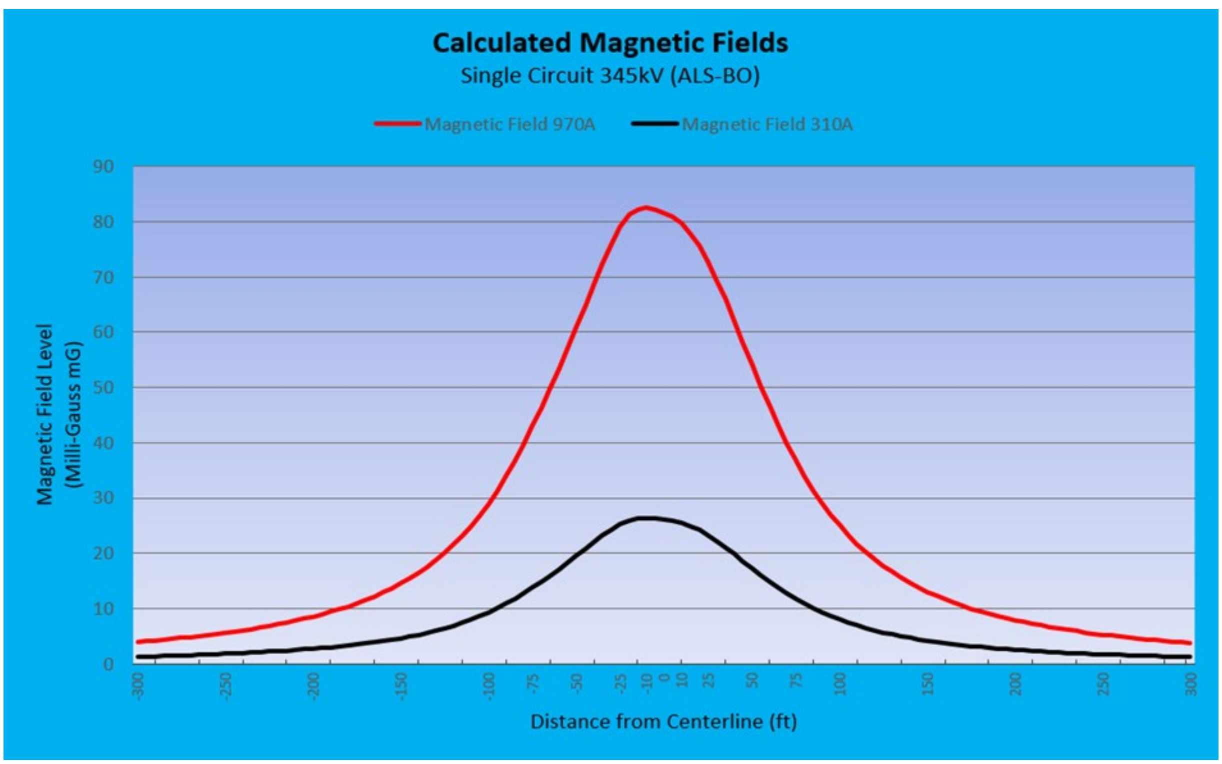
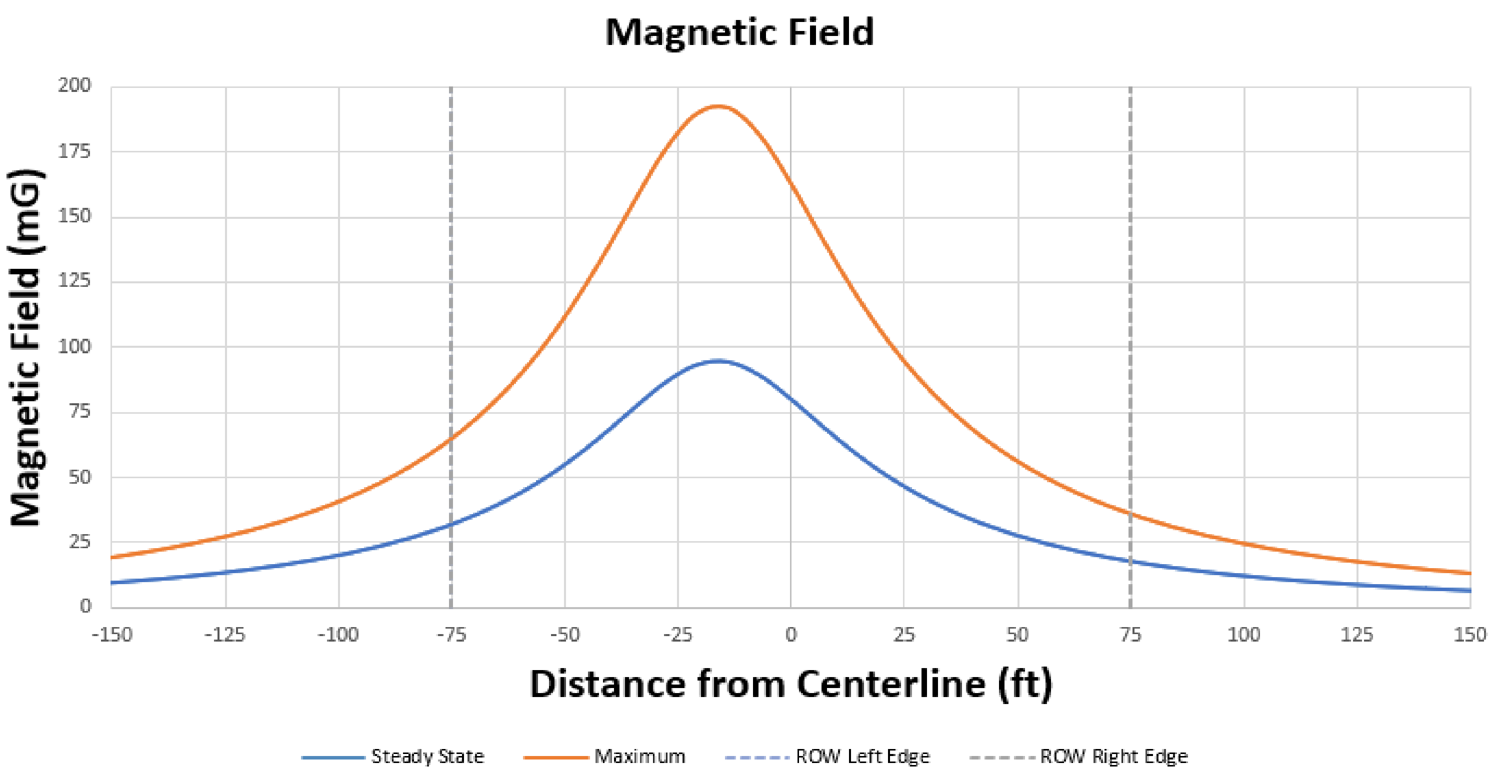

Calculated Magnetic Fields
Single Circuit 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
90
80
70
60
50
40
30
20
10
0
-300
-250
-200
-150
-100
-75
-50
-25
-10
0
10
25
50
75
100
150
200
250
300
Distance from Centerline (ft)

Figure 6-7
Calculated Magnetic Flux density (mG) for Proposed 345 kV Single-Circuit Transmission Line on Double-Circuit Capable Structures For Western Segment
(3.28 feet above ground)



There are presently no Minnesota regulations pertaining to magnetic field exposure. Applicants provide information to the public, interested customers, and employees so they can make informed decisions about magnetic fields. Such information includes the availability for measurements upon request.

Considerable research has been conducted since the 1970s to determine whether exposure to power-frequency (60 hertz) magnetic fields causes biological responses and health effects. Public health professionals have also investigated the possible impact of exposure to EMF on human health for the past several decades. While the general consensus is that electric fields pose no risk to humans, the question of whether exposure to magnetic fields can cause biological responses or health effects continues to be debated.

Since the 1970s, a large amount of scientific research has been conducted on EMF and health. This large body of research has been reviewed by many leading public health agencies such as the U.S. National Cancer Institute, the U.S. National Institute of Environmental Health Sciences, and the World Health Organization (WHO), among others. These reviews show that exposure to electric power EMF neither causes nor contributes to adverse health effects.

For example, in 2016, the U.S. National Cancer Institute summarized the research as follows:

> Numerous epidemiologic studies and comprehensive reviews of the scientific literature have evaluated possible associations between exposure to non-ionizing EMFs and risk of cancer in children (13–15). (Magnetic fields are the component of non-ionizing EMFs that are usually studied in relation to their possible health effects.) Most of the research has focused on leukemia and brain tumors, the two most common cancers in children. Studies have examined associations of these cancers with living near power lines, with magnetic fields in the home, and with exposure of parents to high levels of magnetic fields in the workplace.

> No consistent evidence for an association between any source of non-ionizing EMF and cancer has been found.[79]

Wisconsin, Minnesota, and California have all conducted literature reviews or research to examine this issue. In 2002, Minnesota formed an Interagency Working Group (Working Group) to evaluate the body of research and develop policy recommendations to protect the public from any potential problems resulting from high voltage transmission line EMF effects. The Working Group consisted of staff from various state agencies and published its findings in a White Paper on Electric and Magnetic Field (EMF) Policy and Mitigation Options in September 2002, (Minnesota Department of Health, 2002). The report summarized the findings of the Working Group as follows:

> Research on the health effects of EMF has been carried out since the 1970s. Epidemiological studies have mixed results – some have shown no statistically significant association between exposure to EMF and health effects, some have shown a weak association. More recently, laboratory studies have failed to show such an association, or to establish a biological mechanism for how magnetic fields may cause cancer. A number of scientific panels convened by national and international health agencies and the United States Congress have reviewed the research carried out to date. Most researchers concluded that there is insufficient evidence to prove an association between EMF and health effects; however, many of them also concluded that there is insufficient evidence to prove that EMF exposure is safe. (*Id.* at p. 1.)[80]

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[79] NAT'L CANCER INSTITUTE, *Electromagnetic Fields and Cancer* (updated May 27, 2016), available at: https://www.cancer.gov/about-cancer/causes-prevention/risk/radiation/electromagnetic-fields-fact-sheet.

[80] THE MINNESOTA STATE INTRAGENCY WORKING GROUP ON EMF ISSUES, *A White Paper on Electric and Magnetic Fields Policy and Mitigation Options* (Sept. 2002).

The Commission, based on the Working Group and WHO findings, has repeatedly found that "there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects."[81]

6.7 Stray Voltage and Induced Voltage

"Stray voltage" is a condition that can potentially occur on a property or on the electric service entrances to buildings from distribution lines serving these buildings - not transmission lines as proposed here. The term generally describes a voltage between two objects where no voltage difference should exist. More precisely, stray voltage is a voltage that exists between the neutral wire of either the service entrance or of premise wiring and grounded objects in buildings such as barns and milking parlors. The source of stray voltage is a voltage that is developed on the grounded neutral wiring network of a building and/or the electric power distribution system.

Transmission lines do not, by themselves, create stray voltage because they do not connect directly to businesses or residences. Transmission lines, however, can induce voltage on a distribution circuit that is parallel and immediately under the transmission line. If the proposed transmission lines run parallel to or cross distribution lines, appropriate mitigation measures can be taken to address any induced voltages.

6.8 Farming Operations, Vehicle Use, and Metal Buildings near Power Lines

The Project will be designed to meet or exceed minimum clearance requirements with respect to electric fencing as specified by the NESC. Nonetheless, insulated electric fences used in livestock operations can be instantly charged with an induced voltage from transmission lines. The induced charge may continuously drain to ground when the charger unit is connected to the fence. When the charger is disconnected either for

[81] *In the Matter of the Application of Xcel Energy for a Route Permit for the Lake Yankton to Marshall Transmission Line Project in Lyon County*, Docket No. E002/TL-07-1407, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO XCEL ENERGY FOR THE LAKE YANKTON TO MARSHALL TRANSMISSION PROJECT at 7-8 (Aug. 29, 2008); *see also In the Matter of the Application for a HVTL Route Permit for the Tower Transmission Line Project*, Docket No. ET2, E015/TL-06-1624, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER ISSUING A ROUTE PERMIT TO MINNESOTA POWER AND GREAT RIVER ENERGY FOR THE TOWER TRANSMISSION LINE PROJECT AND ASSOCIATED FACILITIES at 23 (Aug. 1, 2007) ("Currently, there is insufficient evidence to demonstrate a causal relationship between EMF exposure and any adverse human health effects.").

maintenance or when the fence is being built, shocks may result. The local electrical utility can provide site specific information to landowners about how to prevent possible shocks when the charger is disconnected if requested.

Farm equipment, passenger vehicles, and trucks may be safely used under and near power lines. The power lines will be designed to meet or exceed minimum clearance requirements with respect to roads, driveways, cultivated fields, and grazing lands as specified by the NESC. Recommended clearances within the NESC are designed to accommodate a relative vehicle height of 14 feet.

Vehicles, or any conductive body, located under energized high voltage transmission lines will be immediately charged with an electric charge. Without a continuous grounding path, this charge can provide a nuisance shock. Such nuisance shocks are a rare event because generally vehicles are effectively grounded through tires. Modern tires provide an electrical path to the ground because carbon black, a good conductor of electricity, is added to tires when they are produced. Metal parts of farming equipment are frequently in contact with the ground when tilling or engaging in various other activities. Therefore, the induced charge on vehicles will normally be continually flowing to ground unless they have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground. Applicants can provide additional vehicle-specific methods for reducing the risk of nuisance shocks in vehicles to landowners if requested.

Buildings are permitted near transmission lines but are generally discouraged within the right-of-way itself because a structure under a line may interfere with safe operation of the transmission facilities. For example, a fire in a building within the right-of-way could damage a transmission line. The NESC establishes minimum electrical clearance zones from power lines for the safety of the general public and utilities often acquire easement rights that require clear areas in excess of these established zones. Utilities may permit encroachment into that easement for buildings and other activities when they can be deemed safe and still meet the NESC minimum requirements. Metal buildings may have unique issues due to induction concerns. For example, conductive buildings near power lines of 200 kV or greater must be properly grounded. Any person with questions about a new or existing metal structure can contact the Applicants for further information about proper grounding requirements.

7. TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

7.1 Right-of-Way Acquisition

Early in the detailed design process, typically after the route permit is obtained, the right-of-way acquisition process begins. For transmission lines, utilities typically acquire easement rights across land parcels to accommodate the transmission line. The evaluation and acquisition process includes title examination, initial owner contacts, survey work, document preparation, and acquisition of easement rights.

In areas of the Project that will use existing rights-of-way and the terms of the existing easement are sufficient, the Applicants' right-of-way agents will work with the landowner to address any short-term construction needs, impacts, or restoration.

For portions of the Project where a new or expanded right-of-way will be necessary, the Applicants' right-of-way agents will identify all persons and entities that may have a legal interest in the identified real estate. The Applicants' right-of-way agents contact each property owner to describe the need for the transmission facilities and how the Project may affect each parcel. The Applicants' right-of-way agents also seek information from the property owner about any specific concerns that they may have with the Project.

To aid in the design and routing of the Project, Applicants may request permission to enter the property to conduct preliminary survey and geotechnical work. During this process, the location of the proposed transmission line or substation facility may be staked with permission of the property owner.

The agent will discuss the construction schedule and construction requirements with the property owner. Special consideration may be needed for fences, crops, or livestock. Fences and livestock may need to be moved; temporary or permanent gates may need to be installed; and crops may need to be harvested early. In each case, the right-of-way agent and construction personnel coordinate these processes with the property owner.

Land value data will be collected to assist in determining the fair market value of the easement needed for the land parcels to be crossed by the Project as well as the impact the easement may have on the market value of those parcels. A fair market value offer will be developed that recognizes the impact of the easement to each parcel. Sometimes, a negotiated easement agreement cannot be reached. In those cases, the Applicants may exercise eminent domain pursuant to Minnesota law. The process of exercising the right of eminent domain is called condemnation.

Before commencing a condemnation proceeding, typically, the Applicants must obtain at least one appraisal and provide a copy to the property owner. The property owner may also obtain another property appraisal and the Applicants must reimburse the property owner for the cost of the appraisal according to the requirements and limits set forth in Minn. Stat. §117.036. To start the formal condemnation process, the Applicants file a petition in the district court where the property is located and serves that petition on all owners with an interest in each of the land parcels identified in the petition.

If the district court grants the petition, the court then appoints a three-person condemnation commission that will determine a just compensation amount for the easement. The three people appointed to the condemnation commission must be knowledgeable of applicable real estate matters. The commissioners schedule a viewing of the property and then schedule a valuation hearing where the utilities and property owners offer their evidence, such as testimony by appraisers, as to the fair market value of the property interests required for the Project. The condemnation commission then makes an award as to the value of the property acquired for the easement and that award is filed with the court. Each party has the right to appeal the award to the district court for a jury trial. A jury trial typically occurs in the event of an appeal in which the jury considers the parties' evidence and renders a verdict. At any point in this process, the case can be dismissed if the parties reach a settlement.

There may be instances where a property owner elects to require the Applicants to purchase their entire property rather than acquiring only an easement for the transmission line. The property owner is granted this right under Minn. Stat. § 216E.12, subd. 4, which is sometimes referred to as the "Buy-the-Farm Statute." The Buy-the-Farm Statute applies only to transmission lines that are 200 kV or more; thus, the Buy-the-Farm Statute may apply to parcels crossed by the proposed 345 kV transmission lines.

7.2 Construction Procedures

Construction for the Western Segment and Eastern Segment will occur at different times with construction of the Eastern Segment estimated to last approximately 18 to 20 months and construction of the Western Segment to last between two to four years. It is anticipated that construction of either segment will employ approximately 100 to 150 construction workers.

Construction will begin after necessary federal, state, and local approvals are obtained and property rights are acquired for each respective segment. Construction in areas where new easements are not needed or have already been obtained may proceed while right-of-way acquisition for other areas is still in process. The precise timing of construction will consider various requirements of permit conditions, environmental restrictions, availability of outages for existing transmission lines (if required), available workforce, and materials.

Construction will follow the Applicants' best practices for construction and mitigation to minimize temporary and permanent impacts to land and the environment. Construction typically progresses as follows:

- survey marking of the right-of-way
- right-of-way clearing and access preparation;
- grading or filling if necessary;
- installation of culverts or concrete foundations;
- installation of poles, insulators, and hardware;
- conductor stringing;
- installation of any aerial markers required by state or federal permits; and
- restoration / clean-up.

The Applicants will design the transmission line structures for installations at the existing grades. Where a site slope is required (typically on slopes exceeding 10 percent), working areas may be graded or leveled with fill. If acceptable to the property owner, the Applicants propose to leave the graded/leveled areas after construction to allow access for future maintenance activities. If not acceptable to the property owner, the Applicants will, to the best of its ability, return the grade of the site back to its original condition.

Construction will require the use of many different types of construction equipment including tree removal equipment, mowers, cranes, backhoes, digger-derrick line trucks, drill rigs, dump trucks, front-end loaders, bucket trucks, bulldozers, flatbed tractor-trailers, flatbed trucks, pickup trucks, concrete trucks, helicopters, and various trailers or other hauling equipment. Excavation equipment is often on wheeled or track-driven vehicles. Construction crews will attempt to use equipment, when opportunities are available, that minimizes impacts to land.

Construction staging areas/laydown yards are usually established for transmission projects. Staging involves delivering the equipment and materials necessary to construct the new transmission line facilities. Construction of each segment will likely include two or more staging areas. Structures, conductor, matting, and other materials are delivered to staging areas and stored until they are needed for the Project.

The Applicants will evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails that are near the approved route. When feasible, the Applicants will confine construction activities to the easement area. In certain circumstances, additional off-easement access may be required on a temporary basis. Permission will be obtained from property owners prior to using off-easement access.

Improvements to existing access or construction of new access may be required to accommodate construction equipment. Field approaches and roads may be constructed or improved. Where applicable, the Applicants will obtain permits for new access from local road authorities. The Applicants will also work with appropriate road authorities to ensure proper maintenance of roadways traversed by construction equipment.

After right-of-way clearing and access preparation has been completed, pole and foundation installation will begin. Structures for the Project will require drilled pier concrete foundations.

Drilled pier foundations are typically between eight to ten feet in diameter and are typically 20 to 60 feet deep, depending on soil conditions. An angle or dead-end structure may require a foundation up to 12 feet in diameter. The actual diameter and depth of the hole (and foundation) depend on structure design and soil conditions that are determined during the initial survey and soil testing phases. Concrete is brought to the site by concrete trucks from a local concrete batch plant and filled around a steel rebar support cage and anchor bolts. Once the foundation is cured, the structure is bolted to the foundation.

Structures will be moved from staging areas and delivered to the site of each foundation where they are assembled. Using a crane, the structure is lifted and placed into position. Insulators and other hardware are attached to the structure prior to placing it on the foundation.

Conductor stringing is the last major step of transmission line construction. Stringing setup areas are typically located at two-mile intervals. These sites are located within the right-of-way, when possible, or within temporary construction easements. Conductor stringing often uses helicopters to start the process by pulling a "sock-line" or high strength rope through pulleys attached to the insulators on each structure that is attached to the conductor which are pulled into place and sagged to meet design requirements that are compliant with good utility practice and minimum code clearances. This process requires brief access to each structure to secure the conductor wire to the insulator hardware and to fasten the shield wire on each structure. After conductor installation is complete, conductor marking devices will be installed if required. These marking devices may include bird flight diverters or air navigational markers. The Applicants will work with the appropriate agencies to identify locations where marking devices need to be installed.

Where the transmission line crosses streets, roads, highways, or other energized conductors or obstructions, temporary guard or clearance poles may be installed before conductor stringing. The temporary guard or clearance poles ensure that conductors will not obstruct traffic or contact existing energized conductors or other cables during stringing operations and also protects the conductors from damage if they were to fall during stringing.

Some soil conditions and environmentally sensitive areas will require special construction techniques. The most effective way to minimize impacts to these areas will be to avoid placing poles in the sensitive areas by spanning over wetlands, streams, and rivers. When it is not feasible to avoid traversing sensitive areas, one or more of the following options will be used to minimize impacts, in consultation with the appropriate agencies:

- When possible, construction will be scheduled during frozen ground conditions;
- When construction during winter is not possible and conditions require, construction mats will be used where wetlands and other sensitive areas would be impacted;
- Equipment fueling and other maintenance will occur away from environmentally sensitive and wet areas. These construction practices help ensure that fuel and lubricants do not enter waterways or impact environmentally sensitive areas; and
- Various best management practices (BMPs) will be identified in the Project's Stormwater Pollution Prevention Plan (SWPPP), including the use of silt fences, bio logs, erosion control blankets with embedded seeds, and other sound water and soil conservation practices to protect topsoil and adjacent water resources and to minimize soil erosion.

These techniques are also used to reduce impacts to private property including driveways, yards, and drain tile.

7.3 Restoration and Clean-Up Procedures

Crews will attempt to minimize ground disturbance whenever feasible, but areas will be disturbed during the normal course of work. Once construction is completed in an area, disturbed areas will be restored to their original condition to the maximum extent feasible. Temporary restoration before the completion of construction in some areas along the right-of-way may be required per National Pollution Discharge Elimination System (NPDES) and Minnesota Pollution Control Agency (MPCA) construction permit requirements.

After construction activities have been completed, a utility representative will contact the property owner to discuss any damage that has occurred as a result of the Project. This contact may not occur until after the Applicants have started restoration activities. If fences, drain tile, or other property have been damaged, the Applicants will repair damages or reimburse the landowner to repair the damages.

Farmers will be compensated for crop losses caused by Project construction. The compensation will be based upon the area(s) affected, the typical yield for the crops lost, and the market rates for those crops. A utility representative will measure the area(s) in which planted crops were damaged or destroyed, or not planted at the Applicant's request. The lost yields will be determined in coordination with the property owner. The market rate will also be determined in coordination with the property owner and local elevator and/or other evidence to determine the appropriate rate of payment. The Applicants will also make a payment for future year crop loss due to soil compaction. In addition, property owners will be compensated for their expense to deep rip compacted areas. If an individual does not have access to deep ripping equipment, Applicants will provide this service or access to such equipment.

Ground-level vegetation disturbed or removed from the right-of-way during construction of the Project will naturally reestablish to pre-construction conditions. Additionally, vegetation that is consistent with substation site operation outside the fenced area will be allowed to reestablish naturally at substation sites. Areas where significant soil compaction or other disturbance from construction activities occur will require additional assistance in reestablishing the vegetation stratum and controlling soil erosion. In these areas, the Applicants will use seed that is noxious weed free to reestablish vegetation.

Another aspect of restoration relates to the roads used to access staging areas or construction sites. After construction activities are complete, the Applicants will ensure that township, city, and county roads used for purposes of access during construction will be restored to their prior condition. The Applicants will meet with township road supervisors, city road personnel, or county highway departments to address any issues that arise during construction with roadways to ensure the roads are adequately restored, if necessary, after construction is complete.

7.4 Maintenance Practices

Transmission lines and substations are designed to operate for decades and require only moderate maintenance, particularly in the first few years of operation. On the Eastern Segment, Great River Energy is expected to be responsible for the maintenance of the 345 kV transmission circuit from the Alexandria Substation to the Quarry Substation, located west of St. Cloud, and Xcel Energy is expected to be responsible for the maintenance of the 345 kV transmission circuit from the Quarry Substation to the Big Oaks Substation. Otter Tail will be responsible for the operation and maintenance of the Western Segment of the Project. Great River Energy, Xcel Energy, and Otter Tail will perform aerial inspections of the 345 kV transmission line and inspect the line from the ground every four years. Typically, one to two workers are required to perform aerial inspections and three workers are required to perform the ground inspections. Any defects identified during these inspections will be assessed and corrected. Great River Energy, Xcel Energy, and Otter Tail will also perform necessary vegetation management for the Eastern Segment and the Western Segment. Vegetation maintenance generally occurs every four years.

Line inspections are the principal operating and maintenance cost for transmission facilities. The aerial inspections cost approximately $75 to $100 per mile and the ground inspections cost approximately $200 to $400 per mile. Actual line-specific maintenance costs depend on the setting, the amount of vegetation management necessary, storm damage occurrences, structure types, materials used, and the age of the line.

The estimated service life of the proposed transmission lines for accounting purposes varies among utilities. Applicants use an approximately 60-year service life for their transmission assets. However, practically speaking, high voltage transmission lines are seldom completely retired.

Substations require a certain amount of maintenance to keep them functioning in accordance with accepted operating parameters and the NESC requirements.

Transformers, circuit breakers, batteries, protective relays, and other equipment need to be serviced periodically in accordance with the manufacturer's recommendations. The substation site must be kept free of vegetation and adequate drainage must be maintained. Otter Tail will be responsible for the operation and maintenance of the Big Stone South Substation, Western Minnesota will be responsible for the operation and maintenance of the Alexandria Substation, Great River Energy will be responsible for the operation and maintenance of the Riverview Substation, and Xcel Energy will be responsible for the operation and maintenance of the Quarry Substation and the new Big Oaks Substation.

7.5 Storm and Emergency Response and Restoration

Transmission infrastructure has very few mechanical elements and is built to withstand weather extremes that are normally encountered. With the exception of outages due to severe weather such as tornadoes and heavy ice storms, transmission lines rarely fail. Transmission lines are automatically taken out of service by the operation of protective relaying equipment when a fault is sensed on the line. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent. As a result, the average annual availability of transmission infrastructure is very high, in excess of 99%.

However, unplanned outages of transmission facilities can happen for a variety of reasons. Unplanned outages can occur due to mechanical failures or severe weather like heavy ice, wind, and lightning. In the event an unplanned outage of any facility along the proposed Project occurs, Applicants have the necessary infrastructure and crews in place in order to respond quickly and safely to return these facilities to service.

8. ENVIRONMENTAL INFORMATION

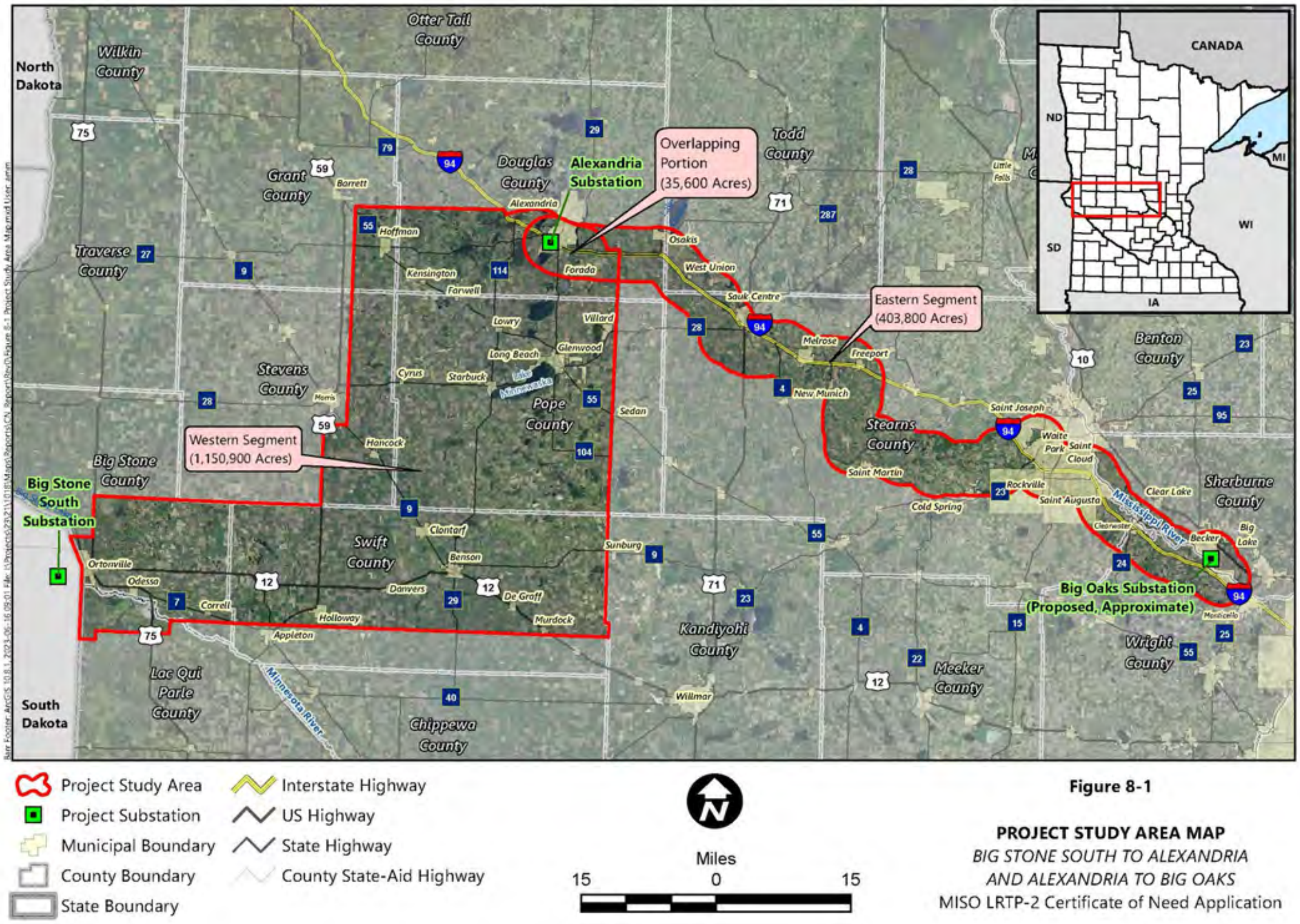
This section provides a general description of the environmental setting, land use and human settlement, land-based economies, archeological and historical resources, hydrological features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur in the Project Study Area shown in **Map 8-1**. This section also identifies potential impacts to existing resources and identifies measures that can be implemented to avoid, minimize, or mitigate impacts. The environmental information for the Project is described generally across the Project Study Area or broken down by major segment where applicable.

8.1 Project Study Area

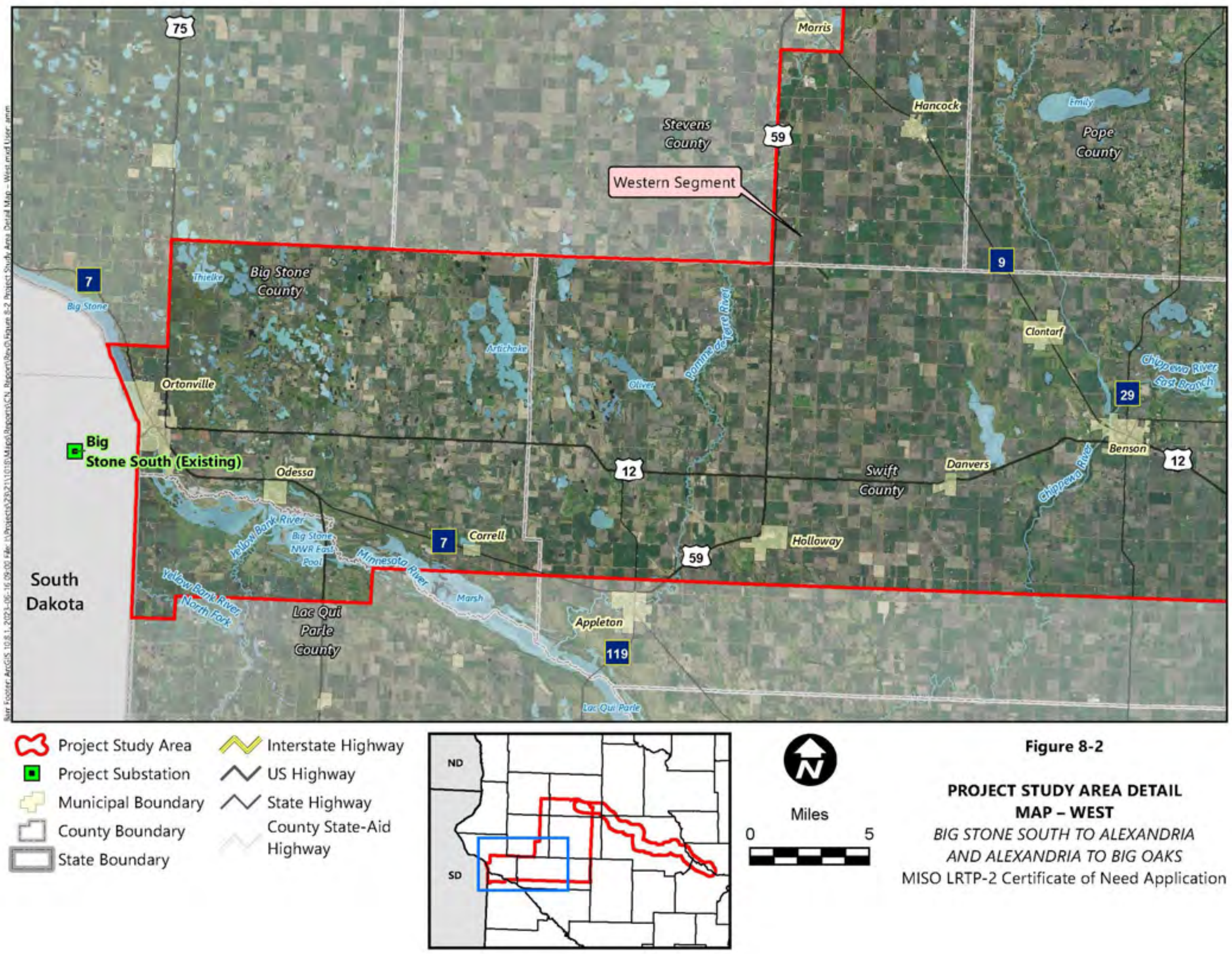
The overall Project Study Area measures approximately 1,519,100 acres and includes portions of Big Stone, Douglas, Grant, Lac Qui Parle, Pope, Sherburne, Stearns, Stevens, Swift, Todd, and Wright counties (**Map 8-1**). The Project Study Area is divided into two segments: the Western Segment and the Eastern Segment. The Project's Western Segment and Eastern Segment are defined in Chapter 1 of this application. The Western and Eastern Segments overlap at the Alexandria Substation, as both portions of the Project connect to this substation. The Project Study Area associated with the Western Segment measures approximately 1,150,900 acres. The Project Study Area associated with the Eastern Segment measures approximately 403,800 acres. The portion of the Project Study Area where the two Segments overlap at the Alexandria Substation measures approximately 35,600 acres. Where discussions regarding Segment size and resources per Segment are included, the resources within the overlapping areas are included in both Segments and therefore are not additive. **Map 8-2** through **Map 8-5** show additional details of the Project Study Area associated with the Western and Eastern Segments.

The Western Segment includes development and construction of a new single-circuit 345 kV transmission line on double-circuit capable structures. The Western Segment begins at the South Dakota/Minnesota border and, depending on the approved route, could travel through a portion of Big Stone County, Lac Qui Parle County, Swift County, Stevens County, Pope County, Grant County, and Douglas County before terminating at the existing Alexandria Substation near Alexandria, Minnesota.

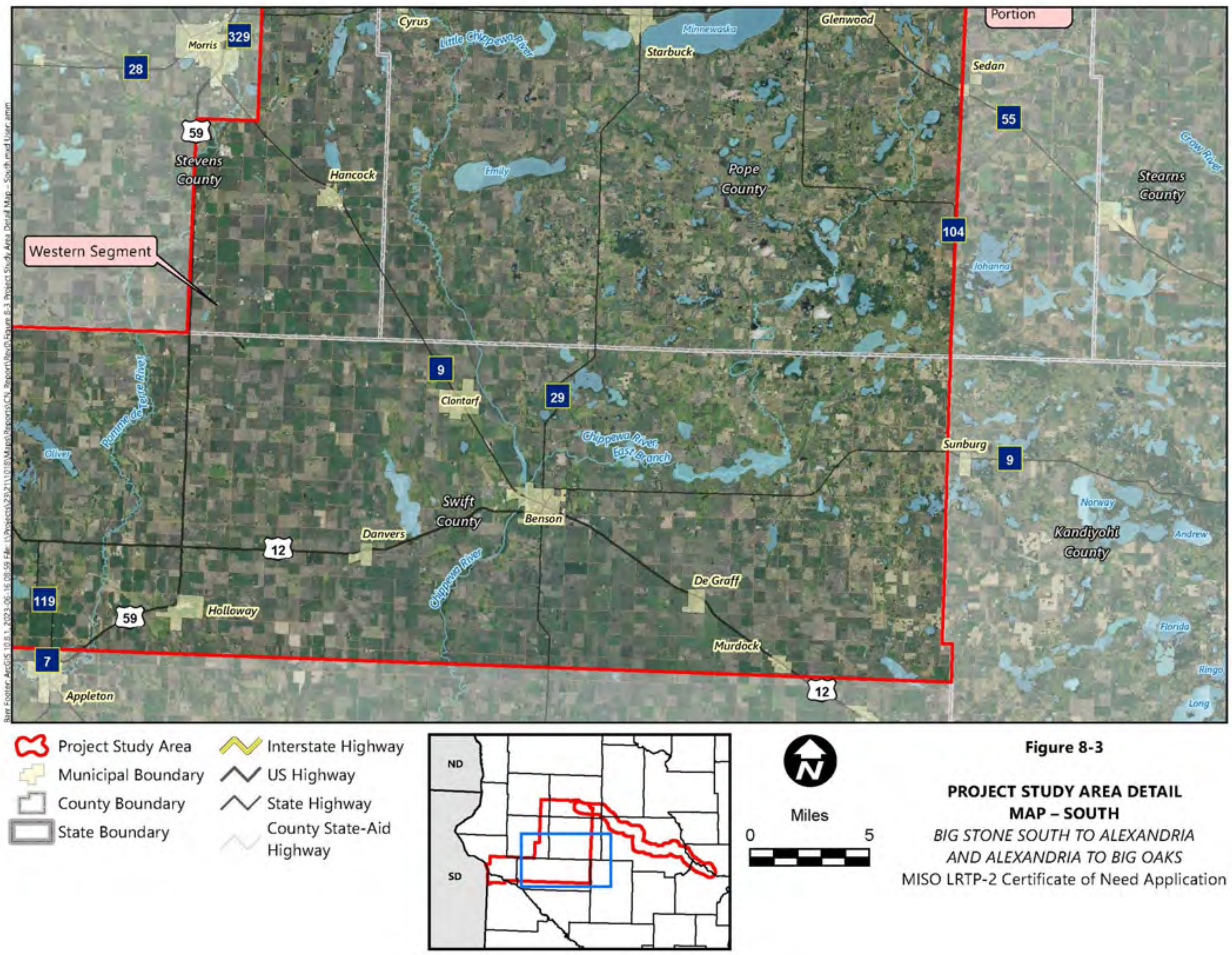
Map 8-1
Project Study Area



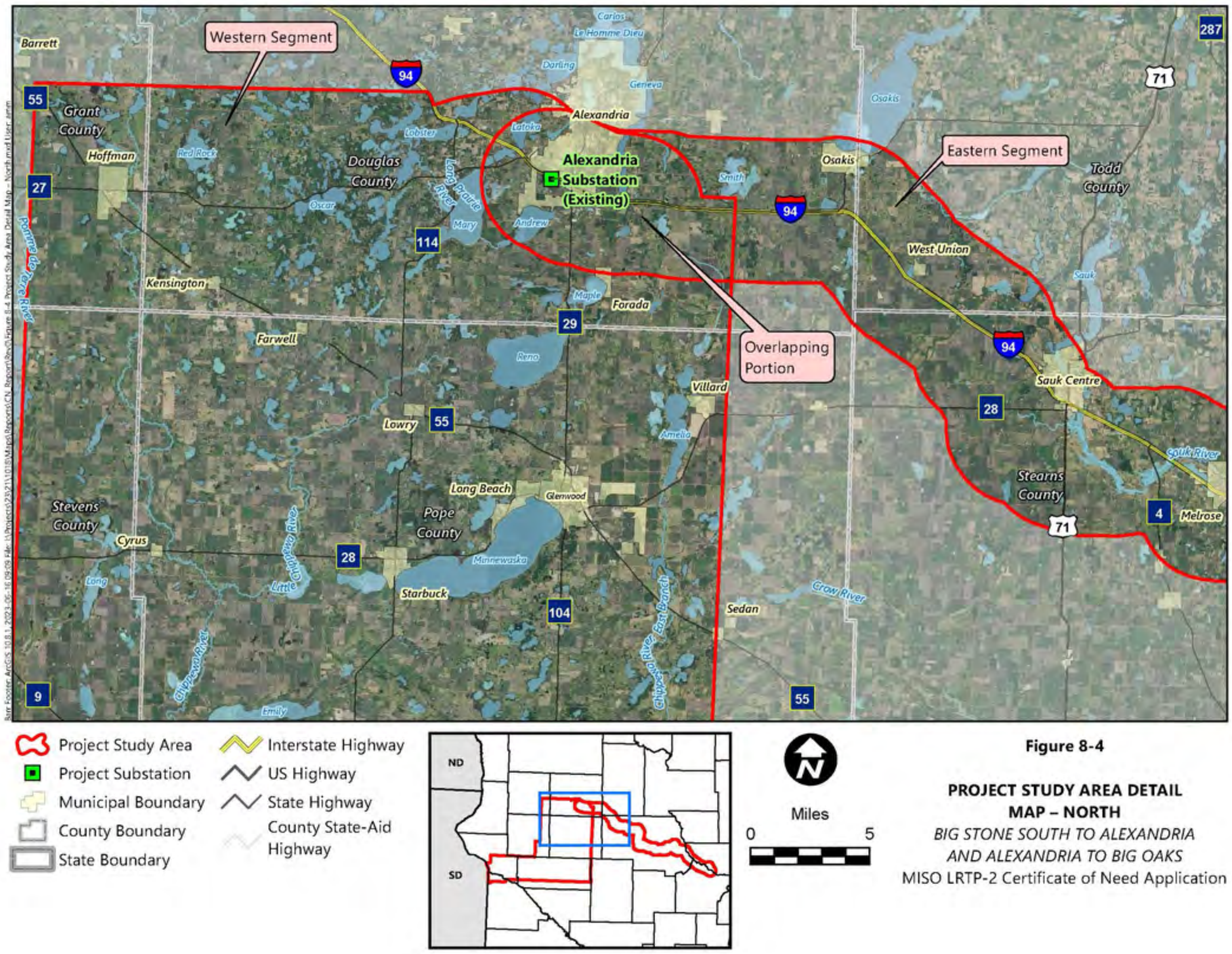
Map 8-2
Project Study Area Detail Map – West



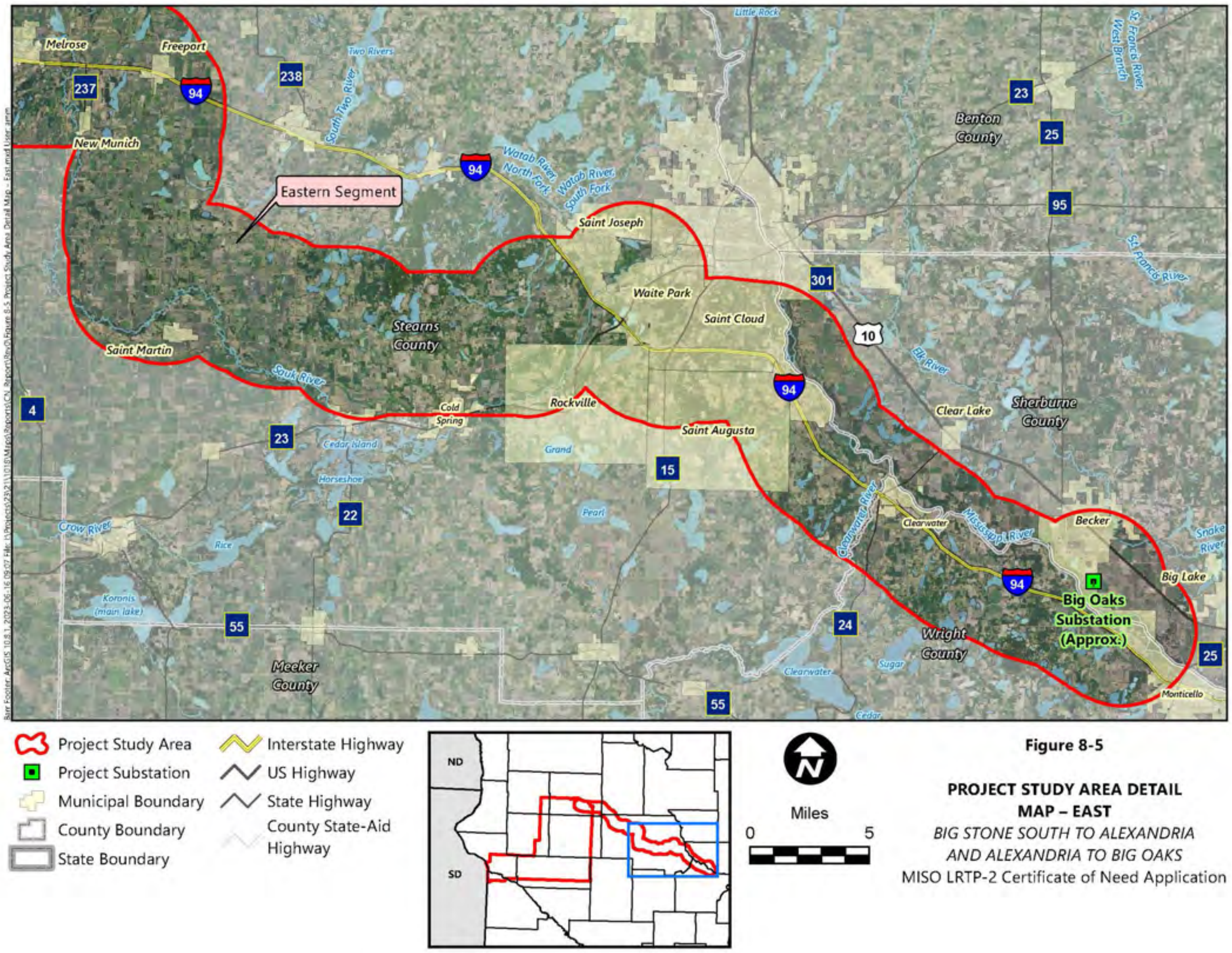
Map 8-3
Project Study Area Detail Map – South



Map 8-4
Project Study Area Detail Map – North



Map 8-5
Project Study Area Detail Map – East



The Eastern Segment begins at the Alexandria Substation and travels through portions of Douglas County, Todd County, Stearns County, Sherburne County, and Wright County before terminating at the new Big Oaks Substation located near the Monticello Nuclear Generating Plant in Becker, Minnesota. The Eastern Segment involves stringing a second 345 kV transmission circuit onto existing structures for approximately 95 to 99 percent of the Project's length of the Eastern Segment. When these existing structures were originally installed, space was left for this future second circuit, allowing electrical capacity to be increased by leveraging these existing structures. As part of the Eastern Segment, approximately 67 to 78 additional foundations and steel structures will be installed at certain locations to accommodate the new 345 kV transmission circuit. These locations are where the original line was designed for two-structure angles but only one structure was installed during construction of either the Monticello – St. Cloud or Fargo – St. Cloud transmission projects. These new structures will be installed within the existing transmission line right-of-way.

At four locations, the proposed route for the Eastern Segment deviates from the existing transmission line right-of-way. New right-of-way will be required for the new 345 kV transmission line to tap into the Alexandria Substation, a reconfiguration of the existing 345 kV circuit from Alexandria to the Quarry Substation to bypass the Riverview Substation near the city of Freeport, and the new 345 kV circuit from Riverview to Big Oaks Substation to bypass the Quarry Substation near the city of Waite Park. The cumulative length of these three areas of new right-of-way is less than one mile total. Additionally, new right-of-way will be required for a new crossing over the Mississippi River to connect the new 345 kV transmission line near Monticello to the new Big Oaks Substation located northwest of the Monticello Nuclear Generating Plant in Becker.

As discussed further in Section 8.1.2, the landscape within the Project Study Area varies between the Western Segment and the Eastern Segment. This is a result of past glacial activity and other ecological factors that affected the landscape over time. These changes are apparent in the hydrology, vegetation, topography, land use, and human settlement patterns within the Project Study Area.

8.1.1 Description of Environmental Setting

The landscape of the Western Segment consists of generally level to slightly undulating landforms that were once tallgrass prairie. (**Map 8-6**). Agricultural fields now dominate this portion of the Project Study Area. The Eastern Segment of the Project Study Area is characterized by a gently rolling to undulating topography with moraines and outwash plains that were formed by the Des Moines lobe of the late Wisconsin glaciation. (**Map 8-6**). The Mississippi River valley bisects the eastern end of the Eastern Segment. Major rivers in the Project Study Area include the Chippewa River, Pomme de Terre River, and the Minnesota River in the Western Segment and the Mississippi River and the Sauk River in the Eastern Segment. Larger cities in the Western Segment include Glenwood, Ortonville, Benson, Starbuck and Alexandria. Larger cities in the Eastern Segment include Saint Cloud, Saint Augusta, Rockville, Waite Park, Becker, Saint Martin, Melrose, Sauk Centre, and Alexandria.

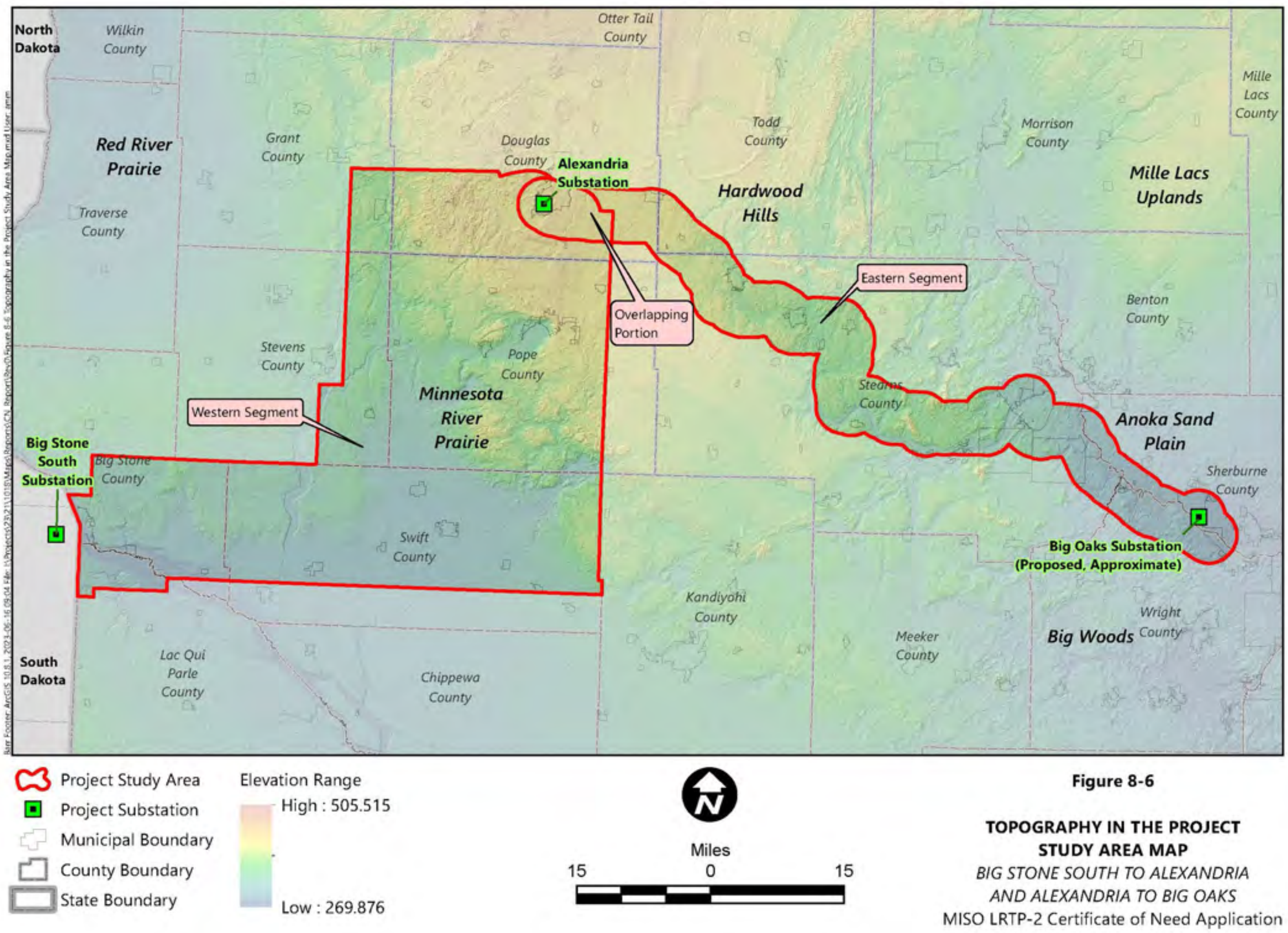
8.1.2 Geomorphology and Physiography

The Minnesota Department of Natural Resources (MDNR) and the U.S. Forest Service (USFS) developed an Ecological Classification System (ECS) for ecological mapping and landscape classification in Minnesota that is used to identify, describe, and map progressively smaller areas of land with increasingly uniform ecological features (reference (1)). Within the ECS, the State of Minnesota is split into ecological provinces, sections, and subsections. Under this classification system, the Western Segment of the Project Study Area is in the North Central Glaciated Plains Section of the Prairie Parkland Province (**Map 8-7**) (reference (4)). The Eastern Segment of the Project Study Area is mainly located in the Minnesota and NE Iowa Morainal Section of the Eastern Broadleaf Forest Province. A portion of the Eastern Segment is also located in the North Central Glaciated Plains Section of the Prairie Parkland Province (reference (4)).

The Minnesota and NE Iowa Morainal Section is further broken down into ecological subsections. The Western Segment of the Project Study Area is within the Minnesota River Prairie subsection of the North Central Glaciated Plains Section. The Eastern Segment of the Project Study Area overlaps the Hardwood Hills, Anoka Sand Plain, and Big Woods subsections. A portion of the Eastern Segment is also located in the Minnesota River Prairie subsection.

Table 8-1 provides the acreage and percentage of the Project Study Area within each ECS subsection. **Map 8-7** depicts the ECS subsections in relation to the Project Study Area. General physiography and geomorphology for each subsection is outlined below.

Map 8-6
Topography in the Project Study Area Map



Map 8-7
Ecological Classification System Subsections Map

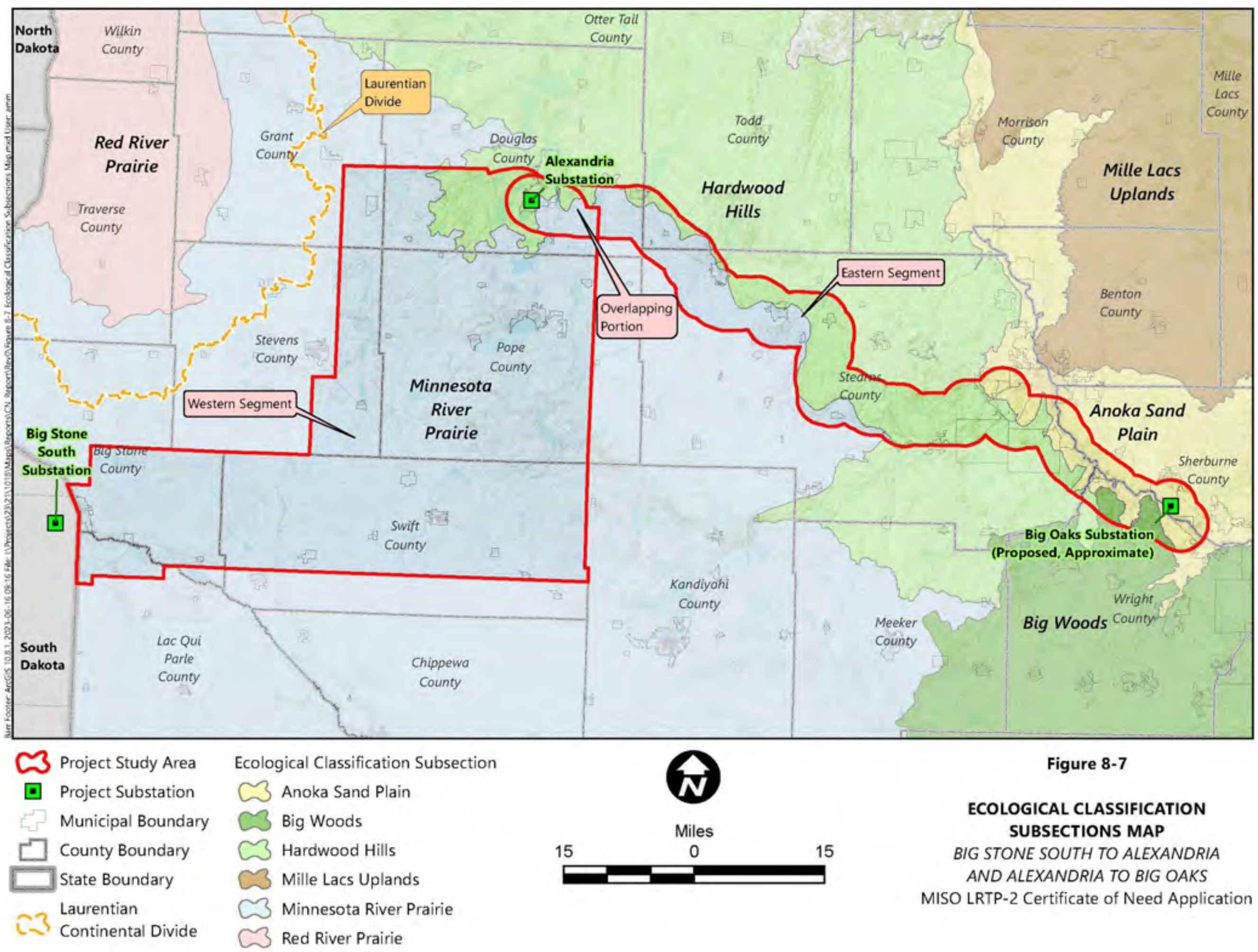


Table 8-1
ECS Subsections in the Project Study Area

ECS Subsection[1]	Counties	Western Segment		Eastern Segment		Total	
		Acres	Percentage	Acres	Percentage	Acres	Percentage
Anoka Sand Plain	Sherburne, Stearns, Wright	0	0	80,855	20	80,855	5
Big Woods	Wright	0	0	14,540	4	14,540	1
Hardwood Hills	Douglas, Pope, Stearns, Todd, Wright	69,185	6	183,647	45	235,360	16

ECS Subsection[1]	Counties	Western Segment		Eastern Segment		Total	
		Acres	Percentage	Acres	Percentage	Acres	Percentage
Minnesota River Prairie	Big Stone, Douglas, Grant, Lac Qui Parle, Pope, Stearns, Stevens, Swift, Todd	1,081,674	94	124,758	31	1,188,350	78
	Total[2]	1,150,859	100	403,800	100	1,519,105	100

[1] ECS boundaries do not conform to county boundaries. As such, portions of each county listed are within the ECS and some counties are within multiple ECSs. Source: https://www.dnr.state.mn.us/ecs/index.html

[2] Acreage within the overlapping portions of the Western and Eastern Project Study Areas are reported for both segments; therefore, the values are not additive.

8.1.2.1 Anoka Sand Plain Subsection

The Anoka Sand Plain subsection is characterized by flat, sandy lake plains and terraces along the Mississippi River, which forms the western boundary of the subsection separating it from the Hardwood Hills and Big Woods subsections (reference (1)). Landforms in the Anoka Sand Plain consist of small dunes, kettle lakes, and tunnel valleys that create a level to gently rolling topography. Sandy terraces are found along the Mississippi River and its tributaries throughout the subsection. Bedrock outcrops can be found near St. Cloud and, in general, surface glacial deposits are less than 200 feet thick. Soils in the subsection are generally sandy, droughty upland soils with some organic soils in ice block depressions and tunnel valleys and poorly drained prairie soils along the Mississippi River. Most rivers and streams in this subsection flow into the Mississippi River, though some flow east to the St. Croix River. Rivers, streams, and lakes are located in old glacial tunnel valleys, and peatlands occupy linear depressions of many of the tunnel valleys.

8.1.2.2 Big Woods Subsection

The Big Woods subsection is characterized by a large block of deciduous forest present at the time of Euro-American settlement (reference (1)). Topography is gently to moderately rolling, and the primary landform is a loamy mantled moraine formed by the Des Moines lobe of the late Wisconsin glaciation. Circular, level-topped hills with smooth side slopes dominate the landscape, with broad level areas between the hills that contain closed depressions with lakes and peat bogs. More than 100 lakes greater than 160 acres in size are present within this subsection. Drainage within this subsection is undeveloped and is generally controlled by groundwater, with no inlets or outlets.

Soils are predominantly loamy and range from loam to clay loam formed by the calcareous glacial till of the Des Moines lobe, with depth to bedrock ranging between 100 and 400 feet. Major rivers within this subsection are the Minnesota River, which bisects the Big Woods subsection, and the Crow River and its tributaries.

8.1.2.3 Hardwood Hills Subsection

The Hardwood Hills subsection is characterized by steep slopes, high hills, and lakes formed in glacial end moraines and outwash plains (reference (1)). During the Wisconsin age glaciation, ice stagnation moraines, end moraines, ground moraines, and outwash plains were formed in this subsection. Kettle lakes are abundant within the moraines and outwash deposits and there are over 400 lakes greater than 160 acres in size within this subsection. Most of this subsection is covered in 100 to 500 feet of glacial drift over diverse bedrock. Loamy soils are dominant, with loamy sands and sandy loams on outwash plains to loams and clay loams on moraines. The high ridge of the Alexandria Moraine is the headwaters region for many rivers and streams that flow east and west; the Chippewa, Long Prairie, Sauk, and Crow Wing are the major rivers in this subsection and the Mississippi River forms part of the eastern boundary. The Hardwood Hills subsection is split by the Continental Divide and waters north of the divide eventually flow toward Hudson Bay and waters south of the divide flow into the Mississippi River system (**Map 8-7**).

8.1.2.4 Minnesota River Prairie Subsection

The Minnesota River Prairie subsection is characterized by large till plains that are bisected by the broad valley of the Minnesota River (reference (1)). The Minnesota River was formed by Glacial River Warren which drained Glacial Lake Agassiz. Topography is steepest along the Minnesota River and the Big Stone Moraine, which has steep kames and broad slopes, while topography outside of the river valley consists of level to gently rolling ground moraine. Glacial drift generally ranges between 100 and 400 feet throughout this subsection. Soils are predominantly well-to-moderately well-drained loams formed in gray calcareous till of the Des Moines lobe with some localized inclusions of clayey, sandy, and gravelly soils. Streams and small rivers drain into the Minnesota River or the Upper Iowa River, though drainage networks are poorly developed due to landscape characteristics. There are 150 lakes greater than 160 acres in size throughout this subsection, though many are shallow. Wetlands were common within this subsection prior to Euro-American settlement, and most have been drained to establish usable cropland.

8.1.2.5 Topography

Topography within the Anoka Sand Plain, Hardwood Hills, and Big Woods subsections is generally rolling to undulating. (**Map 8-6**). Elevation ranges from 860 to 1,460 feet above sea level. The Mississippi River is the main drainage channel in these subsections and creates a natural boundary between the Anoka Sand Plain and the Hardwood Hills and Big Woods subsections. Topography in the Minnesota River Prairie subsection is generally more level to slightly rolling. Elevations here range from 790 to 1,710 feet above sea level. The Minnesota River is the main drainage channel for this subsection and occurs as an abrupt gorge within the Minnesota River Prairie subsection.

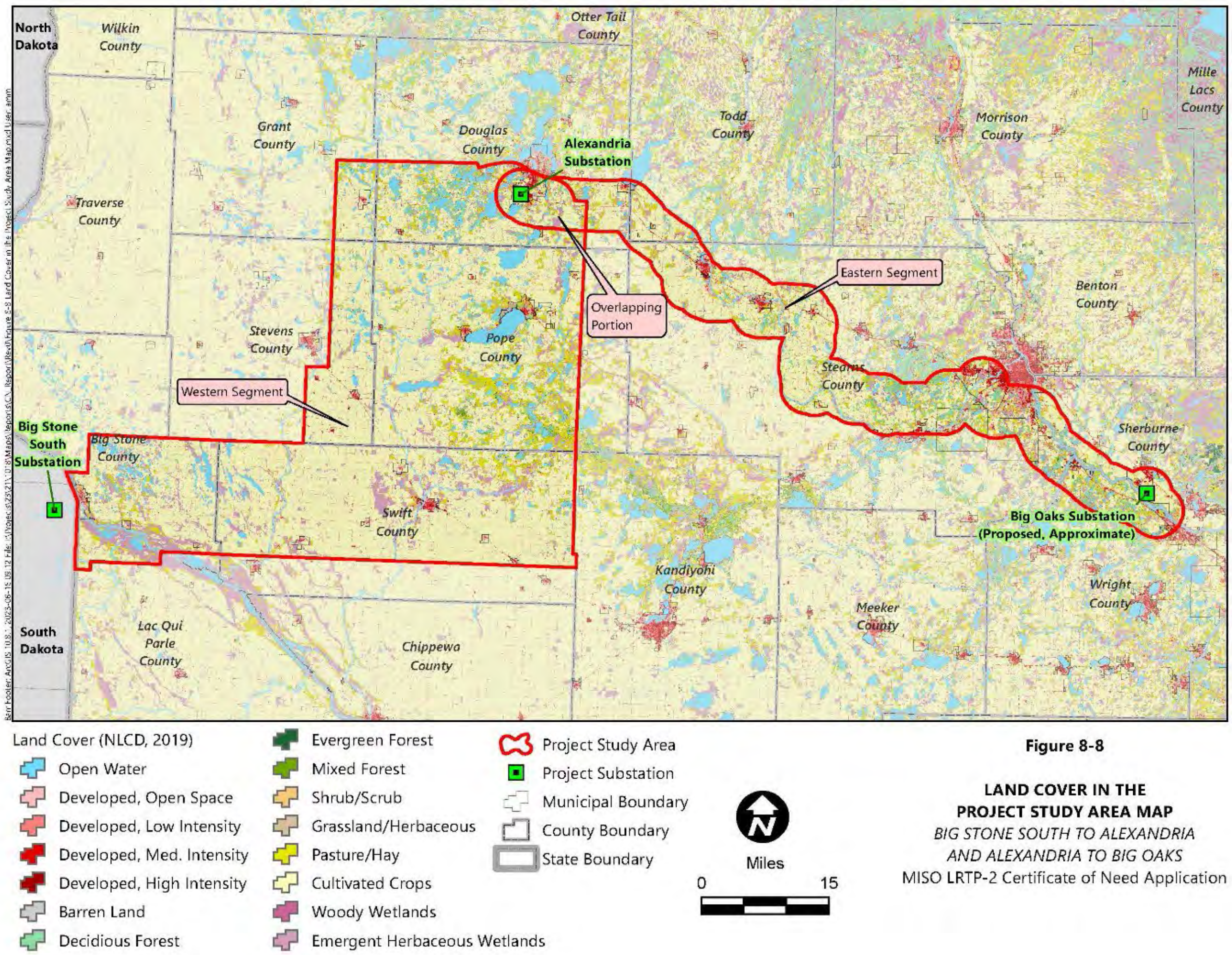
8.1.3 Human Settlement

The following sections describe elements related to human settlement and land uses within the Project Study Area.

8.1.3.1 Land Use and Land Cover

According to the 2019 National Landcover Database – Land Use-Land Cover dataset, cultivated cropland is the dominant land cover making up 61 percent of the Project Study Area (**Table 8-2, Map 8-8**) and, therefore, agriculture is the primary land use. Pasture/Hay and emergent herbaceous wetlands are the second and third most dominant land cover type accounting for 9 percent of the Project Study Area each. The remaining land cover classifications make up approximately 20 percent of the Project Study Area.

Map 8-8
Land Cover in the Project Study Area Map



The Project is not anticipated to significantly alter the existing land use-land cover within the Project Study Area. Impacts to the existing land cover due to new structure construction in the Western Segment and portions of the Eastern Segment would be minimized during the routing process and permitting processes. The Eastern Segment will involve stringing a second circuit on existing transmission structures for approximately 95 to 99 percent of the Project and will not result in conversion of land cover for this portion of the route. Construction of the Big Oaks substation will result in the conversion of approximately 10 acres of cultivated cropland to industrial land use. Impacts to land cover for the new transmission line route for the Eastern Segment would similarly be minimized during the routing and permitting processes. The Applicants will work to route the transmission line, where new transmission line is needed, along road rights-of-way, section lines, or property lines and space transmission line structures in a manner that avoids sensitive areas while maintaining safety and design standards and meeting all permitting requirements.

Table 8-2
Land Cover in the Project Study Area

Land Use Category	Western Segment		Eastern Segment		Total Project Study Area[1]	
	Acres	Percentage	Acres	Percentage	Acres	Percentage
Barren Land	1,620	<1	669	<1	2,228	<1
Cultivated Crops	754,112	66	209,491	52	948,090	61
Deciduous Forest	30,521	3	39,443	10	67,393	4
Developed, High Intensity	1,900	<1	4,481	1	5,749	<1
Developed, Low Intensity	14,606	1	14,556	4	27,733	2
Developed, Medium Intensity	7,647	<1	11,967	3	18,210	1
Developed, Open Space	31,109	3	14,630	4	43,840	3
Emergent Herbaceous Wetlands	111,835	10	30,438	8	138,529	9
Evergreen Forest	589	<1	656	<1	1,191	<1
Pasture/Hay	96,592	8	46,564	12	138,890	9
Herbaceous	8,752	<1	3,160	<1	11,637	1
Mixed Forest	3,587	<1	1,338	<1	4,804	<1
Open Water	79,620	7	16,817	4	93,521	6
Shrub/Scrub	307	<1	306	<1	604	<1
Woody Wetlands	8,062	<1	9,284	2	16,686	1
Total	1,150,859	100	403,800	100	1,519,111	100

[1] Resources within the overlapping portions of the Western and Eastern Project Study Areas are reported for both segments; therefore, the values are not additive.

8.1.3.2 Commercial, Industrial, Residential Land Use

Human settlement within the Project Study Area includes municipalities, farmsteads, rural residences, utility infrastructure, roadways, and commercial and industrial areas. Publicly available information was reviewed to characterize commercial, industrial, and residential land use patterns throughout the Project Study Area.

Municipalities in the Western Segment of the Project Study Area are concentrated along roadways such as Minnesota State Highway 7, 9, 29, 55, and 15 and U.S. Highway 12 (**Map 8-1**). Larger cities and towns in the Western Segment include Glenwood, Ortonville, Benson, Starbuck and Alexandria.

Larger Cities and towns in the Eastern Segment of the Project Study Area are generally concentrated along Interstate 94. Larger cities and towns in the Eastern Segment include Saint Cloud, Saint Augusta, Rockville, Waite Park, Becker, Saint Martin, Melrose, Sauk Centre, and Alexandria.

Residential areas in the Project Study Area are located within large and small cities and towns, as well as scattered rural residences and farmsteads located in more rural areas. Outside of the larger municipalities, communities are generally small and rural in nature with farmsteads and residences located along roadways, away from population centers. Commercial and industrial areas in the Project Study Area are generally located within or adjacent to these larger municipalities.

There are no reservations or other tribal lands located within the Project Study Areas.

The primary method of mitigation for minimizing effects on human settlements and related infrastructure is to route transmission lines away from municipalities and residential areas. Routing a transmission line adjacent to existing utility corridors and roadways can also help to minimize the effects of transmission lines.

The Project will be designed in compliance with State, NESC, and the applicable Applicants' standards for clearance to ground, crossing other utilities, clearance from buildings, strength of materials, vegetation, and other obstructions. Furthermore, the Applicants will comply with their construction standards, which include requirements of NESC and Occupational Safety and Health Administration (OSHA). Adherence to NESC and OSHA standards will limit the effects of the Project on areas of human settlement and related infrastructure.

The Applicants will work with tribal, state, county, city, township, other local stakeholders and landowners to identify areas of concern and work collaboratively to minimize effects on areas of human settlement and related infrastructure.

8.1.3.3 Displacement

The development and construction of the Project is not anticipated to displace any residential homes or businesses. NESC and Applicants' standards require minimum clearances between transmission line facilities and buildings to ensure safe operation of transmission line facilities. To maintain these clearances, the Applicants plan to acquire a 150-foot-wide right-of-way for the 345 kV transmission line in the Western Segment. Approximately 95 to 99 percent of the Eastern Segment will involve stringing a second 345 kV circuit on existing transmission line structures. Additional right-of-way will be required for the Eastern Segment only at the locations described in Section 8.1 where the Project deviates from the existing infrastructure including at the Mississippi River crossing. Where practicable, new right-of-way will be located near existing transmission lines or other infrastructure and is not anticipated to displace any residential homes or businesses.

8.1.3.4 Aesthetics

Overhead electric transmission and distribution lines and other linear infrastructure (e.g., roads, pipelines) are present throughout the Project Study Area. Potential routes for the Western Segment that are yet to be determined may follow existing infrastructure such as existing transmission lines or roads, where possible. In addition, portions of the Western Segment may be located outside of existing transmission line or road rights-of-way. The Applicants will evaluate the visual impact of new segments of the transmission line to the surrounding resources. The 345 kV transmission line in the Eastern Segment will be located along existing transmission line infrastructure for approximately 95 to 99 percent of the route transmission structures and would have a negligible impact on the surrounding aesthetics. Impacts to aesthetics for the new transmission line route for the Eastern Segment will be minimized during the routing and permitting process.

8.1.3.5 Socioeconomics

The existing demographic conditions are based on data reviewed from the U.S. Census Bureau 2020 Census and the 2015-2020 American Community Survey (ACS) 5-Year Estimates (reference (2)). The Project Study Area is located wholly or partially within the 11 counties identified in **Table 8-3**; these counties form the basis of establishing socioeconomic conditions described herein.

Population and socioeconomic data for counties within the Project Study Area and the State of Minnesota are provided in **Table 8-3**. Counties in the Western Segment of the Project Study Area are generally rural in nature. Counties in the Eastern Segment of the Project Study Area, particularly the southeast corner of the Project Study Area, are closer to the Twin Cities metro area and generally have larger populations and are more densely populated.

The unemployment rate within the Project Study Area ranges from a low of 0.9 percent in Pope County to a high of 3.5 percent in Stearns County. Per capita annual income averages, within the 11 counties that the Project Study Area crosses, are below the state average of $38,881 and range from a low of $26,427 to a high of $37,416. Education, health care and social assistance is the primary labor category in all the 11 counties that the Project Study Area crosses, as well as in the State of Minnesota.

Table 8-3
Population and Socioeconomic Data

Location	Project Segment	Population[1]	Unemployment Rate (Percent)[2]	Per Capita Income (Dollars) [2]	Top employment by Industry[2]
Minnesota	N/A	5,706,494	2.6	$38,881	E, P, M
Big Stone County	Western Segment	5,166	1.6	$30,588	E, Ag, R
Douglas County	Western and Eastern Segments	39,006	1.6	$36,559	E, M, R
Grant County	Western Segment	6,074	3.1	$33,407	E, R, M
Lac Qui Parle County	Western Segment	6,719	1.7	$34,091	E, Ag, M
Pope County	Western Segment	11,308	0.9	$35,244	E, M, R
Sherburne County	Eastern Segment	97,183	1.7	$36,022	E, M, R
Stearns County	Eastern Segment	158,292	3.5	$31,574	E, M, R
Stevens County	Western Segment	9,671	1.7	$35,551	E, R, M
Swift County	Western Segment	9,838	2.1	$33,416	E, Ag, M
Todd County	Eastern Segment	25,262	2.5	$26,427	E, M, R
Wright County	Eastern Segment	141,337	2.0	$37,416	E, M, C

U.S. Census Bureau, 2020. Industries are defined under the 2012 North American Industry

Classification System and abbreviated as follows: Ag = Agriculture, Forestry, Fishing, and Hunting, and Mining; C = Construction; E = Educational, Health and Social Services; M = Manufacturing; P= Professional, Scientific, and Management, and Administrative and Waste Management Services; and R = Retail Trade.
[1] Source: reference (3)
[2] Source: reference (4)

The 11 counties within the Project Study Area combined comprise approximately 7 percent of the State's total population. A large majority (89 percent) of this population identifies as white (**Table 8-4**). For the purpose of this review, minority populations are defined as any person who identifies as any race other than white. The minority population within the counties crossed by the Project Study Area makes up approximately 5 percent of the total population within the counties. This is less than the statewide minority population (which makes up approximately 16 percent of the state's population).

Table 8-4
Demographics

Location	Project Segment	White (%)	Black or African American (%)	American Indian (%)	Asian (%)	Native Hawaiian (%)	Some Other Race Alone (%)
Minnesota	N/A	4,423,146 (78%)	398,434 (7%)	68,641 (1%)	299,190 (5%)	2,918 (<1%)	168,444 (3%)
Big Stone County	Western Segment	4,832 (94%)	29 (1%)	49 (1%)	17 (<1%)	4 (<1%)	77 (1%)
Douglas County	Western and Eastern Segments	36,887 (95%)	235 (1%)	129 (<1%)	228 (1%)	11 (<1%)	285 (1%)
Grant County	Western Segment	5,721 (94%)	13 (>1%)	31 (1%)	20 (<1%)	8 (<1%)	50 (1%)
Lac Qui Parle County	Western Segment	6,290 (94%)	36 (1%)	15 (<1%)	40 (1%)	0 (<1%)	113 (2%)
Pope County	Western Segment	10,802 (96%)	39 (>1%)	36 (<1%)	50 (<1%)	2 (<1%)	66 (1%)
Sherburne County	Eastern Segment	85,504 (88%)	3,666 (4%)	444 (<1%)	1,295 (1%)	22 (<1%)	1,189 (<1%)
Stearns County	Eastern Segment	130,858 (83%)	13,315 (8%)	628 (<1%)	3,188 (2%)	69 (<1%)	3,546 (<1%)
Stevens County	Western Segment	8,254 (85%)	84 (1%)	170 (2%)	70 (1%)	1 (<1%)	597 (6%)
Swift County	Western Segment	8,807 (90%)	88 (1%)	49 (<1%)	78 (1%)	133 (1%)	271 (3%)

Location	Project Segment	White (%)	Black or African American (%)	American Indian (%)	Asian (%)	Native Hawaiian (%)	Some Other Race Alone (%)
Todd County	Eastern Segment	22,681 (90%)	145 (1%)	162 (1%)	160 (1%)	7 (<1%)	488 (2%)
Wright County	Eastern Segment	127,090 (90%)	2,637 (2%)	446 (>1%)	1,898 (1%)	4 (<1%)	77 (<1%)

Transmission line projects have the potential to benefit the socioeconomic conditions of an area in the short term through an influx of labor personnel, creation of construction jobs, purchases of construction material and other goods from local businesses, and expenditures on temporary housing, food, fuel, etc. for non-local personnel. In the long term, transmission line projects may beneficially impact the local tax base in the form of revenues generated from utility property taxes. Potential mitigation measures that may enhance the socioeconomic benefits experienced by local communities include use of local personnel and construction material retailers during construction of the Project. The Applicants will work with local communities to identify opportunities for further enhancing the socioeconomic benefits of the Project.

8.1.3.6 Environmental Justice

The United States Environmental Protection Agency (EPA) defines environmental justice as the "fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income in developing, implementing, and enforcing environmental laws, regulations, and policies." (reference (5)). Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies. Meaningful involvement means:

- people have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health;
- the public's contributions can influence the regulatory agency's decision;
- community concerns will be considered in the decision-making process; and

- decision makers will seek out and facilitate the involvement of those potentially affected.

EPA developed a mapping and screening tool, EJScreen, that can be used as an initial step to gather information regarding minority and/or low-income populations; potential environmental quality issues; environmental and demographic indicators; and other important factors (reference (6)). EPA recommends that screening tools like EJScreen be used for a "screening-level" look and a useful first step in understanding or highlighting locations that may require further review.

The Minnesota Pollution Control Agency (MPCA) website "Understanding Environmental Justice" provides tools to help identify environmental justice communities throughout the state and provide guidance for integrating environmental justice principles such as fair treatment and meaningful involvement of environmental justice communities.

The Applicants used the MPCA mapping tool[82] to identify environmental justice communities located near the Project (reference (7)). The MPCA mapping tool considers tribal areas and census tracts with higher concentrations of low-income and minority populations as areas of increased concern for environmental justice. The MPCA defines low-income populations as populations with at least 40 percent of people reporting income less than 185 percent of the federal poverty level (reference (7)). Minority communities are identified as communities with 50 percent or more people of color. (reference (7)).

The Project Study Area is located within portions of 62 census tracts. The MPCA mapping tool identified 17 environmental justice communities within these 62 census tracts (**Map 8-9**). Of these communities, 14 are identified as low-income communities, and three are identified as both low-income and as minority communities. There are no federally recognized tribes located within the Project Study Area.

[82] The Minnesota State Legislature revised the definition of an "environmental justice area" in Minn. Stat. § 216B.1691, subd. 1(e). This revised definition was enacted on February 7, 2023. Although this statute is not directly applicable to the Project, the definition provides a different method for assessing environmental justice areas. These changes are not yet reflected in the MPCA environmental justice mapping tool.

As routes are developed for the Western Segment, the Applicants will review the environmental justice communities to determine if any of these communities would be disproportionately affected by the Project. The Eastern Segment of the Project is not anticipated to disproportionally affect the identified environmental justice communities as the new 345 kV transmission circuit will mostly be strung on existing transmission structures. In addition, the Eastern Segment would not require construction of new transmission line structures or additional right-of-way within low income or minority communities.

8.1.3.7 Recreation

Recreational opportunities in the Project Study Area include outdoor recreational trails, use of public lands and parks, snowmobiling, hunting and fishing, boating, camping, and participation in local area events. There are several types of formally managed and regulated lands across the Project Study Area, including federal easements and managed lands, National Wildlife Refuges (NWRs), Waterfowl Production Areas (WPAs), Wildlife Management Areas (WMAs), Scientific and Natural Areas (SNAs), state trails, state parks, and municipal and county parks and trails (**Map 8-10** and **Map 8-11**).

The Big Stone NWR is the only NWR located within the Project Study Area and is located in the Western Segment. The refuge includes 11,586 acres in Big Stone and Lac Qui Parle Counties, near Ortonville, Minnesota (**Map 8-11**). The NWR provides a variety of recreational activities such as hiking, fishing, wildlife viewing, and boating.

WPAs are lands that were established to conserve migratory bird habitat. There are 187 (consisting of approximately 35,900 acres) WPAs located throughout the Project Study Area (**Map 8-11**). Some WPAs are available for hunting during state-designated hunting seasons.

WMAs are part of Minnesota's outdoor recreation system and are established to protect those lands and waters that have a high potential for wildlife production, public hunting, trapping, fishing, and other compatible recreational uses. There are 88 WMAs located throughout the Project Study Area (**Map 8-11**).

SNA lands are natural areas where native plants and animals flourish and are managed by MDNR. Most SNAs do not have designated hiking trails, restrooms or drinking water; however, they are available for bird and wildlife watching, hiking, photography, snowshoeing and cross-country skiing. There is one SNA (Langhei Prairie) located within the Western Segment. There are three SNAs located within the Eastern Segment: Cold Spring Heron Colony, Clear Lake, and Quarry Park (**Map 8-12**).

The MDNR manages 35 state water trails covering over 4,500 miles throughout Minnesota. These trails provide opportunities for canoeing, kayaking, paddleboarding, and camping. There are approximately 159.9 miles of designated state water trails throughout the Project Study Area (**Map 8-10**). These state water trails are located along the Minnesota River, Sauk River, Pomme de Terre River, and Chippewa River. There are also five state water trail campsites located within the Eastern Segment along the Mississippi River State Water Trail and the Sauk River State Water Trail. (**Map 8-10**).

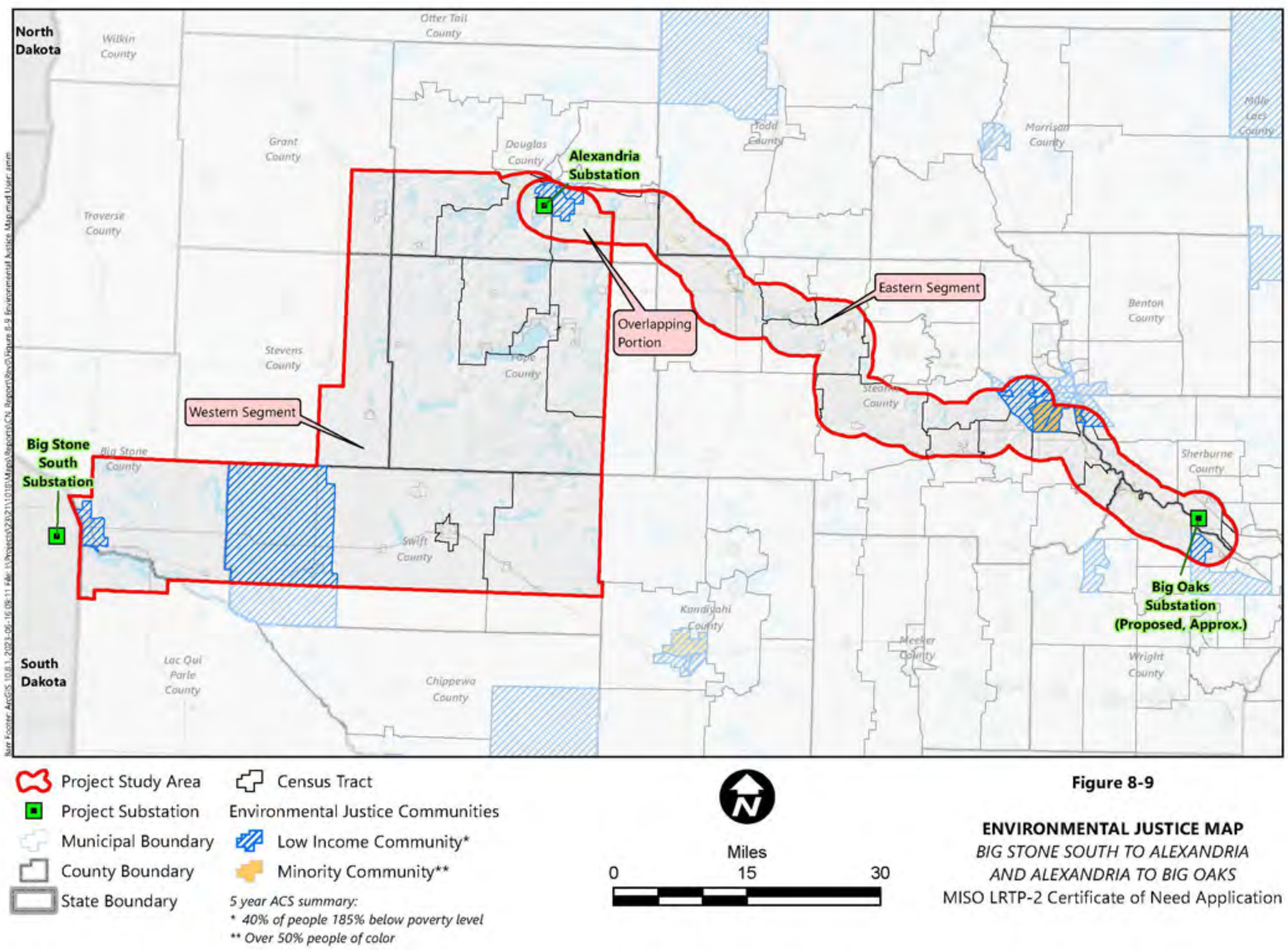
There are two state trails located within the Project Study Area: the Minnesota River State Trail (TRA00750) and the Central Lakes State Trail (TRA00757) (**Map 8-10**). The Minnesota River State Trail is located along the far western end of the Western Segment. The Central Lakes State Trail is located along the northern portion of the Eastern Segment near the city of Osakis. Both of these trails extend outside of the Project Study Area.

Additional hiking trails are located within state, local and county parks throughout the Project Study Area. There are three state parks located within the Project Study Area: Glacial Lakes, Monsoon Lake, and Lake Maria. **Map 8-10** shows the distribution of state parks in the Project Study Area. County and municipal parks are also found throughout the Project Study Area. **(Map 8-10**).

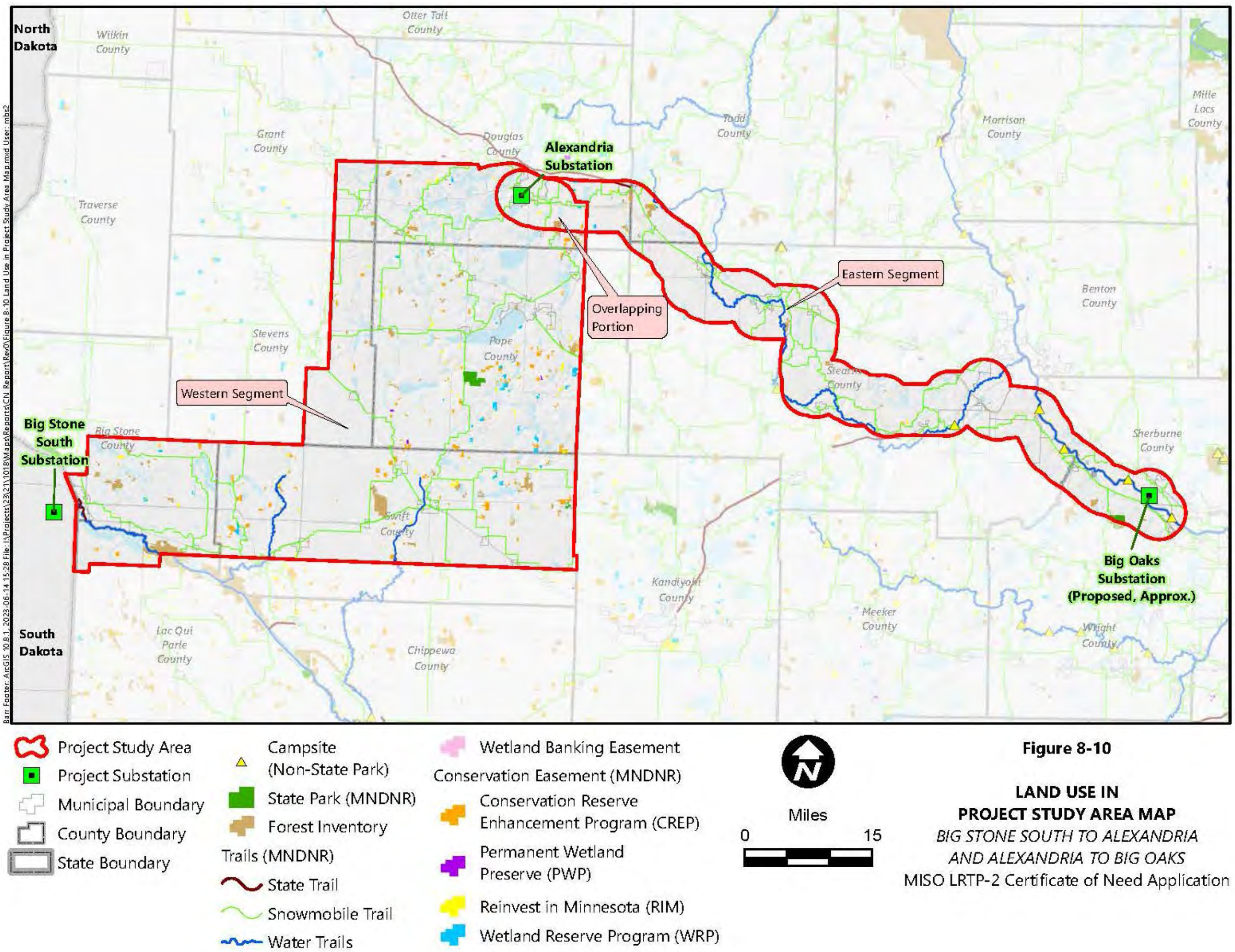
Snowmobile trails are found throughout the Project Study Area and generally follow existing county and township roads, though many state parks and hiking trails also allow snowmobiling during the winter months. In total, there are approximately 720 miles of snowmobile trails within the Project Study Area (**Map 8-10**).

In general, public recreation areas and managed lands can be avoided through routing and siting process, as needed. If these areas cannot be avoided, the Applicants will work with applicable federal, state, county, and local agencies to develop appropriate mitigation measures to minimize impacts on public recreational use of these areas. Mitigation measures could include avoiding construction during seasons of peak use, signage, and ensuring public access to recreation areas is not restricted, as well as obtaining relevant permits/approvals from applicable agencies.

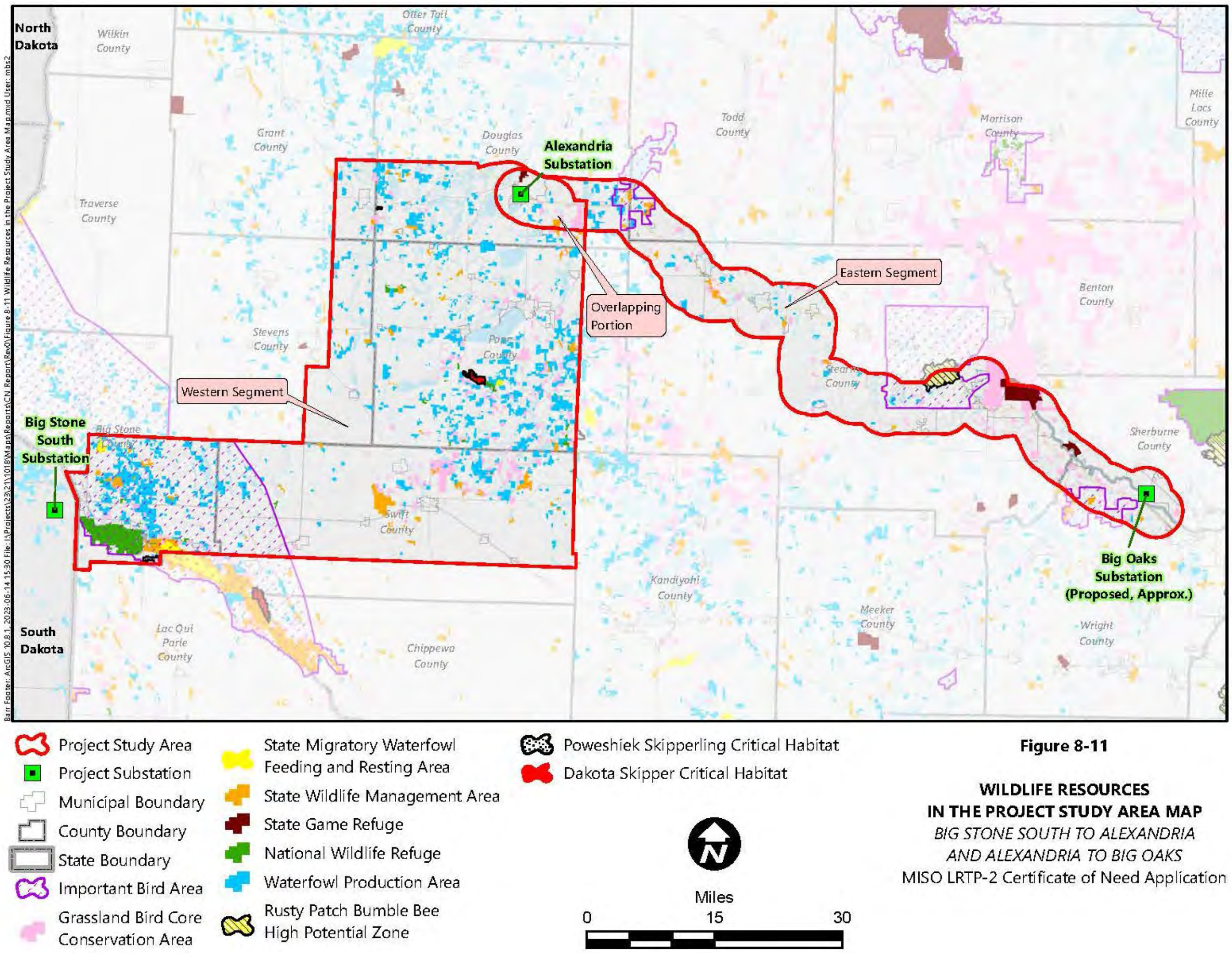
Map 8-9
Environmental Justice Map



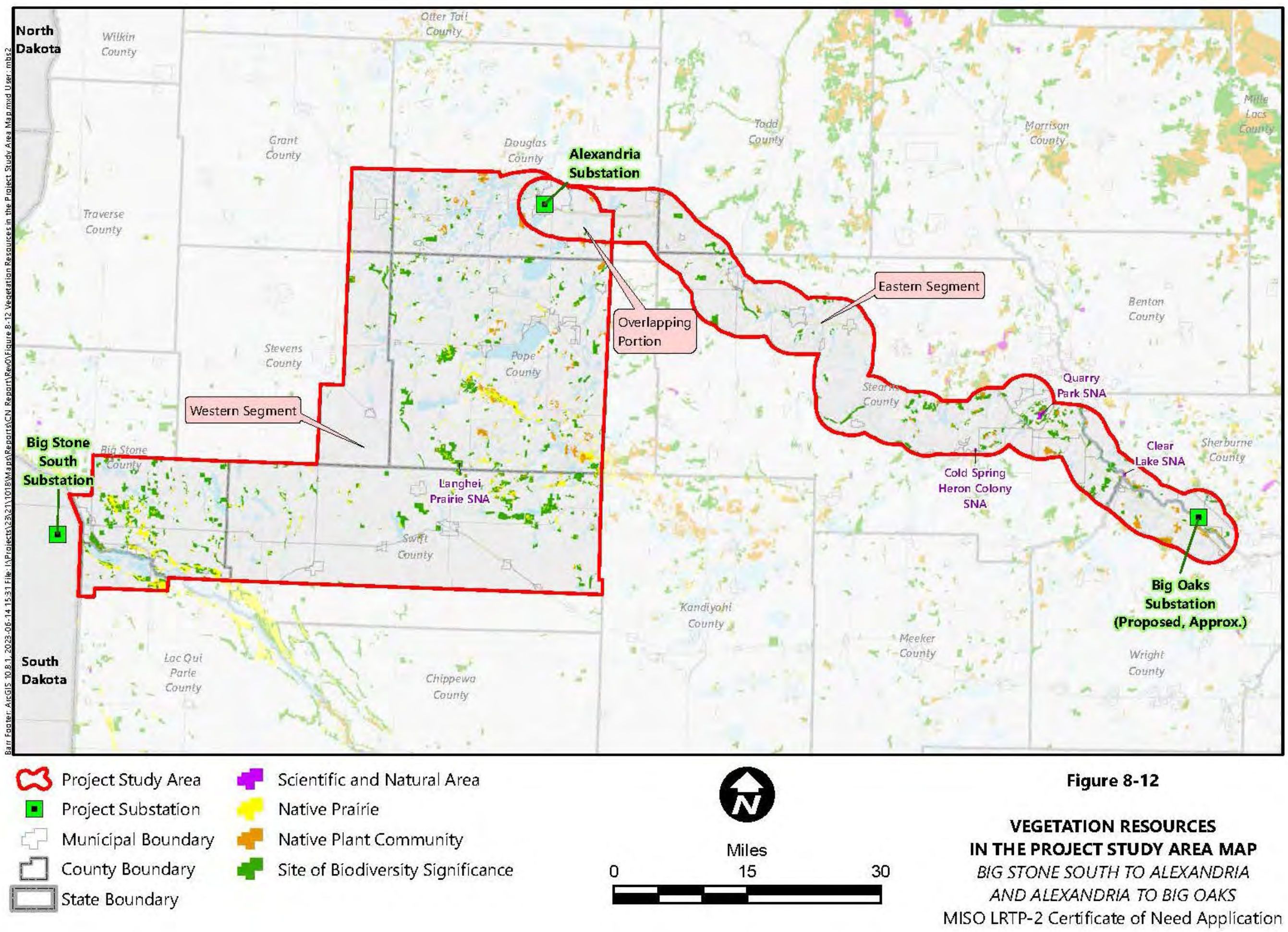
Map 8-10
Land Use in the Project Study Area Map



Map 8-11
Wildlife Resources in the Project Study Area Map



Map 8-12
Vegetation Resources in the Project Study Area Map



8.1.3.8 Conservation Easements

Conservation lands are areas designated by a legal instrument (i.e., contract, easement, regulation) that limits or conditions certain uses of the land to fulfill the respective conservation purpose. Conservation lands in the Project Study Area include:

- Conservation Reserve Enhancement Program (CREP);
- Reinvest in Minnesota (RIM);

- Wetland Reserve Program (WRP);
- Permanent Wetlands Preserves Program (PWP); and
- Wetland Banking Easement.

There are approximately 20,694 acres of conservation easements located in the Western and Eastern Project Study Area (**Map 8-10**; **Table 8-5**). The CREP program is the largest conservation program in the Project Study area and is a land conservation program established to pay farmers a yearly rental fee for agreeing to take environmentally sensitive land out of agricultural production with the intent of improving environmental health and quality (reference (8)). There are 10,434 acres of CREP land located within the Western Segment and 229 acres in the Eastern Segment (**Map 8-10**, **Table 8-5**).

Similarly, the RIM program was implemented by the Minnesota Board of Water and Soil Resources (BWSR) to conserve environmentally sensitive property in order to improve water quality by reducing soil erosion, phosphorus and nitrogen loading, and improving wildlife habitat and flood attenuation on private lands (reference (9)). There are approximately 4,467 acres of land in the RIM program located within the Western Segment and approximately 984 acres in the Eastern Segment (**Map 8-10**, **Table 8-5**).

The WRP properties are established by the United States Department of Agriculture (USDA) and Natural Resource Conservation Service (NRCS) to provide habitat for migratory waterfowl and other wetland dependent wildlife, including threatened and endangered species; improves water quality by filtering sediments and chemicals; reduces flooding; recharges groundwater; protects biological diversity; provides resilience to climate change; and provides opportunities for educational, scientific and limited recreational activities (**Map 8-10**, reference (10)). There are approximately 3,136 acres of WRP land within the Western Segment and approximately 447 acres in the Eastern Segment (**Table 8-5**).

The PWP is a state program that establishes permanent conservation easements to protect at-risk wetlands. There are approximately 257 acres of PWP land within the

Western Segment and approximately 20 acres in the Eastern Segment (**Table 8-5**, **Map 8-10**).

Similarly, wetland banking easements are conservation easements that protect wetlands from future disturbances. There are approximately 288 acres of wetland banking easements within the Western Segment and approximately 432 acres in the Eastern Segment (**Map 8-10**, **Table 8-5**).

Table 8-5
Conservation Easements in Project Study Area

Conservation Easement	Western Segment (Acres)	Eastern Segment (Acres)	Project Study Area[1] (Acres)
Conservation Reserve Enhancement Program (CREP)	10,434	229	10,589
Reinvest in Minnesota (RIM)	4,467	984	5,343
Wetland Reserve Program (WRP)	3,136	447	3,515
Permanent Wetlands Preserves Program	257	20	277
Wetland Banking Easement	288	432	720
Total	18,582	2,112	20,444

[1] Resources within the overlapping portions of the Western and Eastern Project Study Areas are reported for both segments; therefore, the values are not additive.

Depending on the governing conservation program, specific restrictions may be applied that would limit or restrict development of a transmission line. As routing of the portions of the Project that will require new right-of-way proceeds, the Applicants will work with federal, state, and county agencies and landowners to identify conservation easements that may be affected by the Project. If a conservation easement cannot be avoided through modifications in Project routing and siting, the Applicants will work with the owner and managing agency to develop appropriate mitigation measures to minimize effects.

The majority of the Eastern segment will follow the existing 345 kV transmission line right-of-way and will not permanently alter any existing conservation lands. In addition, there are no conservation easements within the proposed Big Oaks Substation, Alexandria Substation Expansion, Riverview Substation Tap, Quarry Substation Bypass, or Mississippi River Crossings.

8.1.3.9 Public Services and Transportation

The Project Study Area is primarily located in a rural setting in western and central Minnesota **Map 8-13**). In rural areas, residents often rely on privately owned domestic water wells and on-site septic systems for their water supply and wastewater treatment. Larger populations centers provide municipal water and sewer treatment via buried public infrastructure.

Existing road infrastructure within the Project Study Area is a mix of federal, state, and county highways and roads, and township roads. The Eastern Segment of the Project Study Area generally follows Interstate 94 from the existing Alexandria Substation to the existing Riverview Substation to the proposed Big Oaks Substation. Major transportation networks located in the Western Segment include Minnesota State Highway 7, 9, 29, 55, 104, 114 and U.S. Highway 12 (**Map 8-13**). In addition, there are 14 railroads located within the Project Study Area. These railroads are operated by SOO Line Railroad, Burlington Northern Santa Fe Railway, and Northern Lines Railway.

Numerous electric transmission lines exist throughout the Project Study Area, as depicted on **Map 8-13**. Electrical substations that support the network of transmission lines are scattered throughout the Project Study Area; these facilities are generally sited on the outer edges of municipalities or away from population centers in rural areas.

Oil and gas transmission and distribution pipelines are present throughout the Project Study Area (**Map 8-13**). Oil and gas transmission pipelines are generally sited away from population centers, while the distribution lines typically supply population centers. The location of pipelines will be identified with more specificity as routes are developed for the Project. If the Project is routed near or crosses public infrastructure, roads, railroads, pipelines, etc., appropriate engineering standards will be incorporated into Project design, and any required crossing permissions or agreements will be obtained from the applicable owners/operators.

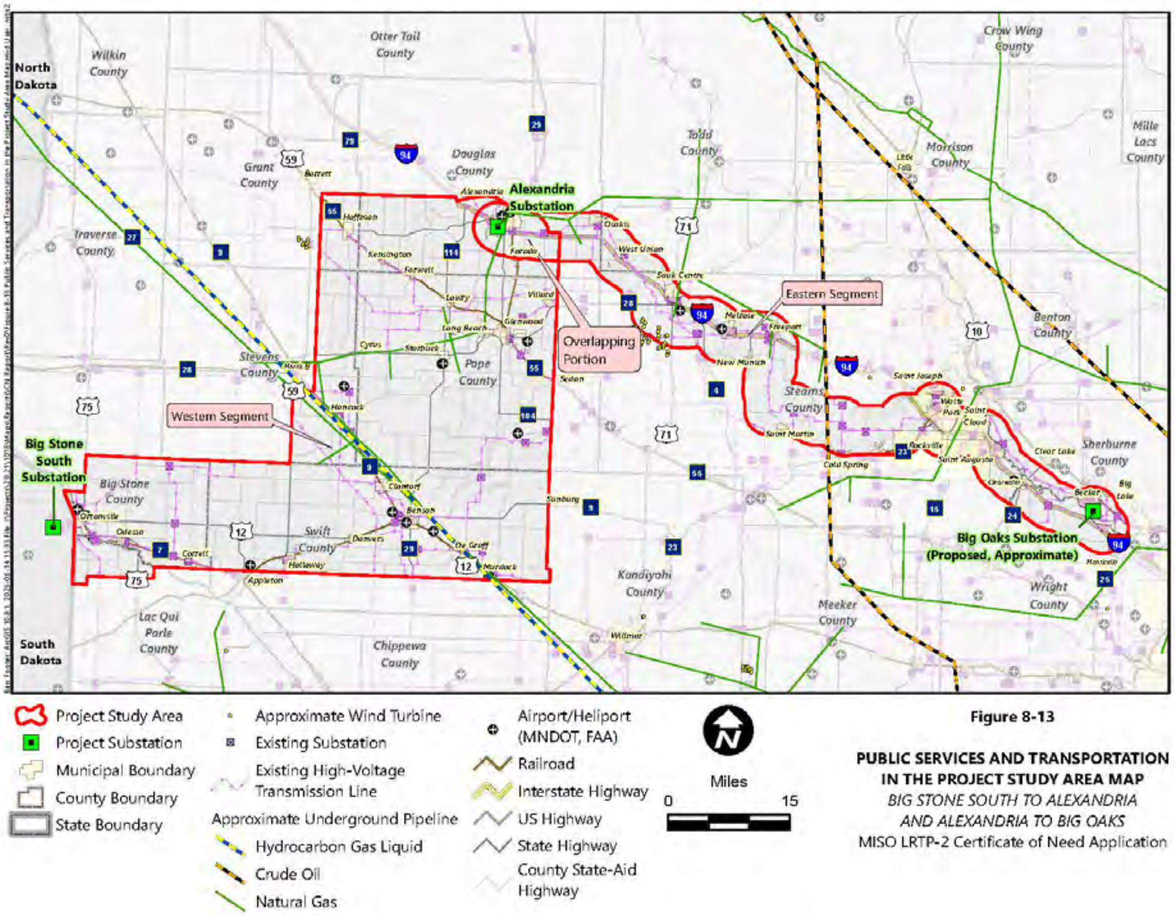
There are 19 airports located within the Project Study Area including nine private airports and 10 public airports (**Map 8-13**; **Table 8-6**). In general, the public airports are located in medium to larger municipalities in the Project Study Area such as

Alexandria (Chandler Field and Douglas County Hospital), Appleton, Benson, Glenwood, Ortonville, Sauk Centre, and Starbuck. Private airports are a mixture of hospital/medical center airstrips or landing pads, and privately-owned landing strips.

Table 8-6
Airports in the Project Study Area

Airport	Type
Appleton Muni	Public
Bakko Aviation	Private
Benson	Private
Benson Muni	Public
Brown's Private	Private
Chandler Field	Public
Douglas County Hospital	Private
Glenwood Muni	Public
Lorenz	Private
Melrose Hospital	Private
Murdock Muni	Public
Ortonville Hospital	Private
Ortonville Muni/Martinson Field	Public
Sauk Centre Muni	Public
Seven Hills	Private
Starbuck Muni	Public

Map 8-13
Public Services and Transportation in Project Study Area Map



Airport impacts for the Western Segment of the Project can be addressed through the route selection process (generally through avoidance) and structure design (where an airport cannot be avoided). A flight hazard determination from the Federal Aviation Administration (FAA) may be required depending on the location of the approved route. The FAA requires notification of any transmission line constructed near an airport if the structure height exceeds a slope of 100:1 within 20,000 feet (3.8 miles) or a slope of 50:1 within 10,000 feet (1.9 miles) of the airport. In general, a transmission line will need to be approximately one mile from municipal airports to avoid conflicts with local requirements (14 Code of Federal Regulations (CFR) Part 77). The Project will comply with other rules that establish safety zones for airports, where appropriate. The portion of the Eastern Segment that will be using the existing transmission line structures already complies with airport setback requirements. There are no airports located within one mile of the proposed Big Oaks Substation, Alexandria Substation Expansion, Riverview Substation Tap, Quarry Substation Bypass, or Mississippi River Crossing options.

Hospitals, fire stations and police departments are located throughout the Project Study Area. Generally, these public services are located within municipalities identified in Section 8.1.3.2. Some rural hospitals, fire stations, and police departments located outside of municipal boundaries provide services to rural residences.

In general, impacts on public services and transportation can be avoided or minimized through routing, design, permitting and construction including paralleling existing utility corridors and other linear infrastructure. To the extent possible, the portions of the Project that will require new right-of-way will be routed to avoid impacts to public services and transportation features. If impacts cannot be avoided, the Applicants will work with applicable authorities to identify ways to minimize impacts.

During Project construction roadway closures or diversions may be necessary to accommodate construction equipment, construction activities and restoration work. If road closures cannot be avoided, the Applicants will work with the applicable federal, state, and county agencies to develop appropriate mitigation measures to minimize impacts on public services and transportation. Mitigation measures could include avoiding construction during hours of peak use, detours, signage, and ensuring access to public service infrastructure is not restricted.

8.1.4 Land-Based Economies

8.1.4.1 Agriculture

The agricultural production industry is a significant part of local economies throughout Minnesota. Information from the USDA's 2017 Census of Agriculture for each of the counties in the Project Study Area is provided in **Table 8-7**.

The percent of land used for farmland varies by county within the Project Study Area. Stevens County has the greatest percentage of county land used for farmland (92 percent). Stearns County has the most farmland (650,821 acres) and the largest market value for agricultural products sold ($748 million). Corn is the predominant crop produced in each county, typically followed by soybeans. Cattle and hogs are the dominant livestock produced in the Project Study Area (reference (11)).

Table 8-7
Agriculture Statistics by County

Location	Project Segment	Total Farmland (Acres)	Top Crops Produced	Livestock by County Inventory	Market Value of Agricultural products sold (dollars)
Big Stone County	Western Segment	268,769 (85% of county)	Corn, soybeans, wheat	Hogs, cattle, sheep	$138,754,000
Douglas County	Western and Eastern Segments	263,265 (65% of county)	Corn, soybeans, wheat	Cattle, chicken, hogs	$100,345,000
Grant County	Western Segment	324,188 (93% of county)	Corn, soybeans, wheat	Cattle, hogs, chicken	$190,286,000
Lac Qui Parle County	Western Segment	419,884 (86% of county)	Corn, soybeans, hay	Hogs, cattle, chicken	$249,877,000
Pope County	Western Segment	333,009 (78% of county)	Corn, soybeans, oats	Hogs, cattle, sheep	$199,295,000
Sherburne County	Eastern Segment	102,544] (37% of county)	Corn, soybeans, hay	Cattle, poultry, sheep	$75,700,000
Stevens County	Western Segment	330,334 (92% of county)	Corn, soybeans, wheat	Hogs, cattle, chicken	$327,441,000
Stearns County	Eastern Segment	650,821 (73% of county)	Corn, soybeans, oats	Chicken, hogs, cattle	$747,977,000
Swift County	Western Segment	344,976 (72% of county)	Corn, soybeans, wheat	Cattle, hogs, chicken	$284,161,000
Todd County	Eastern Segment	333,408 (55% of county)	Corn, soybeans, sunflowers	Cattle, hogs, chicken	$179,461,000
Wright County	Eastern Segment	240,651 (57% of county)	Corn, soybeans, wheat	Cattle, hogs, sheep	$196,508,000

Source: reference (11)

Impacts on agricultural fields and crop production in the Western Segment will be minimized by working with landowners and routing transmission lines along property lines, section lines and other existing linear infrastructure (e.g., roads, transmission lines, pipelines, etc.) as much as possible. At the discretion of the property owner, structures placed in tilled fields may instead be established far enough from the field edge to allow the farmer to maneuver equipment to farm around them. The Applicants will establish access to agricultural fields, storage areas, structures, and other agricultural facilities from property owners during construction to the extent practicable. If irrigation systems or drain tile are present, the Applicants will work with landowners to avoid these systems.

Crop production on some portions of agricultural lands may be temporarily interrupted for one growing season depending on the timing and duration of construction. In cultivated cropland areas, the Applicants will attempt to conduct construction before crops are planted or following harvest, if possible. The Project would also result in the permanent loss of crop production from the placement of structures within agricultural fields. It is estimated that Western Segment could permanently displace approximately 2 acres of agricultural land. The Applicants will compensate landowners for impacts on crops resulting from the construction, operation, and maintenance of the Project including soil compaction that might result from these activities.

The Eastern Segment will largely avoid impacts to agricultural production by stringing the new 345 kV transmission line on existing transmission line structures. Temporary impacts to crop production may occur during the installation of the new line. The portions of the Eastern Segment that will require new right-of-way will disrupt crop production as new structures will be placed in agricultural fields. In addition, the proposed Big Oaks Substation would result in the conversion of approximately 10 acres of cultivated cropland.

8.1.4.2 Forestry

The Project Study Area is dominated by agricultural lands with minimal forested land. No commercial forestry operations have been identified in the Project Study Area. based upon review of publicly available data. According to the MDNR forest inventory there are approximately 17,000 acres of forested land in the Western Segment and approximately 4,700 acres of forested land in the Eastern Segment (**Map 8-10**); reference (12)). No impacts to commercial forestry operations are anticipated during construction or operation of the Project.

8.1.4.3 Tourism

Tourism in the Project Study Area centers around outdoor recreational opportunities, such as fishing and water sports. Many out-of-state hunters and fishermen visit Minnesota every year to take advantage of these tourism activities. In 2022, the MDNR sold over 260,000 non-resident hunting and fishing licenses (reference (13)). Recreation areas, including state and county parks, WPAs, and WMAs, are located within the

Project Study Area. Design and routing of the Western Segment will consider these potential tourism locations. The Eastern Segment will follow the existing transmission line and will not directly impact any tourist locations. The portions of the Eastern Segment that will require new right-of-way are located adjacent to existing industrial infrastructure and will not adversely affect tourism. Therefore, impacts to tourism in the Project Study Area should be minimized during construction and operation of the Project.

8.1.4.4 Mining

Mining does not comprise a major industry in the Project Study Area. According to the MDNR map of minerals mined in Minnesota, mining operations are located within Big Stone County and Stearns County. (reference (14)). Big Stone County has granite and crushed stone mines located along the Minnesota River corridor. Stearns County also has crushed stone and granite mines near the Mississippi River corridor (reference (14)). Smaller sand, gravel, and stone quarry operations are found within the Project Study Area. The mined sand and gravel material are primarily used for making concrete for highways, roads, bridges, and buildings. The Project is anticipated to avoid these mining resources, and no impacts to mining are anticipated.

8.1.5 Archaeological and Historical Resources

Previously identified archaeological sites (e.g., precontact artifact assemblages, burial mounds and earthworks, historic occupation remnants and artifact scatters) are present in the Project Study Area, primarily along the margins of rivers (e.g., Mississippi and Sauk Rivers) and other surface waters such as Lake Minnewaska, Lake Reno, Lake Mary, Lake Andrew, Long Lake, and Big Fish Lake. The Project Study Area also contains historic architectural resources, the majority of which are located within municipalities (e.g., houses, churches, commercial and industrial buildings, schools, banks, and railroads). Rural farmsteads and homesteads have also been documented throughout the Project Study Area.

Available cultural resources data retrieved from the Minnesota State Historic Preservation Office (SHPO) on March 10, 2023, indicate that 483 archaeological sites and 1,420 historic architectural resources have been documented within the Project

Study Area. Of the 483 known archaeological sites, 366 are located in the Western Segment and 133 are located in the Eastern Segment. Sixteen of these sites overlap both segments and are therefore counted in both segments.

Of the 1,420 historic architectural resources documented within the Project Study Area, 794 are located in the Western Segment, 736 are located in the Eastern Segment, and 110 resources overlap both segments. Resources that overlap both segments are counted in both segments. Several of the identified cultural resources are listed in or eligible for listing in the National Register of Historic Places (NRHP). A summary of listed and eligible resources, broken down by Project Segment and cultural resource type, is included in **Table 8-8**.

Table 8-8
NRHP-Listed and Eligible Cultural Resources in the Project Study Area

	Historic Architectural Resources[1]		Archaeological Sites[1]	
	NRHP-Listed	Considered Eligible	NRHP-Listed	Considered Eligible
Western Segment				
Big Stone County	25	3	--	--
Douglas County	65	1	1	8
Grant County	--	--	--	--
Lac Qui Parle County	1	--	--	--
Pope County	40	2	--	--
Stevens County	--	--	--	--
Swift County	9	4	--	--
Multiple Counties	--	2	--	--
Eastern Segment				
Douglas County	67	2	1	1
Sherburne County	1	1	--	--
Stearns County	160	12	--	2
Todd County	--	--	--	--
Wright County	4	--	--	1
Total	372	27	2	12

[1] Resources within the overlapping portions of the Western and Eastern Project Study Areas are reported for both segments; therefore, the values are not additive.

After routes are identified for the Project, the Applicants will complete a Phase Ia literature review to characterize the prehistoric and historic context along identified route options and further examine the previously recorded archaeological sites and historic architectural resources to determine recommendations regarding avoidance for any sites determined eligible for or listed in the NRHP. A summary of the Phase Ia literature review findings will be presented in the Route Permit Application for each segment.

Impacts to cultural resources would likely vary between segments given the routing differences between the two segments. The Western Segment involves construction of a new transmission line, which may have the potential to impact cultural resources. The Eastern Segment generally follows an existing transmission line for most of the proposed route which has lower potential to impact cultural resources. The Western Segment will require a larger amount of ground disturbance to previously undisturbed areas, which could result in impacts to cultural resources, either known or unknown. Since the majority of the Eastern Segment has already been disturbed from construction of the existing transmission line, there is less potential to impact cultural resources during construction of this Segment.

Effects to NRHP-listed or eligible cultural resources can be minimized by routing the proposed transmission line to avoid these types of resources. Because the Eastern Segment generally follows an existing transmission line, routing has been completed for most of the line, but will be considered in areas of new construction. Routing to avoid NRHP-listed or eligible cultural resources will be incorporated as feasible in the Western Segment, which includes construction of a new transmission line alignment and associated right-of-way.

If impacts to a specific cultural resource cannot be avoided by the Project, that cultural resource would require a formal significance evaluation to determine if it meets the eligibility requirements for listing on the NRHP, if its eligibility has not been previously determined. If found significant, mitigation strategies may be undertaken to reduce impacts. If cultural resources are listed in the NRHP, or if they are considered eligible for listing, they may be afforded protection under federal and state regulations.

The Applicants provided notice to all Minnesota tribal governments and federally recognized tribes with ancestral ties to Minnesota per the Notice Plan, and these tribes were invited to the open houses held in April 2023. The Applicants will work with the appropriate state, federal and tribal agencies during the routing process to avoid known cultural resources as much as possible.

8.1.6 Hydrologic Features

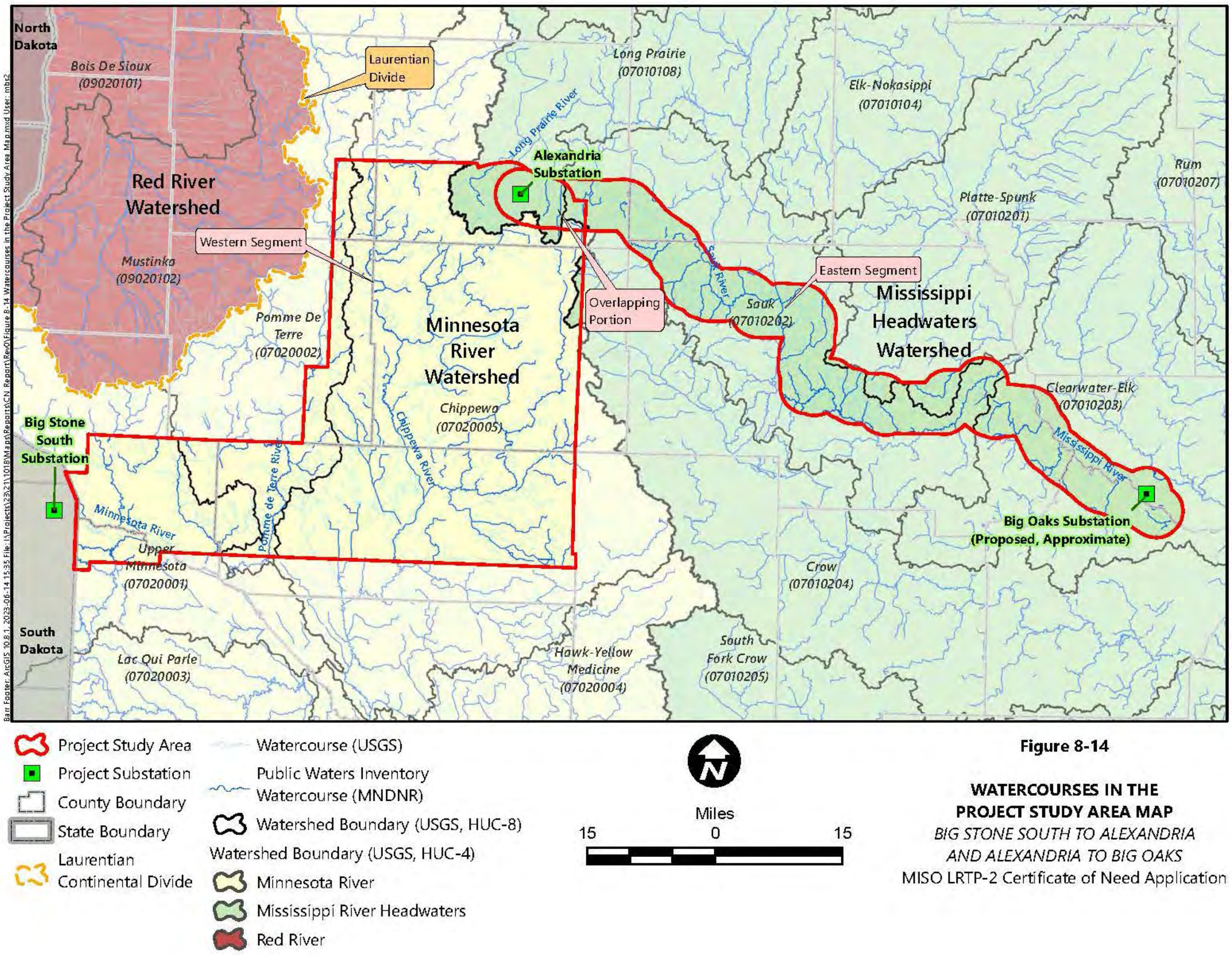
There are eight major watershed basins (HUC-04) and 81 major surface water watersheds (HUC-08) covering Minnesota. The Western Segment is predominantly located within the Minnesota River Watershed (HUC-4), and the Eastern Segment is located within the Mississippi River Headwaters Watershed (HUC-04). There are eight HUC-8 Watersheds located within the Project Study Area (**Map 8-14**; **Table 8-9**); though a watershed may cross the Project Study Area, it does not necessarily mean the major river associated with the watershed is located within the Project Study Area.

According to the MDNR Public Water Inventory (PWI) dataset, there are 627 PWI basins and 693 PWI wetlands located within the Project Study Area (**Map 8-15**). There are nine waterbodies in the Project Study Area that are greater than 1,000 acres in size including Lake Minnewaska, Reno Lake, Lake Mary, Lake Emily, Artichoke Lake, Marsh Lake, Oscar Lake, and two unnamed wetlands.

The Project Study Area is located within the Midwest and Northcentral Northeast wetland delineation region. The Midwest region is characterized by its generally flat to rolling topography, fertile soils, and moderate to abundant rainfall (reference (15)). Wetlands in the region are generally characterized as prairie wetlands or riverine wetlands.

According to the United States Fish and Wildlife Service (USFWS) National Wetland Inventory (NWI) database, the Project Study Area contains approximately 289,734 acres of wetlands, comprising approximately 19 percent of the Project Study Area (**Map 8-15**). The majority of the wetlands are classified as shallow open water wetlands, seasonally flooded wetlands, or shallow marshes (**Table 8-9**).

Map 8-14
Watercourses in the Project Study Area Map



Map 8-15
Waterbodies and Wetlands in the Project Study Area Map

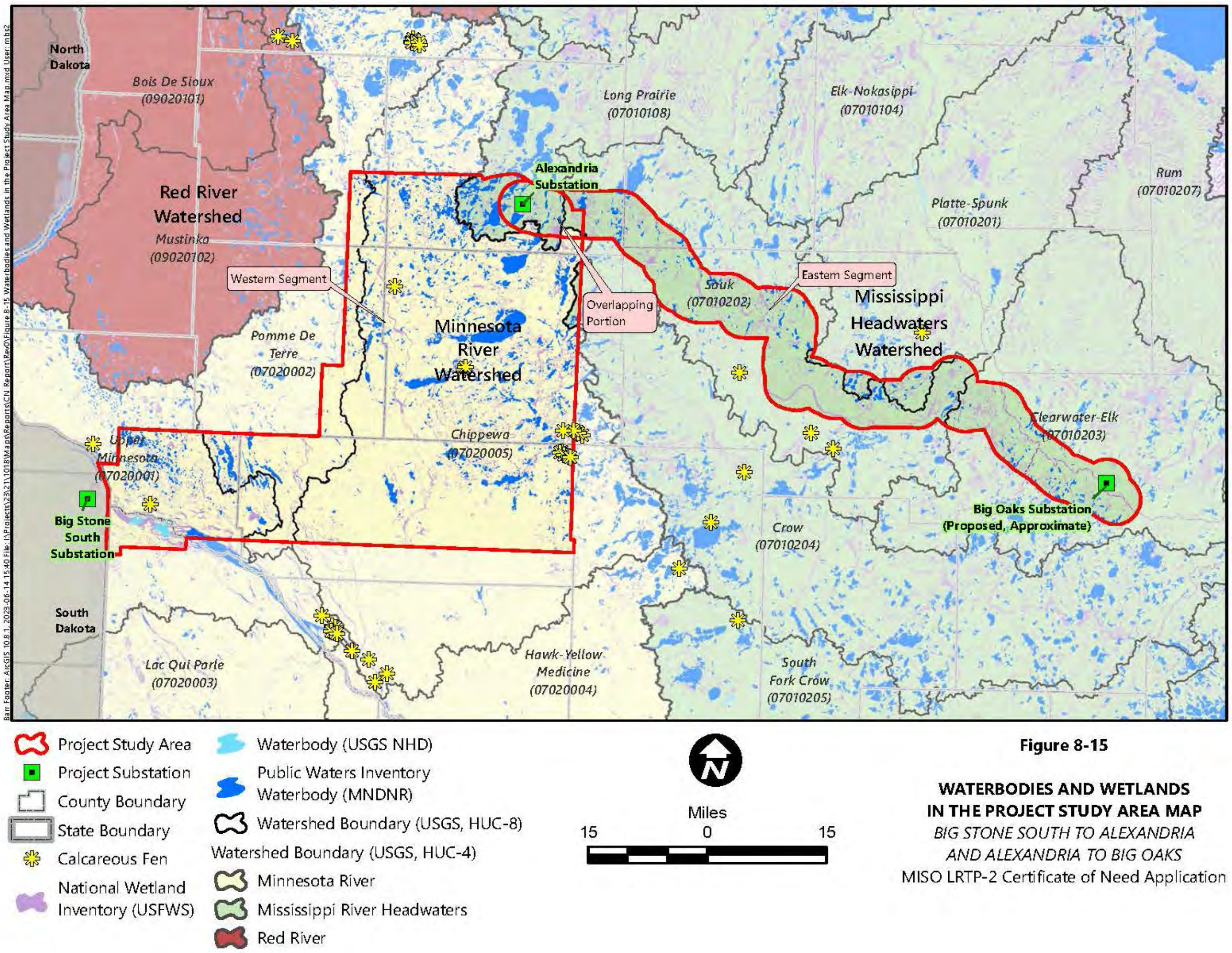


Table 8-9
National Wetland Inventory Wetlands Within the Project Study Area

Cowardin Class [1]	Circular 39 Class[2]	Wetland Type	Acres in Western Segment	Acres in Eastern Segment	Total[3]
PEMA, PUS, PFOA	1	Seasonally Flooded Wetlands	53,368	23,680	75,319
PEMB, PSSB	2	Wet Meadows (including Calcareous Fens)	5,787	1042	6,829

Cowardin Class [1]	Circular 39 Class[2]	Wetland Type	Acres in Western Segment	Acres in Eastern Segment	Total[3]
PEMC and F, PSSH, PUBA and C	3	Shallow Marshes	56,000	19,311	75,311
L2ABF, L2EMF and G, L2US, PABF and G, PEMG and H, PUBB and F	4	Deep Marshes	5,369	748	6,117
L1; L2ABG and H; L2EMA, B, and H; L2RS; L2UB; PABH; PUBG and H	5	Shallow Open Water	80,691	18,739	99,430
PSSA, C, F, and G; PSS1, 5, and 6B	6	Shrub Swamp	6,351	7,128	13,479
PFO1, 5, and 6B; PFOC and F	7	Wooded Swamp	4,265	1054	5,319
PF02, 4, and 7B; PSS2, 3, 4, and 7B	8	Bogs	83	355	438
L2UB, PAB, PUB, PEMK	80	Lake	346	200	546
R2AB; R2UB and S; R4SB	90	Rivers	2,387	4,559	6,946
TOTAL			**214,647**	**76,816**	**289,734**

[1] reference (16)
[2] reference (17)
[3] Resources within the overlapping portions of the Western and Eastern Project Study Areas are reported for both segments; therefore the values are not additive.

Impacts to hydrologic features would likely vary between segments. The Western Segment will require some amount of ground disturbance, which could result in impacts to surface waters. The majority of the Eastern Segment has already been disturbed from construction of the existing transmission line, resulting in minimal impact to surface waters during construction. Effects to surface waters can be minimized by routing the Project to avoid surface waters.

The Big Oaks Substation siting area includes approximately 250 acres located in cultivated cropland. According to the NWI databases there are no wetlands or watercourses located within the Big Oaks Substation siting area. Therefore, construction of the Big Oaks Substation is not anticipated to directly impact any wetlands or watercourses. Similarly, there are no wetlands or watercourses that would be directly impacted by the Alexandria Substation Expansion, Riverview Tap, or Quarry Bypass. The new structure construction at these locations would occur in upland areas and would not directly impact any wetlands or watercourses.

Neither of the two Mississippi River Crossing options would require structures to be placed within the Mississippi riverbed. However, the Eastern Crossing Option would require construction of two structures on an island within the river; The Western Crossing Option would be able to span the Mississippi River without structures placed midway across the waterway.

Calcareous fens are rare distinctive peat accumulating wetlands that depend on a constant supply of calcium and other mineral rich groundwater. This unique microenvironment can support highly diverse and unique rare plant communities. According to the MDNR's Identification List of Known Calcareous Fens (reference (18)), there are 11 known calcareous fens located within the Western Segment. (**Map 8-15**). The Western Segment will be routed to avoid disturbances to calcareous fens. No calcareous fens are located within the Eastern Segment.

8.1.6.1.1 Floodplains

The major floodplains in the Project Study Area occur adjacent to large waterbodies and watercourses. Most of the Project Study Area is mapped as areas with minimal flood hazard (Zone X). The Federal Emergency Management Agency (FEMA) has mapped regulated floodways located along the Chippewa River, Pomme de Terre River, Minnesota River, Sauk River, and Mississippi River. Outside the 100-year floodplain, some areas along these rivers are mapped as 500-year floodplains that reach beyond the adjacent riverine areas into agricultural areas and the edges of communities. Additional floodplains are found adjacent to larger perennial streams and areas with shallow banks and low terraces.

It is anticipated that the Project would have no effect on the flood elevations within the Project Study Area because the Project construction is not expected to result in flood elevations to rise. However, the Applicants will work with local floodplain administrators and FEMA during the route evaluation process to avoid a rise in flood elevations; as such, it is anticipated that the Project would have no effect on the flood elevations within the Project Study Area.

8.1.6.1.2 Groundwater

Groundwater in Minnesota is divided into six aquifer provinces based on glacial geology and bedrock (reference (19)). The Project Study Area is located within four groundwater provinces. The Western Segment is located within the

Arrowhead/Shallow bedrock, Central and Western groundwater provinces. The Eastern Segment is located within the Arrowhead/Shallows bedrock, Central and East-central Groundwater Provinces. The majority of the Project Study Area (78 percent) is located within the Central Groundwater Province.

The Central groundwater province is characterized by buried sand aquifers and relatively extensive surficial sand plains, part of a thick layer of sediment deposited by glaciers overlaying the bedrock. This province has thick glacial sediment, and sand and gravel aquifers are common (reference (19)). The Project is not anticipated to adversely impact groundwater resources within any of the provinces.

8.1.6.1.3 Karst

A karst feature is characterized as a landscape underlain by limestone that has been eroded by dissolution, producing caves, fissures, or sinkholes. According to the MDNR Karst Feature Inventory, there are no karst features located within the Project Study Area. (reference (20)). The nearest karst feature is located approximately 22 miles east of the Project Study Area near Elk River, Minnesota. The Applicants will conduct geotechnical analyses where appropriate to evaluate whether karst areas are present at structure locations and structure foundation design will account for the presence of karst, as needed.

8.1.7 Vegetation

The Western Segment is almost entirely located in the Minnesota River Prairie ECS subsection, with the northeastern corner located in the Hardwood Hills subsection (**Map 8-7**). The Eastern Segment straddles four ECS subsections, the Minnesota River Prairie and Hardwood Hills subsections in the western two-thirds and the Anoka Sand Plain and Big Woods subsections in the eastern third (**Map 8-7**). Thorough descriptions of each subsection are provided in Section 8.1.2.

Pre-settlement vegetation in the Minnesota River Prairie subsection consisted primarily of tallgrass prairie and wet prairie islands. Floodplain forests were present within the riparian areas along watercourses and waterbodies (reference (1)).

In the Hardwood Hills subsection, irregular topography and presence of numerous lakes and wetlands provided a partial barrier to fire, resulting in more woodland or forest compared to the Minnesota River Prairie subsection. At pre-settlement, mixed hardwood forests were found in the eastern portion of the subsection, while tallgrass prairie was found on flatter terrain in the west (reference (1)).

Pre-settlement vegetation in the Anoka Sand Plain subsection primarily consisted of oak barrens and openings. Upland prairie and floodplain forest formed a narrow band along the Mississippi River, while a large portion of the sandplain was primarily brushland (reference (1)).

Pre-settlement vegetation in the Big Woods subsection was dominated by oak woodlands and maple-basswood forests. Aspen forests were common along the western edge of the subsection, along with bur oak forests (reference (1)).

Currently, the Project Study Area is dominated by agricultural land, with corn and soybeans representing the most common crops. Natural vegetation is present in wetlands and the forested areas near waterbodies and watercourses (**Map 8-8**). In addition, areas of native vegetation are found scattered throughout the Project Study Area in lands mapped or managed by the MDNR; these include native prairie remnants, native plant communities, SNAs, and Sites of Biodiversity Significance (**Map 8-12**).

Potential impacts to vegetation in the Project Study Area would occur where clearing of trees and other vegetation is necessary for Project construction and maintenance. Construction and maintenance activities also have the potential to result in the introduction or spread of noxious weeds. Because the Eastern Segment follows the existing transmission line infrastructure, clearing would only occur where the alignment deviates from the existing infrastructure and where new transmission line right-of-way and the new Big Oaks Substation would be located. Clearing would be required in the Western Segment to construct the new transmission line alignment and associated right-of-way.

As routing for the Project is developed and refined, the Applicants would strive to avoid large forested areas and other sensitive native vegetation resources to the extent practicable and would work with agencies to develop the appropriate best management practices (BMPs) and mitigation measures to minimize potential impacts to vegetation resources from the proposed Project facilities.

8.1.8 Wildlife

Several lands that are preserved or managed for wildlife and associated habitat are scattered throughout the Project Study Area, including: Audubon Society Important Bird Areas and Grassland Bird Conservation Areas; Minnesota Migratory Waterfowl Feeding and Resting Areas, WMAs, and game refuges; and USFWS NWRs and WPAs (**Map 8-11**).

The Project Study Area's agricultural landscape, combined with the preserved or managed wildlife lands, provide habitat for a diversity of resident and migratory wildlife species. These species include large and small mammals, songbirds, waterfowl, raptors, fish, reptiles, mussels, and insects. These species use the Project Study Area for forage, shelter, breeding, or as stopover during migration.

Temporary impacts to wildlife may occur during construction from increased noise and human activity, which could cause some species to temporarily abandon their habitat. Permanent habitat loss, conversion, or fragmentation may occur in areas that are permanently cleared for construction and maintenance of the Project. This habitat alteration would be minimal for the Eastern Segment since it follows existing transmission line infrastructure but could occur where the alignment deviates from the existing infrastructure and where new right-of-way is obtained for the Western Segment.

Once the Project is operational, there is potential for avian and transmission line interactions in the form of collisions and potential electrocution. This potential impact is already present along the existing infrastructure in the Eastern Segment but would be a new potential impact anywhere new transmission line construction occurs in the Western or Eastern Segment.

As routing for the Project is refined, the Applicants would strive to avoid preserved or managed wildlife lands to the extent practicable and would work with applicable resource agencies to develop the appropriate BMPs and mitigation measures to minimize the potential for Project activities impacting these sensitive wildlife resources.

The Applicants would also incorporate BMPs, as well as implement design and engineering measures where necessary that are consistent with the Avian Power Line Interaction Committee's (APLIC) guidelines to minimize the potential for avian collisions (reference (21)).

8.1.9 Protected Species

Data on federal and state-protected species were reviewed for the Project using the USFWS Information for Planning and Consultation (IPaC) online tool and the MDNR Natural Heritage Inventory System (NHIS) database (License Agreement #2022-008). Although this review does not represent a comprehensive survey, it provides information on the potential for the presence of protected species within the Project Study Area.

8.1.9.1 Federally Protected Species

The USFWS IPaC online tool was queried on March 13, 2023, for a list of federally threatened and endangered species, proposed species, candidate species, and designated critical habitat that may be present within the Project Study Area. The IPaC query identified seven species as potentially occurring in the Western Segment and four species as potentially occurring in the Eastern Segment (**Table 8-10**). In addition, the IPaC query identified designated critical habitat for two species within the Western Segment.

Table 8-10
Federally Protected Species and Designated Critical Habitat Within the Project Study Area

Common Name	Scientific Name	Federal Status[1]	Segment Occurrence	
			Western Segment	Eastern Segment
Northern long-eared bat	*Myotis septentrionalis*	END	X	X
Tricolored bat	*Perimyotis subflavus*	Proposed END	X	X
Monarch butterfly	*Danaus plexippus*	Candidate	X	X
Dakota Skipper	*Hesperia dacotae*	THR; Designated Critical Habitat[2]	X	
Poweshiek skipperling	*Oarisma poweshiek*	Designated Critical Habitat[3]	X	
Red knot	*Calidris canutus rufa*	THR	X	
Western prairie fringed orchid	*Platanthera praeclara*	THR	X	
Rusty patched bumble bee	*Bombus affinis*	END		X

[1] THR = threatened; END = endangered.

[2] IPaC identified both the Dakota skipper and designated critical habitat for the species as potentially occurring within the Western Segment.
[3] IPaC only identified designated critical habitat for the Poweshiek skipperling within the Western Segment and not the species itself.

8.1.9.1.1 Northern Long-Eared Bat

The federally endangered northern long-eared bat roosts in living and dead trees greater than 3 inches in diameter that have loose or peeling bark, cavities, or crevices during the active season (reference (22)). During winter, they hibernate in caves and mines. According to the MDNR and USFWS a northern long-eared bat hibernacula is present approximately 1 mile north of the Eastern Segment in Stearns and Sherburne counties; no maternity root trees have been identified in the Western or Eastern Segments (reference (23)). However, potentially suitable roosting and foraging habitat is present in the Project Study Area.

Potential impacts to individual northern long-eared bats may occur if removal of woody vegetation occurs during the active season, April 1 - October 31. Tree clearing activities conducted when the species is in hibernation is not anticipated to result in direct impacts to individual bats since they do not hibernate in trees but could result in indirect impacts due to removal of suitable foraging and roosting habitat.

In November of 2022, the USFWS published a final rule to reclassify the northern long-eared bat from threatened to endangered. On January 25, 2023, the USFWS announced that it was extending the effective date of the new rule from January 30, 2023, until March 31, 2023, to allow the agency to finalize conservation tools and guidance (reference (24)). As of March 31, 2023 the northern long-eared bat is listed as federally endangered. The Applicants will consult with the USFWS to develop necessary avoidance and minimization measures for this species and will comply with any applicable USFWS requirements.

8.1.9.1.2 Tri-Colored Bat

Tri-colored bats, a federally proposed endangered species, are found in forested habitats where they roost in trees during the active season; their active season is similar to northern long-eared bats, April 1 – October 31. Tri-colored bats hibernate in caves and mines over the winter (reference (25)).

Similar to the northern long-eared bat, tree clearing may impact individual tri-colored bats if tree removal occurs during their active season. Tree clearing activities conducted when the species is in hibernation is not anticipated to result in direct impacts to individual bats but could result in indirect impacts due to removal of suitable foraging and roosting habitat.

On September 14, 2022, the USFWS published a proposed rule to the Federal Register proposing to list the tricolored bat as an endangered species under the ESA. The USFWS is proposing the species for listing due to substantial declines in tricolored bat abundance across its range. The main threats to the species are the impacts of white nose syndrome, wind-energy-related mortality, the effects of climate change, and habitat loss and disturbance (reference (25)).

Proposed species are not protected under the Endangered Species Act (ESA); however, a decision on the final rule listing the species as endangered is anticipated in late 2023 and may occur prior to construction of the Project. Avoidance and minimization measures implemented for the northern long-eared bat would also serve to protect tri-colored bats. The Applicants will consult with the USFWS to determine if additional measures are needed to prevent adverse impacts to tri-colored bats.

8.1.9.1.3 Monarch Butterfly

Monarch butterflies, a federal candidate species, are found in areas with a high number of flowering plants, which provide sources of nectar. Monarch butterflies rely exclusively on the presence of milkweed (*Asclepias* spp.) to complete the caterpillar life stage (reference (26)).

In December 2020, the USFWS assigned the monarch butterfly a candidate for listing under the ESA due to its decline from habitat loss and fragmentation; however, the USFWS cannot currently implement the listing because there are other listing actions with a higher priority. The species is now a candidate for listing; however, candidate species are not protected under the ESA (reference (27)). The USFWS has added the monarch to the updated national listing workplan and, based on its listing priorities and workload, intends to propose listing the monarch in Fiscal Year 2024, if listing is still warranted at that time, with a possible effective date within 12 months of the proposed rule (reference (28)).

Suitable habitat for monarch butterflies is present in the Project Study Area, and construction activities involving clearing and grading may impact monarch butterfly individuals. If the USFWS determines the monarch butterfly should be listed and protections for the species coincides with Project planning, permitting, and/or construction, the Applicants would review Project activities for potential impacts on the species, develop appropriate avoidance and minimization measures, and consult with the USFWS as appropriate.

8.1.9.1.4 Dakota Skipper and Dakota Skipper Designated Critical Habitat

The federally threatened and state endangered Dakota skipper butterfly inhabits high-quality native prairie. In Minnesota, the Dakota skipper may be found in native dry-mesic to dry prairie where midheight grasses such as little bluestem, prairie dropseed (*Sporobolus heterolepis*), and side-oats grama (*Bouteloua curtipendula var. curtipendula*) dominate (reference (29)). Dakota skippers are present in suitable habitat year-round as the larvae overwinter at the base of plants on which they forage in the spring.

Although the Dakota skipper has been documented in the Western Segment (**Table 8-11**), the current status of the Dakota skipper in Minnesota is tenuous: intensive survey efforts since 2012 have found only one remaining Dakota skipper population in Minnesota (reference (29)). Potentially suitable habitat for Dakota skippers may be present within the areas of remnant native dry-mesic to dry prairie in the Project Study Area (**Map 8-11**). Impacts to prairie habitat could impact Dakota skipper individuals should they be present. If suitable habitat cannot be avoided, the Applicants would consult with the USFWS and MDNR to determine next steps and develop appropriate avoidance and minimization measures.

Designated critical habitat for the Dakota skipper is present in the Western Segment, in the central part of Pope County (**Map 8-11**). Designated critical habitat is defined as those areas that are considered crucial for the conservation of a species and that may require special management or protection. This designation is based on the presence of certain primary constituent elements (i.e., those physical and biological features of habitat that are considered essential for the conservation of the species). The Applicants would avoid intersecting this designated critical habitat in Pope County; to the extent possible, such that Project activities would minimize adverse impacts on Dakota skipper designated critical habitat.

8.1.9.1.5 Poweshiek Skipperling Designated Critical Habitat

The federally and state endangered Poweshiek skipperling butterfly inhabits wet to dry native prairie (reference (30)). The last confirmed sightings of this butterfly in Minnesota were in 2007, despite extensive annual surveys beginning in 2013. While Poweshiek skipperling butterflies have been documented in the Western Segment (**Table 8-11**), they have not been documented there since 2007.

The IPaC results did not identify the Poweshiek skipperling as a species that may be present within the Project Study Area; only designated critical habitat for the species was identified (**Table 8-10**). Designated critical habitat for the Poweshiek skipperling is present in the Western Segment, in the same location as the designated critical habitat for the Dakota skipper (**Map 8-11**). The Applicants would avoid intersecting this designated critical habitat in Pope County to the extent possible, such that Project activities would minimize adverse impacts on Poweshiek skipperling designated critical habitat.

8.1.9.1.6 Red Knot

The federally threatened red knot shorebird primarily inhabits coastal marine and estuarine habitats (reference (31)). The red knot migrates annually between its breeding grounds in the Canadian Arctic and several wintering regions, including the southeastern U.S., the Northeast Gulf of Mexico, northern Brazil, and the southern tip of South America. During migration, red knots use staging and stopover areas to rest and feed. While red knots do not nest in Minnesota, the species may use some of the freshwater habitats, such as wetlands and riverine areas, as stopover habitat during migration.

Potential impacts to red knot individuals could occur should they use stopover habitat in the vicinity of the Project. The Applicants would consult with the USFWS to determine if any measures are required to minimize potential impacts to red knots.

8.1.9.1.7 Western Prairie Fringed Orchid

The federally threatened and state endangered western prairie fringed orchid inhabits moist tallgrass prairie. The species occurs most often in mesic to wet unplowed tallgrass prairies and meadows (native prairie areas and prairie remnants) in full sun on sandy or calcareous till soils (reference (32)).

While the MDNR NHIS database does not document any occurrences of the western prairie fringed orchid in the Project Study Area, potentially suitable habitat for the species may be present in the MDNR remnant prairie communities (**Map 8-12**). Impacts to suitable prairie habitat could impact western prairie fringed orchid individuals should they be present. If suitable habitat for the western prairie fringed orchid cannot be avoided, the Applicants would consult with the USFWS and MDNR to determine next steps and develop appropriate avoidance and minimization measures.

8.1.9.1.8 Rusty Patched Bumble Bee

The federally endangered rusty patched bumble bee inhabits open areas with abundant flowers, nesting sites (underground and abandoned rodent cavities or clumps of grasses), and undisturbed soil for overwintering sites (reference (33)). Suitable habitat for the rusty patched bumble bee is present in the Project Study Area where abundant flowering plants are present. In addition, the Eastern Segment intersects a rusty patched bumble bee high potential zone (HPZ) (**Map 8-11**) (reference (34)). Rusty patched bumble bee HPZs were developed through a model to identify areas around current records (2007-present) where there is a high potential for the species to be present (reference (34)). However, the Project would follow existing transmission line infrastructure in this location, which is over 1.2 miles away from the documented HPZ (**Map 8-11**). As such, no construction activities would occur within a mile of the HPZ.

Clearing and grading activities associated with Project construction could impact rusty patched bumble bees or associated habitat. The Applicants would consult with the

USFWS to determine if any measures are required to minimize potential impacts to rusty patched bumble bees.

8.1.9.1.9 Bald Eagles

Although no longer federally listed under the ESA, bald eagles (*Haliaeetus leucocephalus*) are protected by both the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act (BGEPA). The BGEPA prohibits the take of bald or golden eagle adults, juveniles, or chicks including their parts, nests, or eggs without a permit. The BGEPA also addresses impacts resulting from human-induced alterations occurring around previously used nesting sites. Work conducted within 660 feet of an active eagle nest during the nesting season may disturb nesting eagles to such a degree that adults abandon the nest, resulting in take of eggs and/or chicks; an active nest is one where eggs or chicks are present (reference (35)).

Bald eagles are primarily found near rivers, lakes, marshes, and other waterbodies and habitat suitable for bald eagles is present within the Project Study Area. If construction activities take place in suitable eagle nesting habitat during the species nesting season, surveys to identify active nests within 660 feet of work areas will be conducted in early spring (i.e., early March/early April) of the year of construction. If active nests are identified within the disturbance buffer, the Applicants would consult with the USFWS to determine next steps and develop appropriate avoidance and minimization measures.

8.1.9.2 State Protected Species

The MDNR NHIS database was queried on March 13, 2023 to identify known occurrences of state protected threatened and endangered species within the Project Study Area. The NHIS query identified a total of 33 threatened and endangered species that have been documented within the Project Study Area (30 were documented within the Western Segment and 10 were documented in the Eastern Segment (**Table 8-11**).

Habitat suitable for several state-protected species is potentially present in the vicinity of the Project Study Area. As routing for the Project is developed and refined, the Applicants will conduct a Natural Heritage Review utilizing the Minnesota Conservation Explorer online tool and would consult with the MDNR to minimize the potential for adverse impacts to state-protected species and associated habitat from construction and operation of the Project.

Table 8-11
State Protected Species Within the Project Study Area

Common Name	Scientific Name	State Status[1]	Federal Status [1]	Segment Occurrence	
				Western Segment	Eastern Segment
Birds					
Burrowing Owl	*Athene cunicularia*	END	---	X	
Chestnut-collared Longspur	*Calcarius ornatus*	END	---	X	
Henslow's Sparrow	*Ammodramus henslowii*	END	---	X	X
Horned Grebe	*Podiceps auritus*	END	---	X	
Loggerhead Shrike	*Lanius ludovicianus*	END	---	X	X
Piping Plover	*Charadrius melodus*	END	END; THR	X	
Wilson's Phalarope	*Phalaropus tricolor*	THR	---	X	X
Mollusks					
Elktoe	*Alasmidonta marginata*	THR	---	X	
Fluted-shell	*Lasmigona costata*	THR	---	X	
Mucket	*Actinonaias ligamentina*	THR	---	X	
Yellow Sandshell	*Lampsilis teres*	END	---	X	
Fish					
Pugnose Shiner	*Notropis anogenus*	*THR*	---	*X*	*X*
Skipjack Herring	*Alosa chrysochloris*	END	---	X	
Reptiles					
Blanding's Turtle	*Emydoidea blandingii*	THR	---		X
Insects					
Dakota Skipper	*Hesperia dacotae*	END	THR	X	
Ghost Tiger Beetle	*Cicindela lepida*	THR	---	X	
Poweshiek Skipperling	*Oarisma poweshiek*	END	END	X	X
Plants					
Ball Cactus	*Escobaria vivipara*	END	---	X	
Butternut	*Juglans cinerea*	END	---		X
Eared False Foxglove	*Agalinis auriculata*	END	---	X	
Hair-like Beak Rush	*Rhynchospora capillacea*	THR	---	X	
Hairy Waterclover	*Marsilea vestita*	END	---	X	
Larger Water Starwort	*Callitriche heterophylla*	THR	---	X	
Mud Plantain	*Heteranthera limosa*	THR	---	X	
Prairie Quillwort	*Isoetes melanopoda*	END	---	X	

Common Name	Scientific Name	State Status[1]	Federal Status [1]	Segment Occurrence	
				Western Segment	Eastern Segment
Rock Sandwort	*Minuartia dawsonensis*	THR	---		X
Short-pointed Umbrella-sedge	*Cyperus acuminatus*	THR	---	X	
Sterile Sedge	*Carex sterilis*	THR	---	X	X
Stream Parsnip	*Berula erecta*	THR	---	X	
Tubercled Rein Orchid	*Platanthera flava var. herbiola*	THR	---		X
Waterhyssop	*Bacopa rotundifolia*	THR	---	X	
Whorled Nutrush	*Scleria verticillata*	THR	---	X	
Wolf's Spikerush	*Eleocharis wolfii*	END	---	X	

[1] THR = threatened; END = endangered.

8.1.10 Other Permits and Approvals

In addition to a Certificate of Need, a Route Permit from the Commission is required prior to construction, and the Applicants may also need to obtain other local, state, and federal approvals. The Applicants are planning for a single Certificate of Need for the Project and separate Route Permits for the Western and Eastern Segments. Permits and approvals that may be required for the Project are listed in **Table 8-12**. Typical municipal permit categories are listed, but specific permits may vary from city to city and are limited. Once the Commission issues a Route Permit, local zoning, building, and land use regulations and rules are preempted per Minn. Stat. § 216E.10, subd. 1.

Table 8-12
Potential Permits and Compliance Approvals

Permit/Approval	Administering Agency
Local	
Road Crossing/Right-of-Way Permits	County, Township, City
Public Lands Permits - Local	County, Township, City
Utility Permits	County, Township, City
Oversize / Overweight Permits	County, Township, City
Driveway/Access Permits	County, Township, City
Municipal Stormwater Permits	County, Township, City
State	
Certificate of Need	MNPUC
Route Permit	MNPUC

Permit/Approval	Administering Agency
Threatened & Endangered Species Consultation	MDNR
License to Cross Public Waters and State Lands	MDNR
Construction Dewatering Permit	MDNR
Utility Permit	MnDOT
Driveway/Access Permits	MnDOT
Oversize/Overweight Permits	MnDOT
Wetland Conservation Act Exemption Concurrence	BWSR
Section 401 Water Quality Certification	MPCA
National Pollutant Discharge Elimination System (NPDES) Permit – Construction Stormwater Permit	MPCA
Cultural Resources Consultation	Minnesota State Historic Preservation Office
Federal	
Section 7 Consultation	USFWS
Section 10 Permit	USACE
Section 404 Permit	USACE
Notice of Proposed Construction and Actual Construction or Alteration (7460)	FAA
Spill Prevention, Control, and Countermeasure (SPCC) Plan	EPA
Farmland Protection Policy Act/Farmland Conversion Impact Rating	USDA/NRCS

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Appendix A

Certificate of Need Completeness Checklist

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Big Stone South – Alexandria – Big Oaks 345 kV Transmission Project
Certificate of Need Application
Completeness Checklist

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
Minn. R. 7829.2500, subp. 2	Brief summary of filing on separate page sufficient to apprise potentially interested parties of its nature and general content	Filing Summary
Minn. R. 7849.0200, subp. 2	Title Page and Table of Contents	Title Page and Table of Contents
Minn. R. 7849.0200, subp. 4	Cover Letter	Cover Letter
Minn. R. 7849.0220, subp. 3	Joint Ownership and Multiparty use	§§ 1.1, 1.3
Minn. R. 7849.0240	Need summary and additional considerations	–
subp. 1	Summary of the major factors that justify the need for the proposed facility	§§ 1.1, 3.3, 4.1, 4.2, and 4.3
subp. 2	Relationship of the proposed facility to the following socioeconomic considerations:	–
A.	Socially beneficial uses of the output of the facility	§ 4.9
B.	Promotional activities that may have given rise to the demand for the facility	§ 4.7
C.	Effects of the facility in inducing future development	§ 4.8
Minn. R. 7849.0260	Proposed LHVTL and Alternatives	–
A.	A description of the type and general location of the proposed line, including:	–
(1)	Design voltage	§ 2.1
(2)	Number, sizes and types of conductors	§ 2.1

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(3)	Expected losses under projected maximum loading and under projected average loading in the length of the line and at terminals or substations	**EXEMPT** from providing line-specific loss information, provided alternative data is supplied.
	ALTERNATIVE DATA – Estimated overall system losses.	§ 4.4
(4)	Approximate length of the proposed line	§ 2.2
(5)	Approximate locations of DC terminals or AC substations on a map	Maps 1-1 and 2-1
(6)	List of likely affected counties	§ 8.1
B.	Discussion of the available alternatives including:	–
(1)	New generation	§ 5.2.7
(2)	Upgrading existing transmission lines	§ 5.2.2
(3)	Transmission lines with different voltages or conductor arrays	§ 5.1.1
(4)	Transmission lines with different terminals or substations	§§ 4.2.6, 5.2.1, Appendix E-1
(5)	Double circuiting of existing transmission lines	§ 5.2.3
(6)	If facility for DC (AC) transmission, an AC (DC) transmission line	§ 5.2.4
(7)	If proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line	§ 5.2.5
(8)	Any reasonable combination of alternatives (1) – (7)	Chapter 5, Appendix E-1
C.	For the facility and for each alternative in B, a discussion of:	–
(1)	Total cost in current dollars	§§ 1.5, 2.3.1

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(2)	Service life	§ 7.4
(3)	Estimated average annual availability	§ 7.5
(4)	Estimated annual O&M costs in current dollars	§ 7.4
(5)	Estimate of its effect on rates system wide and in Minnesota	§ 2.3.3, Appendix H
(6)	Efficiency expressed for a transmission facility as the estimated losses under projected maximum loading and under projected average loading in the length of the transmission line and at the terminals or substations.	**EXEMPT** from providing line-specific loss information, provided alternative data is supplied.
	ALTERNATIVE DATA – Estimated overall system losses.	§ 4.4
(7)	Major assumptions made in subitems (1) – (6)	Chapters 2, 5, and 7
D.	A map (of appropriate scale) showing the applicant's system or load center to be served by the proposed LHVTL.	Maps 1-1 and 2-1
E.	Such other information about the proposed facility and each alternative as may be relevant to determination of need.	Chapters 4 and 5
Minn. R. 7849.0270	Content of Forecast	–
Minn. R. 7849.0270, subp. 1	Peak demand and annual consumption data within the applicant's service area and system.	**EXEMPT** from providing specific forecasting and capacity information for the Applicants' systems, provided alternative data is supplied.
	ALTERNATIVE DATA – Forecast information used in analyzing the need for the Project.	§ 4.6, Appendix E-3
Minn. R. 7849.0270, subp. 2 (A)-(D), and (F)	Subps. 2 (A)-(D), and (F) – Minnesota forecast data; forecast demand data by customer class, peak period, and month; estimated system annual revenue per kilowatt hour; estimated average weekday system load factor by month; and estimated average weekday load factor by month.	**EXEMPT** from providing specific forecasting and capacity information for the Applicant's systems, provided alternative data is supplied. *See* Minn. R. 7849.0270, subp. 1

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
Minn. R. 7849.0270, subp. 2 (E)	Estimated annual revenue requirement per kWh in current dollars	**EXEMPT** from providing annual revenue requirements for the project, provided alternative data is supplied.
	ALTERNATIVE DATA – Explanation of how the costs for LRTP projects are shared within the MISO footprint.	§ 2.3.2 and Appendix E-1
Minn. R. 7849.0270, subp. 3	Detail of the forecast methodology used in subp. 2.	**EXEMPT** from providing specific forecasting and capacity information for the Applicant's systems, provided alternative data is supplied. *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 4	Discussion of the database used in current forecasting.	**EXEMPT** from providing specific forecasting and capacity information for the Applicant's systems, provided alternative data is supplied. *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 5	Discussion of forecasting assumptions.	**EXEMPT** from providing specific forecasting and capacity information for the Applicant's systems, provided alternative data is supplied. *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 6	Coordination of Forecasts	**EXEMPT** from providing specific forecasting and capacity information for the Applicant's systems, provided alternative data is supplied. *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0280	System Capacity	–
Minn. R. 7849.0280, subp A.	Power Planning Programs	Chapter 4 and Appendix E-1
Minn. R. 7849.0280, subps. (B)-(I)	System Capacity – description of the ability of the existing system to meet the demand forecast required by Minn. Rule 7849.0270.	**EXEMPT** from providing description of the ability of the existing system to meet the

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
		demand forecast.
Minn. R. 7849.0290	Conservation programs and their effect on the forecast information required by Minn. Rule 7849.0270.	**EXEMPT** from discussing Applicants' conservation programs and their effect on the forecast, provided alternative data is supplied.
	ALTERNATIVE DATA – Information related either to Applicants' conservation programs or to the conservation programs that are available to their members serving load in Minnesota; information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.	§ 5.2.7.5 and Appendix F-1
Minn. R. 7849.0300	Consequence of Delay	**EXEMPT** from providing analysis using three levels of demand (three confidence levels), provided substitute information is supplied.
	ALTERNATIVE DATA – Discussion of the consequences of delay.	§ 5.3
Minn. R. 7849.0310	Required Environmental Information	Chapter 8
Minn. R. 7849.0330	Transmission Facilities	—
	Data for each alternative that would require LHVTL construction including:	—
A.	For overhead transmission lines	—
(1)	Schematics showing dimensions of support structures	§ 2.1.1 and Appendix G
(2)	Discussion of electric fields	§ 6.6
(3)	Discussion of ozone and nitrogen oxide emissions	§ 6.2
(4)	Discussion of radio and television interference	§ 6.4

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
(5)	Discussion of audible noise	§ 6.3
B.	For underground transmission facilities:	N/A
(1)	Types and dimensions of cable systems	N/A
(2)	Types and qualities of cable system materials	N/A
(3)	Heat released in kW per foot of cable	N/A
C.	Estimated right-of-way required for the facility	§ 2.1.1
D.	Description of construction practices	§§ 7.2, 7.3
E.	Description of O&M practices	§ 7.4
F.	Estimated workforce required for construction and O&M	§§ 7.2, 7.4
G.	Description of region between endpoints in likely area for routes emphasizing a three-mile radius of endpoints including:	–
(1)	Hydrological features	§ 8.1.6
(2)	Vegetation and wildlife	§§ 8.1.7, 8.1.8
(3)	Physiographic regions	§ 8.1.2
(4)	Land use types	§§ 8.1.3.1, 8.1.3.2
Minn. R. 7849.0340	No-Facility Alternative	**EXEMPT** from providing analysis using three levels of demand (three confidence levels), provided substitute information is supplied.

AUTHORITY	REQUIRED INFORMATION	LOCATION IN APPLICATION
	ALTERNATIVE DATA – Discussion of the consequences of delay.	§ 5.3

Appendix B

Applicants' Exemption Request

414 Nicollet Mall
Minneapolis, MN 55401

March 10, 2023

—Via Electronic Filing—

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT
DOCKET NO. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency (collectively, the Applicants) submit this Exemption Request to the Minnesota Public Utilities Commission pursuant to Minn. Rule 7849.0200, subp. 6. Please contact me at bria.e.shea@xcelenergy.com or 612-330-6064 if you have any questions regarding this filing.

Sincerely,

/s/ Bria E. Shea

BRIA E. SHEA
REGIONAL VICE PRESIDENT, REGULATORY POLICY

c: Service Lists

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT

MPUC Docket No. E002, E017, ET2, E015, ET10/CN-22-538

REQUEST FOR EXEMPTION FROM CERTAIN CERTIFICATE OF NEED APPLICATION CONTENT REQUIREMENTS

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Western Minnesota Municipal Power Agency (Western Minnesota) (collectively, Applicants) respectfully submit this request for exemptions from certain content requirements for the Certificate of Need application for the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (the Project) pursuant to Minn. Rule 7849.0200, subp. 6.[1]

The Project consists of a new 345 kV transmission line between Big Stone City, South Dakota, and Sherburne County, Minnesota which will be comprised of two segments.

- The western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and

[1] The Cassie's Crossing Substation has been renamed the Big Oaks Substation.

- The eastern segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Eastern Segment).[2]

The proposed 345 kV transmission lines will traverse Grant County in South Dakota and Big Stone, Lac Qui Parle, Swift, Kandiyohi, Stevens, Pope, Douglas, Todd, Stearns, Wright, and Sherburne counties in Minnesota.

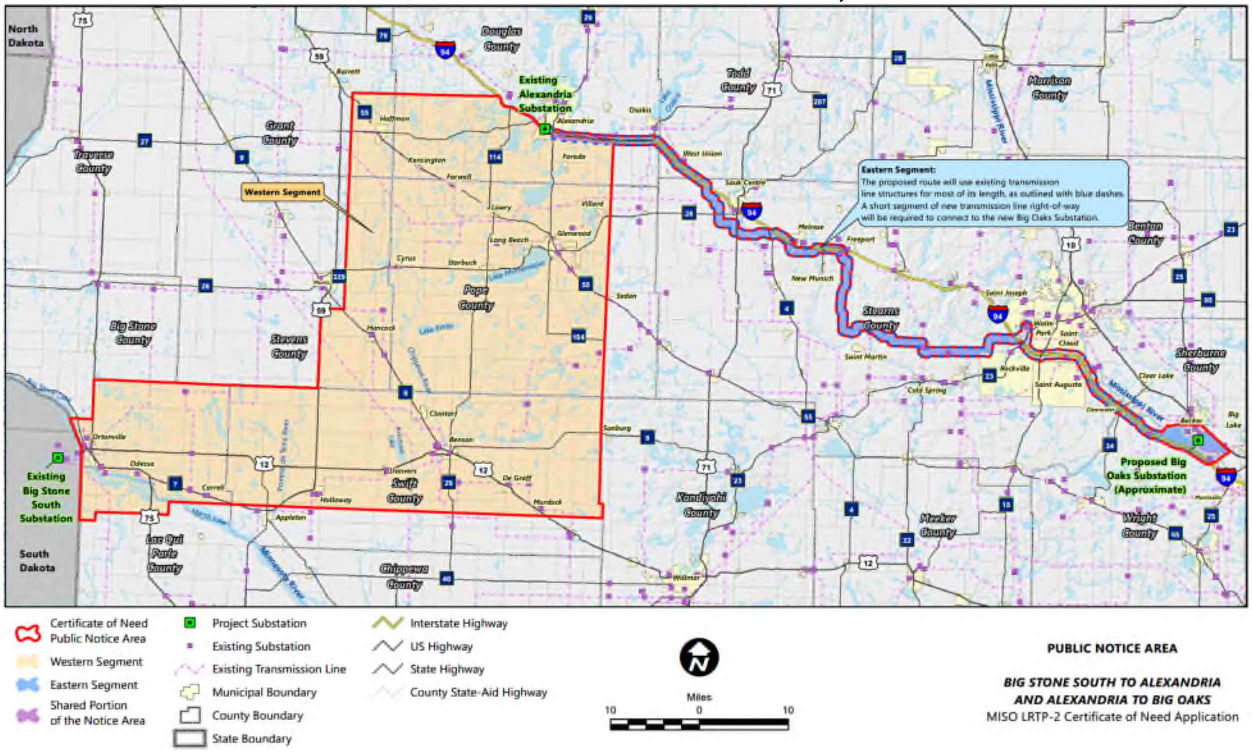
The Applicants intend to file a single Certificate of Need application, pursuant to Minn. Stat. § 216B.243, for the Minnesota portion of both segments of the Project in the third quarter of 2023. The Applicants believe that certain Certificate of Need application content requirements of Minn. Rules Chapter 7849 should be modified to better address the nature of the Applicants, the proposal, and the need for this Project. The Commission has accepted similar adjustments for other transmission line projects in the recent past. The Applicants therefore respectfully request that the Commission grant exemptions from certain requirements as provided under Minn. Rule 7849.0200, subp. 6. In lieu of some content requirements, the Applicants propose to submit alternative information that will better inform the Commission's decision regarding the need for the Project.

II. BACKGROUND

The Project is a Large Energy Facility as defined by Minn. Stat. § 216B.2421, subd. 2(2) because the Project is a 345 kV transmission line that will be longer than 1,500 feet. **Figure 1** below shows the endpoints for the Project as well as other existing transmission facilities of note in the area.

[2] The Western Segment and the Eastern Segment are herein referred to collectively as the Project.

Figure 1: Big Stone South – Alexandria – Big Oaks
345 kV Transmission Line Project



The Project was studied, reviewed, and approved as part of the Long Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO)[3] Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.[4] The Applicants filed a notice of intent to construct, own, and maintain the Project with the Commission on October 12, 2022.

The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as LRTP#2 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is

[3] MISO is a member-based non-profit regional transmission organization (RTO) that is responsible for the planning and operation of transmission grid and wholesale energy market across 15 states and the Canadian province of Manitoba. MISO's members include 48 transmission owners with more than 65,800 miles of transmission lines and $34.5 billion in transmission assets that are under MISO's functional control.

[4] A copy of the MTEP21 report is available online at: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf.

needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

III. LEGAL STANDARD AND SUMMARY EXEMPTION

The content requirements for a Certificate of Need application for a large high-voltage transmission line (LHVTL) are specified in Minn. Rule 7849.0220, subp. 2, Minn. Rule 7849.0240, and Minn. Rules 7849.0260 to 7849.0340. The Commission has authority to grant exemptions from the requirements of Minn. Rules Chapter 7849 pursuant to Minn. Rule 7849.0200, subp. 6, which provides:

> **Subp. 6 Exemptions**. Before submitting an application, a person is exempted from any data requirement of parts 7849.0010 to 7849.0400 if the person (1) requests an exemption from specific rules, in writing to the commission, and (2) shows that the data requirement is unnecessary to determine the need for the proposed facilities or may be satisfied by submitting another document. A request for exemption must be filed at least 45 days before submitting an application. The commission shall respond in writing to a request for exemption within 30 days of receipt and include the reasons for the decision. The commission shall file a statement of exemptions granted and reasons for granting them before beginning the hearing.

Based on the standard set forth in this rule, the Commission may grant exemptions when the data requirements: (1) are unnecessary to determine need in a specific case; or (2) can be satisfied by submitting documents other than those required by the rules.[5]

The Applicants specifically request that the Commission grant exemptions from the following rules as they are either unnecessary to determine the need for the Project or can be satisfied by submitting alternative data:

[5] *In the Matter of The Application for a Certificate of Need for the Appleton – Canby 115 kV Line*, Docket No. E-017/CN-06-0677, ORDER GRANTING EXEMPTIONS AND APPROVING NOTICE PLAN (Aug. 1, 2006).

Minn. Rule	Scope of Exemption
Minn. Rule 7849.0260, subps. A(3) and C(6) (Losses)	Request exemption from providing line-specific loss information. The Applicants propose to provide substitute data in the form of overall system losses.
Minn. Rule 7849.0270, subps. (1) through (6) (Forecasting)	Request exemption from providing specific forecasting and capacity information. The Applicants propose to provide substitute forecast information used in analyzing the need for the Project.
Minn. Rule 7849.0270, subp. 2(E) (Annual Revenue Requirements)	Request exemption from providing annual revenue requirements for the Project. The Applicants propose to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
Minn. Rule 7849.0280, subps. (B) through (I) (System Capacity)	Request full exemption from providing a discussion of the ability of the existing system to meet the forecasted demand for electrical energy identified in response to Minn. Rule 7849.0270.

Minn. Rule 7849.0290 (Conservation)	Request exemption from discussing conservation programs and their effect on the forecast information required by Minn. Rule 7849.0270. The Applicants propose to provide substitute information related either to their conservation programs or to the conservation programs that are available to their members[6] serving load in Minnesota. The Applicants will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
Minn. Rule 7849.0300 (Consequences of Delay); Minn. Rule 7849.0340 (No Facility Alternative)	Request to be exempt from providing analysis using three confidence levels. The Applicants propose to provide substitute data regarding potential impacts caused by delay or by not building the Project.

Attachment A to this filing summarizes all of the Certificate of Need content requirements and identifies the requirements for which an exemption is being requested and whether the Applicants intend to provide substitute data. Each of these exemption requests is discussed in more detail below. This request is being made at least 45 days prior to submitting an application for a Certificate of Need as required by Minn. Rule 7849.0200, subp. 6.

IV. EXEMPTIONS REQUESTED

A. Minn. Rules 7849.0260, subps. A(3) and C(6) – Losses

Minn. Rule 7849.0260, subp. A(3) requires the applicant to provide the expected losses "under projected maximum loading and under projected average loading in the length of the transmission line and at the terminals or substations." Subpart C(6) of the rule requires similar information (efficiency of proposed system under maximum and average loading along the length of the line). The electrical grid operates as a single, integrated system, which prevents electricity from being "directed" along a particular

[6] Western Minnesota Municipal Power Agency owns generation and transmission facilities, the capacity and output of which are sold to Missouri River Energy Services. Missouri River Energy Services provides energy and energy services to its 61 member municipal utilities, including conservation program services.

line or set of lines. Consequently, losses take place across the entire transmission system and is not isolated to a few transmission lines within the integrated regional electric grid. It is necessary, therefore, to calculate losses across the system affected by the addition of new transmission lines, rather than the losses attributable to the transmission addition itself.

The Applicants request an exemption from Minn. Rules 7849.0260, subps. A(3) and C(6) and propose to provide system losses in lieu of line-specific losses required by the rules. Our proposal is consistent with the approach previously approved by the Commission in several other Certificate of Need transmission line dockets.[7]

B. Minn. Rules 7849.0270, subps. 1 through 6 – Forecasting

The Applicants seek an exemption from the content requirements of Minn. Rule 7849.0270, subps. 1-6 which concerns forecasting information. Instead, the Applicants propose to provide substitute forecast information that was used by MISO and the Applicants in studying, planning, and analyzing the Project. This data will include PROMOD production costs analyses MISO used in the MTEP21. This substitute data will better inform the record than the specific forecast data identified in this Rule.

The Commission's rules addressing Certificate of Need content requirements were designed decades ago at a time when the transmission improvements under consideration were typically driven by growing demand for electricity and linked directly to a specific generator proposed to meet that need. Consequently, the rules were designed around the concept that a utility provide detailed forecasts of power demand and electricity consumption to demonstrate the need for a specific generating plant that, in turn, justified the need for the proposed transmission capacity.

The Project is needed for multiple reasons including addressing thermal and voltage issues and to provide additional transmission capacity to integrate renewable generation in the region. Rather than providing the forecasting information required by Minn. Rule 7849.0270, the Applicants will provide information regarding the forecasts used by MISO and the Applicants to assess the need for the Project which will better inform the record in this proceeding.

[7] *In the Matter of the Application of Xcel Energy for a Certificate of Need for Two Gen-Tie Lines From Sherburne County to Lyon County, Minnesota*, Docket No. E002/CN-22-131, ORDER (June 28, 2022); *In the Matter of the Application of Xcel Energy and ITC Midwest, LLC for the Huntley - Wilmarth 345 KV Transmission Line Project*, Docket No. E002,ET-6675/CN-17-184, ORDER (September 1, 2017); *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for a Certificate of Need for the Upgrade of the Southwest Twin Cities Bluff Creek – Westgate Area 69 kV Transmission Line to 115 kV Capacity*, Docket No. E002/CN-11-332, ORDER GRANTING APPLICANT'S EXEMPTION REQUEST (Nov. 16, 2011).

C. Minn. Rules 7849.0270, subp. 2(E) – Annual Revenue Requirements

Minn. Rule 7849.0270, subp. 2(E) requires an estimate of the "annual revenue requirement per kilowatt-hour for the system in current dollars." The Applicants request an exemption from this rule and propose instead to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint. This substitute information will better inform the record regarding the need and cost of the entire LRTP Tranche 1 Portfolio.

D. Minn. Rule 7849.0280, subps. (B) through (I) – System Capacity

Minn. Rule 7849.0280, subps. (B) through (I) pertain to system capacity and generation data. The general purpose of this section is to provide a discussion of the ability of the existing system to meet the forecasted demand for electrical energy in response to Minn. Rule 7849.0270. However, Minn. Rule 7849.0270, subps. (B) through (I) pertain to an examination of generation adequacy and do not address transmission planning considerations. The Applicants request that the Commission grant an exemption to Minn. Rule 7849.0280, subps. (B) through (I). The Commission has previously granted exemption requests from Minn. Rule 7849.0280, subps. (B) through (I) in several other transmission line Certificate of Need dockets where, as here, issues of transmission adequacy, rather than generation adequacy, were at issue.[8]

E. Minn. Rule 7849.0290 – Conservation Programs

Minn. Rule 7849.0290 requires a Certificate of Need application to provide information related to conservation programs the applicant has in place and their effect on the forecast information required by Minn. Rule 7849.0270. The Applicants request an exemption from Minn. Rule 7849.0290 and instead will provide substitute information related either to their conservation programs or to the conservation programs that are available to their members serving load in Minnesota. The Applicants will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project. This information will better inform the record as to the need for the Project.

F. Minn. Rule 7849.0300 – Consequences of Delay and Minn. Rule 7849.0340 – No Facility Alternative

Minn. Rule 7849.0300 requires detailed information regarding the consequences of delay on three specific statistically-based levels of demand and energy consumption.

[8] *Id. See also In the Matter of the Application of Minnesota Power for a Certificate of Need for the HVDC Modernization Project*, Docket No. E015/CN-22-607, ORDER (Feb. 1, 2023) (approving applicant's exemption requests through the Commission's consent agenda).

Minn. Rule 7849.0340 requires a discussion of the impact on existing generation and transmission facilities at the three levels of demand specified in Minn. Rule 7849.0300 for the no-build alternative. Such a discussion is an important element of a determination of the need for new transmission infrastructure. While the Applicants will evaluate the consequences of delay and a no build alternative, the Applicants request a variance from the portions of these rules that require the examination to incorporate the three specific levels of demand required by Minn. Rule 7849.0300. Similar requests for exemptions from the requirements of Minn. Rules 7849.0300 and 7849.0340 were approved by the Commission in other recent transmission line Certificate of Need dockets.[9]

V. CONCLUSION

The Applicants respectfully request that the Commission grant the exemptions requested herein so that the Certificate of Need application provides focused information to evaluate the need for the proposed Project.

[9] *Id.*

Dated: March 10, 2023

Respectfully submitted,

NORTHERN STATES POWER COMPANY, a Minnesota corporation

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Certificate of Need Application Completeness Checklist

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
Minn. R. 7829.2500, subp. 2	Brief summary of filing on separate page sufficient to apprise potentially interested parties of its nature and general content	No
Minn. R. 7849.0200, subp. 2	Title Page and Table of Contents	No
Minn. R. 7849.0200, subp. 4	Cover Letter	No
Minn. R. 7849.0220, subp. 3	Joint Ownership and Multiparty use	No
Minn. R. 7849.0240	Need summary and additional considerations	No
subp. 1	Summary of the major factors that justify the need for the proposed facility	No
subp. 2	Relationship of the proposed facility to the following socioeconomic considerations:	–
A.	Socially beneficial uses of the output of the facility	No
B.	Promotional activities that may have given rise to the demand for the facility	No
C.	Effects of the facility in inducing future development	No
Minn. R. 7849.0260	Proposed LHVTL and Alternatives	–
A.	A description of the type and general location of the proposed line, including:	–
(1)	Design voltage	No
(2)	Number, sizes and types of conductors	No

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
(3)	Expected losses under projected maximum loading and under projected average loading in the length of the line and at terminals or substations	**Exemption Requested** The Applicants request to be exempt from providing line-specific loss information. The Applicants propose to provide substitute data in the form of overall system losses.
(4)	Approximate length of the proposed line	No
(5)	Approximate locations of DC terminals or AC substations on a map	No
(6)	List of likely affected counties	No
B.	Discussion of the available alternatives including:	–
(1)	New generation	No
(2)	Upgrading existing transmission lines	No
(3)	Transmission lines with different voltages or conductor arrays	No
(4)	Transmission lines with different terminals or substations	No
(5)	Double circuiting of existing transmission lines	No
(6)	If facility for DC (AC) transmission, an AC (DC) transmission line	No
(7)	If proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line	No
(8)	Any reasonable combination of alternatives (1) – (7)	No
C.	For the facility and for each alternative in B, a discussion of:	–
(1)	Total cost in current dollars	No
(2)	Service life	No

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
(3)	Estimated average annual availability	No
(4)	Estimated annual O&M costs in current dollars	No
(5)	Estimate of its effect on rates system wide and in Minnesota	No
(6)	Efficiency	**Exemption Requested** The Applicants request to be exempt from providing line-specific loss information. The Applicants propose to provide substitute data in the form of overall system losses.
(7)	Major assumptions made in subitems (1) – (6)	No
D.	A map (of appropriate scale) showing the applicant's system or load center to be served by the proposed LHVTL	No
E.	Such other information about the proposed facility and each alternative as may be relevant to determination of need.	No
Minn. R. 7849.0270	Content of Forecast	–
Minn. R. 7849.0270, subp. 1	Peak demand and annual consumption data	**Exemption Requested** The Applicants request to be exempt from providing specific forecasting and capacity information. The Applicants propose to provide substitute forecast information used in analyzing the need for the Project.
Minn. R. 7849.0270, subp. 2	For each forecast year the following data:	–
A.	Minnesota forecast data	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
B.	Estimates of the number of ultimate consumers and annual electrical consumption by those consumers:	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(1)	Farm, excluding irrigation and drainage pumping	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
(2)	Irrigation and drainage pumping	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(3)	Nonfarm residential	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(4)	Commercial	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(5)	Mining	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(6)	Industrial	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(7)	Street and highway lighting	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(8)	Electrified transportation[1]	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(9)	Other	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(10)	Sum of subitems (1) – (9)	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
C.	Estimate of the demand for power in system at the time of annual system peak demand	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
D.	System peak demand by month	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
E.	Estimated annual revenue requirement per kWh in current dollars	**Exemption Requested** The Applicants request to be exempt from providing annual revenue requirements for the Project. The Applicants propose to provide general information regarding how the costs for LRTP projects are shared within the MISO footprint.
F.	Estimated average weekday load factor by month	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 3	Forecast Methodology	–

[1] Electrified transportation is included in the column labeled "other."

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
	Detail of forecast methodology including:	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
A.	Overall methodological framework used	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
B.	Specific analytical used	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
C.	Manner in which specific techniques are related in producing the forecast	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
D.	Where statistical techniques are used:	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(1)	Purpose of the technique	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(2)	Typical computations	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(3)	Results of statistical tests	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
E.	Forecast confidence levels for annual peak demand and annual electrical consumption	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
F.	Brief analysis of methodology including:	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(1)	Strengths and weaknesses	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(2)	Suitability to the system	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(3)	Cost considerations	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(4)	Data requirements	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(5)	Past accuracy	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
(6)	Other significant factors	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
G.	Explanation of discrepancies	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 4	Discussion of data base used for forecasts including:	–
A.	List of data sets including a brief description of each	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
B.	Identification of adjustments made to raw data including nature, reason and magnitude	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 5	Assumptions and Special Information	–
	Discussion of each essential assumption including need and nature of assumption and sensitivity of forecast results to assumptions	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
	Discussion of assumptions regarding:	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
A.	Availability of alternative sources of energy	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
B.	Expected conversion from other fuels to electricity or vice versa	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
C.	Future prices for customers and their effect on demand	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
D.	Data requested in subp. 2 not historically available or generated by applicant for demand forecast	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
E.	Effect of energy conservation programs on long term demand	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
F.	Other factors considered when preparing forecast	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
Minn. R. 7849.0270, subp. 6	Coordination of Forecasts with Other Systems	—
A.	Extent of coordination of load forecasts with those of other systems	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1
B.	Description of the manner in which those forecasts are coordinated	**Exemption Requested** *See* Minn. R. 7849.0270, subp. 1

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
Minn. R. 7849.0280	System Capacity	—
	Description of ability of existing system to meet demand forecast including:	—
A.	Power planning programs	No
B.	Seasonal firm purchases and sales	**Exemption Requested**
C.	Seasonal participation purchases and sales	**Exemption Requested**
D.	For each forecast year load and generating capacity for:	**Exemption Requested**
(1)	Seasonal system demand	**Exemption Requested**
(2)	Annual system demand	**Exemption Requested**
(3)	Total seasonal firm purchases	**Exemption Requested**
(4)	Total seasonal firm sales	**Exemption Requested**
(5)	Seasonal adjusted net demand	**Exemption Requested**
(6)	Annual adjusted net demand	**Exemption Requested**
(7)	Net generating capacity	**Exemption Requested**
(8)	Total participation purchases	**Exemption Requested**
(9)	Total participation sales	**Exemption Requested**
(10)	Adjusted net capability	**Exemption Requested**

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
(11)	Net reserve capacity obligation	**Exemption Requested**
(12)	Total firm capacity obligation	**Exemption Requested**
(13)	Surplus or deficit capacity	**Exemption Requested**
E.	Summer and winter season load generation and capacity in years subsequent to application contingent on proposed facility	**Exemption Requested**
F.	Summer and winter season load generation and capacity including all projected purchases, sales and generation in years subsequent to application	**Exemption Requested**
G.	List of proposed additions and retirements in generating capacity for each forecast year subsequent to application	**Exemption Requested**
H.	Graph of monthly adjusted net demand and capability with difference between capability and maintenance outages plotted	**Exemption Requested**
I.	Appropriateness and method of determining system reserve margins	**Exemption Requested**
Minn. R. 7849.0290	Conservation Programs	—
A.	Persons responsible for energy conservation and efficiency programs	**Exemption Requested** The Applicants request to be exempt from discussing conservation programs and their effect on the forecast information required by Minn. R. 7849.0270. The Applicants propose to provide substitute information related either to their conservation programs or to the conservation programs that are available to their members serving load in Minnesota. The Applicants will also provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.
B.	List of energy conservation and efficiency goals and objectives	**Exemption Requested**

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
C.	Description of programs considered, implemented and rejected	**Exemption Requested**
D.	Description of major accomplishments in conservation and efficiency	**Exemption Requested**
E.	Description of future plans with respect to conservation and efficiency	**Exemption Requested**
F.	Quantification of the manner by which these programs impact the forecast	**Exemption Requested**
Minn. R. 7849.0300	Consequence of Delay	**Exemption Requested** The Applicants request to be exempt from providing analysis using three confidence levels. The Applicants propose to provide substitute data regarding potential impacts caused by delay in building the Project.
Minn. R. 7849.0310	Required Environmental Information	No
Minn. R. 7849.0330	Transmission Facilities	—
	Data for each alternative that would require LHVTL construction including:	—
A.	For overhead transmission lines	—
(1)	Schematics showing dimensions of support structures	No
(2)	Discussion of electric fields	No
(3)	Discussion of ozone and nitrogen oxide emissions	No
(4)	Discussion of radio and television interference	No
(5)	Discussion of audible noise	No

AUTHORITY	REQUIRED INFORMATION	EXEMPTION REQUESTED?
B.	For underground transmission facilities:	N/A
(1)	Types and dimensions of cable systems	N/A
(2)	Types and qualities of cable system materials	N/A
(3)	Heat released in kW per foot of cable	N/A
C.	Estimated right-of-way required for the facility	No
D.	Description of construction practices	No
E.	Description of O&M practices	No
F.	Estimated workforce required for construction and O&M	No
G.	Description of region between endpoints in likely area for routes emphasizing a three-mile radius of endpoints including:	No
(1)	Hydrological features	No
(2)	Vegetation and wildlife	No
(3)	Physiographic regions	No
(4)	Land use types	No
Minn. R. 7849.0340	No-Facility Alternative	**Exemption Requested** The Applicants request to be exempt from providing analysis using three confidence levels. The Applicants propose to provide substitute data regarding potential impacts caused by not building the Project.

Appendix C

Applicants' Notice Plan Petition

414 Nicollet Mall
Minneapolis, MN 55401

March 10, 2023

—Via Electronic Filing—

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT
DOCKET NO. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency (collectively, the Applicants) submit this Notice Plan for approval by the Minnesota Public Utilities Commission (the Commission) pursuant to Minn. Rule 7829.2550. In accordance with Minn. Rule 7829.2550, subp. 1, copies of this Notice Plan have been provided to the Minnesota Department of Commerce, the Minnesota Office of Attorney General Residential Utilities and Antitrust Division, and to persons listed on the "General List of Persons Interested in Power Plans and Transmission Lines" as maintained by the Commission under Minn. Rule 7850.2100, subp. 1(A). Please contact me at bria.e.shea@xcelenergy.com or 612-330-6064 if you have any questions regarding this filing.

Sincerely,

/s/ Bria E. Shea

BRIA E. SHEA
REGIONAL VICE PRESIDENT, REGULATORY POLICY

cc: Minnesota Department of Commerce
Minnesota Office of Attorney General Residential Utilities and Antitrust Division
Service List(s)

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT

MPUC Docket No. E002, E017, ET2, E015, ET10/CN-22-538

NOTICE PLAN PETITION

Public Comments on this Notice Plan Petition can be submitted to the Minnesota Public Utilities Commission until 4:30 P.M. March 30, 2023.

Replies to Comments can be submitted to the Minnesota Public Utilities Commission until 4:30 P.M. April 19, 2023.

The Minnesota Public Utilities Commission's address is: Minnesota Public Utilities Commission, 121 7th Place East, Suite 350, St. Paul, MN 55101-2147

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Western Minnesota Municipal Power Agency (Western Minnesota) (collectively, the Applicants) submit this Notice Plan for approval by the Minnesota Public Utilities Commission (the Commission) pursuant to Minn. Rule 7829.2550. This Notice Plan is intended to provide notice to all persons reasonably likely to be affected by the Minnesota portion of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (the Project).[1]

The Project consists of a new 345 kV transmission line between Big Stone City, South Dakota, and Sherburne County, Minnesota which will be comprised of two segments.

- The western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- The eastern segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Eastern Segment).[2]

The Applicants intend to include both segments in a single Certificate of Need application and each segment in separate Route Permit applications. The proposed 345 kV transmission lines will traverse Grant County in South Dakota and Big Stone, Lac Qui Parle, Swift, Kandiyohi, Stevens, Pope, Douglas, Todd, Stearns, Wright, and Sherburne counties in Minnesota. The proposed Project is shown on **Attachment A**, **Figure 1**.

The Project was studied, reviewed, and approved as part of the Long-Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO) Board of Directors in July 2022 as part of its 2021 Transmission Expansion Plan (MTEP21) report.[3] The Applicants filed a notice of intent to construct, own, and maintain the Project with the Commission on October 12, 2022.

The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as LRTP#2 in MTEP21, is a key part of the

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[1] The Cassie's Crossing Substation has been renamed the Big Oaks Substation.
[2] The Western Segment and the Eastern Segment are herein referred to collectively as the Project.
[3] A copy of MTEP21 report is available online at: https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf.

LRTP Tranche 1 Portfolio. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy to customers in Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

Minn. Rule 7829.2550 requires a Notice Plan to be submitted for review by the Commission at least three months before filing a Certificate of Need application for any high voltage transmission line under Minn. Stat. § 216B.243. The Applicants therefore submit this Notice Plan for the Commission's approval.

II. NOTICE PLAN PROPOSAL

The Applicants file this Notice Plan Petition and intend to file a Certificate of Need application for the entire Minnesota portion of the Project pursuant to Minn. Stat. § 216B.243 in the third quarter of 2023. Two separate Route Permit applications are being planned for the Project—one for the Western Segment and one for the Eastern Segment. Xcel Energy is leading this Notice Plan Petition and eventual Certificate of Need application for the Minnesota portion of the Project on behalf of the Applicants. Xcel Energy is also leading the Route Permit application for the Eastern Segment on behalf of the Applicants and will file that Route Permit application in accordance with Minn. Stat. § 216E.03.

Otter Tail and Missouri River Energy Services, on behalf of Western Minnesota, are assessing route alternatives for the Western Segment between the Big Stone South Substation in South Dakota and the Alexandria Substation in Minnesota. This assessment involves evaluating route alternatives, identifying opportunities and constraints, conducting stakeholder outreach including engaging applicable governmental and regulatory agencies, developing engineering, design, and construction information and preparing the Route Permit application. Otter Tail will lead the Route Permit application for the Western Segment and will file the application on behalf of itself and Western Minnesota in accordance with Minnesota Statutes § 216E.03. Otter Tail and Western Minnesota will also file the Route Permit application in South Dakota, along with any other applicable permits required within South Dakota, for the portion of the Western Segment that will be located in South Dakota.

This Notice Plan is prepared as an initial step in the Certificate of Need regulatory process. Preparation of a Notice Plan, and its review and approval by the

Commission, will ensure that interested persons are aware of the proceeding and have the opportunity to participate.

The area proposed to be included in notices under this proposal (Notice Area) is depicted in **Attachment A**, **Figure 1**. The Notice Area for the Western Segment, between the South Dakota border and the Alexandria Substation, is a wide area as potential routes for the new 345 kV transmission line for this portion of the Project are in development. The Notice Area for the Eastern Segment, between the Alexandria Substation and the Big Oaks Substation, is narrower as the majority of the Eastern Segment will involve stringing a second 345 kV circuit on existing transmission line structures. The Notice Area near the new Big Oaks Substation along the Eastern Segment is slightly wider to accommodate the development of route alternatives to connect the new 345 kV transmission line to this new substation.

A. Direct Mail Notice

Attachment A presents a letter that will be mailed to landowners, residents, local units of government, elected officials, tribal contacts, and agencies in and around the Notice Area.

1. Landowners

Minn. Rule 7829.2550, subp. 3(A) requires an applicant for a Certificate of Need to provide direct mail notice to all landowners reasonably likely to be affected by the proposed transmission line. The Applicants will compile landowner names and addresses within the Notice Area using tax records.

2. Mailing Addresses

Minn. Rule 7829.2550, subp. 3(B) requires an applicant for a Certificate of Need to provide direct mail notice to all mailing addresses in the area that are reasonably likely to be affected by the proposed transmission line. The Applicants will obtain a list of mailing addresses in the Notice Area and remove addresses common to the landowner list.

3. Tribal Governments

Minn. Rule 7829.2550, subp. 3(C) requires an applicant for a Certificate of Need to provide direct mail notice to tribal governments whose jurisdictions are reasonably likely to be affected by the proposed transmission line. A list of tribal governments and tribal government officials that will receive notice as part of this Notice Plan is included in **Attachment B**.

4. Local Governments

Minn. Rule 7829.2550, subp. 3(C) requires an applicant to provide direct mail notice to governments of towns, cities, home rule charter cities, and counties whose jurisdictions are reasonably likely to be affected by the proposed transmission line. The Applicants propose to provide direct mail notice to lead administration personnel in the towns, cities, home rule charter cities, and counties within the Notice Area. The notice will also be provided to the elected officials of those local units of government and to those State Senators and State Representatives whose districts are within the Notice Area. A complete list of government recipients is included in **Attachment B**.

B. Newspaper Notice.

Minn. Rule 7829.2550, subp. 3(D) requires an applicant to publish notice in newspapers in the areas reasonably likely to be affected by the transmission line. The proposed notice text is provided in **Attachment C**. The Applicants propose to place notice advertisements in the newspapers listed in **Table 1** below.

Table 1. Newspaper Notice.

Name of Newspaper	County in General Circulation
Star Tribune	Statewide
Ortonville Independent	Big Stone County
Alexandria Echo Press	Douglas County
Elbow Lake Grant County Herald	Grant County
Wilmar West Tribune	Kandiyohi County
Dawson Sentinel	Lac qui Parle County
Glenwood Pope County Tribune	Pope County
Becker Patriot News	Sherburne County
Cold Spring Record	Stearns County
St. Cloud Times	Stearns County
Morris/Hancock Stevens County Times	Stevens County
Appleton Press	Swift County

Swift County Monitor	Swift County
Long Prairie Leader	Todd County
Wright County Journal Press	Wright County

After the filing of a Certificate of Need application, Minn. Rule 7829.2500, subp. 5 requires the applicant to publish newspaper notice of the filing in a newspaper of general circulation throughout the state. Given that under the proposed Notice Plan, the Applicants will publish newspaper notice of the Certificate of Need proceeding shortly before a Certificate of Need application is filed in the newspapers of local, regional, and statewide circulation, the Applicants request a variance of Minn. Rule 7829.2500, subp. 5, to remove this additional newspaper notice requirement.

The Commission shall grant a variance pursuant to Minn. Rule 7829.3200 when it determines that the following three requirements are met:

> 1. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
>
> 2. granting the variance would not adversely affect the public interest; and
>
> 3. granting the variance would not conflict with standards imposed by law.

All three requirements are met in this instance. Per the Applicants' proposed Notice Plan, notice of the Project will be published in a statewide newspaper within 30 days of the Commission's approval of the plan. The rule would be an excessive burden on the Applicants because it would require an additional newspaper notice to be provided after the Certificate of Need application is filed, which will be close in time to the newspaper notice provided as part of the proposed Notice Plan. The public interest will not be adversely affected because notice of the Project in a statewide newspaper will be provided prior to the filing of the Certificate of Need application as part of the implementation of the Notice Plan. Granting the variance will not conflict with any legal standards as notice of the Project will still be provided in a statewide newspaper. As all three factors are met here, a variance of Minn. Rule 7829.2500, subp. 5 should be granted.

C. Notice Content

Minn. Rule 7829.2550, subp. 4 requires notice packets to include several pieces of information including: a map; right-of-way requirements and statement of intent to acquire property rights; notice that the transmission upgrade cannot be constructed unless the Commission certifies that it is needed; Commission contact information; utility website information; a statement that the Minnesota Department of Commerce, Energy Environmental Review and Analysis (EERA) staff will prepare an environmental report; an explanation of how to get on the Project's mailing list; and a list of applicable regulatory laws and rules. As shown in the Example Landowner Notice (**Attachment A**) the Applicants' notice mailing will include these requirements.

The notice letter will serve three purposes: 1) to introduce and explain the need and location of the Project; 2) to encourage potentially-affected persons to participate in the regulatory process; and 3) to provide contact information for citizens and officials to obtain additional information about the Project and the regulatory process. The map (**Attachment A**, **Figure 1**) that will be included with the notice letter will depict the transmission line endpoints, existing transmission lines and substations, counties, townships, and notable landmarks to aid in orientation.

D. Distribution of Notice Plan Filing

As required under Minn. Rule 7829.2550, subp. 1, this Notice Plan filing has been sent to EERA, the Office of the Attorney General – Residential Utilities and Antitrust Division, and to those parties listed on the "General List of Persons Interested in Power Plants and Transmission Lines."

III. CONCLUSION

The Applicants respectfully request that the Commission: (1) approve this Notice Plan; and (2) grant the variance from duplicative newspaper notice requirements under Minn. Rule 7829.2500, subp. 5.

Dated: March 10, 2023

Respectfully submitted,

NORTHERN STATES POWER COMPANY, a Minnesota corporation

/s/Matthew B. Harris

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Managing Attorney for State Regulatory
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(612) 330-6600
Matt.B.Harris@xcelenergy.com

OTTER TAIL POWER COMPANY, a Minnesota corporation

/s/Robert M. Endris

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Associate General Counsel
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Fergus Falls, MN 56537
(218)739-8234
rendris@otpco.com

MINNESOTA POWER, a Minnesota corporation

/s/David R. Moeller

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dmoeller@allete.com

GREAT RIVER ENERGY,
a Minnesota cooperative corporation

/s/Brian Meloy
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Associate General Counsel
12300 Elm Creek Blvd. N.
Maple Grove, MN 55369
(763) 445-5212
bmeloy@GREnergy.com

WESTERN MINNESOTA MUNICIPAL POWER AGENCY,
a Minnesota municipal power agency

/s/David C. McLaughlin
David C. McLaughlin
Fluegel, Anderson, McLaughlin & Brutlag, Chartered
129 NW 2nd Street
Ortonville, MN 53278
(320) 839-2549
dmclaughlin@fluegellaw.com

Attachment A

Example Notice Letter

_________, 2023

RE: Notice of Certificate of Need Application for the Big Stone South – Alexandria – Big Oaks Transmission Project
MPUC Docket No. E002, E017, ET2, E015, ET10/CN-22-538

This letter is intended to notify you of a proposed transmission line project and to:

1. Outline general Project location and a description of the need for the Project;
2. Describe how you can participate in the regulatory process; and
3. Provide contact information to receive additional information and to sign up for email and mailing lists.

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Missouri River Energy Services on behalf of Western Minnesota Municipal Power Agency (Western Minnesota) (collectively, the Applicants) are proposing to construct a new 345 kV transmission line between Big Stone City, South Dakota, and Sherburne County, Minnesota, which will be comprised of two segments (collectively referred to as the Project):

- The western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- The eastern segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Eastern Segment).

The majority of the Eastern Segment of the Project will include adding a second set of wires that will be strung on existing transmission line structures except for a short one-to four-mile segment of new construction to connect the new 345 kV transmission line to the new Big Oaks Substation. Proposed routes for the Western Segment of the Project are currently under evaluation by Otter Tail and Missouri River Energy Services, on behalf of Western Minnesota.

This notice is being provided to you because you fall into one of the categories listed below as they relate to the area shown in the attached "Notice Area" map.

- Landowners with property within the Notice Area;
- Residents living within the Notice Area;
- Local units of government in and around the Notice Area;
- State elected officials; and
- Government agencies and offices.

Why is the Project needed?

The Project is a key part of a portfolio of new transmission projects that is necessary to maintain a reliable, safe, and affordable transmission system in the Upper Midwest. The existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity, leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

What is the regulatory process for the Project?

Before construction can begin on the Project, the Minnesota Public Utilities Commission (the Commission) must determine whether the Project is needed in a Certificate of Need proceeding. If the Commission determines the Project is needed, it will then determine where the Project should be built through Route Permit proceedings.

The Certificate of Need process is governed by Minnesota law, including Minnesota Statutes Section 216B.243, and Minnesota Rules Chapters 7829 and 7849, specifically, Rules 7849.0010 to 7849.0400 and 7849.1000 to 7849.2100. A copy of the Certificate of Need application, once submitted, can be obtained by visiting the Commission's website at www.mn.gov/puc/ in Docket No. E002, E017, ET2, E015, ET10/CN-22-538.

As part of the Certificate of Need process, the Minnesota Department of Commerce, Energy Environmental Review and Analysis (EERA) will prepare an environmental report as required by Minnesota Rule 7849.1200.

As noted, the Commission must also grant a Route Permit for the Project before it can be built. The routing of the Minnesota portion of the Project is governed by Minnesota law, including Minnesota Statutes Chapter 216E and Minnesota Rules Chapter 7850.

The Commission will not make these determinations until it has completed a thorough process that encourages public involvement and analyzes the impacts of the Project. The table below provides a high-level summary of the major steps in the Certificate of Need process.

Major Certificate of Need Process Steps and Summary Schedule

Step	Approximate Date
Pre-Application public meetings and stakeholder outreach	Second Quarter 2023
Certificate of Need Application submitted to Commission	Third Quarter 2023
Informational Meetings (public meeting and comment)	Fourth Quarter 2023
Environmental Report Issued	Fourth Quarter 2023/ First Quarter 2024
Public Hearings (public meeting and comment period)	First Quarter 2024/ Second Quarter 2024
Commission Decision	Second Quarter 2024/ Third Quarter 2024

How will the regulatory process be structured?

The Applicants intend to file a Certificate of Need Application for the entire Minnesota portion of the Project and two separate Route Permit applications—one for the Western Segment and one for the Eastern Segment.

Although all Applicants will participate in the regulatory process, Xcel Energy is leading the Certificate of Need application on behalf of the Applicants for the Minnesota portion of the Project and the Route Permit application for the Eastern Segment. With the exception of a short one-to four-mile 345 kV line near the new Big Oaks Substation, the Eastern Segment of the Project involves adding a second set of wires to the existing structures.

Otter Tail is leading the Route Permit application for the Western Segment on behalf of itself and Western Minnesota. Otter Tail and Missouri River Energy Services, on behalf of Western Minnesota, are assessing route alternatives for the Western Segment between the Big Stone South Substation in South Dakota and the Alexandria Substation in Minnesota by identifying opportunities and constraints, conducting stakeholder outreach, engaging applicable governmental and regulatory agencies, and developing engineering, design and construction information. Otter Tail and Western Minnesota will also file the Route Permit application in South Dakota, along with any other applicable permits required within South Dakota, for the portion of the Western Segment that will be located in South Dakota.

How will the utilities acquire right-of-way necessary for the Project?

Before beginning construction, the utilities will acquire property rights for the right-of-way, typically through an easement that will be negotiated with the landowner for each parcel. The typical right-of-way for a transmission line operated at 345 kV is 150-feet wide. Except for a short one-to four-mile segment, the Eastern Segment of the Project involves adding a second set of wires to existing structures so new right-of-way is not anticipated to be needed for the majority of the Eastern Segment of the Project.

How can I obtain additional information about the Project?

To subscribe to the Project's Certificate of Need docket and to receive email notifications when information is filed in that docket, please visit www.edockets.state.mn.us, click on the "Subscribe to a Docket" button, enter your email address and select "Docket Number" from the Type of Subscriptions dropdown box, then select "22" from the first Docket number drop down box and enter "538" in the second box before clicking on the "Add to List" button. You must then click the "Save" button at the bottom of the page to confirm your subscription to the Project's Certificate of Need docket.

To be placed on the Project Certificate of Need mailing list (MPUC Docket ET6675/CN-22-538), mail, fax, or email Robin Benson at Minnesota Public Utilities Commission, 121 7th Place E., Suite 350, St. Paul, MN 55101-2147, Fax: 651-297-7073 or robin.benson@state.mn.us.

If you have questions about the state regulatory process, you may contact the Minnesota state regulatory staff listed below:

Minnesota Public Utilities Commission
[Commission contact to be added]
121 7th Place East, Suite 350
St. Paul, Minnesota 55101
651-296-0406
800-657-3782
Email: *[email to be added]*
Website: www.mn.gov/puc/

Minnesota Department of Commerce EERA
[DOC-EERA contact to be added]
85 7th Place East, Suite 280
St. Paul, Minnesota 55101
651-296-1500
800-657-3602
Email: *[email to be added]*
Website: www.mn.gov/commerce

Please visit the Project websites at: www.BigStoneSouthtoAlexandria.com (for the Western Segment) and www.AlexandriatoBigOaks.com (for the Eastern Segment) for more information and to learn more about our upcoming informational meetings for the public. Phone numbers and e-mail addresses for the Project are as follows:

Western Segment of the Project:

Project Phone Number: 1-800-598-5587

Project e-mail address: connect@bigstonesouthtoalexandria.com

Eastern Segment of the Project:

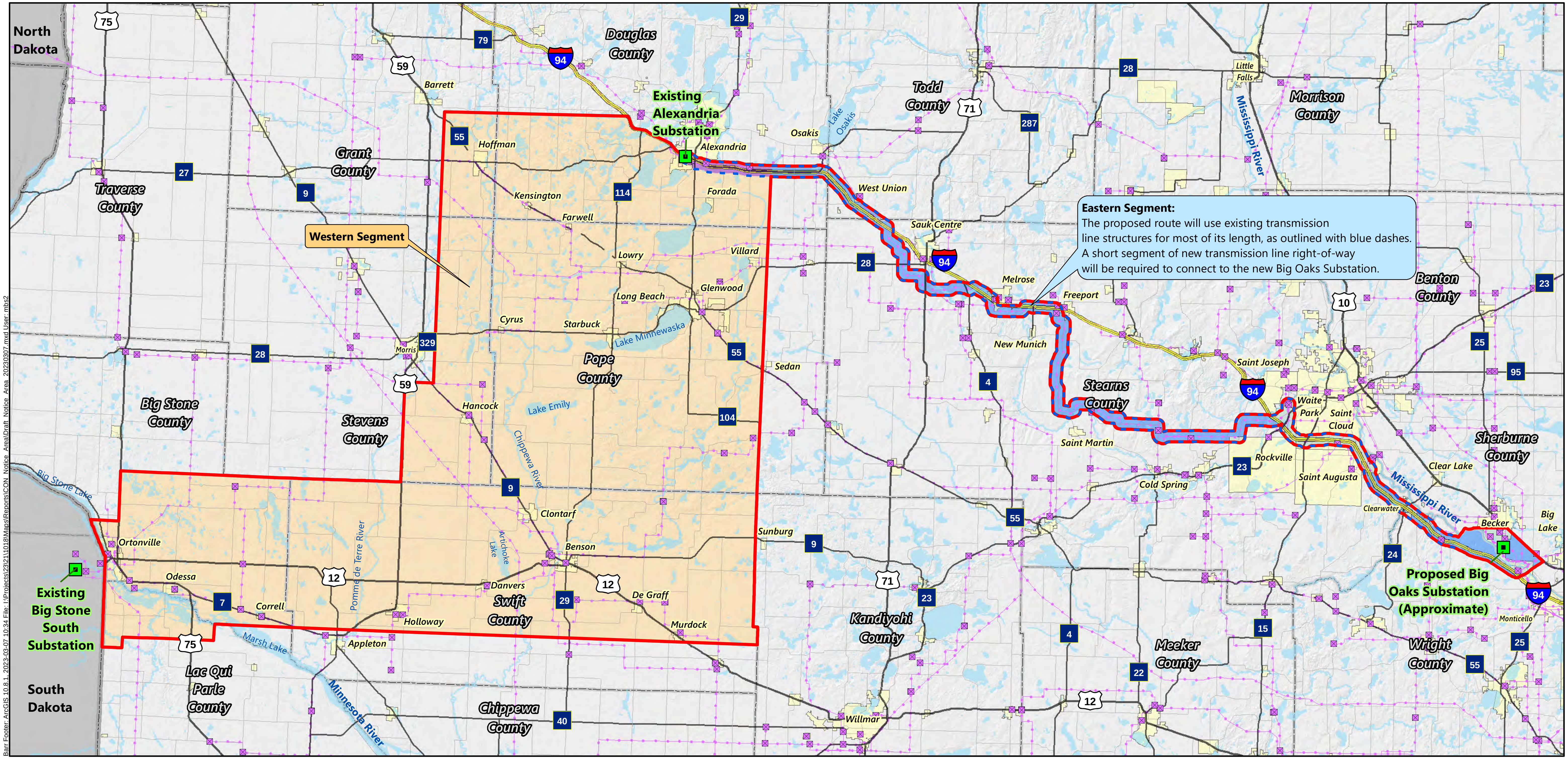
Project Phone Number: 1-888-231-7068

Project e-mail address: AlexandriatoBigOaks@XcelEnergy.com

How do I learn more about other transmission projects and the transmission planning process in Minnesota?

Minnesota Statutes § 216B.2425 require that each electric transmission-owning utility in the state file a biennial transmission planning report with the Commission by November 1st of each odd-numbered year. These reports provide information on the transmission planning process used by utilities in the state of Minnesota and information about other transmission line projects. The 2021 Biennial Transmission Planning Report is available at: www.minnelectrans.com.

FIGURE 1



- Certificate of Need Public Notice Area
- Western Segment
- Eastern Segment
- Shared Portion of the Notice Area
- Project Substation
- Existing Substation
- Existing Transmission Line
- Municipal Boundary
- County Boundary
- State Boundary
- Interstate Highway
- US Highway
- State Highway
- County State-Aid Highway

Miles

10 0 10

PUBLIC NOTICE AREA

BIG STONE SOUTH TO ALEXANDRIA AND ALEXANDRIA TO BIG OAKS

MISO LRTP-2 Certificate of Need Application

THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT CERTIFICATE OF NEED STAKEHOLDER CONTACT LIST

Type	County	Municipality/Township/State Electoral District	First	Last	Title	Address	City	State	Zip
Township	Big Stone	Odessa Township	Tammy	Neubauer	Clerk	66301 440th Street	Odessa	MN	56276
Township	Big Stone	Odessa Township	Tammy	Neubauer	Clerk	PO Box 67	Odessa	MN	56276
Township	Big Stone	Artichoke Township	Amy	Larson	Clerk	39671 580th Ave	Appleton	MN	56208
Township	Big Stone	Otrey Township	Kimberly	Danielson	Clerk	64366 360th St.	Ortonville	MN	56278
Township	Big Stone	Big Stone Township	Holly	Wellendorf	Clerk	20 2nd St SE	Ortonville	MN	56278
Township	Big Stone	Akron Township	Warren	Wiese	Clerk	41602 640th Ave	Ortonville	MN	56278
Township	Douglas	La Grand Township	Kelly	Beilke	Clerk	3999 County Road 82 NW	Alexandria	MN	56308
Township	Douglas	La Grand Township	Ben	Johnson	Chairperson	501 TownHall Road	Alexandria	MN	56308
Township	Douglas	Hudson Township	Carol	Hedlund	Clerk	3499 Caribou Lane, SE	Alexandria	MN	56308
Township	Douglas	Hudson Township	Cindy	VanLuik	Treasurer	11393 State Hwy 29 S	Alexandria	MN	56308
Township	Douglas	Urness Township	Judi	Andreasen	Clerk	4078 Shorewood Drive, SW	Kensington	MN	56343
Township	Douglas	Urness Township	Joan	Barsness	Treasurer	19590 County Road 8 NW	Brandon	MN	56315
Township	Douglas	Holmes City Township	Christopher	Wanner	Clerk/Treasurer	10983 Easy St SW, Lowry	Lowry	MN	56349
Township	Douglas	Holmes City Township	Gary	Schuneman	Chairman	11180 Tewes Trail SW	Farwell	MN	56327
Township	Douglas	Lake Mary Township	Susan	Hanson	Clerk	2640 Lodge Hall Road SW	Alexandria	MN	56308
Township	Douglas	Lake Mary Township	James	Schmidt	Chairman	4791 County Road 4 SW	Alexandria	MN	56308
Township	Douglas	Moe Township	Todd	Egenes	Clerk	9948 Cherry Point Road, SW	Alexandria	MN	56308
Township	Douglas	Moe Township	Lynn	Bushard	Chairperson	14641 Pioneer Park Rd Sw	Brandon	MN	56315
Township	Douglas	Solem Township	Marcy	Holl	Clerk	23756 Mellow Lane, SW	Kensington	MN	56343
Township	Douglas	Solem Township	Bruce	Wohlforth	Supervisor	23569 County Road 99 SW	Kensington	MN	56343
Township	Douglas	Orange Township	Jennifer	Dietrich	Clerk	8186 Molly Creek Road, SE	Osakis	MN	56360
Township	Douglas	Orange Township	Barb	Boogaard	Treasurer	11455 County Road 2 SE	Osakis	MN	56360
Township	Grant	Elk Lake Township	Peggy	Pasche	Clerk	16287 County Rd. 5	Hoffman	MN	56339
Township	Grant	Elk Lake Township	Judy	Boots	Treasurer	12502 250th	St. Barrett	MN	56311
Township	Grant	Land Township	Jeanne	Marts	Clerk	13993 Co. Rd. 23	Hoffman	MN	56339
Township	Grant	Land Township	Cheryl	Long	Treasurer	13186 Co. Rd. 5	Hoffman	MN	56339
Township	Lac qui Parle	Yellow Bank Township	Beth	Mueller	Clerk	1063 390th St.	Ortonville	MN	56278
Township	Lac qui Parle	Yellow Bank Township	Darrel	Ellefson	Chairperson	1845 287th Avenue	Dawson	MN	56232
Township	Lac qui Parle	Agassiz Township	Michael	Gloege	Clerk	1771 360th St.	Bellingham	MN	56212
Township	Lac qui Parle	Agassiz Township	Dan	Larson	Chairperson	3630 195TH AVE	Bellingham	MN	56212
Township	Pope	Nora Township	Kerri	Mattson	Clerk	35451 100th St	Kensington	MN	56343
Township	Pope	Nora Township	Josh	Andreasen	Chairman	11720 380th Ave	Kensington	MN	56343
Township	Pope	Chippewa Falls Township	Bernadine	Gerde	Clerk	27774 Lake Linka Ln	Glenwood	MN	56334
Township	Pope	Chippewa Falls Township	Brannon	Lange	Chairman	18475 Co Rd 18	Glenwood	MN	56334
Township	Pope	Bangor Township	Gregg	Weller	Chairman	11629 240th S	Brooten	MN	56316
Township	Pope	Bangor Township	Gerald	Vanderbeek	Clerk	13052 270th Street	Brooten	MN	56316
Township	Pope	New Prairie Township	Karla	Larson	Clerk	40612 State Hwy 28	Cyrus	MN	56323
Township	Pope	New Prairie Township	DeWayne	Larson	Chairman	21564 Co Rd 3	Cyrus	MN	56323
Township	Pope	Gilchrist Township	Joseph	White	Clerk	1309 Douglas St	Alexandria	MN	56308
Township	Pope	Gilchrist Township	John	Tvedt	Chairman	30955 190th Ave	Glenwood	MN	56334
Township	Pope	Reno Township	Richard	Moen	Clerk	P.O. Box 7	Glenwood	MN	56337
Township	Pope	Reno Township	Keith	Hvezda	Chairman	11123 Co Rd 15	Lowry	MN	56349
Township	Pope	White Bear Lake Township	Andy	Aslagson	Clerk	PO Box 215	Starbuck	MN	56381
Township	Pope	White Bear Lake Township	Mike	Hoffmann	Chairman	32745 180th St	Starbuck	MN	56381
Township	Pope	Barsness Township	Tony	Douvier	Clerk	26657 245th Ave	Glenwood	MN	56334
Township	Pope	Barsness Township	Allen	Braaten	Chairman	26234 245th Ave	Glenwood	MN	56334
Township	Pope	Walden Township	Theresa	Fisher	Clerk	518 1st St.	Hancock	MN	56244
Township	Pope	Walden Township	Norman	Nissen	Chairman	24149 380th Ave SW	Hancock	MN	56244
Township	Pope	Hoff Township	Joanna	Rustad	Clerk	39956 Co Rd 2	Hancock	MN	56244
Township	Pope	Hoff Township	Ted	Kannegiesser	Chairman	36752 320th St	Clontarf	MN	56226
Township	Pope	Grove Lake Township	Jamie	Dietzmann	Clerk	10387 182nd St	Villard	MN	56385
Township	Pope	Grove Lake Township	Dan	Jasmer	Chairman	13385 Co Rd 22	Glenwood	MN	56334
Township	Pope	Westport Township	Nancy	Ahlfors	Clerk	P.O. Box 135	Villard	MN	56385
Township	Pope	Westport Township	Todd	Malecha	Chairman	14542 Co Rd 33	Villard	MN	56385
Township	Pope	Glenwood Township	David	Sibell	Clerk	19396 State Hwy 104	Glenwood	MN	56334
Township	Pope	Glenwood Township	Matthew	Laubach	Chairman	19668 200th St	Glenwood	MN	56334
Township	Pope	Blue Mounds Township	Terri	Mitchell	Clerk	26594 295th Ave	Starbuck	MN	56381
Township	Pope	Blue Mounds Township	Warren	Hagestuen	Chairman	26296 St Hwy 29 S	Starbuck	MN	56381
Township	Pope	Leven Township	Kathy	Tauber	Clerk	11775 176th Ave	Villard	MN	56385
Township	Pope	Leven Township	Patrick	Gaffaney	Chairman	20187 Co Rd 30	Glenwood	MN	56334
Township	Pope	Rolling Forks Township	Brian	Jergenson	Clerk	23039 310th Street	Glenwood	MN	56334
Township	Pope	Rolling Forks Township	Steve	Nelson	Chairman	25271 335th St	Starbuck	MN	56381
Township	Pope	Minnewaska Township	Dianne	Ronnie	Clerk	25807 Nordic Point Dr	Glenwood	MN	56334
Township	Pope	Minnewaska Township	Jill	Solomonson	Chairman	27885 N Shore Dr	Starbuck	MN	56381
Township	Pope	Langhei Township	Gary	Williams	Clerk	30539 338th Ave	Clontarf	MN	56226
Township	Pope	Langhei Township	Eric	Danielson	Chairman	28191 Co Rd 10	Starbuck	MN	56381

Type	County	Municipality/Township/State Electoral District	First	Last	Title	Address	City	State	Zip
Township	Pope	Ben Wade Township	Vernon	Hedlin	Clerk	33742 State Hwy 55	Farwell	MN	56327
Township	Pope	Ben Wade Township	Paul	Terhaar	Chairman	11749 300th Ave	Lowry	MN	56349
Township	Sherburne	Becker Township	Lucinda	Messman	Clerk	PO Box 248	Becker	MN	55308
Township	Sherburne	Becker Township	Brian	Kolbinger	Chairman	12165 Hancock St	Becker	MN	55308
Township	Stearns	Lynden Township	Jenny	Schmidt	Clerk	21367 County Road 44	Clearwater	MN	55320
Township	Stearns	Lynden Township	David	Johnson	Chairman	18378 County Road 145	Clearwater	MN	55320
Township	Stearns	Oak Township	Thomas	Roelike	Clerk	34993 County Road 172	Freeport	MN	56331
Township	Stearns	Oak Township	Pete	Welle	Chairman	28093 7th Street SW	Freeport	MN	56331
Township	Stearns	Farming Township	Judy	Bruemmer	Clerk	27555 County Road 41	Albany	MN	56307
Township	Stearns	Farming Township	Jaosn	Willenbring	Chairman	20104 275th Street	Richmond	MN	56368
Township	Stearns	Saint Martin Township	Donald	Rausch	Clerk	28422 County Road 177	Paynesville	MN	56362
Township	Stearns	Saint Martin Township	Kenneth	Utsch	Chairman	31161 Sauk Valley Road	Paynesville	MN	56362
Township	Stearns	Collegeville Township	Joe	Pohl	Clerk	27724 Co Rd 50	Cold Spring	MN	56320
Township	Stearns	Collegeville Township	Terry	Stein	Chairperson	27724 Co Rd 50	Cold Spring	MN	56320
Township	Stearns	Ashley Township	Jessica	Minette	Clerk	43250 433rd Avenue	Sauk Centre	MN	56378
Township	Stearns	Ashley Township	Bob	Ritter	Chairperson	45925 430th Street	Sauk Centre	MN	56378
Township	Stearns	Wakefield Township	Heidi	Stalboerger	Clerk	22295 Frostview Road	Cold Spring	MN	56320
Township	Stearns	Wakefield Township	Jerry	Frieler	Treasurer	22295 Frostview Road	Cold Spring	MN	56320
Township	Stearns	Wakefield Township	Shawn	Garding	Chairperson	16275 County Road 49	Cold Spring	MN	56320
Township	Stearns	Munson Township	Boni	Behnen	Clerk	24285 193rd Avenue	Richmond	MN	56368
Township	Stearns	Munson Township	Butch	Gertkin	Chairperson	20704 243rd Street	Richmond	MN	56368
Township	Stearns	Grove Township	Kris	Leukam	Clerk	34308 Overton Road	Melrose	MN	56352
Township	Stearns	Grove Township	Ron	Schaefer	Chairperson	33323 Oakshire Road	Melrose	MN	56352
Township	Stearns	Melrose Township	Cecilia	Tylutki	Clerk	32721 Birch Field Court	Melrose	MN	56352
Township	Stearns	Melrose Township	Jane	Salzi	Chairperson	42557 County Road 13	Melrose	MN	56352
Township	Stearns	Sauk Centre Township	Missy	Schirmers	Clerk	43216 400th Street	Sauk Centre	MN	56378
Township	Stearns	Sauk Centre Township	John	Bosl	Chairperson	38171 County Road 29	Sauk Centre	MN	56378
Township	Stearns	Saint Joseph Township	Anna	Reischl	Clerk	200 Hill St. W	St. Joseph	MN	56374
Township	Stearns	Saint Joseph Township	Doug	Fredrickson	Chairperson	26545 Jade Road	St. Cloud	MN	56301
Township	Stevens	Moore Township	Robert	Nohl	Clerk	29121 County Rd 1	Hancock	MN	56244
Township	Stevens	Moore Township	Brett	Duncan	Chairman	43752 290th St	Hancock	MN	56244
Township	Stevens	Swan Lake Township	Becky	Meyer	Clerk	40304 115th St	Kensington	MN	56343
Township	Stevens	Swan Lake Township	Geoff	Carlson	Chairman	45386 147th St	Morris	MN	56267
Township	Stevens	Hodges Township	Michele	Greiner	Clerk/Treasurer	40878 280th St	Hancock	MN	56244
Township	Stevens	Hodges Township	Royce	Anderson	Chairman	43646 250th St	Hancock	MN	56244
Township	Stevens	Framnas Township	Sharon	Ehlers	Clerk	18391 430th Ave	Morris	MN	56267
Township	Stevens	Framnas Township	Richard	Buro	Chairman	21411 Lake Ave	Morris	MN	56267
Township	Stevens	Horton Township	Lori	Kill	Clerk	51804 330th St	Morris	MN	56267
Township	Stevens	Horton Township	Wayne	Spohr	Chairman	33302 470th Ave	Hancock	MN	56244
Township	Stevens	Darnen Township	Dennis	Sleiter	Clerk	50495 250th St	Morris	MN	56267
Township	Stevens	Darnen Township	Jerry	Hentges	Chairman	23939 480th Ave	Morris	MN	56267
Township	Swift	Appleton Township	Sonya	Allpress	Clerk	2210 70th St. SW	Appleton	MN	56208
Township	Swift	Appleton Township	Gene	Meyer	Chairperson	2410 60th St SW	Appleton	MN	56208
Township	Swift	Fairfield Township	Denise	Mahoney	Clerk	1910 50th St. NW	Appleton	MN	56208
Township	Swift	Fairfield Township	Lawrence	Mahoney	Chairperson	1910 50th St. NW	Appleton	MN	56208
Township	Swift	Edison Township	Karen	Meyer	Clerk/Treasurer	223 S. Behl St.	Appleton	MN	56208
Township	Swift	Hegbert Township	Cherri	Banken	Clerk	2170 50th St. NW	Appleton	MN	56208
Township	Swift	Shible Township	Bonnie	Franklin	Clerk	340 190th Ave. SW	Appleton	MN	56208
Township	Swift	Shible Township	Ronald	Trager	Chairperson	170 200th Ave NW	Appleton	MN	56208
Township	Swift	West Bank Township	Linda	Styrbicky	Clerk	870 100th Ave. SW	Danvers	MN	56231
Township	Swift	Kildare Township	William	Bridgland	Clerk	345 65th Ave. SE	DeGraff	MN	56271
Township	Swift	Pillsbury Township	Lyle	Stai	Clerk	1185 160th Ave SE	Kerkhoven	MN	56252
Township	Swift	Tara Township	Patti	Buyck	Clerk	520 110th Ave. NW	Danvers	MN	56231
Township	Swift	Swenoda Township	Laurie	Golden	Clerk	660 110th St. SW	Danvers	MN	56231
Township	Swift	Dublin Township	Paula	Grace	Clerk/Treasurer	890 80th Ave. SE	DeGraff	MN	56271
Township	Swift	Torning Township	Roman	Kalthoff	Clerk	525 50th St. SE	DeGraff	MN	56271
Township	Swift	Benson Township	Grant	Herfindahl	Clerk	520 27th Ave. NE	Benson	MN	56215
Township	Swift	Camp Lake Township	Rebecca	Turnquist	Clerk	300 120th Ave. NE	Murdock	MN	56271
Township	Swift	Marysland Township	Cheryl	Beyer	Clerk	275 130th Ave. SW	Danvers	MN	56231
Township	Swift	Marysland Township	Jerome	McGeary	Chairperson	150 110th Ave SW	Danvers	MN	56231
Township	Swift	Moyer Township	James	Dehne	Clerk	217 Victoria Drive	Alexandria	MN	56308
Township	Swift	Kerkhoven Township	David	Barrett	Clerk	1445 70th St. NE	Murdock	MN	56271
Township	Swift	Hayes Township	Jean	Rood	Clerk	1455 20th St. NE	Murdock	MN	56271
Township	Swift	Six Mile Grove Township	Sara	Wersinger	Clerk	420 MN Ave.	Danvers	MN	56231
Township	Swift	Clontarf Township	Anne	Schirmer	Clerk	P.O. Box 347	Clontarf	MN	56226
Township	Swift	Cashel Township	Gail	Brehmer	Clerk	815 50th Ave SE	DeGraff	MN	56271
Township	Todd	West Union Township	John	Chalmers	Clerk	14622 County 57	Osakis	MN	56360
Township	Todd	West Union Township	Earyl	Didier	Chairperson	15489 150th St	Osakis	MN	56360

Type	County	Municipality/Township/State Electoral District	First	Last	Title	Address	City	State	Zip
Township	Wright	Monticello Township	Cathy	Shuman	Clerk	8550 Edmonson Avenue NE	Monticello	MN	55362
Township	Wright	Monticello Township	Brett	Holker	Chairperson	8550 Edmonson Avenue NE	Monticello	MN	55362
Township	Wright	Clearwater Township	Jean	Just	Clerk	15015 State Hwy 24	Clearwater	MN	55320
Township	Wright	Clearwater Township	John	Notsch	Chairperson	15015 State Hwy 24	Clearwater	MN	55320
Township	Wright	Silver Creek Township	Heidi	Eckerman	Clerk/Treasurer	3827 134th ST NW	Monticello	MN	55362
Township	Wright	Silver Creek Township	Chris	Newman	Chairperson	3827 134th ST NW	Monticello	MN	55362
County	Todd		Chris	Pelzer	County Coordinator	215 1st Ave S, Suite 300	Long Prairie	MN	56347
County	Grant		Kimberly	Sundbom-Trudeau	County Coordinator	10 2nd St. NE	Elbow Lake	MN	56531
County	Douglas		Heather	Schlangen	County Coordinator	821 Cedar Street	Alexandria	MN	56308
County	Stevens		Rebecca	Young	County Administrator	400 Colorado Ave, Suite 302	Morris	MN	56267
County	Stearns		Michael	Williams	County Administrator	705 Courthouse Square, Room 121	St. Cloud	MN	56303-4701
County	Pope		Kersten	Kappmeyer	County Administrator	130 East Minnesota Avenue	Glenwood	MN	56334
County	Big Stone		Pam	Rud	County Coordinator	20 Second St SE	Ortonville	MN	56278
County	Sherburne		Bruce	Messelt	County Administrator	13880 Business Center Drive NW, Suite 100	Elk River	MN	55330-4668
County	Swift		Tesa	Tomaschett	County Administrator	301 14th Street North	Benson	MN	56125
County	Wright		Lee	Kelly	County Administrator	3650 Braddock Avenue NE Room 3200	Buffalo	MN	55313
County	Lac Qui Parle		Jake	Sieg	County Administrator	600 6th Street, Suite 6	Madison	MN	56256
Municipality		Alexandria	Bobbie	Osterberg	Mayor	704 Broadway	Alexandria	MN	56308
Municipality		Alexandria	Martin	Schultz	City Administrator	705 Broadway	Alexandria	MN	56309
Municipality		Alexandria Light & Power Utilities (ALP Utilities)	Ted	Cash	General Manager	316 Fillmore St	Alexandria	MN	56308
Municipality		Alexandria Light & Power Utilities (ALP Utilities)	Josh	Waldorf	Electric Manager	316 Fillmore St	Alexandria	MN	56308
Municipality		Becker	Tracy	Bertram	Mayor	12060 Sherburne Avenue	Becker	MN	55308
Municipality		Becker	Greg	Lerud	City Administrator	12061 Sherburne Avenue	Becker	MN	55309
Municipality		Benson	Jack	Evenson	Mayor	1410 Kansas Avenue	Benson	MN	56215
Municipality		Benson	Val	Alsker	City Administrator	1410 Kansas Avenue	Benson	MN	56215
Municipality		Benson	Rob	Wolfington	Acting City Manager	615 11th St S	Benson	MN	56215
Municipality		Benson Municipal Utilities	John	Goulet	Distribution Maintenance Crew Leader	1540 Kansas Ave	Benson	MN	56215
Municipality		Clearwater	Andrea	Lawrence-Wheeler	Mayor	PO Box 9	Clearwater	MN	55320
Municipality		Clearwater	Anita	Smythe	City Administrator	PO Box 9	Clearwater	MN	55320
Municipality		Clontarf	Thomas	Staton	Mayor	PO Box 307	Clontarf	MN	56226-0307
Municipality		Correll	Diane	Koepp	Mayor	109 Hwy 7 E Ste 100	Correll	MN	56227
Municipality		Cyrus	Tyler	Berg	Mayor	PO Box 36, 126 W. Main St	Cyrus	MN	56323
Municipality		Cyrus	Betsey	Alessi	City Clerk	PO Box 36, 126 W. Main St	Cyrus	MN	56323
Municipality		Danvers	Julie	Commerford	Mayor	PO Box 76	Danvers	MN	56231
Municipality		Danvers	Shari	Swanberg	City Clerk	PO Box 76	Danvers	MN	56231
Municipality		De Graff	Randy	Simmonds	Mayor	405 5th Street South	De Graff	MN	56271-9097
Municipality		Farwell	Curt	Huizinga	Mayor	PO Box 12A	Farwell	MN	56327
Municipality		Farwell	Jannel	Brockopp	City Clerk	PO Box 12A	Farwell	MN	56327
Municipality		Forada	Bob	Verkinderen	Mayor	10991 Toby's Ave SE	Alexandria	MN	56308
Municipality		Forada	David	Reller	City Clerk/Treasurer	10991 Toby's Ave SE	Alexandria	MN	56308
Municipality		Freeport	Mike	Eveslage	Mayor	PO Box 301	Freeport	MN	56331
Municipality		Freeport	Jon	Nelson	City Clerk	PO Box 301	Freeport	MN	56331
Municipality		Glenwood	Sherri	Kazda	Mayor	100 17th Avenue NW	Glenwood	MN	56334
Municipality		Glenwood	David	Iverson	City Administrator	100 17th Avenue NW	Glenwood	MN	56334
Municipality		Hancock	Bruce	Malo	Mayor	PO Box 68 662 6th ST	Hancock	MN	56244
Municipality		Hancock	Jodi	Bedel	City Clerk	PO Box 68 662 6th ST	Hancock	MN	56244
Municipality		Hoffman	Dennis	Satre	Mayor	PO Box 227	Hoffman	MN	56339-0227
Municipality		Hoffman	Janee	Strunk	City Clerk	PO Box 227	Hoffman	MN	56339-0227
Municipality		Holloway	Bradley	Oyen	Mayor	PO Box 108	Holloway	MN	56249
Municipality		Holloway	Joanna	Schliep	City Clerk	PO Box 108	Holloway	MN	56249
Municipality		Kensington	Jim	Schecker	Mayor	PO Box 156	Kensington	MN	56343
Municipality		Kensington	Jennifer	Kangas	City Clerk	PO Box 156	Kensington	MN	56343
Municipality		Long Beach	Mike	Pfeiffer	Mayor	23924 N. Lakeshore Drive	Glenwood	MN	56334
Municipality		Long Beach	Gerald	Rust	Assistant Mayor	23924 N. Lakeshore Drive	Glenwood	MN	56334
Municipality		Long Beach	Patia	Jensen	City Clerk	23924 N. Lakeshore Drive	Glenwood	MN	56334
Municipality		Lowry	Dan	Sutton	Mayor	PO Box 56	Lowry	MN	56349
Municipality		Lowry	Kristi	Kramber	City Clerk	PO Box 56	Lowry	MN	56349
Municipality		Melrose	Joe	Finken	Mayor	225 1st NE	Melrose	MN	56352
Municipality		Melrose	Colleen	Winter	City Administrator	225 1st NE	Melrose	MN	56352
Municipality		Melrose Public Utilities	Roger	Avelsgard	Electrical Supervisor	225 1st St NE	Melrose	MN	56352
Municipality		Monticello	Lloyd	Hilgart	Mayor	505 Walnut Street	Monticello	MN	55362
Municipality		Monticello	Rachel	Leonard	City Administrator	505 Walnut Street	Monticello	MN	55362
Municipality		Monticello	Jennifer	Schreiber	City Clerk	505 Walnut Street	Monticello	MN	55362
Municipality		Murdock	Craig	Cavanagh	Mayor	300 Frederick St	Murdock	MN	56271
Municipality		Murdock	Kimberly	Diederich	City Clerk	300 Frederick St	Murdock	MN	56271
Municipality		Odessa	Catherine	Teske	Mayor	PO Box 67	Odessa	MN	56276
Municipality		Ortonville	Gene	Hausauser	Mayor	751 Highland Hwy	Ortonville	MN	56278
Municipality		Ortonville	Char	Grossman	City Administrator	315 Madison Avenue	Ortonville	MN	56278

Type	County	Municipality/Township/State Electoral District	First	Last	Title	Address	City	State	Zip
Municipality		Ortonville Municipal Utilities	Tom	Dew	Distribution Maintenance Crew Leader	315 Madison Ave	Ortonville	MN	56278
Municipality		Rockville	Duane	Willenbring	Mayor	PO Box 93	Rockville	MN	56369
Municipality		Saint Augusta	Mike	Zenzen	Mayor	2162 County Road 115	St Augusta	MN	56301
Municipality		Saint Augusta	Bill	McCabe	City Administrator	1914 250th Street	St Augusta	MN	56302
Municipality		Saint Cloud	Dave	Kleis	Mayor	1201 7th St. S.	St. Cloud	MN	56301
Municipality		Saint Cloud	Matthew	Staehling	City Administrator	1201 7th St. S.	St. Cloud	MN	56301
Municipality		Saint Cloud	Seth	Kauffman	City Clerk	1201 7th St. S.	St. Cloud	MN	56301
Municipality		Sedan	Keith	Kirchhevel	Mayor	241 Pope Ave	Sedan	MN	56334
Municipality		Sedan	Julie	Lloyd	City Clerk	241 Pope Ave	Sedan	MN	56334
Municipality		Starbuck	Gary	Swenson	Mayor	PO Box 606	Starbuck	MN	56381
Municipality		Starbuck	Joan	Kerkvliet	City Clerk	PO Box 606	Starbuck	MN	56381
Municipality		Villard	Jason	Rupp	Mayor	PO Box 7	Villard	MN	56385
Municipality		Villard	Ann	Butler	City Clerk	PO Box 7	Villard	MN	56385
Municipality		Waite Park	Richard	Miller	Mayor	PO Box 339	Waite Park	MN	56387
Municipality		Waite Park	Shauna	Johnson	City Administrator	PO Box 339	Waite Park	MN	56387
Municipality		Waite Park	Adri	Brenny	City Clerk	PO Box 339	Waite Park	MN	56387
Municipality		West Union	Roger	Engle	Mayor	PO Box 106	West Union	MN	56389
Municipality		West Union	Janet	Macey	City Clerk	PO Box 106	West Union	MN	56389
State		District 12	Torrey	Westrom	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2201	St. Paul	MN	55155
State		District 13	Jeff	Howe	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2231	St. Paul	MN	55155
State		District 14	Aric	Putnam	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 3215	St. Paul	MN	55155
State		District 15	Gary	Dahms	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2219	St. Paul	MN	55155
State		District 27	Andrew	Mathews	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2233	St. Paul	MN	55155
State		District 29	Bruce	Anderson	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2209	St. Paul	MN	55155
State		District 5	Paul	Utke	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2403	St. Paul	MN	55155
State		District 9	Jordan	Rasmusson	Senator	95 University Avenue W. Minnesota Senate Bldg., Room 2409	St. Paul	MN	55155
State		District 12A	Paul	Anderson	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 277	St. Paul	MN	55155
State		District 12B	Mary	Franson	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 303	St. Paul	MN	55155
State		District 13A	Lisa	Demuth	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 267	St. Paul	MN	55155
State		District 14A	Bernie	Perryman	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 321	St. Paul	MN	55155
State		District 15A	Chris	Swedzinski	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 245	St. Paul	MN	55155
State		District 27A	Shane	Mekeland	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 215	St. Paul	MN	55155
State		District 29A	Joe	McDonald	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 241	St. Paul	MN	55155
State		District 29B	Marion	O'Neill	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 357	St. Paul	MN	55155
State		District 5B	Mike	Wiener	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 327	St. Paul	MN	55155
State		District 9A	Jeff	Backer	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 369	St. Paul	MN	55155
State		District 9B	Tom	Murphy	Representative	100 Rev. Dr. Martin Luther King Jr. Blvd. Minnesota State Office Bldg,, Room 313	St. Paul	MN	55155
Tribe		Bad River Band of the Lake Superior Tribe of Chippewa Indians of the Bad River Reservation, Wisconsin	Lawrence	Plucinski	Deputy Tribal Historic Preservation Office	PO Box 39	Odanah	WI	54861
Tribe		Cheyenne and Arapaho Tribes, Oklahoma	Max	Bear	Tribal Historic Preservation Officer	700 Black Kettle Blvd	Concho	OK	73022
Tribe		Flandreau Santee Sioux Tribe of South Dakota	Garrie	Kills A Hundred	Tribal Historic Preservation Officer	PO Box 283	Flandreau	SD	57028
Tribe		Fond du Lac Band of the Minnesota Chippewa Tribe	Evan	Schroeder	Tribal Historic Preservation Officer	1720 Big Lake Rd	Cloquet	MN	55720
Tribe		Fort Belknap Indian Community of the Fort Belknap Reservation of Montana	Michael	Blackwolf	Tribal Historic Preservation Officer	656 Agency Main Street	Harlem	MT	59526-9455
Tribe		Grand Portage Band of the Minnesota Chippewa Tribe	Rob	Hull	Tribal Historic Preservation Officer	PO Box 428	Grand Portage	MN	55605
Tribe		Iowa Tribe of Kansas and Nebraska	Lance	Foster	Tribal Historic Preservation Officer	3345 B Thrasher Rd.	White Cloud	KS	66094
Tribe		Keweenaw Bay Indian Community, Michigan	Alden	Connor	Tribal Historic Preservation Officer	16429 Beartown Rd.	Baraga	MI	49908
Tribe		Lac Vieux Desert Band of Lake Superior Chippewa Indians of Michigan	Alina	Shively	Tribal Historic Preservation Officer	E23709 US HWY 2 West	Watersmeet	MI	49969
Tribe		Lower Sioux Indian Community in the State of Minnesota	Cheyanne	St. John	Tribal Historic Preservation Officer	PO Box 308	Morton	MN	56270

Type	County	Municipality/Township/State Electoral District	First	Last	Title	Address	City	State	Zip
Tribe		Mille Lacs Band of Ojibwe (The Mille Lacs Band of the Minnesota Chippewa Tribe Mille Lacs Band of Ojibwe)	Terry	Kemper	Tribal Historic Preservation Officer	43408 Oodena Drive	Onamia	MN	56359
Tribe		Minnesota Chippewa Tribe	Rob	Hull	Tribal Historic Preservation Officer	P.O. Box 428	Grand Portage	MN	55605
Tribe		Prairie Island Indian Community in the State of Minnesota	Noah	White	Tribal Historic Preservation Officer	5636 Sturgeon Lake Road	Welch	MN	55089
Tribe		Red Cliff Band of Lake Superior Chippewa Indians of Wisconsin	Marvin	DeFoe	Tribal Historic Preservation Officer	88455 Pike Road	Bayfield	WI	54814
Tribe		Santee Sioux Nation, Nebraska	Misty	Frazier	Tribal Historic Preservation Officer	425 Frazier Ave. N. Suite 2	Niobrara	NE	68760
Tribe		Sisseton-Wahpeton Oyate of the Lake Traverse Reservation, South Dakota	Dianne	Desrosiers	Tribal Historic Preservation Officer	12554 BIA HWY 711, PO Box 907	Agency Villiage	SD	57262
Tribe		Spirit Lake Tribe, North Dakota	Kenneth	Graywater	Tribal Historic Preservation Officer	P.O. Box 359	Fort Totten	ND	58335-0359
Tribe		Upper Sioux Community, Minnesota	Samantha	Odegard	Tribal Historic Preservation Officer	PO Box 147	Granite Falls	MN	56241-0147
Tribe		White Earth Band of the Minnesota Chippewa Tribe	Jaime	Arsenault	Tribal Historic Preservation Officer	PO Box 418	White Earth	MN	56591
Tribe		Apache Tribe of Oklahoma	Durrell	Cooper	Chairman	PO Box 1330	Anadarko	OK	73005
Tribe		Lac du Flambeau Band of Lake Superior Chippewa Indians of the Lac du Flambeau Reservation of Wisconsin	Sarah	Thompson	Tribal Historic Preservation Officer	PO Box 67	Lac du Flambeau	WI	54538
Tribe		Leech Lake Band of the Minnesota Chippewa Tribe	Amy	Burnette	Tribal Historic Preservation Officer	190 Sailstar Drive NE	Cass Lake	MN	56633
Tribe		Menominee Indian Tribe of Wisconsin	David	Grignon	Tribal Historic Preservation Officer	PO Box 910	Keshena	WI	54135-0910
Tribe		Sokaogon Chippewa Community, Wisconsin	Michael	Laronge	Tribal Historic Preservation Officer	3051 Sand Lake Road	Crandon	WI	54520
Tribe		Bois Forte Band of Chippewa	Jaylen	Strong	Tribal Historic Preservation Officer	1500 Bois Forte Road	Tower	MN	55790
Tribe		Red Lake Band of Chippewa Indians	Kade	Ferris	Tribal Historic Preservation Officer	PO Box 274	Red Lake	MN	56671
Tribe		Shakopee Mdewakanton Sioux Community	Leonard	Wabasha	Tribal Historic Preservation Officer	2330 Sioux Trail NW	Prior Lake	MN	55372
Tribe		Minnesota Indian Affairs Council	Shannon	Geshick	Executive Director	161 St. Anthony Ave, Ste 919	St. Paul	MN	55103
Tribe		Mille Lacs Band of Ojibwe (The Mille Lacs Band of the Minnesota Chippewa Tribe Mille Lacs Band of Ojibwe)	Charlie	Lippert	Air Quality Specialist	43408 Oodena Drive	Onamia	MN	56359

Proposed Public Notice

Big Stone South-Alexandria-Big Oaks newspaper notice draft

Public Notice

RE: Notice of Certificate of Need Application for the Big Stone South – Alexandria – Big Oaks Transmission Project

MPUC Docket No. E002, E017, ET2, E015, ET10/CN-22-538

This notice is intended to inform you of a proposed transmission line project and to:

1. Outline general Project location and a description of the need for the Project;
2. Describe how you can participate in the regulatory process; and
3. Provide contact information to receive additional information and to sign up for email and mailing lists.

Northern States Power Company, doing business as Xcel Energy (Xcel Energy), along with Great River Energy, Minnesota Power, Otter Tail Power Company (Otter Tail), and Missouri River Energy Services on behalf of Western Minnesota Municipal Power Agency (Western Minnesota) (collectively, the Applicants) are proposing to construct a new 345 kV transmission line between Big Stone City, South Dakota, and Sherburne County, Minnesota, which will be comprised of two segments (collectively referred to as the Project):

- The western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- The eastern segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Eastern Segment).

The majority of the Eastern Segment of the Project will include adding a second set of wires that will be strung on existing transmission line structures except for a short one-to four-mile segment of new construction to connect the new 345 kV transmission line to the new Big Oaks Substation. Proposed routes for the Western Segment of the Project are currently under evaluation by Otter Tail and Missouri River Energy Services, on behalf of Western Minnesota.

We are publishing this notice to inform those in the Notice Area, including:

- Landowners who own property in the area;
- Residents who live in the area;
- Local government units in the area;

- State elected officials; and
- Government agencies and offices.

Please see the Notice Area map for detail on where the Project may be located.

Why is the Project needed?

The Project is a key part of a portfolio of new transmission projects that is necessary to maintain a reliable, safe, and affordable transmission system in the Upper Midwest.

The existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

What is the regulatory process for the Project?

Before construction can begin on the Project, the Minnesota Public Utilities Commission (the Commission) must determine whether the Project is needed in a Certificate of Need proceeding. If the Commission determines the Project is needed, it will then determine where the Project should be constructed through a Route Permit proceeding.

The Certificate of Need process is governed by Minnesota law, including Minnesota Statutes Section 216B.243, and Minnesota Rules Chapter 7829 and 7849, specifically, Rules 7849.0010 to 7849.0400 and 7849.1000 to 7849.2100. A copy of the Certificate of Need application, once submitted, can be obtained by visiting the Commission's website at www.mn.gov/puc/ in Docket No. E002, E017, ET2, E015, ET10/CN-22-538.

As part of the Certificate of Need process, the Minnesota Department of Commerce, Energy Environmental Review and Analysis (EERA) will prepare an environmental report as required by Minnesota Rule 7849.1200.

As noted, the Commission must also grant a Route Permit for the Project before it can be built. The routing of the Minnesota portion of the Project is governed by Minnesota law, including Minnesota Statutes Chapter 216E and Minnesota Rules Chapter 7850.

The Commission will not make these determinations until it has completed a thorough process that encourages public involvement and analyzes the impacts of the Project. The table below provides a high-level summary of the major steps in the Certificate of Need process.

Major Certificate of Need Process Steps and Summary Schedule

Step	Approximate Date
Pre-Application public meetings and stakeholder outreach	Second Quarter 2023
Certificate of Need Application submitted to Commission	Third Quarter 2023
Informational Meetings (public meeting and comment)	Fourth Quarter 2023
Environmental Report Issued	Fourth Quarter 2023/ First Quarter 2024
Public Hearings (public meeting and comment period)	First Quarter 2024/ Second Quarter 2024
Commission Decision	Second Quarter 2024/ Third Quarter 2024

How will the regulatory process be structured?

The Applicants intend to file a Certificate of Need Application for the entire Minnesota portion of the Project and two separate Route Permit applications—one for the Western Segment and one for the Eastern Segment.

Although all Applicants will participate in the regulatory process, Xcel Energy is leading the Certificate of Need application on behalf of the Applicants for the Minnesota portion of the Project and the Route Permit application for the Eastern Segment. With the exception of a short one-to four-mile 345 kV line near the new Big Oaks Substation, the Eastern Segment of the Project involves adding a second set of wires to the existing structures.

Otter Tail is leading the Route Permit application for the Western Segment on behalf of itself and Western Minnesota. Otter Tail and Missouri River Energy Services, on behalf of Western Minnesota, are assessing route alternatives for the Western Segment between the Big Stone South Substation in South Dakota and the Alexandria Substation in Minnesota by identifying opportunities and constraints, conducting stakeholder outreach, engaging applicable governmental and regulatory agencies, and developing engineering, design and construction information. Otter Tail and Western Minnesota will also file the Route Permit application in South Dakota, along with any other applicable permits required within South Dakota, for the portion of the Western Segment that will be located in South Dakota.

How will the utilities acquire right-of-way necessary for the Project?

Before beginning construction, the utilities will acquire property rights for the right-of-way, typically through an easement that will be negotiated with the landowner for each parcel. The typical right-of-way for a transmission line operated at 345 kV is 150-feet wide. Except for a short one-to four-mile segment, the Eastern Segment of the Project involves adding a second set of wires to existing structures so new right-of-way is not anticipated to be needed for the majority of the Eastern Segment of the Project.

How can I obtain additional information about the Project?

To subscribe to the Project's Certificate of Need docket and to receive email notifications when information is filed in that docket, please visit www.edockets.state.mn.us, click on the "Subscribe to a Docket" button, enter your email address and select "Docket Number" from the Type of Subscriptions dropdown box, then select "22" from the first Docket number drop down box and enter "538" in the second box before clicking on the "Add to List" button. You must then click the "Save" button at the bottom of the page to confirm your subscription to the Project's Certificate of Need docket.

To be placed on the Project Certificate of Need mailing list (MPUC Docket ET6675/CN-22-538), mail, fax, or email Robin Benson at Minnesota Public Utilities Commission, 121 7th Place E., Suite 350, St. Paul, MN 55101-2147, Fax: 651-297-7073 or robin.benson@state.mn.us. If you have questions about the state regulatory process, you may contact the Minnesota state regulatory staff listed below:

Minnesota Public Utilities Commission
[Commission contact to be added]
121 7th Place East, Suite 350
St. Paul, Minnesota 55101
651-296-0406
800-657-3782
Email: *[email to be added]*
Website: www.mn.gov/puc/

Minnesota Department of Commerce EERA
[DOC-EERA contact to be added]
85 7th Place East, Suite 280
St. Paul, Minnesota 55101
651-296-1500
800-657-3602
Email: *[email to be added]*
Website: www.mn.gov/commerce

Please visit the Project websites at: www.BigStoneSouthtoAlexandria.com (for the Western Segment) and www.AlexandriatoBigOaks.com (for the Eastern Segment) for more information and to learn more about our upcoming informational meetings for the public. Phone numbers and e-mail addresses for the Project are as follows:

Western Segment of the Project:

Project Phone Number: 1-800-598-5587

Project e-mail address: connect@bigstonesouthtoalexandria.com

Eastern Segment of the Project:

Project Phone Numbers: 1-888-231-7068

Project e-mail addresses: AlexandriatoBigOaks@XcelEnergy.com

How do I learn more about other transmission projects and the transmission planning process in Minnesota?

Minnesota Statutes § 216B.2425 require that each electric transmission-owning utility in the state file a biennial transmission planning report with the Commission by November 1st of each odd-numbered year. These reports provide information on the transmission planning process used by utilities in the state of Minnesota and information about other transmission line projects. The 2021 Biennial Transmission Planning Report is available at: www.minnelectrans.com.

Appendix D

Commission Order on Exemption Request and Notice Plan

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project

SERVICE DATE: April 19, 2023

DOCKET NO. E-017, ET-2, E-002, ET-10, E-015/CN-22-538

The above entitled matter has been considered by the Commission and the following disposition made:

1. **Approved the Notice Plan Petition.**

2. **Approved a variance to require the notice plan be implemented no more than 60 days and no less than one week prior to the filing of the Certificate of Need Petition.**

3. **Approved the Request for Exemption from Certain Certificate of Need Application Content Requirements.**

This decision is issued by the Commission's consent calendar subcommittee, under a delegation of authority granted under Minn. Stat. § 216A.03, subd. 8 (a). Unless a party, a participant, or a Commissioner files an objection to this decision within ten days of receiving it, it will become the Order of the full Commission under Minn. Stat. § 216A.03, subd. 8 (b).

The Commission agrees with and adopts the recommendations of the Department of Commerce, which are attached and hereby incorporated into the Order.

BY ORDER OF THE COMMISSION

Will Seuffert
Executive Secretary

To request this document in another format such as large print or audio, call 651.296.0406 (voice). Persons with a hearing or speech impairment may call using their preferred Telecommunications Relay Service or email consumer.puc@state.mn.us for assistance.

COMMERCE DEPARTMENT

March 30, 2023

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. Docket No. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Application for a Certificate of Need for the Big Stone South—Alexandria—Big Oaks Transmission Project.

The Petition was filed on March 10, 2023 by:

Bria E. Shea
Regional Vice President, Regulatory Policy
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends **approval with a condition** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ja
Attachment

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Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E002, E017, ET2, E015, ET10/CN-22-538

I. INTRODUCTION

On March 10, 2023 Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency (collectively, the Applicants) submitted their *Notice Plan Petition* (Petition). The Petition provided the Applicants' proposal to provide notice to all persons reasonably likely to be affected by the Minnesota portion of the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) transmission line project (the Project).

Also on March 10, 2023 the Applicants filed their *Request for Exemption from Certain Certificate of Need Application Content Requirements*.

Below are the comments of the Minnesota Department of Commerce (Department) regarding the Petition.

II. DEPARTMENT ANALYSIS

A. GOVERNING STATUTES AND RULES

The Applicants filed the Petition pursuant to Minnesota Rules, part 7829.2550 subpart 1 which states, in part "Three months before filing a certificate of need application for a high-voltage transmission line as defined by Minnesota Statutes, section 216B.2421, the applicant shall file a proposed plan for providing notice to all persons reasonably likely to be affected by the proposed line."

Minnesota Statutes § 216B.2421 includes in its definition of a Large Energy Facility (LEF) "any high-voltage transmission line with a capacity of 200 kilovolts or more and greater than 1,500 feet in length." Given that the proposed Project is a 345 kV transmission line substantially longer than 1,500 feet, the proposed Project falls within the definition of "large energy facility" and, therefore, requires a notice plan.

B. TYPES OF NOTICE

Minnesota Rules, part 7829.2550, subpart 3, requires types of notice as follows:

- direct mail notice, based on county tax assessment rolls, to landowners reasonably likely to be affected by the proposed transmission line;

- direct mail notice to all mailing addresses within the area reasonably likely to be affected by the proposed transmission line;
- direct mail notice to tribal governments and to the governments of towns, statutory cities, home rule charter cities, and counties whose jurisdictions are reasonably likely to be affected by the proposed transmission line; and
- newspaper notice to members of the public in areas reasonably likely to be affected by the proposed transmission line.

The Applicants proposed to provide notice to the area shown in Figure 1 of Attachment A of the Petition. The potential routes within the notice plan area are not identified at this time. Instead, the Notice Petition describes an overall Notice Area with three different subparts:

- The Notice Area for the Western Segment, between the South Dakota border and the Alexandria Substation, is a wide area as potential routes for the new 345 kV transmission line for this portion of the Project are in development.
- The Notice Area for the Eastern Segment, between the Alexandria Substation and the Big Oaks Substation, is narrower as the majority of the Eastern Segment will involve stringing a second 345 kV circuit on existing transmission line structures.
- The Notice Area near the new Big Oaks Substation along the Eastern Segment is slightly wider to accommodate the development of route alternatives to connect the new 345 kV transmission line to this new substation.

The list of individuals and entities to be provided notice are as follows:

- Regarding landowner notice—the Applicants will compile landowner names and addresses within the Notice Area using tax records.
- Regarding notice to mailing addresses—the Applicants will obtain a list of mailing addresses in the Notice Area and remove addresses common to the landowner list.
- Regarding notice to governmental jurisdictions—the Applicants will compile a list of lead administrative personnel in the towns, cities, home rule charter cities, and counties within the Notice Area. In addition, the Applicants will provide notice to the elected officials of those local units of government and to those State Senators and State Representatives whose districts are within the Notice Area.[1]
- Regarding notice to tribal governments—A list of tribal governments and tribal government officials that will receive notice is included in Attachment B of the Petition.
- Regarding newspaper notice—The Applicants propose to place notice advertisements in the newspapers listed in Table 1 of the Petition.

[1] A complete list of government recipients is included in Attachment B of the Petition.

After reviewing the data in Figure 1 of Attachment A and Attachment B of the Petition, the Department concludes that the Applicants' proposed identification of individuals and organizations that should receive notice is reasonable

C. CONTENT OF NOTICE

Minnesota Rules, part 7829.2550, subpart 4 require the notices to provide the following information:

- a map showing the end points of the line and existing transmission facilities in the area;
- a description of general right-of-way requirements for a line of the size and voltage proposed and a statement that the applicant intends to acquire property rights for the right-of-way that the proposed line will require;
- a notice that the line cannot be constructed unless the Commission certifies that it is needed;
- the Commission's mailing address, telephone number, and website;
- if the applicant is a utility subject to chapter 7848, the address of the website on which the utility applicant will post or has posted its biennial transmission projects report required under that chapter;
- a statement that the Environmental Quality Board[2] will be preparing an environmental report on each high-voltage transmission line for which certification is requested;
- a brief explanation of how to get on the mailing list for the Environmental Quality Board's proceeding; and
- a statement that requests for certification of high-voltage transmission lines are governed by Minnesota law, including specifically chapter 4410, parts 7849.0010 to 7849.0400, and 7849.1000 to 7849.2100, and Minnesota Statutes, section 216B.243.

The Department reviewed the notices, letters and maps provided by the Applicants and concludes that the proposal for the resident/landowner notice, governmental notice, and newspaper notice contains the required information.

D. NOTICE TIMING

Minnesota Rules, part 7829.2550, subpart 6, requires the applicant to implement the notice plan within 30 days of its approval by the Commission. The Applicants did not request any change to this timing requirement. To avoid substantial gap between when notice is provided and when the proceeding begins, the Department recommends that the Commission direct the notices identified in this notice plan to occur no more than 60 days and no less than one week prior to the filing of the certificate of need (CN) petition. The Commission has ordered a similar approach in several dockets.[3]

[2] This function has since been transferred to the Commission.
[3] Examples include:
• November 3, 2006 in Docket No. E002, ET2, et al/CN-08-1115;
• November 29, 2007 in Docket No. E017, E015, ET6/CN-07-1222;

Minnesota Rules, part 7829.3200 governs such variance requests and establishes the following criteria:

1. enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;
2. granting the variance would not adversely affect the public interest; and
3. granting the variance would not conflict with standards imposed by law.

The Department concludes that enforcement of the rule would burden all parties involved by creating the potential for substantial separation between the provision of notice and the start of the proceeding. Granting the variance would not adversely affect the public interest since the proposal would more closely tie the implementation of the notice plan to the beginning of the CN proceeding. The Department is not aware that the variance would conflict with standards imposed by law. Therefore, the Department recommends that the Commission approve a variance to require the notice plan be implemented no more than 60 days and no less than one week prior to the filing of the CN petition.

E. NEWSPAPER NOTIFICATION REQUIREMENTS

In addition to the newspaper notice discussed above, Minnesota Rules, part 7829.2500, subpart 5, requires the Applicants to publish newspaper notice of the CN filing in newspapers of general circulation throughout the state. The Applicants interpret this as requiring notice upon filing the CN and not prior to the CN. Therefore, the Applicants request a variance to Minnesota Rules, part 7829.2500, subpart 5 to remove the requirement to publish notice in a newspaper of general circulation throughout the state upon filing the CN petition.

All Applicants conclude that all three requirements are met.

1. The Applicants' proposal includes notice being published in a statewide newspaper. The rule would be an excessive burden on the Applicants because it would require an additional newspaper notice to be provided after the CN application is filed, which will be close in time to the newspaper notice provided as part of the proposed Notice Plan.
2. The public interest will not be adversely affected because notice of the Project in a statewide newspaper will be provided prior to the filing of the CN application as part of the implementation of the Notice Plan.

• November 12, 2008 in Docket No. E002/CN-08-992;
• January 26, 2010 in Docket No. E002/CN-09-1390;
• August 17, 2010 in Docket No. E002/CN-10-694;
• February 4, 2013 in Docket No. E002/CN-12-1235;
• December 8, 2014 in Docket No. E015/CN-14-787; and
• January 30, 2015 in Docket No. E015/CN-14-853.

3. Granting the variance will not conflict with any legal standards as notice of the Project will still be provided in a statewide newspaper.

The Department agrees with the Applicants' analysis and recommends the variance be approved.

III. DEPARTMENT RECOMMENDATION

The Department recommends that the Commission approve the Notice Petition and direct the notices identified in the notice plan to occur no more than 60 days and no less than one week prior to the filing of the CN petition.

March 30, 2023

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. Docket No. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Attached are the comments of the Minnesota Department of Commerce, Division of Energy Resources (Department) in the following matter:

Application for a Certificate of Need for the Big Stone South—Alexandria—Big Oaks Transmission Project.

The Petition was filed on March 10, 2023 by:

Bria E. Shea
Regional Vice President, Regulatory Policy
Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401

The Department recommends the Minnesota Public Utilities Commission **approve the petition** and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ja
Attachment

Before the Minnesota Public Utilities Commission

Comments of the Minnesota Department of Commerce
Division of Energy Resources

Docket No. E002, E017, ET2, E015, ET10/CN-22-538

I. INTRODUCTION

On March 10, 2023 Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency (collectively, the Applicants) submitted their *Request for Exemption from Certain Certificate of Need Application Content Requirements* (Petition). The Petition provided the Applicants proposal to obtain exemptions from certain data requirements of Minnesota Rules 7849.0010 to 7849.0400

Also on March 10, 2023 the Applicants filed their *Notice Plan Petition*.

On March 22, 2023 the Minnesota Public Utilities Commission (Commission) issued its *Notice of Comment Period on Request For Exemption from Certain Certificate of Need Filing Requirements* (Notice) indicating that the topic open for comment is should the Commission grant the exemptions to the certificate of need (CN) application content requirements.

Below are the comments of the Minnesota Department of Commerce (Department) regarding the Petition and the Notice.

II. DEPARTMENT ANALYSIS

A. GOVERNING STATUTES AND RULES

The Applicants filed the Petition pursuant to Minnesota Rules, part 7849.0200 subpart 6 which states, in part:

> Before submitting an application, a person is exempted from any data requirement of parts 7849.0010 to 7849.0400 if the person (1) requests an exemption from specified rules, in writing to the commission, and (2) shows that the data requirement is unnecessary to determine the need for the proposed facility or may be satisfied by submitting another document. A request for exemption must be filed at least 45 days before submitting an application.

Based on this standard the Commission may grant exemptions when the data requirements are shown to be unnecessary to determine need or can be satisfied by submitting alternative information. In the

Petition the Applicants request to be exempted from certain data requirements of parts 7849.0010 to 7849.0400.

B. BACKGROUND

The Applicants propose to file a CN petition to construct a 345 kV transmission line running from the Big Stone South substation, to the Alexandria substation to the Big Oaks substation (Project). The proposed Project is divided into two sections:

- The western segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota (Western Segment); and
- The eastern segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Eastern Segment).

The proposed Project will be considered in one CN petition but two routing petitions.

The proposed Project was studied, reviewed, and approved as part of the Long Range Transmission Planning (LRTP) Tranche 1 Portfolio by the Midcontinent Independent System Operator, Inc.'s (MISO) Board of Directors in July 2022 as part of the 2021 MISO Transmission Expansion Plan (MTEP21) report.

The Petition describes the LRTP Tranche 1 Portfolio as follows:

> The LRTP Tranche 1 Portfolio will provide significant benefits to the Midwest subregion of the MISO footprint by facilitating more reliable, safe, and affordable energy delivery. The Project, designated as LRTP#2 in MTEP21, is a key part of the LRTP Tranche 1 Portfolio. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region.

C. REQUESTED EXEMPTIONS

The Petition requests exemptions from the following requirements:

- 7849.0260 subparts A (3) and C (6)—line-specific loss information;
- 7849.0270 subparts 1 to 6—specific forecasting and capacity information;
- 7849.0270 subpart 2 (E)—annual revenue requirements;

- 7849.0280 (B) through (I)—system capacity;
- 7849.0290—conservation;
- 7849.0300—consequences of delay; and
- 7849.0340—no facility alternative.

The Department examines each specific exemption request separately. The required criterion is whether the Applicants have shown that "the data requirement is unnecessary to determine the need for the proposed facility or may be satisfied by submitting another document" as discussed above.

D. ANALYSIS OF EXEMPTION REQUESTS

1. 7849.0260 subparts A (3) and C (6)

Minnesota Rules 7849.0260 subparts A (3) and C (6) require an applicant for a CN to provide estimated "losses under projected maximum loading and under projected average loading in the length of the transmission line and at the terminals or substations." The Petition explains that "losses take place across the entire transmission system and is not isolated to a few transmission lines within the integrated regional electric grid." The Applicants request an exemption from Minnesota Rules 7849.0260, subps. A(3) and C(6) and propose to provide system losses in lieu of line-specific losses required by the rules.

The Department agrees that line losses for the system are more relevant to the analysis than line losses for individual lines. Also, as indicated in the Petition the proposal is consistent with the approach previously approved by the Commission in several other transmission line CN dockets. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0260 subpart A (3) and C (6) with the provision of the proposed alternative data.

2. 7849.0270 subparts 1 to 6

Minnesota Rules 7849.0270 subparts 1 to 6 requires an applicant for a CN to provide detailed forecasting information. The Petition explains that the rules assume that transmission improvements under consideration are driven by growing demand for electricity and the transmission project is linked directly to a specific generator proposed to meet that forecasted need. In contrast, the Applicants state that the proposed Project is needed for multiple reasons including addressing thermal and voltage issues and to provide additional transmission capacity to integrate renewable generation in the region. The Applicants request an exemption from Minnesota Rules 7849.0270 subparts 1 to 6 and propose to provide information regarding the forecasts used by MISO and the Applicants to assess the need for the proposed Project.

The Department agrees that using information actually used by MISO and the Applicants is superior to using the information required by the rule. Therefore, the Department recommends that the

Commission grant the requested exemption to Minnesota Rules 7849.0270 subparts 1 to 6 with the provision of the proposed alternative data.

3. 7849.0270 subpart 2 (E)

Minnesota Rules 7849.0270 subpart 2 (E) requires an applicant for a CN to provide the estimated annual revenue requirement per kilowatt hour for the system in current dollars. The Applicants request an exemption from this rule and instead propose to provide information regarding how the costs for LRTP projects are shared within the MISO footprint.

The Department agrees that providing information regarding how the costs for LRTP projects are actually allocated across the MISO footprint is superior to using the information required by the rule. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0270 subpart 2 (E) with the provision of the proposed alternative data.

4. 7849.0280 (B) through (I)

Minnesota Rules 7849.0280 subps. (B) through (I) requires an applicant for a CN to provide information that describes the ability of its existing system to meet forecasted demand; in essence, load and capability information. The Applicants state that this information pertains to an examination of generation adequacy and does not address transmission planning considerations. Also, the Applicants state that the Commission has previously granted exemption requests from Minn. Rule 7849.0280, subps. (B) through (I) in several other transmission line CN dockets. Thus, the Applicants request a complete exemption from this rule.

The Department agrees with the Applicants that the Commission has previously granted exemption requests from Minnesota Rules 7849.0280, subps. (B) through (I) in several other transmission line CN dockets where, as here, the issue relates to transmission adequacy rather than generation adequacy. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0280, subps. (B) through (I).

5. 7849.0290

Minnesota Rules 7849.0290 requires the applicant for a CN to provide conservation program information and quantification of the impact of conservation programs on forecast data. Instead of the required information the Applicants propose to provide:

- substitute information related either to their conservation programs or to the conservation programs that are available to their members serving load in Minnesota; and
- information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the proposed Project.

The Department agrees that the proposed information, particularly how MISO considered energy efficiency, will better inform the record as to the need for the proposed Project than the required information. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0290 with the provision of the proposed alternative data.

6. 7849.0300

Minnesota Rules 7849.0300 requires an applicant for a CN to provide detailed information regarding the consequences of delay on three specific statistically-based levels of demand and energy consumption. The Applicants state that "such a discussion is an important element of a determination of the need for new transmission infrastructure." However, while the Applicants will evaluate the consequences of delay, the Applicants request a variance from the portions of these rules that require the examination to incorporate the three specific levels of demand.

The Department agrees with the Applicants that information on the consequences of delay tied to three specific statistically-based levels of demand and energy consumption is not likely to be a critical part of the analysis for the proposed Project and that a general discussion is appropriate. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0300 with the provision of the proposed alternative data.

7. 7849.0340

Minnesota Rules 7849.0340 requires an applicant for a CN provide a discussion of the impact on existing generation and transmission facilities at the three levels of demand specified in part 7849.0300 for the no-build alternative. As with Minnesota Rules 7849.0300, the Applicants state that "such a discussion is an important element of a determination of the need for new transmission infrastructure." However, while the Applicants will evaluate a no build alternative, the Applicants request a variance from the portions of these rules that require the examination to incorporate the three specific levels of demand.

The Department agrees with the Applicants that information on the consequences of a no-build alternative tied to three specific statistically-based levels of demand and energy consumption is not likely to be a critical part of the analysis for the proposed Project and that a general discussion is appropriate. Therefore, the Department recommends that the Commission grant the requested exemption to Minnesota Rules 7849.0340 with the provision of the proposed alternative data.

III. DEPARTMENT RECOMMENDATION

The Department recommends that the Commission approve the Petition.

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

April 4, 2023

—Via Electronic Filing—

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
350 Metro Square Building
121 Seventh Place East
St. Paul, MN 55101

Re: IN THE MATTER OF THE APPLICATION FOR A CERTIFICATE OF NEED FOR THE BIG STONE SOUTH – ALEXANDRIA – BIG OAKS TRANSMISSION PROJECT
DOCKET NO. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, along with Great River Energy, Minnesota Power, Otter Tail Power Company, and Western Minnesota Municipal Power Agency (collectively, the Applicants) submit these reply comments concerning the Notice Plan and Exemption Request for the Big Stone South – Alexandria – Big Oaks 345 kilovolt (kV) Transmission Line Project (Project),[1] which were submitted in the above-referenced proceeding on March 10, 2023.

<u>Notice Plan</u>

The Department of Commerce, Division of Energy Resources (Department) submitted comments on March 30, 2023 regarding the Applicants' Notice Plan. The Department recommended approval of the Notice Plan with the modification that the notices identified in the Notice Plan occur no more than 60 days and no less than one week prior the filing of the Certificate of Need Application. The Applicants appreciate the Department's careful review of the Notice Plan and agree with the Department's recommendation.

<u>Exemption Request</u>

The Department also submitted comments on March 30th regarding the Applicants' Exemption Request and recommended that the Commission approve the

[1] The Cassie's Crossing Substation has been renamed the Big Oaks Substation. The Project is designated as LRTP#2 by the Midcontinent Independent System Operator, Inc. (MISO).

requested exemptions from certain Certificate of Need application filing requirements. The Applicants again appreciate the Department's thorough review of the Exemption Request and agree with the Department's recommendation.

Please contact me at bria.e.shea@xcelenergy.com or 612-330-6064 if you have any questions regarding this filing.

Sincerely,

/s/ Bria E. Shea

BRIA E. SHEA
REGIONAL VICE PRESIDENT, REGULATORY POLICY

cc: Service List

April 6, 2023

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, Minnesota 55101-2147

RE: **Supplemental Comments of the Minnesota Department of Commerce, Division of Energy Resources**
Docket No. E002, E017, ET2, E015, ET10/CN-22-538

Dear Mr. Seuffert:

Based upon the April 4, 2023 reply comments of Northern States Power Company, doing business as Xcel Energy the Minnesota Department of Commerce, Division of Energy Resources recommends that the Minnesota Public Utilities Commission approve the requested exemptions and is available to answer any questions the Minnesota Public Utilities Commission may have.

Sincerely,

/s/ STEVE RAKOW
Analyst Coordinator

SR/ar

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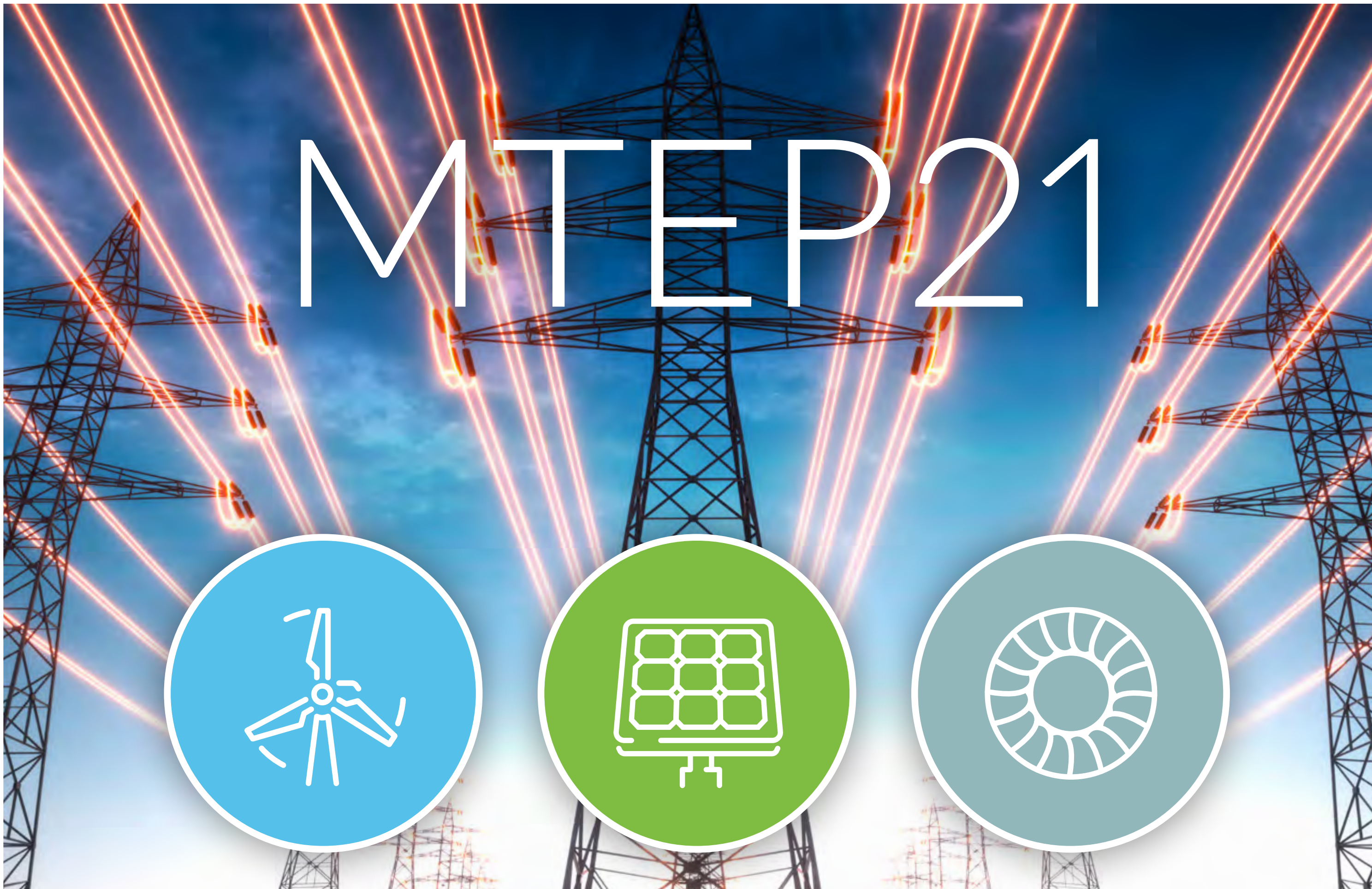
Appendix E

MISO Transmission Studies and Reports

TABLE OF CONTENTS

Appendix E-1

MISO's MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary, Report, and Appendix A



MTEP21 REPORT ADDENDUM:
LONG RANGE TRANSMISSION PLANNING TRANCHE 1
EXECUTIVE SUMMARY

Highlights

- This addendum proposes a portfolio of 18 transmission projects located in the MISO Midwest Subregions with a total investment of $10.3 billion, and benefit-to-cost ratios average of 2.6, where benefits well exceed costs

- This Tranche 1 portfolio of least-regrets transmission projects will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change over the next 20 years

- The Tranche 1 portfolio, with more than 2,000 miles of transmission line, represents the most complex transmission study efforts in MISO's history

MISO

misoenergy.org

MISO's Long Range Transmission Planning to address the Reliability Imperative: Tranche 1 Portfolio

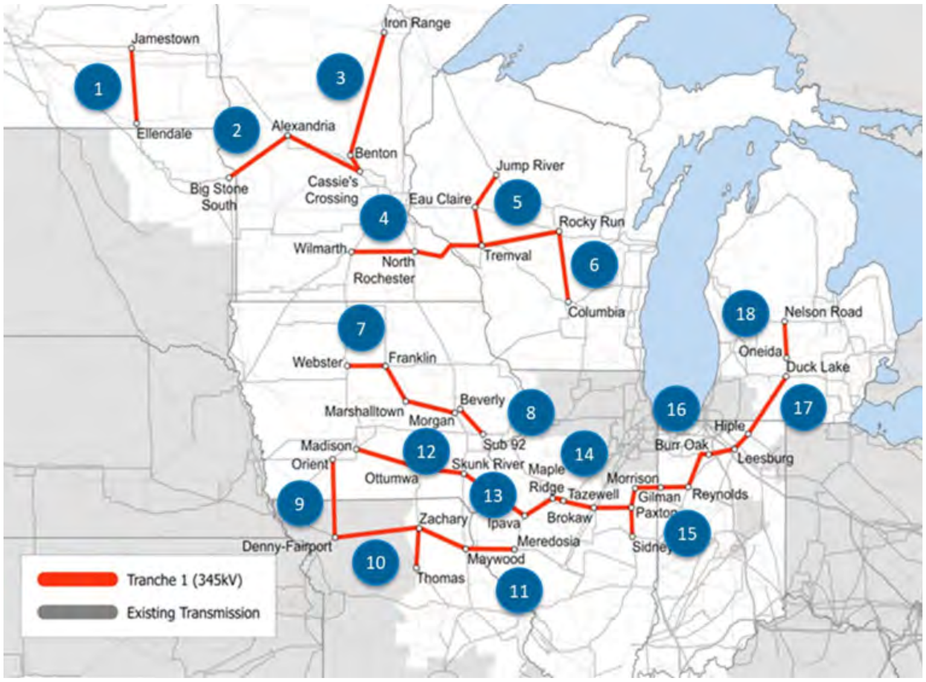
The *Long Range Transmission Planning (LRTP) Tranche 1 Portfolio* report presents the study findings and benefits analysis associated with the development of regional transmission solutions needed to provide reliable and economic delivery of energy. The report proposes a set of least-regrets transmission projects that will help to ensure a reliable, resilient and cost-effective transmission system as the resource mix continues to change and represents the largest and most complex transmission study effort in MISO's history. Since the last major set of regional overlay projects was approved in 2011, the pace towards more variable renewable generation has increased. Carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery and hybrid projects. Indeed, the anticipated landscape changes are much more significant and require transformational changes at a faster rate than the previous 2011 portfolio of projects were built to accommodate.

The resulting urgency has required a much more intensive and focused effort. While it took four years to develop the 2011 portfolio of projects, this LRTP Tranche 1 portfolio, which is significantly larger in terms of the cost and line miles, came to fruition in less than half that time, without sacrifice of analytical quality or identification of robust solutions. The resulting portfolio includes 18 transmission projects located in the MISO Midwest subregion, with a total initial investment of $10.3 billion.

The LRTP Tranche 1 portfolio was developed to ensure that the regional transmission system can meet demand in all hours while supporting the resource plans and renewable energy penetration targets reflective of MISO member utilities' goals and state policies. LRTP approached transmission portfolios in tranches in part because the urgent needs identified by the Reliability Imperative are appearing in the near-term for the Midwest subregion, including retirements and resource portfolio changes. This more urgent need put the focus for Tranches 1 and 2 in the Midwest Subregion. Tranche 3 will shift to focus on the South Subregion, with Tranche 4 then looking to strengthen the connection between the Midwest and South subregions.

Further, reflecting the portfolio's urgency, the LRTP Tranche 1 portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way, which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high-value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environmental and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

In addition to the primary benefits of system reliability, the LRTP Tranche 1 portfolio meets the criteria for Multi-Value Projects defined in the Tariff through addressing policy, reliability or economic needs, meeting the minimum cost threshold, and exceeding a benefit-to-cost ratio of 1.0. The types of economic benefits that could be used to meet these criteria represent a broad range of benefits provided by this portfolio of projects.



ID	DESCRIPTION	EXPECTED ISD	EST COST ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689
5	Tremval – Eau Claire – Jump River	6/1/2028	$505
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755
8	Beverly – Sub 92	12/31/2028	$231
9	Orient – Denny – Fairport	6/1/2030	$390
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769
11	Maywood – Meredosia	6/1/2028	$301
12	Madison – Ottumwa – Skunk River	6/1/2029	$673
13	Skunk River – Ipava	12/31/2029	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572
15	Sidney – Paxton East – Gilman South – Morrison Ditch	6/1/2029	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261
17	Hiple – Duck Lake	6/1/2030	$696
18	Oneida – Nelson Rd.	12/29/2029	$403
	TOTAL PROJECT PORTFOLIO COST		$10,324

Figure 1: LRTP Tranche 1 portfolio includes 18 projects in MISO's Midwest Subregion, with an investment cost of $10.3 billion

QUANTIFIED BENEFITS INCLUDE:

- **Congestion and Fuel Savings** – LRTP projects will allow more low-cost resources to be integrated, replacing higher-cost resources and lowering the overall cost to serve load.
- **Avoided Capital Cost of Local Resources** – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local buildout.
- **Avoided Transmission Investment** – LRTP projects will reduce loading and avoid future reliability upgrades, avoiding the cost for replacing facilities due to age and condition.
- **Resource Adequacy Savings** – LRTP projects will increase transfer capability, which will allow access to resources in otherwise constrained areas and defer the need for investment in local resources.
- **Avoided Risk of Load Shedding** – The LRTP portfolio will enhance the resilience of the grid and reduce risk of load loss caused by severe weather events.
- **Decarbonization** – The higher penetration of renewable resources enabled by the LRTP portfolio will result in less carbon dioxide emissions.

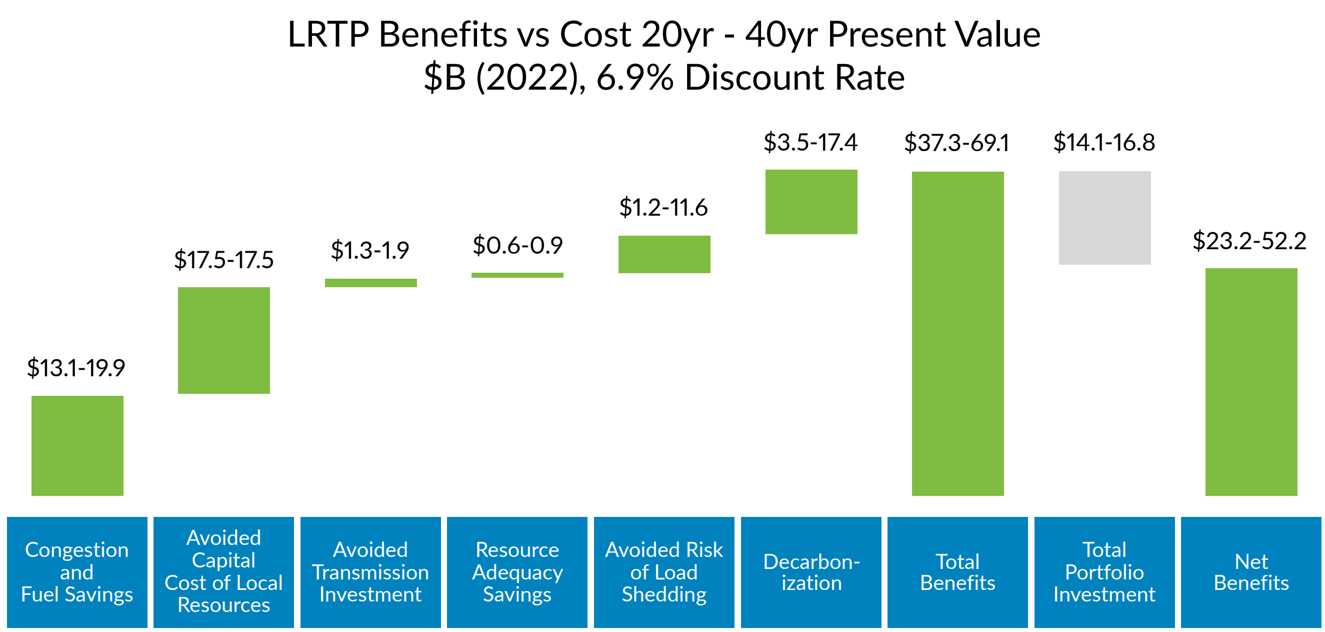


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*Note: This implies benefit-to-cost (B/C) ratio ranges of 20-yr PV B/C = 2.6 and 40-yr PV B/C = 4.0

The Tranche 1 portfolio has a benefit-to-cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit-to-cost ratio of at least 2.2 for every zone, with benefits well in excess of the LRTP costs. The proposed projects and costs are spread across the entire MISO Midwest subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

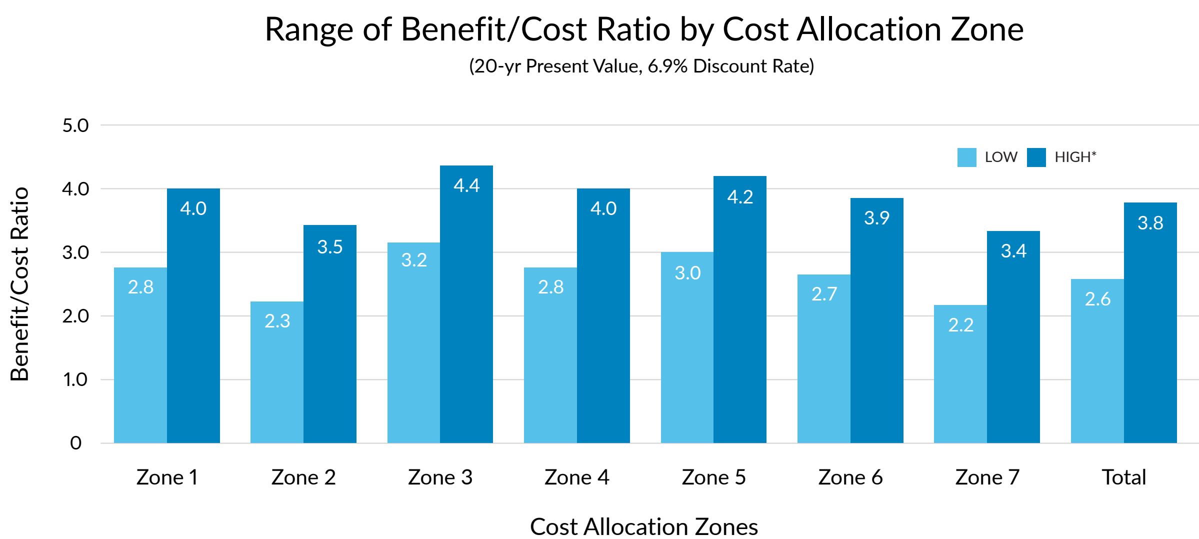


Figure 3: Benefits from the LRTP Tranche 1 portfolio exceed costs in every Midwest Subregion cost allocation zone

* The low and high range of benefit/cost ratios by Cost Allocation Zone are driven by changing two assumptions in the 20-year present value analysis: 1) increasing the Value of Lost Load (VOLL) from $3,500/MWh (low) to $23,000/MWh (high); and 2) increasing the price of carbon from $12.55/ton (low) to $47.80/ton (high).

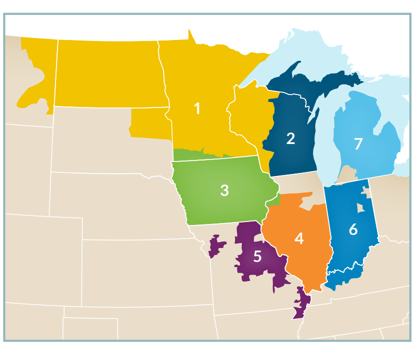


Figure 3a: Map of Midwest Cost Allocation Zone Boundaries (MISO Tariff, Attachment WW)

Transmission for the Future: LRTP Tranche 1 Projects are a "Least Regrets" Imperative

This least-regrets portfolio meets the needs of the first of MISO's three future planning scenarios, Future 1, which incorporates known and projected generation and load presented by member plans. This portfolio is "least regrets" because MISO is planning for an uncertain future and has chosen to plan towards the needs that represent a current view of member plans. Those portfolio plans continue to accelerate and expand, making Future 1 the conservative, expected case and presenting reliability implications that the Tranche 1 portfolio addresses. That's why Tranche 1 is a "yes-and" set of transmission that the Tranche 2 study will build off of to continue to meet the increasing renewable penetration levels and electrification growth that the MISO system is expected to see in the future.

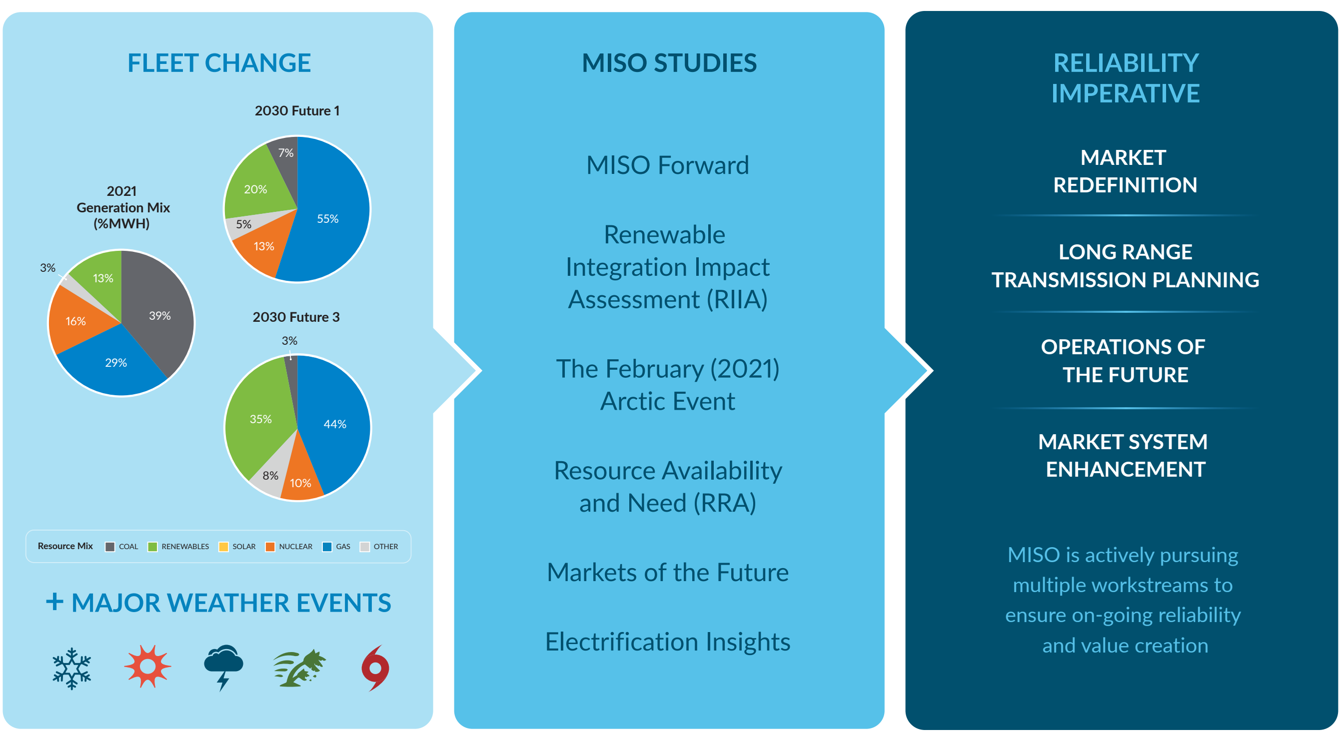


Figure 4: Challenges resulting from the changing resource portfolio and increasing extreme weather risk have created an imperative for broad changes

Subsequent tranches will improve interconnectivity, which helps to move power from where it's generated to where it's needed and, in doing so, not only integrates weather-based resources but improves resiliency during emergency events. Collectively, the multiple tranches of the LRTP comprise one of the four key elements of MISO's Reliability Imperative, which outlines a shared responsibility to evolve MISO's planning, markets, operations, and systems in an orderly fashion that preserves system reliability in the face of rapid changes in the MISO region. Unlike generation resource additions and retirements, which take as little as six months to complete, transmission projects can take up to 10 years from conception to in-service date. Given the long lead time, we must act now to ensure the transmission infrastructure is in place by 2030 to move both renewable and conventional generation across the grid in an efficient and reliable manner.

RELIABLE SYSTEM	Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
COST EFFICIENT	Enable access to lower-cost energy production
ACCESSIBLE RESOURCE	Provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
FLEXIBLE RESOURCES	Allow more flexibility in the fuel mix for customer choice

Figure 5: The LRTP Tranche 1 results were identified consistent with the objectives of the LRTP effort

How the Portfolio Evolved: MISO, Stakeholders Execute Accelerated, Robust Study

In response to resource shift trends, MISO began working with its stakeholders through the Planning Advisory Committee (PAC) and LRTP workshops to identify the transmission infrastructure needed to support these changes and ensure reliability. MISO introduced the LRTP conceptual roadmap to stakeholders in March 2021 and began discussions on the study scope and approach. A few months later, MISO began a series of monthly technical workshops to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings. In September 2021, MISO introduced a business case development process to identify the components and define the metrics for quantifying the benefits provided by the initial LRTP Tranche 1 portfolio of LRTP transmission investments.

In parallel, MISO engaged its stakeholders to develop an appropriate cost allocation methodology for such a transmission portfolio through the Regional Expansion Cost and Benefits Working Group (RECBWG).

The conceptual roadmap provided a long-range conceptual regional transmission plan to map out further study and potential solution ideas needed to address future transmission needs. Reliability analysis was then conducted on a series of study models representing various system conditions and dispatch patterns, as reviewed by MISO and stakeholders. Next, MISO evaluated potential alternative solutions developed by stakeholders and MISO to identify the most effective transmission solutions, including both reliability and economic analysis.

Once Tranche 1 projects were identified, MISO calculated the economic benefits of the portfolio. While the primary objective of the LRTP projects was to address reliability issues considering a range of system conditions, their value can extend well beyond reliability. This is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant broad economic benefits as well.

COSTS COMMENSURATE WITH BENEFITS

The transmission limitations between MISO Midwest and MISO South subregions effectively reduced the flow of benefits between the two subregions. To ensure costs align with beneficiaries, MISO submitted a cost allocation option for new Multi-Value Project portfolios, the cost of which would be regionally allocated on a subregional basis.

In February 2022, after months of work with stakeholders and state regulators, MISO filed with FERC for a cost allocation methodology for Multi-Value Projects to meet the unique needs of the region in developing the LRTP projects. The filing, supported by a majority of MISO transmission owners, was submitted and subsequently approved on May 18, 2022.

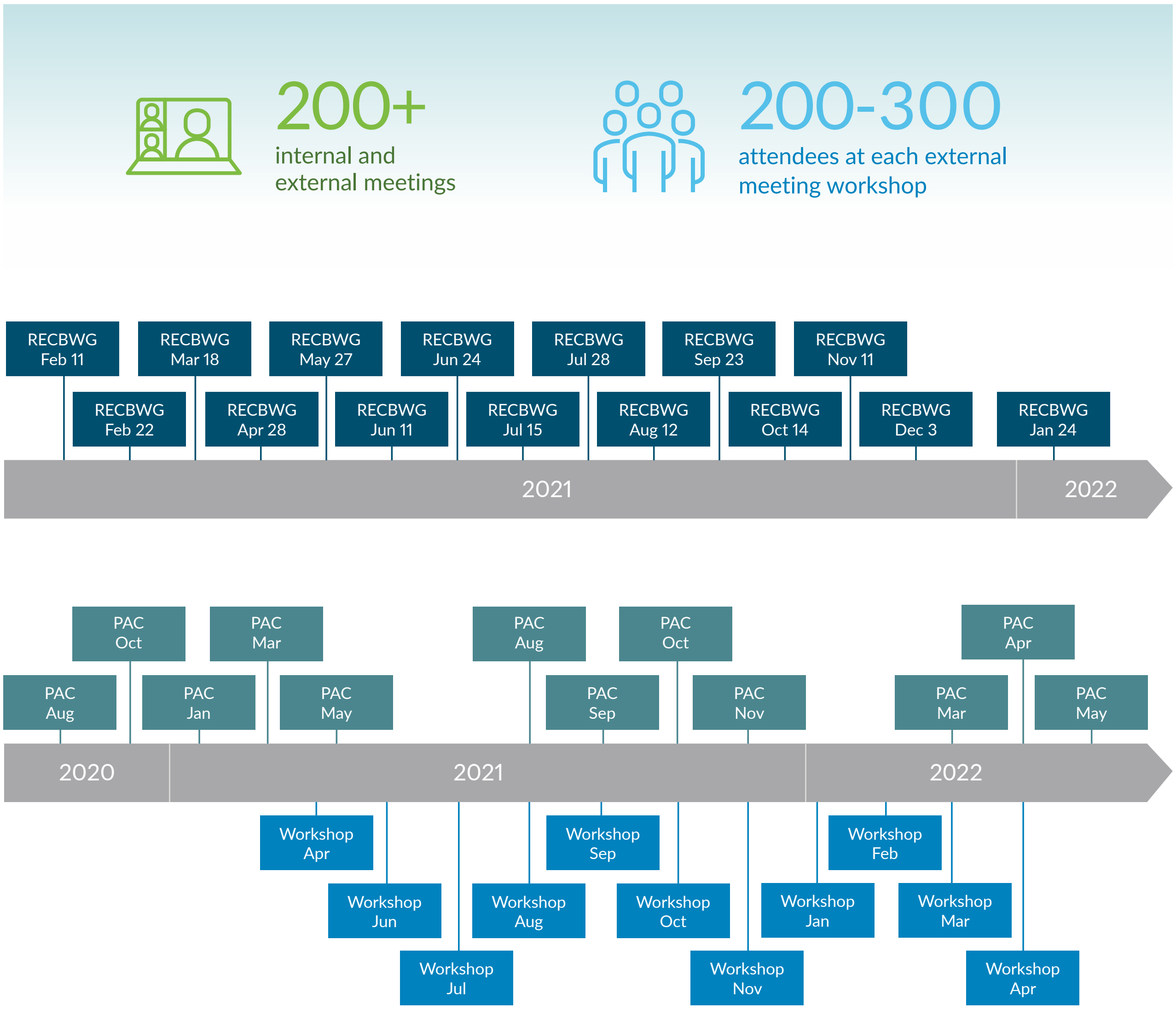


Figure 6: MISO's Long Range Transmission Plan Tranche 1 followed an extensive stakeholder process

Tranche 1 projects solve specific transmission issues across the MISO footprint

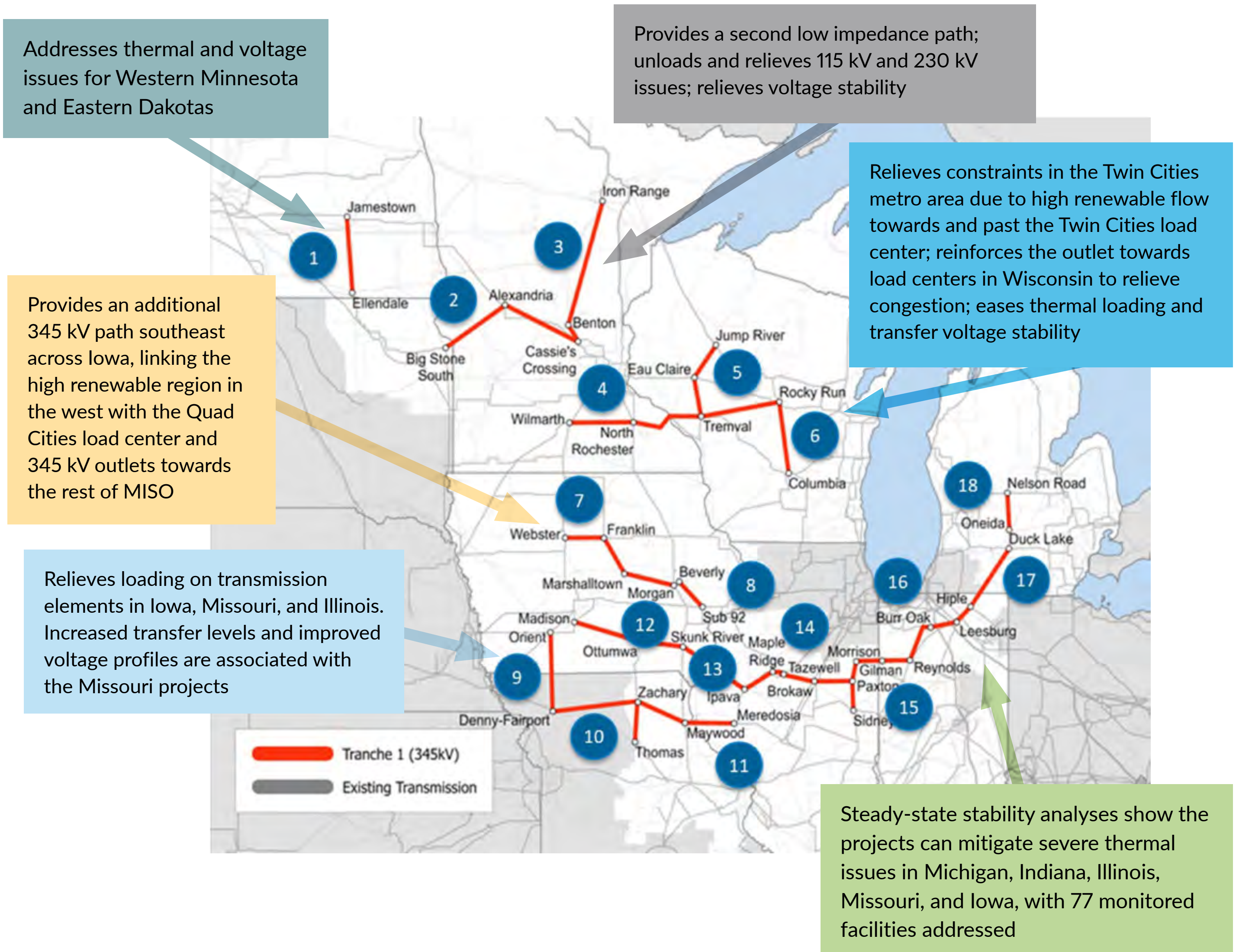
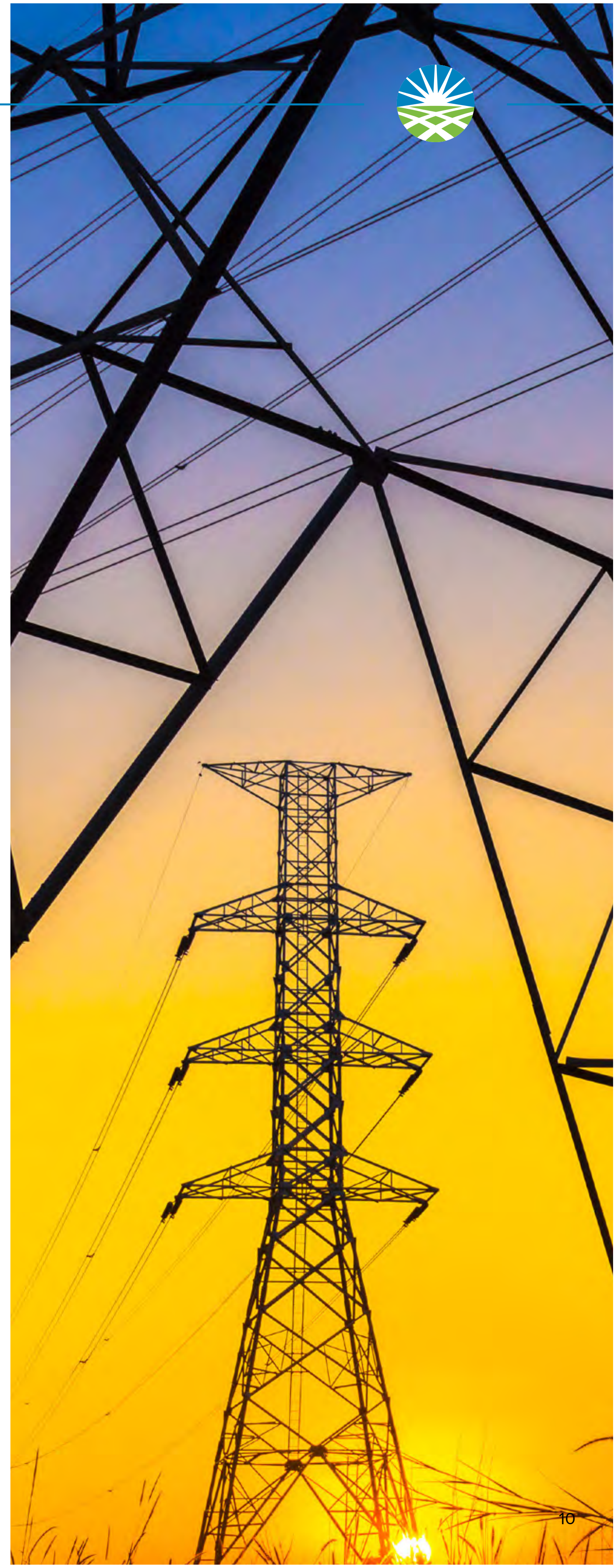


Figure 7: The Tranche 1 portfolio of 18 transmission projects can be divided into six sections with unique regional benefits

ID	DESCRIPTION
1	Jamestown – Ellendale
2	Big Stone South – Alexandria – Cassie's Crossing
3	Iron Range – Benton County – Cassie's Crossing
4	Wilmarth – North Rochester – Tremval
5	Tremval – Eau Claire – Jump River
6	Tremval – Rocky Run – Columbia
7	Webster – Franklin – Marshalltown – Morgan Valley
8	Beverly – Sub 92
9	Orient – Denny – Fairport
10	Denny – Zachary – Thomas Hill – Maywood
11	Maywood – Meredosia
12	Madison – Ottumwa – Skunk River
13	Skunk River – Ipava
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East
15	Sidney – Paxton East – Gilman South – Morrison Ditch
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple
17	Hiple – Duck Lake
18	Oneida – Nelson Rd



Next Steps: A Foundation for Future Needs

A more interconnected system is stronger. Additional study work and stakeholder engagement will help identify the nature and benefits of future LRTP tranches needed to address further deployment of variable, weather-dependent resources, continued volatility created by severe weather events and the benefits of improved interregional connectivity.

While Tranche 1 provides a meaningful start, much work is left to ensure that the shifting resource fleet transition occurs in an orderly, efficient and reliable manner. Though Tranche 1 provides a more robust system in the Midwest, future tranches are needed to address other parts of the MISO footprint and future levels of fleet transition beyond what is captured in Future 1. MISO looks forward to continuing the conversation with stakeholders and regulators to ensure adequate planning to meet future needs.

MISO

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MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report

Table of Contents

1 Introduction

MISO's multi-year Long Range Transmission Planning (LRTP) initiative assesses reliability risks looking 10-20 years into the future to identify the transmission investments needed to enable regional delivery of energy. Projections show a drastically different resource fleet, along with other influences such as electrification, that is driving a need for the bulk electric system to be better prepared for these massive shifts. MISO proposes a Tranche 1 Portfolio of 18 transmission projects, equaling approximately $10 billion of investment, to enhance connectivity and maintain adequate reliability for the Midwest Subregion by 2030 and beyond (Figure 1-1, Table 1-1).

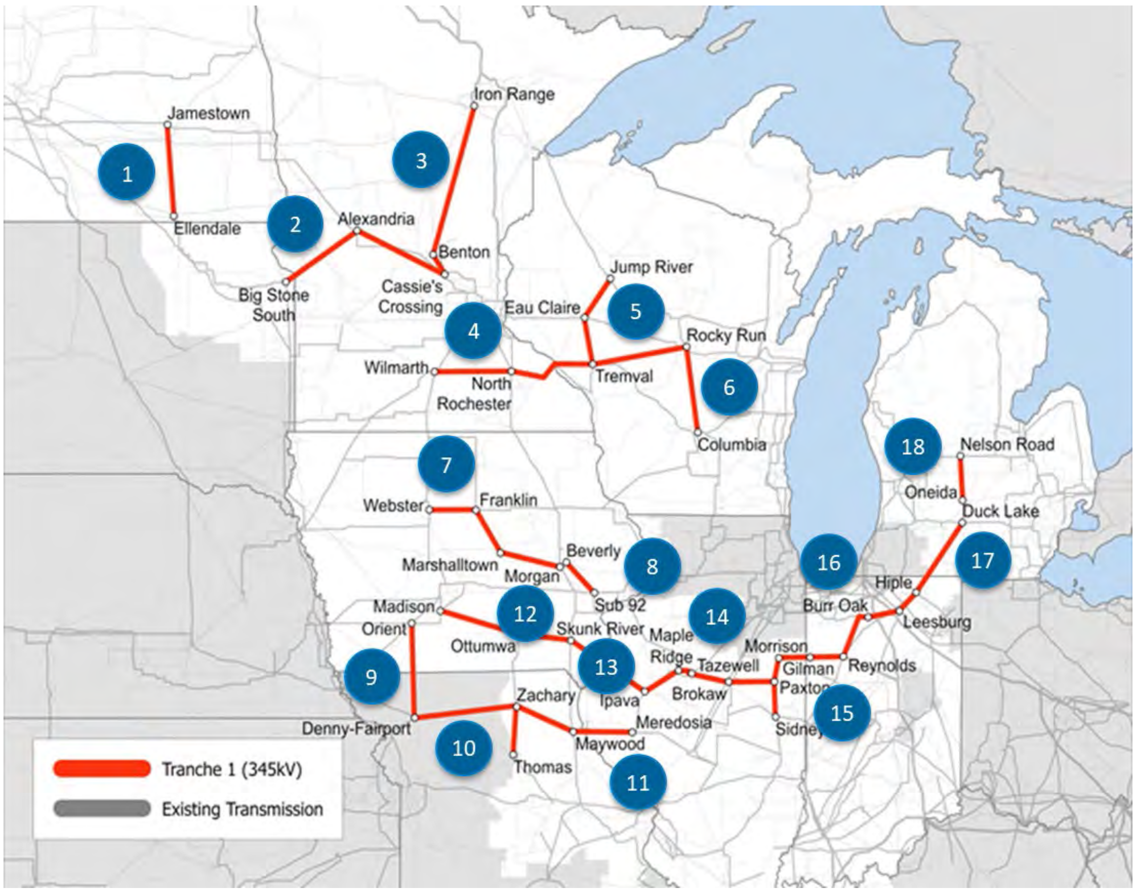


Figure 1-1: LRTP Tranche 1 Transmission Portfolio

LRTP Tranche 1 Portfolio of Projects

ID	Description	Expected ISD	Estimated Cost ($2022M)
1	Jamestown – Ellendale	12/31/2028	$439M
2	Big Stone South – Alexandria – Cassie's Crossing	6/1/2030	$574M
3	Iron Range – Benton County – Cassie's Crossing	6/1/2030	$970M
4	Wilmarth – North Rochester – Tremval	6/1/2028	$689M
5	Tremval – Eau Claire – Jump River	6/1/2028	$505M
6	Tremval – Rocky Run – Columbia	6/1/2029	$1,050M
7	Webster – Franklin – Marshalltown – Morgan Valley	12/31/2028	$755M
8	Beverly – Sub 92	12/31/2028	$231M
9	Orient – Denny - Fairport	6/1/2030	$390M
10	Denny – Zachary – Thomas Hill – Maywood	6/1/2030	$769M
11	Maywood – Meredosia	6/1/2028	$301M
12	Madison – Ottumwa – Skunk River	6/1/2029	$673M
13	Skunk River – Ipava	12/31/2029	$594M
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	6/1/2028	$572M
15	Sidney – Paxson East – Gilman South – Morrison Ditch	6/1/2029	$454M
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	6/1/2029	$261M
17	Hiple – Duck Lake	6/1/2030	$696M
18	Oneida – Nelson Rd.	12/29/2029	$403M
	Total Project Portfolio Cost:		$10,324M

Table 1-1: Proposed Tranche 1 Portfolio of Projects
(Costs as of June 1, 2022 and are subject to change. Costs represent "overnight" costs)

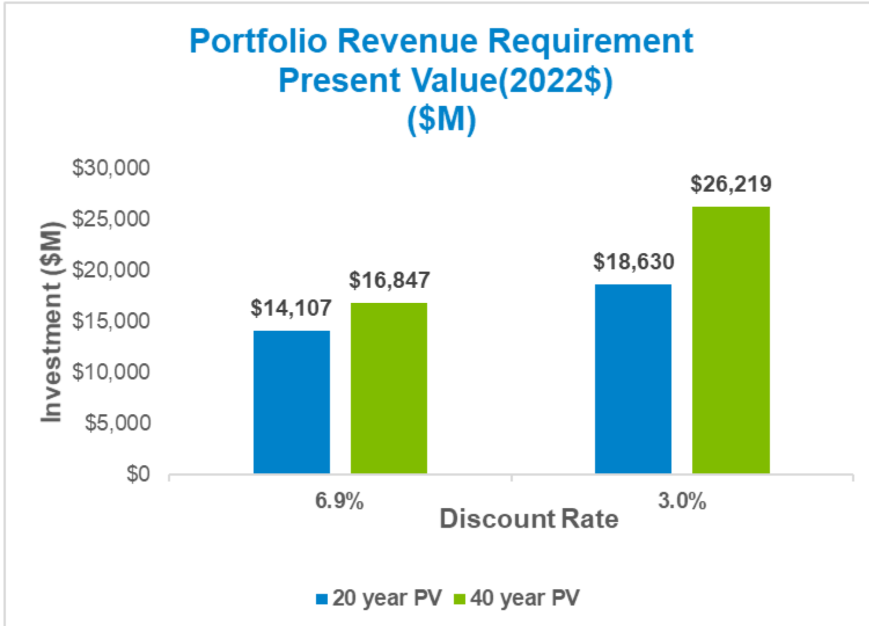


Figure 1-2: Present Value of LRTP Tranche 1 Portfolio (values as of 6/1/2022)

The Tranche 1 Portfolio has a benefit to cost ratio of between 2.6 and 3.8, and MISO studies show benefits of this investment at a benefit to cost ratio of at least 2.2 for every Cost Allocation Zone, well in excess of the LRTP Tranche 1 Portfolio costs (Figure 1-2 and 1-3). The proposed projects and costs are spread across the entire MISO Midwest Subregion, allowing it to benefit multiple states, MISO members and customers. Benefits include more reliable and resilient energy delivery; congestion and fuel savings; avoided resource and transmission investment; improved distribution of renewable energy; and reduced carbon emissions.

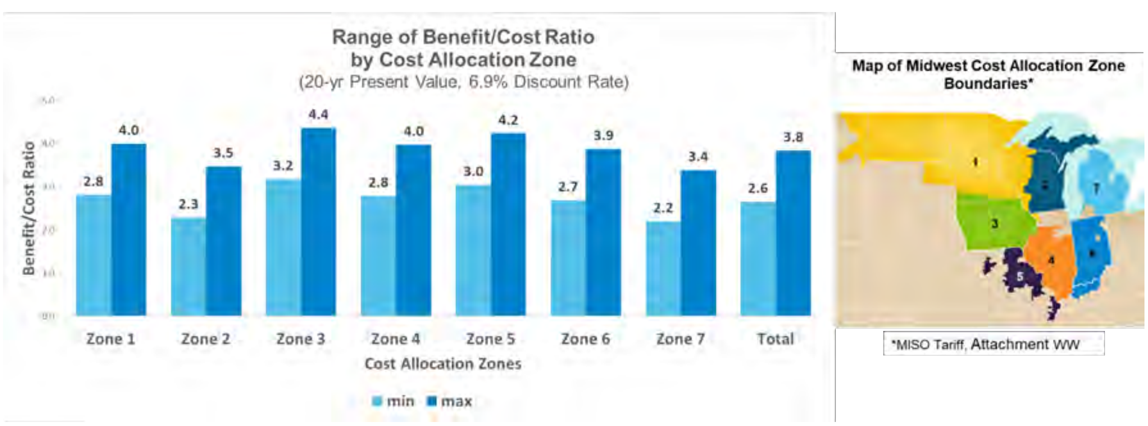


Figure 1-3: Distribution of benefits to Cost Allocation Zones in Midwest (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP study was initiated in 2020, and the LRTP Tranche 1 Portfolio Report is the first iteration of MISO's findings and recommendations. This report identifies reliability challenges in the Midwest Subregion associated with MISO's Future 1.

Efforts on Tranche 2 will be underway in the second half of 2022 and will continue to focus on the Midwest Subregion and addressing the needs identified in MISO's Futures. Tranche 3 of the LRTP study will focus on identifying system needs in the MISO South Subregion, and Tranche 4 will look at the part of the system connecting the Midwest and South Subregions.

While the Tranche 1 Portfolio is the result of MISO's long-range planning process being executed for only the second time, the rapid change within the industry will require that it become a more routine aspect of the MISO planning process going forward.

2 History of MISO's Innovative Long Range Transmission Planning Process

The transmission grid, while not top of mind for many people, is a critical component of ensuring the lights come on when a switch is flipped, our favorite devices can be charged, and life-saving machines can operate. But even with that level of importance, transmission investments, especially on a large scale, are very difficult to undertake and are not very common in the United States currently. However, the clear direction of the industry, towards a cleaner energy future, requires investments of this nature. Fortunately, MISO has a proven process, experience, and an engaged stakeholder community to draw upon as we embark on this very difficult journey. This is not the first time we have been here, or successfully facilitated significant grid investment.

As a Regional Transmission Organization/Independent System Operator, MISO coordinates with its members to facilitate transmission system investments needed to ensure continued reliable and efficient delivery of least-cost electricity across the MISO region. This requires a continuous execution of MISO's recurring transmission planning process. The culmination of the extensive work executed during each 18-month planning cycle, including proposed new projects, are codified annually in a MISO Transmission Expansion Plan (MTEP). These plans have put in motion approximately $42 billion in transmission investments going back to 2003.

Section 1.2 of MTEP21 provides an overview of MISO's overall transmission planning process, so only the primary aspects are described here to provide high-level context. The process involves both top-down and bottom-up identification of issues and potential solutions associated with transmission system maintenance and enhancement. There are also several aspects, or objectives of different components of MISO's transmission planning process, including resolving grid reliability issues, transmission expansion needed to connect new generation resources to the grid, and reducing congestion on the system. Assessing these types of needs can occur as often as annually and involves looking out 5-15 years to identify near- and mid-term needs.

The overall process also includes a component that has been exercised less frequently, the long-range transmission planning (LRTP) process, which considers challenges projected in the 20 year and beyond timeframe. Given the extensive lead time associated with large-scale transmission investment, this process is designed to be responsive to situational grid needs and utilized when incremental transmission system fixes, upgrades, and/or additions will not be sufficient to effectively or efficiently address those needs. These situations require that MISO consider the range of potential future states, the implications of those outcomes for the industry, and the transmission system needs this will create. Those potential future scenarios serve to provide bookends for the uncertainty that exists when planning this far out.

The inaugural iteration of MISO's long range planning process culminated in the first-of-its-kind portfolio of projects being approved by the MISO Board of Directors in 2011. Beginning in 2007, in response to an increase of individual Renewable Portfolio Standards within MISO states, MISO began the initial execution of the LRTP process to mitigate the significant impact on the future generation mix and the reliability of the system. During this multi-year effort, a new project type — Multi-Value Project (MVP) — was developed. As codified in the MISO Tariff, a project must meet one or more of the following criteria to be included in an MVP portfolio:

> *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade.*
>
> *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*
>
> *Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.*

As the criteria demonstrate, economic benefits are a significant part of the requirements for these types of projects. Given the regional scope of these projects, the level of investment, and the uncertainty associated with the time horizon, a strong business case is paramount. The types of economic benefits that could be used to meet these criteria were defined through collaboration with stakeholders. Those benefits are:

- *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be* *realized through reductions in both transmission congestion and transmission energy losses. Production cost savings can also be realized through reductions in Operating Reserve requirements.*

- *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*
- *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*
- *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*
- *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the Transmission System and related to the provisions of Transmission Service.*

The ground-breaking work executed during this process culminated in a nearly $6 billion portfolio, with a projected 1.8-3.1 benefit-to-cost ratio, being approved by the MISO Board of Directors in 2011. MISO was required to periodically reassess the projected benefits to determine if modifications to the MVP criteria were necessary. Each of those analyses found that the projected benefits remained consistent with, and were sometimes greater than, initially estimated, as shown in Figure 2-1. This, along with the fact that all but one of the 17 MVP projects are currently (as of June 2022) in service and fully utilized, demonstrates the effectiveness of MISO's value-based planning process and the use of future scenarios to bookend uncertainty and identify robust solutions, and to project benefits.

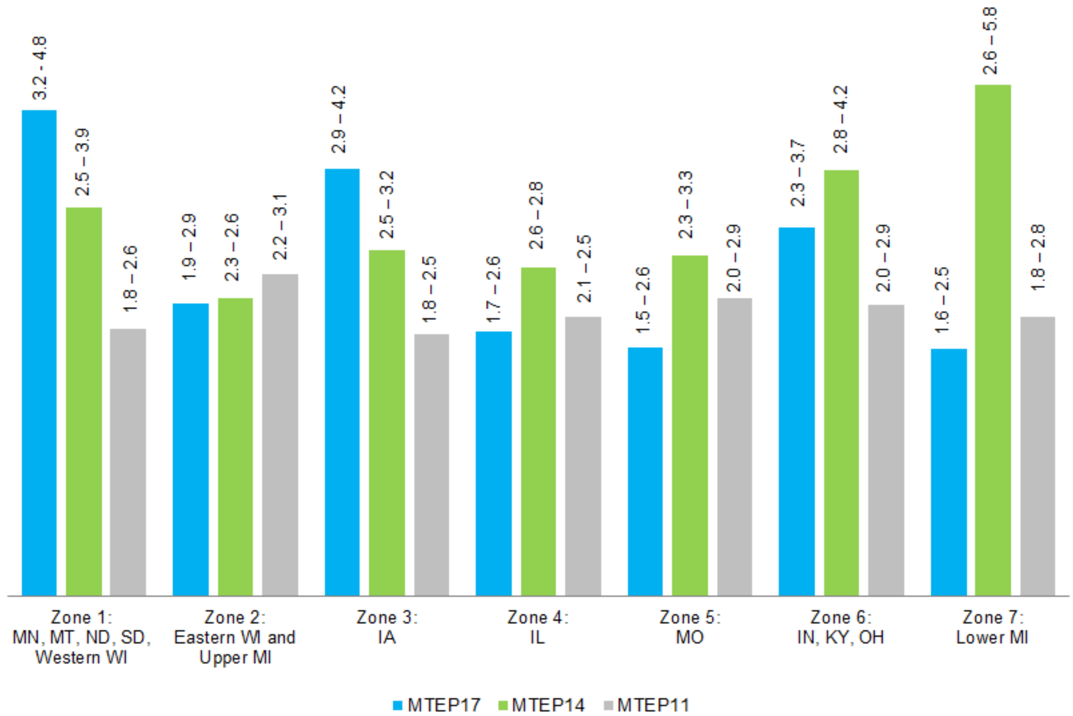


Figure 2-1: Zonal benefit to cost ratios for the original MTEP11 MVP Analysis and subsequent MTEP14 and MTEP17 Triennial Reviews

In the years immediately following the approval of the MVP portfolio, the level of annual investment put forward in MTEP reports returned to historical levels of approximately $1.5 billion annually. Upgrades or replacements of aging assets, and the added investment associated with the integration of the South Subregion have contributed to the annual average investment rising to $3.4 billion over the last five years, but still well below the level approved in 2011 with the MVPs. While this increased rate of investment is strengthening the grid in the MISO Region, it is not reflective of the magnitude of change that has been occurring across the landscape during this time.

3 The Long Range Transmission Planning Component of MISO's Broad-Based Response to Current Industry Change

The generation mix evolution in the MISO Region that drove the need for the MVP portfolio didn't end with that portfolio's approval. In fact, the pace towards more renewables has increased since that time. Progressively increased carbon-free and clean energy goals set by MISO member utilities, state and municipal government policies and customer preferences continue to drive growth in wind, solar, battery storage and hybrid projects. MISO made a number of incremental changes to its markets, tools, and processes along the way to mitigate the early impacts of this change. However, beginning in 2016, the challenge was becoming obvious and more difficult to mitigate.

Change Drivers and Implications Contributing to Aligning Interests

Over the last several years, MISO began to experience operational situations that required the use of emergency procedures, even outside of the summer period when demand peaks occur, and supply becomes strained. In the real time horizon, when resource margins are projected to be significantly low, MISO will begin to implement the steps in its emergency procedures in an attempt to gain access to additional resources. While not having to make a single emergency declaration in the two years preceding 2016, 41 such emergency declarations have been required since 2016. These events are largely the result of reduced generation capacity due to the retirement of conventional generation as the fleet has transitioned toward more renewable resources and greater reliance on Load Modifying Resources for meeting capacity requirements.

Figure 3-1: Historical MISO MaxGen Alerts, Warnings, and Events

In response to this growing challenge, MISO launched the Resource Availability and Need (RAN) initiative to understand the drivers and identify a variety of changes to markets and resource adequacy process solutions to generation availability issues.

At the same time, and driven by the ongoing fleet shift, MISO executed a multiple-year study called the Renewable Integration Impact Assessment (RIIA) to deepen its understanding of the implications of more renewable generation on the system. This assessment identified inflection points, or renewable energy penetration levels where challenges would get increasingly more complex. It also identified key risks that would result, including insufficient transmission infrastructure.

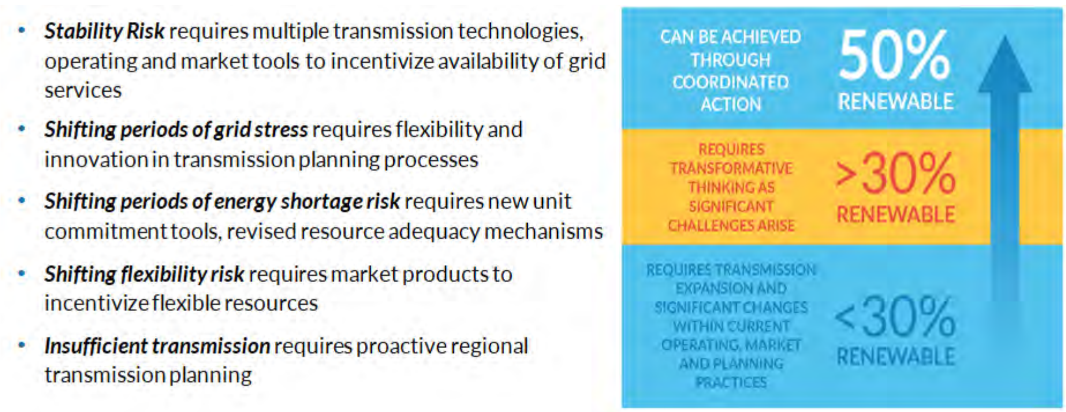


Figure 3-2: RIIA Study Identified Key Risks with increasing levels of Renewable Energy

The timing of when the region would reach these inflection points was then uncertain. However, an additional driver emerged that accelerated the pace towards more renewables: a growing customer preference for clean energy. MISO began to see a growing number of member utilities and state policies incorporating decarbonization goals into their resource fleet strategies. Around this same time another trend was emerging on the demand side as well. The movement towards electrification will have a significant impact on electricity demand, which has in recent years been relatively stable.

This level of uncertainty makes it very difficult to plan for the future with confidence. However, as demonstrated with the development of the 2011 MVP portfolio, MISO has an existing process to effectively manage these types of risks. MISO, in collaboration with stakeholders, establishes future planning scenarios to understand the economic, policy and technological impacts on future resource needs. Starting in 2019, MISO examined three future scenarios to define and bookend regional resource expectations over the next 20 years (MISO Futures Report[1]). These Futures recognize the widespread clean energy goals of states and utilities within the region, as well as the associated rapid pace of regional resource transformation.

[1] MISO Futures Report

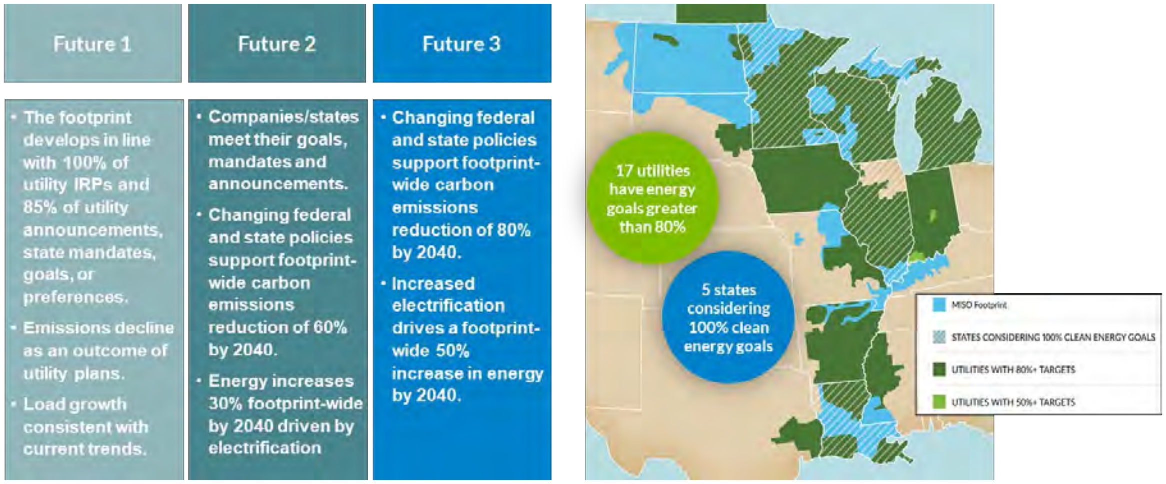


Figure 3-3: MISO Futures Key Drivers

MISO's Reliability Imperative Response: The Long Range Transmission Planning Initiative

These future scenarios reflect the significance of the changes the region must prepare for, and similar to the situation facing the region back in 2007, incremental changes will no longer be adequate. The magnitude of landscape changes has created an imperative for transformational changes across MISO's markets, planning, operations, and technology. The Reliability Imperative Report[2] documents the collection of related initiatives that address the growing risks and that are required to enable member resource plans and strategies. MISO, members, regulators, and other entities responsible for system reliability all have an obligation to work together to address these challenges.

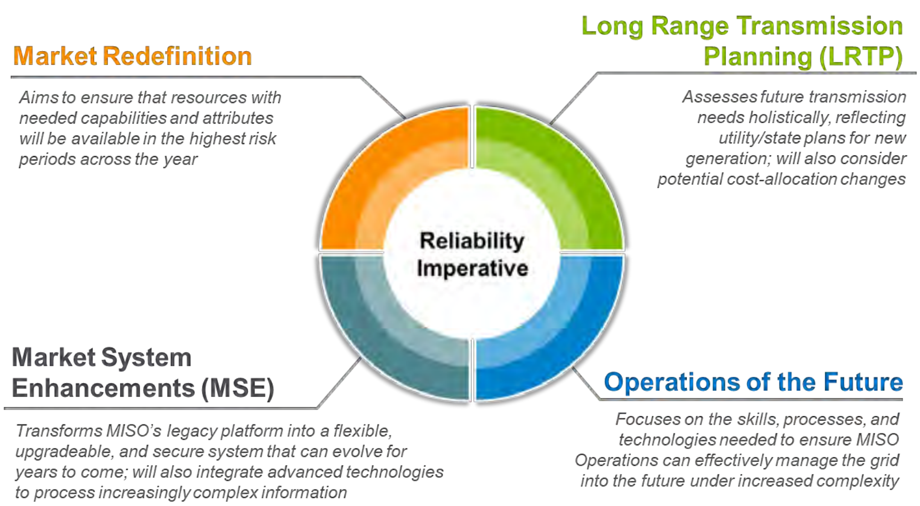


Figure 3-4: MISO's Reliability Imperative Key Initiatives

[2] MISO'S Response to the Reliability Imperative

As work has been underway, an additional risk emerged that has increased the urgency associated with progressing these initiatives. An increase in the frequency of extreme weather events is exacerbating the risks and challenges that originally drove the need for the Reliability Imperative. These types of scenarios can force a large number of generators out of service in a local area, putting reliability at risk. This has contributed to the emergency procedure declarations over the last several years (Figure 3.1).

Robust Business Case for Long-Range Transmission Plan

As the region faces both a changing resource fleet and increased prevalence of extreme weather events, the ability to move electricity from where it is generated to where it is needed most becomes paramount. One needs only to consider the need for increased power flow within and between regions during Winter Storm Uri in February 2021 to understand the importance of transfer capability. MISO can leverage its large geographic footprint and diversity of resources to ease some of these challenges. However, adequate transmission infrastructure is key.

With the landscape once again shifting and expected to do so even more dramatically in the future, the transmission planning aspect of the Reliability Imperative includes the second execution of MISO's long-range transmission planning process. The MISO LRTP initiative, introduced to stakeholders in August 2020 to invite their collaboration, provides a regional approach to transmission planning that addresses future challenges of the resource fleet evolution and electrification. The transformational changes occurring in the industry necessitate the identification of transmission solutions to ensure continued grid reliability and cost-effective transmission investments that will serve future needs.

The objective of LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply
- **Cost Efficient** – enable access to lower-cost energy production
- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice

LRTP is designed to assess the region's future transmission needs in concert with utility and state plans for future generation resources.

LRTP is a multi-year effort to address the myriad and complex issues associated with the significant resource transformation underway. Because there is urgency to keep pace with this rapid evolution, MISO is seeking to recommend projects identified in the LRTP effort over several MTEP cycles as work progresses. While it is important to move quickly, MISO must ensure reliable power delivery for customers with investment decisions that appropriately balance generation and transmission solutions on a regional scale to ensure the best cost outcomes for customers.

LRTP continues the MISO Value-Based Planning approach to extend value beyond the traditional planning processes to achieve a more efficient comprehensive long-term system plan.

Tariff Requirements

The needs driving the LRTP portfolio, the scope of the projects and types of benefits they enable aligns relatively well with those of the MVP portfolio and the associated MVP tariff requirements are being applied for the LRTP. The criteria to meet the project definition are listed in their entirety in Section 2, and in summary are: 1) enable the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws, 2) provide multiple types of economic value, with a benefit-to-cost of 1.0 or greater, or 3) address at least one reliability issue and provide at least one type of transmission-based economic value.

LRTP Cost Allocation Aligned with Beneficiaries

A condition that must be met prior to any transmission investment being approved is to determine how the costs will be allocated. The original MVP ruleset established a cost allocation methodology of spreading costs footprint-wide on a load-ratio share basis. With the initial Tranche of LRTP projects identified to address reliability issues in MISO's Midwest Subregion only, this approach was not going to meet FERC's requirement of costs spread roughly commensurate with benefits.

To address this risk, MISO proposed a modified MVP methodology where costs could be spread to a subregion only, if the projects within the portfolio primarily provide benefits to a single subregion. This proposal was approved by FERC on May 18, 2022 with a May 19, 2022 effective date. With FERC's approval the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion.

4 Rigorous, Collaborative Approach Ensures Robust LRTP Solutions

With this being the second execution of MISO's long-range transmission planning process, it was not groundbreaking, but it is no less significant than the first execution that developed the 2011 MVP portfolio. In fact, the landscape changes being planned for are much more significant now and require prompt action to address the fast pace of transformational changes occurring in the industry. The initial tranche of LRTP projects was developed in a focused effort to deliver a set of least regrets solutions that would be ready to address needs in the next 10 years.

While the process was executed in significantly less time, the quality of the analysis and commitment to identifying robust solutions was not sacrificed. This portfolio of projects represents over 2,000 miles of transmission, a significant level of investment unprecedented in the industry and will have its benefits and costs shared broadly. Given this backdrop, it is incumbent on MISO to perform a rigorous analysis to ensure we identify a robust set of projects that most effectively and efficiently resolve the identified issues and future system needs.

The process MISO follows to identify projects and create a portfolio is designed to result in a business case that justifies the investments. As described in Section 3 of this report, the first step in this process is to create potential future scenarios, or Futures, to essentially establish a target for our planning efforts. In some situations, the Futures could bookend very different directions for the region's generation fleet due to uncertainty around energy policy and other factors. However, given the current clear trends that include Members and States increasingly establishing clean energy goals, the continued retirement of fossil fueled resources from the system, and a growing trend toward electrification, the current set of futures reflect different progressions or the velocity of change in that singular direction.

MISO developed a long range conceptual regional transmission plan to explore and further study possible solutions needed to address future transmission needs. The conceptual plan serves as a set of solution ideas that guide the development of candidate transmission projects that meet the objective of long range planning to achieve reliable and economic delivery of energy in a range of future scenarios. Reliability analysis is conducted on a series of study models that represent various system conditions and dispatch patterns to identify issues. MISO then evaluates the candidate projects and potential alternative solutions developed by MISO and stakeholders to identify the most effective transmission investments to address the issues and performs an economic analysis that factors into selecting the best of the options. Section 5 of this report is a detailed walk-through of the reliability analysis that was undertaken, with the results provided in Section 6.

Once the portfolio of projects is identified, MISO then calculates the economic benefits created by the portfolio. The primary objective of the LRTP projects was to address reliability issues identified in the planning studies that considered a range of system conditions. However, while transmission investments are usually built for a specific purpose, the value that any particular investment brings can extend well beyond addressing the singular issue driving it. That is especially true for investments like the LRTP projects, whose regional scope and high voltage levels can enable significant economic benefits as well.

While the objective of LRTP is primarily focused on the need for reliable energy delivery, the analysis of economic benefits is essential to the demonstration of value of the portfolio as required by the Tariff for eligibility as regionally cost shared projects. The economic benefit types that can be assessed were identified in Section 2 of this report in the discussion on Multi-Value Projects, which the LRTP will be categorized as. The specific metrics that were used to determine the economic benefits of the LRTP portfolio are:

- Congestion and fuel savings – LRTP projects will allow more low-cost renewables to be integrated, which will replace higher-cost resources and lower the overall production cost to serve load.
- Avoided local resource capital costs – LRTP projects will allow renewable resource build-out to be optimized in areas where they can be more productive compared to a wholly local resource build out.
- Avoided future transmission investment – LRTP projects will reduce loading on other transmission lines, in some cases preventing lines from becoming overloaded in the future and thus avoiding the need to upgrade those lines.
- Reduced resource adequacy requirement – LRTP projects will expand transfer capability, which will in certain situations increase the ability for a utility to use a new or existing resource from another part of the MISO region, rather than construct one locally, to meet its resource adequacy obligation.
- Avoided risk of load shed – the LRTP portfolio will increase the resilience of the grid and lower the probability that a major service interruption occurs.
- Decarbonization – the higher penetration of renewable resources that the LRTP portfolio will enable will result in less CO_2 emissions.

The methodology used to calculate each of these economic benefits and the results are the focus of Section 7.

As described in Section 8 of this report, the allocation of LRTP portfolio costs is spread broadly to the entire Midwest Subregion. The Federal Energy Regulatory Commission requires that transmission costs associated with investments of this nature be allocated roughly commensurate with how the benefits are realized. Given the large-scale of the LRTP projects and the fact that they span the Midwest Subregion, benefits flow to the entire subregion. To illustrate this and demonstrate support of FERC's guidance, Section 8 shows the benefits by MISO Cost Allocation Zone.

Given the expected continued key role of natural gas generation, volatility in the price of natural gas can have a significant impact on the cost of producing electricity. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than natural gas. Chapter 8 includes a sensitivity analysis performed using a range of natural gas prices to demonstrate the robustness of the LRTP Tranche 1 Portfolio across a range of scenarios.

5 LRTP Tranche 1 Portfolio Development and Scope

Most good plans result not from a single work effort, but rather develop from refinements to an effective starting point. The latter characterizes the path to the LRTP Tranche 1 Portfolio. In anticipation of reliability needs in a future with growing renewable penetration and load consumption, MISO developed an indicative transmission roadmap of potential transmission expansions throughout the region for both Future 1 and a combined Future 1, 2, and 3. The roadmap provides an indication of the potential magnitude of transmission expansions that may be needed to maintain reliable and efficient operations under the expected Futures and candidate transmission solutions to be used as a starting point in determining potential projects. This roadmap was developed by MISO planning staff as extensions of the existing grid that would provide for logical connections that could increase connectivity, close gaps between subregions, and support a more robust and resilient grid by enabling the delivery of energy from future resources to future loads and increasing the reliance on geographic diversity to manage the increased dispatch volatility and uncertainty associated with the future resource fleet. The indicative roadmap is not a final plan but instead a starting point for considering solutions to transmission issues expected.

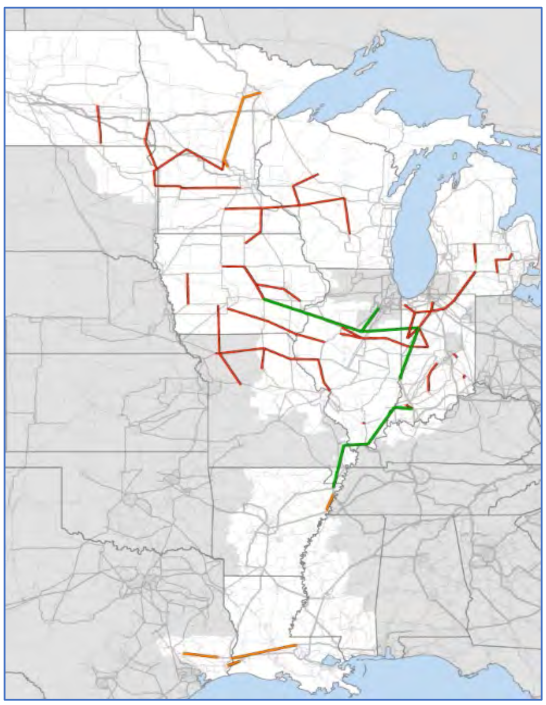


Figure 5-1: Future 1 Indicative Roadmap

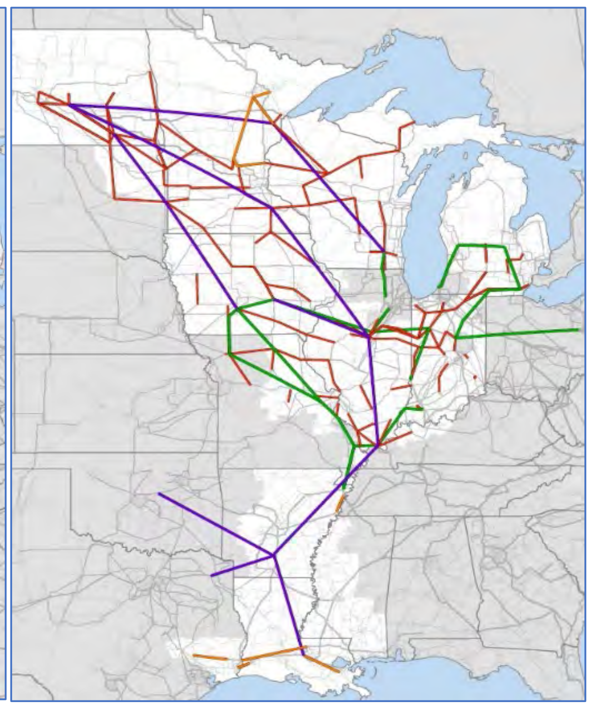


Figure 5-2: Futures 1, 2, & 3 Indicative Roadmap

The initial tranche of the LRTP is focused primarily on enabling the resource expansion and load forecasts associated with the 10- and 20-year timeframe under Future 1 in the Midwest

Subregion. In Future 1, the most significant aspects are resource retirements and increased renewable penetration.

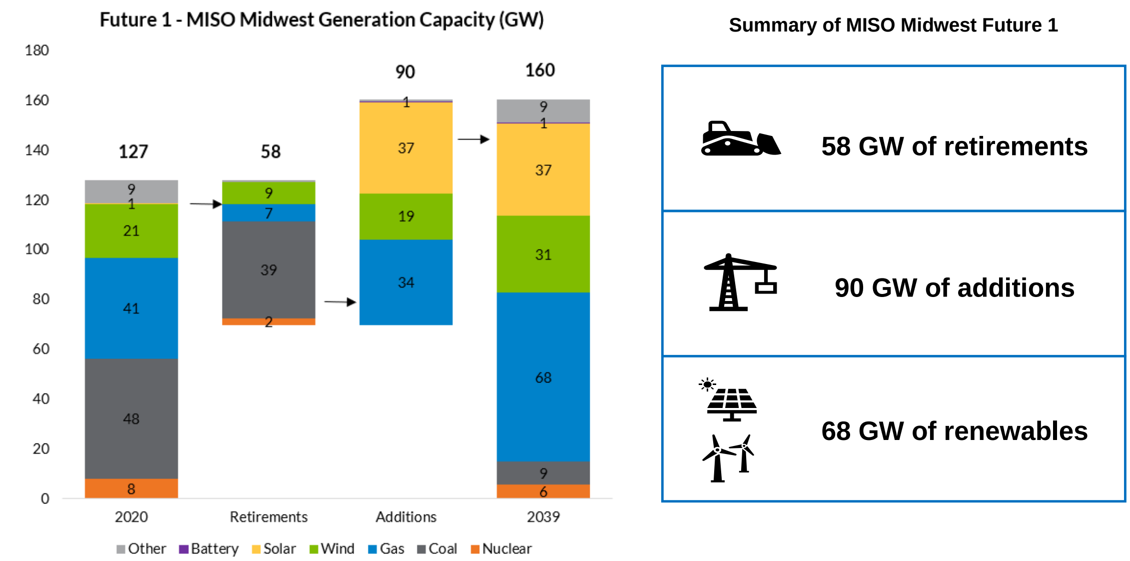


Figure 5-3: Future 1 changes in Generation Capacity for Midwest Subregion

In Futures 2 and 3, higher levels of resource retirements and renewable resource penetration coupled with higher levels of electrification will be significant. Later tranches of LRTP will focus more on Future 2 and Future 3 scenarios.

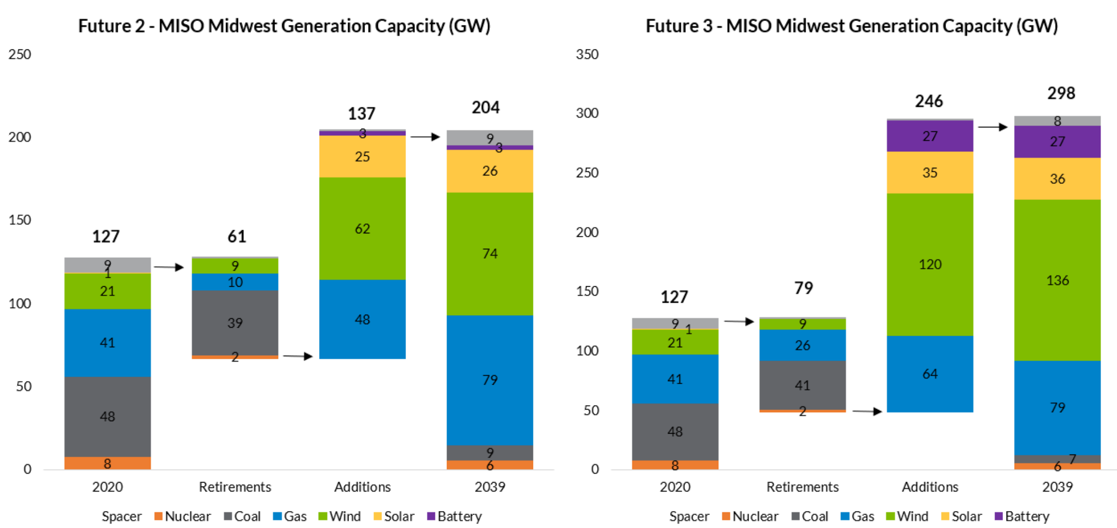


Figure 5-4: Future 2 & 3 changes in Generation Capacity for Midwest Subregion

Reliability Study Scope

MISO developed snapshots of system stress under a Future 1 resource expansion in the 10-year and 20-year timeframe. These scenarios, or base cases, vary based on season of the year, time of the day, load level, and coincident availability of renewable resources. MISO then used the scenarios to test the impact of the LRTP Tranche 1 Portfolio.

Model	Season	Hours	Range of dates and hours used to characterize the model	LRTP modeling definition of load level
1	Summer Peak	Day	Summer :6/21 to 9/20 Hours ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served. (system load >=90 percentile during day)
2	Summer Peak	Night	Summer: 6/21 to 9/20 Hours NOT ending 7:00 to 22:00 EST	The Summer Peak demand expected to be served (system load >=90 percentile during night)
3	Fall/Spring Light load	Day	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Day)
4	Fall/Spring Light load	Night	Fall: 9/21 to 12/20 Spring: 3/21 to 6/20 Hours NOT ending 8:00 to 21:00 EST	Fall / Spring Light load within 50-70% of Summer Peak (Night)
5	Fall/Spring shoulder load	Day	Fall: 9/21 to 12/20 Spring à 3/21 to 6/20	70% to 80% of the Summer Peak Load (Day)
6	Winter Peak	Day	Winter: 12/21 - 3/20 Hours ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during day)
7	Winter Peak	Night	Winter: 12/21 - 3/20 Hours NOT ending 8:00 to 19:00 EST	The Winter Peak demand expected to be served (system load >=90 percentile during night)

Table 5-1: Temporal and load parameters for defining base models

The purpose of the reliability study is to ensure the MISO Transmission System can reliably deliver energy from future resources to future loads under a range of projected load and dispatch patterns associated with the Future 1 scenario in the 10-year and 20-year time horizon. The analysis includes ensuring transmission system performance is reliable and adequate with both an intact system and one where contingencies have occurred, and high regional power transfer scenarios that result when geographic diversity must be relied upon to help manage dispatch volatility and uncertainty. Techniques used to analyze projected performance with and without the proposed transmission solutions included steady state contingency analysis to identify thermal loading and voltage issues under normal and contingency conditions, transfer analysis to ensure MISO can rely upon geographic diversity to manage renewable dispatch volatility and uncertainty and voltage stability analysis to ensure voltage stability in the Midwest subregion.

Steady-state contingency analysis is performed to identify any thermal and voltage violations that exist in the seven base reliability cases for each of the 10-year and 20-year models. The analysis requires simulation of the MTEP20 NERC Category P0, P1, P2, P4, P5, and P7 contingency events and selected NERC Category P3, P6 events. Facilities in the Midwest Subregion were monitored for steady state thermal loading in excess of 80% of applicable ratings and for voltage violations per the Transmission Owner voltage criteria.

Transfer analysis is performed to test for robust performance under varying dispatch patterns. The LRTP transfer study includes eight transfer scenarios to assess import requirements in situations where unexpected loss of renewable and thermal resources could occur due to changing weather conditions.

Scenario	Description	Objective	Resource	Sink
1	Central to Iowa	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	All Gen. Local Resource Zones (LRZ) 4-6	Wind in LRZs 1&3
2	MISO to Michigan	Support resource deficient areas due to unexpected drops in high concentration areas of renewables	Renewables in LRZs 1-6	Renewable in LRZ 7
3	Michigan to MISO	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZ 7	Renewables in LRZs 1-6
4	Iowa/MN to MH	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Manitoba Hydro load
5	MISO West to Wisconsin	Support resource deficient areas due to unexpected high magnitude resource outages due to extreme weather events (Uri, polar vortex) – renewable or thermal	Renewables in LRZs 1 and 3	Renewables in LRZ 2
6	Central Renewables to rest of MISO Midwest	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	Renewables in LRZs 4-6	Gen. in LRZs 1,2,3,7
7	MISO Midwest to Central Region	Ensure reciprocal export capability to MISO Subregions in high resource deficiencies	Gen. in LRZs 1,2,3,7	Gen. in LRZs 4-6
8	MISO West to East across the Mississippi	Eliminate export limitations from high renewable concentration areas to support deficient regions of MISO	MISO West of the Mississippi River Renewables in LRZs 1,2,3,5	MISO East of the Mississippi river Gen. in LRZs 4,6,7

Table 5-2: Transfer Scenarios

Economic analysis supports reliability analysis evaluation of project candidates as needed for selecting the preferred solutions. Production cost simulations analyze the impact of the proposed project on production costs to assess how the economic performance of a project compares to other alternatives that have been proposed. These results are used to supplement the reliability analysis results and provide an additional measure of economic performance to aid in selecting the preferred solution.

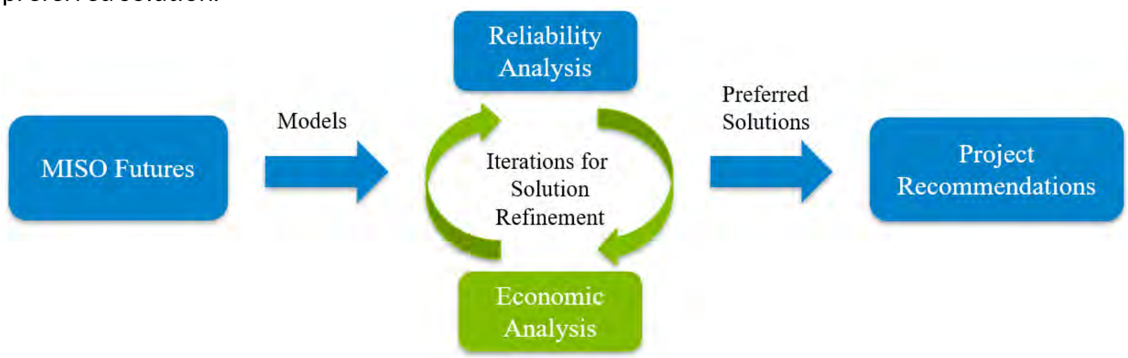


Figure 5-5: Iterative Solution Refinement

The results of the reliability analysis contained in Section 6 of this report discusses the detailed results from this iterative selection process and explains the reasons for selecting the preferred solution, including a summary of any significant economic analysis findings, for projects to be included in the LRTP Tranche 1 Portfolio.

6 LRTP Tranche 1 Projects and Reliability Issues Addressed

The reliability studies were performed on the Future 1 power flow models to assess the system performance and identify any necessary upgrades to ensure reliable energy delivery under different load and dispatch patterns. Analysis of the Future 1 10-year and 20-year base case models without the LRTP Tranche 1 Portfolio indicated numerous thermal and voltage violations throughout the Midwest Subregion. Additionally, transfer analysis was performed to assess transfer capability and identify limiting constraints to be addressed to assess effectiveness of projects under broader future assumptions. Variations of candidate projects identified in the LRTP indicative roadmap were studied to determine areas of focus for project development.

It is important to understand that LRTP is not a NERC compliance study whereby every issue identified must be resolved according to NERC standards and requirements. A NERC compliance study, which is more local in nature in terms of modeling assumptions, is different than the approach taken in a long-range transmission planning study. From that perspective, the LRTP reliability solution testing sought to find solutions that provided a balance between issues resolved and cost to mitigate. This included discounting some issues, for example, as more local in nature or others that will be dealt with in the generator interconnection process. It is also related to the fact that more study work will be done in the next tranches using other Futures and additional needs will be dealt with at that time.

In doing so, MISO used the roadmap as a starting point for testing system solutions but also looked to alternative solutions either from MISO or submitted by stakeholders. Several alternatives have been considered for the Tranche 1 effort. The final portfolio represents those solutions that provided the best fit solution. It is also important to note that the ability to efficiently use existing corridors in developing transmission is a key element. As final solutions were developed, the ability of those solutions to use existing system right of way was a key consideration. Ultimately though final routing will be determined by the applicable state and/or local authorities.

Project selection involved detailed analysis in five geographic focus areas:

- Dakotas and Western Minnesota
- Minnesota – Wisconsin
- Central Iowa
- Northern Missouri Corridor
- Central-East Corridor

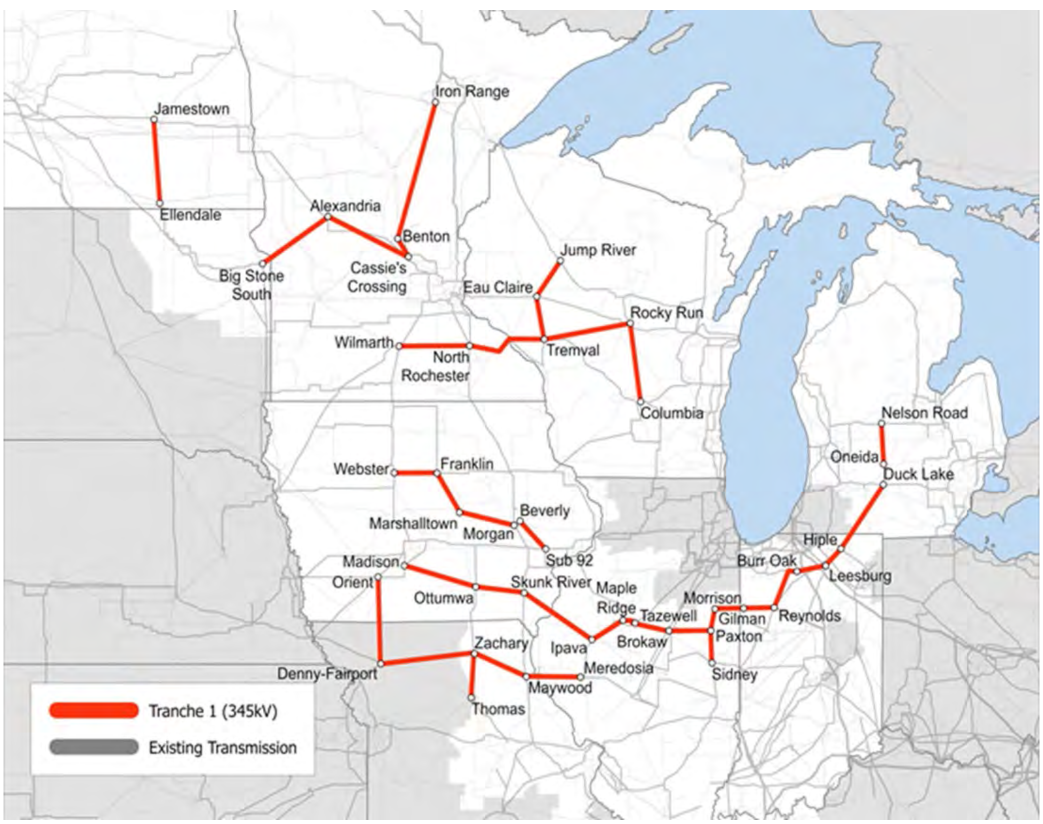


Figure 6-1: LRTP Tranche 1 Transmission Portfolio

Dakotas and Western Minnesota

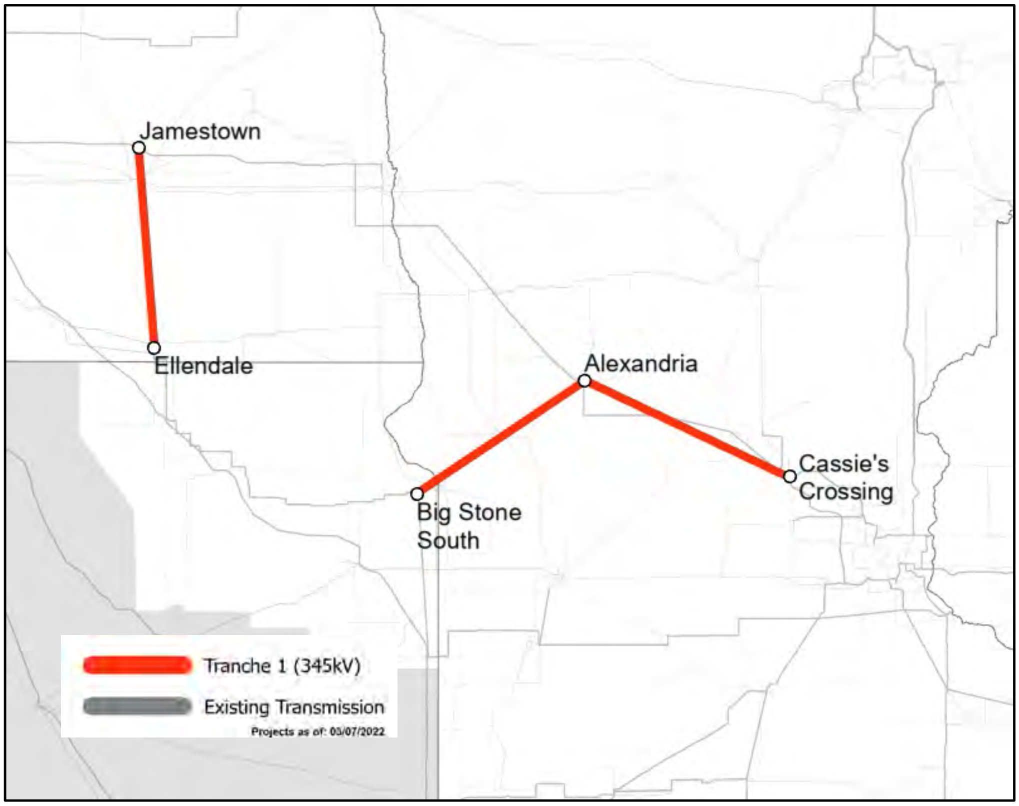


Figure 6-2: Dakotas and Western Minnesota Final Solution

Projects:
Jamestown - Ellendale 345 kV
Bigstone – Alexandria – Cassie's Crossing 345 kV

Rationale:
The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and into Minnesota. Under shoulder load levels and high renewable output, this energy has a bias towards the Southeast into the Twin Cities load center. During peak load, particularly in Winter, this system is a key link for serving load in central and northern Minnesota. The 230 kV system is at capacity and shows many reliability concerns not only for N-1 outages in Future 1, but also for system intact situations. The 345 kV lines in the area provide additional outlets for the Dakotas by tying two existing 345 kV systems together. These lines unload the 230 kV system of concern and improve reliability across the greater Eastern Dakotas and Minnesota.

Issues Addressed:

The Dakotas and Western Minnesota project addresses many thermal and voltage issues for Western Minnesota and Eastern Dakotas. Most notable, the 230 kV system from Ellendale and Big Stone South to Fergus Falls is relieved for all N-1 and N-1-1 outages, as you can see in Figure 6-3 geographically. The solid green lines in Figure 6-3 depict Transmission Lines which no longer have overloads because of the project with circles depicting transformers that are relieved. Voltage depression was seen for a wide geographical area along the South Dakota, North Dakota, and Minnesota border typically described as the Red River Valley Area. Table 6-1 describes overloads seen in Future 1 for the Dakotas and Western Minnesota area which are relieved by the Big Stone South – Alexandria – Cassie's Crossing & Jamestown – Ellendale project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

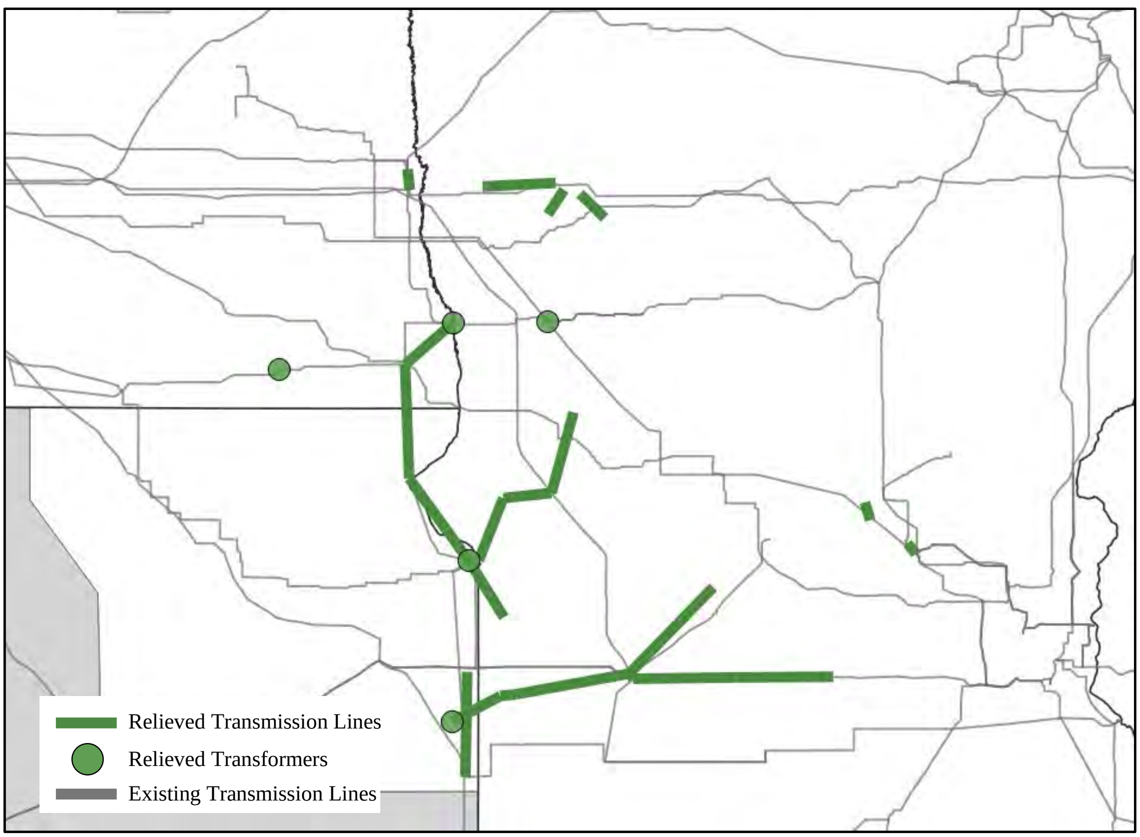


Figure 6-3: Dakotas and Western Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	40	214	70	209
230 kV Lines	18	157	25	153

Table 6-1: Elements with thermal issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	97	0.80	91	0.81
345 & 230 kV Buses	23	0.80	30	0.81

Table 6-2: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the OTP area (620)

Alternatives Considered:
Big Stone South – Alexandria 345 kV & Jamestown – Ellendale 345 kV
Without double circuit to Cassie's Crossing there are new N-1 issues around Alexandria.

Big Stone South – Hankinson – Fergus Falls 345 kV & Jamestown – Ellendale 345 kV
Solves overloads of concern on 230 kV system around Wahpeton but creates new issues on the 230 kV and 115 kV system around Fergus Falls.

Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV
Reduces nearly all overloads of concern but not to the extent of the preferred project.

Big South – Alexandria 345 kV & Big Stone South – Hazel Creek – Blue Lake 345 kV & Jamestown – Ellendale 345 kV.
Combination of alternative 1 and 3. This alternative creates new overloads on the 115 kV system around Alexandria but fully relieves reliability issues of concern as the preferred project. However, as this is a combination of alternatives, the southern circuit to Blue Lake (Alternative 3) does not add enough additional value over the preferred project.

Big Stone South – Breckenridge – Barnesville 345 kV & Jamestown – Ellendale 345 kV
Solves many issues in the area of concern without any new issues. However, there are still a few key overloads on the key 230 kV system around Wahpeton which are not solved by this alternative.

Western Minnesota - Dakota

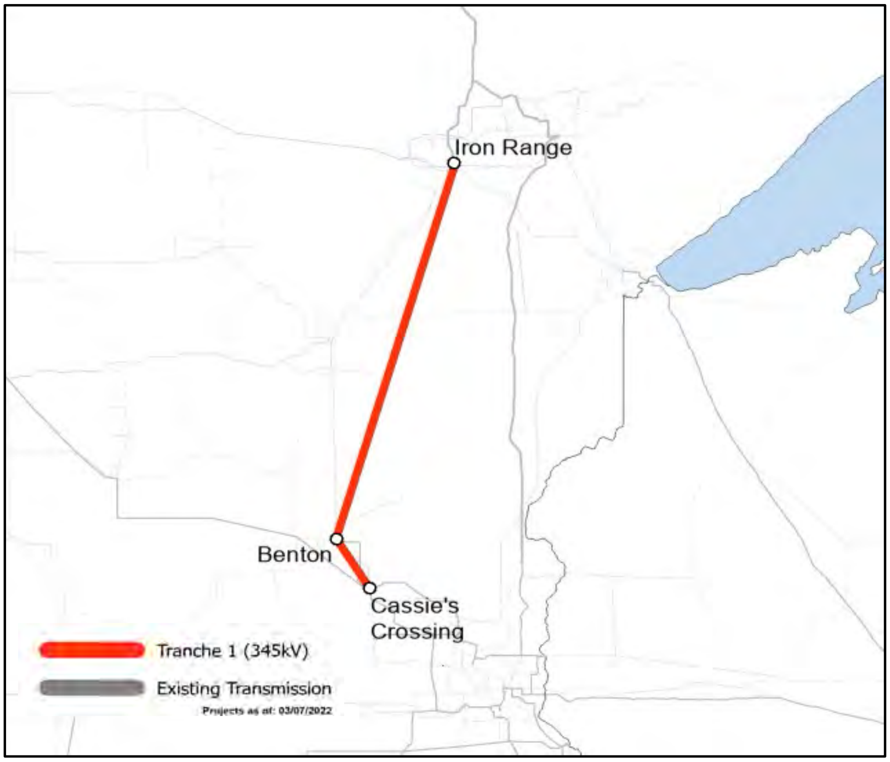


Figure 6-4: Western Minnesota - Dakota Final Solution

Project:
Iron Range – Benton - Cassie's Crossing 345 kV

Rationale:
Minnesota has and is projected to continue to undergo fleet change. This generation shift has resulted in central and northern Minnesota to have a drastic decrease in generation resources creating a large geographical area to be served by only 115 kV and 230 kV transmission. Central to northern Minnesota has moderate load, with heavy load being further north relating to iron mining operations. During the winter, Minnesota load increases significantly. This causes strain on the widespread 115 kV and 230 kV system as power is needing to get from the twin cities to the north to serve load. This large geographical disparity in generation and weak transmission causes voltage stability concerns for a majority of the Minnesota system north of the Twin Cities. The Iron Range – Benton – Cassie's Crossing 345 kV line provides a second low impedance path for power flow from southern Minnesota to the north. This unloads and relieves the 115 kV and 230 kV issues seen and relieves voltage stability concerns.

Issues Addressed:
Iron Range – Benton – Cassie's Crossing 345 kV prevents many thermal and voltage issues on the lower voltage system in central and northern Minnesota, especially for situations where the single 500 kV line heading north from the Twin Cities is lost. Under heavy winter loading situations central and northern Minnesota suffer from voltage collapse issues during transfer scenarios.

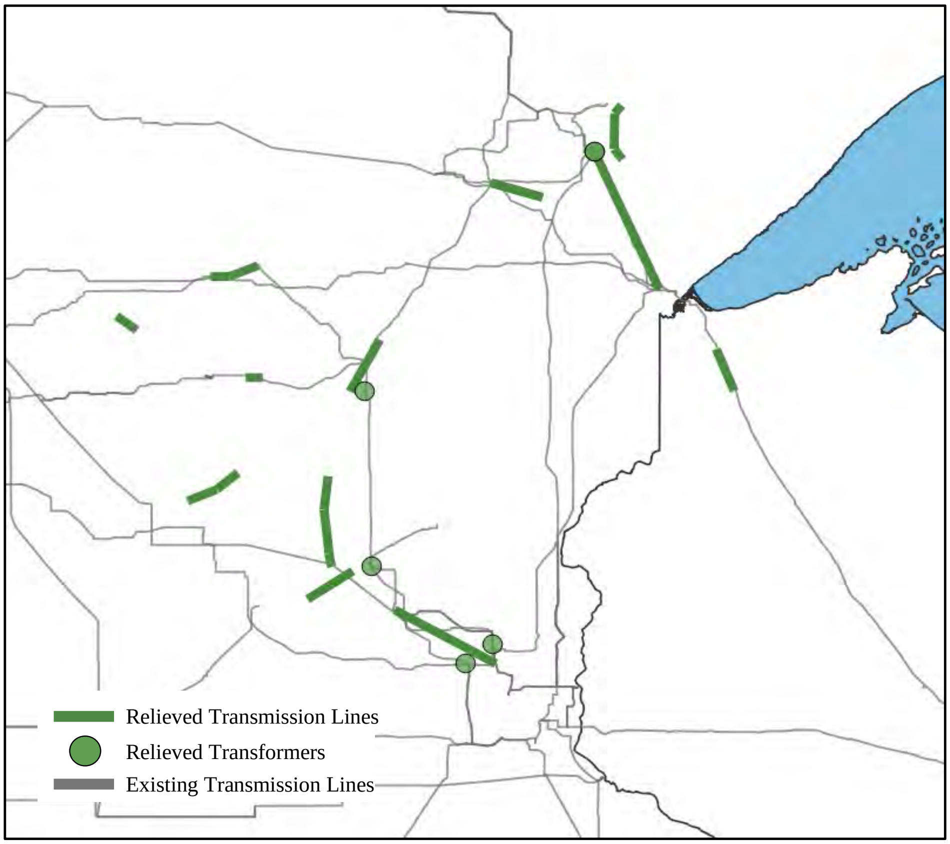


Figure 6-5: Central and Northern Minnesota map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

The chart below is a graph of the Red River Valley area (northwestern Minnesota) voltage after loss of the 500 kV line from Chisago to Forbes for varying levels of transfer to the north through Minnesota. Without Iron Range – Benton – Cassie's Crossing voltage collapses for transfers less than 500 MW. Post project, transfers through Minnesota can be greater than 2000 MW without voltage collapse.

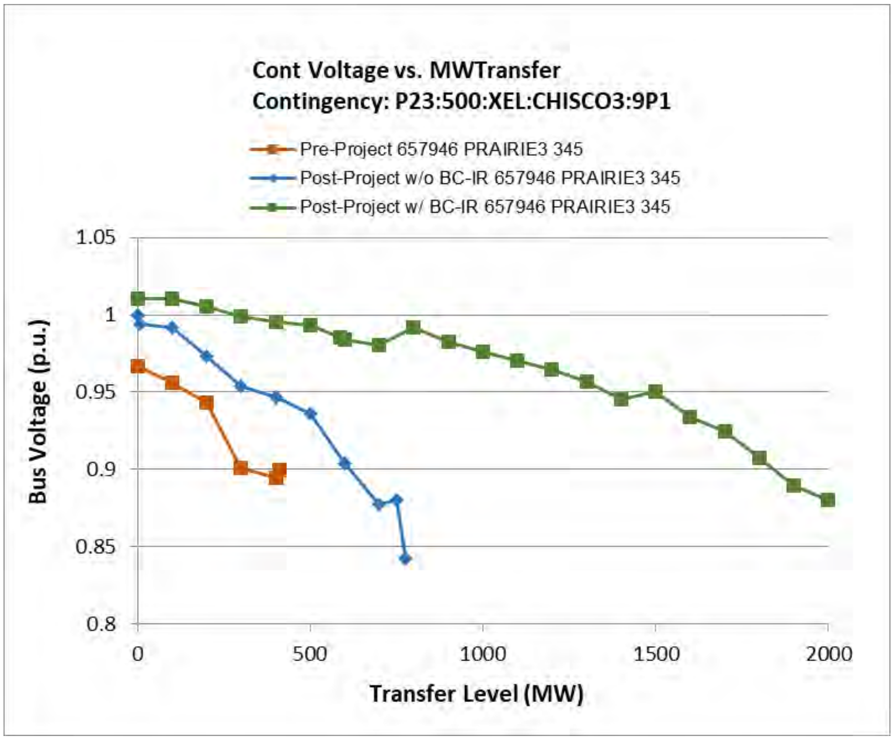


Figure 6-6: Voltage Stability Analysis P-V curve for Minnesota transfers after losing the 500 kV lines from Chisago to Forbes

The tables below describe thermal and voltage issues relieved by the Iron Range to Benton to Cassie's Crossing 345 kV line. Figure 6-5 shows geographically lines and transformers relieved by the project. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	15	110	25	165

Table 6-3: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Minimum p.u. voltage Pre-Project	Count Elements	Minimum p.u. voltage Pre-Project
All	23	<0.80	105	0.80
230 kV Buses	3	0.93	18	0.85

Table 6-4: Elements with voltage issues relieved by the Dakotas and Western Minnesota project in Future 1 power flow cases for the MP area (608).

Alternatives Considered:

1. Iron Range – Alexandria 500 kV
2. Iron Range – Arrowhead 500 kV
3. Iron Range – Bison 500 kV
4. Iron Range – Benton 500 kV

A study interface was created to analyze alternatives to the Iron Range – Benton – Cassie's Crossing line. This interface is defined as the northern Minnesota interface (NOMN) which includes the Forbes – Chisago 500 kV line and six underlying 230 kV lines which connect central and northern Minnesota to the Twin cities and North Dakota. This interface was determined to study the system's ability to meet two primary goals.

1. Understand an operating limit for central and northern Minnesota to ensure the ability to serve peak load with a 10% or greater stability margin.
2. Maintain the ability to serve the existing 1400 MW Manitoba Import Limit while also achieving goal 1.

The proposed project, Iron Range – Benton County – Cassie's Crossing double circuit 345 kV meets both goals. Alternatives 1 (Iron Range – Alexandria 500 kV), 2 (Iron Range – Arrowhead 500 kV), and 3 (Iron Range – Bison 500 kV) do not achieve the above goals. Alternative 4 (Iron Range – Benton 500 kV) achieves both goals, however the double circuit 345kV was chosen for many reasons over the 500 kV as described below:

a. Double circuit 345 kV has a higher capacity
    i. 500 kV: 1732 MVA
    ii. 345 kV: 1195 MVA per circuit (2390 MVA Total)
b. Double circuit 345 kV is cheaper per mile compared to 500 kV
    i. 500 kV: $3,036,384 per mile
    ii. 345 kV: $2,829,742 per mile
c. A double circuit creates two lines for N-1 protection
d. Series compensation near Riverton would allow for easier 345/230 kV conversion for future expansion and support for central Minnesota as 345 kV to lower kV is more standard in the Minnesota area than 500 kV to lower kV transformation

Minnesota – Wisconsin

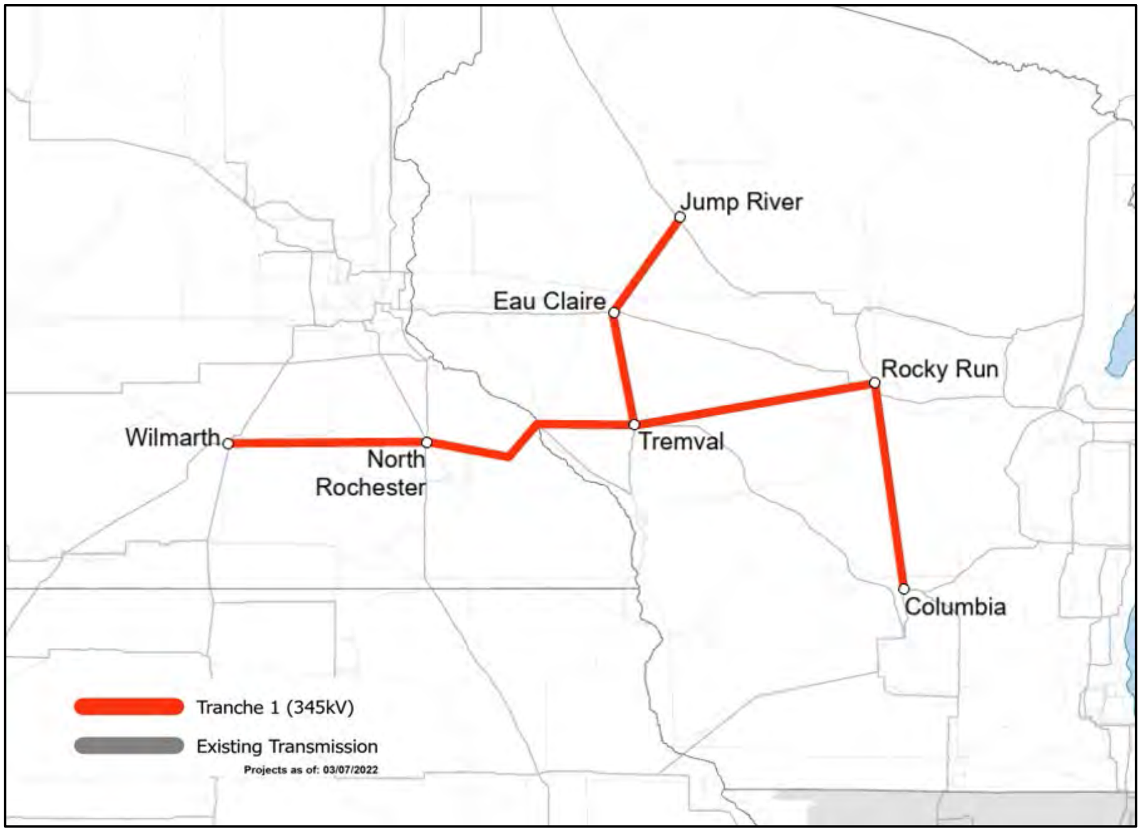


Figure 6-7: Minnesota-Wisconsin Final Solution

Projects:
Wilmarth – North Rochester – Tremval – Eau Claire – Jump River 345 kV
Tremval – Rocky Run – Columbia 345 kV

Rationale:
The transmission system in southern Minnesota is a nexus between significant wind and renewable resources in Minnesota and North and South Dakota, the regional load center of the Twin Cities, and transmission outlets to the East and South. In a future with significant renewable energy growth, MISO sees strong flows West to East across Minnesota to Wisconsin and a need for outlet for those renewables in times of high availability to deliver that energy to load centers in MISO. The Minnesota to Wisconsin projects relieve constraints in the Twin Cities metro area due to high renewable flow towards and past the Twin Cities load center. The projects also reinforce the outlet towards load centers in Wisconsin, providing relief of congestion as well as easing both thermal loading and transfer voltage stability.

Issues Addressed:

The Minnesota – Wisconsin series of projects work together to relieve a number of related issues. Table 6-5 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 Portfolio attributed to the Minnesota – Wisconsin set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-8.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
	Count Elements	Max % Loading Pre-Project	Count Elements	Max % Loading Pre-Project
All	39	95-132%	96	95-151%
345 kV Lines	6	98-119%	9	97-120%
345/xx kV Transformers	9	97-132%	12	95-132%

Table 6-5: Summary of elements relieved by the Minnesota – Wisconsin projects in Future 1 power flow cases

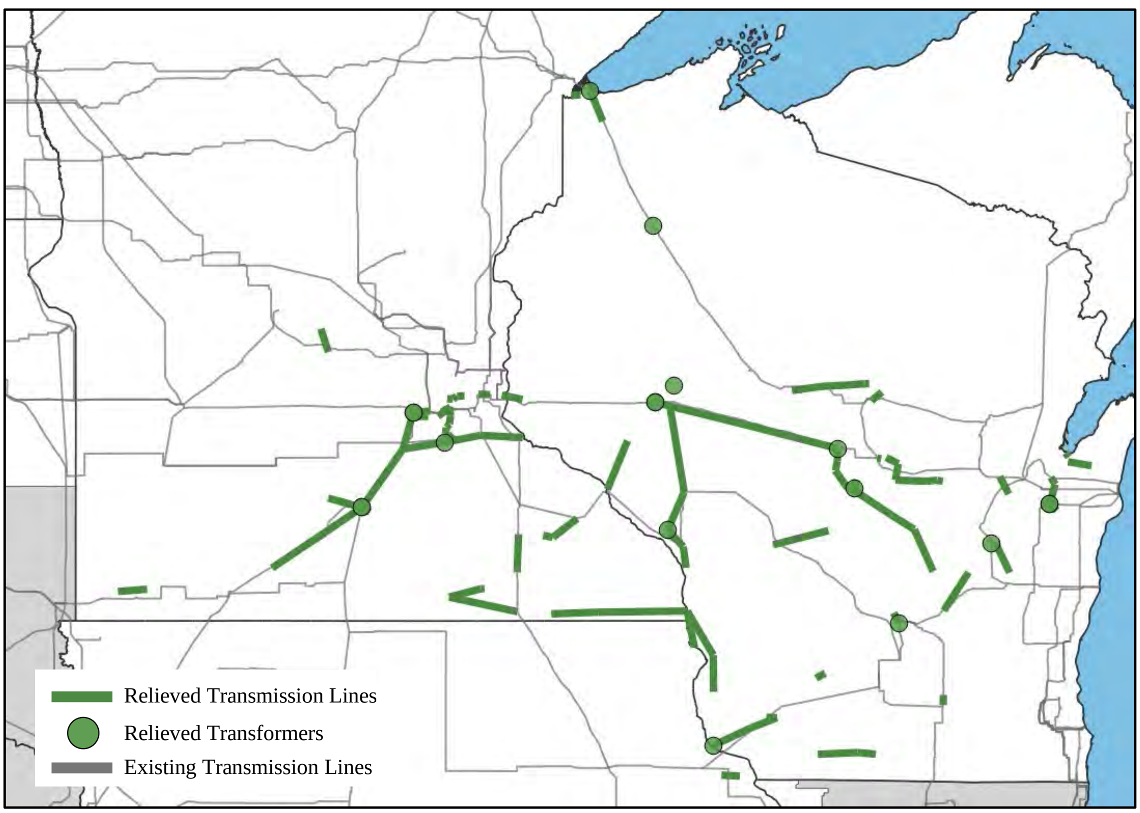


Figure 6-8: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Wilmarth to North Rochester parallels a number of 345 kV lines across the Southern Twin Cities that are heavily loaded under high renewable output from southwestern Minnesota and northwestern Iowa. In doing so, it relieves several 345 kV lines and 345/115 kV transformers in the region including Wilmarth – Shea's Lake – Helena – Chub Lake 345 kV and 345/115 kV transformers at Wilmarth and Scott County. These increased flows cause new congestion and overloads on the existing Crandall – Wilmarth 345 kV line. This project includes the rebuild of that line. If uprated, the congestion savings associated with the Wilmarth – North Rochester circuit specifically, and the rest of the Minnesota – Wisconsin project generally, increase significantly.

The connection out of North Rochester towards Tremval and east creates a lower impedance path that pulls power across Wilmarth – North Rochester and diverts power from other heavily loaded Twin Cities facilities, increasing the efficacy of that line. The sections from Tremval to Eau Claire and Jump River relieve loading on a handful of 161 kV and 115 kV facilities in Northwest Wisconsin. Those facilities increase the redundancy of the two Northern 345 kV circuits across Wisconsin and relieve overloads seen on one of the Eau Claire 345/161 kV transformers.

The new path from Tremval to Rocky Run to Columbia completes an outlet for renewable power flow across Wisconsin to the Madison and Milwaukee area load centers. These circuits also bolster voltage stability limited transfer capability across and into Wisconsin. It also relieves overloads on a variety of 345 kV and 138 kV facilities throughout central Wisconsin.

The traditional analysis of voltage stability for the voltage stability interface across Western Wisconsin uses a load to load transfer. MISO performed this analysis for a transfer using Local Resource Zone 2 (LRZ2, roughly comprised of ATC member companies in eastern and central Wisconsin) as the destination subsystem, to capture the impact of directly serving LRZ2 load. MISO measured the impact to voltage stability both with and without Tremval – Rocky Run and Rocky Run – Columbia segments are included in this project. The addition of these facilities adds 250 MW to the transfer capability. Figure 5-9 shows the post-contingent bus voltage for the most limiting bus and outage for either the pre-project or post-project case. Those buses and outages are:

Eau Claire 345 kV for loss of King – Eau Claire 345 kV
Eau Claire 345 kV for loss of Stone Lk. – Gardner Pk 345 kV
Briggs Rd. 345 kV for loss of Stone Lk. – Gardner Pk 345 kV

Both the steady state voltages and the final nose of the stability curve can be seen to improve, with the increase measured from either point being approximately 250 MW. MISO also reviewed this analysis for scenarios using a wide area load subsystem consisting of both Wisconsin load and loads further East in MISO's system. Those cases also showed an approximate increase of 250 MW in the low voltage and voltage stability limits of the system.

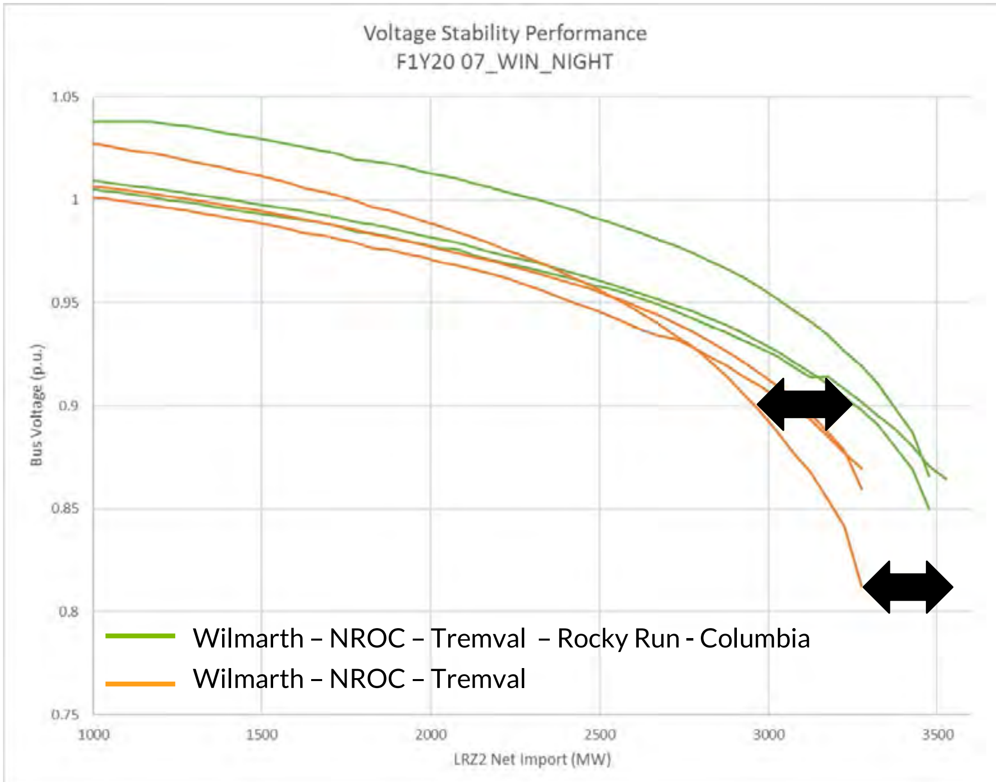


Figure 6-9: Voltage performance for key buses and outages for transfers into LRZ2.
Orange lines indicate buses and outages with just Wilmarth – North Rochester – Tremval 345 kV, while green lines indicate performance with Tremval – Rocky Run – Columbia 345 kV included as well

System Design Benefits of Tremval – Eau Claire – Jump River

To date there are three 345 kV lines that connect Minnesota to Wisconsin. The lines and their lengths are listed below:

Arrowhead – Stone Lake - Gardner Park:	220 Miles
King – Eau Claire – Arpin - Rocky Run:	183 Miles
North Rochester – Briggs Road – North Madison:	250 Miles

Assuming an average Surge Impedance Loading (SIL) value of approximately 400 MW for legacy 345 kV lines such as the ones above, the Safe Loading Limits on these three 345 kV long lines based on the St. Clair curve would be as follows:

Arrowhead – Stone Lake - Gardner Park:	460 MW
King – Eau Claire – Arpin - Rocky Run:	560 MW
North Rochester – Briggs Road – North Madison:	440 MW

Safe Loading Limits[3] were proposed to avoid or mitigate excessive operating risks by limiting the voltage drop along a transmission circuit to 5% or less while maintaining a Steady State Stability Margin of 30% or greater along the transmission circuit. The excessive 345 kV line lengths between Minnesota and Wisconsin result in safe loading limits for these 345 kV lines well below the thermal limits of the lines. Even more alarming is the fact that under an N-1 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall from 1,460 MW to 900 MW, and for an N-2 contingency, the combined Safe Loading Limit on the 345 kV MWEX lines would fall to 440 MW.

The addition of the fourth 345 kV circuit from Minnesota – Wisconsin will significantly improve the situation above by adding additional transmission capacity across MWEX. In the case of a North Rochester – Rocky Run line, the length and Safe Loading Limit of this additional 345 kV line would be as follows:

North Rochester – Rocky Run 345 kV Mileage:	162 – 187 Miles
North Rochester – Rocky Run Safe Loading Limit:	540 MW – 600 MW

While the fourth 345 kV circuit adds considerable benefit, for an N-2 contingency with the fourth 345 kV circuit added, the combined safe loading limit of the 345 kV circuits falls to about 900 MW.

An effective method to strengthen the four parallel 345 kV circuit is to add an intermediate connection between the four 345 kV circuits as close to the midpoint as possible. A major benefit of the Tremval 345 kV Substation and the Tremval – Eau Claire – Jump River 345 kV line is that under contingency conditions, the overall reduction in the combined Safe Loading Limit of the parallel 345 kV circuits is minimized. For example, for a loss of the Eau Claire – Arpin 345 kV circuit, a 345 kV connection remains between the King - Eau Claire 345 kV circuit, and the other three 345 kV lines across the MWEX interface. This not only mitigates loading issues on the transformers at Eau Claire, but also reduces the effective 345 kV impedance across the MWEX interface, which in turn increases the capacity and combined safe loading limit of the MWEX interface. In addition, because the King – Eau Claire 345 kV circuit is still connected at the midpoint of the MWEX interface, the distributed line capacitance associated with the King – Eau Claire 345 kV circuit is available to support voltages in western Wisconsin. Lower overall impedance coupled with higher distributed capacitance means a higher effective SIL for the MWEX interface under contingency conditions.

In summary, there are desirable benefits of tying together long lines at an intermediate point, and there are examples of this technique throughout North America. These types of system design benefits will be crucial to the success of the future transmission system to operate with reliability,

[3] Dunlop, R.D., Gutman, R., Marchenko, P.P., *Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines,* IEEE Transactions on Power Apparatus and Systems, Vol. PAS-98, No. 2, March/April 1979.

robustness, and resilience under a future with higher renewable generation penetration and electrification.

Alternatives Considered:

MISO reviewed a wide variety of project alternatives in the project focus area between Minnesota and Wisconsin – many of them submitted by stakeholders.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included Wilmarth – North Rochester – Tremval – Eau Claire – Jump River as well as a double circuit rebuild between Adams and North Rochester, and a new 345 kV line from Colby to Adams. MISO found that the Wilmarth – North Rochester segment was important for resolving Twin Cities area loading, and that the river crossing from North Rochester to Tremval and then Tremval to elsewhere in Northern Wisconsin was effective at both relieving loading across Western Wisconsin and boosting the effectiveness of Wilmarth – North Rochester by providing an outlet and a shorter electrical path towards load centers. The double circuit from North Rochester to Adams directly relieved loading on parallel facilities. Colby – Adams relieved some loading associated with a large amount of future generation sited at Adams, but the effects were very localized.

Several stakeholders submitted alternative projects along the "Southern Corridor". These included a line from Huntley to Pleasant Valley (between Adams and North Rochester), and from Adams to Genoa and Hill Valley. One stakeholder also submitted Colby – Adams as an alternative. MISO reviewed the performance of Huntley – Pleasant Valley and Colby – Adams as alternatives to the Wilmarth – North Rochester line. Colby – Adams by itself is not effective at reducing the West to East loading across Southern Twin Cities 345 kV facilities and shows little reliability value on its own. Huntley – Pleasant Valley, when combined with a double circuit rebuild between Pleasant Valley and North Rochester, resolved many but not all of the same 345 kV and 345 stepdown transformer overloads as Wilmarth – North Rochester. It also showed higher adjusted production cost savings when included in PROMOD simulations. However, the difference in production cost savings was less than the difference in increased cost of Huntley-Pleasant Valley to North Rochester. MISO sees Huntley – Pleasant Valley as a valuable project that may be helpful in reinforcing this region in future cycles of the LRTP study.

Another proposed stakeholder alternative was a line from Adams to Genoa and Hill Valley. MISO initially viewed this project as an alternative to North Rochester – Tremval – Jump River – Eau Claire. However, analysis showed these paths address different sets of reliability concerns, with the Adams – Genoa – Hill Valley project better addressing constraints across northeast Iowa and southern Wisconsin. When tied into Hill Valley, once the Hickory Creek – Hill Valley line is in service, this would effectively form an additional path parallel to Adams – Hazleton 345 kV, and relieve flows being pushed south across eastern Iowa. MISO is prioritizing a northern path (North Rochester – Tremval) in order to address the voltage stability interface and tie into load centers. For that reason, MISO does not propose pursuing Adams – Genoa Hill Valley at this time, but

MISO understands the project's value, especially when paired with Huntley-Pleasant Valley, to potentially reinforcing the region in future cycles of the LRTP study.

MISO initially viewed Tremval – Eau Claire – Jump River and Tremval – Rocky Run – Columbia as alternatives to each other, specifically due to their relationship to the existing voltage stability interface. After some review, though, MISO found them to be addressing separate but complementary sets of issues. Tremval – Eau Claire -Jump River has only a minor impact to the voltage stability performance but relieves a variety of constraints across northern Wisconsin, including several sub-345 kV facilities and some high loading on one of the 345/161 kV transformers at Eau Claire. Tremval – Rocky Run – Columbia has a more significant impact on the voltage stability performance and resolves a number of thermal constraints East of Tremval and Eau Claire. That complimentary performance is what prompted MISO's recommendation of both project segments. MISO also reviewed several variations on the Tremval – Eau Claire – Jump River segment, which proposed different endpoints along either North Rochester – Briggs Rd – North Madison 345 kV or Stone Lake – Gardner Park. MISO found that a line from Alma to Eau Claire would have very similar cost and perform just as well electrically, when compared to Tremval – Eau Claire. MISO sees Tremval as a better tie-in point, due to its more easterly location with better accessibility, which would position it as a better long term hub. A line from Eau Claire to Stone Lake, in comparison to Eau Claire – Jump River, would be significantly more expensive and MISO's screening showed that it was less effective at relieving thermal loading on lines that Eau Claire – Jump River successfully unloaded.

Central Iowa

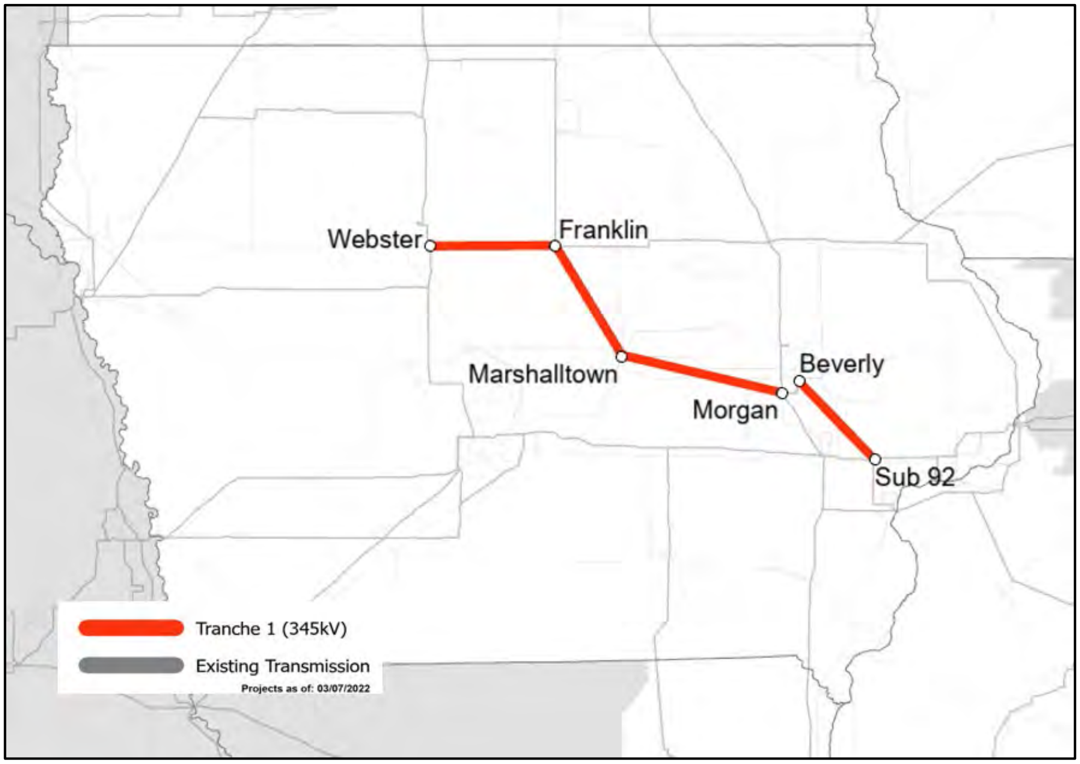


Figure 6-10: Central Iowa Final Solution

Projects:
Webster – Franklin – Morgan Valley 345 kV
Beverly – Sub 92 345 kV

Rationale:
Within MISO's system, the state of Iowa acts as both a major source of renewable energy and a gateway between MISO's members in the upper Midwest and MISO's Central planning region – Missouri, Illinois, and Indiana. Wind resources sited in Iowa are located primarily in the north and west parts of the state, and a large amount of wind resources are also located in western Minnesota and the Dakotas. During hours with high renewable output levels, power must flow southeast across and out of this region towards MISO load centers. In the LRTP models as well as in previous MISO planning studies, we have seen overloads and congestion across Iowa's central corridor. This project is intended to provide an additional 345 kV path southeast across the state, linking the high renewable region in the west with the Quad Cities load center and 345 kV outlets towards the rest of MISO. In doing so, we form a corridor both west-east and north-south across central Iowa.

Issues Addressed:
The Central Iowa projects between Webster and Sub 92 relieve a number of related issues. Table 6-6 summarizes overloads seen in the Future 1 models which are relieved by the LRTP Tranche 1 projects and attributed to the Central Iowa set of projects. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project. Those same elements are shown on a map in Figure 6-11.

	N-1 (P1, P2, P4, P5, P7)		N-1-1 (P3, P6)	
		Max % Loading		Max % Loading
	Count Elements	Pre-Project	Count Elements	Pre-Project
All	21	95-128%	34	96-132%
345 kV Lines	6	96-128%	7	97-128%
345/xx kV Transformers			4	96-127%

Table 6-6: Elements relieved by the Central Iowa projects in Future 1 power flow cases

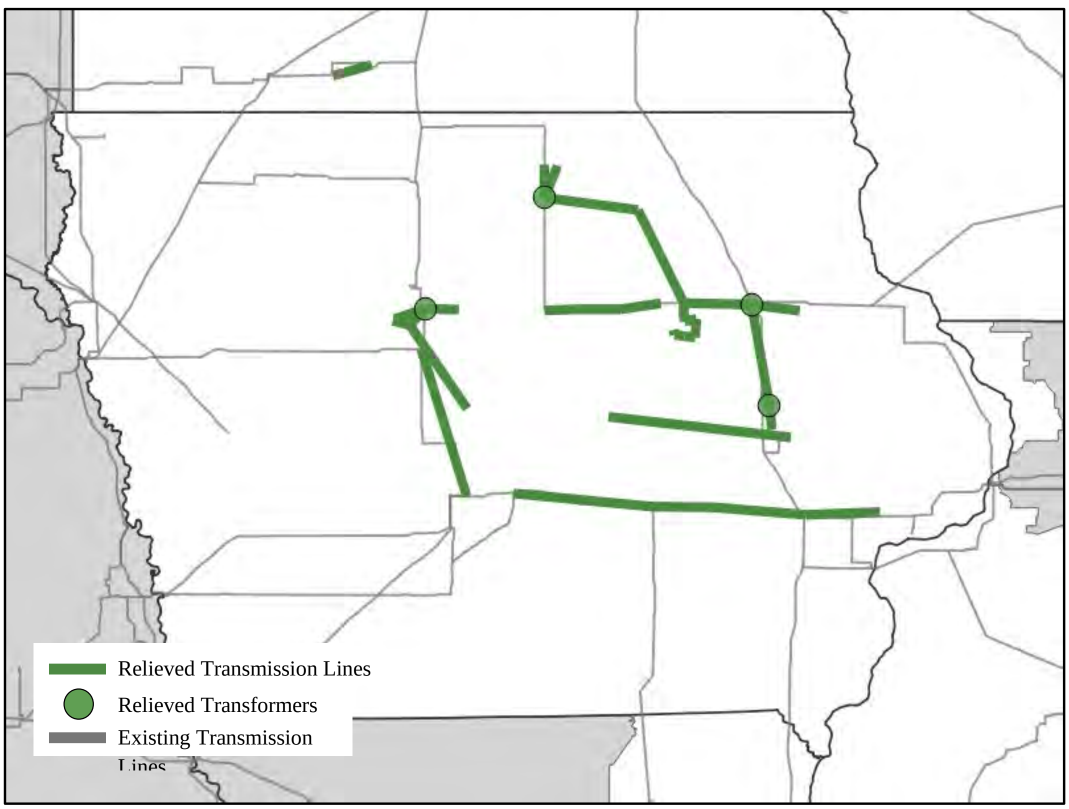


Figure 6-11: Map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Webster – Franklin – Marshalltown – Morgan Valley 345 kV forms a new connection from the 345 kV network in northwest Iowa (roughly west and north of Lehigh) to the north-south corridor across eastern Iowa (Adams – Hazleton – Hills – Maywood 345 kV). A previously approved line from Morgan Valley to Beverly stretches a few miles to the east, from which a new line can connect south from Beverly to Sub 92 345 kV. With that added segment, the overall path also completes a link from the northern 345 kV across central Iowa (Ledyard – Colby – Killdeer – Blackhawk – Hazleton 345 kV) down to a southern corridor (Bondurant – Montezuma – Hills – Sub 92 345 kV). By reinforcing the system in both directions, the project relieves loading on both west-east and north-south transmission facilities paralleling it. This loading is primarily seen in high renewable output cases, when renewable resources across western Iowa and southern Minnesota are producing high output. Lines seeing the greatest relief include Hazleton – Arnold 345 kV, Lehigh – Beaver Creek – Grimes 345 kV, and Montezuma – Diamond Trail – Hills 345 kV.

Alternatives Considered:

MISO reviewed several project alternatives and variations of the proposed central Iowa project set.

MISO began by reviewing the performance of an LRTP roadmap project against identified needs. This project included the proposed version of this project (Webster – Franklin – Marshalltown – Morgan Valley 345 kV and Beverly – Sub 92 345 kV), as well as some additional facilities. These included a new line between Marshalltown and Montezuma, with both the Franklin – Marshalltown and Marshalltown – Montezuma lines built as double circuit 345 kV. Two transformers were also sited at Franklin and Marshalltown. MISO found that the double circuit line sections did not relieve an appreciable number of additional facility overloads. MISO saw that the inclusion of a line from Marshalltown to Montezuma contributed minimal reliability benefit. Of the proposed transformers, MISO found no clear benefit to including 345/161 kV transformers at Franklin. At Marshalltown, a single 345/161 kV transformer can relieve some local loading on the lower kV system, but a second 345/161 kV transformer did not appear necessary.

MISO also reviewed a roadmap project in western Iowa that was submitted as a stakeholder alternative as well. Ida County – Avoca 345 kV would create a new line between Ida County in NW IA and a new 345 kV substation in SW Iowa adjacent to the existing Avoca 161 kV station. In comparison to the proposed project, this project was similarly successful at relieving loading on Lehigh – Beaver Creek – Grimes 345 kV and parallel facilities, but ineffective at relieving constraints east of that corridor, or generally east of the Des Moines metro area.

MISO reviewed portions of the Iowa – Michigan corridor project and the Iowa – Missouri project, in comparison to the proposed project. These facilities were not effective at relieving most of the facilities north and east of Des Moines that are relieved by the proposed project. They did relieve overloads in the Des Moines metro area and in southeastern Iowa and reduced some of the loading that the proposed project moved into southeastern Iowa. Within Iowa, MISO sees the reliability benefit of these two additional project groups as additive, in addition to the benefits of the central Iowa project.

East-Central Corridor

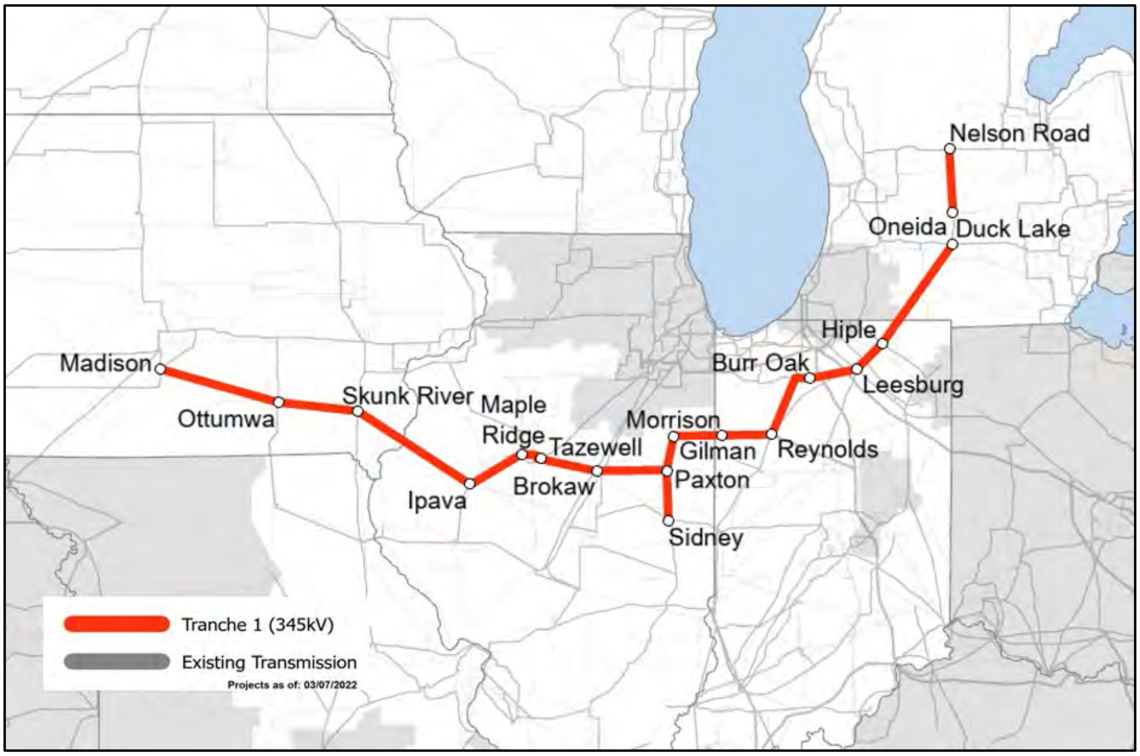


Figure 6-12: East-Central Corridor (Iowa to Michigan) Final Solution

Projects:
Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345 kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345 kV
Paxton – Sidney 345 kV
Oneida – Nelson Road 345 kV

Rationale:
MISO performed steady-state and voltage stability analyses on the proposed Iowa to Michigan LRTP projects. The steady-state results show the projects can mitigate severe thermal issues in Michigan, Indiana, Illinois, Missouri, and Iowa, with 77 monitored facilities addressed. The top 20 monitored facilities with worst-case contingencies are shown in Table 6-7.

The voltage stability results further demonstrate the effectiveness of the projects in improving voltage profiles and increasing transfer levels from West-East/East-West (Figures 6-14, 6-15, 6-16).

Issues Addressed:
The Iowa to Michigan projects addresses 600 thermal violations associated with 77 unique monitored facilities (Figure 6-13). For this metric, a constraint was considered relieved if its worst

pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the projects.

- 28 issues resolved in Michigan
- 16 issues resolved in Indiana
- 19 issues resolved in Missouri and Illinois
- 14 issues resolved in Iowa

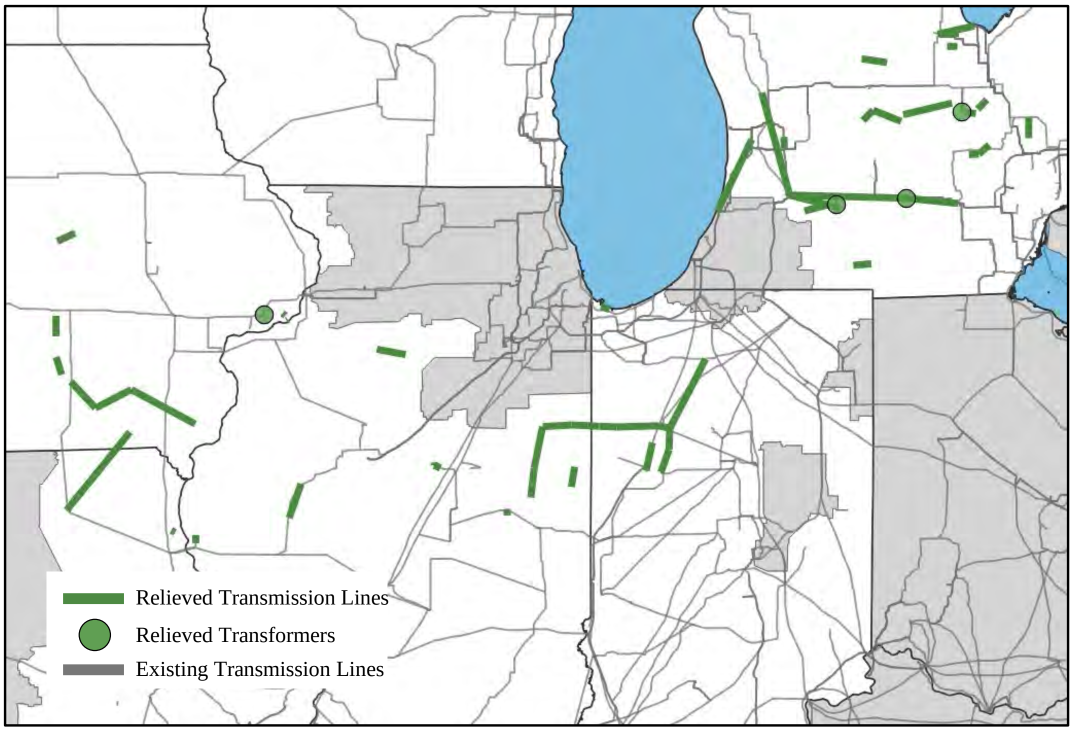


Figure 6-13: East-Central Corridor (Iowa to Michigan Line) map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

		% Loading	
Monitored Facility	**Area**	**Base + West LRTP***	**+ IA to MI Projects**
Goodland – Reynolds 138 kV Ckt. 1	NIPS	383	< 65
Reynolds 345/138 kV Transformer	NIPS	278	86
Reynolds – Magnetation 138 kV Ckt. 1	NIPS	264	67
Monticello – Magnetation 138 kV Ckt. 1	NIPS	263	67
Springboro – Monticello 138 kV Ckt. 1	DEI/NIPS	230	72
Lafayette 2 – Springboro 138 kV Ckt. 1	DEI	186	< 65
Morrison Ditch – Sheldon South 138 kV Ckt. 1	NIPS/AMIL	181	< 65
Gilman – Paxton East 138 kV Ckt. 1	AMIL	171	< 65
East Winamac – Headlee 138 kV Ckt. 1	NIPS	163	79

Westwood – South Prairie 138 kV Ckt. 1	DEI/NIPS	163	<65
Sheldon South – Watseka 138 kV Ckt. 1	AMIL	157	< 65
Burr Oak – East Winamac 138 kV Ckt. 1	NIPS	155	72
Island Rd 138 kV Bus	METC	155	67
Ottumwa 345/161 kV Transformer	ALTW	150	96
Poweshiek – Irvine 161 kV Ckt. 1	ALTW	144	98
Monticello – Headlee 138 kV Ckt. 1	NIPS	144	< 65
Gilman – Watseka 138 kV Ckt. 1	AMIL	136	< 65
Goodland – Morrison Ditch 138 kV Ckt. 1	NIPS	135	< 65
Tompkin – Majestic 345 kV Ckt. 1	METC/ITCT	133	82
Mahomet 138 kV Bus	AMIL	127	93

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-7: Top 20 thermal issues addressed by East-Central Corridor

Transfer levels increase and voltage profiles improve in Indiana, Missouri, and Michigan with the IA – MI projects (Figures 6-14, 6-15, and 6-16).

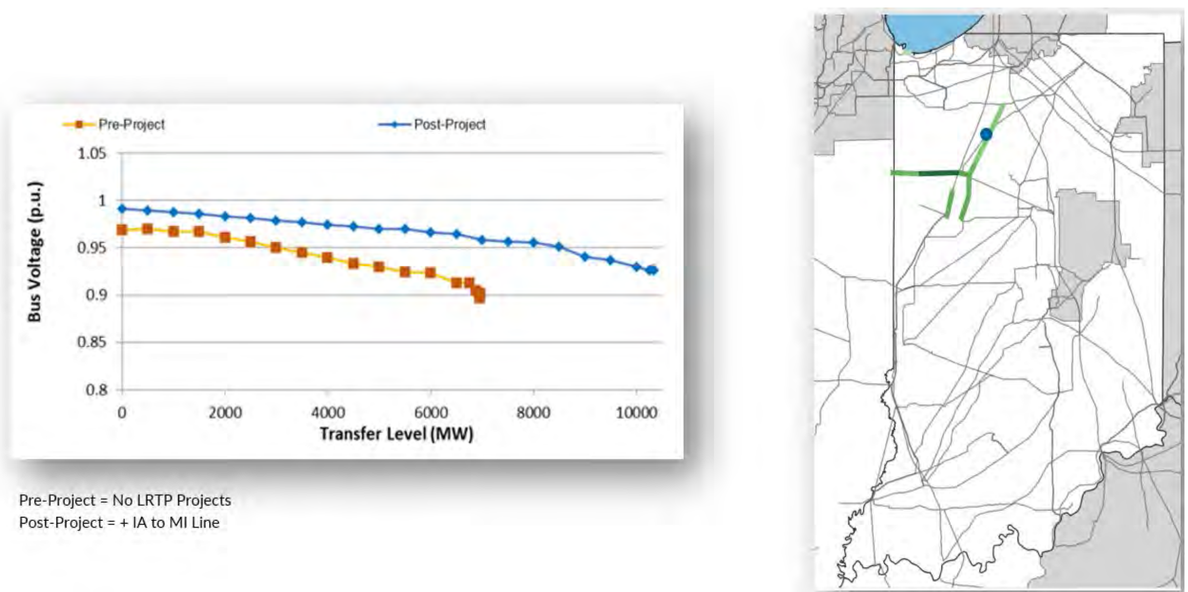


Figure 6-14: Improved voltage profiles in Indiana and Increased transfer levels with the Iowa to Michigan Projects

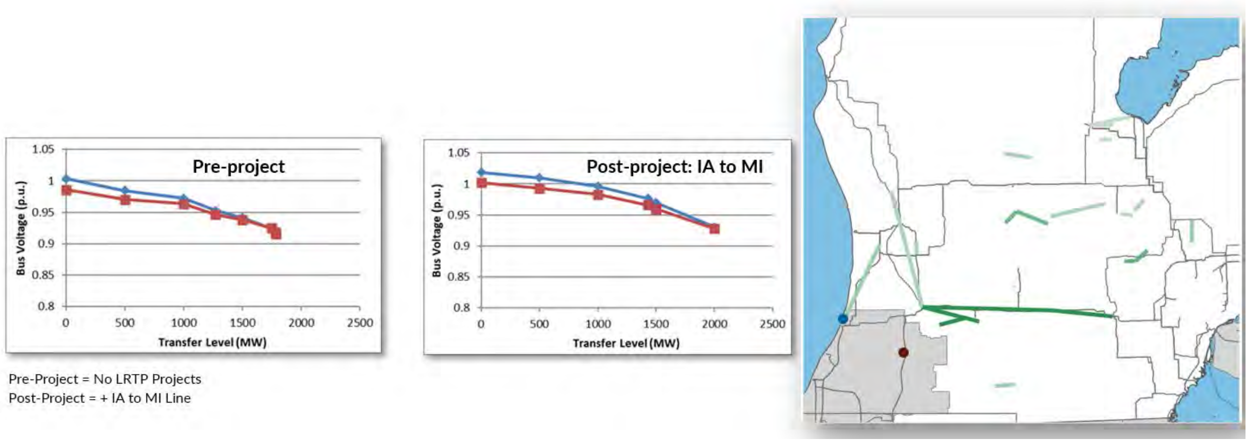


Figure 6-15: Improved voltage profiles in Michigan and Increased transfer levels with the Iowa to Michigan Projects

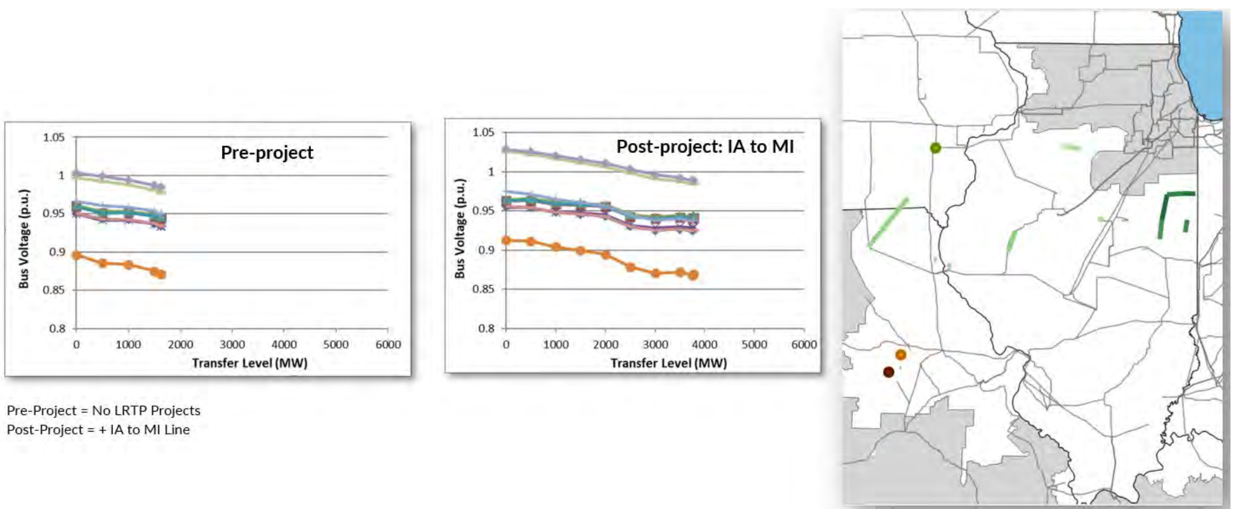


Figure 6-16: Improved voltage profiles in Missouri and Increased transfer levels with the Iowa to Michigan Projects

Alternatives Considered:

Two alternative solutions were received during the alternative submittal period, Duck Lake to Weeds Lake and Hiple to Duck Lake (MISO Main Proposal). Four additional alternatives were also evaluated. The alternative solutions resolve issues in Michigan, but fewer unsolved contingencies are associated with the road map project or MISO Main Proposal.

- Duck Lake to Weeds Lake, resolves 28 thermal issues:
- Hiple to Duck Lake (MISO main proposal), resolves 28 thermal issues
- Tie One Circuit in Argenta (resolves 28 thermal issues)
  - Argenta – Hiple
  - Argenta – Duck-Lake
- Oneida to Madrid (double-circuit), resolves 36 thermal issues
- Iowa to Indiana with Duck Lake Configuration, resolves 15 thermal issues

Northern Missouri Corridor

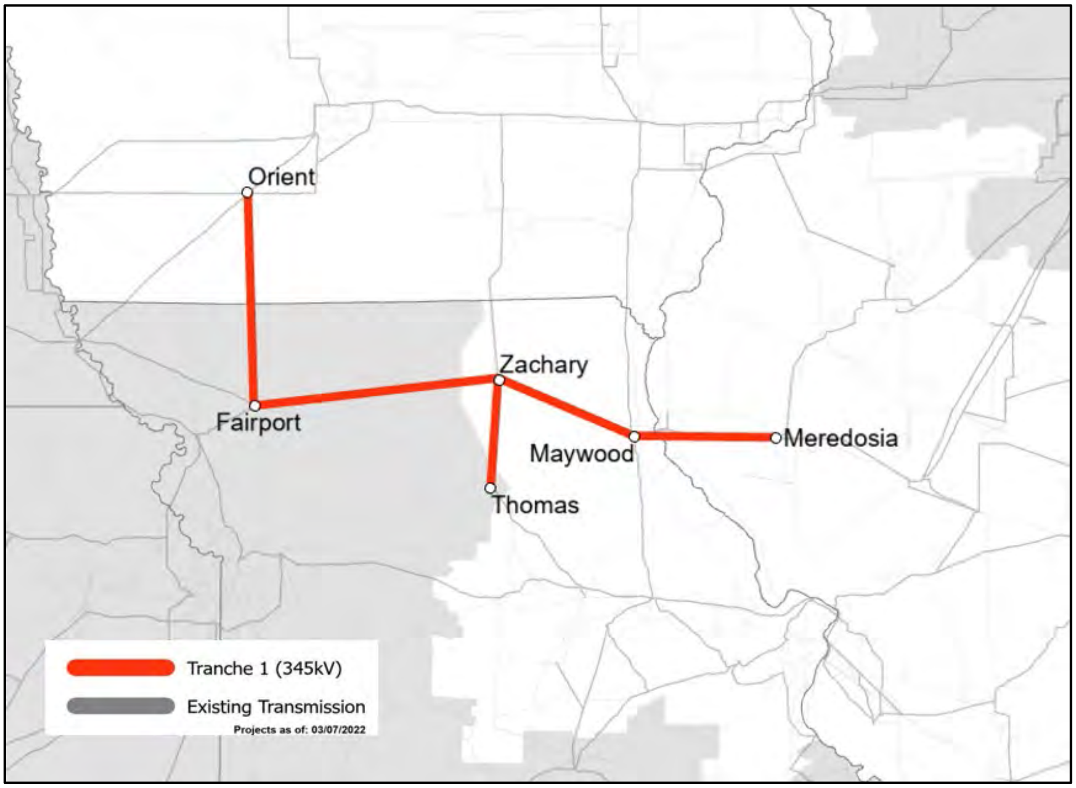


Figure 6-17: Northern Missouri Corridor Final Solution

Projects:
Orient – Fairport – Zachary – Maywood – Meredosia 345 kV
Zachary – Thomas 345 kV

Rationale:
The northern Missouri Corridor relieves loading on transmission elements in Iowa, Missouri, and Illinois. Increased transfer levels and improved voltage profiles are associated with the Missouri projects (Figure 6-17).

Issues Addressed:
The Missouri Corridor addressed thermal issues (Figure 6-18). Facilities mitigated by the Missouri Corridor are listed in Table 6-8. For this metric, a constraint was considered relieved if its worst pre-project loading was greater than 95% of its monitored Emergency rating, its worst post-project loading was less than 100% of its monitored Emergency rating, and the worst loading decreased by greater than 5% following the addition of the project.

- 14 issues resolved in Missouri and Illinois
- 5 issues resolved in Iowa

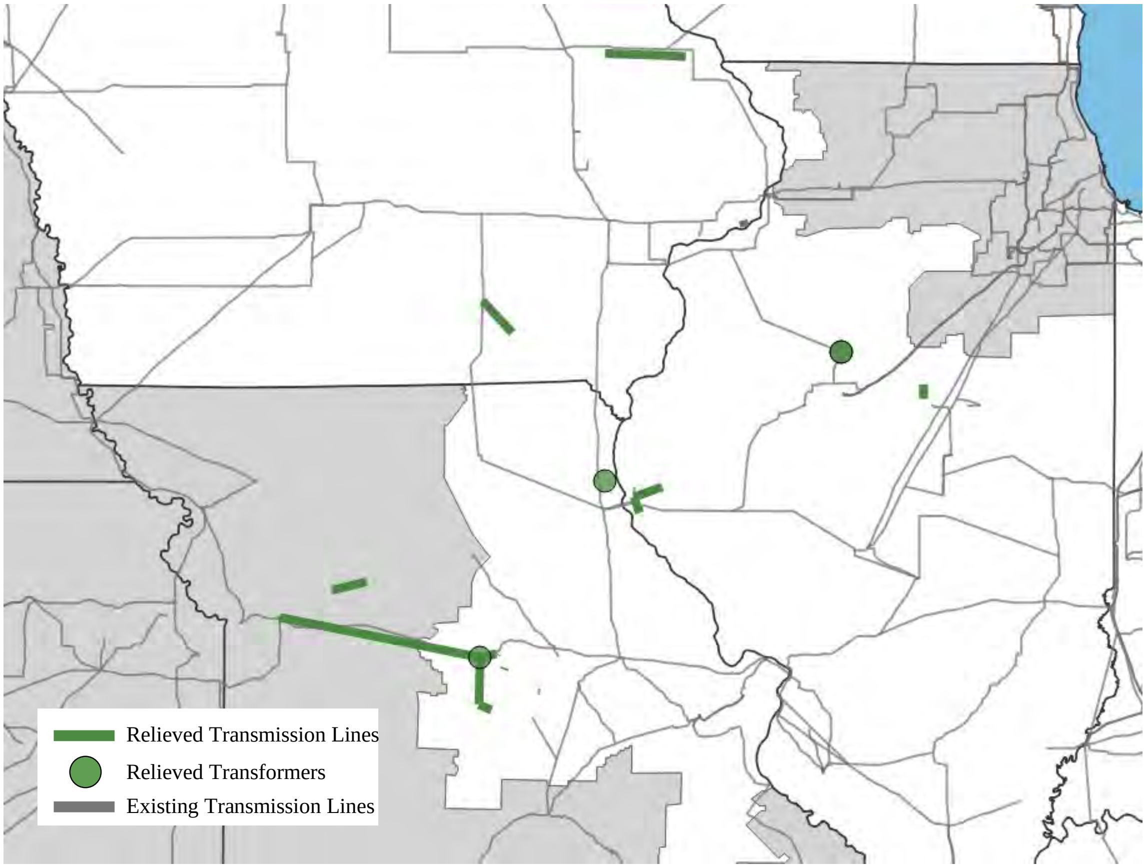


Figure 6-18: Northern Missouri Corridor map of facilities relieved in Future 1 power flow cases, for either N-1 or N-1-1 overloads. Transformers in green circles, and lines in green lines.

Monitored Facility	Area	% Loading	
		Base + West LRTP*	+ IA to MI Project + MO Projects
Marblehead 161/138 kV Transformer	AMIL	137	85
Fargo 345/138 kV Transformer 1	AMIL	122	98
Fargo 345/138 kV Transformer 2	AMIL	122	98
Herleman 3 – Quincy S. 138 kV Ckt. 73	AMIL	120	79
Herleman 1 – Quincy N. 138 kV Ckt. 50	AMIL	120	79
Diamond Start Tap – White Oak Wind Bus 138kV Ckt. 1	AMIL	114	100
Overton 345/161 kV Transformer	AMMO	109	97
Overton – Sibley 345 kV Ckt. 1	AMMO	102	88
Huntsdale – Overton 1 161 kV Ckt. 1	AMMO	101	91
California 161 kV Bus 1 – Overton 2 161 kV Ckt. 1	AMMO	98	88
Huntsdale – Perche Creek 161 kV Ckt. 1	CWLD	97	87
McBaine Bus #2 – McBaine Tap 161 kV Ckt. 1	AMMO	97	85

Maurer Lake 161 kV Bus 1 – Carrollton 161 kV Ckt. 1	AMMO	96	70
California 161 kV Bus	AMMO	95	85
Sub 71 – Sub 88 161 kV Ckt. 1	MEC	109	98
Heights – Ottumwa 161 kV Ckt. 1	ALTW	103	95
Heights – Woody 161 kV Ckt. 1	ALTW	101	93
Liberty – Hickory Creek 161 kV Ckt. 1	ALTW	98	91
Liberty – Dundee 161 kV Ckt. 1	ALTW	98	91

*Base + West LRTP projects = Ell-Jam, BSS-Alex-Cass, MN-WI

Table 6-8: Facilities mitigated by the Missouri Corridor

The Missouri projects can help power delivery, in addition to increasing transfer levels from East-West/West-East. Moreover, the projects address voltage instability in Missouri (Figure 6-19).

- In the Pre-project case (without LRTP projects), with the transfer level reaching 1640 MW, one 345 kV bus in Missouri shows voltage dropping to 0.87 p.u. following loss of a large generating plant, which demonstrates voltage instability in this source area
- With the proposed IA – MI 345 kV line, the transfer level is increased to 3773 MW
- With the addition of the MO Project, the transfer level is further increased to 6000 MW

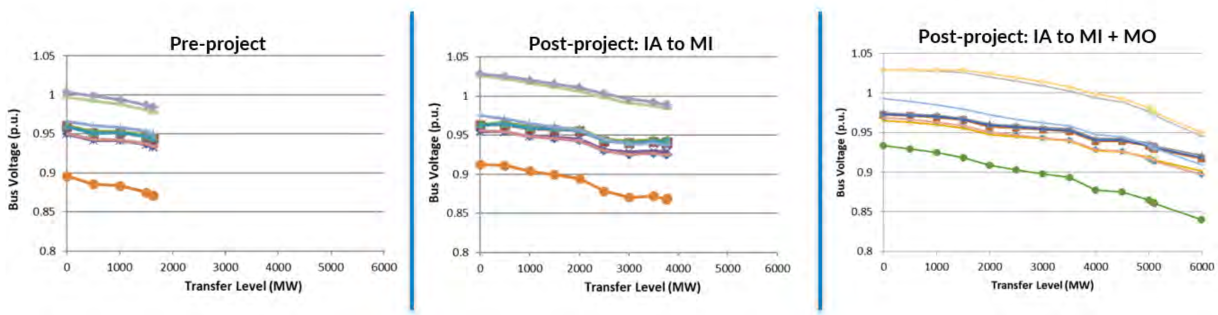


Figure 6-19: Bus Voltage Profiles

Alternatives Considered:
Segments of the Missouri corridor were considered separately, the full Missouri path (Orient – Fairport – Zachary – Maywood – Meredosia 345 kV / Zachary – Thomas 345 kV) is a better solution, with 19 issues addressed by the full path compared to:

- Zachary – Thomas – Maywood – Meredosia, resolves 11 issues
- Thomas – Zachary, resolves 4 issues
- Zachary – Maywood, resolves 6 issues
- Zachary – Maywood – Meredosia, resolves 9 issues
- Zachary – Maywood – Thomas, resolves 5 issues

7 LRTP Tranche 1 Portfolio Benefits

In accordance with the guiding principles of the MISO planning process, the allocation of costs for the transmission investment must be roughly commensurate with the expected benefits. As Multi-Value Projects, the eligibility of LRTP projects is established by Tariff requirements that define the need to demonstrate financially quantifiable benefits in excess of costs.

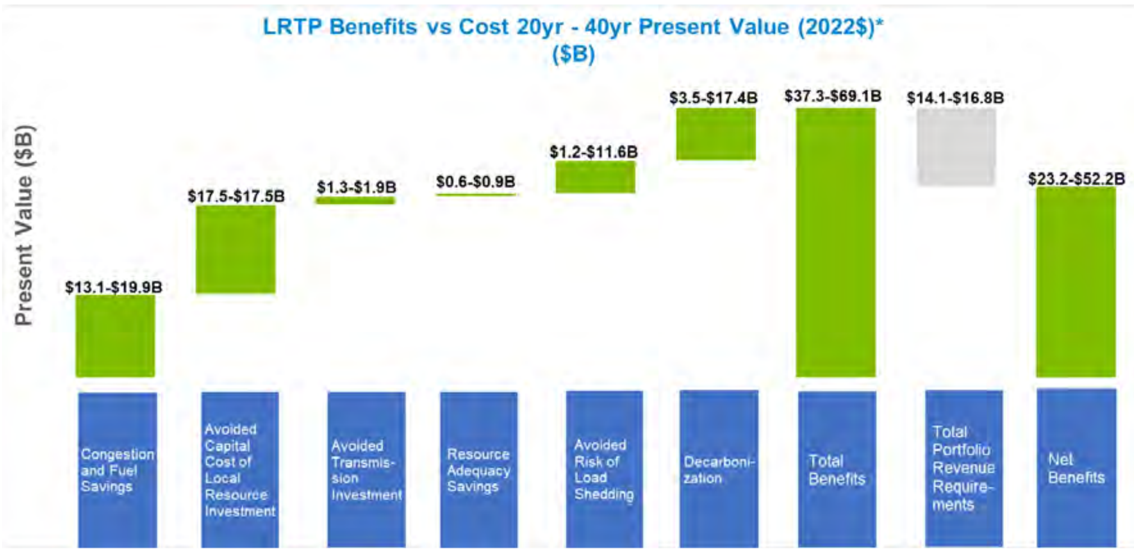


Figure 7-1: Financially Quantifiable Benefits of LRTP Tranche 1 Portfolio (values as of 6/1/22)

Guided by the allowable economic benefits defined in the tariff for MVP projects, the following benefit components were evaluated to determine the amount of value delivered by the LRTP Tranche 1 Portfolio:

- Congestion and fuel cost savings
- Avoided capital costs of local resource investment
- Avoided future transmission investment
- Reduced resource adequacy requirements
- Avoided risk of load shedding
- Decarbonization

Each benefit metric represents a distinct piece of the overall value resulting from either the transmission investments or the generation changes enabled by the transmission projects. Each benefit component is discussed in more detail, explaining what is captured in the metric, how LRTP projects impact the value being measured, and the methodology used to calculate the benefit. Starting from their assumed in-service year of 2030, benefits were calculated over a twenty-year horizon to evaluate eligibility as a multi-value project, and over a forty-year period to demonstrate the additional value provided over the expected useful life of the assets.

For consistency and comparability, a general set of assumptions and variables was applied in the analysis of benefits. All benefit values are expressed in 2022 dollars. An inflation rate of 2.5% is assumed when adjusting for the benefit period. A rate of 3 percent is used to represent the value a ratepayer would typically receive on a risk-adjusted investment. A discount rate of 6.9 percent is used to calculate the minimum value used to assess the benefit to cost ratio and based on the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments. The benefits analysis also includes evaluation of a natural gas price sensitivity to determine how benefits change with respect to swings in natural gas prices. While the benefits of the LRTP Tranche 1 Portfolio business case are analyzed for a Future 1 resource expansion scenario based on a specific gas price assumption, the sensitivity analysis offers additional insights into the value of LRTP under a broader set of assumptions.

Congestion and Fuel Cost Savings

In the MISO Futures[4], transmission limitations require robust solutions that not only reduce system congestion but also facilitate access to the diverse, ever-changing resource mix. The LRTP Tranche 1 Portfolio helps deliver economic benefits by providing more transmission infrastructure to distribute loading on other facilities and by enabling the connection of more low-cost resources.

Congestion and Fuel Savings benefit analysis is determined by calculating Adjusted Production Cost (APC[5]) savings between a reference case and a change case production cost model. The makeup of the reference case includes sufficient resources to meet Future 1 energy requirements, without applying the limitations of the transmission system, as well as Future 1 Regional Resource Forecast (RRF) resources that do not require the LRTP Tranche 1 Portfolio to connect to the system. The change case includes the LRTP Tranche 1 Portfolio and Future 1 RRF resources enabled by regional transmission to connect to the system. To determine which RRF resources are included in the reference and change case models, MISO performed a distribution factor (DFAX[6]) analysis on reliability constraints addressed by the LRTP Tranche 1 Portfolio. Only renewable RRF resources with ≥ 5% DFAX are included in the change case and renewable RRF resources with < 5% DFAX will be included in both the reference and change cases (Figure 7-2).

[4] MISO Futures Report
[5] MISO APC White Paper
[6] The DFAX analysis utilized LRTP Powerflow models and identified LRTP reliability issues addressed by the LRTP Tranche 1 Portfolio and involves the computation of change in flow on a network branch in the transmission model to the injection of power at a bus where generation is located which determines the amount of generator impact on facility loading.

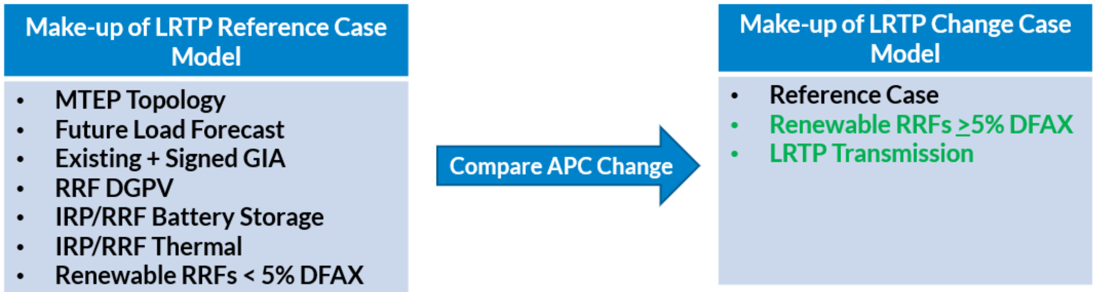


Figure 7-2: LRTP Reference and Change Case Criteria

As seen in Figure 7-3, application of this criteria resulted in 136.6 GW of resources being added to the LRTP Reference Case to meet Future 1 energy requirements and left 20.4 GW of renewable RRF resources available for DFAX analysis. This assessment resulted in the enablement of 20.1 GW of renewable RRF resources being added to the change case. Reference Figure 7-4 for geographical representation of the enabled renewable RRF resources in relation to the LRTP Tranche 1 portfolio.

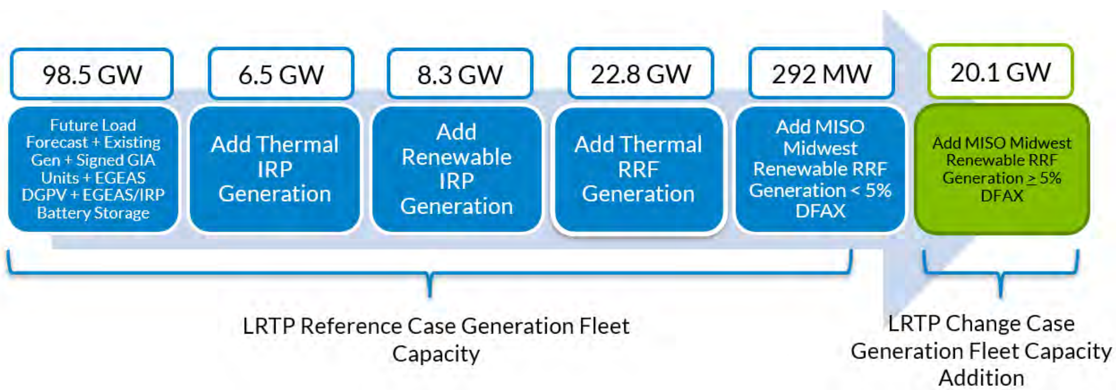


Figure 7-3: LRTP Reference and Change Case Criteria Capacity Result

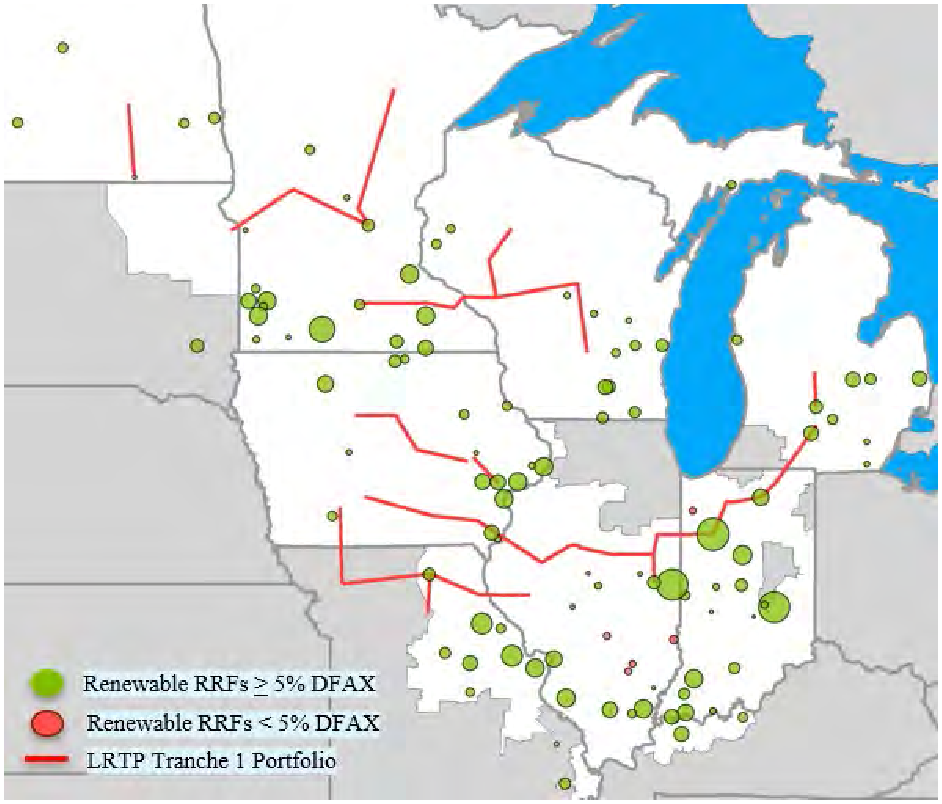


Figure 7-4: Geographic Map of RRF Resources Enabled by LRTP Tranche 1 Portfolio

The APC savings created by the LRTP Tranche 1 Portfolio generated $13.1 billion in congestion and fuel savings benefits over a 20-year period at a 6.9% discount rate. See Table 7-1 for additional benefit details on a Cost Allocation Zone (CAZ) granularity.

Present Value		20-year PV (Millions-2022$)		40-year PV (Millions-2022$)	
Discount Rate		**6.9%**	**3.0%**	**6.9%**	**3.0%**
CAZ	**1**	$3,169	$4,455	$4,668	$8,797
	2	$1,049	$1,511	$1,667	$3,313
	3	$2,195	$3,060	$3,151	$5,823
	4	$1,352	$1,934	$2,107	$4,133
	5	$1,471	$2,078	$2,205	$4,210
	6	$2,884	$4,133	$4,517	$8,890
	7	$1,006	$1,432	$1,543	$2,993
		$13,125	**$18,603**	**$19,858**	**$38,160**

Table 7-1: LRTP Tranche 1 Portfolio Congestion and Fuel Savings Benefits

Avoided Capital Costs of Local Resource Investments

The Avoided Capital Costs of Local Resource Investments metric captures the cost savings realized from a more cost-effective regional resource buildout that is enabled by regional transmission investment instead of depending on a more costly local resource buildout that is required due to local transmission limitations. In this specific case, the cost savings created by the LRTP Tranche 1 Portfolio will be determined by calculating an increase in costs for the resources enabled by the LRTP Tranche 1 Portfolio using a local versus regional capacity ratio.

To determine what the local resource investments would be, MISO had to first build local resource expansion models in EGEAS utilizing the same Future 1 assumptions[7] used in the regional expansion plan.

The local expansion plan EGEAS model assumptions are as follows:

- Local representation would be represented by Local Balancing Authority (LBA) granularity.
- Each LBA is treated as its own pool, self-constructing resources necessary to meet simulation constraints such as Planning Reserve Margin (PRM) and emissions.
- MISO PRM value of 18% was scaled for each LBA based upon its alignment to the MISO coincident peak.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are attributed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM due to limitations driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

[7] MISO Futures Report

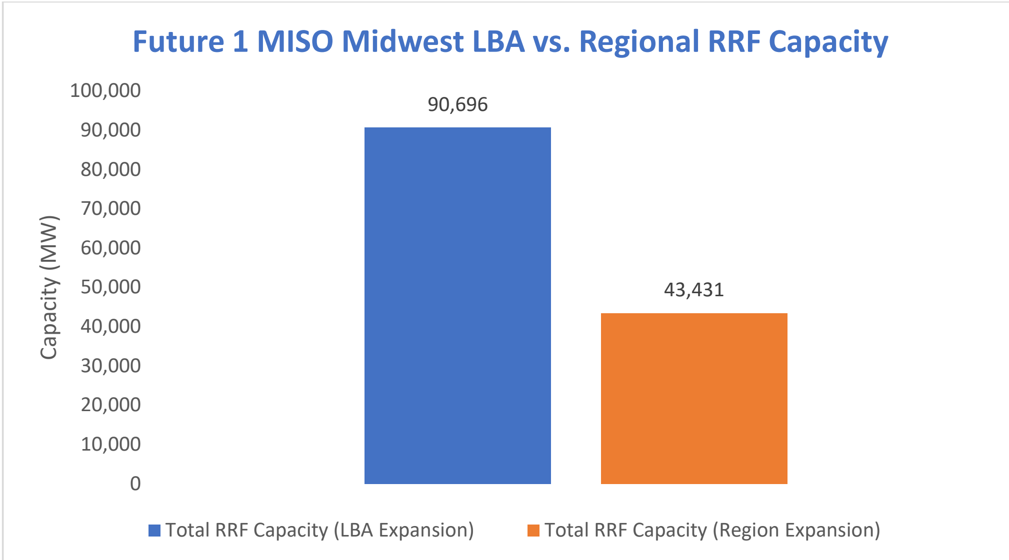


Figure 7-5: Future 1 LBA vs. Regional RRF Expansion Plan

As indicated in Figure 7-5, the LBA-specific scenario requires a much greater amount of localized resource expansion due to limited transmission capability, which is represented by isolating each LBA into its own EGEAS (transmission-less) model, compared to the equivalent regional expansion.

While Future 1 assumptions[8] were modeled consistently between the regional and LBA EGEAS models, the avoided capital cost benefit cannot be calculated by directly subtracting the regional expansion capital costs from local LBA expansion capital costs, as this would over-state the benefit created directly by regional transmission. To avoid this situation MISO had to consider what cost savings the Tranche 1 Portfolio would create. After evaluating several different options[9] with stakeholders to link the LRTP Tranche 1 Portfolio to the regional and local expansion, MISO proposed revised calculations and reviewed the details of the changes with stakeholders in the LRTP workshop discussions.[10] The ultimately decided on calculations are shown in equations (1) and (2) below:

$$Adjusted\ Capital\ Cost_{LBA\ Expansion} = \sum_{Year\ 2020}^{Year\ 2040} Enabled\ RRF\ Capital\ Cost_{Region\ Expansion} \times \frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})} \tag{1}$$

[8] MISO Futures Report
[9] January 21, 2022, LRTP Workshop
[10] February 25, 2022 LRTP Workshop

$$Avoided\ Capital\ Cost\ of\ Local\ Resource\ Investments\ = \quad (2)$$
$$Adjusted\ Capital\ Cost_{LBA\ Expansion} - Enabled\ RRF\ Capital\ Cost_{Region\ Expansion}$$

Equation (1) is used to determine what the assumed local resource expansion cost would be by increasing the cost of the enabled resources by a ratio set by the LBA and regional EGEAS expansion results.

- $Adjusted\ Capital\ Cost_{LBA\ Expansion}$ represents the assumed capital cost of a local (LBA) resource expansion for MISO Midwest
- $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$ is the capital cost associated with the enabled[11] Regional Resource Forecasting (RRF) units determined by EGEAS using Future 1 assumptions[12], reduced to MISO Midwest
- $Total\ RRF\ Capacity_{LBA\ Expansion}$ is a summation of MISO Midwest's LBA RRF capacity determined through EGEAS by applying Future 1 assumptions on a LBA level
- $Total\ RRF\ Capacity_{Regional\ Expansion}$ is a summation of MISO Midwest's regional RRF capacity determined through EGEAS by applying Future 1 assumptions on a regional level

Equation (2) is used to determine what the Avoided Capital Costs of Local Resource Investments would be by subtracting the $Enabled\ RRF\ Capital\ Cost_{Regional\ Expansion}$, that is already accounted for, from the assumed LBA expansion capital cost calculated in equation (1).

As a result of being able to utilize the regional transmission buildout of the LRTP Tranche 1 Portfolio, approximately $17.5 billion of savings can be realized through the avoidance of local resource investment (Figure 7-6).

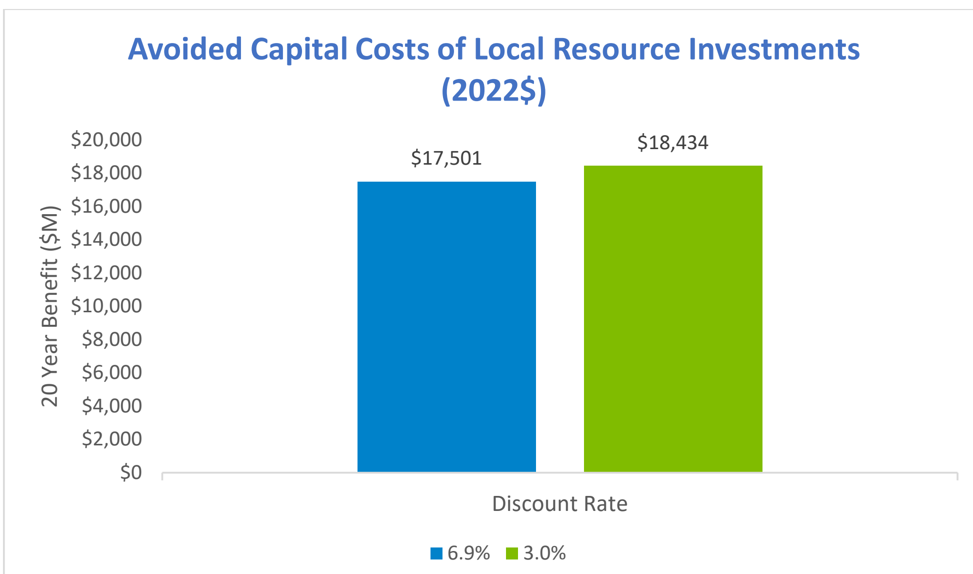


Figure 7-6: Avoided Capital Cost of Local Resource Investments Created by LRTP Tranche 1 Portfolio

[11] Renewable RRFs located in MISO Midwest Subregion which have ≥5% DFAX on reliability constraints addressed by LRTP Projects
[12] MISO Futures Report

Avoided Transmission Investment

The development of the LRTP Tranche 1 Portfolio provides a regional solution to addressing the future energy needs rather than an incremental approach to reliability planning. Avoided Transmission Investment captures the benefit provided by LRTP regional projects that address both avoided reliability projects and avoided age and condition replacement projects on right-of-way shared by LRTP projects.

LRTP projects deliver benefits by addressing future reliability issues and avoiding the costs of future upgrades that would have been required absent the LRTP Tranche 1 Portfolio. Benefits of avoided future reliability upgrades are based on potential overloads in the future rather than issues observed within the LRTP study period, in order to avoid double counting of benefits.

Identification of future upgrades considers facilities with high thermal loading but not overloaded in the 20-year reference case without LRTP reinforcements, and uses the thermal loading observed in the 10-year reference case to calculate the projected overload (equation below).

$$Flow_{proj} = Flow_{20} + (Flow_{20} - Flow_{10})$$

These projected overloads are analyzed in the LRTP case to determine if the LRTP Tranche 1 Portfolio mitigates the overload condition and are included as candidates for avoided future upgrades.

For future avoided transmission facilities >=345 kV a cost adjustment is applied to reduce the value by 50% to offset future production cost benefits that may be realized. These upgraded extra high voltage (EHV) facilities will reduce future congestion and offset production cost savings in the long term and discounting reduces potential for double counting of benefits. EHV facilities support regional energy delivery and generally have greater influence on production cost than lower voltage facilities that provide local reliability.

LRTP solutions in some cases make use of existing transmission corridors to reduce the need for new right-of-way and often the existing facilities have long been in service and in need of replacement. The avoided transmission investment benefit component also includes the avoided cost of upgrades where LRTP Tranche 1 projects are constructed on existing right-of-way with facilities that would have required upgrades as a result of facility age and condition. Where LRTP Tranche1 projects require rebuilding the structures and facilities of the aging circuits to accommodate the new transmission line, the future cost of the replacement is eliminated.

Facilities included in the Avoided Transmission Investment metric were verified with Transmission Owners to determine if facility upgrades are already planned or existing circuits on shared right-of-way are not candidates for age and condition replacement and were excluded from further consideration. Costs for avoided transmission investment use exploratory cost estimates that are based on the type of upgrade or replacement required. MISO estimated costs are derived from the MISO *Transmission Cost Estimation Guide for MTEP21* and are show in Table 7-2 below.

Upgrades are assumed to be needed prior to the end of the LRTP 20-year study period, and capital investment is assumed to be spread equally over the 5-year period prior to the in-service date of 2040.

Facility Improvement Type	Unit Cost($M)	Quantity/Miles	Cost ($M)
Bus-tie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

Table 7-2: Estimated Costs of Avoided Transmission Investment (values as of 6/1/22)

Analysis Results

Cost savings associated with avoided future upgrades and future facility replacement for age and condition yields 20-40 year present value benefits from $1.3B to $1.9B (2022$).

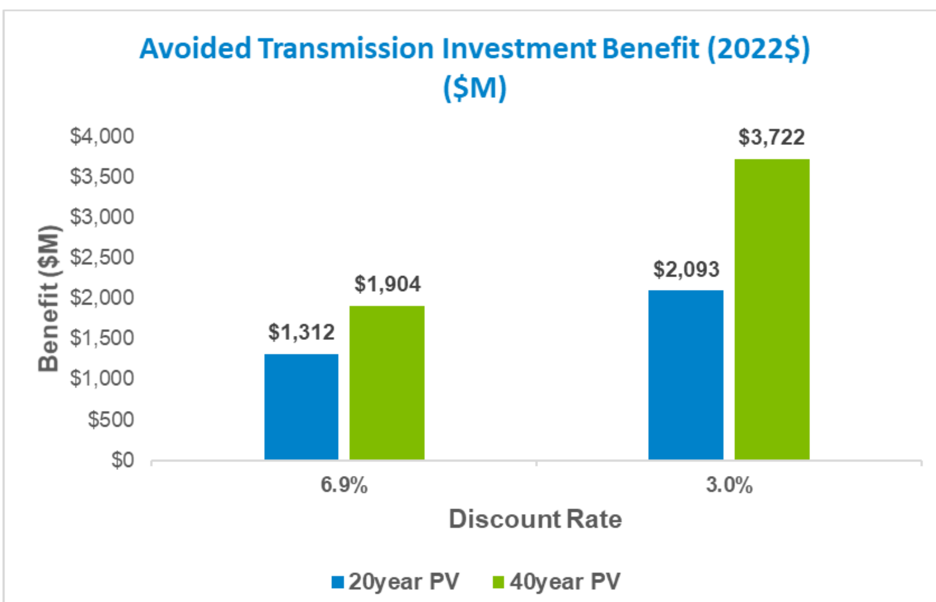


Figure 7-7: Avoided Transmission Investment Benefit (values as of 6/1/22)

Reduced Resource Adequacy Needs

The Reduced Resource Adequacy benefit metric represents a deferral of capacity that would be needed to address resource adequacy requirements due to increased zonal import limits. The transmission enhancements provided by the LRTP Tranche 1 Portfolio increases import capability and enables access to resources across the subregion. This decreases the need to procure capacity locally to meet resource adequacy needs.

The load serving entities (LSEs) that are located within the Local Resource Zones (LRZ) in MISO are required to meet two planning reserve margins in the Planning Resource Auction (PRA): the zonal planning reserve margin requirement (PRMR), which is based on the MISO-wide coincident peak load and MISO-wide PRM, and the local clearing requirement (LCR), which is based on each zone's non-coincident peak load and the local reliability requirement (LRR). The resource adequacy benefits presented in this section are related to the LCR.

Modeling and Assumptions

The modeling includes two parts; the first one involves a transfer analysis and the second one includes the monetization of the benefit.

1. Transfer Study: The CIL analysis generally aligns with the study methodology used in the Planning Resource Auction (PRA). The transfer analysis starts with the Future 1-2040 "peak load day" power flow model and associated input files (monitored elements and contingencies and sub-systems). These are then used in the TARA simulation tool to determine the incremental amount of power that can be transferred from source to sink. The First Contingency Incremental Transfer Capability (FCITC) is determined and the CIL is calculated for a base case (without LRTP Tranche 1 Portfolio) and change case (including LRTP Tranche 1 Portfolio). The definition of each case, in terms of the resource dispatch and demand levels, is consistent with the LRTP Future 1 reliability models.

2. Economic value of LCR reductions: The economic value of the LCR reduction is estimated as a function of the total unforced capacity (UCAP), CIL, and the LRR. The 2040 unforced capacity for each LRZ is determined using forced outage rates for thermal resources and the effective load carrying capability for non-thermal resources.

   The excess capacity within each LRZ is calculated as follows:

   Excess Capacity (LRZ_i) = 2040 UCAP (LRZ_i) – 2040 LCR (LRZ_i; without LRTP),
   where "i" represents the LRZ number (from 1-7).

   The RA benefits are estimated as follows:

   If Excess Capacity < 0 → Benefit = (Cost of new entry) x (-Excess Capacity)
   If Excess Capacity > 0 → Benefit = $0/year

   The LRR-UCAP percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ. The cost of new entry (CONE) assumptions is also consistent with the PY22-23 MISO LOLE study.

Analysis Results

The resulting CIL, with and without the LRTP Tranche 1 Portfolio, are shown in Table 7-3. The CIL values include the net-area interchange (e.g., the base transfer) gathered from the power flow model. Although their impact on the LCR benefit is negligible, the other components used in the CIL equation, e.g., border external resources (BER), coordinated owner (CO), and exports are kept unchanged in the base and reference cases.

Local Resource Zone	CIL (Base)	CIL (Change-With LRTP)	Delta CIL(MW)
1	5412	6070	658
2	4188	5223	1035
3	5062	6453	1391
4	7117	7609	492
5	6131	6183	52
6	6005	6171	166
7	3367	4659	1292

Table 7-3: Change in Capacity Import Limits (CIL)

A summary of the UCAP, LCR, LRR, and the Excess Capacity calculated for each LRZ is included in Table 7-4. The excess capacity shown in row 7 reflects the pre-LRTP scenario and a negative value represents a potential shortfall situation. The excess capacity shown in row 8 reflects the case with LRTP and confirms the ability of Tranche 1 projects to hedge against potential shortfall situations. The total 20-year and 40-year net present values are shown in Figure 7-8.

Row Number	Summary of resource adequacy benefits								
	LRZ	1	2	3	4	5	6	7	Formula Key
1	2040 Unforced Capacity (MW)	22,981	15,458	12,079	11,111	8,274	20,659	23,982	A
2	2040 Local Reliability Requirement Unforced Capacity (MW)	23,672	16,431	12,405	14,230	12,391	24,196	27,814	B
3	Without LRTP CIL (MW)	5,412	4,188	5,062	7,117	6,131	6,005	3,368	C
4	With LRTP CIL (MW)	6,070	5,223	6,453	7,609	6,183	6,171	4,659	D
5	Without LRTP LCR (MW)	18,260	12,243	7,343	7,113	6,260	18,191	24,446	E=B-C
6	With LRTP LCR (MW)	17,602	11,208	5,952	6,621	6,208	18,025	23,155	F=B-D
7	Excess capacity after LCR	4,721	3,216	4,737	3,998	2,014	2,468	-465	G=A-E

	without LRTP (MW)								
8	Excess capacity after LCR with LRTP (MW)	5,379	4,251	6,128	4,490	2,066	2,634	827	H=A-F
9	Deferred capacity value (M$)	0	0	0	0	0	0	-44	I=G*CONE

Table 7-4: Summary of resource adequacy benefits

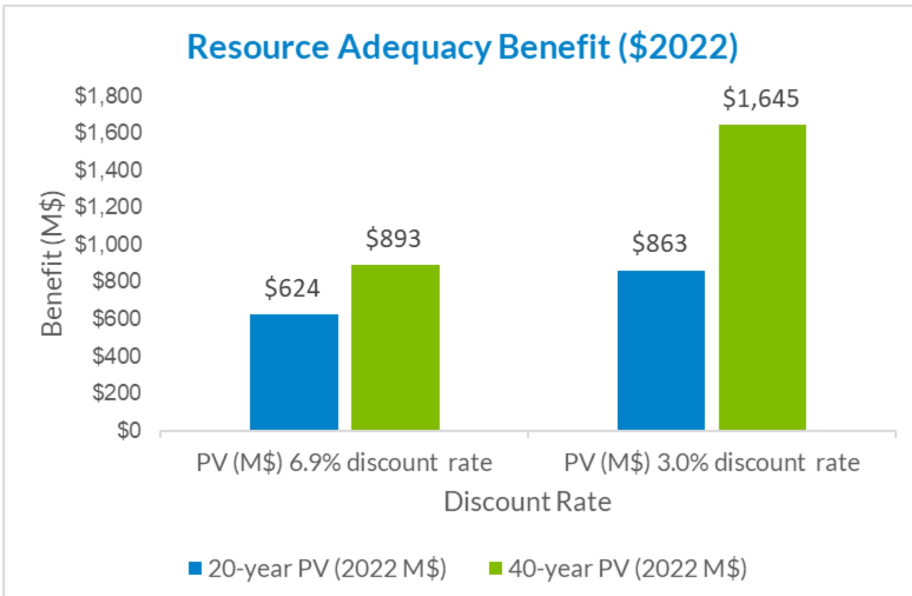


Figure 7-8: Resource Adequacy Benefit Total 20-year and 40-year Present Value

Avoided Risk of Load Shedding

Avoided Risk of Load Shedding is one of several metrics that is used to quantify the benefits provided by the LRTP Tranche 1 Portfolio. The method for determining this resiliency value considers high impact events with an expectation of a significant amount of controlled load shedding to ensure reliable system performance and/or prevent system collapse. While smaller, more common contingencies can result in the need for load shedding actions to maintain reliability, these events are often local in nature and beyond the scope of this analysis, which examines the impact of large-scale generation loss events caused by changing weather conditions or under extreme weather events. In a future with extensive penetration of renewable resources, the variability in weather introduces the potential for loss of renewable production. Additionally, extreme winter weather patterns can cause fuel supply disruptions that may result in extensive thermal generation outages. LRTP projects help to enable regional transfers mitigating the risk associated with these high impact generation outage events.

Analysis of load shedding risk was performed using 2040 winter peak reliability powerflow models, which represent system conditions under which the severe winter weather generation loss event is expected to occur. Weather events may be limited in scale to smaller areas that can affect a single resource zone or may be extreme in nature and have widespread impacts across the footprint. Study scenarios are defined for zonal and system-wide events that specify the generation outages resulting from severe winter weather impacts. Analysis of severe winter weather impacts on generation performance is generally straightforward but captures only one area of the risk associated with loss of load. This narrow focus results in a conservative estimate of the value of avoided risk of load shedding.

Historical weather event data is used to understand and develop assumptions about the frequency of significant winter weather events that could lead to large scale generation loss. MISO analyzed information on significant freeze and storm events over the past 40 years that have resulted in significant economic impact in order to establish the frequency of occurrence for evaluating risk (Figure 7-9).

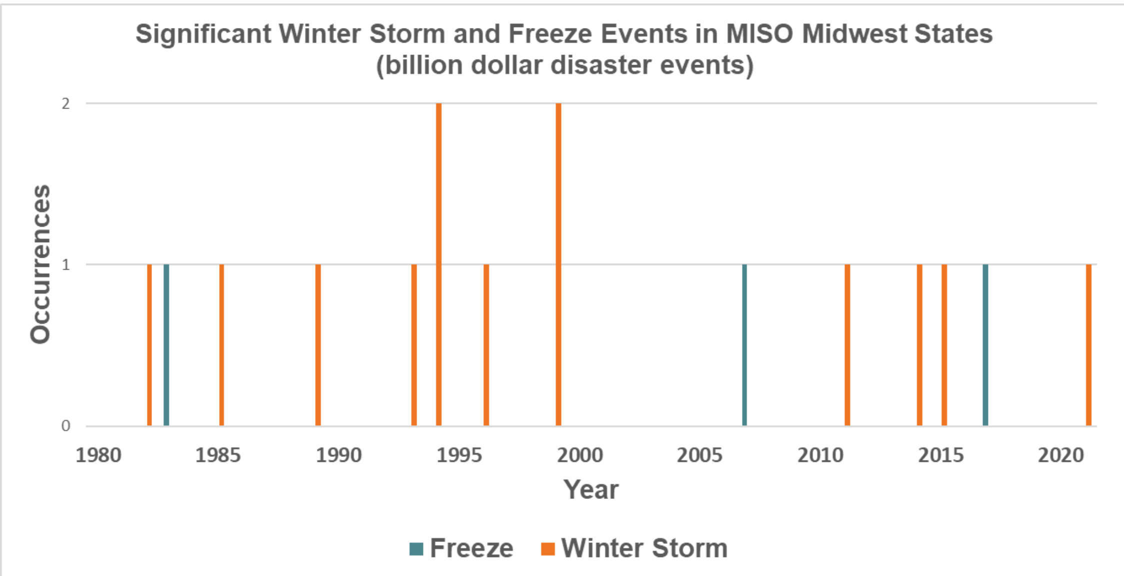
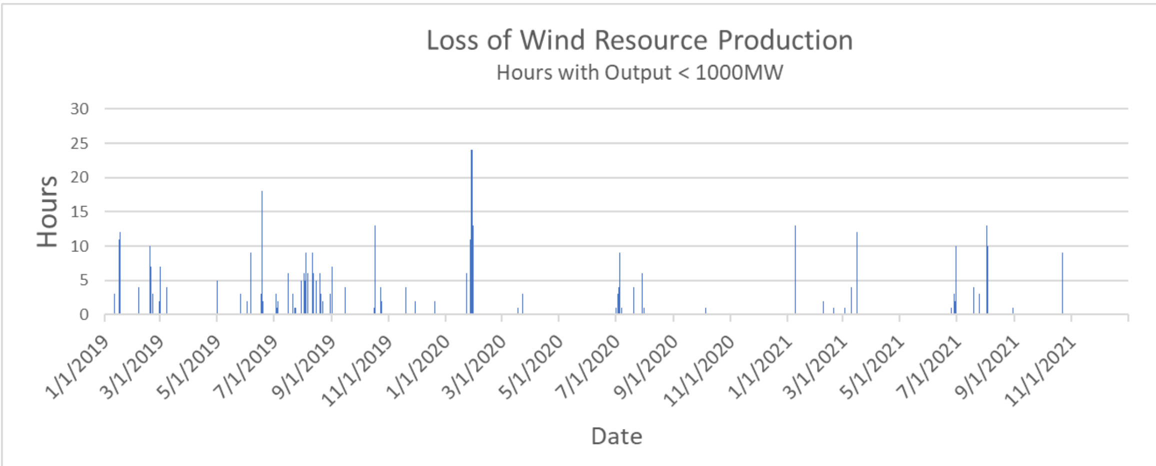


Figure 7-9: Winter storm and freeze events have been occurring every three years on average

Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Additionally, operational event data was analyzed to examine trends in resource availability events over time when severe winter weather conditions occur, which provides insights into how fleet composition affects the risk of generation deficiency. While many of these weather events have not caused major disruption of generation supply in the past, recently there have been a growing number of instances where weather conditions caused the need to implement emergency measures to maintain adequate supply. In the last five years, tight generation supply during winter conditions presented operational challenges that will continue with growing dependency on renewable resources and gas-fired generation. The MISO response to the Reliability Imperative report[13] notes a key indicator of the change in risk profile for the region is seen in the 41 MaxGen emergencies that have been declared since 2016.

Historical generation output data highlights recurring risks associated with periods of low renewable production which can occur during any season and any time of the day (Figure 7-10). Such events can leave a significant amount of generation capacity unavailable to meet load requirements and where the duration of generation shortfall can last several hours.



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

Figure 7-10: Periods of low wind production may last several hours

The interruption of load may have far reaching impacts that include risk to public health and safety, financial loss, and regulatory/legal burdens, which are difficult to accurately quantify. The monetization of value of lost load is often considered in the context of customer willingness to pay to avoid interruption. While the application of the MISO Tariff defined Value of Lost Load (VOLL) in the LRTP business case does not suggest that VOLL represents the full value of risk, it does provide a reasonable measure that is indicative of the LRTP benefits and closely aligns with other business processes. The value of avoided risk of load loss of the LRTP Tranche 1 Portfolio considers a range of VOLL from $3,500/MWh to $23,000/MWh. The $3,500/MWh is currently defined by the MISO Tariff for use in market pricing while $23,000/MWh is a value recommended by the MISO Independent Market Monitor to be more representative of the value. This value of VOLL is applied to the calculated MW value of load loss determined by the zonal and system-wide studies in order to capture the benefits associated with the LRTP Tranche 1 Portfolio.

[13] MISO's Response to the Reliability Imperative

Method for Calculating Value of Avoided Risk of Load Shedding

Scenario Development

Analysis of historical winter storm and freeze event data from the past 20 years and recent extreme winter weather events indicates that significant winter storms are recurring every three years on average with extreme winter storms and temperature conditions observed periodically (polar vortex, Uri). The increased influence of weather due to the variability of renewable resources and impact of cold temperatures on fuel supply and availability of gas-fired generation will result in more periods of risk for load loss. Thus, each occurrence of a severe winter event every one out of three years represents a risk of load shedding due to the widespread generation outages. This risk persists beyond a single day since winter storms often occur over multiple days.

Duration of the load loss was derived using hourly wind production data to examine periods of low wind output since variability in wind output will have a large influence on the risk of an event. While the duration of low wind output events can range from 1 hour to 24 hours for a given day (Figure 7-10), approximately half of the events occurring in winter season are greater than 10 hours and period of risk for load loss is assumed to be eight hours per day over a two-day period for the purpose of assessing the risk of load shedding caused by a severe winter weather event.

A series of event scenarios were developed to represent significant generation loss due to weather related conditions. Events were created to reasonably reflect the loss of future renewable and thermal resources within defined zones or groups of zones. Loss of wind resources was modeled to represent a 90% drop in output from the maximum capacity and loss of solar output was modeled as a 50% reduction from maximum capacity. For regional and zonal event analysis, loss of thermal generation was derived by using outage information from the recent extreme winter storm event to establish a 50% outage rate in regional scenarios and 40% outage rate in zonal scenarios to capture the higher impact from future growth in gas-fired resources. Where modeled wind output is less than 10% of maximum capacity or solar output less than 50% in either zonal or regional scenarios, no adjustment is applied to the wind or solar output.

Load Loss Analysis

In zonal load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given local resource zone. Load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis. Reliability analysis models normally apply a 50/50 load forecast, which reflects the normal peak load expected in the planning horizon. However, during extreme weather conditions, the peak load is expected to reach a 90/10 peak load forecast level, which is typically 5% higher. Resources were grouped within a single zone and event generation outage scenario applied to determine the amount of generation remaining. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total zone load and losses and adding any net imports into the zone. The future CIL calculated in the resource adequacy analysis is used to determine if sufficient import capability exists to support any shortfall and any change in CIL due to the addition of the

LRTP projects is used to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Area/Zonal Event Scenario

Generation Loss:
Thermal: 40% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Capacity Import Limit (CIL)

For all LRZ 1-7

LoadLossMW = GenMW_{net} – 1.05 * LoadMW – TxLossMW + Capacity Import Limit (MW)
where $\text{GenMW}_{net} = \text{GenMW}_{cap} - \text{GenMW}_{loss}$

In regional load loss analysis, the 2040 winter peak powerflow models were used to evaluate available generation, load requirements, and import capability for a given group of local resource zones. Similar to zonal analysis, the load is escalated by 5% to assess the risk of load higher than normally forecast in planning analysis due to the extreme weather. Resources were grouped within a set of zones and event generation outage scenario applied to determine the amount of generation remaining. In the regional analysis scenarios, the amount of thermal generation loss is escalated to 50% of capacity to represent a more extreme condition with regional scale impacts. The amount of shortfall or surplus, in MW, is then calculated by subtracting the total load and losses and adding any net imports into the study group. The incremental transfer capability is calculated using the power flow model and added to the existing group net imports to determine the total transfer capability to support any shortfall and the change in total transfer capability due to the LRTP projects is calculated to determine the amount of benefit, in MW, provided by the LRTP Tranche 1 Portfolio.

Two scenarios are included for evaluating risk of load loss for regional scale events:

Scenario 1 assesses the impact of an extreme winter storm primarily on the western part of the MISO footprint causing large scale loss of generation in MISO upper Midwest areas and Southwest Power Pool (SPP) with SPP imports assumed to be 7,500 MW.

Scenario 2 assesses the impact of extreme winter storm activity in the MISO central areas and Ohio Valley with PJM exports curtailed to 0 MW.

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

LoadLossMW = $GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability (MW)
where $GenMW_{net}$ = $GenMW_{cap}$ – $GenMW_{loss}$

The value of avoided risk of load shedding is monetized by the use of the Value of Lost Load (VOLL) to represent a portion of the outage costs associated with load curtailment during generation deficiency events. While VOLL is based on outage costs, it is a market pricing mechanism that considers a customer's willingness to pay for energy to avoid load curtailment under emergency conditions and does not fully consider the related impacts or the effects of extended outages in more extreme scenarios. Furthermore, there is a wide range of opinion concerning the appropriate value that should be used with $3,500/MWh currently being used in the MISO market pricing structure while MISO's Independent Market Monitor has recommended a value of $23,000/MWh to be used in the MISO market. Thus the $3,500/MWh figure is a conservative estimate for capturing the benefit of avoided risk of load loss with the $23,000/MWh value used to establish the upper bound of the value.

The load loss hours are summed for all scenarios to obtain the load risk of load loss in MWhr and the range of values for VOLL is applied to obtain the monetary value.

Avoided Load Loss Value ($) = VOLL * LoadLossMW * duration(hrs.)
where VOLL – Value of Lost Load: $3,500- $23,000[14]

[14] IMM Quarterly Report: Summer 2020,

Analysis Results

The additional transfer capability provided by the LRTP Tranche 1 Portfolio enables power transfers to address supply deficiency caused by weather related generation outages and delivers 20- to 40-year present value benefits of $1.2 billion to $11.6 billion (2022$).

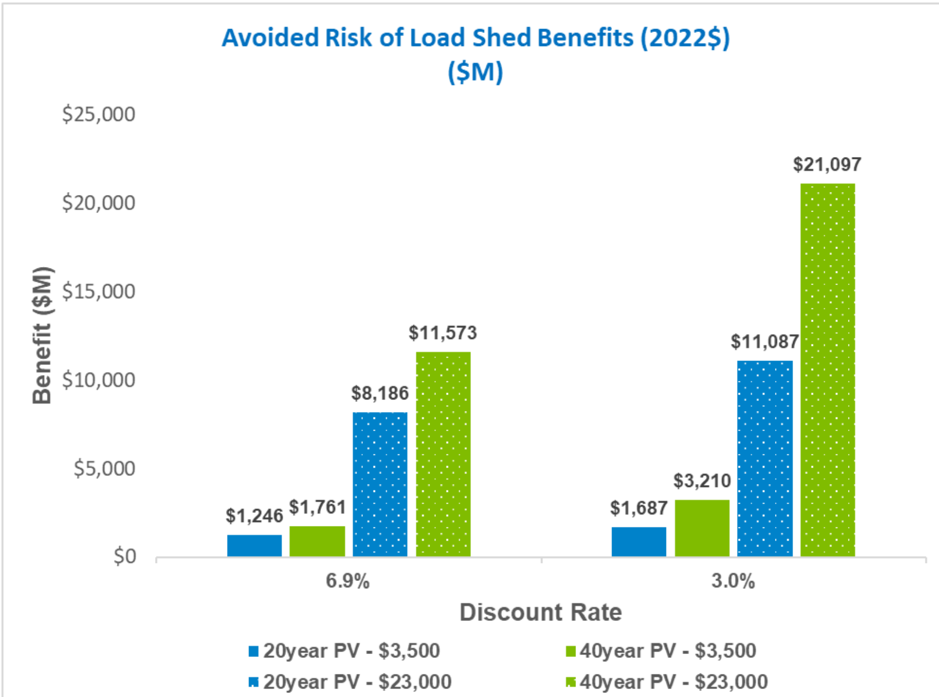


Figure 7-11: Benefits of Avoided Risk of Load Shedding (values as of 6/1/2022)

Decarbonization

MISO continues to explore how the rapid growth of members' decarbonization goals creates additional needs and opportunities to provide value. The robust transmission planning embodied by the LRTP initiative can signal better locations that deliver decarbonization, among other benefits. This item captures a range of potential cost savings from LTRP-enabled Decarbonization.

MISO acknowledges there is no cost of carbon applicable to the entire footprint currently. However, with the energy transition and changing landscape, it is possible that additional emissions standards may be placed on the electric industry. Since the 1990s, sulfur dioxide has decreased by 94%, nitrogen oxides by 88% and mercury emissions by 95% across the U.S. electric power sector.[15] Many of the benefits associated with these emission reductions have already been captured throughout the footprint.

[15] Edison Electric Institute: Climate and Clean Air

Over the past several years, MISO members have announced large carbon emission reduction goals that will rely on intermittent low-cost energy. The LRTP initiative aims to help ensure an efficient dispatch of energy across MISO during this fleet transition. With the rationale above, MISO conducted research to develop a price range to express Decarbonization's value. MISO chose sources within the U.S., at state and federal levels, within and outside of the MISO footprint. The range in prices draws from regulatory and market-based approaches, both of which are influenced by policy. From MISO's PROMOD analysis, carbon emissions are reduced by 399 million metric tons over 20 years and 677 million metric tons over 40 years of LRTP Tranche 1 project life (Figure 7-11).[16]

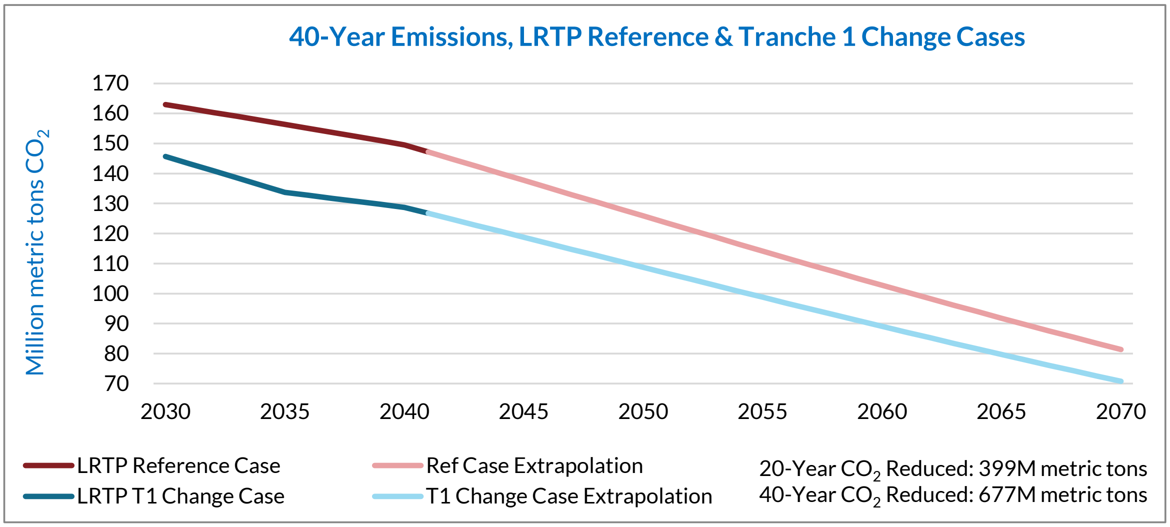


Figure 7-12: 40-Year CO_2 Emissions of LRTP Reference and Tranche 1 Change Cases

MISO took two steps to standardize price terms. First, as applicable, MISO converted source price data to dollars per metric ton, using a conversion factor of one U.S. (short) ton = 0.9071847 metric tons.[17] Second, MISO converted prices from nominal dollar-years of origin into 2022 dollars using the Consumer Price Index Inflation Calculator.[18] For consistency, the month of January was used for dollar-year conversions except in cases related to market prices, which used the month of auction settlement as the origin date. A range of CO_2 emission prices were identified to estimate a benefit value, and are summarized below:

- The Minnesota Public Utility Commission (MN PUC) price began with the 2022 Low[19] price of $9.46 per short ton in 2015 dollars and yielded $10.43 per metric ton; $12.55 per metric ton in 2022 dollars.

[16] MISO interpolated emissions data among PROMOD model years 2030, 2035, and 2040 and used linear extrapolation for post-2040 emissions reductions. 20-year and 40-year benefits refer to projects' in-service value to 2050 and 2070, respectively.
[17] U.S. Energy Information Administration
[18] U.S. Bureau of Labor Statistics Consumer Price Index Inflation Calculator
[19] Minnesota Public Utility Commission

- The Regional Greenhouse Gas Initiative (RGGI) Q4 2021 Auction average (mean)[20] price of $12.47/short ton yielded $13.75/metric ton; $13.87 in 2022 dollars.
- The California and Quebec (CA-QC) Cap-and-Trade Program Q4 2021 Auction settlement[21] price of $28.26/metric ton is $28.59 in 2022 dollars.
- The Federal price is the average of two price data inputs: the 45Q Tax Credit and the Social Cost of Carbon.[22] The 45Q Tax Credit follows a prescribed price schedule; starting with $31.77/metric ton in 2020, increasing to $50 by 2026, and inflation-adjusted afterwards by 2.5% annually. This interpolation yields a 2022 value of $37.85. The Social Cost of Carbon (SCC) follows a similar schedule, but in 2020 dollars. Converting the SCC schedule in 2020 dollars from $51/metric ton (2020) yields $55.58 and $85 (2050) yields $92.64 for those price-years, in 2022 dollars. The SCC's 2022 value in 2022 dollars is $57.76. Beyond 2050, annual inflation of 2.5% is applied. To produce the Federal price, the annual values of 45Q and SCC through 2069 are averaged, beginning in 2022 at $47.80/metric ton in 2022 dollars.

The Decarbonization assessment employs the following overall methodology:

- From the Congestion and Fuel Cost Savings analysis, calculate the difference in CO_2 emissions between the LRTP Reference case and LRTP Change case
- Convert the reduced emissions to metric tons
- Use range of carbon prices to produce yearly values at 2.5% inflation as applicable
- Multiply yearly values by annual reduced emissions and discount rates to produce discounted annual benefits
- Sum discounted annual benefits to yield net present values for 20- and 40-year emission reduction benefits along the price range (Figure 7-12, Table 7-4, Table 7-5)

Detailed assumptions, calculations and formulas are found in the supplementary LRTP Business Case Analysis workbook.

	MN PUC	RGGI Q4 2021	CA-QC Q4 2021	Federal
2022$/metric ton	$12.55	$13.87	$28.59	$47.80
20-Year Benefit (2022$, M):	$3,473	$3,839	$7,913	$13,438
40-Year Benefit (2022$, M):	$4,548	$5,026	$10,361	$17,364

Table 7-4: Full Range of Carbon Prices and Tranche 1 Decarbonization Benefits at 6.9% Discount Rate

[20] Regional Greenhouse Gas Initiative (Q4 2021 average [mean] price)
[21] California-Quebec Carbon Allowance Price (November 2021)
[22] Federal: 45Q Tax Credit, Social Cost of Carbon

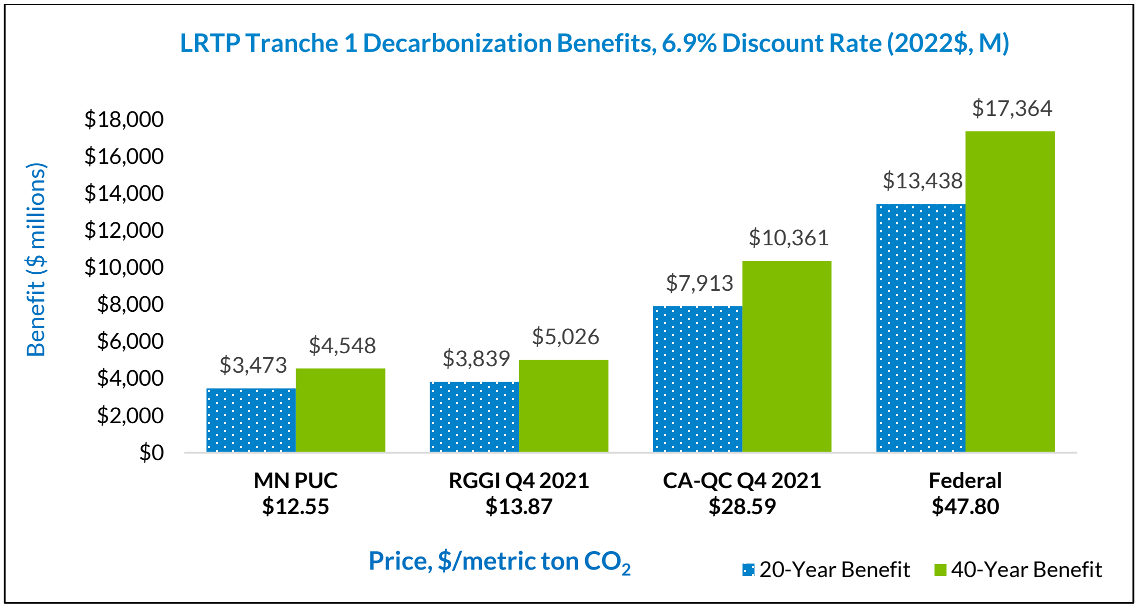


Figure 7-13: LRTP Tranche 1 Decarbonization 20- and 40-Year Benefits Using Full Carbon Price Range, Applying 6.9% Discount Rate (2022$, M)

	6.9% Discount Rate		3% Discount Rate	
	MN PUC (Min)	Federal (Max)	MN PUC (Min)	Federal (Max)
2022$/metric ton	$12.55	$47.80	$12.55	$47.80
20-Year Benefit (2022$, M):	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M):	$4,548	$17,364	$7,818	$29,498

Table 7-5: Min/Max Carbon Prices and Tranche 1 Decarbonization Benefits at Two Discount Rates

8 Benefits Are Spread Across the Midwest Subregion

The LRTP Tranche 1 Portfolio of projects was developed to address regional energy delivery needs for the MISO Midwest subregion. As Multi-Value-Projects, the costs of the LRTP Tranche 1 Portfolio will be recovered on a pro-rata basis from load in the MISO Midwest Subregion. Analysis of benefits examined how much each benefit accrued to the Midwest Subregion Cost Allocation Zones in order to compare the relative impacts between zones and the relationship with cost allocation. The distribution of benefits of the LRTP Tranche 1 Portfolio is shown to yield significant benefits for all Cost Allocation Zones (CAZs) well in excess of the share of portfolio costs.

Distribution of Benefits

Congestion and fuel savings are distributed to CAZs based on the production cost simulations used to calculate the savings and aggregated to the CAZs.

Avoided capital cost of local resource investment benefits are assigned based on load ratio share of each CAZ and aligns with the goal of the resource expansion to meet the future energy needs of the Midwest Subregion.

Avoided transmission investment benefits are allocated to the CAZ in which the baseline transmission upgrades, and age and condition replacement facilities are located. Costs for these avoided projects would otherwise be borne by the local pricing zone which yields a benefit to those specific CAZs.

Reduced Resource Adequacy savings are assigned directly to the CAZs in which the cost savings are realized since each CAZ has a responsibility for their own resource adequacy needs, and the CAZs in the Midwest Subregion align with the Local Resource Zones used for resource adequacy.

Avoided Risk of Load Shedding benefits are distributed to CAZs based on load ratio share to reflect the widespread protection against load loss in the interconnected electric system.

Decarbonization captures the benefits of reduced carbon emissions in energy production that is used to serve load across the Midwest subregion and is allocated by load ratio share to CAZs.

Distribution of LRTP Tranche 1 Portfolio Costs

The cost for Multi-Value Projects are allocated to load in the Midwest Subregion according to load ratio share of energy withdrawals. To determine the benefit/cost ratios by Cost Allocation Zone the energy withdrawals by the applicable LBAs included in each zone have been aggregated for Figure 8-1. Additionally, indicative annual MVP usage rates for the LRTP Tranche 1 Portfolio were calculated over a 40-year period using the current project cost estimates and estimated in-service dates. This information on the estimated MVP usage rates is provided in Appendix A-3.

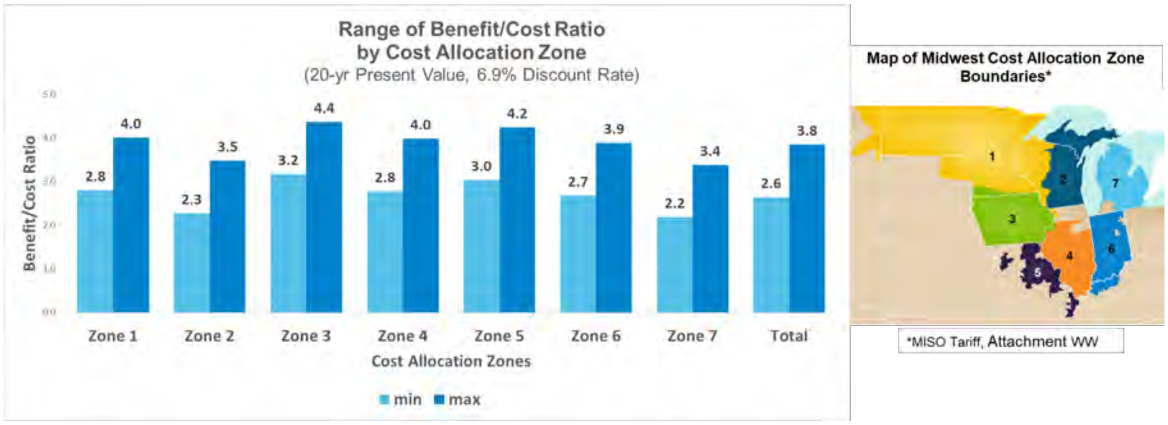


Figure 8-1: Distribution of benefits to Cost Allocation Zones in Midwest Subregion (MISO Tariff Attachment WW) (values as of 6/1/22)

The LRTP Tranche 1 Portfolio provides broad distribution of benefits across the Midwest subregion zones and delivers a benefit to cost ratio of at least 2.2 for every CAZ. Analysis of the zonal benefit distribution indicates that the spread of benefits is roughly commensurate with the allocation of portfolio costs.

9 Natural Gas Price Sensitivity

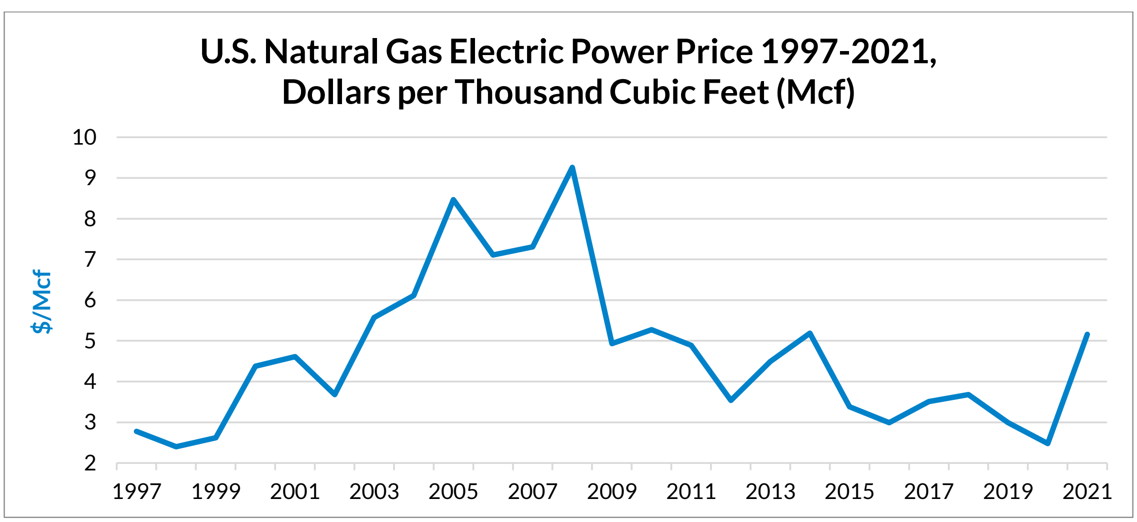


Figure 9-1: Historic U.S. Natural Gas Electric Power Prices

Beginning in 2021, natural gas prices increased sharply, reversing the general price decline seen over the last decade as production grew dramatically from the shale revolution (Figure 9-1).

U.S. export capacity of liquefied natural gas (LNG) has grown rapidly since beginning in 2016, from 0.55 billion cubic feet per day (Bcf/d) to an estimated peak of 11.6 Bcf/d as of November 2021. The U.S. Energy Information Administration estimates U.S. LNG peak export capacity will reach 16.3 Bcf/d by the end of 2024.[23]

Considering the expansion of LNG exports along with the growing prevalence of extreme weather events and current geopolitical developments, U.S. gas price exposure to the global market has increased as well. The recommended LRTP Tranche 1 Portfolio can partially offset the gas price risk by providing additional access to generation powered by fuels other than gas.

Two sensitivity analyses were performed on the LRTP Tranche 1 Congestion and Fuel Savings Reference and Change Case PROMOD models to quantify the impact of changes in gas prices. The sensitivity cases maintained the same production cost modeling assumptions from the business case analysis, except for the gas prices. The sensitivity assumed gas price increases of 20 and 60 percent, respectively. For both analyses, the prices increased starting in the year 2030 and escalated by inflation thereafter.

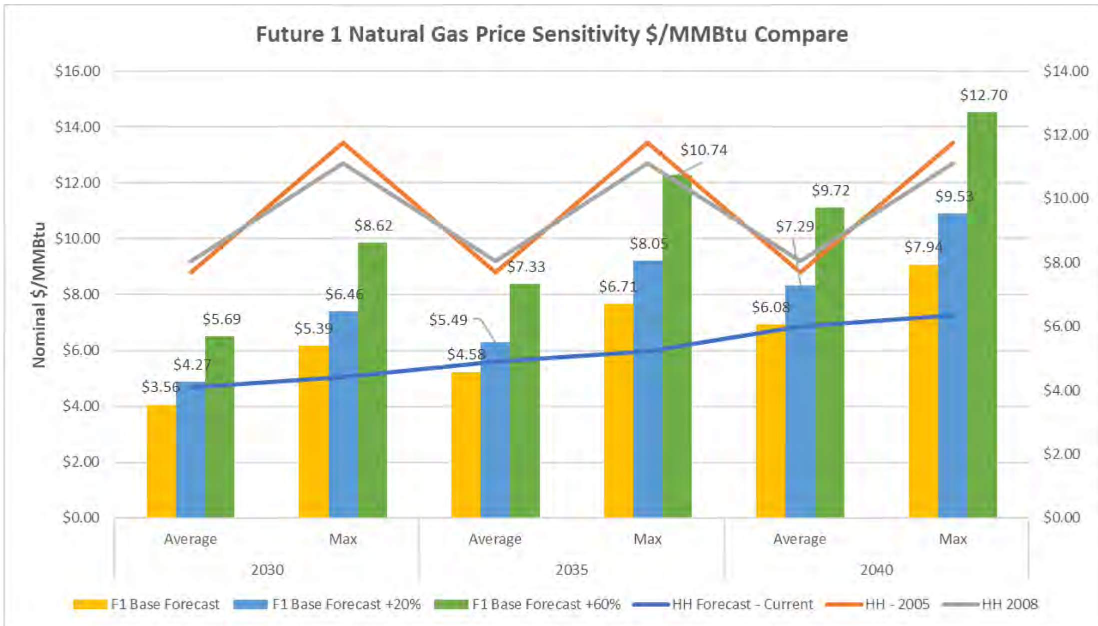


Figure 9-2: Future 1 Natural Gas Price Sensitivity $/MMBtu per LRTP PROMD Study Year

The resulting natural gas price increases achieved (Figure 9-2) created a gas price increase that ensures each study year's average fuel cost is greater than current Henry Hub (HH) projections as

[23] https://www.eia.gov/todayinenergy/detail.php?id=50598

well as representing HH highest historical sale prices from 2005 and 2008. This sensitivity concluded that the LRTP Tranche 1 Portfolio offsets gas price volatility by providing additional Congestion and Fuel Savings benefits by enabling access to renewable energy, as shown in Figure 9-3.

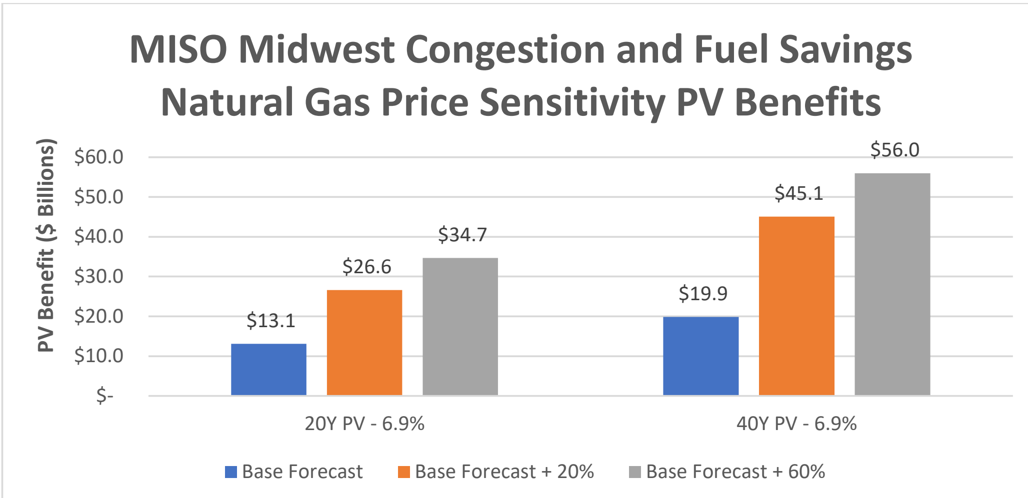


Figure 9-3: Natural Gas Price Sensitivity Results

10 Other Qualitative and Indirect Benefits

In addition to the quantifiable economic and reliability benefits, the LRTP Tranche 1 Portfolio enables other value streams that are reflected qualitatively.

Transmission reinforcements strengthen the grid to support the stability of the larger interconnection and provide greater resilience to recover from unexpected system events without adverse impacts. The interconnected nature of the power system provides support between neighboring systems during severe system disturbances. Regional transmission projects bolster the network, enabling greater bulk power transfers to address the developing conditions and avoid further degradation of the system performance.

Investment in regional transmission projects expand access to a greater diversity of lower-cost resources across the footprint, allowing more options for customer choice of fuel mix. Transmission allows for leveraging of the wide geographic and fuel diversity offered by the MISO region. The stronger regional ties offer more flexibility to handle the variability of renewable output caused by differences in weather patterns across different areas of the MISO footprint. This capability offers greater protection against both market price risk and possible load curtailment measures.

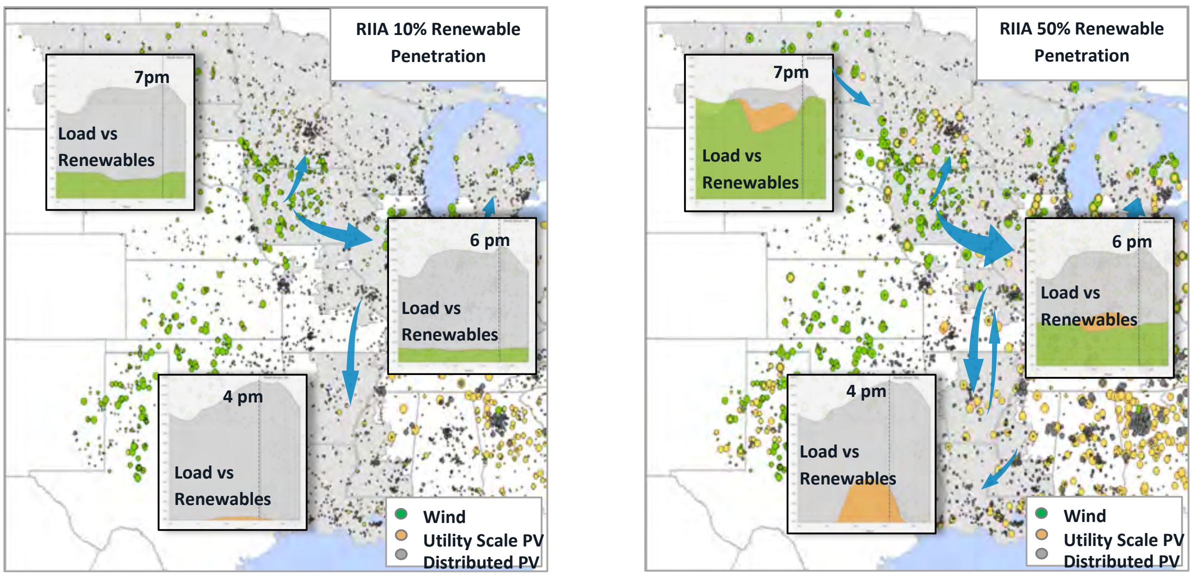


Figure 10-1: Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

The addition of transmission facilities allows greater operational flexibility related to unplanned and planned transmission facility outages. While the Congestion and Fuel Savings metric described earlier captures economic value related to reduced congestion, it represents value under normal system intact conditions. In practice, numerous outages occur throughout the year which introduce additional congestion which is not reflected in the calculation of the economic benefits. Furthermore, as the grid moves to a higher penetration of renewables and seasonal load curve flattens, outage scheduling becomes more challenging. Additional transmission improves system utilization and allows more opportunity for scheduling transmission outages with less risk of causing operational issues or rescheduling of outages.

The LRTP Tranche 1 Portfolio makes use of existing routes, where possible, to reduce the need to acquire additional greenfield right-of-way which lowers costs and allows a shorter time to implementation. Construction of new transmission routes across navigable waterways, protected areas and high value property faces extensive cost and regulatory risks that impede progress in meeting future reliability needs. Co-locating new facilities with existing transmission assets enables more efficient development of transmission projects and minimizes the environment and societal impacts of infrastructure investment needed to achieve the needs identified in MISO's Future 1.

The LRTP Tranche 1 Portfolio gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning of regional transmission provides regulators greater confidence in achieving their policy goals by reducing uncertainty around the future resource expansion plans. Elimination of much of the high transmission cost barriers allows resource planners to assume less risk in making resource investment decisions.

Project Table Field Legend

Appendix A contains projects which are being or have been approved by MISO Board of Directors.
Transmission Owners are obligated to make a good faith effort to construct projects in Appendix A.

Project table has blue highlighted header. A project may have multiple facilities.
Facility table has beige highlighted header. A project's facilities may have different in service dates.

*In some cases, it is not possible to identify the entity with responsibility to own and construct facilities identified in Appendix A of MTEP at the time of Board approval, such as where the facilities are Competitive Transmission Facilities or subject to a State Right of First Refusal law ("ROFR") that requires the applicable Transmissible Owner confirm its intent to construct the facilities within a specified period. MISO has indicated where this has occurred by listing "Local TO(s)" or "To Be Determined" in Column D of Appendix A. MISO staff shall update such entries to list the name of the applicable entity: (1) within 90 days after Board of Director Approval of Appendix A for all facilities subject to state ROFR law; and (2) at the conclusion of the Competitive Developer Selection Process for all Competitive Transmission Facilities.

Project Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEPyy planning cycle. Example: "A in MTEP15" projects were reviewed in MTEP15. .
Region	MISO Planning Region: Central, East, West or South
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems*
PrjID	Project ID: MISO project identifier
Project Name	Project name (short name)
Project Description	A description of the project's components
State 1	State project is located or first state if in multiple states
State 2	If applicable, the second state the project is located
Allocation Type per FF	Project Type per Attachment FF of Tariff. BaseRel is Baseline Reliability, GIP is Generator Interconnection Project, TDSP is Transmission Delivery Service Project, MEP is Market Efficiency Project, MVP is Multi Value Project, Other is none of the above. Preliminary project allocation types may be designated for projects in Appendix B
Share Status	Cost allocation status for projects in Appendix A or moving to Appendix A in current planning cycle. Projects are Shared, Not Shared or Excluded. Preliminary sharing designations may be input for Appendix B projects
Other Type	Indicates the project driver behind Other type projects.
Estimated Cost	Total estimated project cost from Facility table
Expected ISD (Min/Max)	Dates when project is expected to be in service. Min and Max dates. Expected ISD are in Facility table.
Max kV	Maximum facility voltage in project. Summary information from Facility table
Min kV	Minimum facility voltage in project. Summary information form Facility table

MTEP21 LRTP Addendum Appendix A (data as of 06/17/2022)

Target Appendix	Planning Region	Geographic Location by TO Member System	Preliminary PrjId	Project Name	Project Description	State1	State2	System Need	Submitting Comp.	Allocation Type per FF	Share Status	Expected ISD	Max kV	Min kV	Min of Plan Status	Estimated Cost
A in MTEP21	North	MDU, OTP, Local TO(s)	LRTP-1	Jamestown – Ellendale	Install single circuit 345kV transmission line (constructed with double circuit capable 345kV structures) from the existing Jamestown Substation, to the existing Ellendale Substation.	ND	ND	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345	230	Proposed	$438.7M
A in MTEP21	North	Local TO(s)	LRTP-2	Big Stone South – Alexandria – Cassie's Crossing	Install single circuit 345kV transmission line from existing Big Stone South Substation, to the existing Alexandria Substation (constructed with double circuit capable 345kV structures), to the new Cassie's Crossing Substation.	SD	MN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$573.5M
A in MTEP21	North	Local TO(s)	LRTP-3	Iron Range – Benton County – Cassie's Crossing	Install double circuit 345kV transmission line from the existing Iron Range Substation, to the existing Benton Country Substation, to the new Cassie's Crossing Substation.	MN	MN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	500	345	Proposed	$969.9M
A in MTEP21	North	ATC, DPC, SMMPA, WPPI, XEL, Local TO(s)	LRTP-4	Wilmarth – North Rochester – Tremval	Install single circuit 345kV transmission line from the existing Wilmarth Substation, to the existing North Rochester Substation, to the existing Tremval Substation.	MN	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	69	Proposed	$689.1M
A in MTEP21	North	ATC, XEL, Local TO(s)	LRTP-5	Tremval – Eau Claire – Jump River	Install single circuit 345kV transmission line from the existing Tremval Substation, to the existing Eau Claire Substation, to the new Jump River Substation.	WI	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	115	Proposed	$504.5M
A in MTEP21	North	ATC, XEL, Local TO(s)	LRTP-6	Tremval – Rocky Run – Columbia	Install single circuit 345kV transmission line from the existing Tremval Substation, to the existing Rocky Run Substation, to the existing Columbia Substation.	WI	WI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	69	Proposed	$1,049.5M
A in MTEP21	North	Local TO(s)	LRTP-7	Webster – Franklin – Marshalltown – Morgan Valley	Install single circuit 345kV transmission line from the existing Webster Substation, to the existing Franklin Substation, to the existing Marshalltown Substation (constructed with double circuit capable 345kV structures), to the existing Morgan Valley Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345	115	Proposed	$755.0M
A in MTEP21	North	Local TO(s)	LRTP-8	Beverly – Sub 92	Install single circuit 345kV transmission line from the existing Beverly Substation to the existing Sub 92 Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2028	345		Proposed	$231.0M
A in MTEP21	North	Local TO(s), To Be Determined	LRTP-9	Orient – Denny - Fairport	Install single circuit 345kV transmission line from the existing Orient Substation to a new Denny Substation, to the existing Fairport Substation.	IA	MO	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$389.9M
A in MTEP21	Central	AmerenMO, To Be Determined	LRTP-10	Denny – Zachary – Thomas Hill – Maywood	Install single circuit 345kV transmission line from the new Denny Substation to the existing Zachary Substation, to the existing Thomas Hill Substation, to the existing Maywood Substation.	MO	MO	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345	161	Proposed	$768.7M
A in MTEP21	Central	AmerenIL, AmerenMO	LRTP-11	Maywood – Meredosia	Install single circuit 345kV transmission line from the existing Maywood Substation to the existing Meredosia Substation.	MO	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	161	Proposed	$300.8M
A in MTEP21	Central	Local TO(s)	LRTP-12	Madison – Ottumwa – Skunk River	Install single circuit 345kV transmission line from the existing Madison Substation, to the existing Ottumwa Substation, to the existing Skunk River Substation.	IA	IA	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	161	Proposed	$673.0M
A in MTEP21	Central	AmerenIL, Local TO(s)	LRTP-13	Skunk River – Ipava	Install single circuit 345kV transmission line from the existing Skunk River Substation to the existing Ipava Substation.	IA	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/31/2029	345	161	Proposed	$594.4M
A in MTEP21	Central	AmerenIL	LRTP-14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	Install single circuit 345kV transmission line from the existing Ipava Substation, to the existing Maple Ridge Substation, to the existing Tazewell Substation, to the existing Brokaw Substation, to the existing Paxton East Substation.	IL	IL	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2028	345	138	Proposed	$571.7M
A in MTEP21	Central	AmerenIL, NIPSCO	LRTP-15	Sidney – Paxson East – Gilman South – Morrison Ditch	Install single circuit 345kV transmission line from the existing Sidney Substation, to the existing Paxton East Substation, to the existing Gilman South Substation, to the existing Morrison Ditch Substation.	IL	IN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	138	Proposed	$454.1M
A in MTEP21	East	NIPSCO	LRTP-16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	Install single circuit 345kV transmission line from the existing Morrison Ditch Substation, to the existing Reynolds Substation, to the existing Burr Oak Substation, to the existing Leesburg Substation, to the existing Hiple Substation.	IN	IN	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2029	345	138	Proposed	$260.9M
A in MTEP21	East	Local TO(s), To Be Determined	LRTP-17	Hiple – Duck Lake	Install double circuit 345kV transmission line from the existing Hiple to the new Duck Lake Substation.	IN	MI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	6/1/2030	345		Proposed	$696.2M
A in MTEP21	East	Local TO(s)	LRTP-18	Oneida – Nelson Rd.	Install double circuit 345kV transmission line from the existing Oneida Substation, to the existing Nelson Road Substation.	MI	MI	LRTP F1 driven reliability, economic, and public policy needs	MISO	MVP	Shared	12/29/2029	345		Proposed	$403.4M

Facility Table Field Legend

Project table has blue highlighted header. A project may have multiple facilities.
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Facilty Table Field Legend

Field	Description
Target Appendix	Target appendix for the MTEPyy planning cycle. Example: "A in MTEP15" projects were reviewed in MTEP15.
Region	MISO Planning Region: Central, East, West or South
Geographic Location by TO Member System	Project geographic location by Transmission Owner member systems*
PrjID	Indicates the Facility's Project. Projects may have multiple facilities.
Facility ID	Facility ID: MISO facility identifier
Expected ISD	Expected In Service Date for this facility
From Sub	From substation for transmission line or location of transformer or other equipment
To Sub	To substation for transmission line or transformer designation
Ckt	Circuit identifier
Max kV	Maximum voltage of this facility
Min kV	Minimum voltage of this facility (transformer low-side voltage)
Facility Rating	Rating of the facility in applicable units. Typically Summer rate
Facility Description	Brief description of transmission facility
State	State the facility is located in
Miles Upg.	Transmission line miles on existing rights of way (ROW)
Miles New	Transmission line miles on new rights of way (ROW)
Plan Status	Indicates status of project in planning or implementation. Conceptual, Proposed, Planned, Last Milestone Achieved, Under Construction and In Service
Estimated Cost	Total estimated facility cost
Cost Shared	Y if facility is cost shared per Attachment FF
Postage Stamp	Y if facility has postage stamp cost allocation per Attachment FF
MISO Facility	Y for facilities under MISO functional control. NT for non-transferred facilities under Agency Agreements

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	North	OTP	1		SUB	12/31/2028	Jamestown 345 kV			345		3000	1793	Add 1-345kV line position (replace existing 345kV ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Ellendale)	ND				$15.6M
A in MTEP21	A	North	MDU, OTP	1		LN	12/31/2028	Jamestown 345 kV	Ellendale 345		345		3000	1793	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	ND		95		$379.6M
A in MTEP21	A	North	MDU	1		SUB	12/31/2028	Ellendale 345			345		3000	1793	Add 1-345kV line position (replace existing 345kV ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Jamestown)	ND				$9.5M
A in MTEP21	A	North	OTP	1		SUB	12/31/2028	Maple River 345 kV			345	230		2 transformer each 500MVA	Replace two existing 230/345kV, 336MVA transformers with two new 230/345kV 500MVA transformers	ND				$22.0M
A in MTEP21	A	North	Local TO(s)	1		SUB	12/31/2028	Twin Brooks 345 kV			345		N/A	N/A	Add 2-345kV 25MVAr shunt connected reactors in substation	SD				$12.0M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Big Stone South 345 kV			345		3000	1793	Add 1-345kV line position (replace existing ring bus with breaker-and-a-half bus) Add 1-345kV 50MVAr line reactor (for outgoing transmission line to Alexandria 345kV)	SD				$12.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Big Stone South 345 kV	Alexandria 345kV		345		3000	1793	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	SD/MN		128		$441.2M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Alexandria 345kV			345		3000	1793	Add 2-345kV breaker-and-a-half positions (replace existing 345kV ring bus with breaker-and-a-half bus) Add 2 345kV 50MVAr line reactors (for outgoing transmission line to Big Stone South and outgoing transmission line to Cassie's Crossing)	MN				$16.7M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Alexandria 345kV	Outside Monticello Substation		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on Alexandria - Monticello 345kV line.	MN	106			$36.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Outside Monticello Substation	Cassie's Crossing		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit capable 345kV transmission line, one circuit initially strung, Mississippi river crossing will include second circuit. Strung circuit will carry Alexandria-Cassie Crossing circuit.	MN	1.5	1.5		$15.0M
A in MTEP21	A	North	Local TO(s)	2		LN	6/1/2030	Cassie's Crossing			345		3000	1793	Modify existing 345kV transmission lines to connect into Cassie's Crossing Substation.	MN	2			$10.3M
A in MTEP21	A	North	Local TO(s)	2		SUB	6/1/2030	Cassie's Crossing			345		3000	1793	Construct new 11-position, 345kV breaker-and-a-half bus substation	MN				$42.3M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Cassie's Crossing	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. Both lines will tie to Benton County.	MN	12.5			$48.8M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2028	Sherco	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W		345		3000	1793	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including south deadend structure for new conductor. This line will tie to Benton County.	MN	7.3			$25.0M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Benton County		345		3000	1793	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. One line will tie to Sherco and other to Cassie Crossing.	MN	12.5			$48.8M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2028	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Benton County		345		3000	1793	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including north deadend structure for new conductor. This line will tie to Cassie Crossing.	MN	14.1			$47.4M

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A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Benton County			345		3000	1793	Add 345kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two line connected 70MVAr shunt reactors on Iron Range lines, and modify 230kV position for one 230/345kV transformer	MN				$25.5M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Benton County	Riverton 230/115kV		345		3000	1793	Construct new 345kV double circuit transmission line	MN		78		$312.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Riverton 230/115kV			345		3000		Add 4-345kV series capacitor bank groups (2 in series for each circuit) with protective bypass equipment. Impedance of series capacitor bank will be approximately 60% compensation of line	MN				$80.0M
A in MTEP21	A	North	Local TO(s)	3		LN	6/1/2030	Riverton 230/115kV	Iron Range 500/230kV		345		3000	1793	Construct new 345kV double circuit transmission line	MN		78		$312.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			345		3000	1793	Add 4-position 345kV ring bus (expandable to breaker-and-a-half bus) for 2-345/500kV transformer positions and 2 line positions (includes 2-345 kV shunt reactors on lines to Benton, est. 50 MVAR each)	MN				$20.0M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			500	345		1200	Add 2-345/500kV 1200MVA transformers (with 1 single phase spare on-site)	MN				$36.4M
A in MTEP21	A	North	Local TO(s)	3		SUB	6/1/2030	Iron Range 500/230kV			500		3000	2598	Add 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX)	MN				$14.0M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Crandall	Last double circuit structure from Wilmarth (44.032, -94.293)		345		3000	1793	Increase load capability of existing transmission line	MN	30			$69.2M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			345		3000	1793	Add 1-345kV transformer position (replace existing ring bus with breaker-and-a-half bus)	MN				$3.3M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			345	115		448	Add 1-115/345kV 448MVA transformer	MN				$6.8M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2026	Chub Lake			115		3000	598	Add 1-115kV transformer position (replace existing ring bus with breaker-and-a-half bus)	MN				$2.6M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Wilmarth			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	MN				$4.6M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Wilmarth	North Rochester		345	115	345kV: 3000 115kV: 1834	345kV: 1793 115kV: 365.3	Replace existing XEL Wilmarth - Faribault Energy Park single circuit 115kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 115kV. Construct new 345kV single circuit transmission line from Faribault Energy Park - North Rochester	MN	44	42		$327.9M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	North Rochester			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MN				$6.5M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	North Rochester	161kV structure along line to Chester (44.173, -92.390)		161		1746	487	Construct new 161kV single circuit transmission line	MN		17		$28.7M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	North Rochester	161kV structure along line to Chester (44.173, -92.390)		345		3000	1793	Re-energize existing (currently operated at 161kV) conductors to 345kV	MN				$.0M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line to Chester (44.173, -92.390)	161kV structure along line Wabaco (44.1937, -92.0859)		345		3000	1793	Install second 345kV circuit on existing spare position	MN	17			$7.7M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line Wabaco (44.1937, -92.0859)	Kellogg		161		2000	558	Construct new 161kV single circuit transmission line	MN		11		$18.8M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg			161		2000		Construct transmission structures to cut-in existing Wabaco - Alma 161kV transmission line into Kellogg Substation	MN	1			$1.5M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			161		2000		Construct new 3-position 161kV ring bus in the Kellogg Substation 1. Cut-in to existing Wabaco - Alma 161kV transmission line 2. Cut-in to existing Wabaco - Alma 161kV transmission line 3. 69/161kV, 112MVA transformer	MN				$6.7M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			161	69		112	Add 1-69/161kV, 112MVA transformer	MN				$.7M

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A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Kellogg			69		2000		Construct new 2-position 69kV straight bus in the Kellogg Substation and cut-in existing Alma-Utica 69 kV transmission line.	MN				$1.9M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg			69		2000		Construct transmission structures to cut-in existing Alma-Utica 69kV transmission line into Kellogg Substation	MN	1			$1.3M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	Kellogg	Alma						Install OPGW across Mississippi River to provide communications protection of new Alma-Kellogg 161 kV line	MN				$.2M
A in MTEP21	A	North	DPC	4		SUB	6/1/2028	Alma			161				Protection Upgrade at Alma to accommodate new Alma-Kellogg 161 kV line protection Requirements	WI				$.3M
A in MTEP21	A	North	Local TO(s)	4		LN	6/1/2028	161kV structure along line Wabaco (44.1937, -92.0859)	345kV deadend structure (44.297, -91.905)		345		3000	1793	Re-energize existing (currently operated at 161kV) conductors to 345kV	MN				$.0M
A in MTEP21	A	North	DPC	4		LN	6/1/2028	345kV deadend structure (44.297, -91.905)	161kV structure outside Alma Substation		345	69	345kV: 3000 69kV: 552	345kV: 1793 69kV: 66	Replace existing DPC single circuit 69kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 69kV.	WI	1			$4.3M
A in MTEP21	A	North	DPC	4		LN	6/1/2028	161kV structure outside Alma Substation	Tremval		345	161	345kV: 3000 161kV: 1237	345kV: 1793 161kV: 345	Replace existing DPC single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV.	WI	34			$167.8M
A in MTEP21	A	North	ATC, DPC, SMMPA, WPPI, XEL	4		LN	6/1/2028	Tremval			345		3000	1793	Modify existing Briggs Road - North Madison single circuit 345 kV transmission line to construct transmission structures to cut-in existing Briggs Road - North Madison 345kV transmission line into Tremval Substation	WI	1			$4.6M
A in MTEP21	A	North	Local TO(s)	4		SUB	6/1/2028	Tremval			345		3000	1793	Add 6-345kV line positions (breaker-and-a-half bus). 1. New transmission line from near Alma 2. New transmission line to Eau Claire 3. Cut-in to existing Briggs Road-North Madison 345kV line 4. Cut-in to existing Briggs Road-North Madison 345kV line 5. New transmission line to Rocky Run Substation 6. Bus connected 345kV, 80MVAr reactor	WI				$23.7M
A in MTEP21	A	North	Local TO(s)	5		LN	6/1/2028	Tremval	Eau Claire		345	161	345kV: 3000 161kV: 601	345kV: 1793 161kV: 167.6	Replace existing Xcel single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV.	WI	46			$226.7M
A in MTEP21	A	North	XEL	5		SUB	6/1/2028	Eau Claire			345		3000	1793	Add 2-345kV line positions (ring bus). 1. New transmission line to Tremval 2. New transmission line to Jump River	WI				$5.4M
A in MTEP21	A	North	ATC, XEL	5		LN	6/1/2028	Eau Claire	Jump River		345	115	345kV: 3000 161kV: 1266 115kV: 1200	345kV: 1793 161kV: 353 115kV: 239	Replace existing Xcel single circuit 161kV and 115kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV or 115kV.	WI	51			$250.9M
A in MTEP21	A	North	ATC	5		LN	6/1/2028	Jump River (45.3, -90.95)			345		3000	1793	Modify existing Stone Lake -- Gardner Park 345 kV single-circuit transmission line to construct transmission structures to cut-in existing Stone Lake - Gardner Park 345kV transmission line into Jump River Substation. Remote station upgrades.	WI	1			$4.6M
A in MTEP21	A	North	ATC	5		SUB	6/1/2028	Jump River (45.3, -90.95)			345		3000	1793	Construct new 4-position, 345kV ring bus substation. 1). New transmission line from Eau Claire 2). Cut-in to existing Stone Lake to Gardner Park 3). Cut-in to existing Stone Lake to Gardner Park 4). Bus-connected 345kV, 80MVAr reactor	WI				$16.9M
A in MTEP21	A	North	~~ATC, XEL~~ Local TO(s)	6		LN	6/1/2029	Tremval	Rocky Run		345		345kV: 3000 138kV: 895 69kV: 142	345kV: 1793 138kV 214 69kV: 17	Replace existing Xcel single circuit 69 kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 69kV for approximately 21 miles. Construct new 345kV single circuit transmission line for approximately 47 miles. Replace existing ATC single and double circuit 69kV, 138kV and 345kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 69kV, 138kV or 345kV for approximately 31 miles.	WI	52	47		$398.4M
A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Rocky Run			345		3000	1793	Modify existing transmission lines to connect to Rocky Run substation	WI	3			$9.5M

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A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Rocky Run			345		3000	1793	Replace existing 6-position 345kV ring bus, with 9-position 345kV breaker-and-a-half bus. Replaced bus will terminate all existing 6-positions, and 3 new bus positions - 1). New transmission line from Tremval 2). New transmission line to Columbia 3). Bus-connected 345kV, 80MVAr reactor	WI				$38.3M
A in MTEP21	A	North	ATC	6		LN	6/1/2029	Rocky Run	Columbia		345	69	345kV: 3000 138kV: 766 115kV: 1682 69kV: 669	345kV: 1793 138kV: 183 115kV: 335 69kV: 80	Replace existing single circuit 69kV, 115kV, 138kV, and 345kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 69kV, 115kV, 138kV or 345kV.	WI	114			$558.2M
A in MTEP21	A	North	ATC	6		LN	6/1/2029	345 kV Structure (43.477439, -89.284950)	Columbia		345		345kV: 3000	345kV: 1793	Replace existing double circuit 345 kV structures with new double circuit 345 kV structures, both 345 kV circuits rated for 3000Amps	WI	9			$35.2M
A in MTEP21	A	North	ATC	6		SUB	6/1/2029	Columbia			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus). 1). New transmission line to Rocky Run 2). Bus-connected 345kV, 80MVAr reactor	WI				$9.9M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2026	Webster			345		3000	1793	Add 1-345kV line position (ring bus)	IA				$3.8M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2026	Webster	North Franklin		345	161	345kV: 2912 161kV: 1008	345kV: 1740 161kV: 281	Replace existing MEC single circuit 161kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	42	1		$135.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2026	North Franklin			345		3000	1793	Construct new 4-345kV line position (breaker-and-a-half bus) substation. 1. New transmission line from Webster 2. New transmission line to Marshalltown 3. Cut-in to existing Quinn-Black Hawk 345kV line 4. Cut-in to existing Quinn-Black Hawk 345kV line Add 2-345kV 50MVAr line reactors for outgoing transmission lines to Webster and to Marshalltown	IA				$44.3M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2028	North Franklin	Marshalltown		345		2912	1740	Construct new 345kV single circuit transmission line (constructed with double circuit capable 345kV structures)	IA		69		$310.5M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			345		3000	1793	Add 3-345kV positions (ring bus, expandable to breaker-and-a-half bus). 1. New transmission line to North Franklin 2. New transmission line to Morgan Valley 3. 1-161/345kV 560MVA transformer Add 1-345kV 55MVAr line reactor for outgoing transmission line to Morgan Valley	IA				$21.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			345	161		560	Add 1-161/345kV 560MVA transformer	IA				$7.5M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			161	115		250	Add 1-115/161kV 250MVA transformer	IA				$3.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			161		3000	837	Add 1-161kV transformer position (breaker-and-a-half bus) for the 161/345kV transformer Utilize existing spare 161 kV position for 115/161kV transformer	IA				$2.3M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Marshalltown			115		2000	398	Add 1-115kV transformer position	IA				$1.5M
A in MTEP21	A	North	Local TO(s)	7		LN	12/31/2027	Marshalltown	Morgan Valley		345		3000	1793	Replace existing 115kV transmission line with new 345kV single circuit transmission line	IA	65			$221.0M
A in MTEP21	A	North	Local TO(s)	7		SUB	12/31/2027	Morgan Valley			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IA				$5.1M
A in MTEP21	A	North	Local TO(s)	8		SUB	12/31/2028	Beverly			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus) Add 1-345kV 55MVAr line reactor for outgoing transmission line to Sub 92	IA				$9.0M
A in MTEP21	A	North	Local TO(s)	8		LN	12/31/2028	Beverly	Sub 92		345		2912	1740	Construct new 345kV single circuit transmission line and replace existing 115kV transmission line with new 345kV single circuit transmission line for a portion of the route	IA	28	30		$203.0M
A in MTEP21	A	North	Local TO(s)	8		SUB	12/31/2028	Sub 92			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus)	IA				$19.0M
A in MTEP21	A	North	Local TO(s)	9		SUB	6/1/2030	Orient			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus) Add 1-345kV 50 MVAr line reactor (for outgoing line to Denny)	IA				$10.0M
A in MTEP21	A	North	Local TO(s)	9		LN	6/1/2030	Orient	IA/MO State Border		345		2912	1740	Construct new 345kV single circuit transmission line.	IA	8	44		$208.0M

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A in MTEP21	A	North	To Be Determined	9		LN	6/1/2030	IA/MO State Border	Denny		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		50		$139.3M
A in MTEP21	A	North	To Be Determined	9		SUB	6/1/2030	Denny			345		3000	1793	Construct new 4-position 345kV ring bus substation. 1. New transmission line to Orient. 2. New transmission line to Fairport. 3. New transmission line to Zachary. 4. Add 1-345kV bus 50 MVAr reactor	MO				$15.3M
A in MTEP21	A	North	To Be Determined	9		LN	6/1/2030	Denny	Fairport		345		3000	1793	Construct new 345kV single circuit transmission line	MO		2		$6.0M
A in MTEP21	A	North	To Be Determined	9		SUB	6/1/2030	Fairport			345		3000	1793	Add 1-345kV line position (replace existing bus with ring bus)	MO				$11.3M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Denny	Zachary		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		135		$375.0M
A in MTEP21	A	Central	AmerenMO	10		SUB	6/1/2030	Zachary			345		3000	1793	Add 3-345kV positions (replace existing ring bus with breaker-and-a-half bus). 1. New transmission line to Denny 2. New transmission line to Thomas Hill 3. New transmission line to Maywood	MO				$12.6M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Zachary	Maywood		345		3000	1793	Construct new 345kV single circuit transmission line.	MO		60		$166.5M
A in MTEP21	A	Central	AmerenMO	10		LN	6/1/2030	Zachary	Thomas Hill		345	161	161kV: 1198	161kV: 334	Replace existing Ameren single circuit 161kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 161kV. Replace existing 161kV conductor, insulators, and hardware.	MO	44			$189.5M
A in MTEP21	A	Central	To Be Determined	10		LN	6/1/2030	Zachary	Thomas Hill		345	161	345kV: 3000	345kV: 1793	Install new 345kV conductor, insulators, and hardware on replaced transmission line structures.	MO	44			$14.4M
A in MTEP21	A	Central	To Be Determined	10		SUB	6/1/2030	Thomas Hill			345		3000	1793	Add 1-345kV line position	MO				$4.2M
A in MTEP21	A	Central	AmerenMO	10		SUB	6/1/2030	Maywood			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MO				$6.5M
A in MTEP21	A	Central	AmerenIL, AmerenMO	11		LN	6/1/2028	Maywood	Meredosia		345	161	345kV: 3000 161kV: 1162 138kV: 1360	345kV: 1793 161kV: 324 138kV: 325	Replace existing Ameren 161kV single circuit transmission line with double circuit structures capable of support 1 circuit at 345kV and 1 circuit at 161kV for approximately 6 miles. Replace existing Ameren 138kV single circuit transmission line with double circuit structures capable of support 1 circuit at 345kV and 1 circuit at 138kV for approximately 56 miles. Construct new 345kV single circuit transmission line for approximately 2.5 miles	MO/IL	62	2.5		$296.6M
A in MTEP21	A	Central	AmerenIL	11		SUB	6/1/2028	Meredosia			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IL				$4.2M
A in MTEP21	A	Central	Local TO(s)	12		SUB	12/31/2028	Madison County			345		3000	1793	Add 1-345kV line position (ring bus) Add 1-345kV, 50MVAr line reactor (for outgoing line to Ottumwa)	IA				$10.3M
A in MTEP21	A	Central	Local TO(s)	12		LN	12/31/2028	Madison County	Ottumwa Generation		345	161	345kV: 3000 161kV: 599	345kV: 1793 161kV: 167	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Lucas County - Ottumwa). The portion that uses the existing 161kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	42	53		$378.5M
A in MTEP21	A	Central	Local TO(s)	12		SUB	12/31/2026	Ottumwa Generation			345		3000	1793	Add 3-345kV line positions (replace existing bus with breaker-and-a-half bus). 1. New transmission line to Madison County 2. New transmission line to Skunk River 3. Bus-connected 345kV, 55MVAr reactor	IA				$11.9M
A in MTEP21	A	Central	Local TO(s)	12		LN	12/31/2026	Ottumwa Generation	Skunk River		345	161	345kV: 3000 161kV: 599	345kV: 1793 161kV: 167	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Ottumwa - Woody - Jefferson County - Henry County). The portion that uses the existing 161kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA	60	2		$248.0M
A in MTEP21	A	Central	Local TO(s)	12		SUB	6/1/2029	Skunk River (40.973, -91.634)			345		3000	1793	Modify existing Sub T - Maywood 345 kV single-circuit transmission line to construct transmission structures to cut-in existing Sub T - Maywood 345kV transmission line into Skunk River Substation	IA	1			$2.6M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	Central	Local TO(s)	12		SUB	6/1/2029	Skunk River (40.973, -91.634)			345		3000	1793	Construct new 5-position 345kV breaker-and-a-half bus substation 1. New transmission line to Ottumwa 2. New transmission line to Denmark 3. Cut-in to existing Sub T - Maywood transmission line 4. Cut-in to existing Sub T - Maywood 5. Bus-connected 345kV, 50MVAr reactor	IA				$21.7M
A in MTEP21	A	Central	Local TO(s)	13		LN	12/31/2029	Skunk River	Denmark		345	161	345kV: 3000 161kV: 800	345kV: 1793 161kV: 223	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Jefferson County - Henry County - Denmark). The portion that uses the existing 161 kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA		25		$102.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			161		3000	837	Add 1-161kV transformer position (replace existing bus to breaker-and-a-half bus)	IA				$18.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			345	161		560	Add 161/345kV 560 MVA transformer	IA				$7.5M
A in MTEP21	A	Central	Local TO(s)	13		SUB	12/31/2029	Denmark			345		3000	1793	Add 3-345kV positions (ring bus) 1. New Transmission line to Skunk River 2. New transmission line to Ipava 3. New 161/345kV 560MVA transformer Add 1-345kV, 55MVAr line reactor (for outgoing transmission line to Ipava)	IA				$15.6M
A in MTEP21	A	Central	Local TO(s)	13		LN	12/31/2029	Denmark	IA/IL State Border - Mississippi River		345		3000	1793	Construct new 345kV single circuit transmission line (a portion of the route assumed to be double circuit with existing ITCM single circuit 161kV structures between Denmark - Burlington). The portion that uses the existing 161 kV line route will utilize double circuit structures 1 circuit operated at 345kV and 1 circuit operated at 161kV.	IA		30		$123.0M
A in MTEP21	A	Central	AmerenIL	13		LN	6/1/2028	IA/IL State Border - Mississippi River	Ipava		345		3000	1793	Replace existing Ameren-IL 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138 kV.	IL	69			$320.8M
A in MTEP21	A	Central	AmerenIL	13		SUB	6/1/2028	Ipava			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IL				$6.5M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Ipava	Maple Ridge		345		Replaced segment: 3000 Spare position segment: 2000	Replaced segment: 1793 Spare position segment: 1195	Replace existing transmission line, and install second 345kV on spare position. Replaced transmission line structures will be capable of supporting 2-345kV circuits. Replaced segment: 21 miles of Ameren-IL single circuit 345kV structures from Ipava, to a structure outside Duck Creek (40.4598, -89.9851). Replace existing 345kV conductor with new conductor. Second circuit on spare position: 21 miles from a structure outside Duck Creek (40.4598, -89.9851) to Maple Ridge	IL	42			$90.5M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Maple Ridge			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	IL				$7.3M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Maple Ridge	Tazewell		345		345kV: 2000 138kV: 2000 69kV: 1200	345kV: 1195 138kV: 478 69kV: 143	Construct new and re-energize existing conductors to a higher voltage (currently operated at 69kV from Maple Ridge to Edwards & at 138kV from Edwards to Tazewell) to 345kV. Construct new 69kV single circuit transmission line for approximately 5.5 miles from a structure outside Maple Ridge (40.595, -89.759) to Edwards Construct new 138kV single circuit transmission line from Edwards to Tazewell for approximately 9 miles.	IL		14.5		$22.3M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Tazewell			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IL				$6.5M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Tazewell	Brokaw		345		345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures (Havanna - Old Danvers) with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 25 miles. Construct new 345kV single circuit transmission line for approximately 20 miles.	IL	25	20		$173.0M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Brokaw			345		3000	1793	Add 6-position 345kV breaker-and-a-half bus 1. Re-terminate Brokaw-South Bloomington into added bus 2. Re-terminate Brokaw-Clinton into added bus 3. New transmission line to Tazewell 4. New transmission line to Paxton East 5. Tie to existing Brokaw ring bus 6. Tie to existing Brokaw ring bus	IL				$21.7M
A in MTEP21	A	Central	AmerenIL	14		LN	6/1/2028	Brokaw	Paxton East		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV.	IL	45			$209.1M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			345		3000	1793	Add 5-position 345kV breaker-and-a-half bus 1. New transmission line to Brokaw 2. New transmission line to Gilman South 3. New transmission line Sidney 4. 1-138/345kV 700MVA transformer 5. Bus-connected, 345kV, 50MVAr reactor	IL				$23.1M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			345	138		700	Add 1-138/345kV 700MVA transformer	IL				$5.9M
A in MTEP21	A	Central	AmerenIL	14		SUB	6/1/2028	Paxton East			138		3000	717	Replace 6-position 138kV breaker-and-a-half bus 1. Re-terminate Paxton-Paxton East into replaced bus 2. Re-terminate Paxton East-Gilman South into replaced bus 3. Re-terminate Paxton East-Sidney into replaced bus 4. Re-terminate Paxton East-Hoopeston into replaced bus 5. Re-terminate Paxton East-Pioneer Wind into replaced bus 6. New 138/345kV 700MVA transformer	IL				$12.3M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Sidney			345		3000	1793	Add 1-345kV line position (breaker-and-a-half bus)	IL				$3.8M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Sidney	Paxton East		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures with 1 circuit operated at 345kV and 1 circuit operated at 138kV.	IL	31			$144.7M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Paxton East	Gilman South		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren single circuit 138kV structures with double circuit structures, with 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 21 miles. Construct new 345kV single circuit transmission line for approximately 2.5 miles	IL	21	2.5		$104.8M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			345		3000	1793	Add 3-position 345kV ring bus (expandable to breaker-and-a-half bus) 1. New transmission line to Paxton East 2. New transmission line to Morrison Ditch 3. 1-138/345kV 700MVA transformer	IL				$12.0M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			345	138		700	Add 1-138/345kV 700MVA transformer	IL				$5.9M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Gilman South			138		3000	717	Add 1-138kV line position (replace existing bus with ring bus)	IL				$6.7M
A in MTEP21	A	Central	AmerenIL, NIPSCO	15		LN	6/1/2029	Gilman South	Morrison Ditch		345	138	345kV: 3000 138kV: 2000	345kV: 1793 138kV: 478	Replace existing Ameren & NIPSCO single circuit 138kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 30 miles. Construct new 345kV single circuit transmission line for approximately 2 miles.	IL	30	2		$147.5M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			345		3000	1793	Add 3-345kV positions ring bus (expandable to breaker-and-a-half bus) 1. New Transmission line from Gilman South 2. New Transmission line to Reynolds 3. New 138/345kV 560MVA transformer	IN				$11.8M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			345	138		560	Add 1-138/345kV 560MVA transformer	IN				$4.8M
A in MTEP21	A	Central	NIPSCO	15		SUB	6/1/2029	Morrison Ditch			138		3000	717	Add 1-138kV transformer position (ring bus) Replace substation bus for 3000A	IN				$2.3M
A in MTEP21	A	Central	AmerenIL	15		LN	6/1/2029	Hoopeston West	Rossville		138		2000	478	Replace 138kV conductor to achieve 2000A	IL	5.5			$8.8M
A in MTEP21	A	Central	AmerenIL	15		SUB	6/1/2029	Hoopeston West			138		2000	478	Replace substation bus to achieve 2000A	IL				$1.0M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Morrison Ditch	Reynolds		345	138	345kV: 3000 138kV: 3000	345kV: 1793 138kV: 717	Replace existing NIPSCO single circuit 138kV structures with double circuit structures capable of supporting 1 circuit operated at 345kV and 1 circuit operated at 138kV for approximately 30 miles. Construct new 345kV single circuit transmission line for approximately 7 miles.	IN	30	7		$157.7M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Goodland				138	3000	717	Replace terminal equipment to achieve 3000A	IN				$1.0M

Target Appendix	App ABC	Planning Region	Geographic Location by TO Member System	PrjID2	Facility ID	Facility Type	Expected ISD	From Sub	To Sub	Ckt	Max kV	Min kV	Minimum Summer Emergency Facility Rating (Amps)	Minimum Summer Emergency Facility Rating (MVA)	Facility Description	State	Miles Upgrade	Miles New	Plan Status	Estimated Cost
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			345		3000	1793	Add 3-345kV line positions (breaker-and-a-half bus) 1. New transmission line to Morrison Ditch 2. New transmission line to Burr Oak 3. New 138/345kV 560MVA transformer	IN				$14.9M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			345	138		2 transformers of 560MVA each	Add 1-138/345kV 560 MVA transformer Replace 1-138/345kV 350 MVA transformer with a 138/345kV 560MVA transformer	IN				$9.5M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Reynolds			138		3000	717	Add 1-138kV transformer position Replace existing straight bus with a ring (expandable to breaker-and-a-half) bus	IN				$7.7M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Reynolds	Monticello		138		2368	566	Replace 138kV conductor from ACSR conductor to ACSS conductor of same size and replace fiber optic cable	IN	7			$11.1M
A in MTEP21	A	East	NIPSCO	16		SUB	6/1/2029	Monticello			138		3000	717	Replace terminal equipment to achieve 3000A	IN				$1.0M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Reynolds	Burr Oak		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on existing Reynolds - Burr Oak 345kV transmission line	IN	48			$15.8M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Burr Oak			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	IN				$6.5M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Burr Oak	Leesburg		345		3000	1793	Install second 345kV circuit on open spare position on existing structures on existing Burr Oak - Leesburg 345kV line	IN	29			$9.5M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Leesburg			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	IN				$7.3M
A in MTEP21	A	East	NIPSCO	16		LN	6/1/2029	Leesburg	Hiple, F G		345		3000	1793	Add 345kV circuit to spare position on existing transmission line structure	IN	23			$7.6M
A in MTEP21	A	East	NIPSCO	16		Sub	6/1/2029	Hiple, F G			345		3000	1793	Add 3-345kV line positions (breaker-and-a-half bus) 1. New transmission line to Leesburg 2. New transmission line to Duck Lake 3. New transmission line to Duck Lake	IN				$11.3M
A in MTEP21	A	East	To Be Determined	17		LN	6/1/2030	Hiple, F G	IN/MI State Border		345		3000	1793	Construct new 345kV double circuit transmission line	IN		55		$253.7M
A in MTEP21	A	East	Local TO(s)	17		LN	6/1/2030	IN/MI State Border	Duck Lake		345		3000	1793	Construct new 345kV double circuit transmission line	MI		72		$406.7M
A in MTEP21	A	East	Local TO(s)	17		SUB	12/29/2026	Duck Lake (42.41, -84.792)			345		3000	1793	Construct new 8-position 345kV breaker-and-a-half bus substation. Loop in Argenta-Tompkins, Battle Creek-Oneida, and Oneida-Majestic 345 kV lines into Duck Lake.	MI				$35.8M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2029	Oneida			345		3000	1793	Add 2-345kV line positions (replace existing bus with breaker-and-a-half bus)	MI				$8.9M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2029	Oneida	Nelson Road		345		3000	1793	Construct new 345kV double circuit transmission line	MI		38.5		$181.9M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2029	Nelson Road			345		3000	1793	Add 2-345kV line positions (breaker-and-a-half bus)	MI				$5.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2026	Duck Lake (42.41, -84.792)	Tompkins		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	16			$20.6M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2027	Tompkins	Majestic		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	28			$36.0M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Tompkins			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$2.2M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Majestic			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$1.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2028	Majestic	Wayne		345		3000	1793	Replace conductor to achieve 3000A	MI	31			$55.9M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Wayne			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$5.5M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2028	Majestic	Coventry		345		3000	1793	Replace conductor to achieve 3000A	MI	20			$26.5M
A in MTEP21	A	East	Local TO(s)	18		SUB	12/29/2028	Coventry			345		3000	1793	Replace terminal equipment to achieve 3000A	MI				$1.1M
A in MTEP21	A	East	Local TO(s)	18		LN	12/29/2027	Duck Lake (42.41, -84.792)	Majestic		345		3000	1793	Replace double circuit 345kV transmission line (one circuit)	MI	43.5			$57.8M

Appendix E-2

MISO's LRTP Tranche 1 Portfolio Detailed Business Case

LRTP Tranche 1 Portfolio Detailed Business Case

1

- Long Range Transmission Planning (LRTP) addresses the future challenges of the resource fleet evolution
- The LRTP Detailed Business Case summarizes the analysis of the reliability and economic benefits used to demonstrate that the value exceeds the total cost of the projects and supports recommendation of the portfolio
- The LRTP Tranche 1 portfolio provides a total 20-year present value benefit to cost ratio of 2.6

MISO Transmission Planning Objectives

- The goal of MISO Planning is to identify and support development of transmission infrastructure that is sufficiently robust to meet reliability needs and support a competitive energy market, policy goals and competitive transmission development
- MISO Board of Directors Guiding Principles
  - Ensure a reliable and resilient transmission system to meet operational needs
  - Make benefits of an economically efficient electricity market available to customers by identifying transmission solutions that enable access to the electricity at the lowest total electric system cost
  - Support federal, state and local energy policy and member goals by planning for access to a changing resource mix
  - Provide an appropriate cost allocation mechanism that ensures that costs are allocated in a manner roughly commensurate with the projected benefits
  - Analyze system scenarios and make results available to energy policy makers and stakeholders to provide context and inform their choices
  - Coordinate planning process with neighbors and work to eliminate barriers to reliable and efficient operations

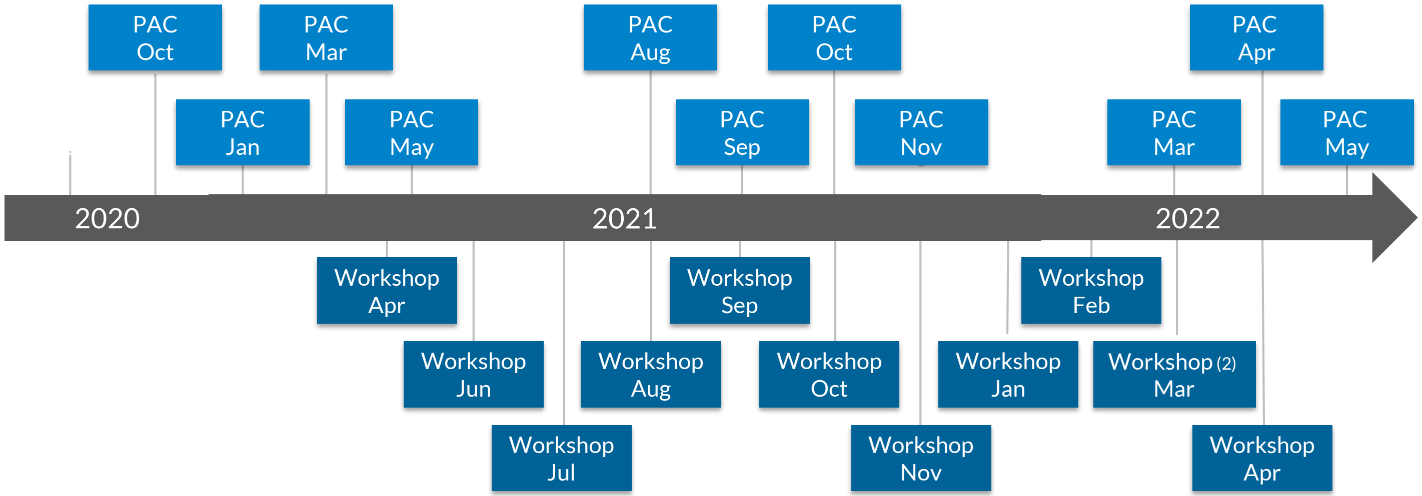
Long range focus on system planning needed in response to unprecedented industry changes

- The initial 2019 MISO Forward report began to examine industry trends around resource and technology developments that highlighted growing challenges around resource availability, flexibility and visibility of the resource fleet in meeting future energy needs
- The Renewable Integration Impact Assessment explored challenges of increased renewable penetration and identified significant reliability issues that would need to be addressed through possible reinforcements to maintain robust performance
- In recognition of the need for more long-term proactive planning to meet the pace of change, Long Range Transmission Planning began with a conceptual roadmap of ideas to help guide development of planning analysis that would be needed to identify possible transmission solutions

Timeline of LRTP development

- MISO introduced the LRTP conceptual roadmap to stakeholders in June 2020 to begin discussions on the study scope and approach
- MISO began a series of technical discussions in Aug 2020 to seek input from stakeholders on the study methods and assumptions and to provide regular status updates on the ongoing work and analysis findings
- MISO initiated discussions on cost allocation mechanisms with the Regional Expansion Criteria and Benefits Working Group in Feb 2021 to investigate possible Tariff changes that would be needed before recommendation of projects
- MISO introduced Business Case development in the Sept 2021 LRTP workshop to begin identifying the benefit components and defining the metrics for quantifying the benefits provided by the initial portfolio of LRTP transmission investments

Workshops and Stakeholder feedback are critical to the LRTP process and success



LRTP Projects must meet one of three MVP criteria defined in the MISO Tariff

MISO Tariff - Attachment FF, II.C.2...

a. *Criterion 1. A Multi-Value Project must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade*

b. *Criterion 2. A Multi-Value Project must provide multiple types of economic value across multiple pricing zones with a Total MVP Benefit-to-Cost ratio of 1.0 or higher where the Total MVP Benefit -to-Cost ratio is described in Section II.C.7 of this Attachment FF. The reduction of production costs and the associated reduction of LMPs resulting from a transmission congestion relief project are not additive and are considered a single type of economic value.*

c. ***Criterion 3. A Multi-Value Project must address at least one Transmission Issue associated with a projected violation of a NERC or Regional Entity standard and at least one economic-based Transmission Issue that provides economic value across multiple pricing zones. The project must generate total financially quantifiable benefits, including quantifiable reliability benefits, in excess of the total project costs based on the definition of financial benefits and Project Costs provided in Section II.C.7 of Attachment FF.***

The MISO MVP Tariff further defines the 'specific types of economic value' which may be included

MISO Tariff - Attachment FF, II.C.5...

a. *Production cost savings where production costs include generator startup, hourly generator no-load, generator energy and generator Operating Reserve costs. Production cost savings can be realized through reductions in both transmission congestion and transmission energy losses. Productions cost savings can also be realized through reductions in Operating Reserve requirements within Reserve Zones and, in some cases, reductions in overall Operating Reserve requirements for the Transmission Provider.*

b. *Capacity losses savings where capacity losses represent the amount of capacity required to serve transmission losses during the system peak hour including associated planning reserve.*

c. *Capacity savings due to reductions in the overall Planning Reserve Margins resulting from transmission expansion.*

d. *Long-term cost savings realized by Transmission Customers by accelerating a long-term project start date in lieu of implementing a short-term project in the interim and/or long-term cost savings realized by Transmission Customers by deferring or eliminating the need to perform one or more projects in the future.*

e. *Any other financially quantifiable benefit to Transmission Customers resulting from an enhancement to the transmission system and related to the provisions of Transmission Service.*

The objective of LRTP is to enable reliable and economic delivery of energy in the future with lower-carbon resources

Enable access to lower-cost energy production

Provide more flexibility in fuel mix for customer choice

Maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply

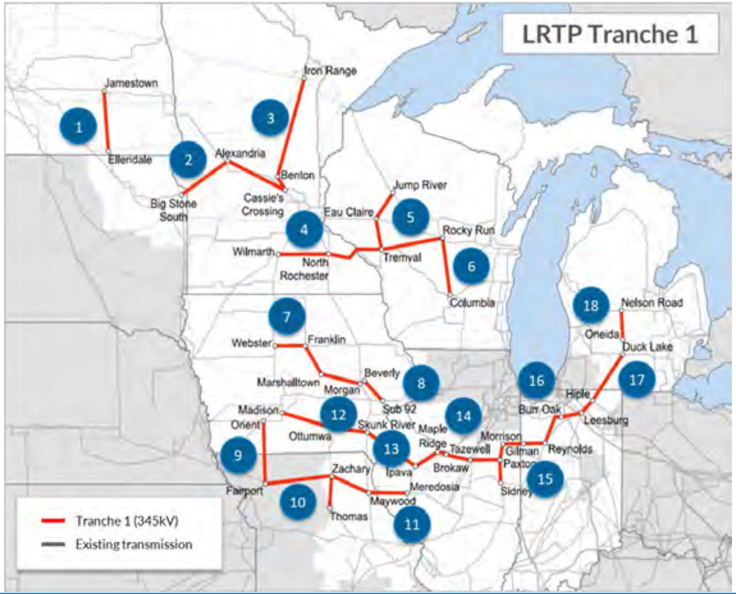
The scope of LRTP business case analysis includes quantifying the reliability and economic benefits

A. Congestion and fuel savings
B. Avoided capital costs of local resource investments
C. Avoided transmission investment
D. Reduced resource adequacy requirements
E. Avoided risk of load shedding
F. Decarbonization
G. Reliability issues addressed by LRTP
H. Other qualitative and indirect benefits

LRTP business case analysis uses a range of variables

- LRTP benefits examine value over the 20- to 40-year period from the in-service date (All projects assumed in service by 2030)
  - Benefit/cost calculations are evaluated on a 20-year time horizon
  - Additional benefits are shown for the 40-year horizon to align with assumed life of the assets
- LRTP benefits are evaluated for a range of discount rates from 3.0 – 6.9%
  - The social discount rate of 3.0% represents the value a ratepayer would typically receive on their risk-adjusted investment
  - The Weighted Average Cost of Capital (WACC) of 6.9% is the gross-plant weighted average of the Transmission Owners' cost of capital and represents the minimum return required on their transmission investments

- Portfolio embodies needed transmission for the ever-changing fleet
- Addresses needs across the MISO Midwest subregion
- Analysis of reliability needs and benefits associated with Future 1 resource expansion

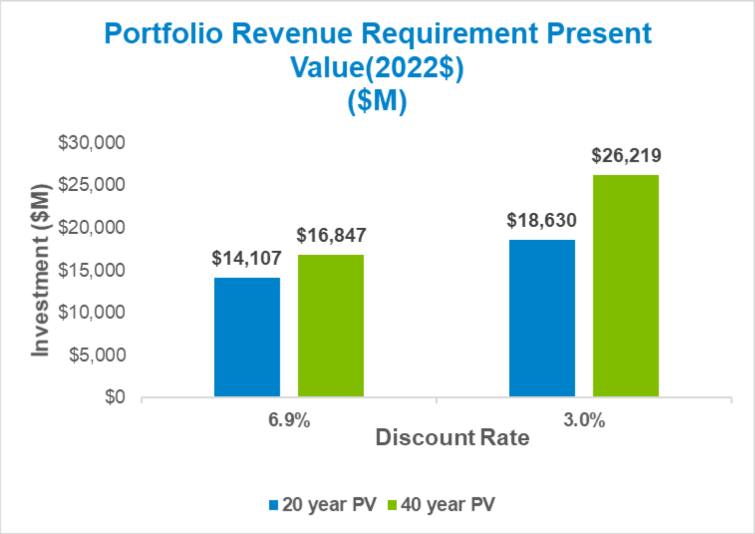


MISO

Total portfolio cost estimate for LRTP Tranche 1 is $10.3 B for projects located across the MISO Midwest subregion

ID	Project Description	Est. Cost ($M, 2022)
1	Jamestown – Ellendale	$439
2	Big Stone South – Alexandria – Cassie's Crossing	$574
3	Iron Range – Benton County – Cassie's Crossing	$970
4	Wilmarth – North Rochester – Tremval	$689
5	Tremval – Eau Clair – Jump River	$505
6	Tremval – Rocky Run – Columbia	$1,050
7	Webster – Franklin – Marshalltown – Morgan Valley	$755
8	Beverly – Sub 92	$231
9	Orient – Denny - Fairport	$390
10	Denny – Zachary – Thomas Hill – Maywood	$769
11	Maywood – Meredosia	$301
12	Madison – Ottumwa – Skunk River	$673
13	Skunk River – Ipava	$594
14	Ipava – Maple Ridge – Tazewell – Brokaw – Paxton East	$572
15	Sidney – Paxson East – Gilman South – Morrison Ditch	$454
16	Morrison Ditch – Reynolds – Burr Oak – Leesburg – Hiple	$261
17	Hiple – Duck Lake	$696
18	Oneida – Nelson Rd.	$403
	Total Project Portfolio Cost	**$10,324**

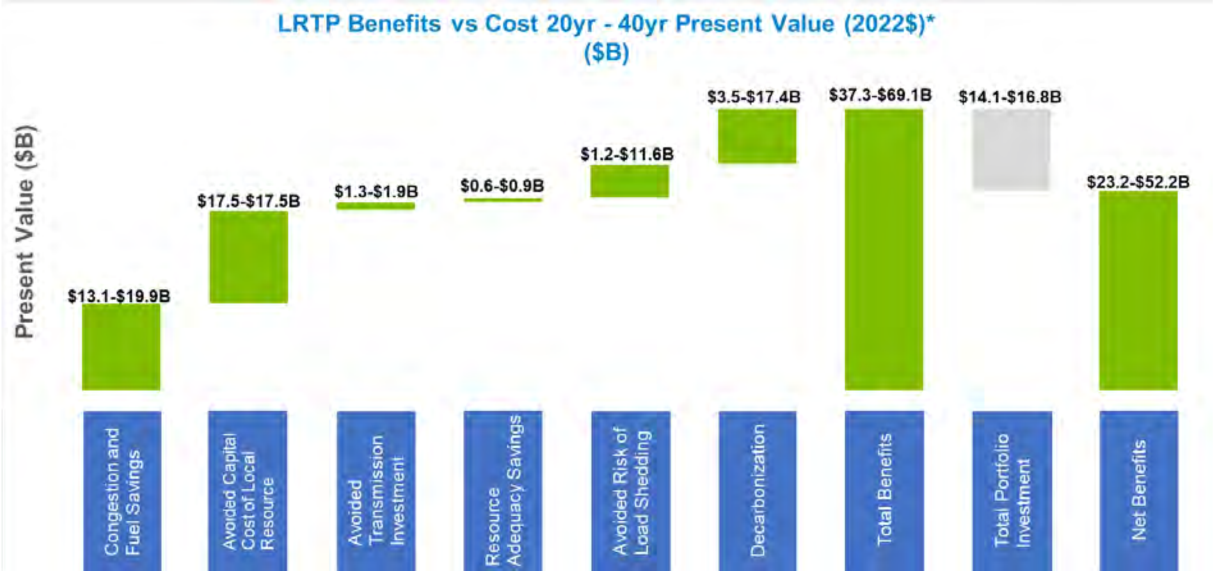
The LRTP Tranche 1 portfolio cost (20-year and 40-year present value at 6.9% and 3.0% discount rate)



*6.9% Discount Rate

Benefit Metrics

The business case analysis indicates total economic benefits significantly exceed cost of the Tranche 1 LRTP portfolio



A. Congestion and Fuel Savings

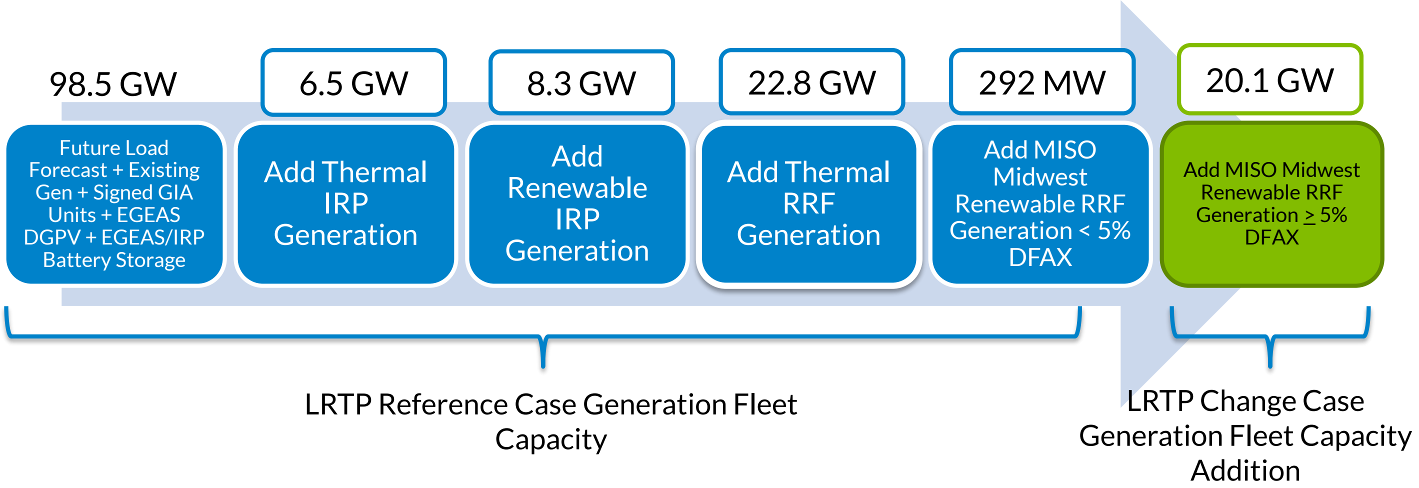
APC Benefits will be determined by comparing MISO Midwest APC in the LRTP Reference Case with the MISO Midwest APC in the LRTP Change Case

Make-up of LRTP Reference Case Model		Make-up of LRTP Change Case Model
• MTEP Topology • Future Load Forecast • Existing + Signed GIA • RRF DGPV • IRP/RRF Battery Storage • IRP/RRF Thermal • Renewable RRFs < 5% DFAX	Compare APC Change →	• Reference Case • Renewable RRFs ≥5% DFAX • LRTP Transmission

- The LRTP Reference Case represents necessary generation to serve Futures Load Forecast (on copper sheet)
- The LRTP Change Case includes Renewable RRFs located in MISO Midwest which have ≥ 5% DFAX on reliability constraints addressed by LRTP projects

A. Congestion and Fuel Savings

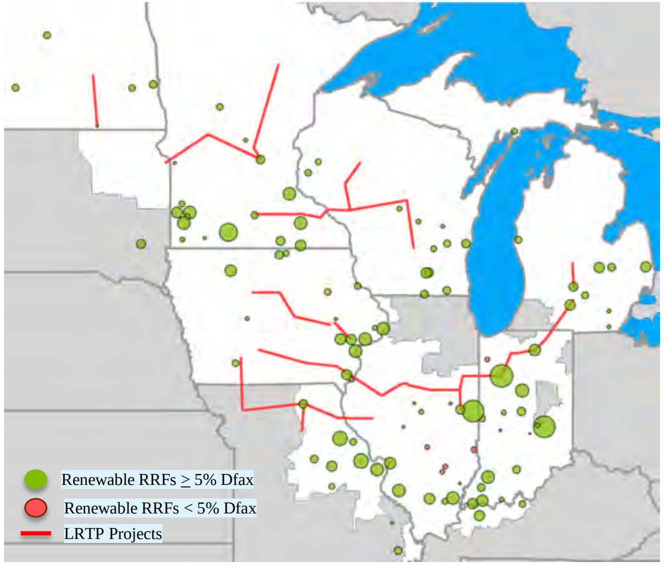
MISO Midwest-focused Reference Case generation determination process and results to meet copper sheet energy requirements in Future 1



A. Congestion and Fuel Savings

LRTP Tranche 1 projects congestion and fuel savings results

Present Value	20 year PV (Millions-2022$)		40 year PV (Millions-2022$)	
Discount Rate	6.9%	3.0%	6.9%	3.0%
CAZ				
1	$3,169	$4,455	$4,668	$8,797
2	$1,049	$1,511	$1,667	$3,313
3	$2,195	$3,060	$3,151	$5,823
4	$1,352	$1,934	$2,107	$4,133
5	$1,471	$2,078	$2,205	$4,210
6	$2,884	$4,133	$4,517	$8,890
7	$1,006	$1,432	$1,543	$2,993
	$13,125	**$18,603**	**$19,858**	**$38,160**



MISO

Resource capital investments can be avoided by taking advantage of broader regional renewables instead of purely local resources

- Magnitude, cost, & locations of resources differ based upon approach used
- Regional transmission is the bridge between these scenarios

- EGEAS LBA (local) granularity expansion models utilizing Future 1 assumptions
- Calculation to relate the LBA and Regional expansion to LRTP transmission and determine what the avoided capital costs of local resource investments would be

Overview of EGEAS LBA expansion models used to determine what a local build out would be

- The runs treat each LBA as its own pool.
- Each LBA then self-constructs resources necessary to meet the simulation constraints such as PRM and emissions.
- Utilizes the same assumptions as the regional Future 1 analysis and resources are ascribed to LBAs based on resource ownership.
- Capacity purchases are enabled for the first year to meet each LBA's PRM and is driven by the construction lead time for new resource alternatives.
- LBA-specific wind and solar profiles are used instead of the regional profiles which averaged multiple profiles from different locations across MISO.

Calculation to relate the LBA and Regional expansion to LRTP transmission to determine cost savings

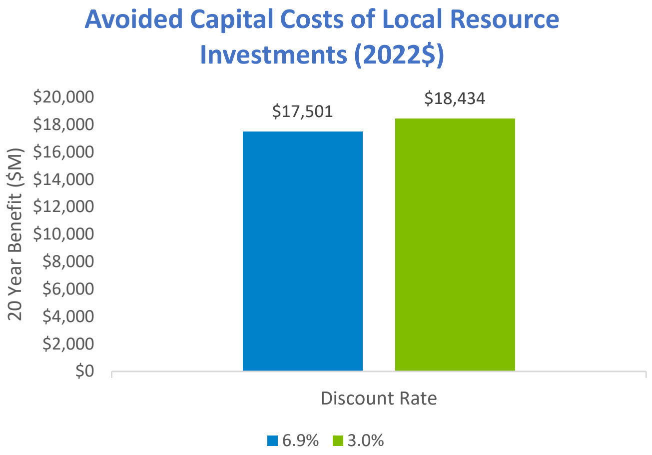
- Due to Regional and LBA modeling assumptions, the avoided capital costs of local resources investments can not be determined by subtracting Regional expansion costs from the total LBA expansion costs (doing so would over-state realized benefit)
- Regional and LBA Regional Resource Forecasting (RRF) expansion reflects Local Resource Zones (LRZ) that make up MISO Midwest (LRZ 1 – LRZ 7)
- Enabled RRF capacity reflects RRF resources enabled by LRTP transmission, meaning those resources have ≥ 5% Dfax for LRTP transmission resolved reliability issues
- Utilizes costs of LRTP transmission enabled capacity to infer avoided capital cost of local resources savings

$$\frac{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{LBA\ Expansion})}{\sum_{LRZ\ 1}^{LRZ\ 7}(Total\ RRF\ Capacity_{Regional\ Expansion})}$$

Avoided capital costs of local resource investments benefit

$$\frac{90{,}969\ MW}{43{,}431\ MW} = \$33.58B$$

- LRTP enables regional resource sharing and reduces local overbuild yielding a 20-year present value benefit of $17.5B*



* using the 6.9% Discount Rate

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Captures the avoided cost of reliability upgrades and replacements that will not be required in the future as a result of the addition of LRTP projects
- Includes facilities where thermal loading is approaching the rating but not overloaded
  - Avoided reliability upgrades are determined by using the 10-year and 20-year analysis results to project future loading on facilities loaded near the rating with and without LRTP projects

$$Flow_{proj} = Flow_{20} + (Flow_{20}-Flow_{10})$$

Example: Facility is included in avoided costs of future transmission investment							
Line name	kv	RatingMVA	case	Flow10	Flow20	Flowproj	
Forest - Valley 161kV	161kV	335	w/o LRTP	324	331	338	without LRTP, future upgrade is needed
			w/ LRTP	315	322	329	with LRTP the overload is resolved

- Includes replacement of existing facilities due to age and condition that would not be required because the LRTP projects use existing ROW of aging facilities

Re-use of existing ROW for LRTP projects offsets the costs of age and condition replacement of aging facilities

- The LRTP Tranche 1 portfolio of projects potentially use 836 miles of existing facilities where age and condition of the facilities is expected to require replacement of assets
- Construction of LRTP on the existing right-of-way would include replacement of existing structures and equipment that would avoid the future cost of replacing the existing facilities

C. Avoided Transmission Investment

Transmission investment is avoided by developing regional solutions vs incremental fixes

- Avoided transmission investment uses exploratory cost estimates based on type of facility improvement required
- Like in the 2011 MVP business case, an adjustment is applied to avoided reliability upgrades >=345kV to reduce value by 50% to account for potential production cost benefits provided by the upgrades
- Capital investment for future transmission is assumed to be spread equally over the 5-year period prior to the in-service date (2040) of the avoided reliability upgrades
- The Annual Transmission Revenue Requirement was calculated to obtain the 20-year net present value discounted to 2022$ values

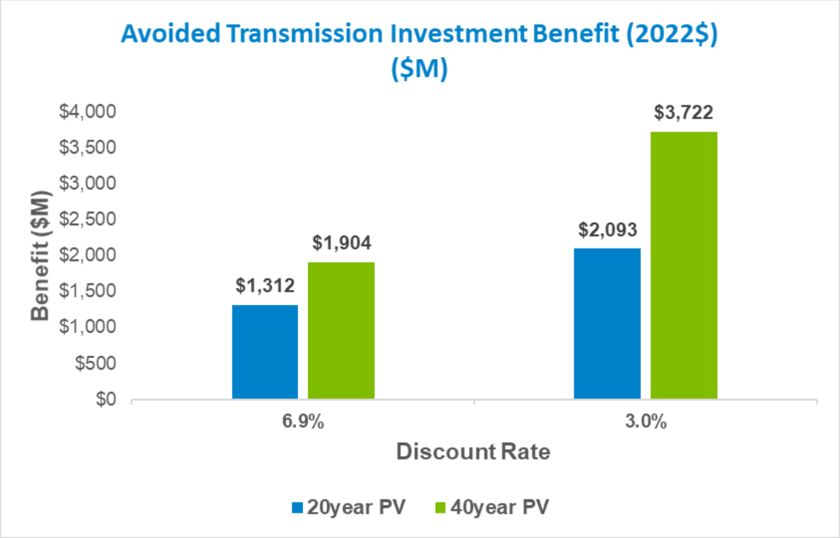
Facility Improvement Type	Unit Cost ($M)	Quantity/Miles	Cost ($M)*
Bustie Replacement	$1.50	2	$3
Transformer Replacement =345	$5.00	4	$20
Transformer Replacement <345	$3.00	5	$15
Transmission line Replacement =345kV (per mile)	$2.65	21	$56
Transmission line Replacement <345kV (per mile)	$1.60	1012	$1,617
Transmission line upgrade=345kV (per mile)	$0.56	230	$64
Transmission line upgrade <345kV (per mile)	$0.34	124	$43
		Total	**$1,819**

*MISO Estimates

C. Avoided Transmission Investment

LRTP provides benefits by eliminating the need for other transmission projects

- LRTP avoids the need for transmission investment that yields 20- to 40-year present value benefits from $1.3B to $1.9B*



* using the 6.9% Discount Rate

The resource adequacy benefits are related to an increase in transfer capability and a reduction in the total LCR*

- As LRTP increases the transfer capability within the footprint, the increase in transfer limit is quantified
- The potential economic value unlocked by the availability of least-cost resources across the footprint due to increase in transfer capability is estimated
- A two-step process was developed to quantify the LCR reduction benefits and approximate the monetary value

*Local Clearing Requirement

Step 1: Perform a transfer analysis to determine the LCR for each local resource zone (LRZ)

1. Calculate the capacity import limit (CIL) for each LRZ and case*
   - Determine the import limit (e.g., TrLim) for each LRZ and study case
   - Determine the area interchange for each LRZ and study case
2. Determine the LCR for each LRZ and case*
   - The LRR UCAP** percentages from the PY22-23 LOLE Study and the 2040 non-coincident peak load forecasts are used to set the LRR for each LRZ

Local Resource Zone	CIL (Base)	CIL (With LRTP)	Delta CIL (MW)
LRZ1	5412	6070	658
LRZ2	4188	5223	1035
LRZ3	5062	6453	1391
LRZ4	7117	7609	492
LRZ5	6131	6183	52
LRZ6	6005	6171	166
LRZ7	3367	4659	1292

*With and without LRTP projects (14 total cases) | **Unforced capacity

Step 2: Monetize the benefits identified in Step 1

1. The 2040 unforced capacity for each LRZ is determined using forced outage rates (thermal) and ELCC* (non-thermal)
2. The excess capacity within each LRZ is calculated as follows:
   - Excess Capacity = 2040 Unforced Capacity – LCR (without LRTP)
3. The RA benefit is estimated as follows:
   - If Excess Capacity < 0 → Benefit = (CONE**) x (-Excess Capacity)
   - If Excess Capacity > 0 → Benefit = $0/year

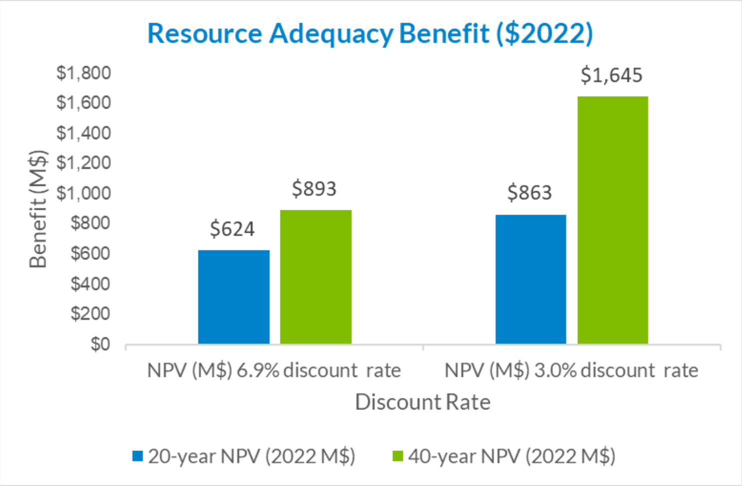
LRZ	1	2	3	4	5	6	7
PY22-23 CONE ($/MW-yr)	$91,270	$89,490	$86,380	$90,300	$97,190	$89,040	93,770

* Effective Load Carrying Capability | ** Cost of new entry

D. Reduced Resource Adequacy Requirements

The annual economic benefits related to resource adequacy are estimated to be $44M per year

- LRTP reduces the total LCR and yields 20- to 40-year present value benefits from $624-$893M*



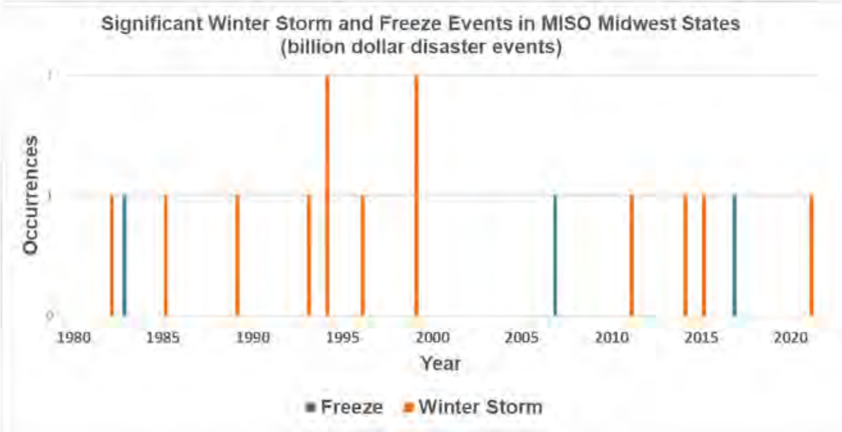
* using a 6.9% Discount Rate

LRTP transmission can reduce risk of load shedding due to unplanned generation events

- Large scale unexpected loss of generation in an area presents a risk of significant load shedding
- Transmission reinforcements provided by LRTP increase transfer capability to allow load to be served from resources located in other areas
- Benefits are associated with avoided risk of load shedding focus on risks of large-scale generation loss caused by severe weather
  - Renewable production is dependent on weather conditions
  - Thermal resources have operational limitations under extreme temperature conditions
- Weather-related events occur in various scales
  - Event scenarios examine generation and load balance after loss of significant resources to determine if import capability is sufficient to cover generation deficiency
  - Risk of load shedding exists where generation deficiency cannot be covered by existing import capability
- Benefits are calculated using Value of Lost Load (VOLL) ranging from $3500-$23,000* /MWh

*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

Analysis of risk focus on recurring severe winter weather events and variability of renewable resources

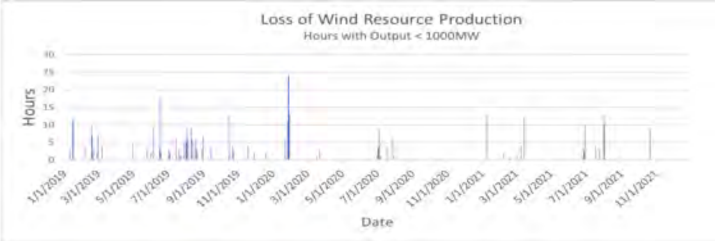


Data Source: NOAA National Centers for Environmental Information (NCEI) U.S. Billion-Dollar Weather and Climate Disasters (2022). https://www.ncei.noaa.gov/billions/, DOI: 10.25921/stkw-7w73

Weather conditions affect the availability of resources

- Renewable resources regularly experience periods of low output lasting several hours

Source: *MISO's Response to the Reliability Imperative*, https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf



Data Source: MISO Historical Hourly Wind, https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3ASummary&t=10&p=0&s=MarketReportPublished&sd=desc

LRTP transmission can reduce risk of load shedding due to unplanned loss of generation due to severe winter weather events

Area/Zonal Event Scenario

Regional Event Scenario

Generation Loss:
Thermal: 50% Pmax, Wind: 90% of Pmax, Solar 50% of Pmax
Load Forecast margin: 5% margin

Import Limit: Total Transfer Capability

Scenario 1: Source: MISO Zones 4-7 + PJM
Sink: MISO Zones 1-3 + SPP

Scenario 2: Source: MISO Zones 1-3 + SPP
Sink: MISO Zones 4-7

+

LoadLossMW =
$GenMW_{net}$ – 1.05 * LoadMW – TxLossMW + Capacity Import Limit(MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

LoadLossMW =
$GenMW_{net}$ - 1.05 * LoadMW – TxLossMW + Total Transfer Capability(MW)
where $GenMW_{net} = GenMW_{cap} - GenMW_{loss}$

Total avoided risk of load shedding includes all winter event scenarios

Zonal

zone	GenLoss(therm)	GenLoss(wind)	GenLoss(solar)	Gen Remaining		Gen Surplus	CIL (no LRTP)	shortfall	newCIL (LRTP)	CIL diff	benefit
1	6607	6693	4612	12178		-5083	5412	-329	6070	658	
2	5369	1082	1049	8246		-3527	4188	-661	5223	1035	
3	3762	8001	3306	9529		-195	5062	-4867	6453	1391	
4	3358	2442	2065	6645		-2532	7117	-4585	7609	492	
5	2414	691	1185	5499		-2092	6131	-4039	6183	52	
6	7362	1461	2858	11873		-6680	6005	675	6171	166	166
7	6164	1714	3445	13387		-3574	3368	206	4659	1291	206
							Total Avoided Load shed				372
							Assumed duration				16
							Total Avoided Load shed hours				5954

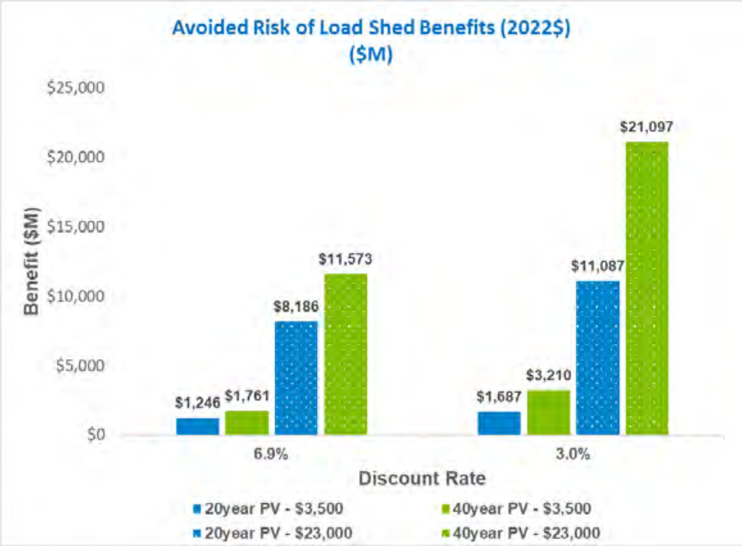
Regional

zone	GenLoss(th)	GenLoss(w)	GenLoss(s)	Gen Remaining	Extimp	Gen Surplus	TTC (no LRTP)	shortfall	newTTC (LRTP)	TTC diff	benefit
Lrz1-3	19672.34	15776.433	8967.45	26018.897	7500	-20239.783	7260.8	12978.983	9391	2130.2	2130.2
Lrz4-7	24123.405	6307.11	9553.2	32579.295	0	-19702.2	6192.5	13509.695	8185	1992.5	1992.5
							Total Avoided Load shed				4122.7
							Assumed duration				16
							Total Avoided Load shed hours				65963.2
							Total for all Events				71917.1

Risk of load shedding is assumed to occur every three years based on the frequency of severe winter weather events

E. Avoided Risk of Load Shedding

Value of avoided risk of load shedding is determined by applying the Value of Lost Load (VOLL)



*IMM Quarterly Report: Summer 2020, https://cdn.misoenergy.org/IMM%20Quarterly%20Report_Summer%202020478028.pdf

 ** using a 6.9% Discount Rate

F. Decarbonization

MISO has developed a carbon price range to capture LRTP's long-term benefits of reducing CO_2 emissions by enabling reliable delivery of low-cost, clean energy

- Calculate emissions reduced between LRTP Reference Case and LRTP Change Case used for the congestion and fuel cost savings benefit metric.
- Convert to metric tons.
- Using 2.5% annual inflation and discount rates below, apply range of carbon costs to calculate 20- and 40-year NPV of reduced carbon emissions.

20-Year CO_2 Emissions Reduced: 399M metric tons

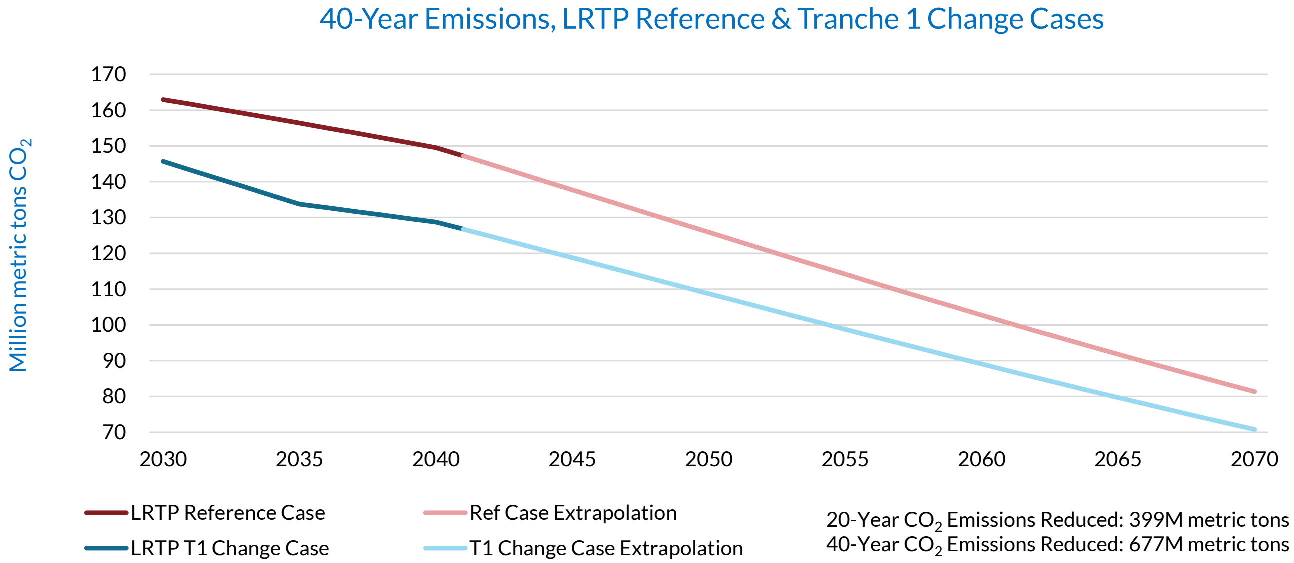
40-Year CO_2 Emissions Reduced: 677M metric tons

	6.9% Discount Rate		3% Discount Rate	
2022$/metric ton	MN PUC (Min) $12.55	Federal (Max) $47.80	MN PUC (Min) $12.55	Federal (Max) $47.80
20-Year Benefit (2022$, M)	$3,473	$13,438	$4,781	$18,404
40-Year Benefit (2022$, M)	$4,548	$17,364	$7,818	$29,498

Prices converted to 2022$. Full range of carbon prices demonstrated in previous workshops.
20-year and 40-year benefits = projects' in-service value to 2050 and 2070, respectively.
Emissions data interpolated between PROMOD model years 2030, 2035, and 2040; and extrapolated post-2040.

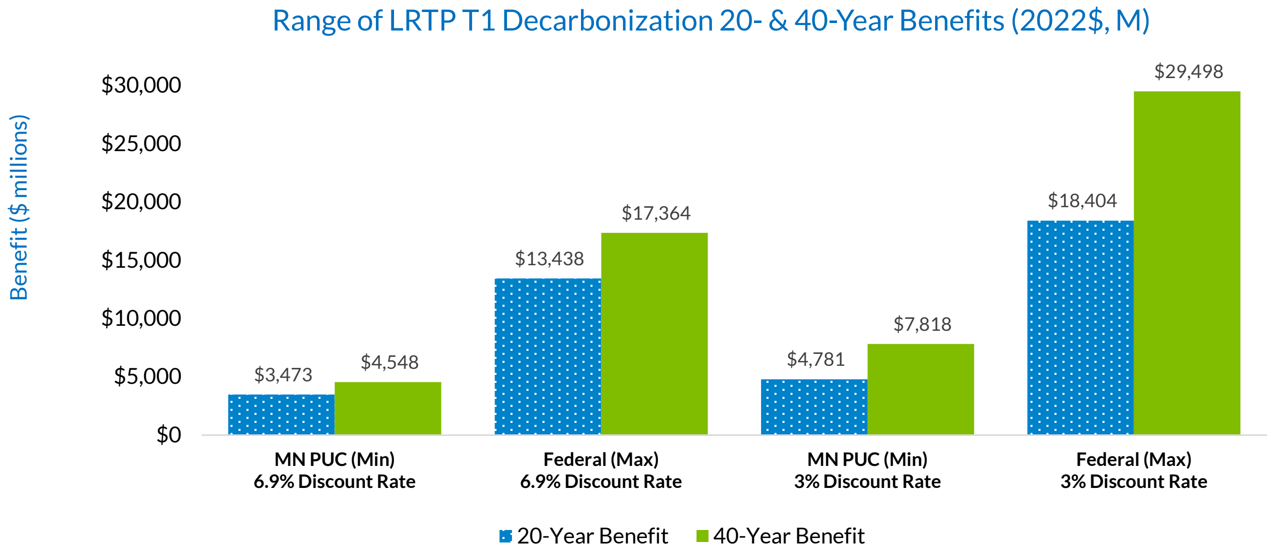
Minnesota Public Utility Commission (2022 Low)
Federal = Average of 45Q Federal Tax Credit and Federal Social Cost of Carbon

LRTP Change Case illustrates the emissions reduced through enabled resources



F. Decarbonization

With the price range considered, Decarbonization benefits range from $3.5B to $29.5B over 40 years of project life



MISO

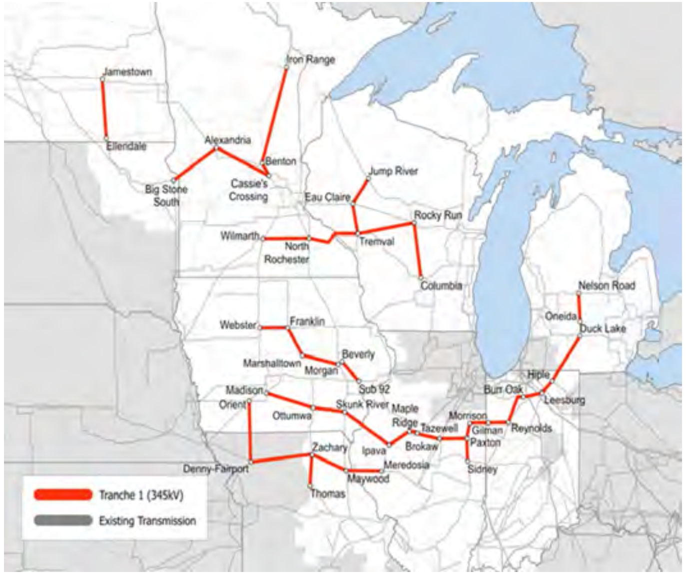
LRTP Tranche 1 portfolio allows reliable delivery of energy from future resource portfolio to serve load across the footprint

Reliability analysis was performed to assess the impact of the LRTP projects on steady state system performance

- Thermal and voltage issues were mitigated by the LRTP projects under base conditions reflecting varying load and dispatch patterns
- Additional upgrades were identified to mitigate issues resulting from the addition of LRTP projects

Transfer Analysis

- Improvements in transfer capability allows energy requirements to be met under varying dispatch patterns driven by differences in weather conditions across the Midwest subregion
- LRTP projects provides more robust interconnection to improve system stability during periods of heavy power transfers



MISO

MN-Dakotas Reliability Needs Addressed

Jamestown - Ellendale 345kV, Big Stone South – Alexandria - Cassie's Crossing 345kV

- Assists in transport of energy out of Dakotas toward central MN and Twin Cities area
- Relieves issues on the 230kV system and improves connections between 345kV systems to improve long distance movement of power
- Relieves 40 elements with excessive thermal loading for N-1 contingencies and 70 elements with excessive loading for N-1-1 contingencies
- Performs better than other six alternatives removing almost all existing congestion with only minimal new congestion.

Iron Range - Benton County – Cassie's Crossing 345kV

- Provides low impedance path from Northern to Central Minnesota improving Voltage stability and transfer performance with >10% increase in Manitoba Import limit performing better with higher capacity and lower cost than the four other alternatives
- Relieves 15 elements with excessive thermal loading for N-1 contingencies and 25 elements with excessive loading for N-1-1 contingencies

MN-WI Reliability Needs Addressed

Wilmarth - N. Rochester – Tremval - Eau Claire - Jump River
Tremval – Rocky Run – Columbia 345kV

- Provides outlet for renewables located in Minnesota
- Congestion relief and raises stability limit by 250MW to increase transfer capability on the MN-WI interface
- Improves connectivity to serve load centers
- Relieves 39 elements with N-1 heavy loading and severe overloads in MN and WI and 96 elements for N-1-1 contingencies

Central Iowa Reliability Needs Addressed

Webster-Franklin-Marshalltown-Morgan 345kV
Beverly-Sub92 345kV

- Provides outlet for renewables located in IA and SW Minnesota
- Provides corridor for delivery of energy to load centers in central portions of MISO
- Addresses 21 elements with N-1 heavy thermal loading and severe overloads in Iowa and 34 elements for N-1-1 contingencies

Iowa, Illinois, Indiana, Michigan Reliability Needs Addressed

Madison – Ottumwa – Skunk River – Ipava – Maple Ridge 345kV
Tazewell – Brokaw - Paxton – Gilman – Morrison – Reynolds – Hiple – Duck Lake 345kV
Paxton – Sidney 345kV
Oneida – Nelson Road 345kV

- Delivers significant increase in transfer capability to support generation deficient areas due to unexpected decrease in renewable output
- Mitigates 28 thermal overloads in Michigan, 16 thermal overload in Indiana, 19 thermal overloads in Missouri and Illinois, 14 thermal overloads in Iowa
- Provides more robust performance under large shifts in dispatch of generation across the region

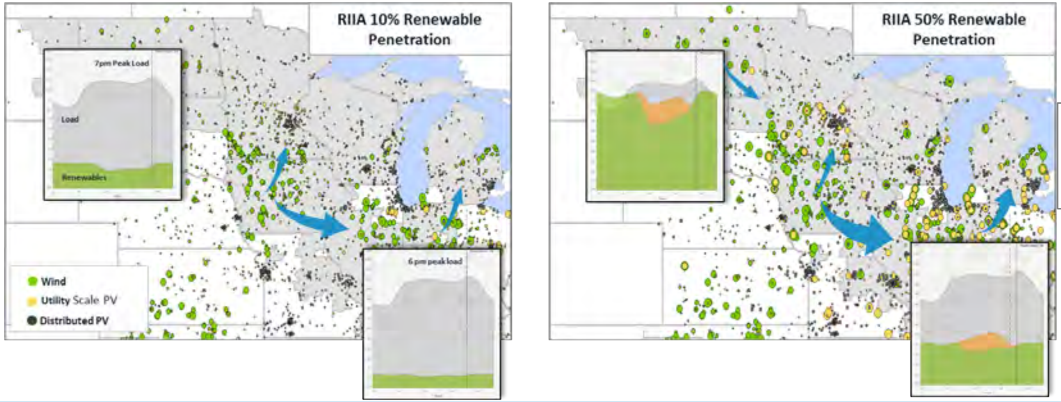
Missouri Reliability Needs Addressed

Orient – Fairport – Zachary – Maywood – Meredosia 345kV
Zachary – Thomas Hill 345kV

- Provides increased transfer capability of 250MW West-to-East and 438MW MISO-to-Michigan to address voltage collapse conditions in Missouri
- Mitigates heavy loading and severe overloads on 19 elements for N-1 and N-1-1 contingencies
- Provides more robust performance under large shifts in dispatch of generation across the region addressing 14 thermal overloads

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- An increasingly connected system is needed to balance generation resource variability across an increasingly heterogeneous footprint.
- Additional transmission reinforcements provided by LRTP increases the ability of the system to manage the increasing different regional flows and operational events without adverse impacts to system performance

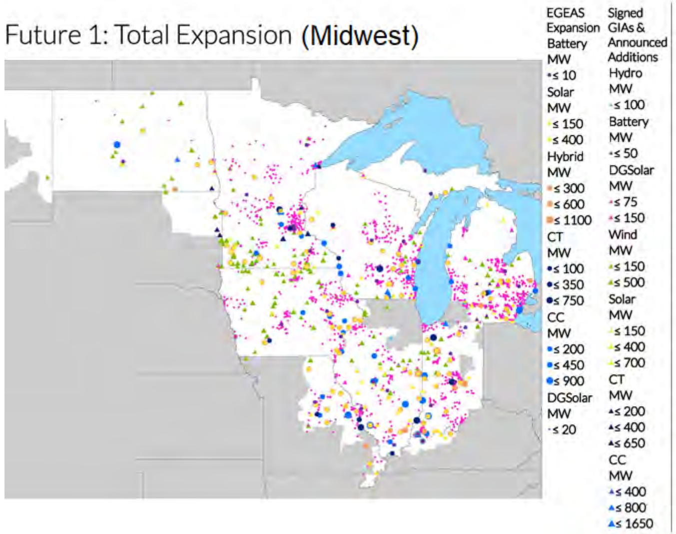


Regional energy transfers increase in magnitude and becomes more variable, leading to a need for increased extra-high voltage transfer capabilities

Illustration of flow changes with increasing renewable penetration spread throughout the MISO footprint (MISO Renewable Integration Impact Assessment (RIIA) Summary Report, February 2021 https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf)

Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Increased transmission capacity better leverages the geographic and fuel diversity of the broader footprint to more effectively manage dispatch variability due to changing weather patterns



MISO Futures Report (December 2021) https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

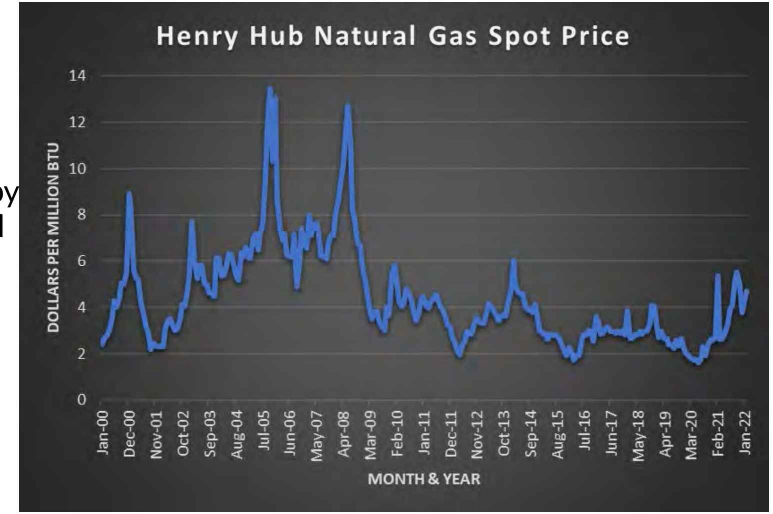
Transmission investment provides other qualitative benefits that support the LRTP Tranche 1 business case

- Transmission expansion provides additional operational flexibility and allows more opportunity for planning of transmission and generation outages with less risk of operational issues or rescheduling of outages
- Transmission expansion allows better use of the transmission network and provides more flexibility to meet changing customer needs and diverse policy goals

Congestion and Fuel Savings Natural Gas Price Sensitivity

LRTP projects decrease system-wide impacts of natural gas volatility

- Local transmission investment cannot completely insulate electric consumers from the risks associated with fuel price volatility
- However, LRTP projects offset the risk by providing additional congestion and fuel savings benefits under high natural gas prices by enabling renewable energy
- Congestion and fuel savings benefits were analyzed through a series of production cost analyses, with higher natural gas cost assumptions



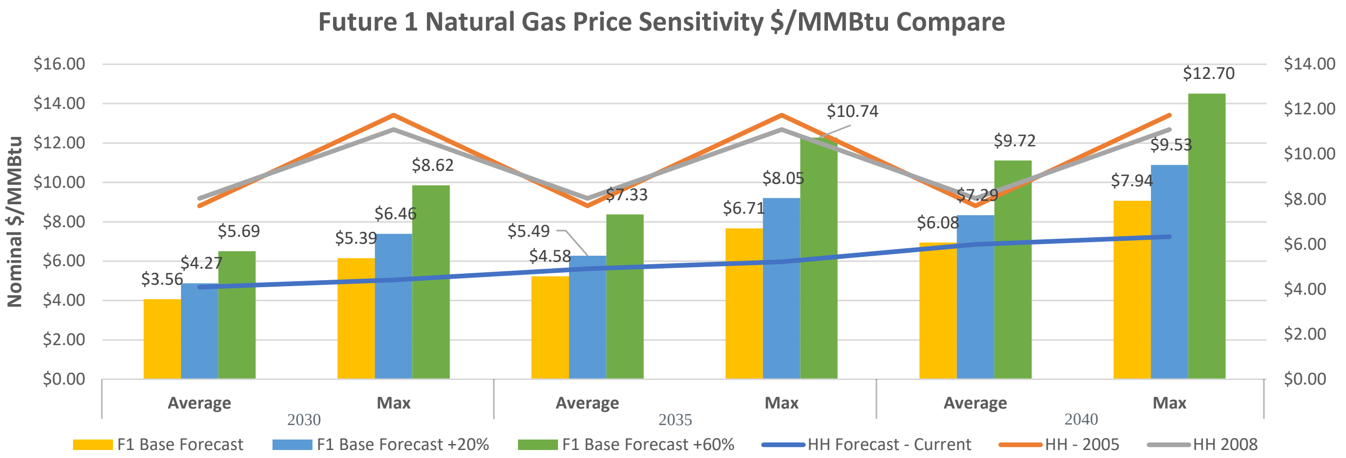
A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

MISO Futures used for the LRTP study utilized new natural gas price forecast methodology

- GPCM Natural Gas Market Forecasting System was used to develop forecasts instead of locked-down Henry Hub (HH) and blend of three different forecasts
- Use on base forecast gas price in EGEAS for all Futures
- Using the same assumptions, but referencing PROMOD output, create Future-specific and area-specific gas prices for use in PROMOD models
- A range of gas prices were tested on LRTP Reference and Change Case PROMOD models

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

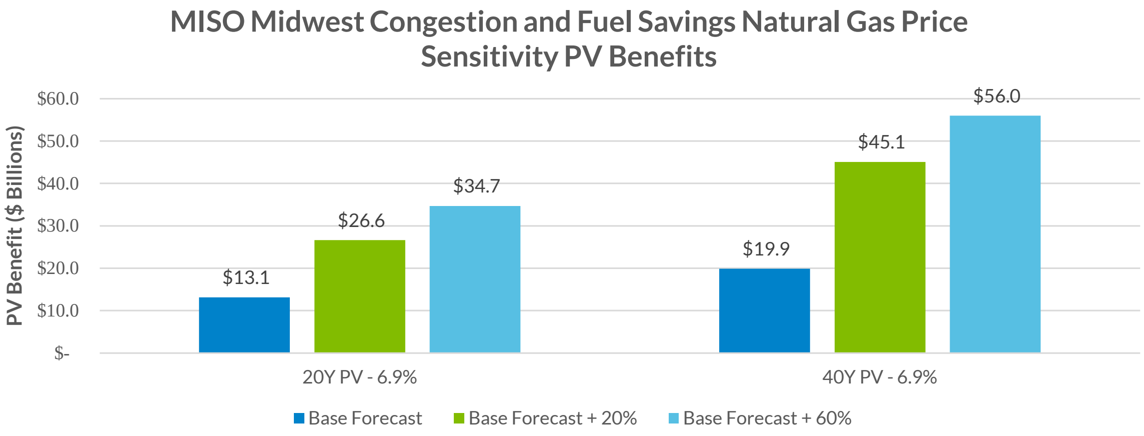
Future 1 Natural Gas prices were increased by 20 – 60% for sensitivity evaluation



- When comparing to HH prices, a 20% increase was found to facilitate the best starting point, which ensures year 2040 average price is greater than HH projected price
- A 60% increase was selected as the endpoint, to create a year 2040 value that represented HH highest sale prices historically (2005 and 2008)

A. Congestion and Fuel Savings – Natural Gas Price Fuel Sensitivity

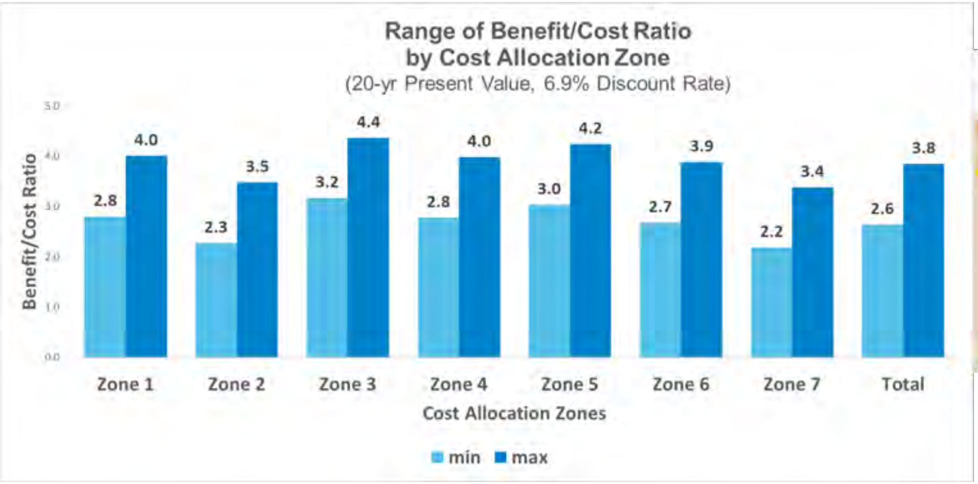
LRTP Tranche 1 transmission will provide greater congestion and fuel savings as natural gas price increases



- 20% price increase generates a $13.4B congestion and fuel savings increase
- 60% price increase generates a $21.5B congestion and fuel savings increase

Distribution of Benefits for Midwest Subregion

The benefits provided by the LRTP Tranche 1 Portfolio are distributed across the Midwest subregion in a manner commensurate with the costs



MISO

For the lower range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 2.2 where VOLL=$3,500 and with a carbon price of $12.55 per metric ton

Footprint Benefits (minimum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	**CAZ Allocation Method**	**Zone 1**	**Zone 2**	**Zone 3**	**Zone 4**	**Zone 5**	**Zone 6**	**Zone 7**	**Total**
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$248	$168	$133	$121	$96	$233	$246	**$1,246**
Decarbonization**	Based on load ratio share	$691	$468	$370	$339	$268	$651	$687	**$3,473**
Total Benefits		$7,867	$4,326	$4,763	$3,824	$3,311	$7,094	$6,096	**$37,281**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		2.8	2.3	3.2	2.8	3.0	2.7	2.2	**2.6**

For the upper range of quantifiable benefits, benefit to cost ratio for the cost allocation zones is at least 3.4 where VOLL=$23,000 and with a carbon price of $47.80 per metric ton

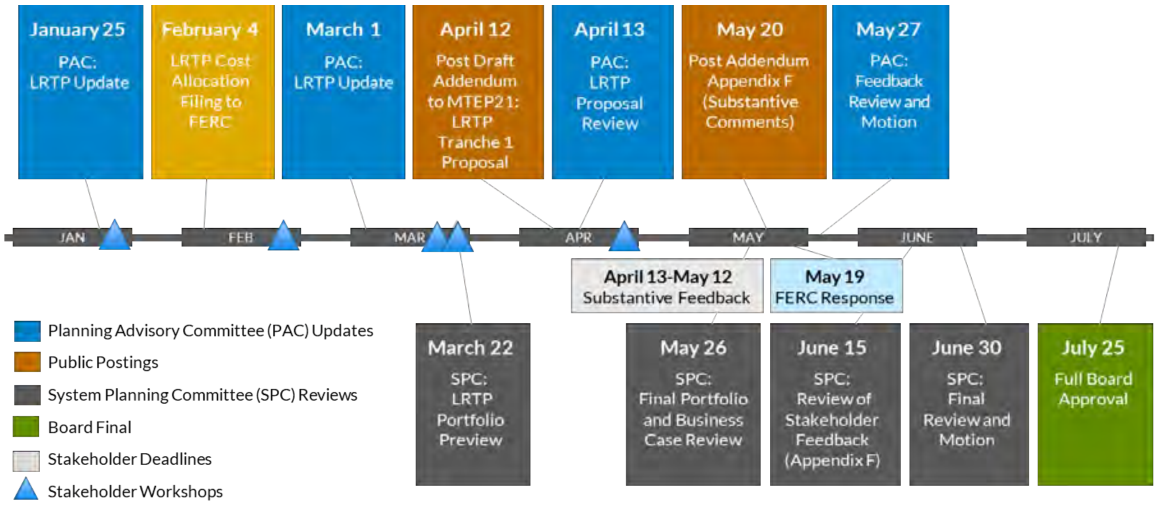
Footprint Benefits (maximum)- 20 Year NPV, 6.9%, 2022$		($M)							
Benefit Metric	CAZ Allocation Method	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Total
Congestion and Fuel Savings	Derived directly from PROMOD resutls	$3,169	$1,049	$2,195	$1,352	$1,471	$2,884	$1,006	**$13,125**
Avoided Capital Cost of Local Resource Investment	Based on load share ratio	$3,481	$2,358	$1,864	$1,707	$1,351	$3,280	$3,460	**$17,501**
Avoided Transmission Investment	Based on the zonal location of upgrade	$278	$283	$201	$305	$125	$45	$74	**$1,312**
Resource Adequacy Savings	Based on zonal capacity savings	$0	$0	$0	$0	$0	$0	$624	**$624**
Avoided Risk of Load Loss*	Based on load ratio share	$1,629	$1,103	$872	$798	$632	$1,534	$1,618	**$8,186**
Decarbonization**	Based on load ratio share	$2,673	$1,811	$1,431	$1,311	$1,037	$2,519	$2,656	**$13,438**
Total Benefits		$11,231	$6,604	$6,563	$5,472	$4,616	$10,262	$9,438	**$54,187**
Total Costs		$2,806	$1,901	$1,502	$1,376	$1,089	$2,644	$2,789	**$14,107**
B/C		4.0	3.5	4.4	4.0	4.2	3.9	3.4	**3.8**

Conclusion

The LRTP Tranche 1 portfolio provides a regional transmission solution to addressing future energy needs

- For a capital investment of $10.3B, the LRTP portfolio provides $37.0B in financially quantifiable benefits over 20 years
- LRTP transmission projects enhance system performance to maintain reliable operation in the future with more variability and uncertainty in energy supply
- The LRTP Tranche 1 portfolio reflects a cost-effective set of solutions that enable delivery of energy to support future energy requirements of the MISO customers
- The LRTP Tranche 1 portfolio provides economic and reliability benefits that exceed the cost of the investment and are broadly distributed across the MISO Midwest subregion

The timeline for approval of Tranche 1 is targeted for July 25



Appendix E-3

MISO Futures Report (April 2021, Updated December 2021)

MISO Futures Report

- Published April 2021 -

Updated December 2021

Highlights

- Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

- The three MISO Futures encompass scenarios that bookend the fleet resource mix over the next twenty years and are intended to be used for several years with minimal updates.

- Analysis of three scenarios allows for insights to the MISO system once it transforms to dual summer and winter peaking as renewable energy and projected demand increase.

- December 2021 updates include revised expansion results for Futures 2 and 3. Explanation and details of these results can be found in the September, October, and November 2021 PAC presentations in the Presentation Materials section of this report.

MISO

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Executive Summary

MISO is tasked with delivering safe, reliable, and cost-effective power across 15 states and the Canadian province of Manitoba. Within MISO's diverse regional footprint, utility members are making future plans, committing to near and long-term retirements and investments, and announcing increasingly advanced decarbonization goals. Although MISO's role is to remain policy- and resource-agnostic, there is a clear fleet transition underway that has implications for system operations.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving what MISO refers to as a regional "Reliability Imperative." MISO, our member utilities, and state regulators all share the responsibility to address this Reliability Imperative. A key element of [MISO's response to the Reliability Imperative] is our Long-Range Transmission Planning (LRTP) initiative. The "Futures" defined in this document will be a key driver of those efforts and other elements of the [Reliability Imperative].

How can MISO, as a regional grid operator, support its member utilities and state policy makers as they continuously refine how to serve the 42 million people in the MISO footprint? One tool at MISO's disposal is the use of forward-looking planning scenarios to provide outlooks of the future. These Future planning scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period. This information is used to model a capacity expansion, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives. Using the range of resource generation modeled, MISO will then apply the Futures' expansion results to the development of transmission plans, the LRTP, and other MISO initiatives that ensure continued reliability and economic energy delivery.

This report captures an eighteen-month collaboration between MISO and stakeholders to develop three Future scenarios that bookend the uncertainty over the next twenty years. When carried forward into the transmission planning models, this set of Futures will enable the diverse goals and policies of MISO's states and utilities.

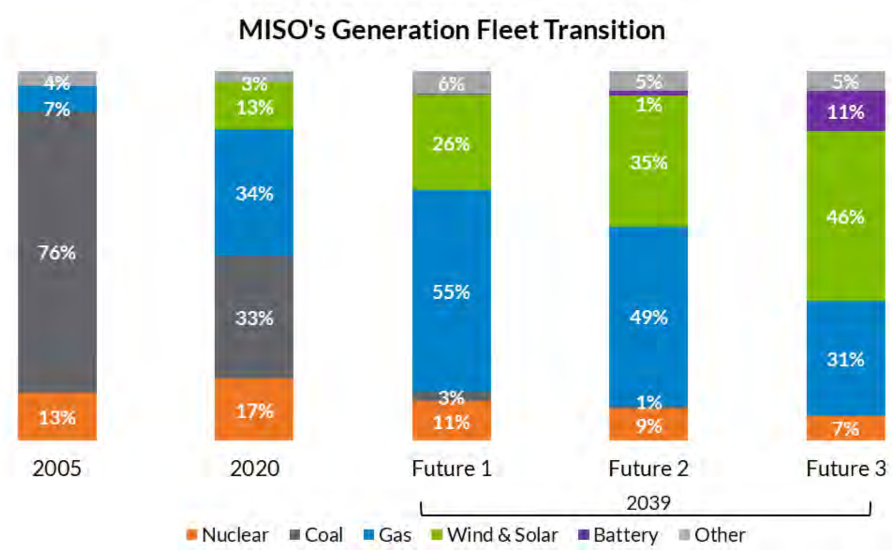


Figure 1: Overview of MISO's Generation Fleet Mix Transition [82]

Future 1 Assumptions – This Future reflects substantial achievement of state and utility announcements and includes a 40% carbon dioxide reduction trajectory.[1] While Future 1 incorporates 100% of utility integrated resource plan (IRP) announcements, state and utility goals that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these announced goals and respective timelines. Future 1 assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate[2] of 0.5%.

Future 2 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including a 60% carbon dioxide reduction. Future 2 introduces an increase in electrification, driving an approximate 1.1% annual energy growth rate.

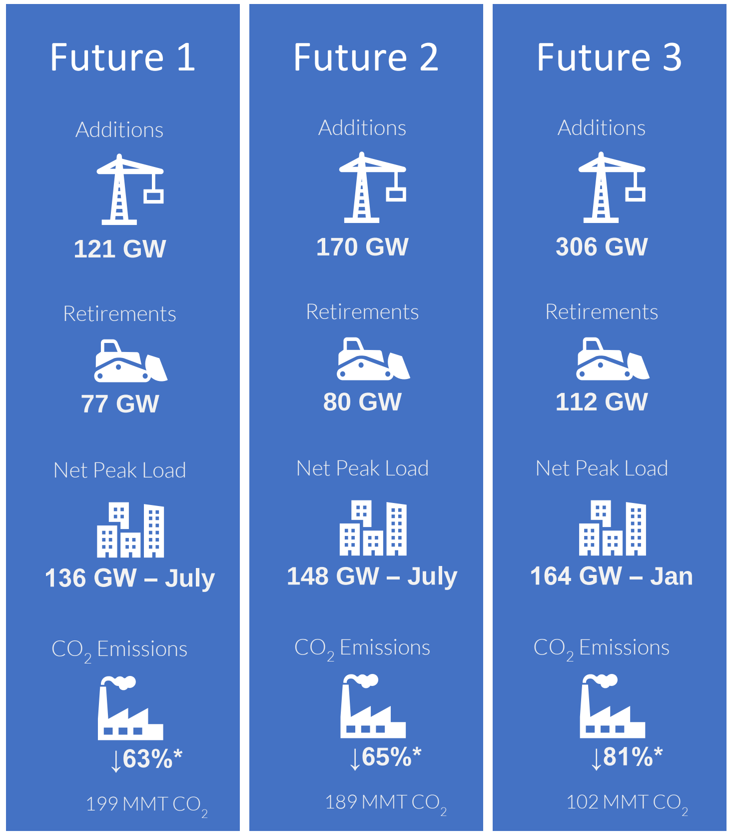


Figure 2: Summary of Future Scenario Impacts, 2039

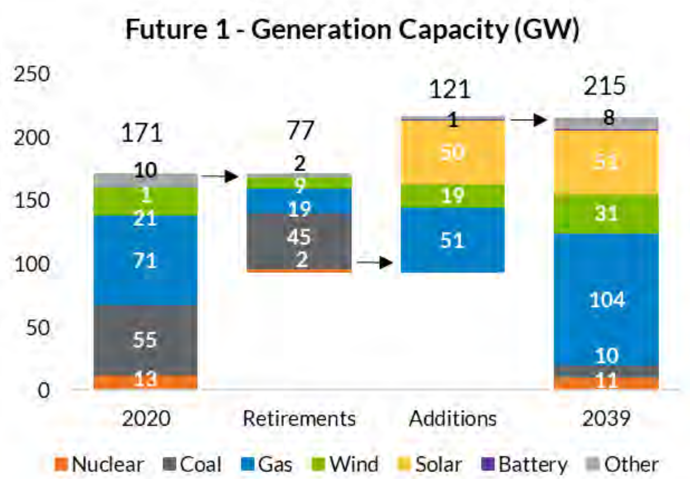
Future 3 Assumptions – This Future incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines, while also including an 80% carbon dioxide reduction. Future 3 requires a minimum penetration of 50% wind and solar and introduces a larger electrification scenario, driving an approximate 1.7% annual energy growth rate.[82]

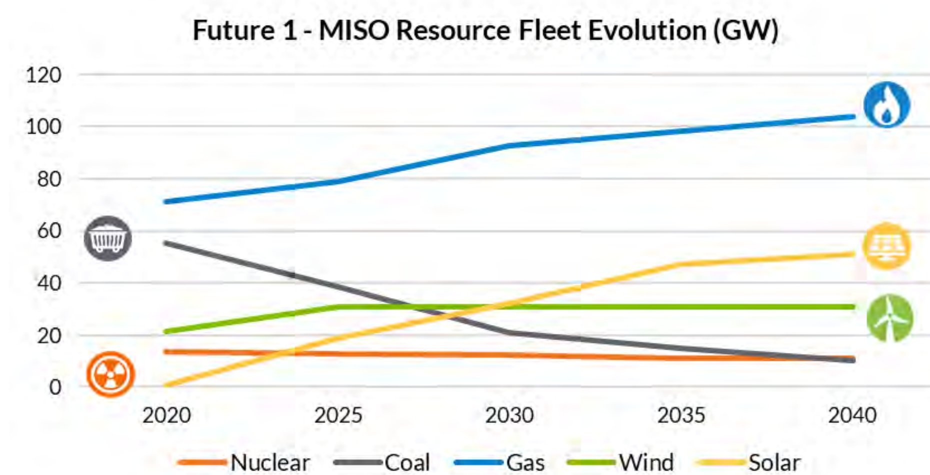
The Futures utilized announced goals and other input assumptions through September 2020 to represent a snapshot in time. Since the modeling of the Future scenarios, new announcements and updates to utility and state goals have been publicized. While the Futures Assumptions above summarize each scenario's inputs, Figure 2 details several key results of the modeling. For example, Future 1 included a 40% carbon reduction trajectory, and the model resulted in 63% carbon reduction. Additionally, "net peak load" results refer to peak load values, net of load modifying resources.

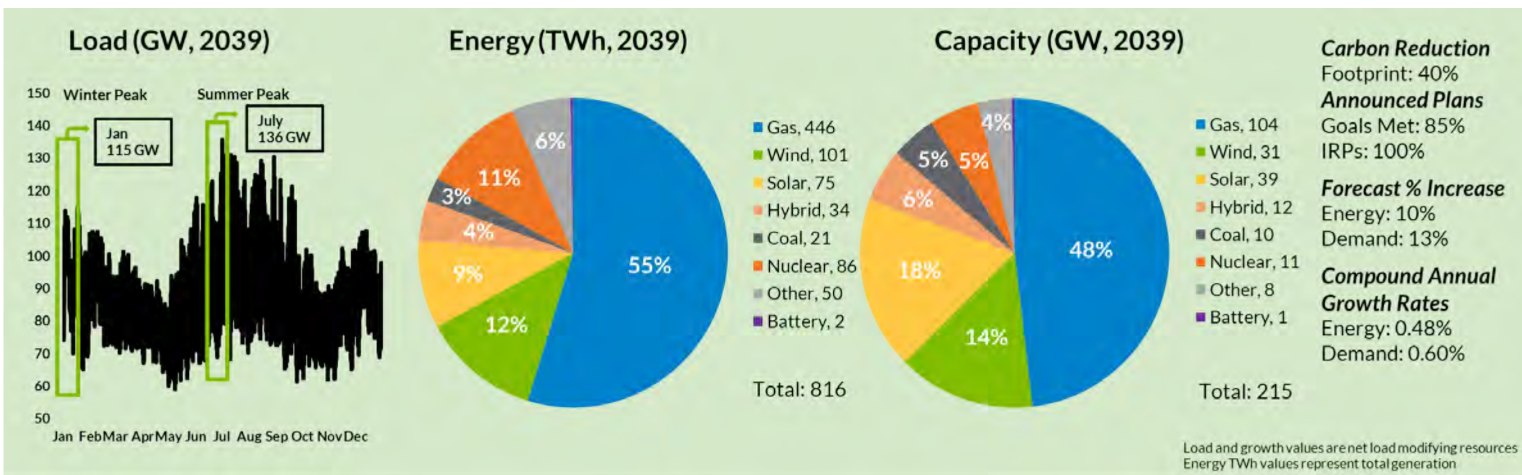
[1] Carbon emission reduction in Future scenarios refer to power sector emissions across the MISO footprint from a 2005 baseline.
[2] Futures energy growth rates are compound annual growth rates (CAGR).

Future 1 Results

This Future assumes demand and energy growth are driven by existing economic factors, with small increases in EV adoption. Modeling for Future 1 results in the retirement of 77 GW and the addition of 121 GW of resources to the MISO footprint.

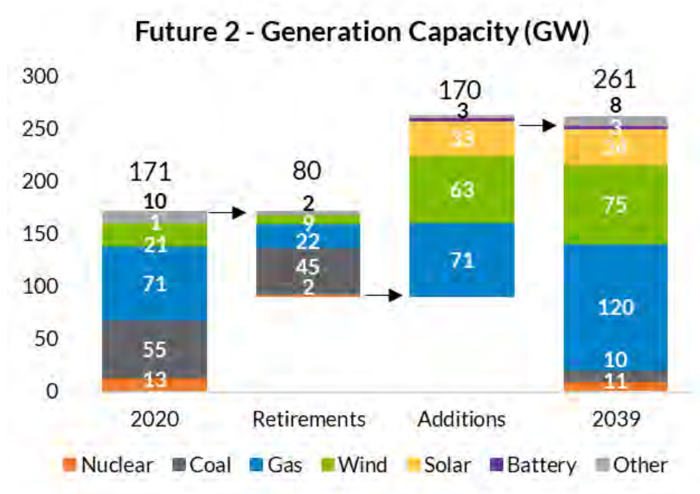


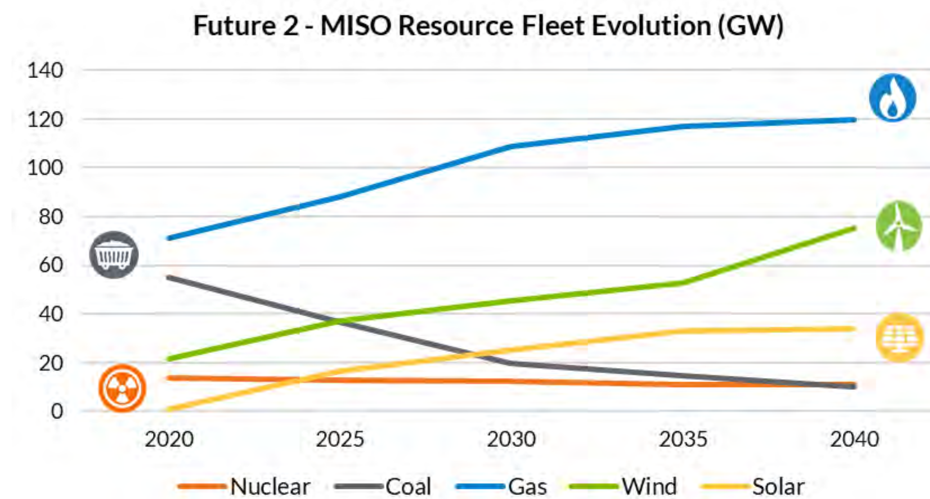


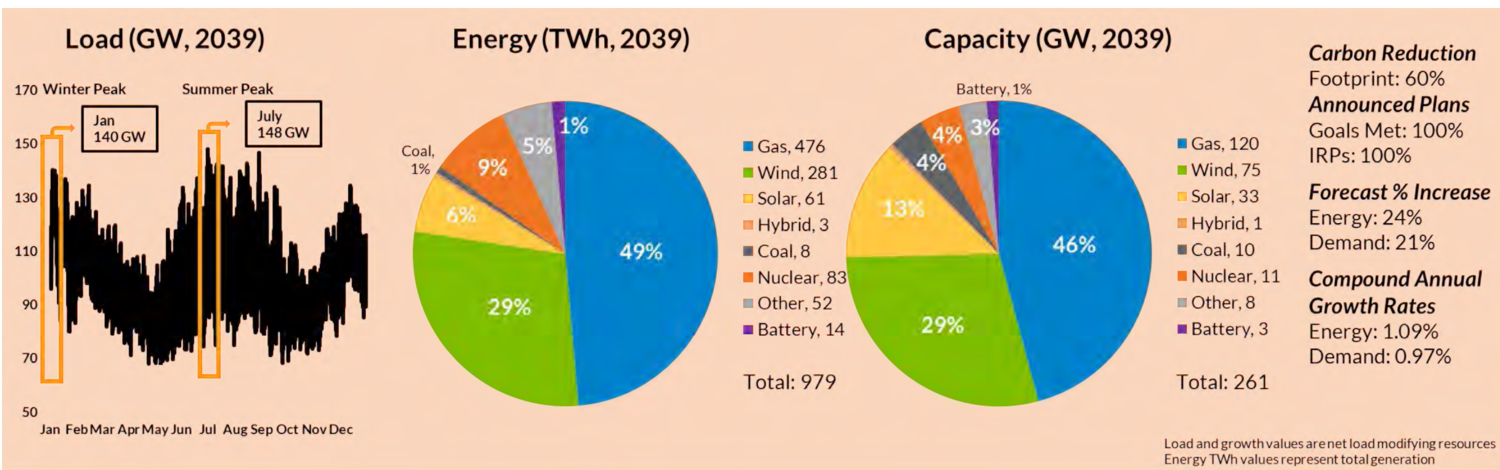


Future 2 Results

Due to retirements and increased electrification, moderate increases in demand and energy cause Future 2's load shape to have a larger peak in the summer but remain relatively dual peaking. Modeling of Future 2 results in the retirement of 80 GW and the addition of 170 GW of resources to the MISO footprint.

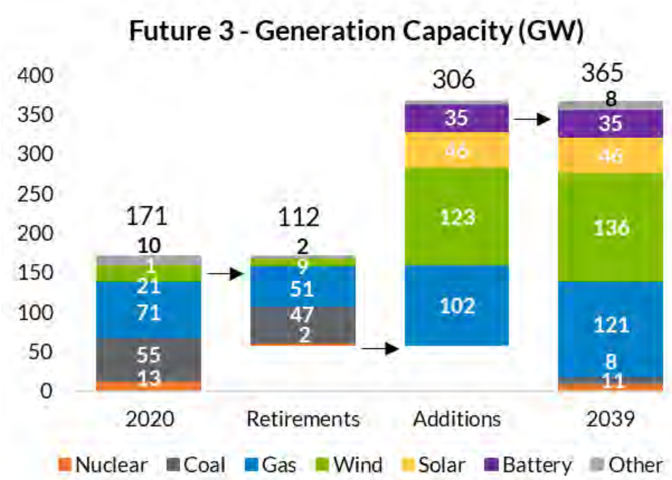


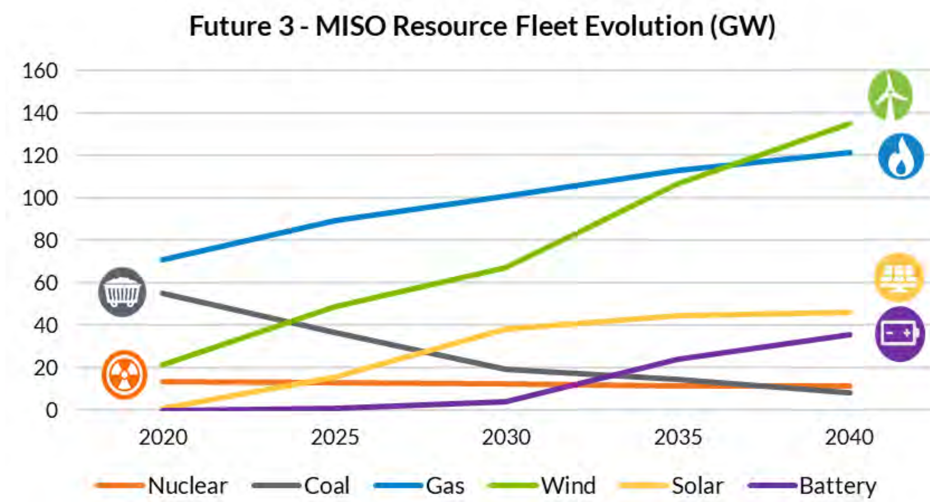


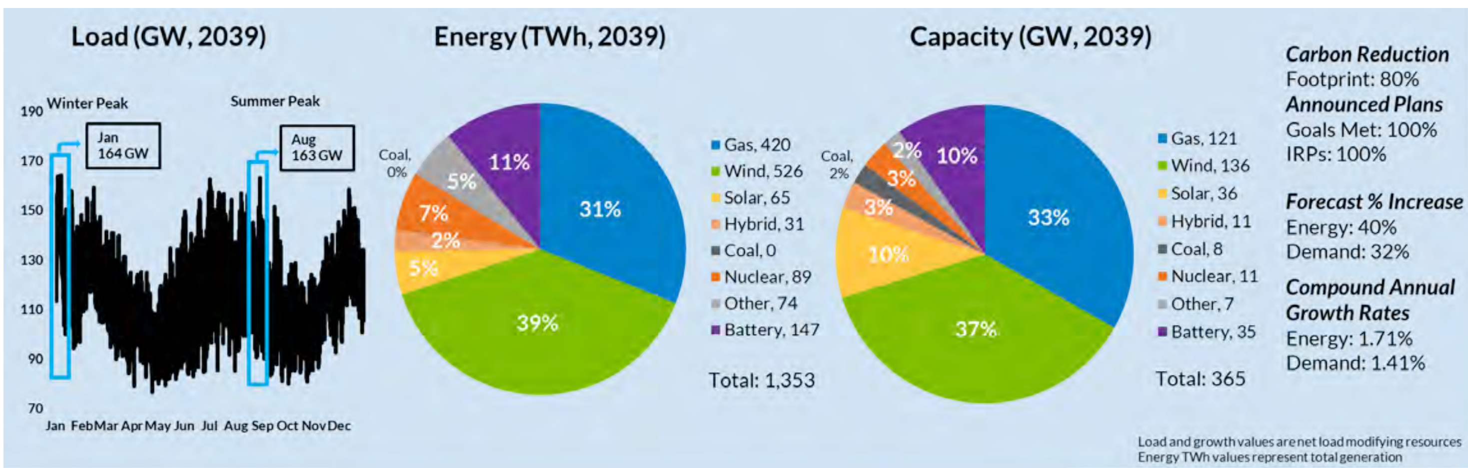


Future 3 Results

Due to retirements, decarbonization, and electrification, large increases in demand and energy produce a prominent dual peaking load shape in the later years of the study period. Modeling of Future 3 results in the retirement of 112 GW and the addition of 306 GW of resources to the MISO footprint.







MISO Futures Purpose and Assumptions

In order to perform analysis on the bulk electric system twenty years into the future, many assumptions must be made to bridge what is known about the system today to what it could be in the future. Complicating matters is the uncertainty of future developments.

A tool that MISO has developed to address this uncertainty is the use of multiple forward-looking scenarios to provide a range of future outlooks. Within MISO, the collection of assumptions defining these multiple forward-looking scenarios are called the "Futures". These Future scenarios establish different ranges of economic, policy, and technological possibilities – such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost – over a twenty-year period.

One of the core components of analyzing the grid twenty years into the future is an understanding of what the electric generation resource fleet will be. Since MISO is not an integrated resource planner, MISO relies on its stakeholders, policy direction, and industry trends to bridge the gap between what the generation fleet is today and what it will be in the future. The Futures are used to hedge uncertainty by utilizing an economic resource expansion analysis, which forecasts the fleet mix that meets MISO's planning reserve margin at the lowest cost while adhering to policy objectives.

As the fleet transforms, the need to keep the system operating reliably and efficiently is driving changes within the Futures process, and throughout MISO more broadly as part of the Reliability Imperative. As the 2019 MISO FORWARD Report identified, three major trends that are changing the energy landscape have emerged – demarginalization, decentralization, and digitalization. Electric utilities in the MISO region are responding to the energy industry's ongoing transition in different ways. At an aggregate level, there is a dramatic and rapid transformation underway of the resource mix in MISO's footprint.

MISO received a clear message of urgency from its stakeholders including member utilities, policy makers, and large end-users asking MISO to move quickly from identifying high-level needs to providing solutions that allow states and utilities to reach their energy transition goals. In response, MISO initiated a public stakeholder process to update the Futures process to align with the ongoing rapid transformation and to better incorporate the plans of MISO's members and states, while also creating a bookended range of future scenarios that could be utilized in multiple study cycles. The public stakeholder process kicked off in August 2019, included thirteen different public stakeholder meetings, and concluded in December 2020.

MISO is not an integrated resource planner. The MISO Futures reflect resource plans announced by member utilities and states and forecast additional resources to meet forecasted energy demand, policy objectives, and reserve margins.

The Future scenarios in this document are a product of continued collaboration between MISO and its stakeholders. They represent challenges and compromises enabling member utilities to achieve significant fleet transition goals with diverse approaches or a more traditional resource portfolio. This report describes three Futures that are intended to be used as inputs for multiple MISO Transmission Expansion Plan (MTEP) cycles, the Long-Range Transmission Plan (LRTP) initiative, and other planning studies. These Futures will form the basis for all components of the Reliability Imperative, such that MISO and its stakeholders can plan to a consistent set of scenarios across transmission, markets, and operations.

Assumptions within the three Future scenarios vary to encompass reasonable bookends of the MISO footprint over the next twenty years. Future 1 represents a scenario driven by state and members' plans, with demand and energy growth driven by existing economic factors. Future 2 builds upon Future 1 by fully incorporating state and members' plans and includes a significant increase in load driven by electrification (discussed in the Electrification section of this report). In the final scenario analyzed, Future 3 advances from Future 2, evaluating the effects of large load increases due to electrification, 50% penetration of wind and solar, and an 80% carbon reduction across the footprint by 2039.

MISO conducted the Renewable Integration Impact Assessment (RIIA) to evaluate the impact of large installations of wind and solar to the system. This assessment found that managing MISO's grid, particularly beyond the 30% system-wide renewable level, will require transformational change in planning, markets, and operations. RIIA concludes that renewable penetration of at least 50% can be achieved through additional coordinated action. MISO members have continued to update their goals and look to MISO to help integrate these resources within the grid. With the analysis of the Future scenarios, wind and solar penetrations reach 26% in Future 1 and 46% in Future 3.[82]

Figure 3 shows the resulting wind and solar energy generation in each Future. Since load forecasts differ, the energy required of wind and solar to reach these penetrations is larger in each scenario. Futures 1, 2, and 3 reach maximum wind and solar penetrations of 26%, 35%, and 46% respectively.

Resulting Wind and Solar Penetration Levels

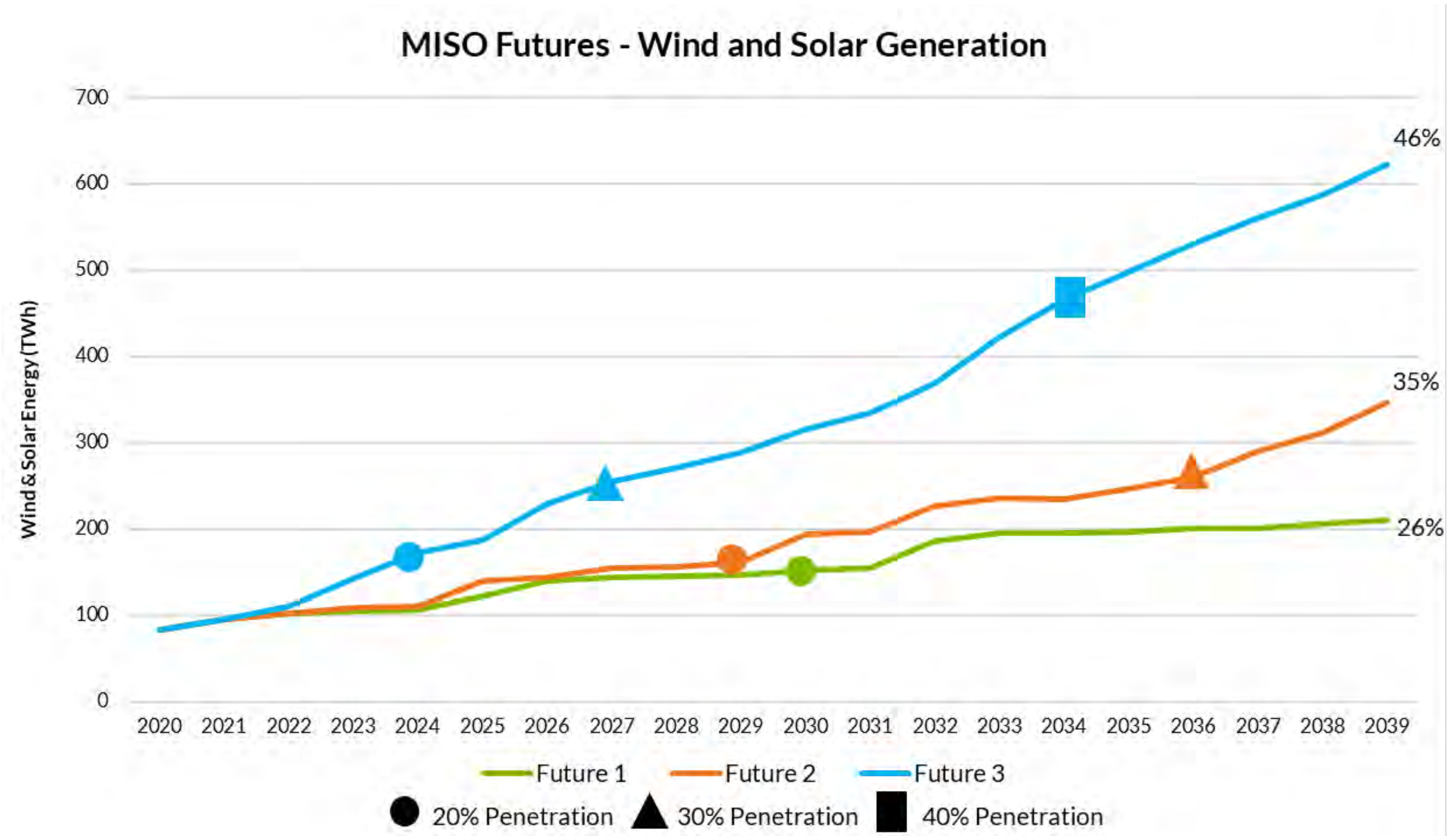


Figure 3: Wind and Solar Energy Generation Throughout Study[82]

Changing Energy Across MISO

Cities, states, large commercial and industrial corporations, and utilities are exploring and setting decarbonization goals that often include reaching 100% renewable energy supply or net zero carbon by 2050. Although not all states and utilities share these clean energy goals, a fleet transition of this magnitude will have implications on what resources will be needed across the MISO footprint to ensure reliability of the grid. The role of MISO is to remain resource-agnostic and to ensure a reliable and economic Bulk Electric System in an ever-changing energy, regulations, and economics environment.

Throughout the analysis of each Future scenario, MISO incorporated specific state and utility goals relative to carbon and renewable energy percentages into the models. Carbon was broken out into two segments per Future: a footprint-wide reduction applied to all resources and site-specific reductions applicable to carbon-emitting resources within states and utilities with announced carbon goals.

Renewable goals were modeled differently than those of carbon emissions. This was done by converting utility/state goals into relative percentages of MISO and taking the summation of these values to create footprint trajectories. As costs for wind and solar have decreased, the model surpassed these goals in Futures 1 and 2. Resources were assigned to their respective areas in the siting process.

Internal analysis indicates the MISO footprint has decarbonized by 29% since 2005. Early thermal retirements, public announcements, and evolving IRPs support MISO's preparation for a broad range of Future scenarios, enabling continual adaptation to the changing energy landscape while ensuring better grid reliability.

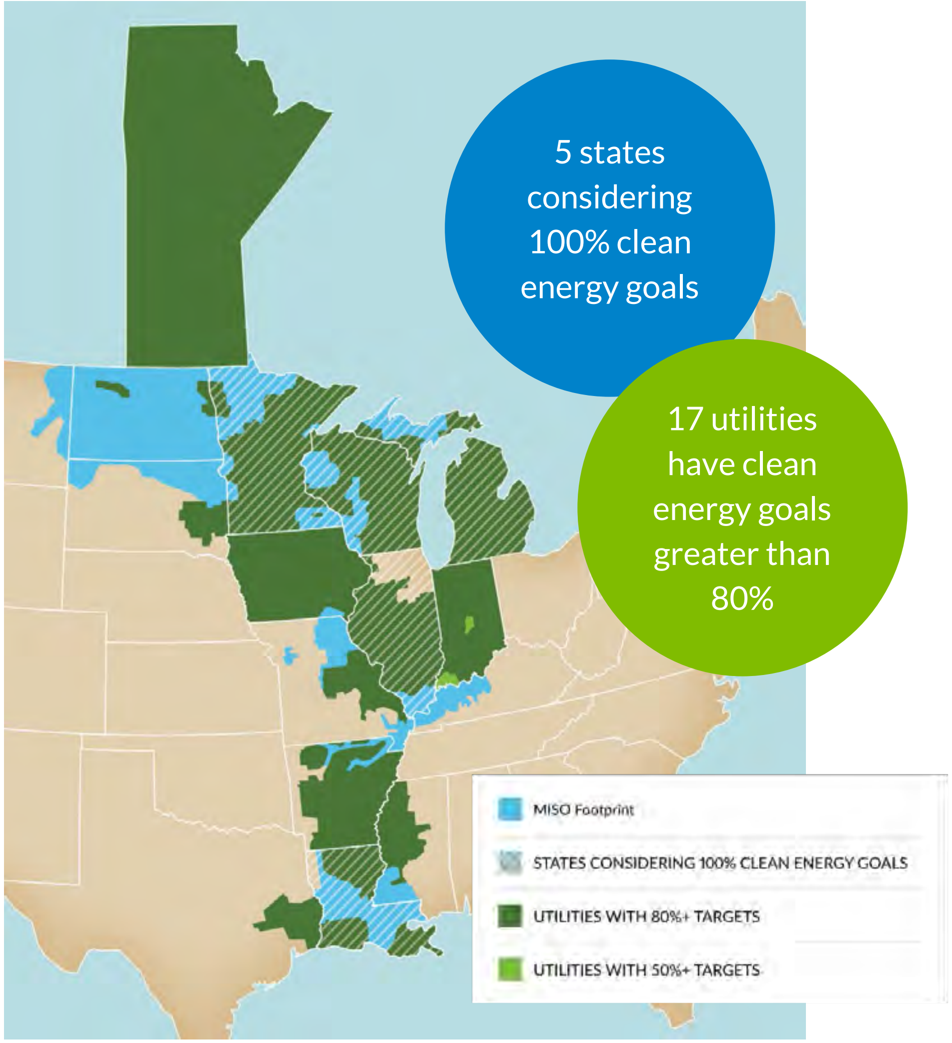


Figure 4: Clean Energy Goals above 50% Across Footprint[3]

State and Utility Clean Energy Goals

Today, state and utility policies and goals are changing rapidly and continued to do so during the Futures process, regarding carbon reductions, renewable energy targets, and unit retirement assumptions. To best account for these changes, MISO continuously updated these announced goals until the final Future scenario models were complete in October 2020. Since then, several members have updated or announced their plans, noted with asterisks in Table 1.

When collecting goal announcements, MISO staff examined companies' IRPs, state publications, and results from the MISO/OMS State Data Survey. (OMS refers to the Organization of MISO States). Once this information was compiled, MISO compared unit addition announcements with signed generation interconnection agreements (GIA) in its queue to ensure that these units would not be double counted. MISO then added IRP units into the base model to account for the announced goals of states and utilities. These units had a variety of fuel types and contained announced additions throughout the study period (2020-2039).

From Figure 4, it is apparent that much of the footprint has a clean energy goal greater than 50% (either from a carbon reduction or renewable energy target).[3] Some goals displayed in the table below were not included in the Futures analysis because their announcement came after the models were complete in October of 2020.[4,5] Table 1 displays state and utility goals within the model, overlapping by service area. In this analysis, MISO considered current trends but also had the opportunity to look beyond and plan for a range of Future scenarios to bookend plausible possibilities over the next 20 years.

[3] Utility goals are represented with green shading while state goals of 100% are given white stripes.

[4] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

[5] Entities who announced or updated their goals after Future scenario modeling was complete are listed here in their respective categories. Carbon reduction goals not modeled: Madison Gas, Vectren, Vistra, IPL, and OTP. Renewable energy targets not modeled: Alliant, CLECO, Vistra, IPL, and Entergy. Entities whose carbon reduction was modeled but a modification to the goal was made: Michigan (28% by 2025), Ameren (80% by 2050), and Minnesota Power (50% by 2021).

State Clean Energy Goals & RPS[6] (source linked)	State	Utility	Utility Carbon Reduction Goals (2005 Baseline)[7]	Utility Renewable Energy Goals
RPS: 15% RE by 2021 (IOUs)	Missouri	Ameren	Net Zero by 2050*	100% by 2050
100% Clean Energy by 2050 (Governor) RPS: 25% by 2025-2026	Illinois	MidAmerican Energy	-	100% by 2021
RPS: 105 MW (completed 2007)	Iowa	Alliant Energy	Carbon Free by 2050	30% by 2030*
		Dairyland Power	-	29% by 2029
Carbon Free by 2050 (Governor) RPS: 10% by 2020	Wisconsin	WEC Energy Group	Carbon Neutral by 2050	-
		Madison Gas & Electric	Net Zero by 2050*	30% by 2030
Carbon Neutral by 2050* RPS: 15% by 2021 (standard), 35% by 2025 (goal, including EE & DR)	Michigan	Consumers Energy	Net Zero by 2040	56% by 2040
		DTE Energy	Net Zero by 2050	25% by 2030
		Upper Peninsula Power	-	50% by 2025
Voluntary clean energy PS, 10% RE by 2025	Indiana	Duke Energy	Net Zero by 2050	16,000 MW by 2025
		Hoosier Energy	80% by 2040	10% by 2025
		Vectren	75% by 2035*	62% by 2025
		NIPSCO	90% by 2028	65% by 2028
Carbon Free by 2050 (Governor) RPS: 26.5% by 2025 (IOUs), 25% by 2025 (other utilities)	Minnesota	Xcel Energy	Carbon Free by 2050	100% by 2050
		SMMPA	90% by 2030	75% by 2030
		Minnesota Power	100% Clean Energy by 2050*	50% by 2021
		Great River Energy	95% by 2023	50% by 2030
Net Zero GHG by 2050 (Governor)	Louisiana	Entergy	Net Zero by 2050 (2000 baseline)	12% by 2030*

Table 1: State & Utility Goals – Service Area Overlay

System-Wide Carbon Modeling

In addition to state and utility renewable goals, each Future scenario had a carbon emission reduction (CER) applied across the entire footprint. Carbon reduction trajectories were made from a total MISO 2005 CO_2 baseline, with linear reductions of 40%, 60%, and 80% (for Futures 1, 2, and 3, respectively) applied through the end of the study period. These trajectories were modeled within EGEAS (Electric Generation Expansion Analysis System). As well as the footprint-wide total CER for each Future, MISO also entered more specific trajectories for states and utilities as applicable.

[6] DR: demand response; EE: energy efficiency; GHG: greenhouse gas; IOU: investor-owned utility; PS: portfolio standard; RE: renewable energy; RPS: renewable portfolio standard

[7] Any goal denoted with an asterisk (*) was updated or announced following the modeling of the Futures.

All utility and state carbon trajectories used a 2005 CO_2 emissions baseline except for Entergy, which used a 2000 baseline in accordance with utility-specific goals. Each CER trajectory was given an approximate 2020 CO_2 starting value and then decreased to a target reduction percentage of the baseline. Consistent with Futures assumptions, CER trajectories reflected 100% of IRPs and 85% of other announced goals for Future 1, while trajectories for Futures 2 and 3 reflected 100% of both.

From analysis of the current fleet in 2005, MISO emitted 543 million (M) tons of CO_2. Figure 5 below illustrates CER for each Future scenario, displaying the tons of carbon emitted (bars) and the percentage of carbon reduction from the 2005 baseline (lines). The dotted line projects the historical trend of carbon emissions that MISO is assumed to have for comparison. From the trend of MISO, it is evident that the carbon emissions of the system will continue to decrease and will be accelerated as members' goals continue to change. Futures 2 and 3 emit more carbon than Future 1 in 2020 due to the increased load assumptions met by the existing fleet. The Future scenarios in this document allow for insights on how quickly carbon reduction across the footprint may occur. By the end of the study period, emissions reduced by 63% in Future 1, 65% in Future 2, and 81% in Future 3.

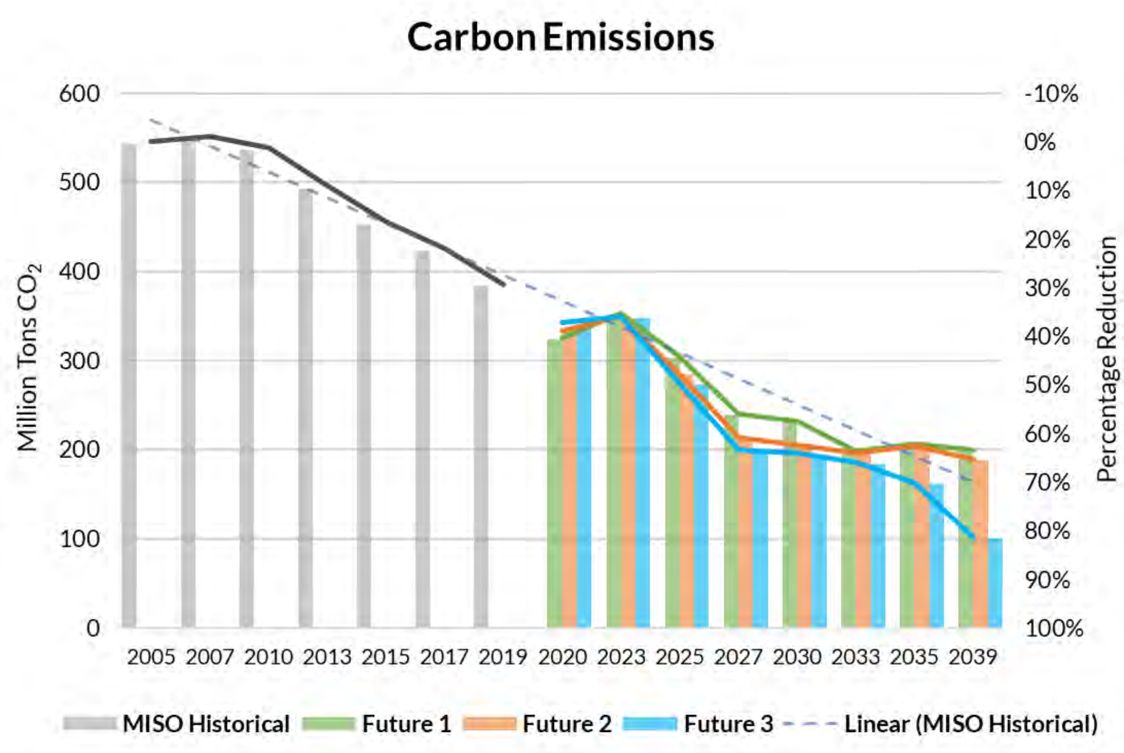


Figure 5: CO_2 Reduction Results (from 2005 Baseline)

Retirement and Repowering Assumptions

Base Retirement Assumptions

Nuclear and Hydroelectric – Retirement of nuclear and hydroelectric units will occur when a unit has a publicly announced retirement plan or is listed to retire in an IRP. Otherwise, these units will remain active throughout the study across all Futures.

Age-Based Retirement Assumptions

Age-based assumptions will be applied to all the units that fall into any of the categories listed below. However, in cases where these assumptions cause older units in the MISO system to retire before the start of the study period (2020), units will be retired by 2025.

Coal – Retirement ages of coal units progressively decrease with each Future. It is assumed that with changing policies and emission standards, coal usage will decline further. The coal retirement ages modeled in the three Futures respectively are: 46, 36, and 30 years. The Future 1 retirement age of 46 years is based on the average age of coal units noted by the Energy Information Administration (EIA).

- Coal retirements in each Future are approximately a 50/50 split between base and age-based retirement assumptions. The amount of coal retired results in similar capacity due to the average coal unit within the MISO fleet being 46 years of age.

Gas – Retirements for gas units were split into two categories, Combined Cycle (CC) and Other-Gas (e.g., Combustion Turbine [CT], IC [Internal Combustion] Renewable, and Integrated Gasification Combined Cycle [IGCC]). Both unit types were given retirement ages that decreased across the Futures scenarios; retirement ages for CC gas units are: 50, 45, and 35 years and retirements for Other-Gas units are: 46, 36, and 30 years respectively.

Oil – Retirement ages of oil units decrease across each Future scenario and are 45, 40, and 35 years respectively.

Wind and Solar – Retirements for utility-scale wind and solar will occur once a unit reaches 25 years of age. However, wind units will be repowered within the same year of retirement. These will be replaced by a new 100m hub height wind turbine with the same capacity as the previous unit but will receive new wind profiles, dependent on location. New profiles have updated capacity factors that are higher than existing wind turbines.

	Future 1	*Future 2*	*Future 3*
Coal	46	36	30
Natural Gas – CC	50	45	35
Natural Gas – Other	46	36	30
Oil	45	40	35
Nuclear & Hydro	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
Solar – Utility-Scale	25	25	25
Wind – Utility-Scale	25	25	25

Table 2: Age-Based Retirement Assumptions

Figure 6 through Figure 8 display the results of differing retirement assumptions across each of the three Future scenarios. Retirement totals were calculated by applying age-based assumptions, announced retirements, and adjusting generation units per stakeholder feedback provided to MISO. Age-based assumptions are the product of Future-specific retirement assumptions, while base retirements are announced by the generator owner, stated in an IRP, or filed with MISO's Attachment Y.[8]

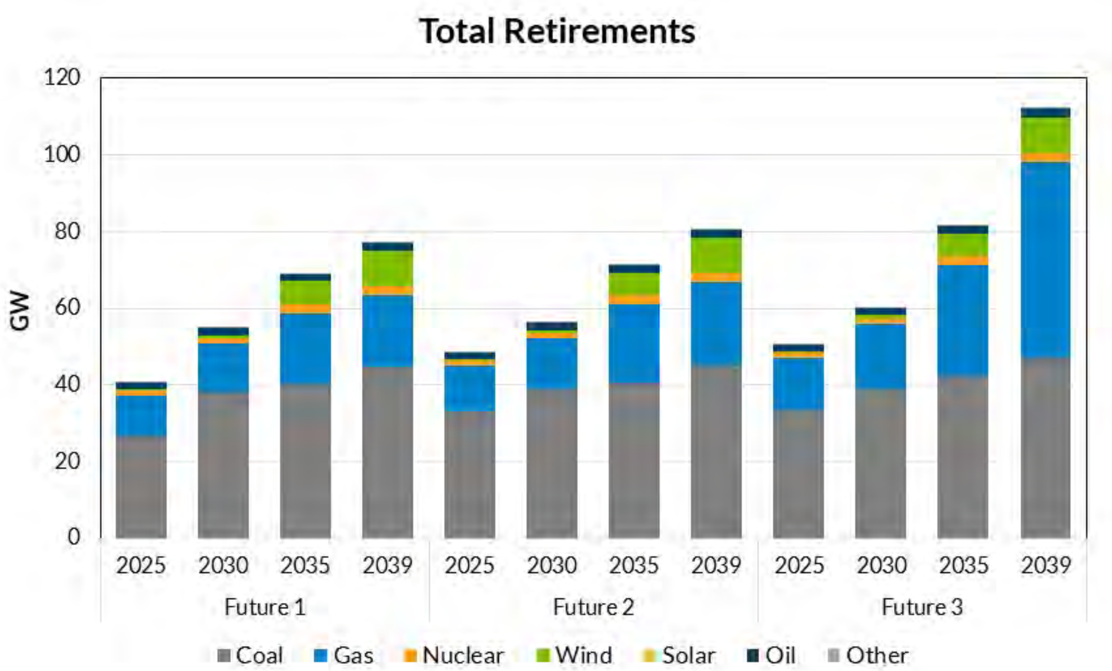


Figure 6: Total Retirements per Future (Cumulative by Year), Equal to Age-Based + Base

[8] MISO's retirement notification process

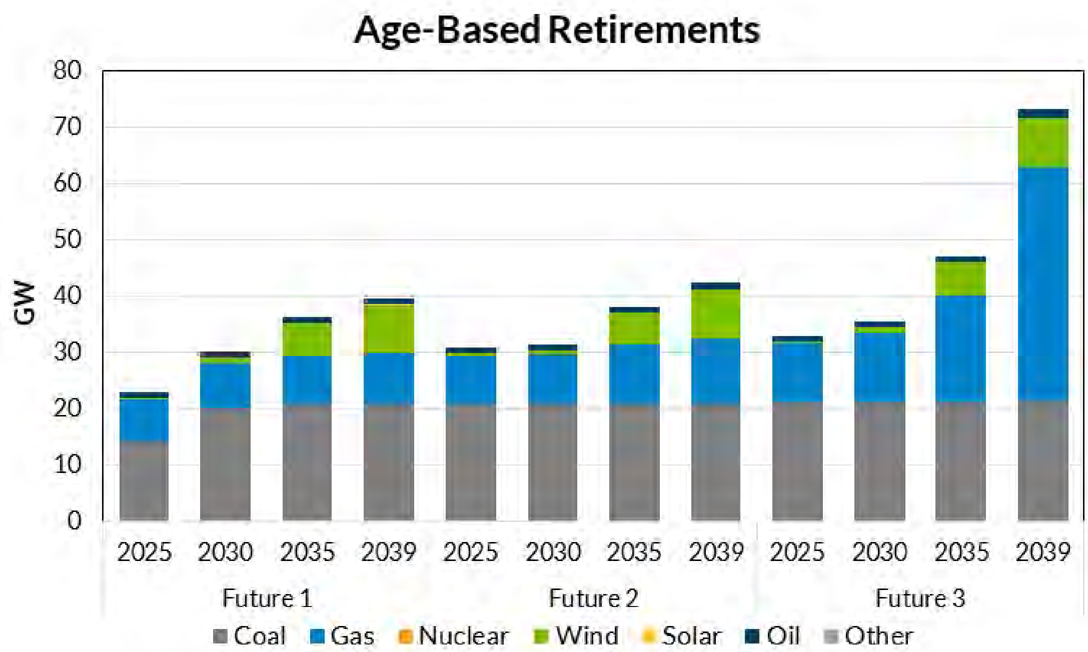


Figure 7: Age-Based Retirements per Future (Cumulative per Year)

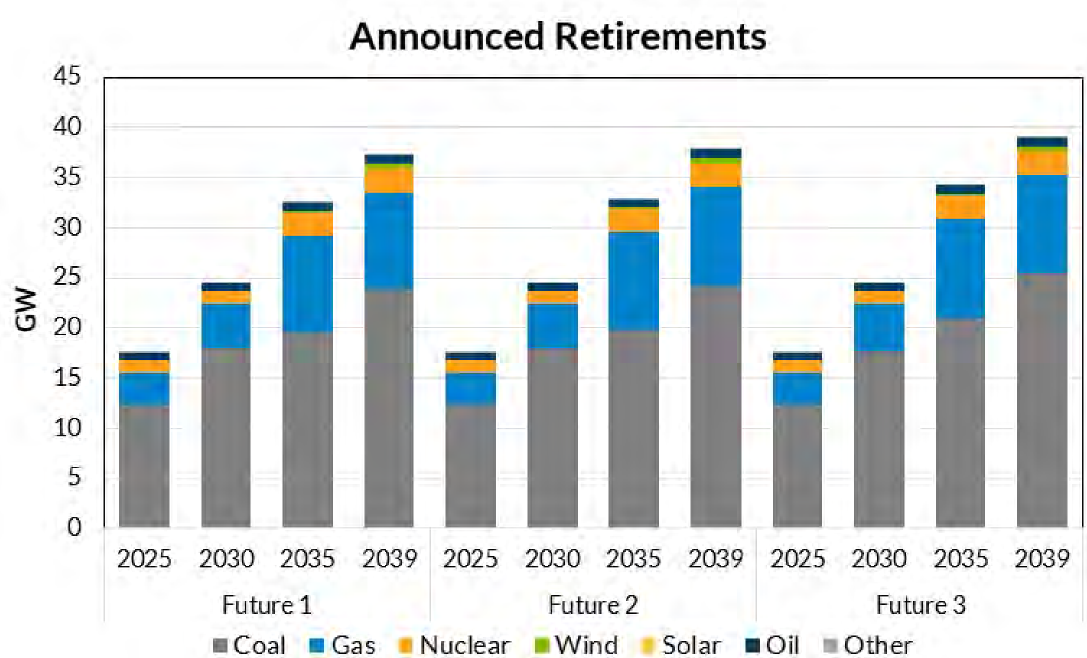


Figure 8: Base Retirements per Future (Cumulative per Year)

Figure 9 through Figure 11 display the results of the Future scenarios' retirement assumptions geographically throughout the MISO footprint. It is important to note that the wind units seen in these figures are assumed to be repowered with the same capacity, albeit with an updated profile that includes a higher capacity factor.

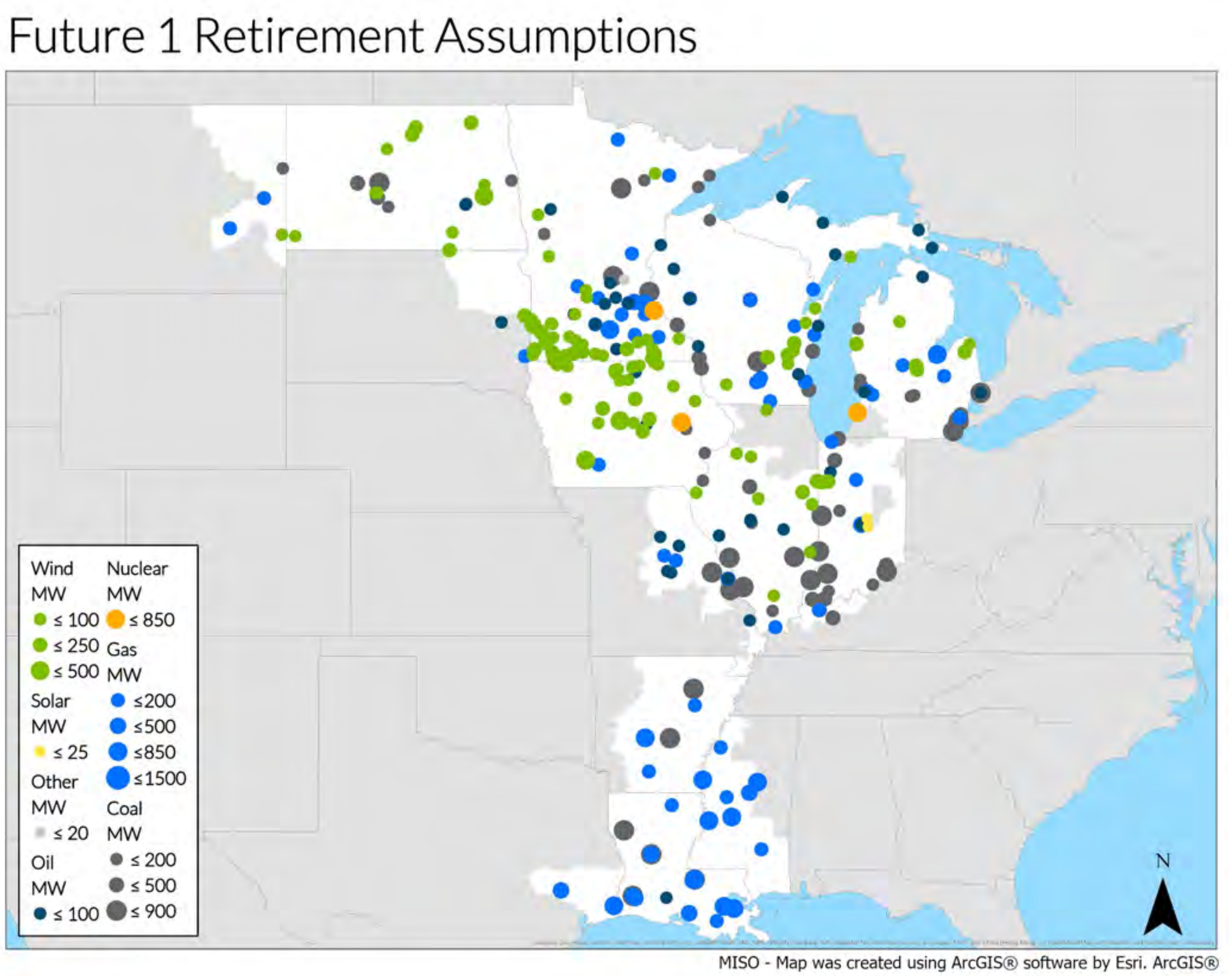
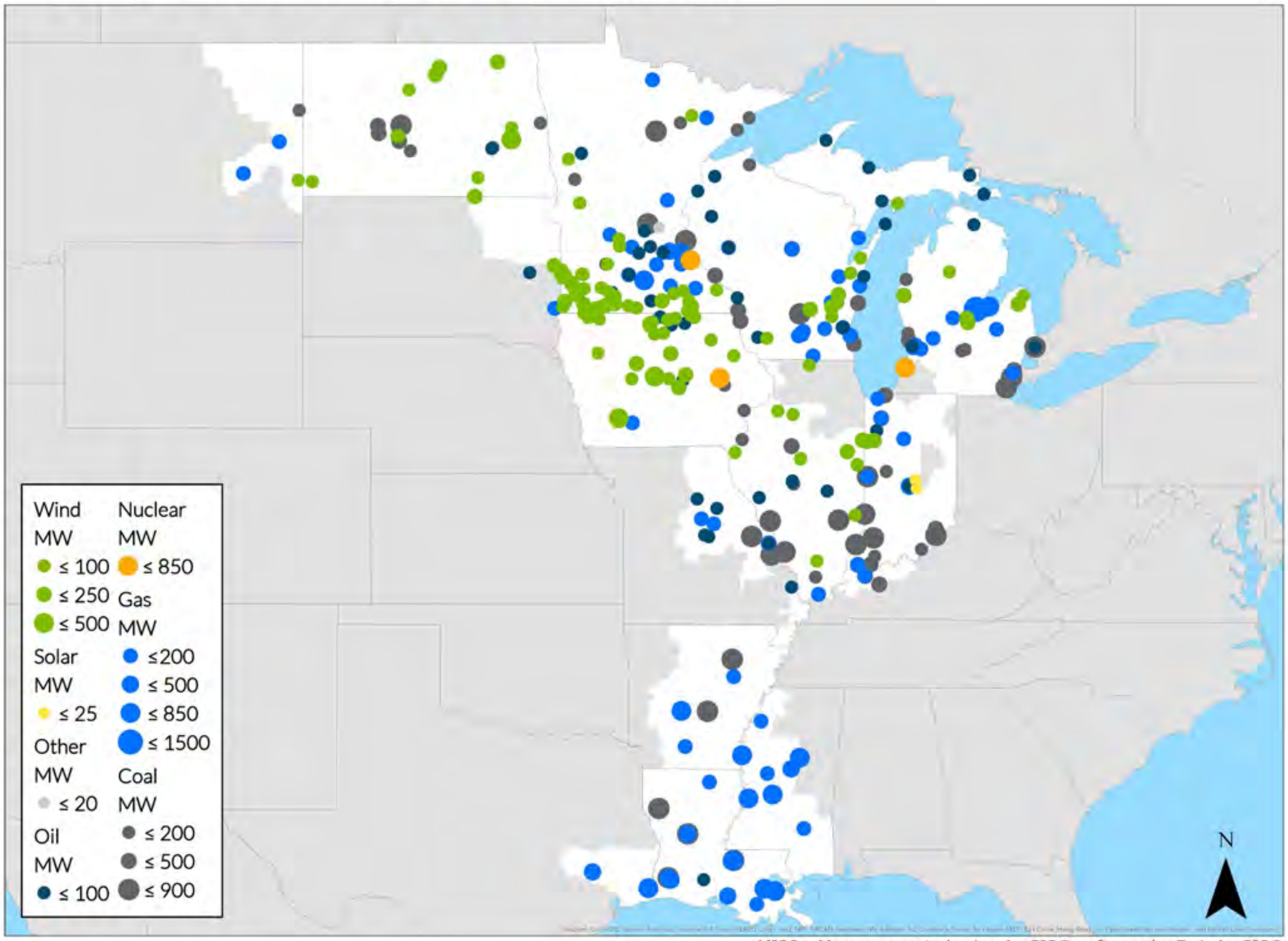


Figure 9: Future 1 Retirements by Fuel Type

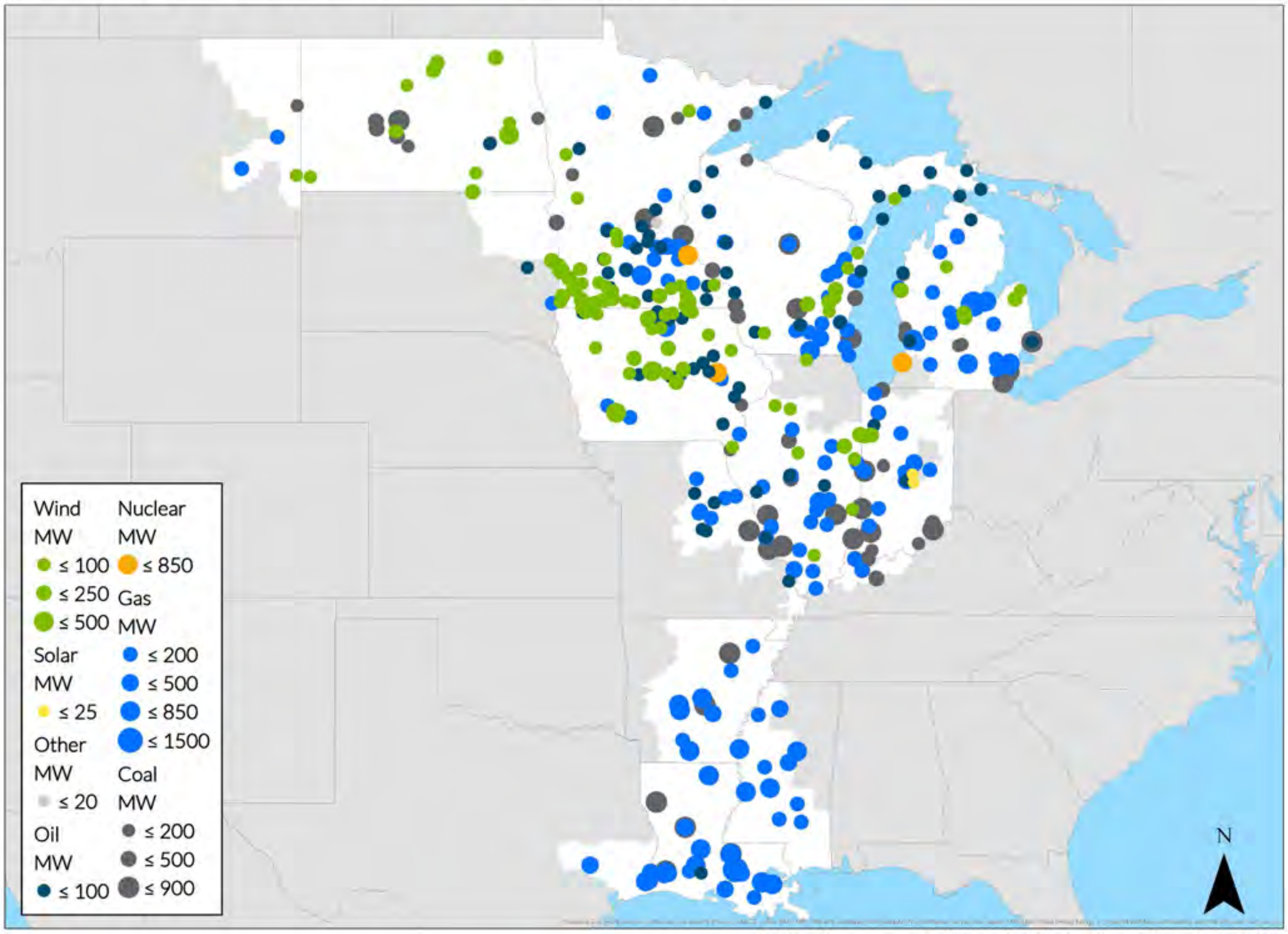
Future 2 Retirement Assumptions



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 10: Future 2 Retirements by Fuel Type

Future 3 Retirement Assumptions



MISO - Map was created using ArcGIS® software by Esri. ArcGIS®

Figure 11: Future 3 Retirements by Fuel Type

Load Assumptions

To analyze what new generation and load modifying resources may be necessary 20 years into the future, assumptions were made regarding the load during that same 20-year period for each Future planning scenario. The three Futures each have differing assumptions representing a wide range of compound annual growth rates (CAGR) during the study period.

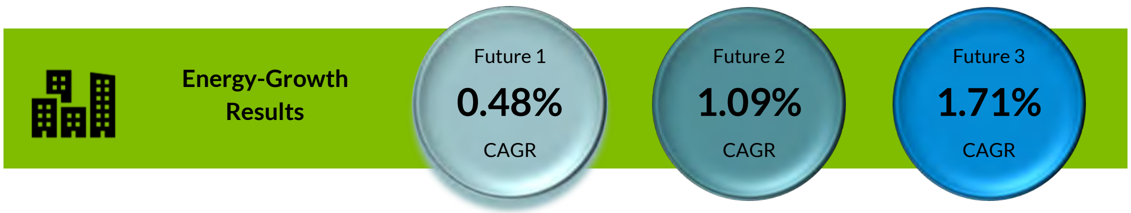


Figure 12: Annual Energy-Growth Rates

Future 1 assumed a load growth[9] consistent with recent trends; 0.48%, including currently low electric vehicle adoption as modeled by Lawrence Berkeley National Laboratory's (LBNL) 'Low' scenario projection.

Future 2 assumed an annual energy growth rate[9] of 1.09% to reach a targeted 30% energy increase by 2040, largely driven by electrification.

Future 3 assumed an annual energy growth rate[9] of 1.71% to reach a targeted 50% energy increase by 2040, driven by additional electrification.

A primary driver of load growth in Futures 2 and 3 is electrification. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). The increased energy assumptions of 30% and 50% were selected by MISO to create a wide but plausible range of growth scenarios. Although electrification drives the load increase in two of the Futures, it is not the sole source of each scenario's load growth. A more detailed discussion of each Future's load growth and electrification assumptions is provided below and in the Electrification Section of this report.

The resulting Future-specific Demand (MW) and Energy (GWh) forecasts are further detailed in the proceeding sections of this report.

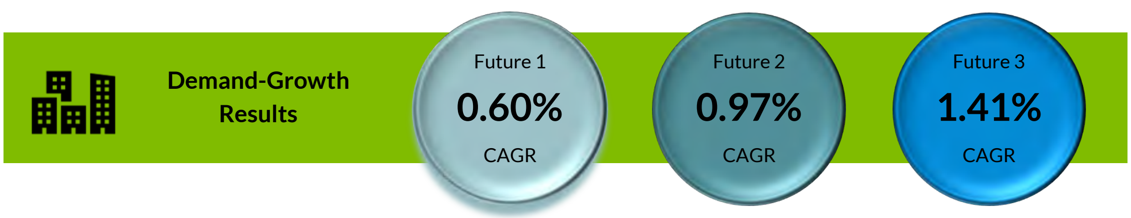


Figure 13: Annual Demand-Growth Rates

[9] Net annual energy and demand growth rates result from reducing the hourly load shape by the energy from energy efficiency (EE) programs.

MISO Forecast Development

The development of the EGEAS-Ready Coincident Peak (CP) Demand and Energy Forecasts for each Future began with MISO's load serving entities' 20-year demand and energy forecasts[10] and ended with the application of the various Future-driven assumptions, creating Future- and year-specific forecasts.

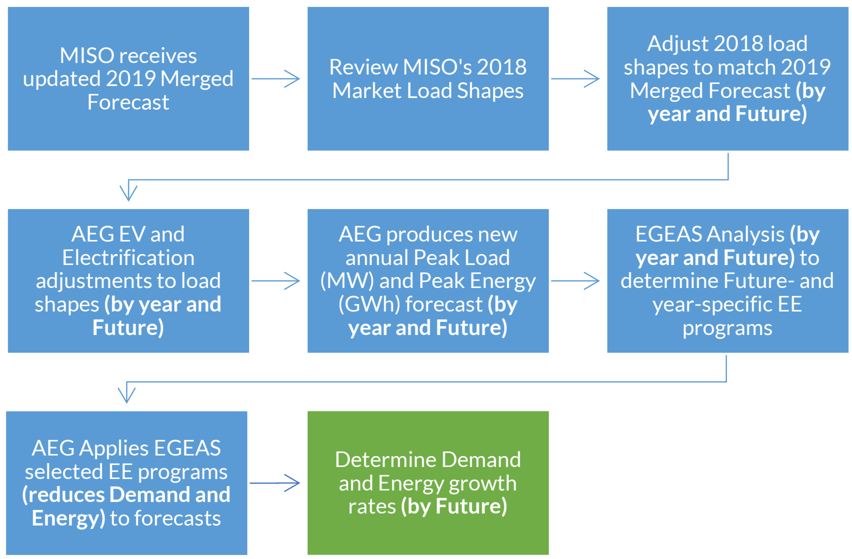


Figure 14: MISO's Forecast Development High-Level Process Flow Chart[11]

Base Forecast and Load Shapes

The 2019 Merged Load Forecast for Energy Planning forecast was reviewed for updates by stakeholders December 17, 2019 through January 10, 2020, and the updates received were incorporated. To accompany the forecast, MISO evaluated its 2018 load shapes for the impact of abnormal outages in operational load shape data due to weather anomalies. MISO evaluated the impact of Atlantic Tropical Cyclones which entered the MISO footprint according to the National Oceanic and Atmospheric Administration and determined that the 2018 shapes are suitable for MISO Futures.[12] MISO's 2018 load shapes also align with wind and solar shapes based on the most current data.

As a Futures process improvement, MISO used PROMOD to adjust each Load Balancing Authority's (LBA) 2018 load shape to meet Peak Load (MW) and Annual Energy (GWh) requirements set by the updated 2019 Merged Load Forecast for Energy Planning forecast. The benefit of this improvement was to create 20 years' worth of unique load shapes for the EGEAS analysis, as well to establish a common load shape for the EGEAS and Market Congestion Planning Studies (MCPS) analyses.

[10] If a particular MISO Load-Serving Entity (LSE) did not provide a 20-year demand and energy forecast, data from the State Utility Forecasting Group's Independent Load Forecast was used for it, creating the 2019 Merged Load Forecast for Energy Planning CP.

[11] Demand and Energy forecast process currently at box highlighted green.

[12] https://www.nhc.noaa.gov/data/tcr/index.php?season=2018&basin=atl

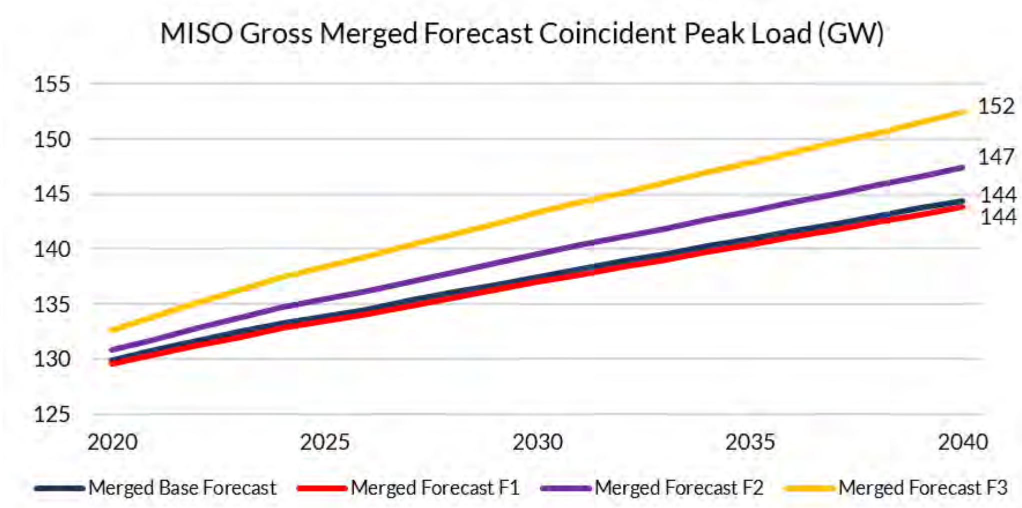


Figure 15: 2019 Merged Load Forecast Peak Load (GW)

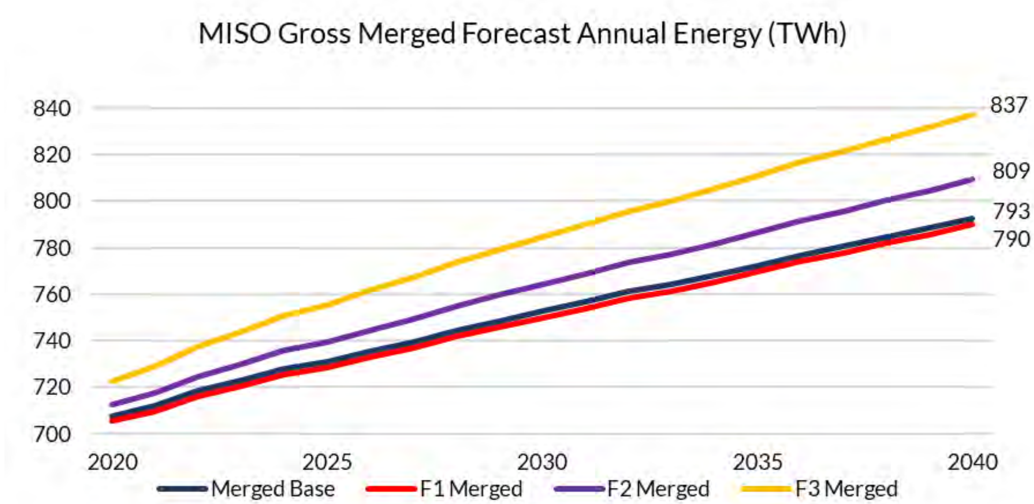


Figure 16: 2019 Merged Load Forecast Annual Energy (TWh)

Future-Specific Forecasts and Load Shapes

Applied Energy Group (AEG) used PROMOD-adjusted load shapes for their base input assumptions and then further modified these load shapes to achieve Future-specific electrification assumptions (EV growth and charging assumptions, residential electrification, and commercial and industrial electrification), ultimately creating 20 years of load shapes for each Future. A representation of the load shape modification is shown in Figure 24.

These Future-specific load shapes were used to calculate the associated Peak Load (MW) and Annual Energy (GWh) forecast for each year to be used in the EGEAS analysis. Refer to the following figures for MISO Footprint and Local Resource Zone (LRZ) representation of this forecast.

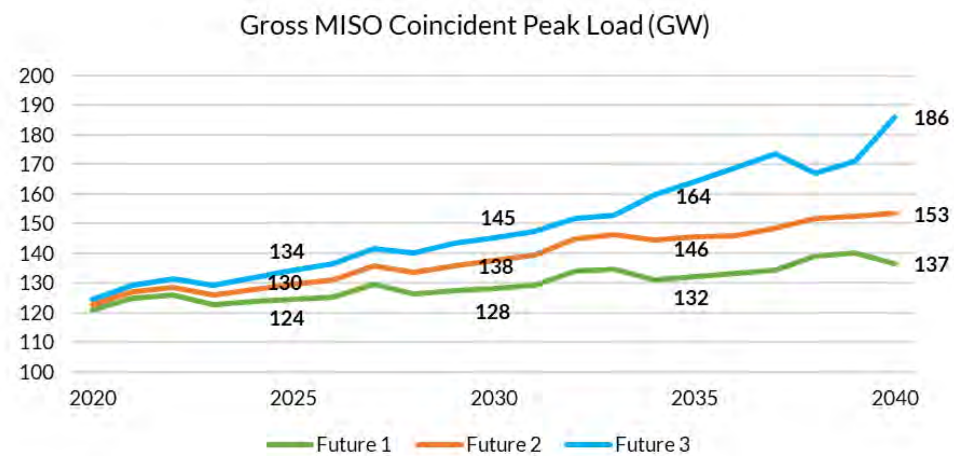


Figure 17: Final AEG Modified MISO Gross Coincident Peak Load (GW) Forecast by Future[13,14]

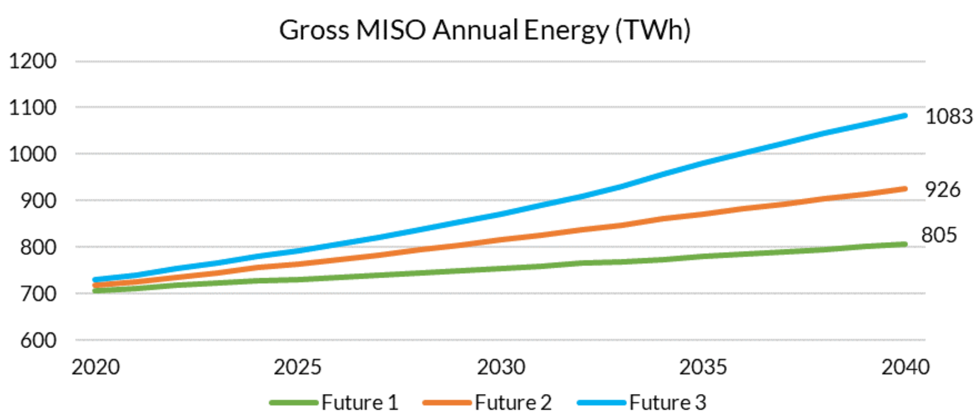


Figure 18: Final AEG Modified MISO Gross Annual Energy (TWh) Forecast by Future

[13] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[14] Dips in Future 3 are due to different peak times of reference, EV charging, and electrification load forecasts.

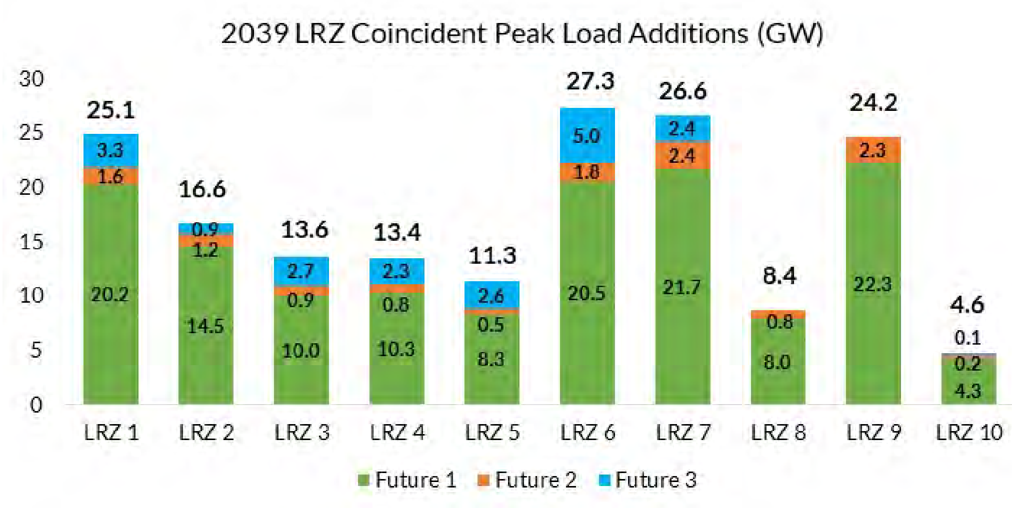


Figure 19: Final AEG Modified LRZ Coincident Peak Load (GW) Forecast[15,16]

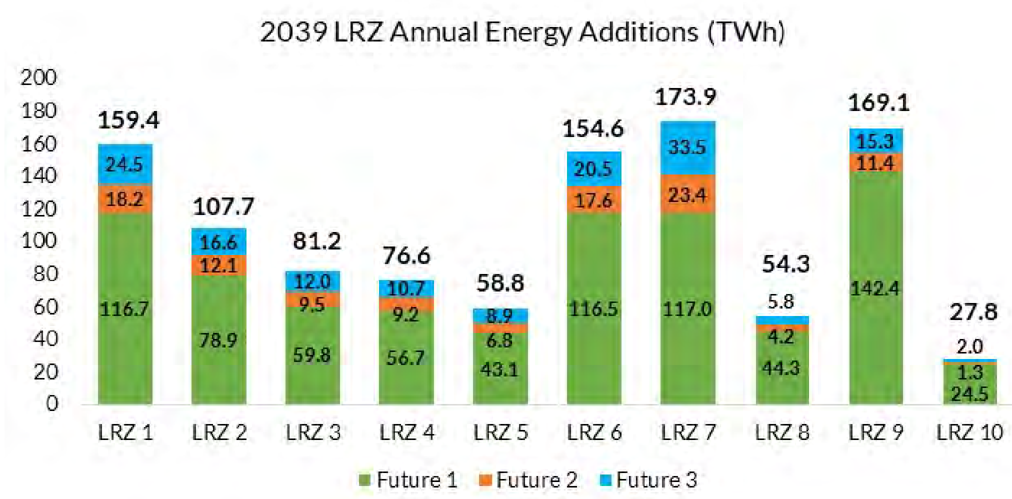


Figure 20: Final AEG Modified LRZ Annual Energy (TWh) Forecast[16]

[15] In LRZs 8 and 9, CP values decrease in Future 3, making the total shown less than the sum of values for Futures 1 and 2.
[16] Values shown do not include load and energy modifiers determined by EGEAS analysis.

Forecast Growth Assumptions

Demand and energy growth values are based on Futures assumptions and were determined once the analysis was finalized; EGEAS having selected hourly load (MW) and energy (GWh) modifiers and programs applied to each Future scenario's Coincident Peak forecast. The following figures represent compound annual growth rates (CAGR) and forecast increases pre- and post-analysis.

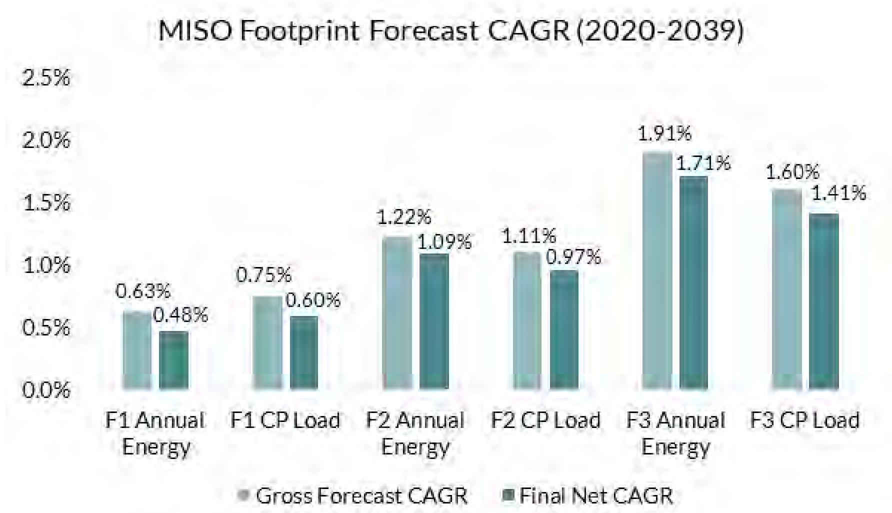


Figure 21: Final AEG Modified MISO Footprint Forecast Compound Annual Growth Rates (CAGR)

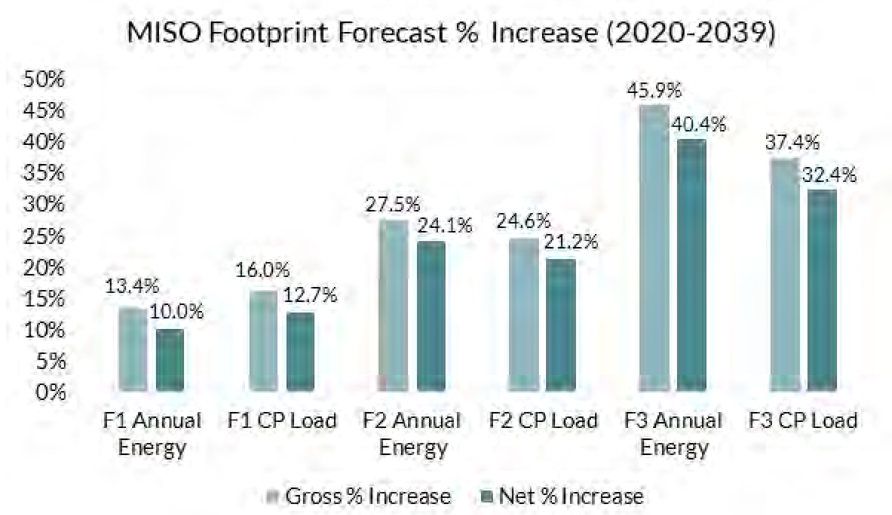


Figure 22: Final AEG Modified MISO Footprint Forecast % Increase[17]

[17] Gross values do not include load and energy modifiers determined by EGEAS analysis, while Net values include EE programs that were selected during modeling.

Forecast Evolution

To ensure the Futures update has effectively created broad and realistic bookends, especially with demand and energy assumptions as key drivers, MISO has compared the 2019 Merged Forecast (pre-application of EV and Electrification assumptions), MTEP21 Coincident Peak (CP) Future-specific forecasts (post-application of EV and Electrification assumptions), and MTEP19 Future forecasts.

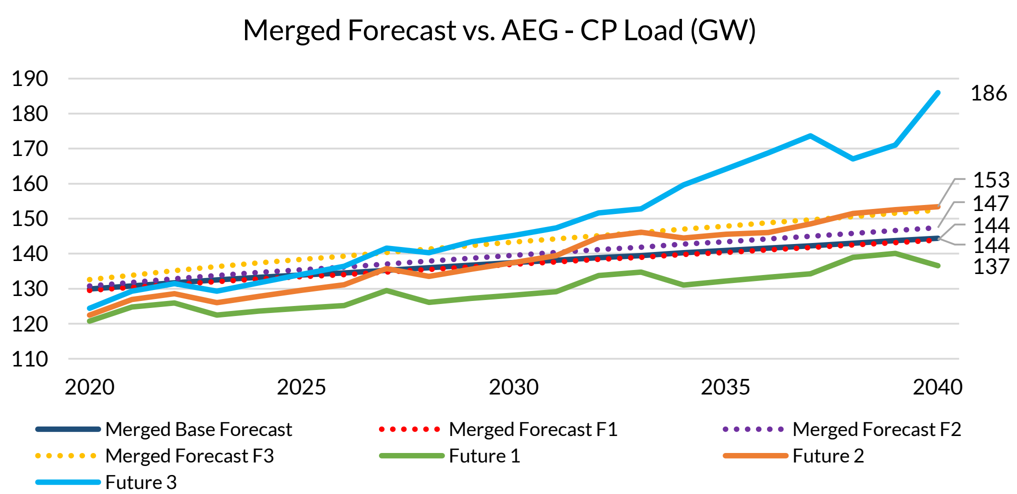


Figure 23: Merged Forecast vs. Future-Specific Adjustments – CP Load (GW)[18,19]

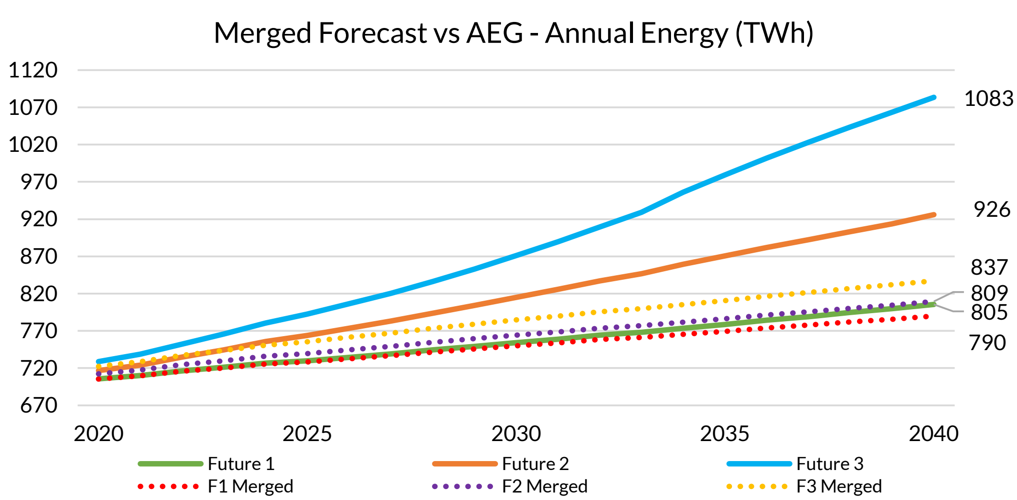


Figure 24: Merged Forecast vs. Future-Specific Adjustments – Annual Energy (TWh)

[18] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[19] Merged Forecast CP Load (GW) values are calculated from monthly peak data while the AEG Peak Load (GW) values are calculated from hourly data. This has the illusory effect of the Merged Forecast CP Load (GW) being reduced.

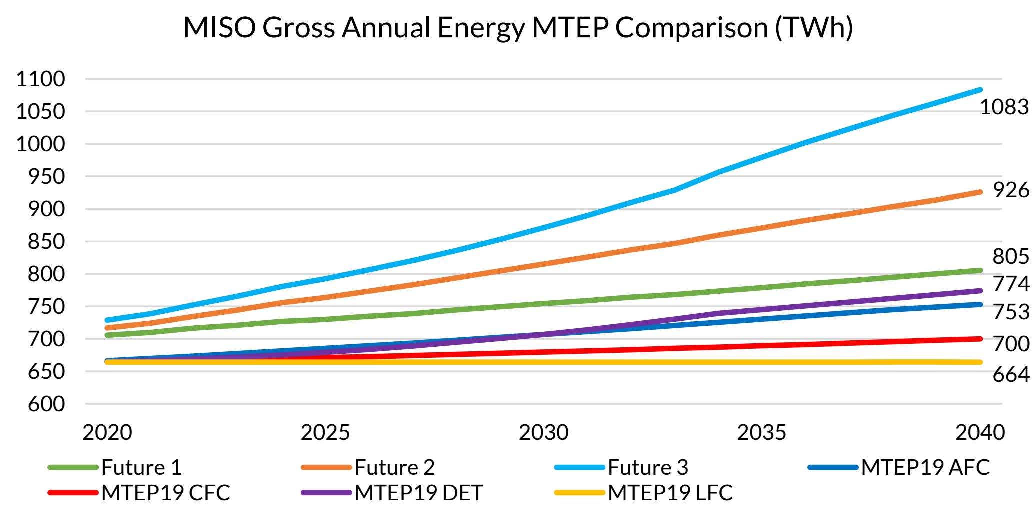


Figure 25: MTEP19 & MTEP21 MISO Annual Energy (TWh) Compare[20]

Final Load Shapes

Upon conclusion of the EGEAS analysis, MISO removed energy proportionate with selected energy efficiency programs in each Future scenario's load shape to produce final net load shapes. In Figure 27 through Figure 29, the evolution of each Future load shape is shown, starting with the initial 2020 load shape developed by SUFG,[21] the final input load shape for year 2039 from AEG that includes electrification assumptions, and then the 2039 load shape post modeling of each scenario that nets out EE programs selected. Figure 26 displays each Future scenario's post-modeling load shape in the final year of the study, for comparison.

[20] Values shown do not include load and energy modifiers determined by EGEAS analysis.

[21] Purdue University's State Utility Forecasting Group

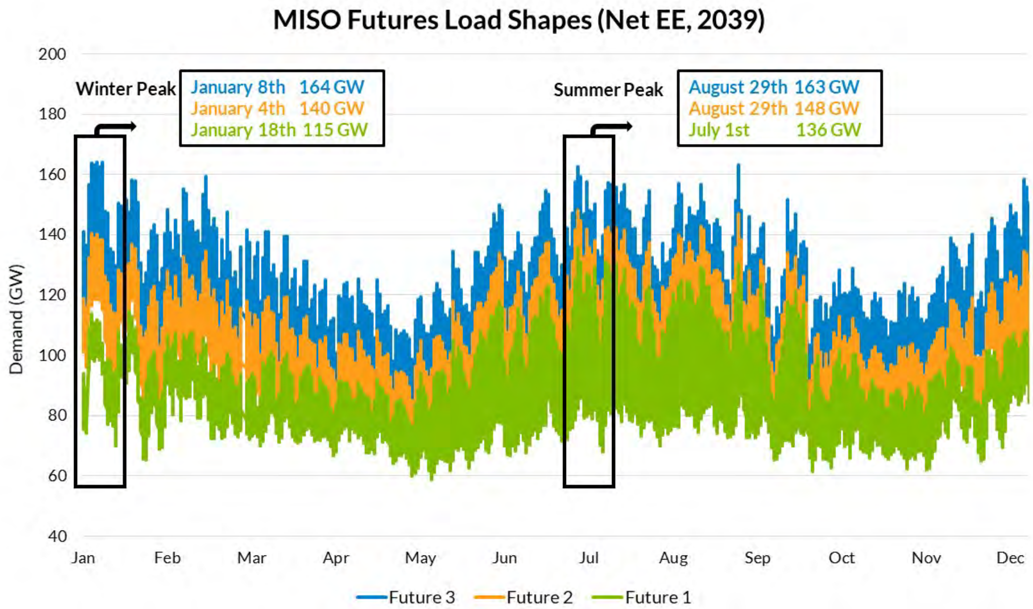


Figure 26: All Futures Final Load Shapes

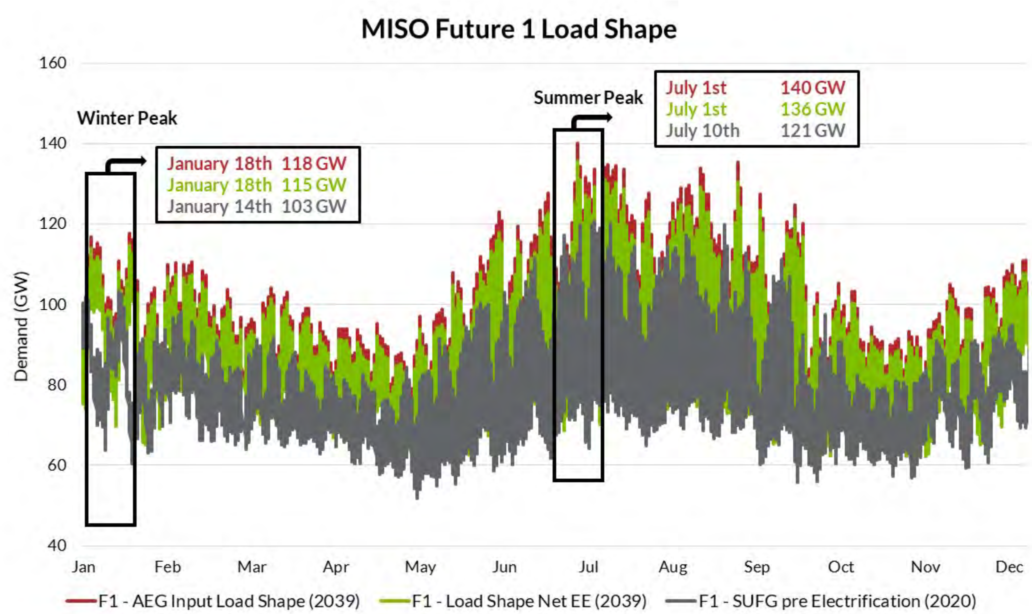


Figure 27: Future 1 Load Shape Evolution

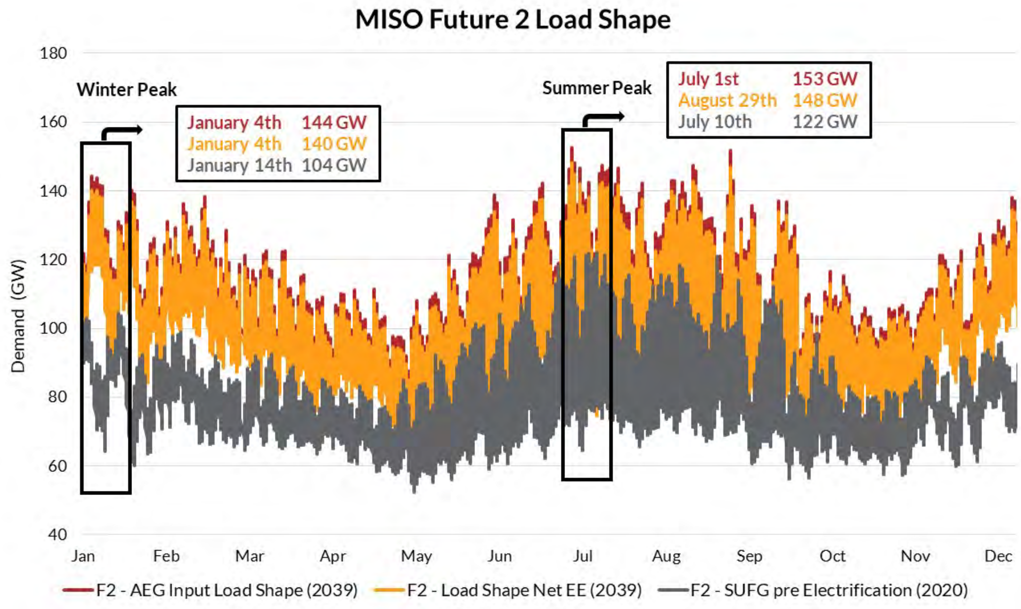


Figure 28: Future 2 Load Shape Evolution

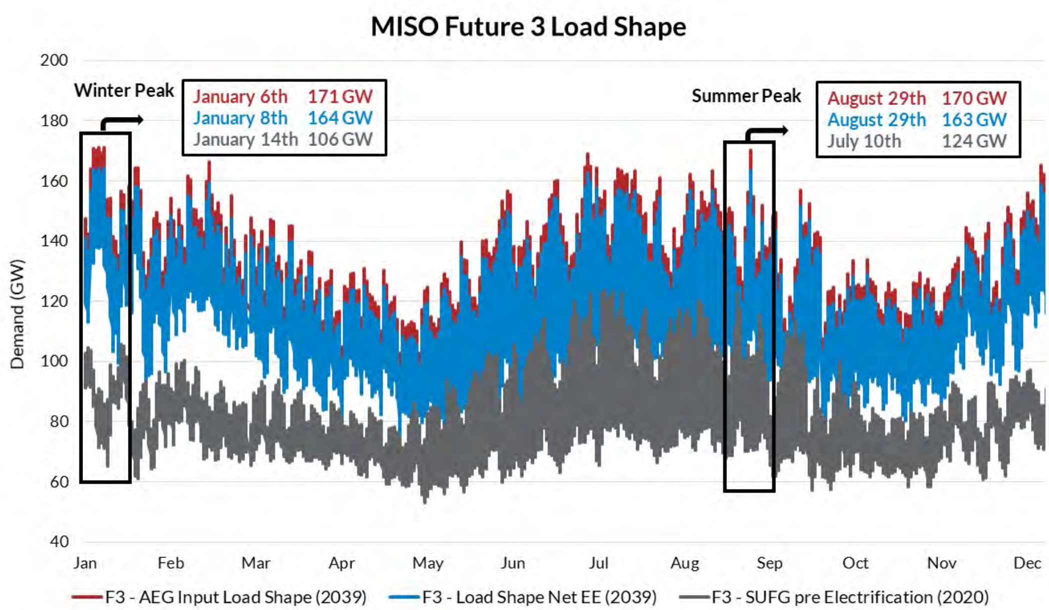


Figure 29: Future 3 Load Shape Evolution

Electrification

MISO contracted Applied Energy Group (AEG) to evaluate the MISO footprint on its potential to electrify. Electrification is the conversion of an end-use device to be powered with electricity, such that it displaces another fuel, (e.g., natural gas or propane). In this study, electrification is calculated as a percentage of technical potential that a given LRZ could achieve. The figure to the right shows the categories of electrification and what percentages of the technical potential they comprise. More details on the assumptions for the categories are included below.

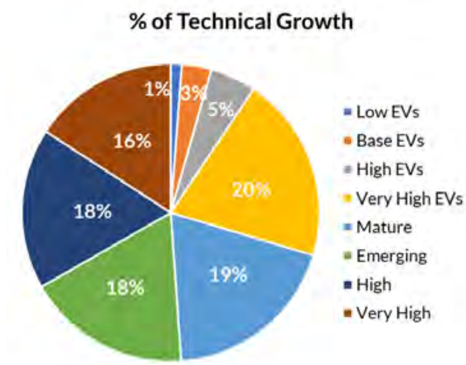


Figure 30: Electrification Categories

To estimate the available market for electrification, AEG started with the end-use load forecasting models developed for MTEP20 (previous set of MISO Futures), which include market data for each state in the MISO footprint. These market data included estimates of the penetration of many types of electric equipment. To estimate the total technical electrifiable load, AEG assumed that 90% of a particular end-use customer load was capable of being electrified, and then subtracted the electric equipment saturations (the load that is already electrified) from that value.

Electrification Categories

AEG identified each electrifiable technology and considered how likely or feasible it would be to be adopted before assigning it to one of four categories: mature technologies, emerging, high, and very high.[22] AEG considered how widespread the technology currently is, whether there are utility EE programs, and whether or not there are known market barriers. Since both mature and emerging versions of known technologies (e.g., traditional air-source heat pumps vs. cold-climate heat pumps) can coexist, AEG distributed the electrification potential for different technologies over more than one category. These are represented by the percentages below.

Additionally, AEG considered the certainty around each assumption. For example, industrial process loads are very customizable and would require a "bottom-up" approach to implementation, considering each industry and state individually. To capture this uncertainty, electrification of industrial process loads was assigned to higher electrification levels.

Each category is described below however, additional insights into the details of these categories may be found in MISO's Electrification Insights Report.

Mature Technologies

The "Mature Technologies" electrification category includes technologies that are widely available on the market today and are the most likely to electrify in the future. One example is an air-source heat pump, which is already found in many homes throughout the United States. Electric cooking equipment, such as induction ovens, is another example of an existing technology that is popular and relatively straightforward to install. Technologies in this category include:

- Air-Source Heat Pumps (50% of single-family [SF], 50% of multi-family [MF], 50% of Commercial and Industrial [C&I])
- Geothermal Heat Pumps (50% of SF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF)
- Clothes Dryers

[22] AEG's 2019 Presentation on Electrification

- Dishwashers
- Stoves

To better understand how much of these technologies are being electrified in each category, it is best to give an example. For air-source heat pumps, this section is saying that 50% of single-family, multi-family, and commercial and industrial heat pumps that can electrify will be electrified in this category.

Emerging Technologies

The "Emerging Technologies" category represents electrification load that is beginning to become available or is more mature but limited by known market barriers. For example, while air-source heat pumps are a mature technology, they may not be easily installable without reconfiguring the ductwork. Gas forced-air furnaces provide hotter air and require smaller ducts, requiring an invasive modification to expand the ductwork to keep a home warm in the winter. Process loads also begin to appear in this category. Technologies in this category include:

- Air-Source Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Geothermal Heat Pumps (50% of SF, 50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of SF, 50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

High Electrification Scenario Technologies

This category represents the point where substantial market barriers exist or where technologies are new or still in development. An example is a large-scale air-source heat pump that would be necessary to replace a large gas boiler heating a hospital. These are not readily available—gas is the most common fuel source in large-scale applications. However, if high levels of electrification are to be achieved, electrification using these new and in-development technologies would need to take place. Technologies in this category include:

- Air-Source Heat Pump (50% of C&I)
- Geothermal Heat Pump (50% of MF, 50% of C&I)
- Heat Pump Water Heaters (50% of MF, 50% of C&I)
- Industrial Process (25% of C&I)

Very High Electrification Scenario Technologies

This category represents the highest levels of uncertainty in the analysis and is only applied in the highest-growth cases. As noted above, much of the industrial process electrification is present in this category. The only technology in this category is noted below:

- Industrial Process (50% of C&I)

Technologies Electrified

HVAC Heat Pumps - Air-source and geothermal heat pumps

- Lower-growth scenarios electrify many residential homes and some businesses, where this technology is already available (rooftop units and residential systems)
- Higher-growth scenarios assume large-scale replacements are available for technologies like gas boilers

Heat Pump Water Heaters - Efficient water heaters with a vapor-compression refrigeration cycle

- Lower-growth scenarios electrify tanks in both the residential and commercial sectors
- Higher-growth scenarios include the electrification of large-scale gas water heaters

Residential Appliances - Clothes dryers, dishwashers, and stoves

- Dishwasher electrification occurs when no existing dishwasher is present

Industrial Process - High growth potential, but only certain processes can be electrified

- Due to the complexity involved in electrifying industrial processes, AEG assumed that most of this occurs in the higher-growth scenarios
- Examples of technologies that may be electrified within industrial processes include ultraviolet (UV) curing and drying, machine drives, and process-specific heating and cooling
- Electric boiler, industrial heat pump, resistance heating industrial heat pump, induction furnace, etc.

LBNL PEV Forecasts[23] - All four forecasts were used in development of these scenarios

- These include combinations of uncontrolled and V2G versions of the: Low, Base, High, and Very High scenarios
- Merged PEV forecasts were selected for each growth scenario – adoption curves and load shapes specific to the selected forecast were used

Figure 32 through Figure 37 display the results of these electrification assumptions across each Future scenario in the MISO footprint. The charts present a detailed view of the results showing yearly cumulative increases in energy from electrification for the footprint, electrification totals for each Local Resource Zone for the entire study, and the proportion of electrification from each technology. Similar charts for external region electrification results are found in the Appendix, Figure 80 through Figure 87.

[23] Lawrence Berkeley National Lab EV Forecast Report

Electrification Potential Across MISO Footprint

This analysis was conducted at the state level in the MISO footprint then aggregated by LRZ. AEG's end-use forecasting and Demand-Side Management (DSM) potential model was used to conduct this analysis, providing estimates of electric equipment penetrations as well as consumption for MISO's fraction of each state. Since local weather and equipment penetration data were used in this analysis, each state will have different end-use consumption patterns and a different electrifiable load, as shown in Figure 31. These are high-level findings based on the end-use models and a result of the differences noted above. The three main drivers of technical potential for electrification are:

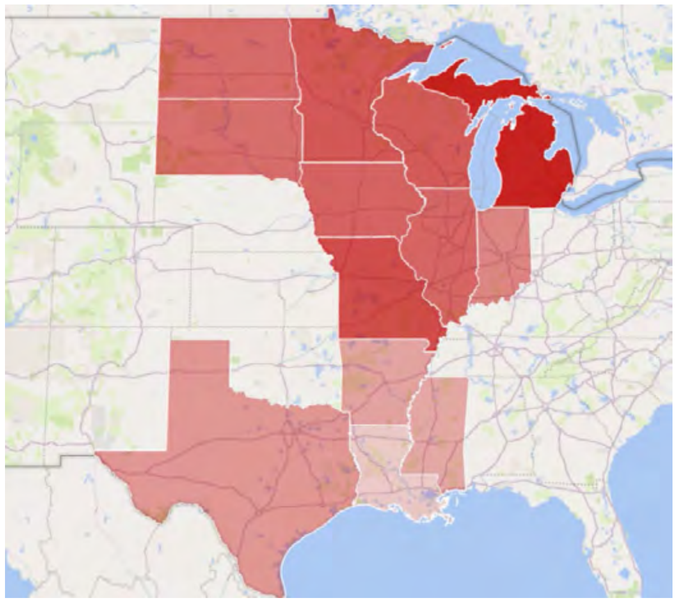


Figure 31: Electrification Potential by State

- **Latitude:** The northern states in the MISO footprint are generally colder than the southern states, resulting in larger space-heating loads. Since the heating end-uses represent some of the largest electrification potential, additional new loads are expected in the northern MISO states.
- **Gas Infrastructure:** Along with latitude, existing gas infrastructure heavily influences the electrifiable load. AEG utilized the state-level market data listed above to estimate gas equipment penetrations by state. If the load in a state is already mostly electric, there would be fewer non-electric units to convert, lowering potential.
- **Cooling Presence:** The final notable factor is the presence of existing cooling equipment. Similar to the gas infrastructure note above, high penetrations of existing cooling equipment limit electrification potential since the remaining non-electric market is smaller. In the warmer southern states, many homes already have cooling equipment installed, so their potential is lower.

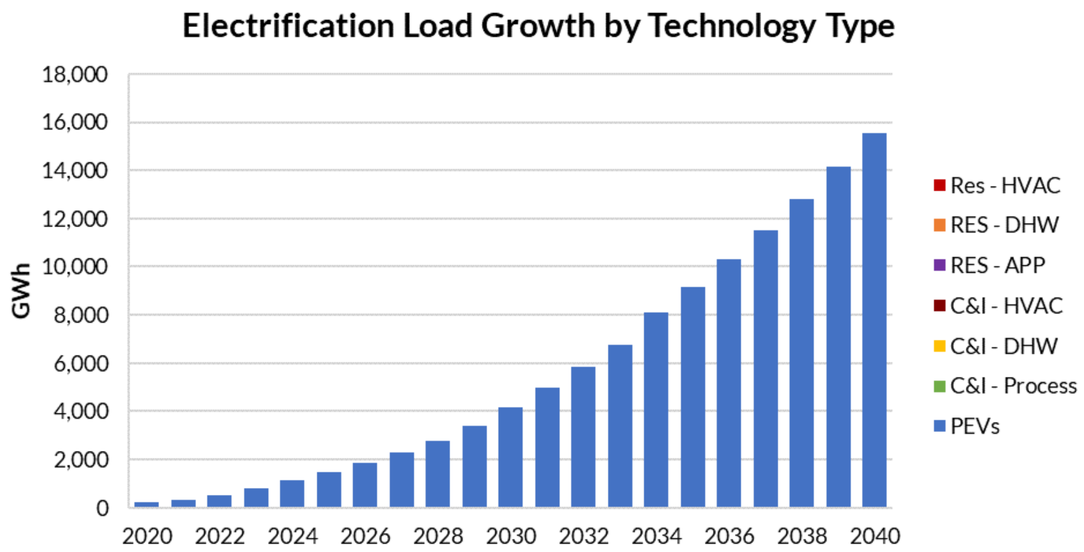


Figure 32: Future 1 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

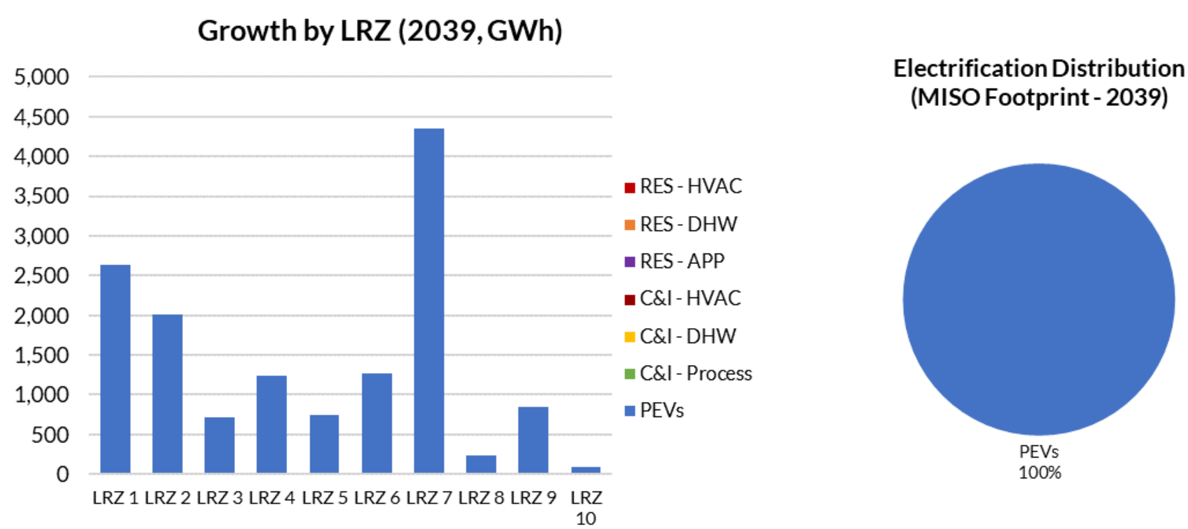


Figure 33: Future 1 Electrification Broken Down by End-Use

Future 2 Electrification

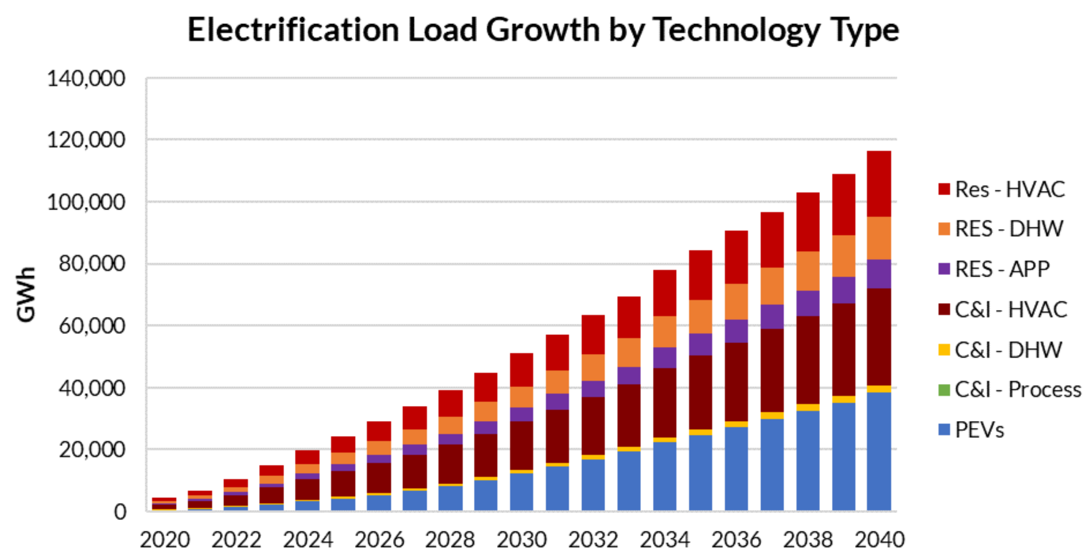


Figure 34: Future 2 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint

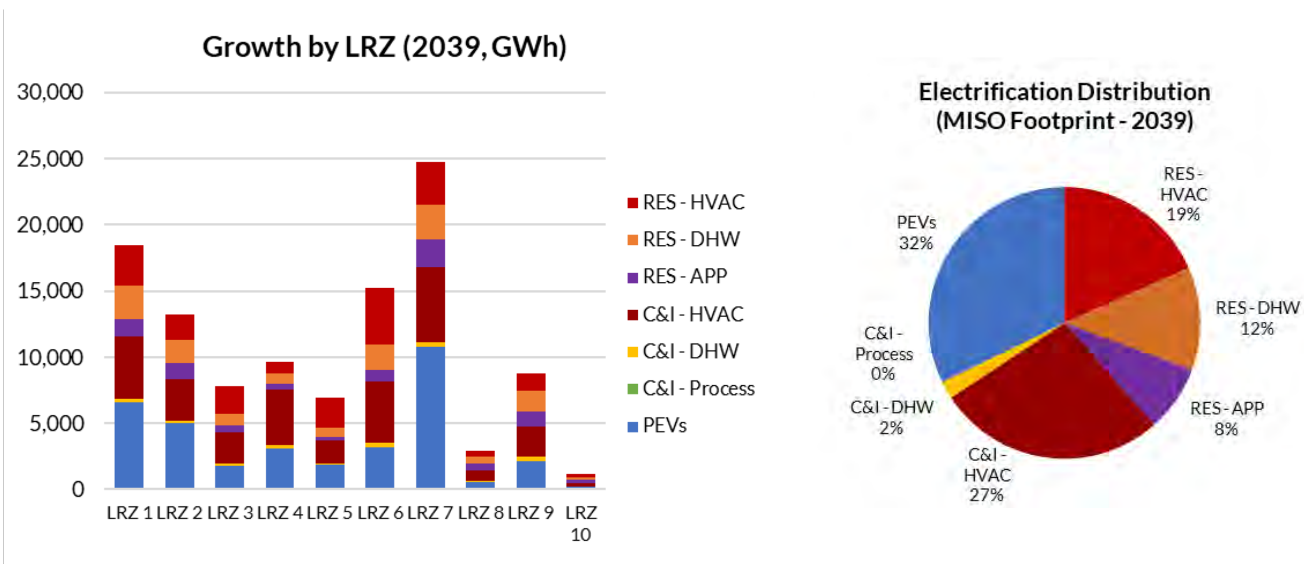


Figure 35: Future 2 Electrification Broken Down by End-Use

Future 3 Electrification

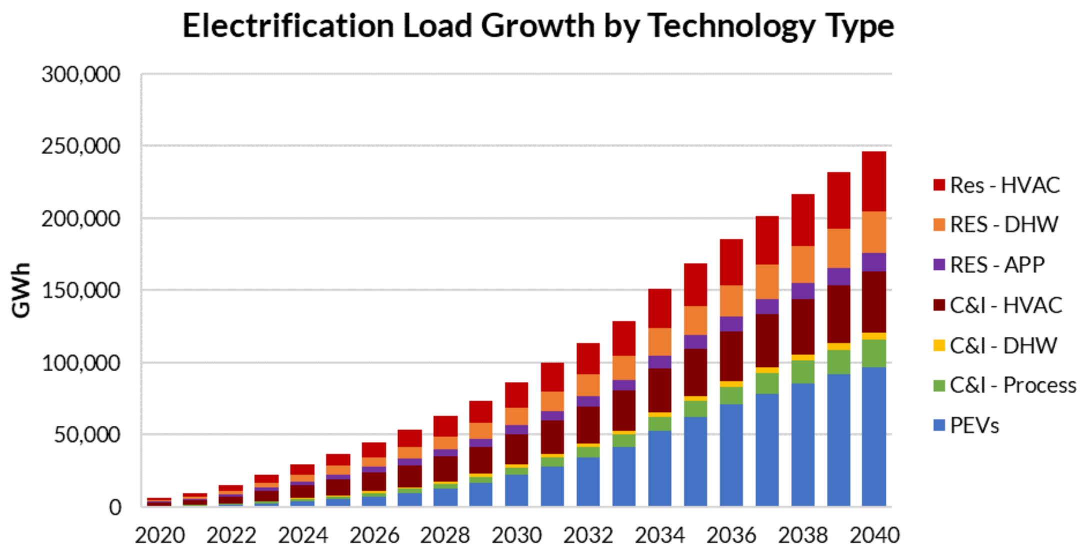
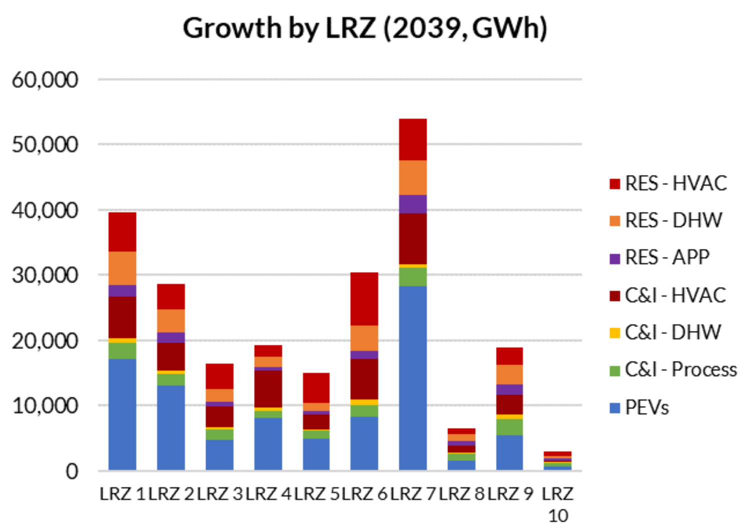


Figure 36: Future 3 Electrification by End-Use (Cumulative per Year) – Entire MISO Footprint



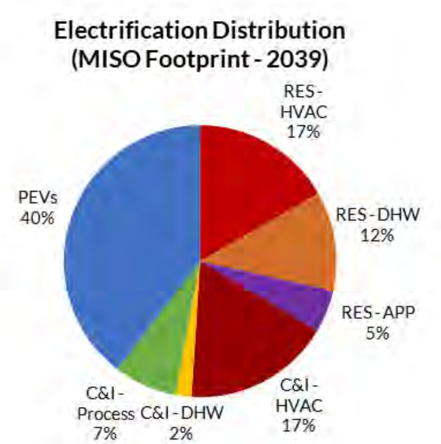
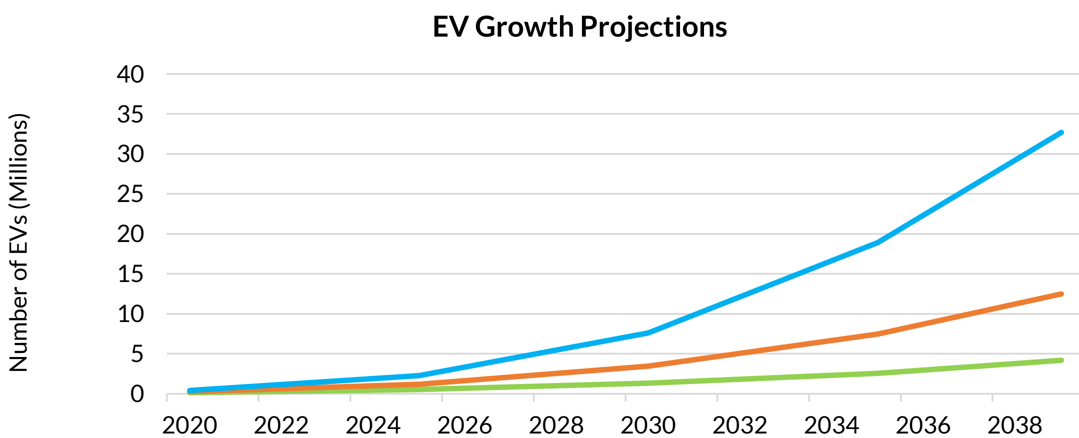


Figure 37: Future 3 Electrification Broken Down by End-Use

Electric Vehicle Forecasts

MISO collaborated with [Lawrence Berkeley National Laboratory (LBNL)]() on a study to determine the potential for EVs within the MISO footprint. This study categorized the projected growth of EVs in into four scenarios: low, base, high, and very high. Each of the three Futures used merged forecasted EV growth scenarios to include different amounts of light-duty EVs. All Futures explored a variety of EV growth and charging scenarios within every LRZ across the 20-year study period.

Future 1 evaluated only uncontrolled charging methods, Future 2 included vehicle-to-grid (V2G) charging after 2035, and Future 3 incorporated V2G charging after 2030. Figure 38 through Figure 41 detail the number of EVs in each scenario, MISO footprint and LRZ.



	2020	2025	2030	2035	2039
Future 1	0.135	0.53	1.33	2.57	4.19
Future 2	0.26	1.205	3.47	7.455	12.49
Future 3	0.416	2.272	7.598	18.91	32.686

Figure 38: EV Growth per Future (MISO footprint)

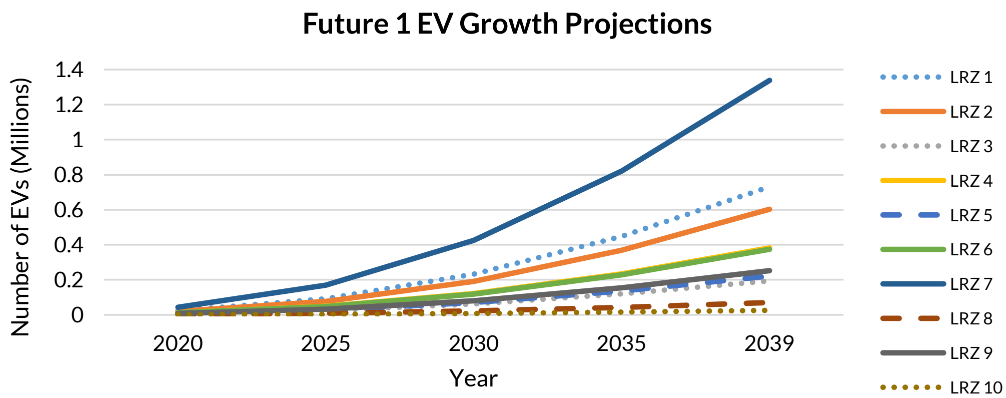


Figure 39: Future 1 EV Growth per LRZ

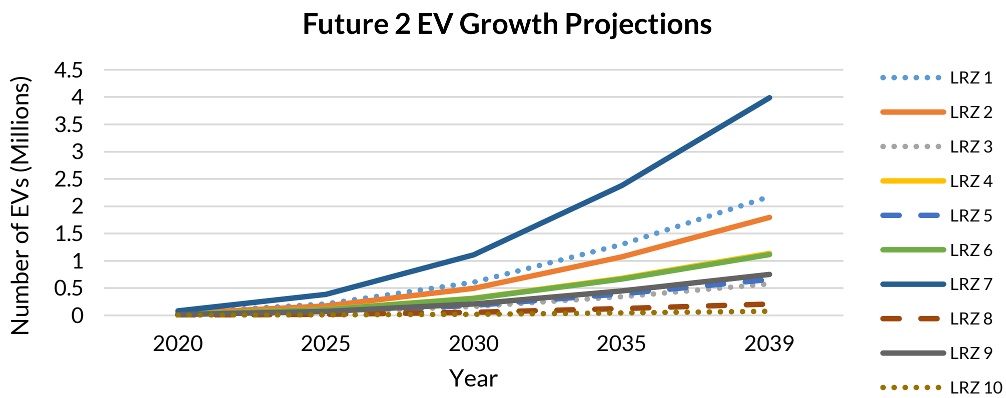


Figure 40: Future 2 EV Growth per LRZ

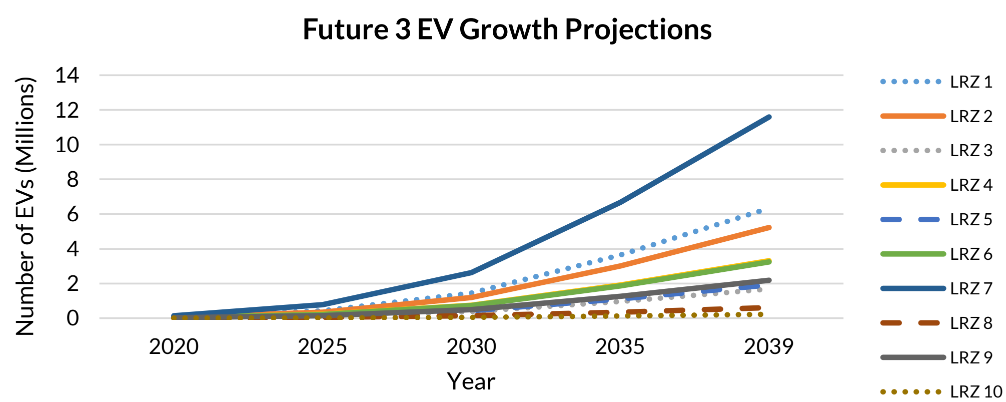


Figure 41: Future 3 EV Growth per LRZ

New Resource Additions

Regional Resource Forecast Units (RRF Units) are various resource types that are defined in and selected by MISO's capacity expansion tool, EGEAS, to achieve each of the Futures scenarios. The RRF units used in MISO Futures are discussed in further detail below.

Wind

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. New RRF units were built at 100m hub height throughout the study period. Existing units used representative 80m hub height hourly profile and all wind units assumed 16.6% capacity credit.

Solar

Vibrant Clean Energy (VCE) 2018 hourly profiles were used as the base data. Existing units used a representative hourly profile and all solar units assumed 50% capacity credit at the beginning of the study period and decreased by 2% starting in year 2026, until the capacity factor reached a minimum of 30%.

Hybrid: Utility-Scale Solar PV + Storage

Hybrid solar profiles were created by modifying VCE 2018 hourly profiles for solar units. Hybrid units were modeled as a 1200 MW inverter attached to 1500 MW of solar panels, resulting in an over-panel of 25%. When solar output exceeded the inverter capacity, the battery charged. Once solar output reached 20% or lower of the max capacity (max capacity is 1500 MW making 20%, 300 MW), the battery discharged until empty. Hybrid units assumed a 60% capacity factor.

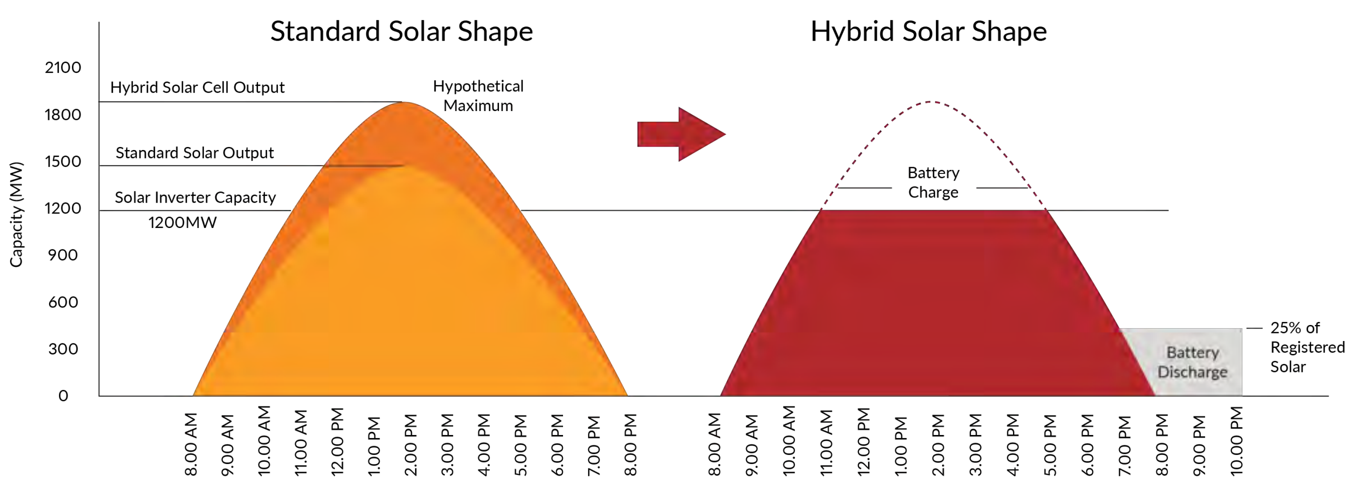


Figure 42: Solar + Storage Hybrid Profile

Storage: Lithium-Ion Battery (4-hour)

Batteries modeled in the capacity expansion were 4-hour duration lithium-ion batteries. Units were sited with a minimum capacity of 5 MW and a maximum capacity of 500 MW across all Future scenarios.

Distributed Energy Resources (DERs)

As in previous Futures cycles, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research. Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for EGEAS.

Previously referred to as demand-side additions or management (DSM), these resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). Programs also fall into two sectors: Residential and Commercial and Industrial (C&I).

During the program selection phase for the models, each block was offered against supply-side alternatives to determine economic viability. For all three Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Future 3 selected Residential Low-Cost Energy Efficiency. “Customer PV” indicates market-driven, naturally occurring solar panel adoption, whereas “Utility Incentive PV” indicates a utility incentive program for solar PV. Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential. A complete list of detailed AEG programs mapped to EGEAS program blocks is below in Table 5.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder additions were implemented in the Futures models. Table 3 and Table 4 show total DER technical potential and additions modeled in MISO by the end of the study period.

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table 3: DER Capacity (GW): 20-Year Technical Potential & Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Table 4: DER Energy (GWh): 20-Year Technical Potential & Additions in MISO

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

* Program was selected as economically viable and utilized by EGEAS in the resource expansion.

Natural Gas Resources

Combined Cycle (CC) and Combustion Turbine (CT) were the two gas resource types modeled. Site priority levels for these units remained the same when selecting a site. However, CC units were given a higher priority over CT units.

CC + Carbon Capture Sequestration

Futures analysis modeled Combined Cycle plus Carbon Capture and Sequestration (noted as CC+CCS in report documentation) due to the need for a low-carbon resource with a high-capacity factor. This was found to be the case when modeling the high carbon reduction in Future 3 (80%) after 2035 and in 2039 of Future 2 (60%). While there are no large-scale CC+CCS plants in operation today, there are several states and utilities testing this resource.

In modified Futures studies to come, MISO will continue to investigate other forms of energy that could include small modular reactors (SMRs) and green hydrogen, for example. Recent announcements show that members are looking into SMRs and hydrogen resources for electricity production.[24,25,26] Due to such recent developments and MISO's role to remain resource-agnostic, MISO used CC+CCS units in modeling to serve as a proxy for a high-capacity factor, low-carbon-emitting resource.

New Resource Addition Siting Process

RRF unit siting processes were developed to help identify where future generation would likely be located. While different RRF unit types need their own siting processes, there are universal criteria that apply to each resource type's unique siting process. These universal siting criteria and resource-specific processes are discussed below.[27]

Universal Siting Criteria

To help improve siting measures, the following criteria underlie all resource-specific siting processes.

1. The same sites were used for each Future and site differences only occurred due to Future-specific renewable capacity needs. This included only using sites that were found in both the Year 5 and Year 10 MTEP Powerflow models.
2. Radial lines and associated buses were identified in the MTEP Powerflow models and excluded from potential resource sites.
3. Sited capacity could not exceed a site's N-1 capacity amount. This means the summation of all the transmission elements, excluding the highest rated capacity element, could not have a lower capacity than the resource capacity.
4. Units were only sited on MISO-owned transmission elements.

Wind and Solar PV

Resources of this type were modeled as a collector system, representing an aggregated capacity potential that can be installed within 10-30 miles of each site. These collector sites were identified by two methods:

1. Compilation of Generation Interconnection (GI) queue projects:
   - 80% of Future-determined capacity was distributed to GI sites.
   - GI projects were ranked based on GI queue status (projects further along in the GI study process were ranked higher) and grouped by project state location, creating a capacity by state penetration percentage.
   - GI projects within 10 miles of each other were identified and combined into a collector system.
   - The capacity by state penetration percentage was applied to the 80% capacity expansion results, creating a state-up siting processes driven by GI Queue activity.
2. Vibrant Clean Energy[28] (VCE) results:
   - VCE sites receive the remaining 20% of Future-determined capacity.
   - Collector buses represent a 20- to 30-mile aggregated capacity potential.

[24] Mitsubishi Power and Entergy Collaboration
[25] Xcel Energy and INL
[26] Xcel Energy
[27] All capacities referenced on this page are (MW).
[28] VCE Report

Utility-Scale Solar PV + Storage (Hybrid)

Hybrid units were sited the same as Solar PV units and utilized the GI Queue only. Due to low GI queue activity for hybrid units not all Hybrid capacity (MW) was able to be distributed. As a result, the remaining balance was sited at unutilized Solar PV GI sites for the respective Future.

Distributed Solar PV Generation (DGPV)

Distributed solar PV resources (DGPV) siting methodology utilized the National Renewable Energy Laboratory's (NREL) Distributed Generation Market Demand Model (dGen) and consisted of the following:

- Using dGen, identify top 25 counties by DGPV potential within each LRZ.
- Identify (up to) top 20 load buses for each county.
- Distribute county capacity using dGen results weighting.
- Use top 20 load buses' Load Ratio Share (LRS) to distribute dGen-weighted capacity to each bus.

Lithium-Ion Battery (4-hour)

Batteries were restricted to a minimum capacity of 5 MW and capped at a maximum capacity of 500 MW (PROMOD performance reasons) and sited in a way to create geographical distribution for each LBA. The geographical distribution process follows:

- Each LBA's LRS was determined using Future-specific forecast data; LRS was then used to determine each LBA's Battery Capacity (MW) allocation.
- Top load buses for each LBA were identified, and the nearest, highest N-1 capacity bus greater than 100kV was selected to site the capacity.
- If an LBA needed more than one battery site, the next bus selected would be at least 10-20 miles away from the previously used bus to maintain geographical distribution.

Combined Cycle and Combustion Turbine

Combined Cycle and Combustion Turbine siting largely remained the same as in past MTEP cycles with site rankings as follows:

- Combined Cycle units got higher priority sites over Combustion Turbine
- Priority 1: Active Definitive Planning Phase (DPP) Phase 1, 2, 3 Generator Interconnection Queue
- Priority 2: Brownfield – Existing and Retired Sites
    - Retired sites ranked by earliest commission date
    - Retired sites had to be 50 MW and greater
- Priority 3.1: SPA or Canceled/Postponed GI Queue
- Priority 3.2: Greenfield Siting Criteria

CC + Carbon Capture Sequestration

Combined Cycle plus Carbon Capture Sequestration (CC+CCS) sites were limited to sites suitable to this technology type. Desirable basins for these resources were determined using the results of the U.S. Geological Survey's (USGS) National Geologic CO_2 Storage Assessment. Potential sites were screened to ensure that their geographic location fell within the boundary of a geologic storage resource. Sedimentary basin locations were overlayed onto Priority Sites for Combined Cycle and Combustion Turbine. Priority sites were then ranked by suitability and reserved for CC+CCS resources.

MISO Expansion Results

While comparing the expansion results of the MISO footprint across each Future scenario, there are several key findings of note:

- All scenarios have relatively large amounts of gas additions; this is due to increasing amounts of coal and gas retirements and the system's need for base generation to replace retired units. CC and CT gas units emit approximately half the amount of CO_2 that coal units emit. Decarbonization and load growth allow for gas to comprise 40% of the total expansion in Future 1, while CC+CCS comprises 40% of the gas units built in Future 3's expansion, illustrating the model's need for a low-carbon, high-capacity factor proxy resource.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load, 80% carbon reduction, and dual peaking system.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across all scenarios. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- Distributed solar and energy efficiency (EE) resources are composed of both selected DER programs and specific member feedback. No demand response (DR) resources were selected in the model, but are present in the expansion due to member feedback.

Future Resource Additions (MW)												
	CC	CT	CC+CCS	Wind	Solar	Hybrid	Battery	Distributed Solar	Hydro	EE	DR	Totals
Future 1	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	7,824	939	129,540
Future 2	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	8,053	939	179,368
Future 3	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	11,722	939	318,530

Future Resource Retirements (MW)								
	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
Future 1	44,827	18,627	2,359	1,996	9,223	21	36	77,089
Future 2	45,109	21,611	2,359	2,027	9,223	21	36	80,386
Future 3	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 6: MISO Resource Additions and Retirement Totals

Figure 43 details the results from each Future scenario's resource additions as displayed in the table above. Solar resources are comprised of utility-scale solar PV, solar hybrid, and distributed solar resources. Wind totals include expansion wind units and repowered wind assumptions. The other resource categorey includes energy efficiency and demand side management programs selected within each future. Gas resources include both CC and CT units for Futures 1, while Future 2 and 3 additionally include CC+CCS expansion units. In Future 3, the CC+CCS resource proxy units (42 GW) are needed in the later years of the study period to serve base load with low CO_2 emissions.

Over the course of the following pages (Figure 44 through Table 12) the detailed expansion results of each Future scenario and the siting locations are displayed. Following the figures in each section are resource-specific additons and retirement (R&A) tables; each table details R&A capacities applicable for each LRZ and MISO per milestone year.

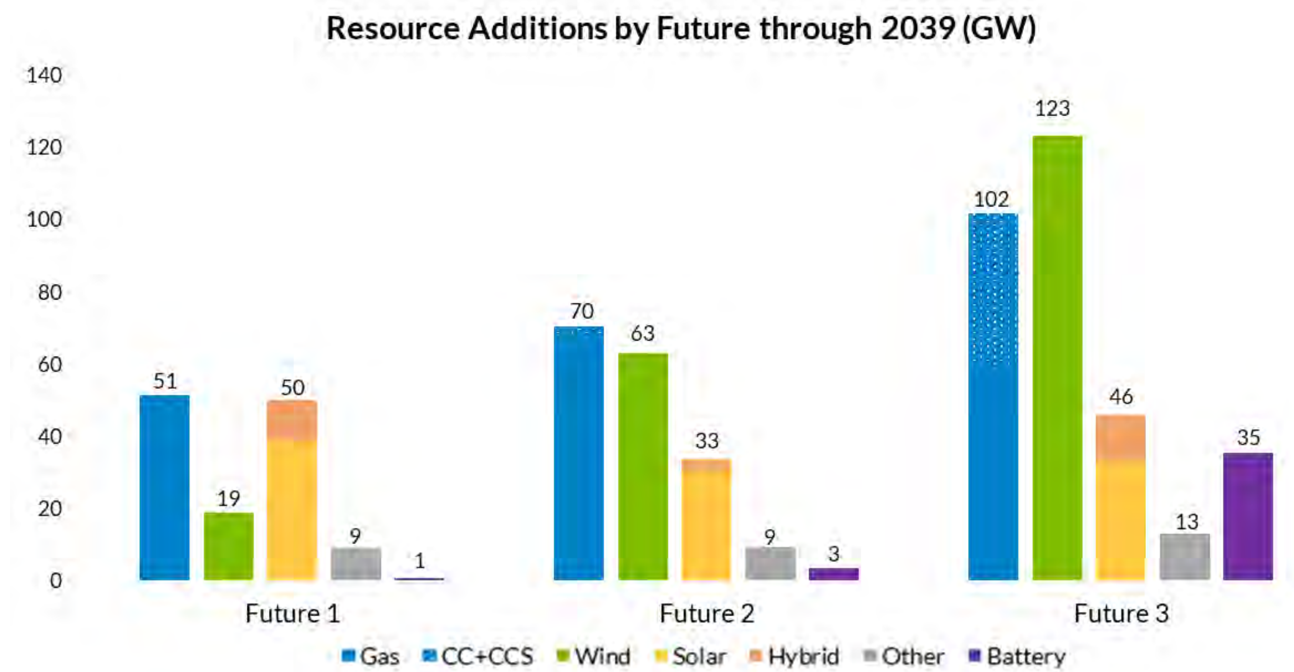


Figure 43: MISO Resource Addition Summary by Future

MISO – Future 1

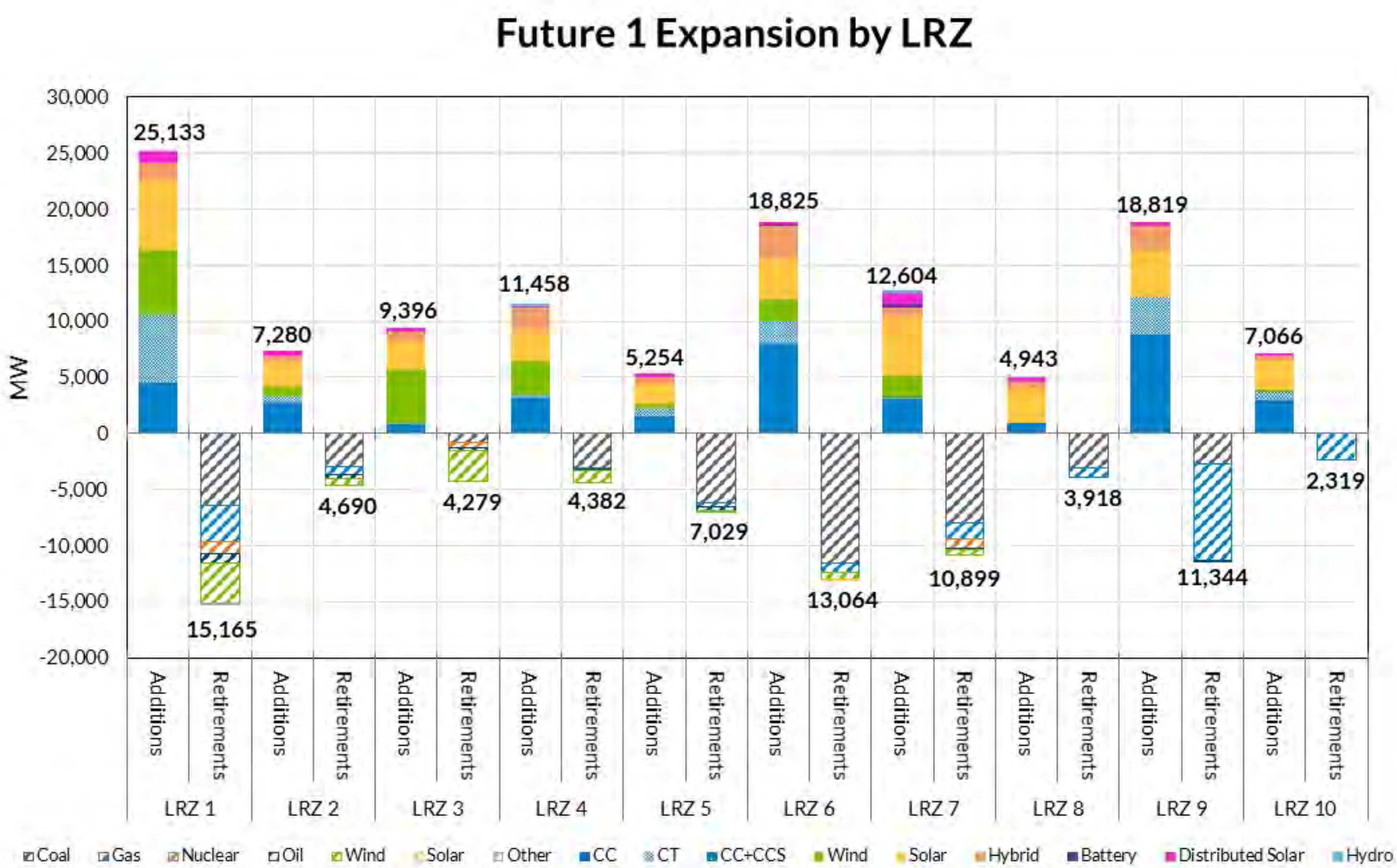


Figure 44: MISO Future 1 Resource Retirement and Addition Summary

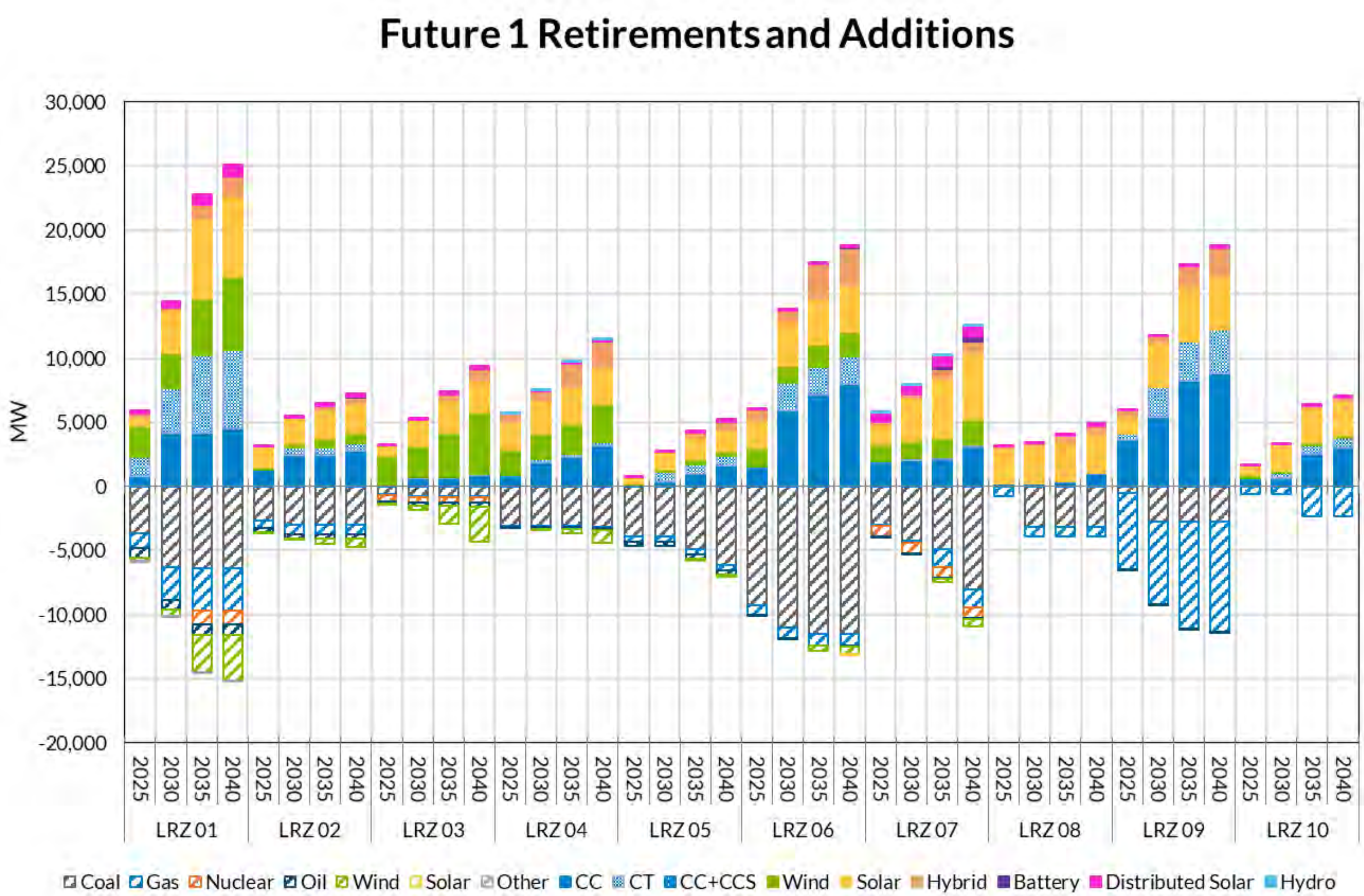


Figure 45: Future 1 Resource Additions per Milestone Year (Cumulative)

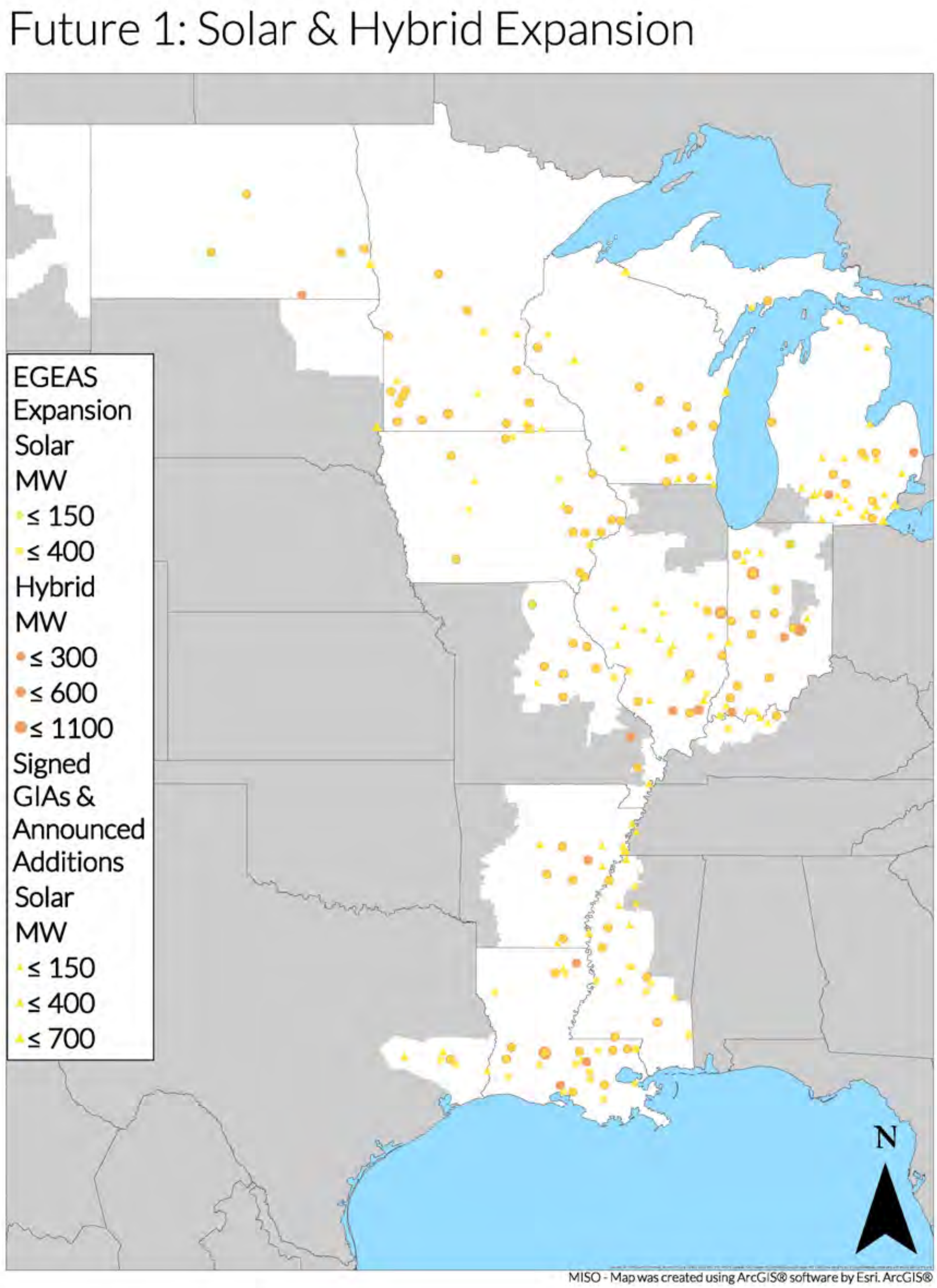


Figure 46: MISO Future 1 Solar and Hybrid Siting

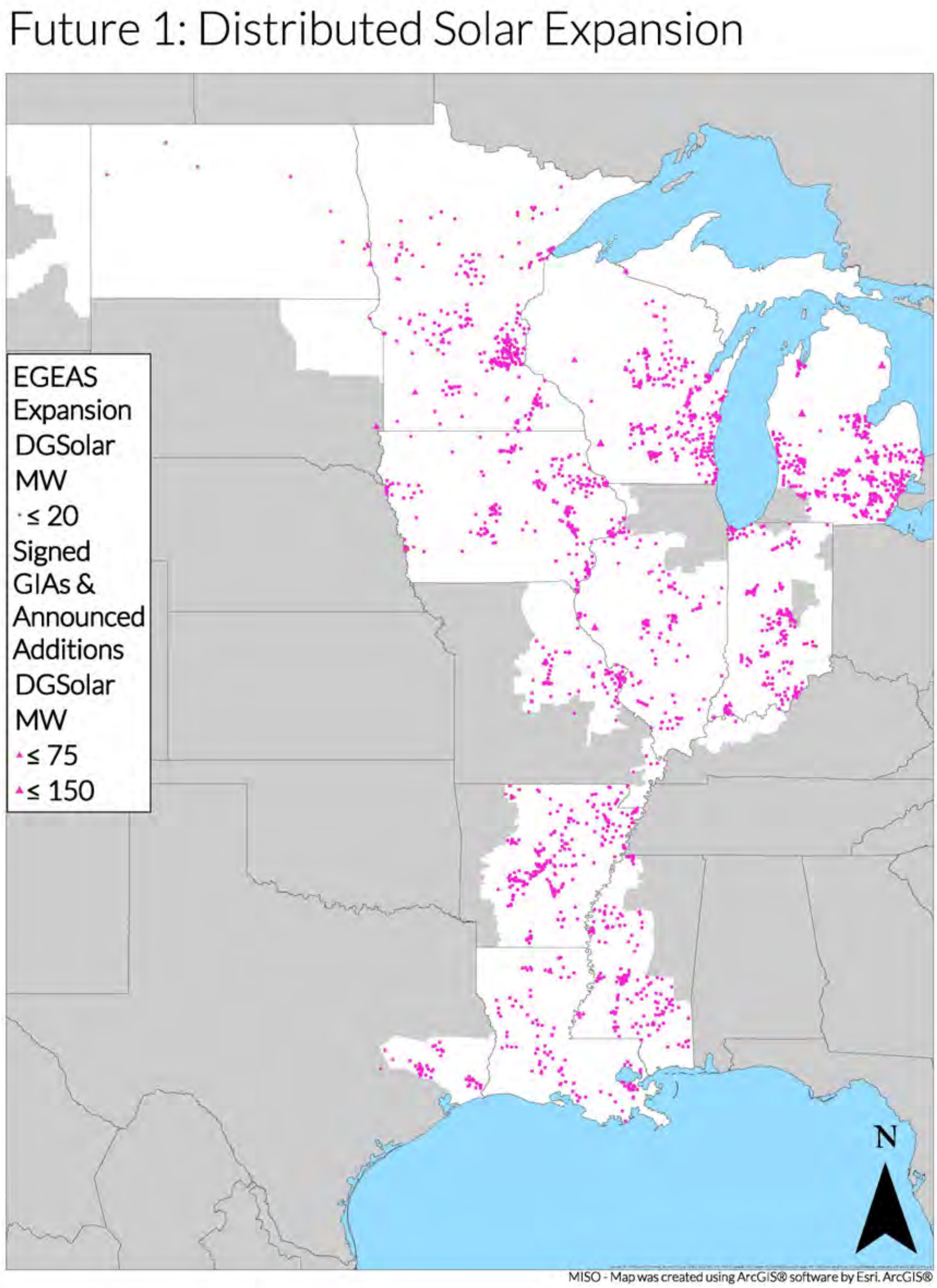


Figure 47: MISO Future 1 Distributed Solar Siting

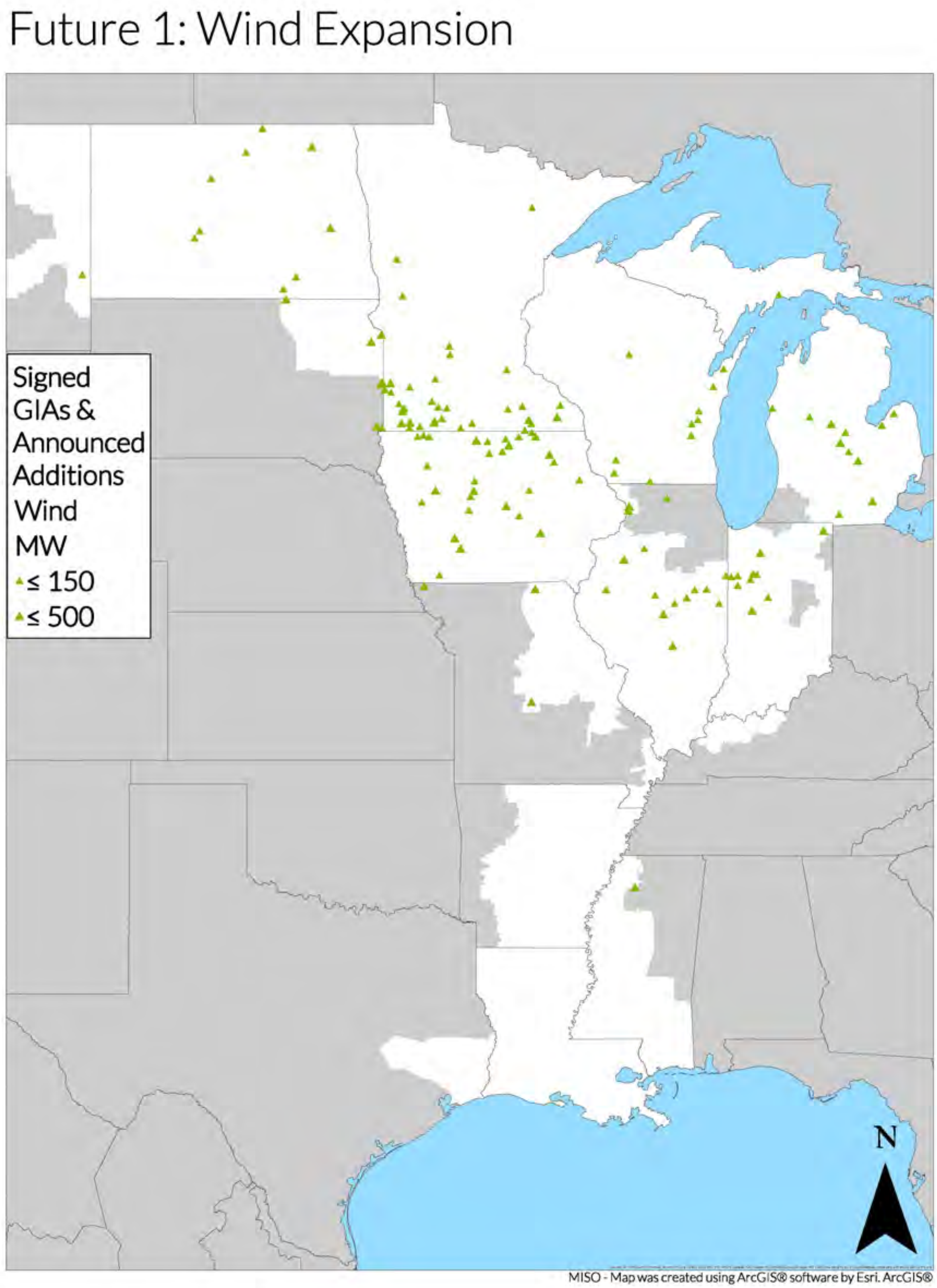


Figure 48: MISO Future 1 Wind Siting

Future 1: Battery Expansion

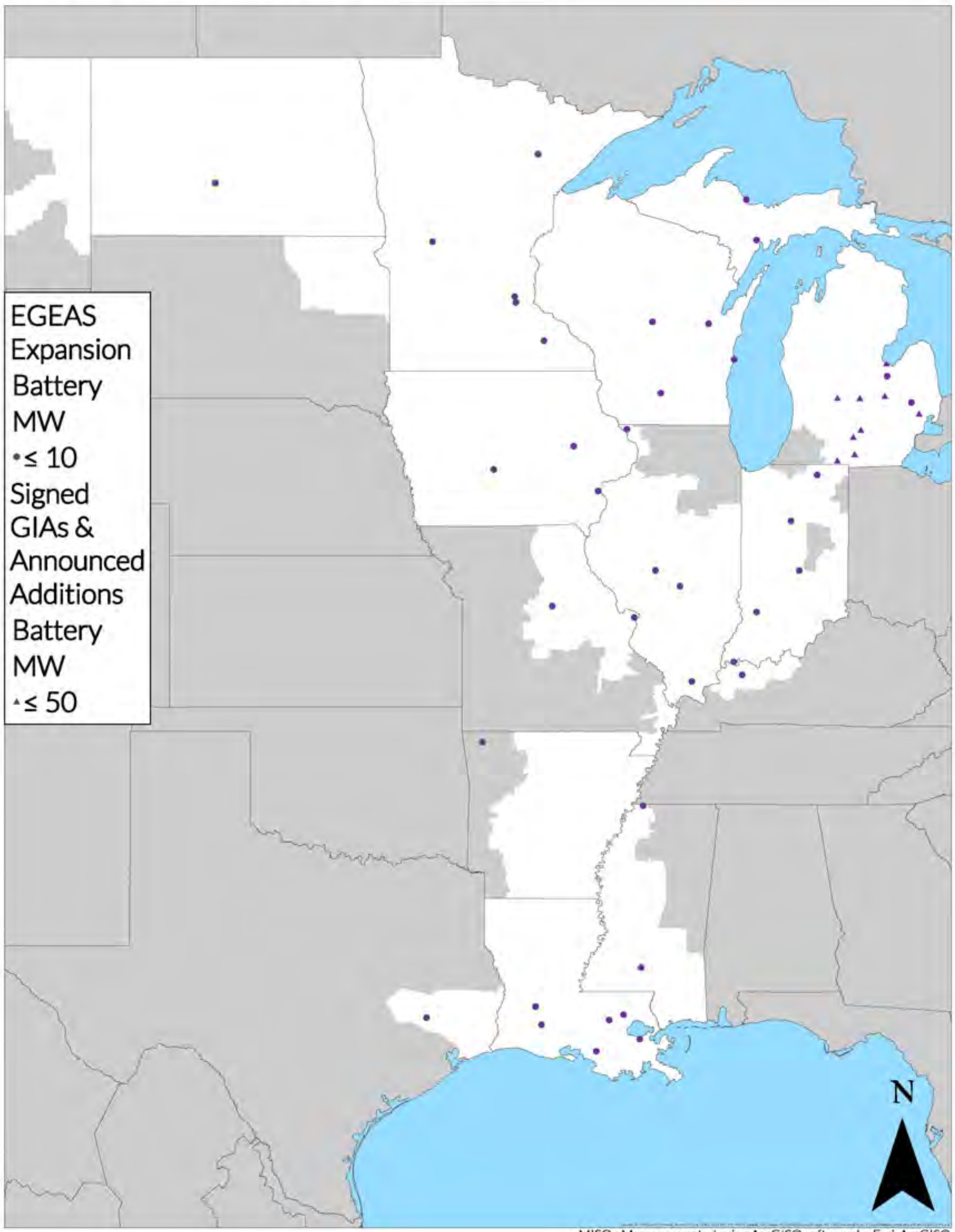


Figure 49: MISO Future 1 Battery Siting

Future 1: Thermal Expansion

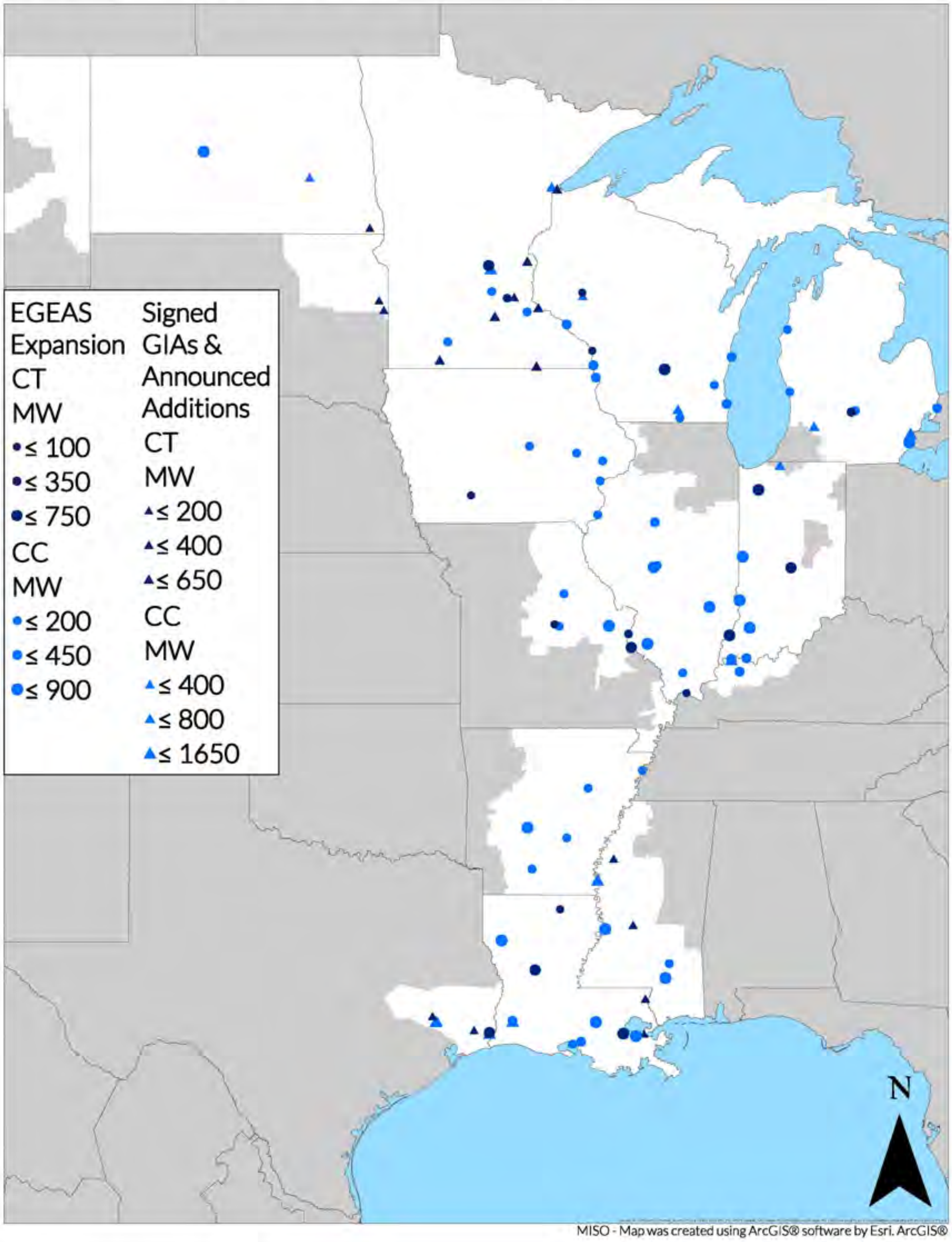


Figure 50: MISO Future 1 Thermal Siting

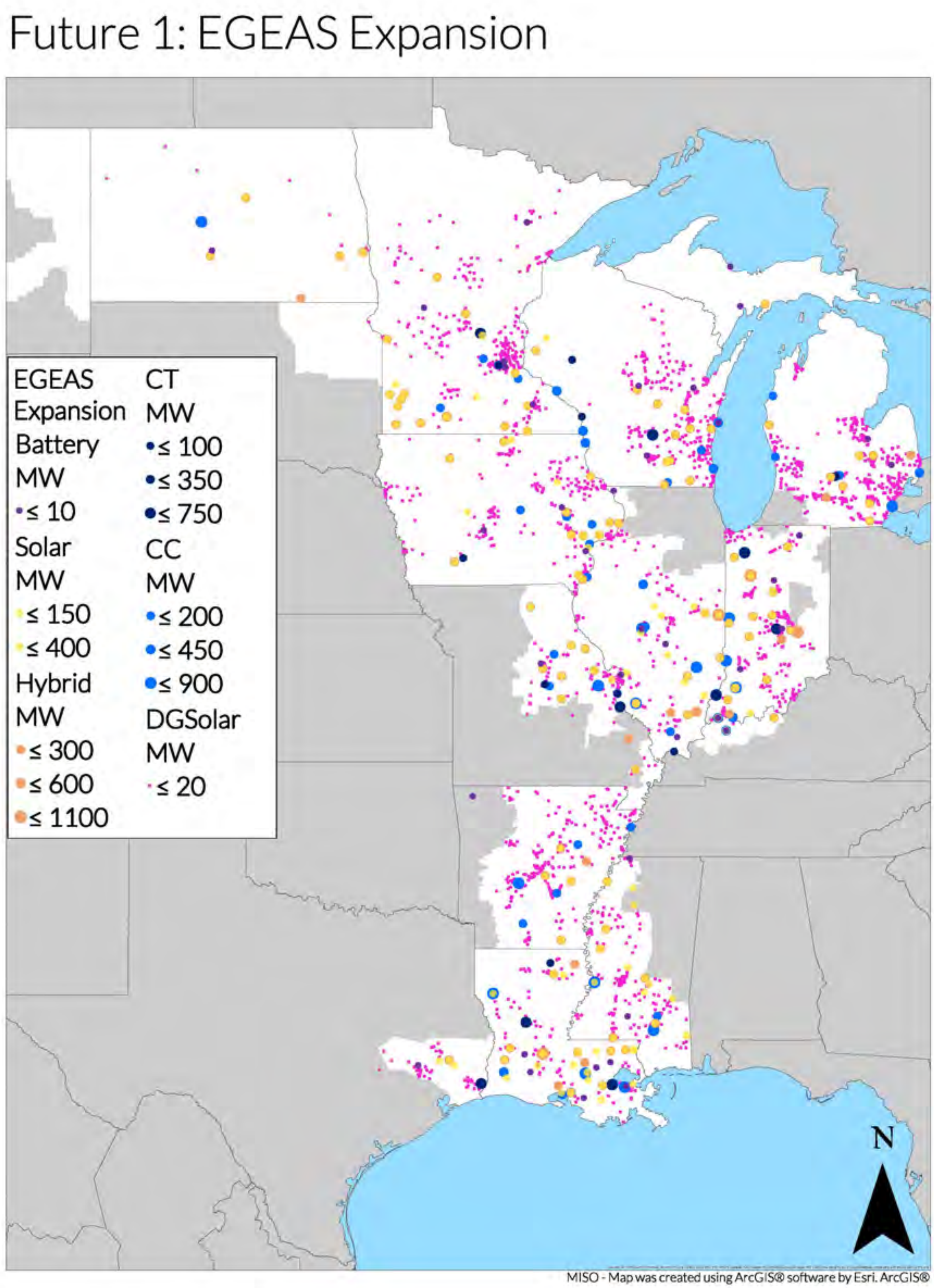


Figure 51: MISO Future 1 Complete EGEAS Expansion Siting

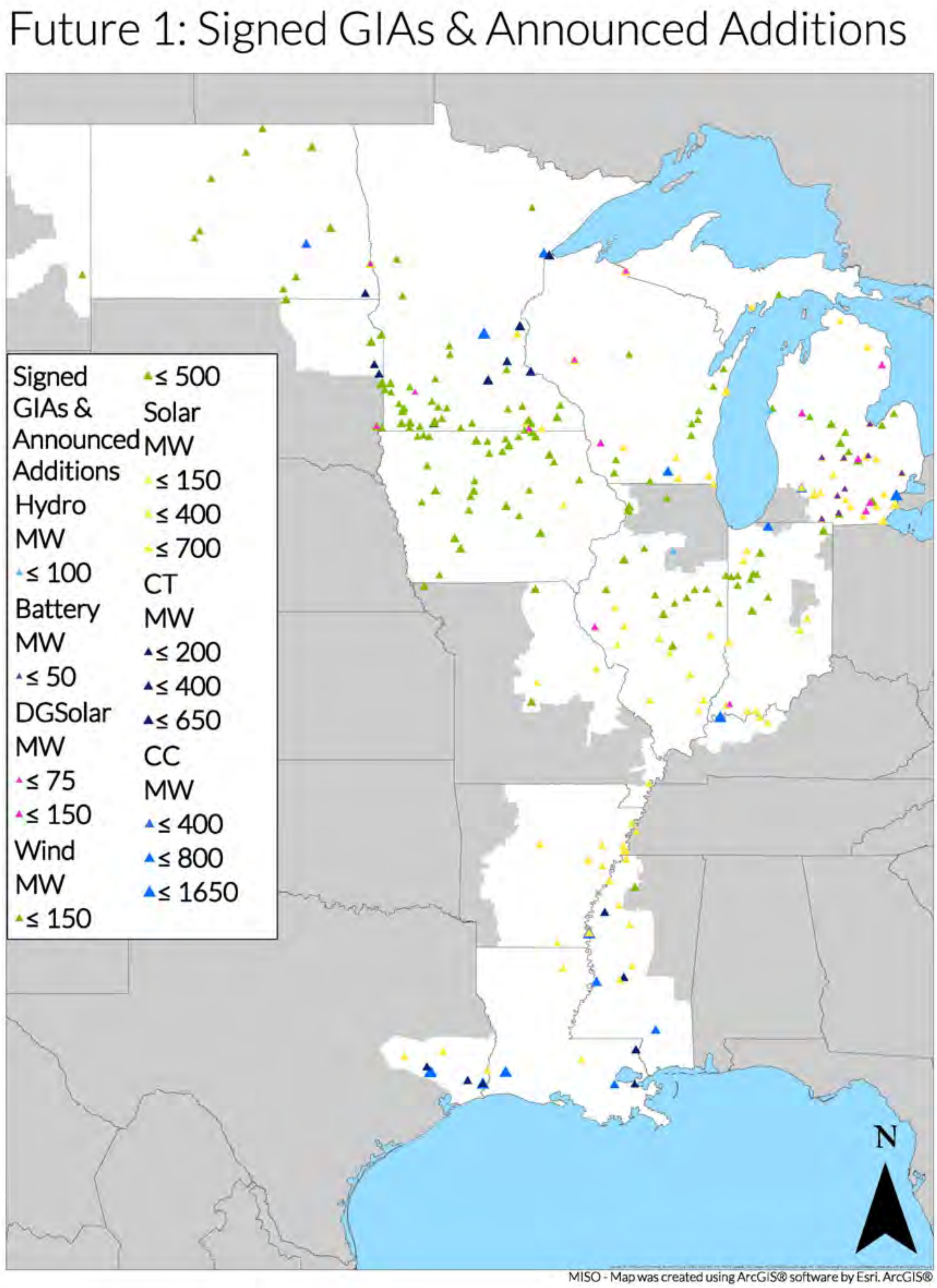


Figure 52: MISO Future 1 Non-EGEAS Expansion Siting

Future 1: Total Expansion

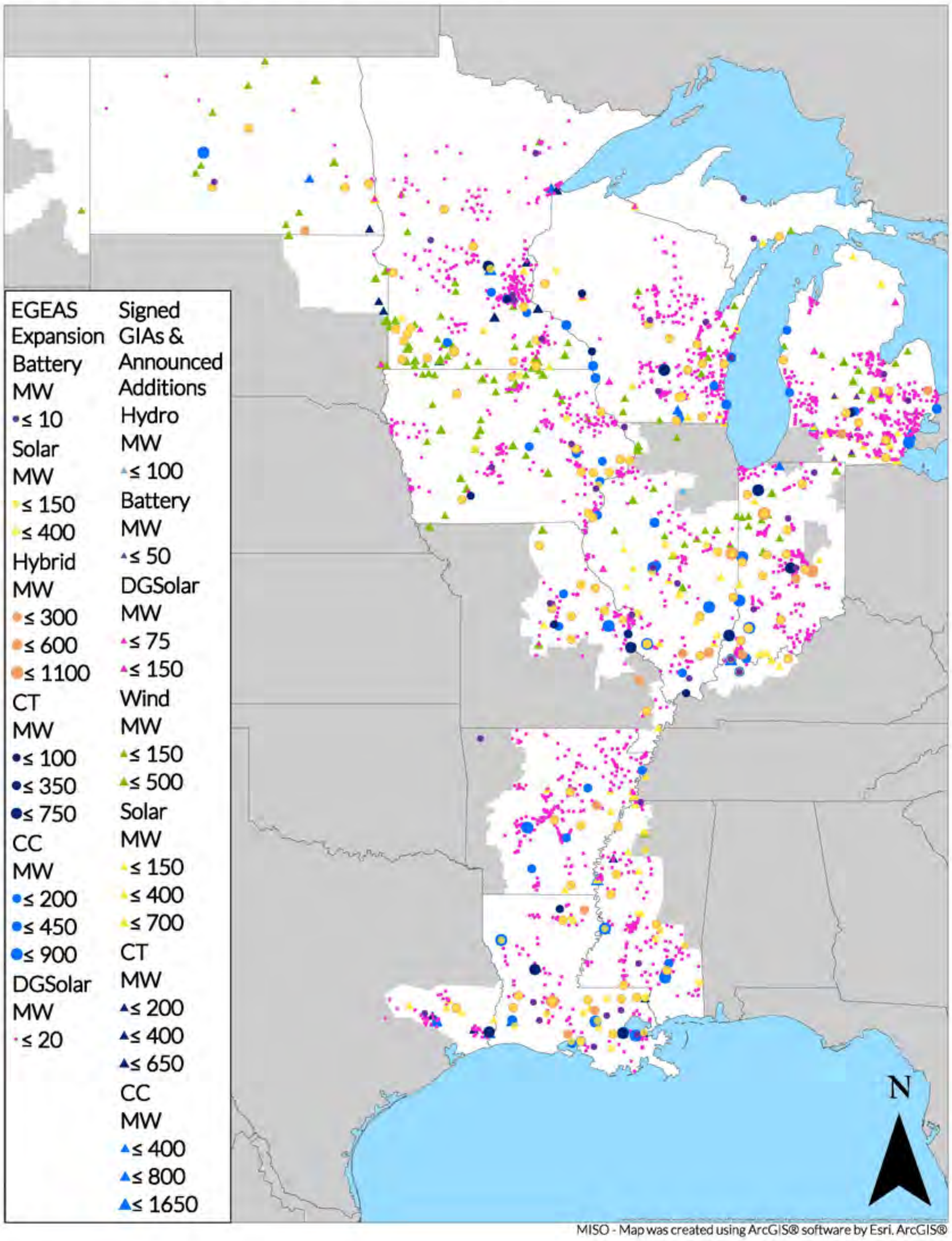


Figure 53: MISO Future 1 Non-EGEAS and EGEAS Expansion Siting

Future 1 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	1,453	0	2,402	771	198	0	283	0	5,957
	2030	4,171	3,520	0	2,669	3,384	198	0	499	0	14,442
	2035	4,171	6,088	0	4,379	6,225	1,129	0	772	0	22,764
	2039	4,560	6,088	0	5,734	6,225	1,547	36	942	0	25,133
LRZ 2	**2025**	1,268	0	0	240	1,585	0	0	38	0	3,131
	2030	2,432	572	0	270	2,099	0	0	122	0	5,495
	2035	2,484	572	0	636	2,304	242	0	246	0	6,484
	2039	2,795	572	0	846	2,304	422	30	311	0	7,280
LRZ 3	**2025**	150	0	0	2,198	875	0	0	33	0	3,256
	2030	608	92	0	2,424	2,103	0	0	104	0	5,331
	2035	608	92	0	3,510	2,522	475	0	210	0	7,417
	2039	881	92	0	4,783	2,522	838	15	265	0	9,396
LRZ 4	**2025**	900	0	0	1,966	2,152	628	0	52	10	5,709
	2030	1,868	240	0	1,986	2,693	628	0	80	10	7,504
	2035	2,285	240	0	2,345	2,871	1,839	0	120	10	9,710
	2039	3,231	240	0	2,979	2,871	1,971	15	141	10	11,458
LRZ 5	**2025**	64	0	0	200	500	0	0	25	0	789
	2030	382	747	0	200	1,381	0	0	80	0	2,790
	2035	979	747	0	369	1,755	322	0	162	0	4,333
	2039	1,596	747	0	369	1,768	560	10	205	0	5,254
LRZ 6	**2025**	1,594	0	0	1,325	2,282	853	0	69	0	6,123
	2030	5,956	2,136	0	1,325	3,466	853	0	103	0	13,839
	2035	7,189	2,136	0	1,702	3,685	2,626	0	153	0	17,491
	2039	7,989	2,136	0	1,907	3,685	2,899	30	179	0	18,825
LRZ 7	**2025**	1,954	0	0	1,322	1,550	189	0	749	72	5,835
	2030	2,051	153	0	1,322	3,421	189	0	781	72	7,988
	2035	2,116	153	0	1,551	4,715	638	200	829	72	10,274
	2039	3,156	153	0	1,887	5,315	755	412	854	72	12,604
LRZ 8	**2025**	250	0	0	0	2,688	155	0	26	0	3,119
	2030	250	0	0	0	2,985	155	0	83	0	3,473
	2035	384	0	0	0	3,059	536	0	168	0	4,147
	2039	1,038	0	0	0	3,059	628	5	212	0	4,943
LRZ 9	**2025**	3,601	493	0	0	1,465	378	0	28	0	5,965
	2030	5,439	2,328	0	0	3,540	378	0	91	0	11,776
	2035	8,287	3,020	0	0	4,238	1,640	0	184	0	17,369
	2039	8,833	3,366	0	0	4,238	2,113	37	232	0	18,819
LRZ 10	**2025**	672	0	0	200	730	0	0	16	0	1,619
	2030	672	350	0	200	2,070	0	0	52	0	3,345
	2035	2,531	700	0	200	2,709	153	0	106	0	6,399
	2039	3,046	700	0	200	2,709	267	10	134	0	7,066
MISO Total	**2025**	11,303	1,946	0	9,853	14,600	2,400	0	1,320	82	41,504
	2030	23,829	10,138	0	10,396	27,144	2,400	0	1,995	82	75,984
	2035	31,035	13,748	0	14,691	34,082	9,600	200	2,950	82	106,388
	2039	37,126	14,094	0	18,704	34,696	12,000	600	3,475	82	120,777

Table 7: MISO Future 1 Resource Additions by LRZ and Footprint

Future 1 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	3,619	1,214	0	698	240	0	36	5,807
	2030	6,303	2,567	0	698	519	0	36	10,123
	2035	6,413	3,281	1,092	771	2,946	0	36	14,539
	2039	6,413	3,281	1,092	771	3,572	0	36	15,165
LRZ 2	**2025**	2,650	599	0	351	11	0	0	3,611
	2030	2,981	736	0	351	41	0	0	4,109
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	741	0	351	617	0	0	4,690
LRZ 3	**2025**	596	92	448	196	122	0	0	1,454
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	196	1,434	0	0	2,927
	2039	757	92	448	275	2,707	0	0	4,279
LRZ 4	**2025**	3,056	134	0	90	0	0	0	3,281
	2030	3,056	134	0	117	20	0	0	3,327
	2035	3,056	134	0	117	379	0	0	3,686
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	9,268	788	0	50	0	0	0	10,106
	2030	11,002	853	0	50	0	0	0	11,905
	2035	11,537	853	0	50	377	0	0	12,816
	2039	11,537	853	0	71	582	21	0	13,064
LRZ 7	**2025**	2,956	155	819	45	0	0	0	3,974
	2030	4,223	161	819	59	0	0	0	5,261
	2035	4,878	1,444	819	59	230	0	0	7,429
	2039	8,013	1,444	819	59	565	0	0	10,899
LRZ 8	**2025**	0	788	0	0	0	0	0	788
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	515	5,919	0	7	0	0	0	6,441
	2030	2,746	6,438	0	7	0	0	0	9,191
	2035	2,746	8,361	0	7	0	0	0	11,114
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	26,553	10,648	1,267	1,782	373	0	36	40,658
	2030	38,091	12,727	1,267	1,822	928	0	36	54,871
	2035	40,397	18,397	2,359	1,896	5,960	0	36	69,044
	2039	44,827	18,627	2,359	1,996	9,223	21	36	77,089

Table 8: MISO Future 1 Resource Retirements by LRZ and Footprint

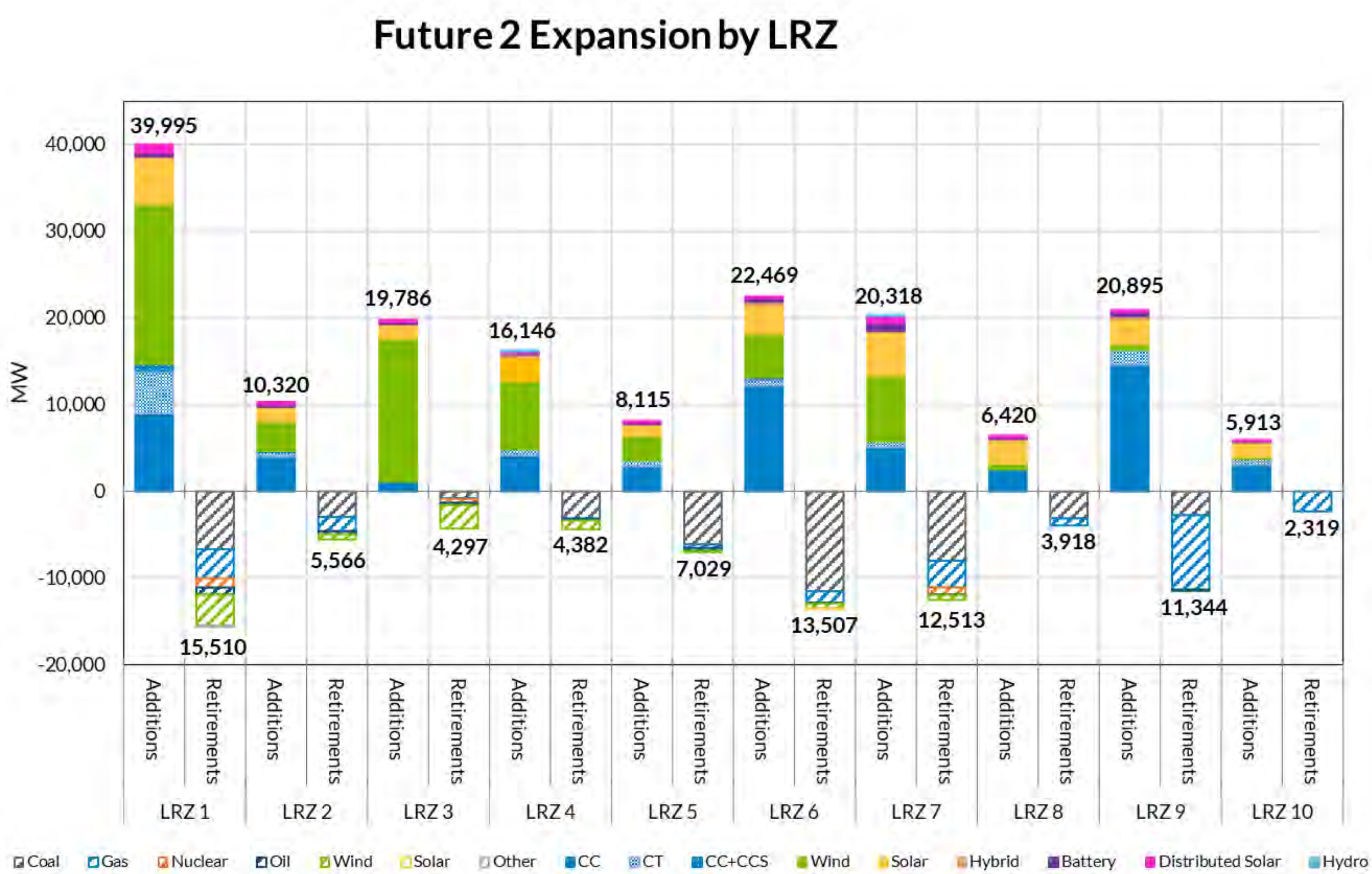


Figure 54: MISO Future 2 Resource Retirement and Addition Summary

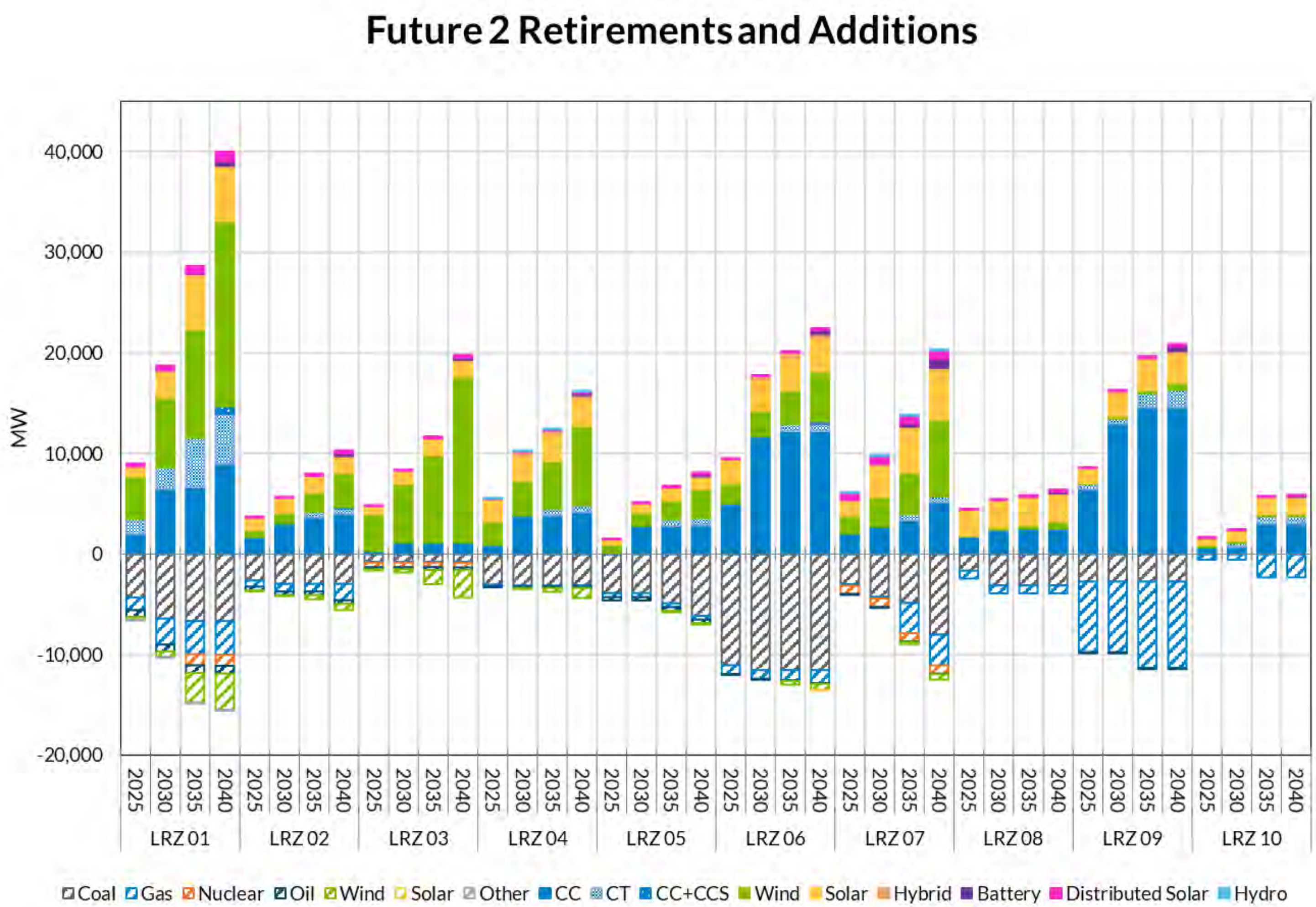


Figure 55: MISO Future 2 Resource Additions per Milestone Year (Cumulative)

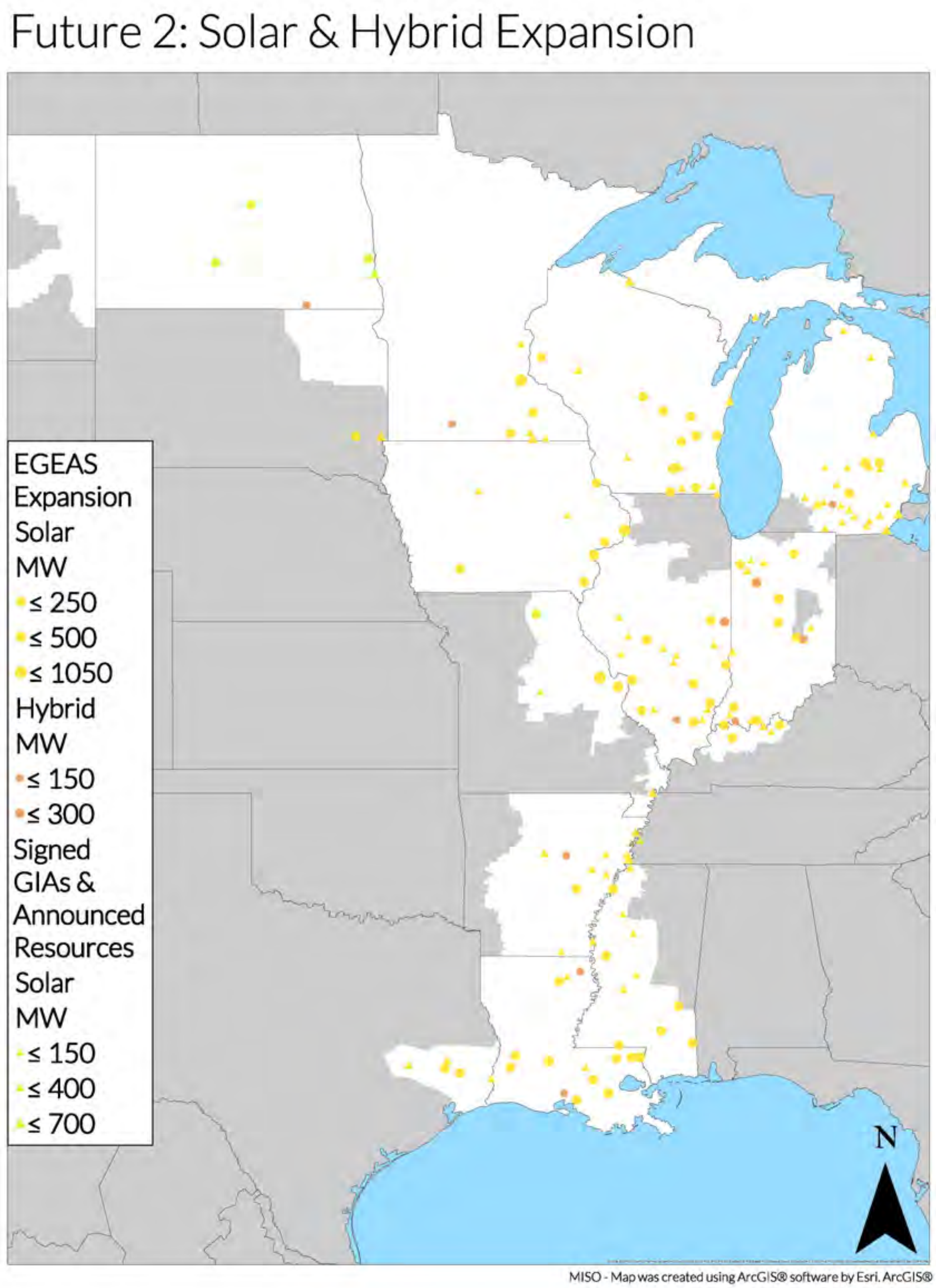


Figure 56: MISO Future 2 Solar and Hybrid Siting

Future 2: Distributed Solar Expansion

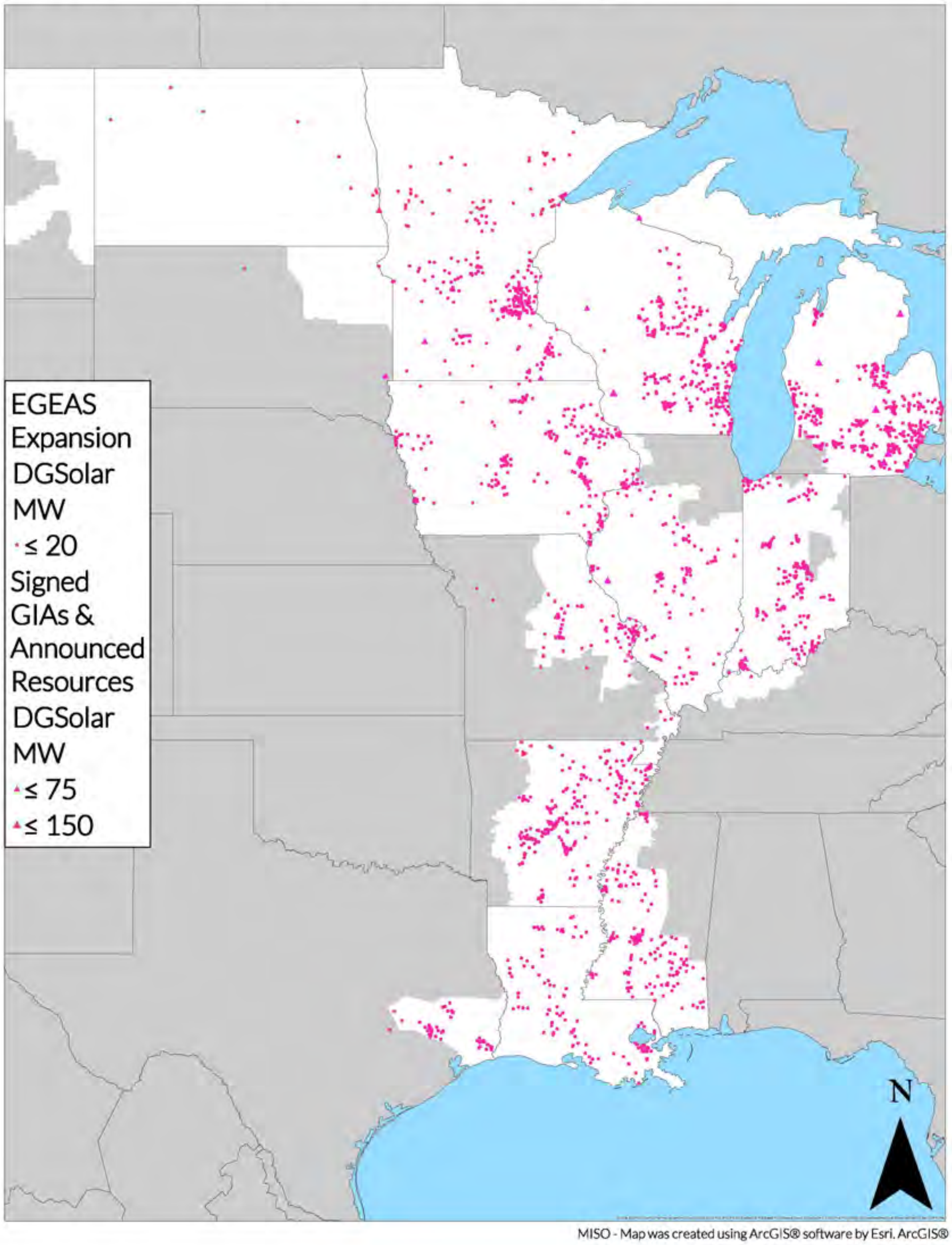


Figure 57: MISO Future 2 Distributed Solar Siting

Future 2: Wind Expansion

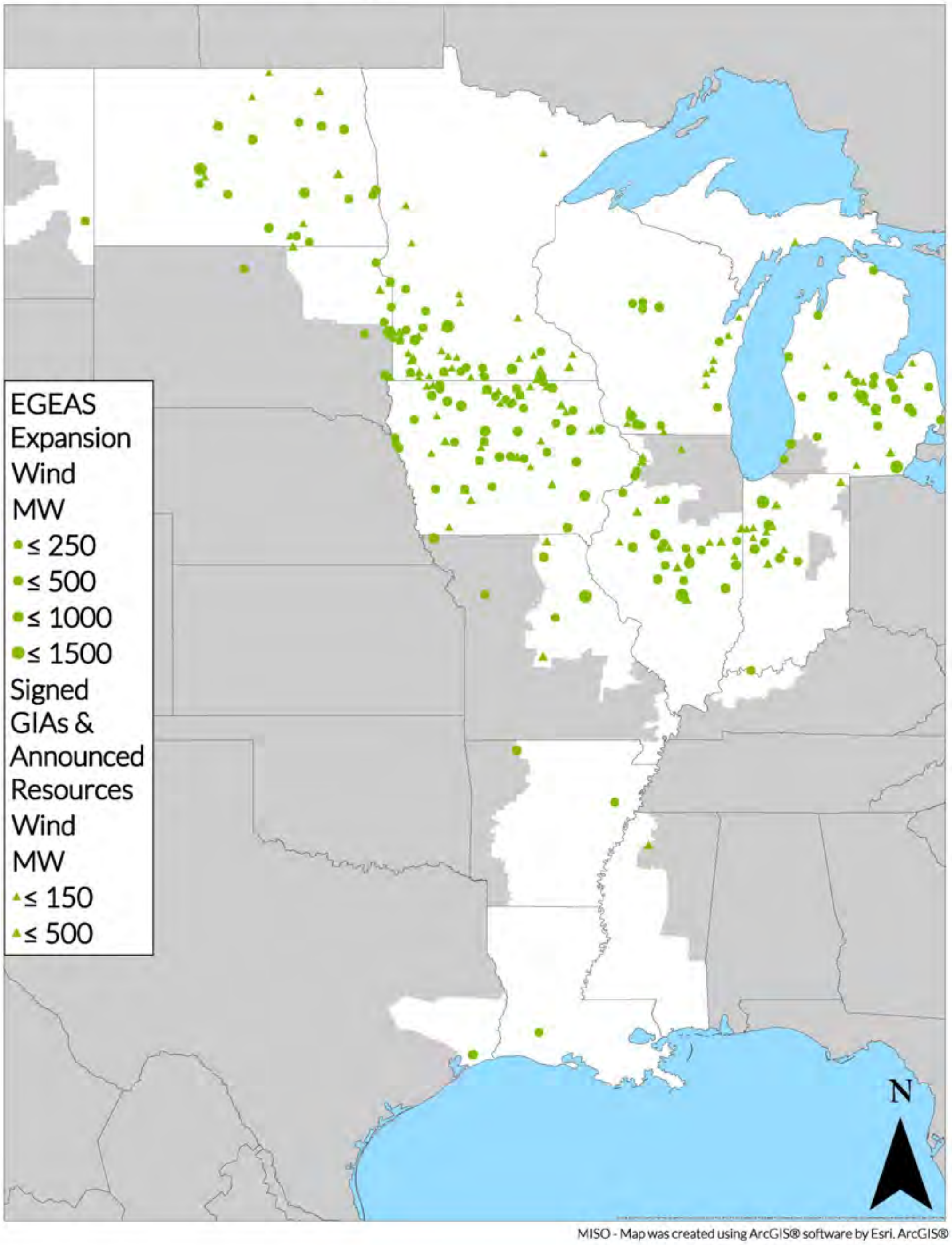


Figure 58: MISO Future 2 Wind Siting

Future 2: Battery Expansion

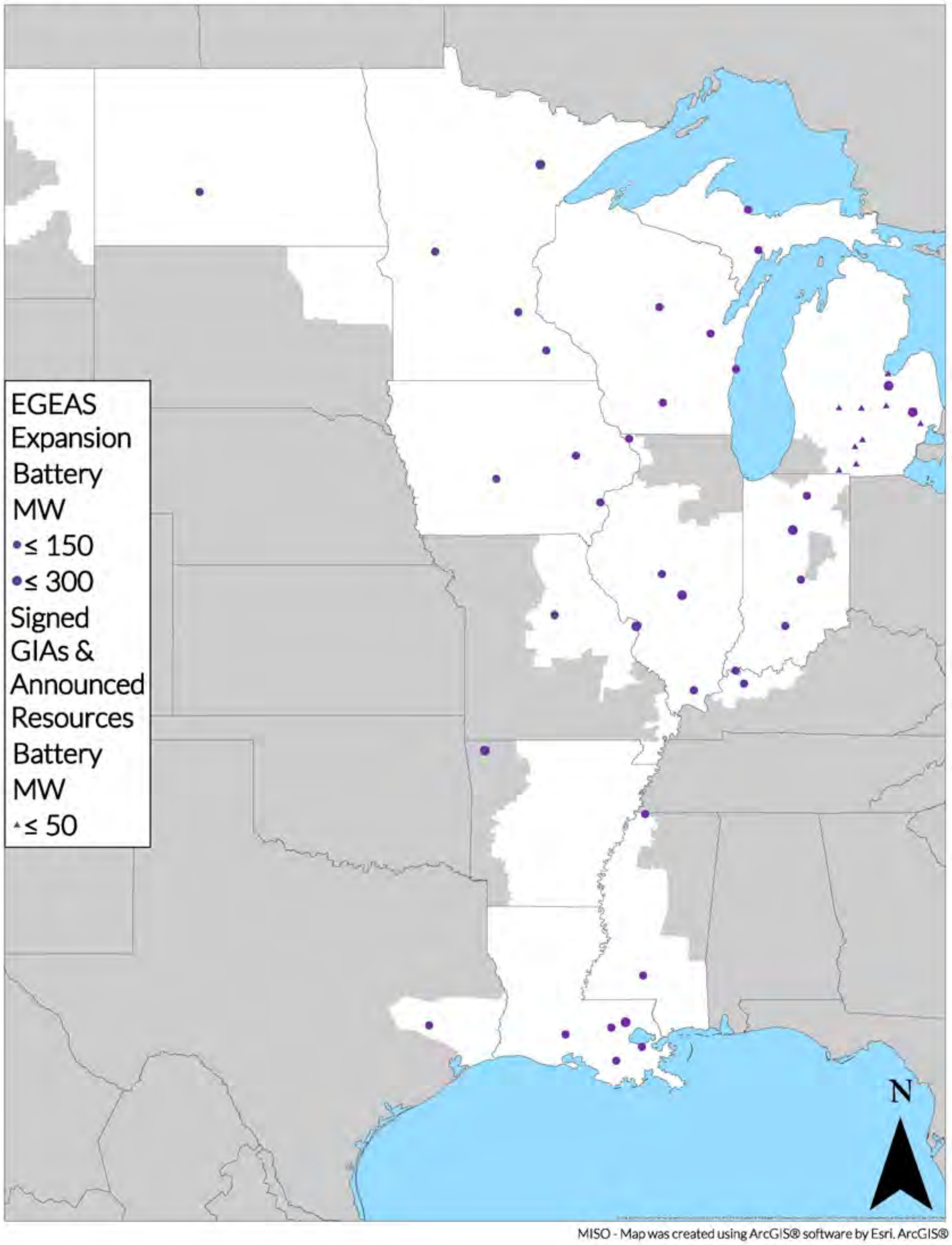


Figure 59: MISO Future 2 Battery Siting

Future 2: Thermal Expansion

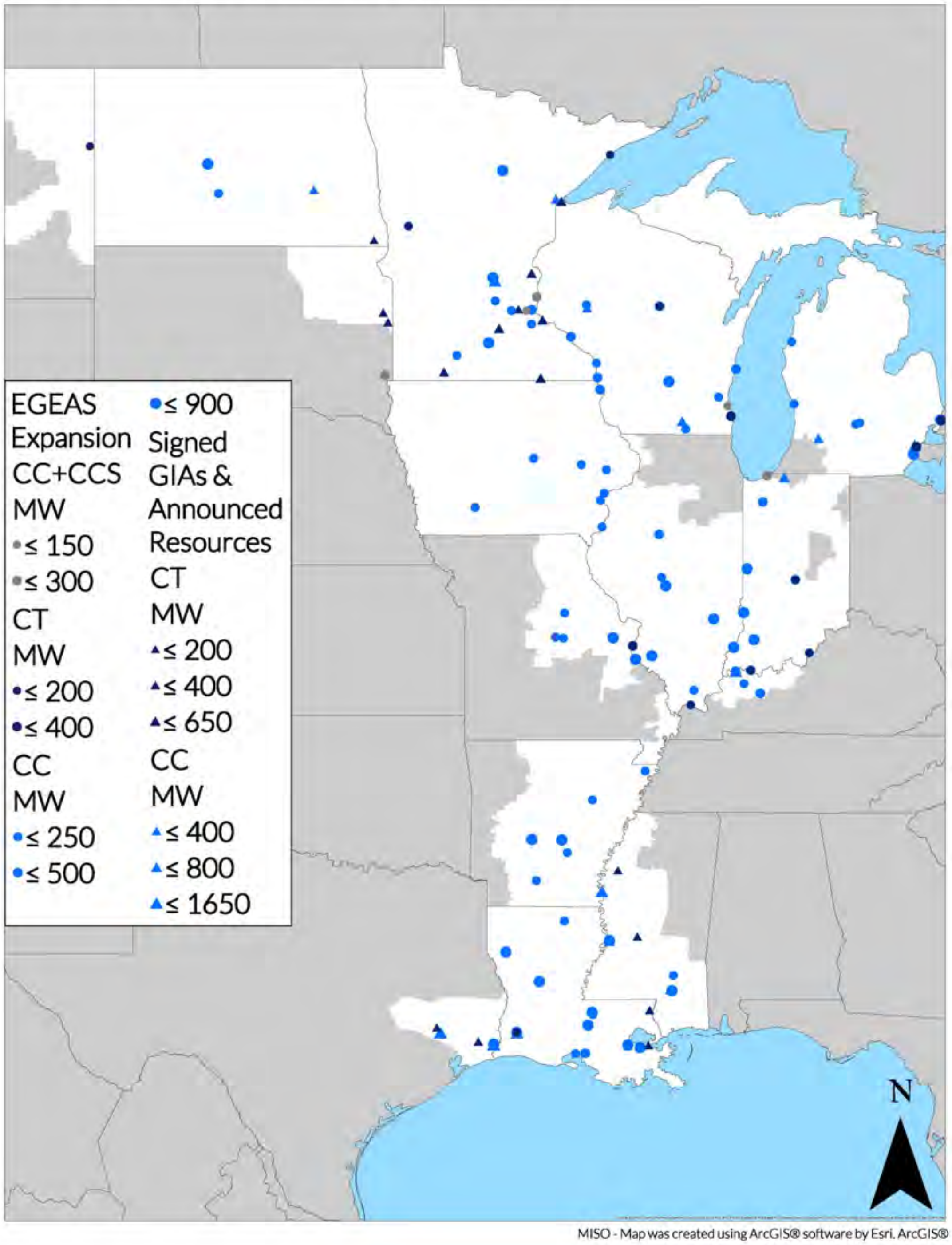


Figure 60: MISO Future 2 Thermal Siting

Future 2: EGEAS Expansion

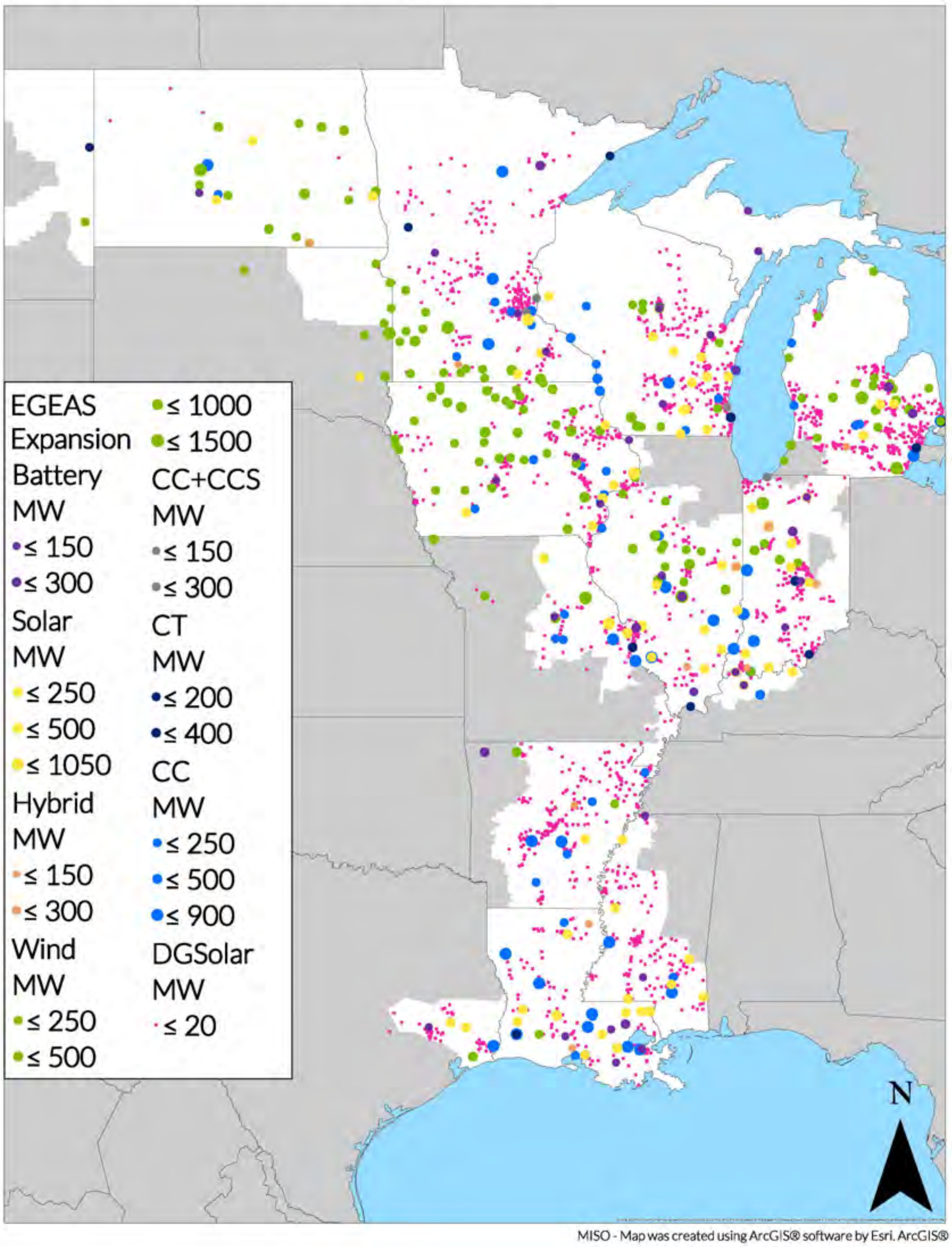


Figure 61: MISO Future 2 Complete EGEAS Expansion Siting

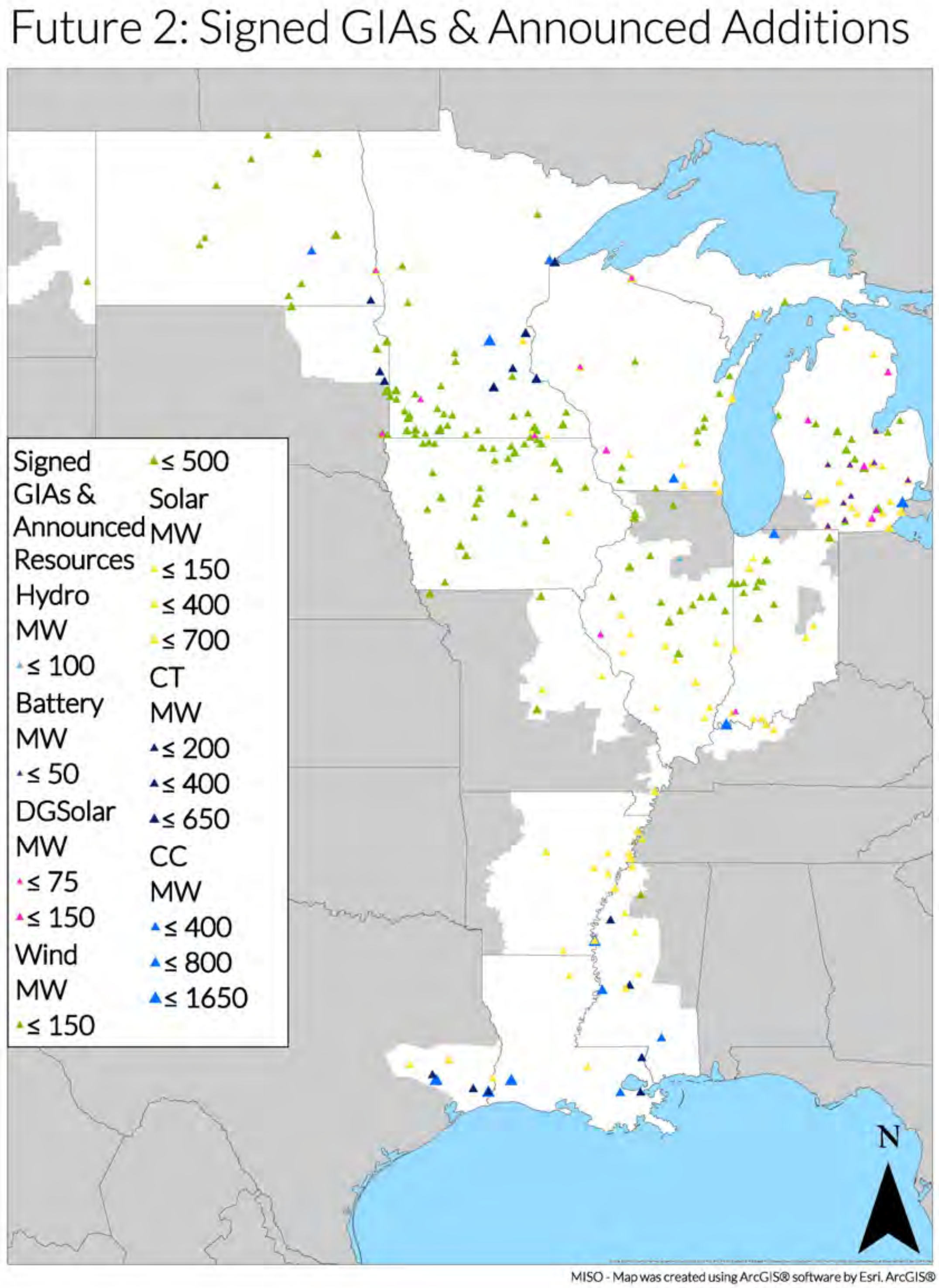


Figure 62: MISO Future 2 Non-EGEAS Expansion Siting

Future 2: Total Expansion

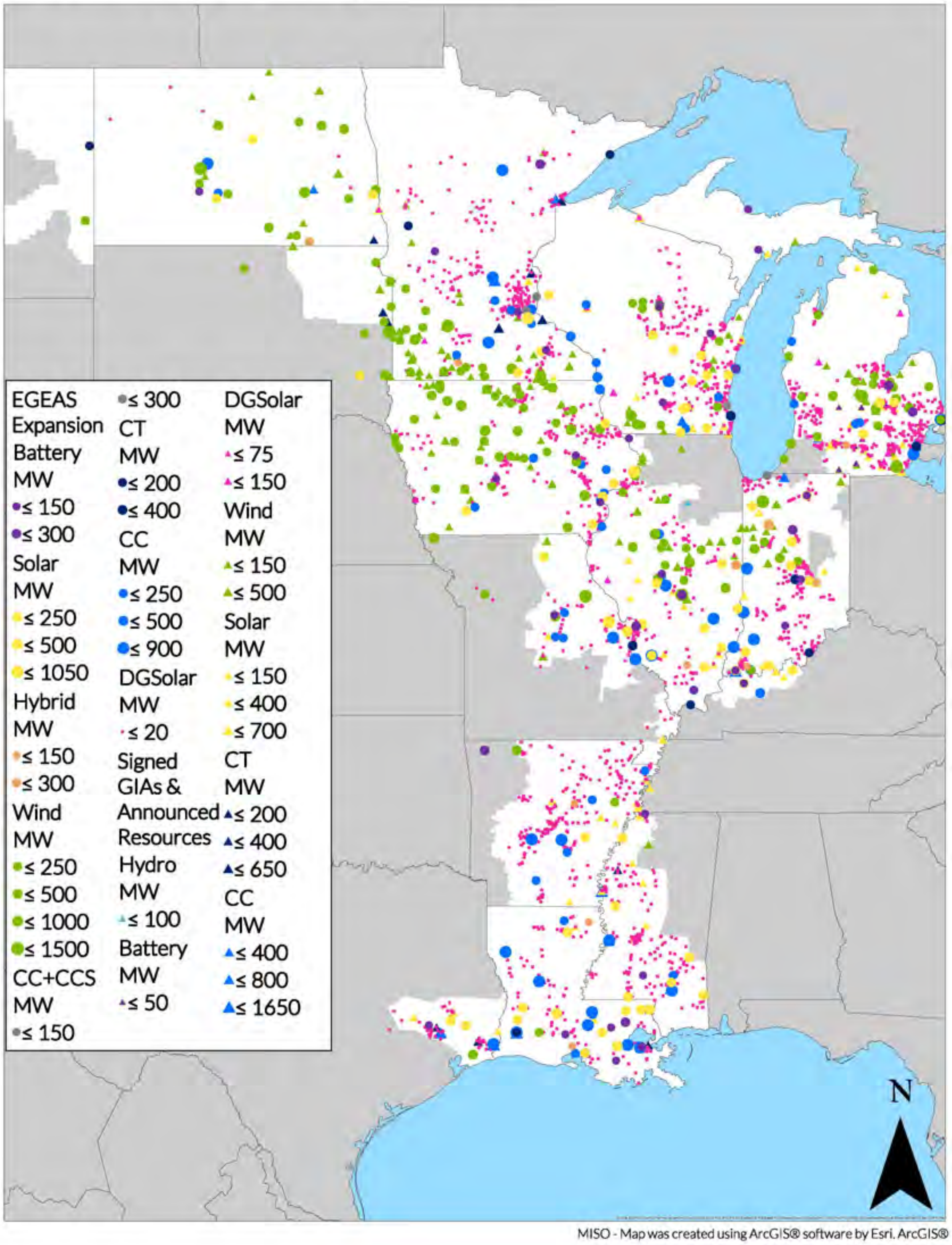


Figure 63: MISO Future 2 Non-EGEAS and EGEAS Expansion Siting

Future 2 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	2,020	1,453	0	4,219	1,032	0	0	283	0	9,007
	2030	6,491	2,095	0	7,006	2,550	99	0	499	0	18,740
	2035	6,641	4,928	0	10,797	5,380	99	33	772	0	28,650
	2039	8,986	4,928	774	18,435	5,380	99	451	942	0	39,995
LRZ 2	**2025**	1,686	0	0	657	1,270	0	0	38	0	3,650
	2030	3,056	0	0	1,041	1,471	0	0	122	0	5,689
	2035	3,673	511	0	1,903	1,680	0	0	246	0	8,012
	2039	4,004	511	138	3,408	1,680	0	268	311	0	10,320
LRZ 3	**2025**	311	0	0	3,630	821	0	0	34	0	4,796
	2030	1,134	0	0	5,850	1,295	0	0	109	0	8,388
	2035	1,134	0	0	8,682	1,666	0	0	220	0	11,701
	2039	1,134	0	0	16,484	1,666	0	224	277	0	19,786
LRZ 4	**2025**	900	0	0	2,328	2,225	0	0	51	10	5,514
	2030	3,850	0	0	3,424	2,557	314	0	75	10	10,230
	2035	3,850	668	0	4,671	2,771	314	0	111	10	12,396
	2039	4,184	668	0	7,862	2,771	314	207	129	10	16,146
LRZ 5	**2025**	64	0	0	881	498	0	0	25	0	1,468
	2030	2,783	0	0	1,358	901	0	0	80	0	5,122
	2035	2,783	660	0	1,905	1,273	0	0	162	0	6,783
	2039	2,909	660	0	2,879	1,287	0	174	205	0	8,115
LRZ 6	**2025**	5,009	0	0	2,002	2,410	0	0	69	0	9,490
	2030	11,699	0	0	2,552	3,027	426	0	103	0	17,807
	2035	12,209	699	0	3,384	3,309	426	0	153	0	20,180
	2039	12,209	699	289	4,935	3,309	426	423	179	0	22,469
LRZ 7	**2025**	2,051	0	0	1,758	1,537	0	0	749	72	6,166
	2030	2,718	0	0	2,937	3,211	94	0	781	72	9,813
	2035	3,378	601	0	4,106	4,498	94	267	829	72	13,845
	2039	5,133	601	0	7,576	5,098	94	889	854	72	20,318
LRZ 8	**2025**	1,734	0	0	93	2,578	0	0	26	0	4,431
	2030	2,400	0	0	222	2,681	77	0	83	0	5,464
	2035	2,522	0	0	334	2,750	77	0	168	0	5,851
	2039	2,522	0	0	686	2,750	77	172	212	0	6,420
LRZ 9	**2025**	6,457	493	0	86	1,512	0	0	28	0	8,577
	2030	12,965	493	0	207	2,360	189	0	91	0	16,305
	2035	14,597	1,381	0	310	3,031	189	0	184	0	19,692
	2039	14,597	1,727	0	638	3,031	189	481	232	0	20,895
LRZ 10	**2025**	672	0	0	200	718	0	0	16	0	1,606
	2030	731	350	0	200	1,091	0	0	52	0	2,425
	2035	3,046	700	0	200	1,723	0	0	106	0	5,776
	2039	3,046	700	0	200	1,723	0	109	134	0	5,913
MISO Total	**2025**	20,903	1,946	0	15,853	14,600	0	0	1,320	82	54,704
	2030	47,828	2,938	0	24,796	21,144	1,200	0	1,995	82	99,983
	2035	53,834	10,148	0	36,291	28,082	1,200	300	2,950	82	132,887
	2039	58,725	10,494	1,201	63,104	28,696	1,200	3,400	3,475	82	170,376

Table 9: MISO Future 2 Resource Additions by LRZ and Footprint

Future 2 Resource Retirements (MW) - *Cumulative*									
Zone	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Totals**
LRZ 1	**2025**	4,324	1,255	0	698	240	0	36	6,553
	2030	6,413	2,584	0	698	519	0	36	10,250
	2035	6,676	3,281	1,092	771	2,946	0	36	14,802
	2039	6,676	3,332	1,092	803	3,572	0	36	15,510
LRZ 2	**2025**	2,650	2,650	0	351	11	0	0	5,663
	2030	2,981	741	0	351	41	0	0	4,114
	2035	2,981	741	0	351	427	0	0	4,500
	2039	2,981	1,617	0	351	617	0	0	5,566
LRZ 3	**2025**	757	92	448	196	122	0	0	1,615
	2030	757	92	448	196	348	0	0	1,841
	2035	757	92	448	275	1,434	0	0	3,006
	2039	776	92	448	275	2,707	0	0	4,297
LRZ 4	**2025**	3,056	134	0	117	0	0	0	3,307
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	134	0	117	379	0	0	3,748
	2039	3,118	134	0	117	1,013	0	0	4,382
LRZ 5	**2025**	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	384	0	345	169	0	0	5,796
	2039	6,132	384	0	345	169	0	0	7,029
LRZ 6	**2025**	11,068	853	0	50	0	0	0	11,970
	2030	11,537	853	0	50	0	0	0	12,439
	2035	11,537	1,008	0	71	377	0	0	12,992
	2039	11,537	1,296	0	71	582	21	0	13,507
LRZ 7	**2025**	2,991	161	819	59	0	0	0	4,029
	2030	4,258	168	819	59	0	0	0	5,303
	2035	4,878	2,973	819	59	230	0	0	8,958
	2039	8,013	3,059	819	59	565	0	0	12,513
LRZ 8	**2025**	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	788	0	0	0	0	0	3,918
	2039	3,130	788	0	0	0	0	0	3,918
LRZ 9	**2025**	2,746	7,013	0	7	0	0	0	9,766
	2030	2,746	7,013	0	7	0	0	0	9,766
	2035	2,746	8,591	0	7	0	0	0	11,344
	2039	2,746	8,591	0	7	0	0	0	11,344
LRZ 10	**2025**	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	2,319	0	0	0	0	0	2,319
	2039	0	2,319	0	0	0	0	0	2,319
MISO Total	**2025**	33,132	13,904	1,267	1,822	373	0	36	50,534
	2030	38,833	13,331	1,267	1,822	928	0	36	56,217
	2035	40,722	20,311	2,359	1,996	5,960	0	36	71,383
	2039	45,109	21,611	2,359	2,027	9,223	21	36	80,386

Table 10: MISO Future 2 Resource Retirements by LRZ and Footprint

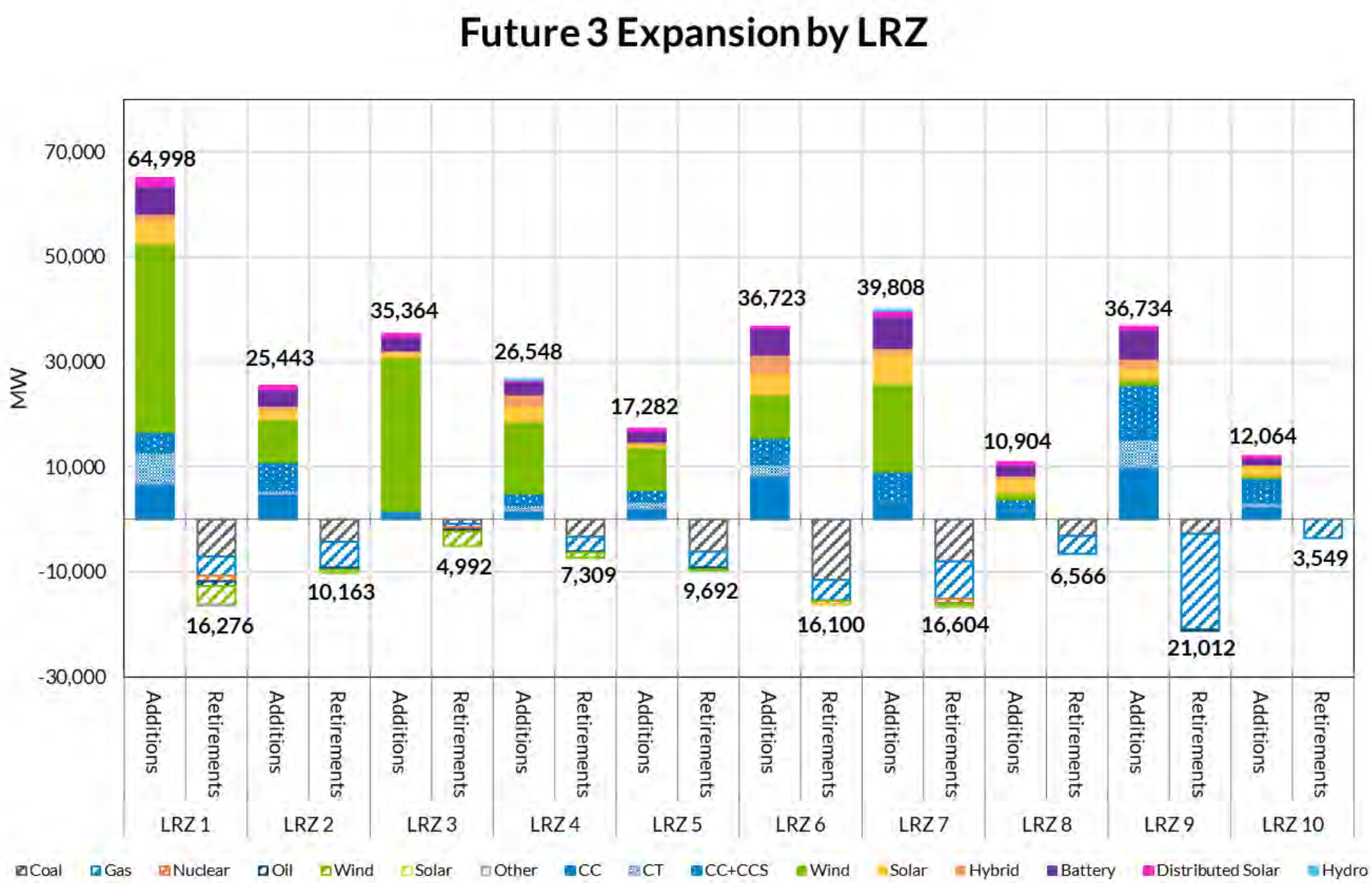


Figure 64: MISO Future 3 Resource Retirement and Addition Summary

Future 3 Retirements and Additions

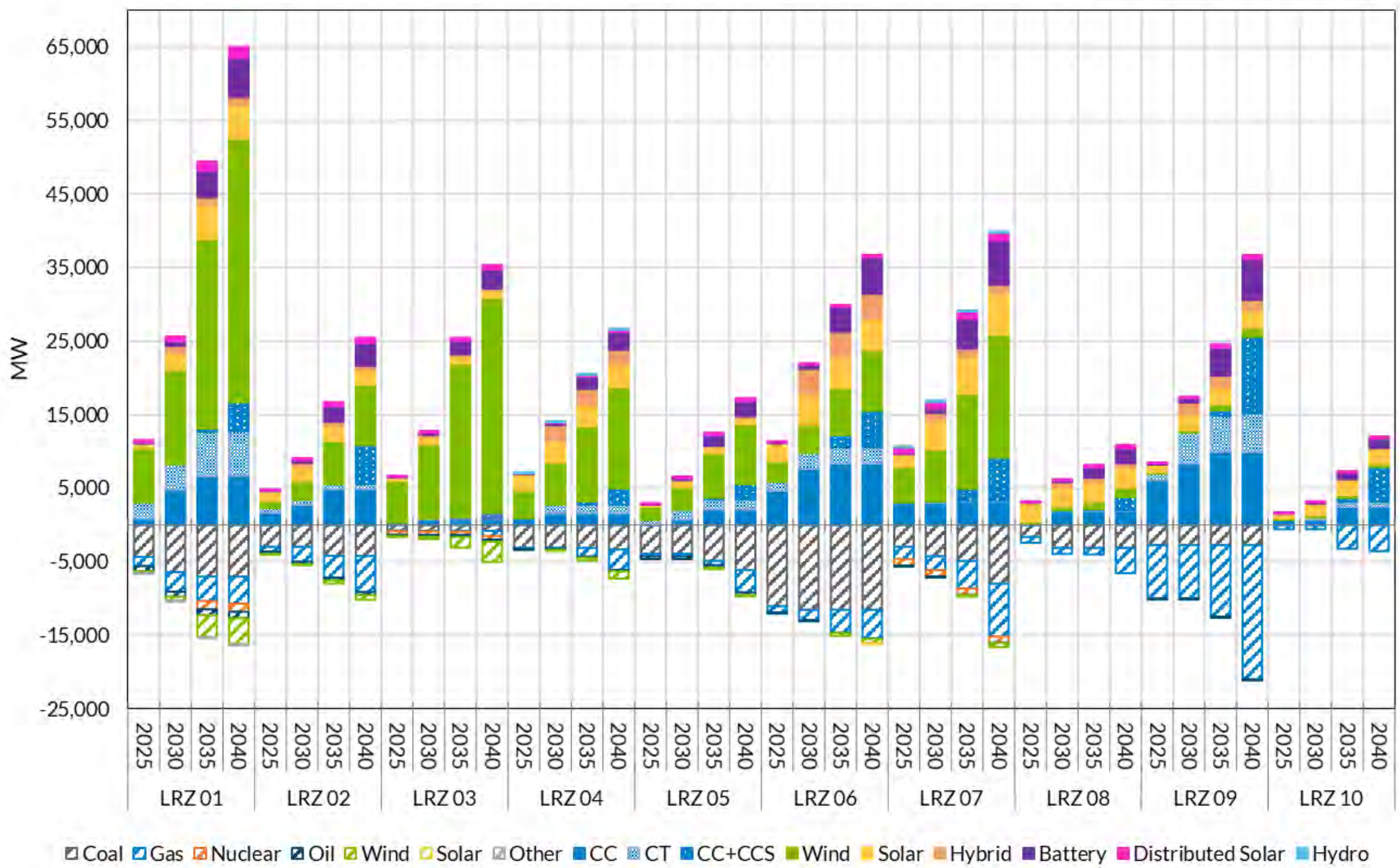


Figure 65: MISO Future 3 Resource Additions per Milestone Year (Cumulative)

Future 3: Solar & Hybrid Expansion

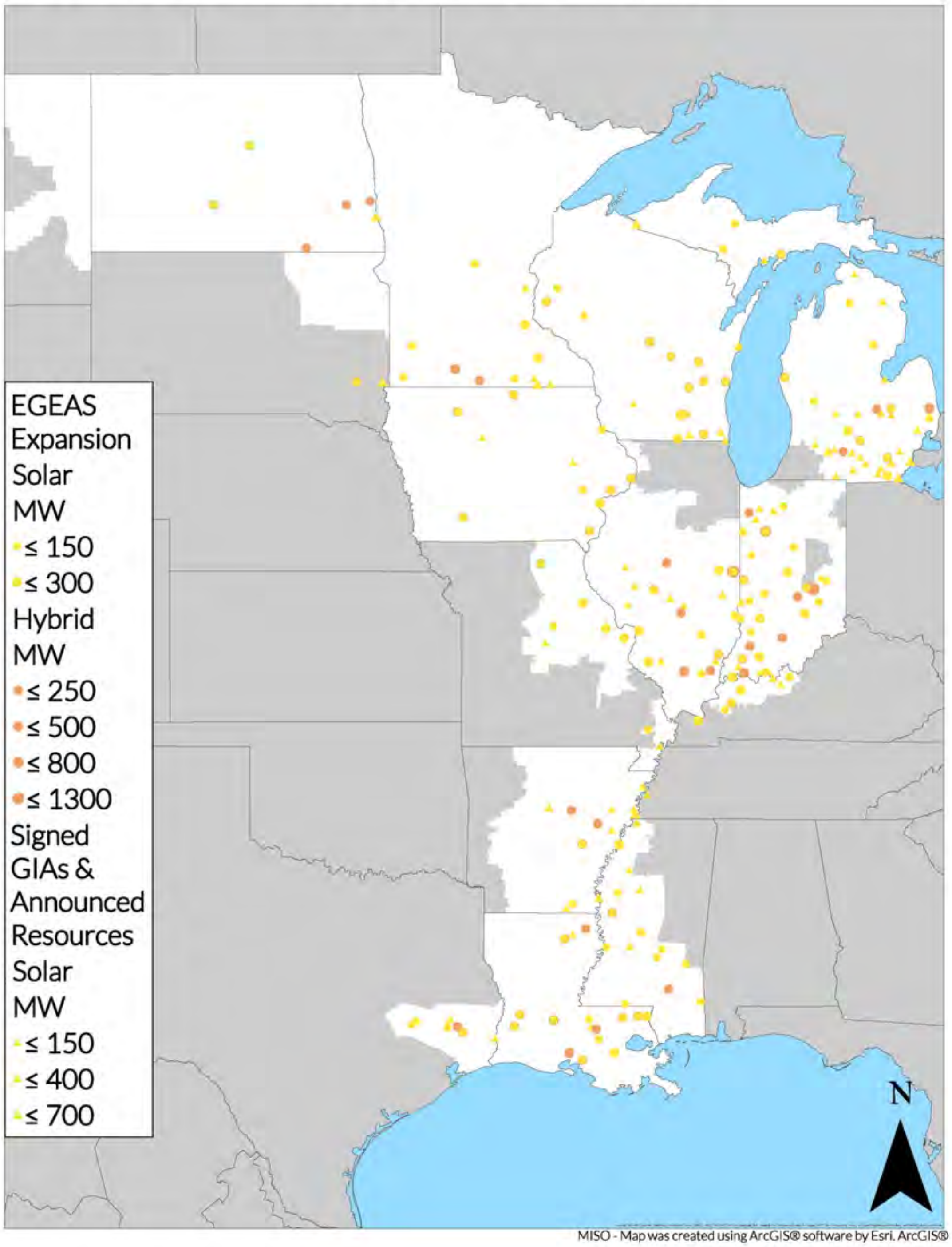


Figure 66: MISO Future 3 Solar and Hybrid Siting

Future 3: Distributed Solar Expansion

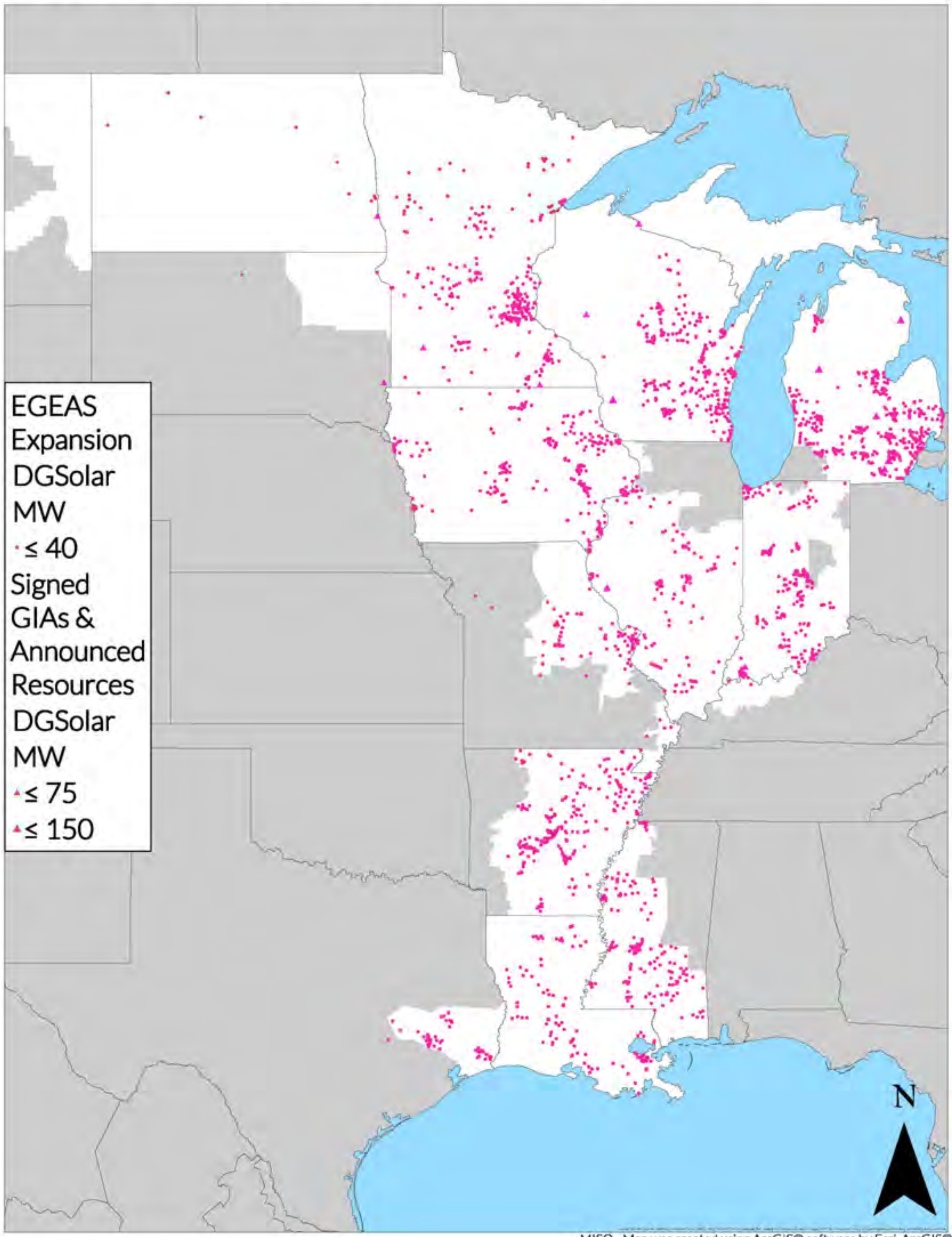


Figure 67: MISO Future 3 Distributed Solar Siting

Future 3: Wind Expansion

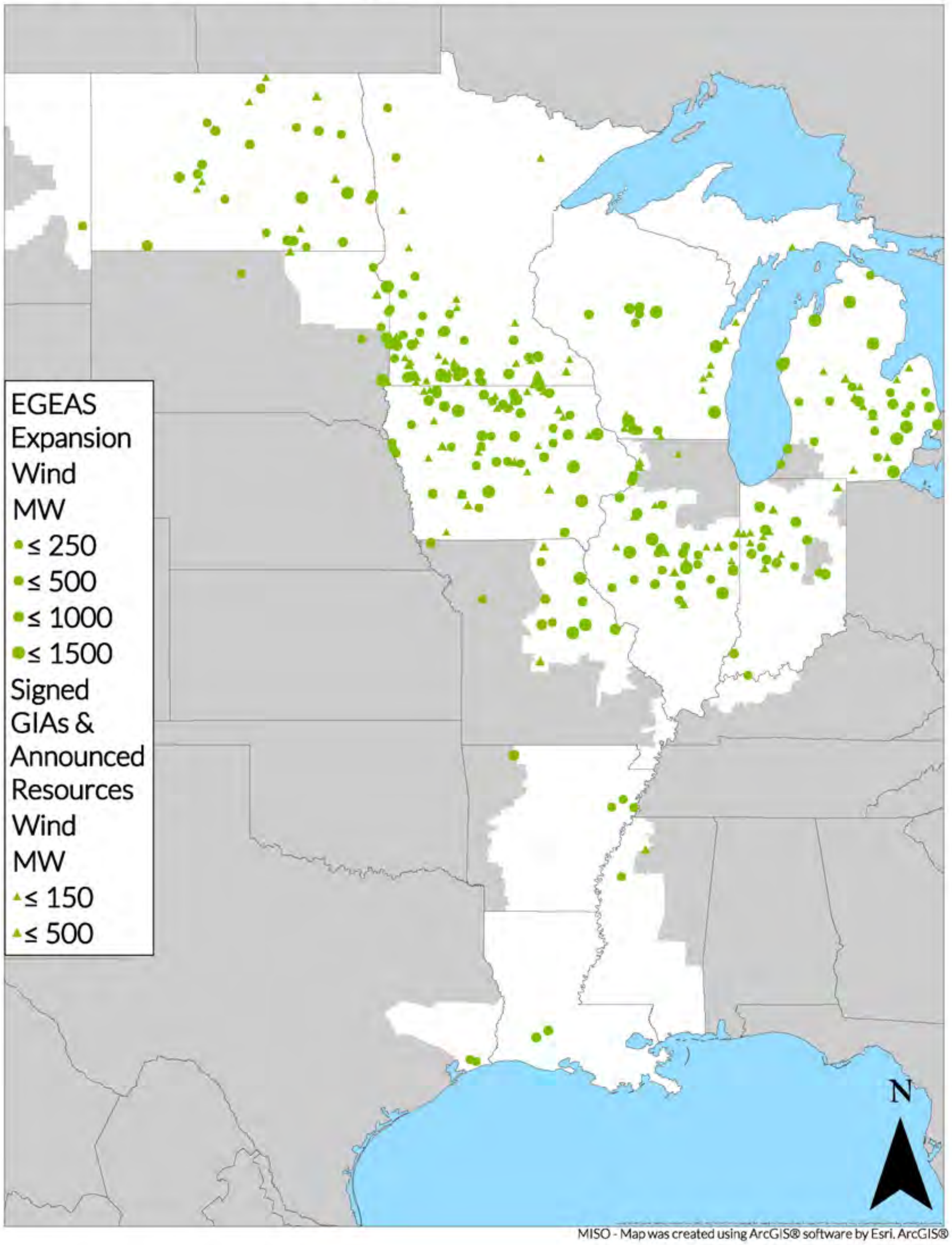


Figure 68: MISO Future 3 Wind Siting

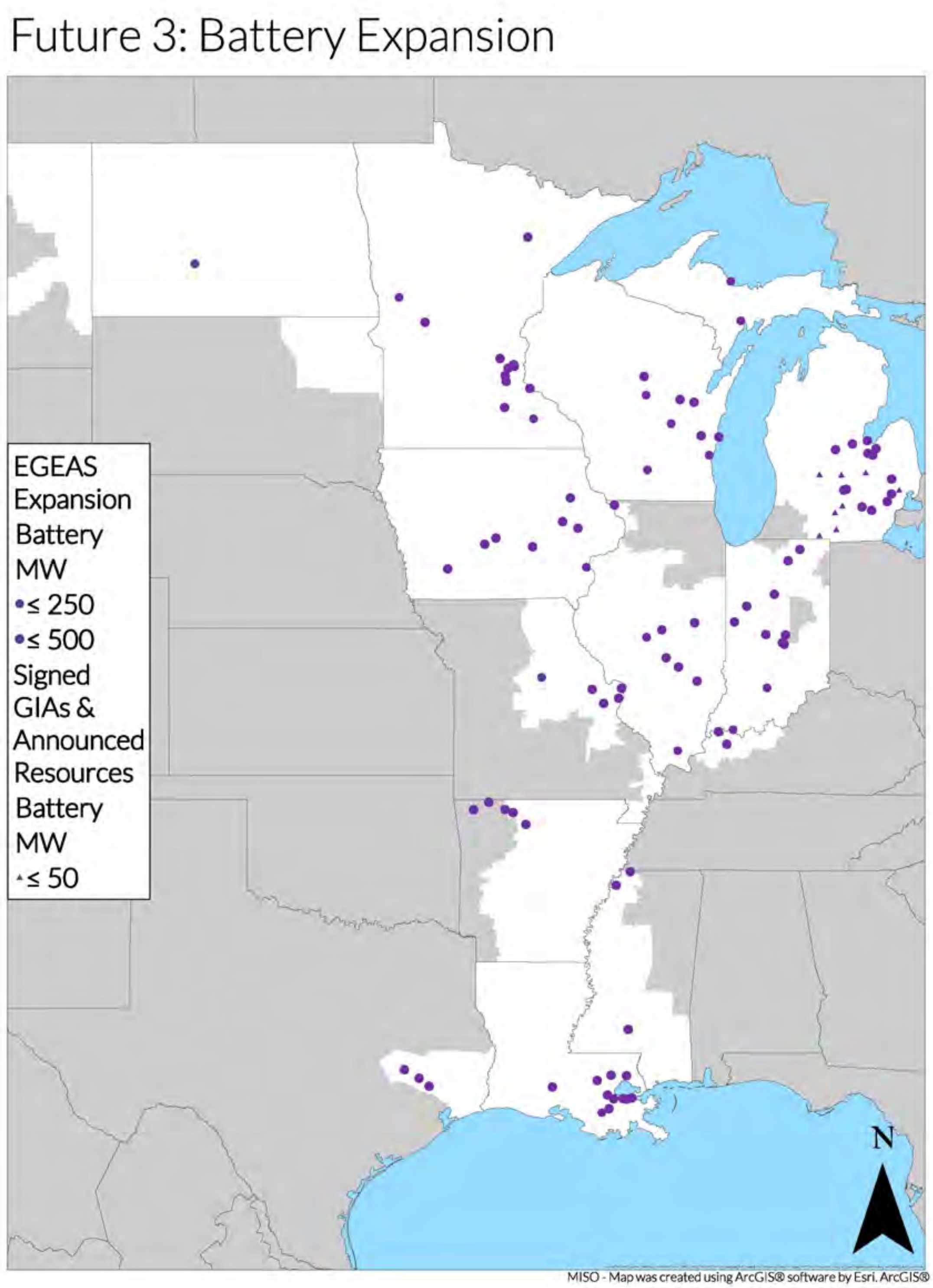


Figure 69: MISO Future 3 Battery Siting

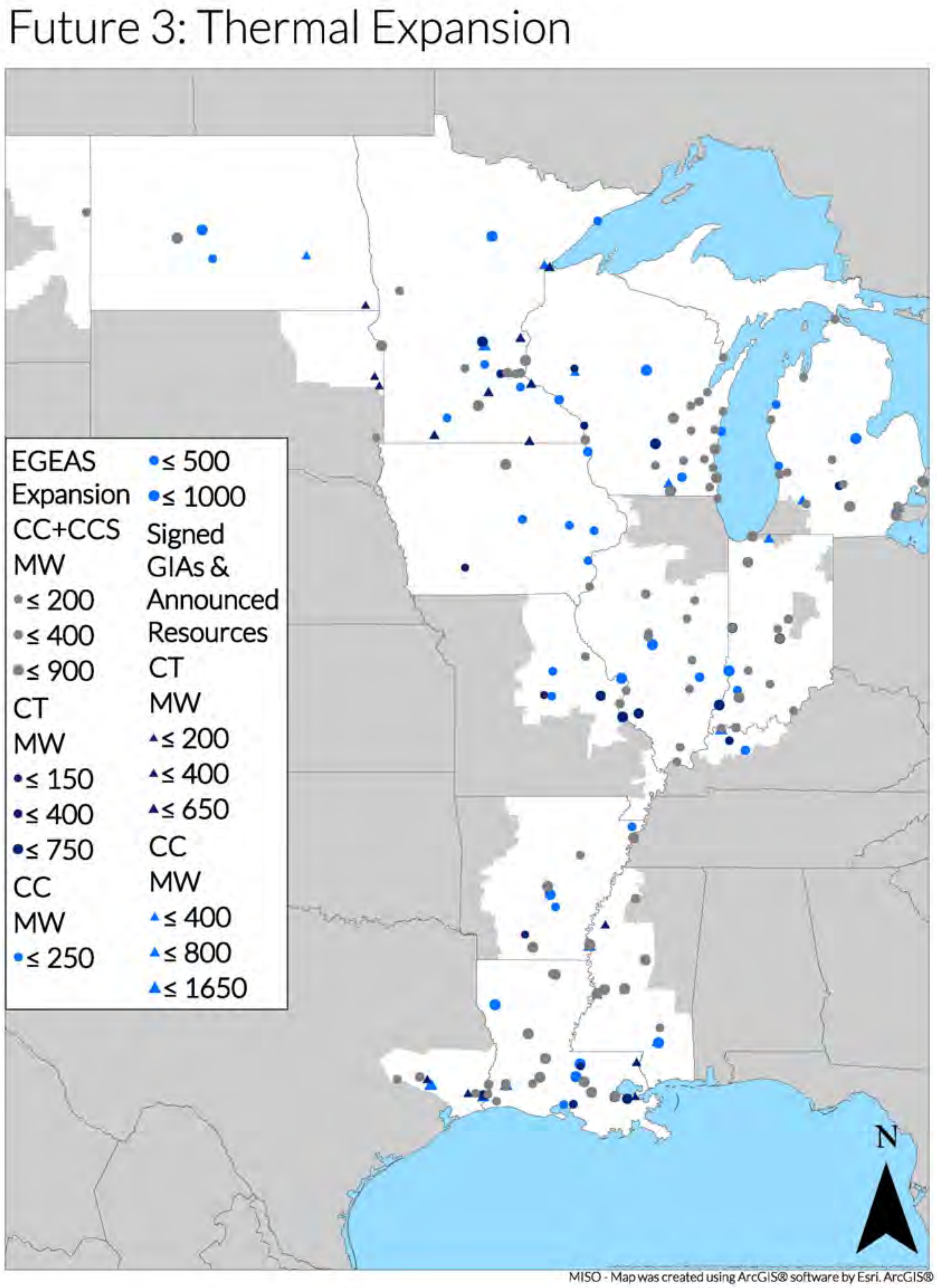


Figure 70: MISO Future 3 Thermal Siting

Future 3: EGEAS Expansion

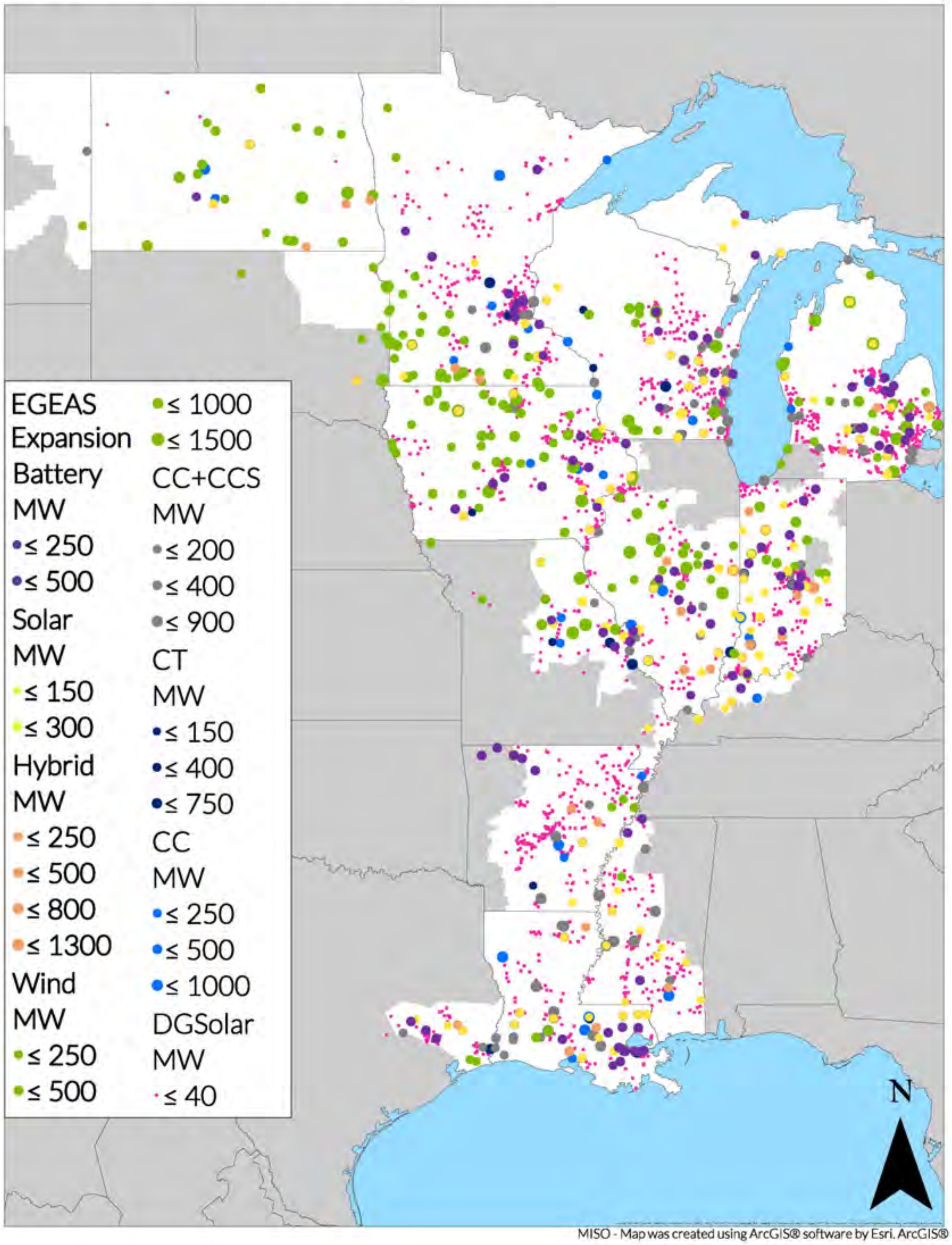


Figure 71: MISO Future 3 Complete EGEAS Expansion Siting

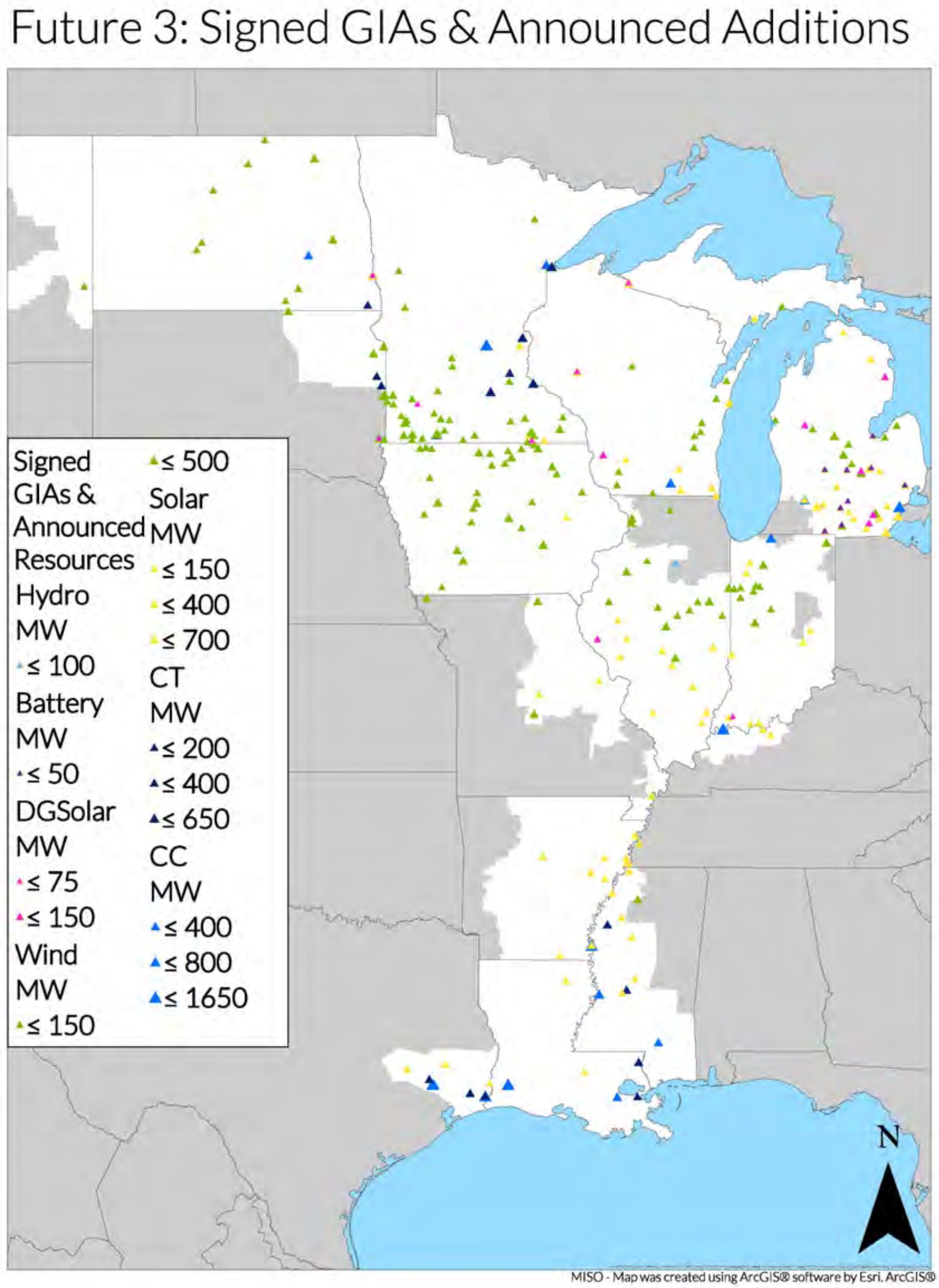


Figure 72: MISO Future 3 Non-EGEAS Expansion Siting

Future 3: Total Expansion

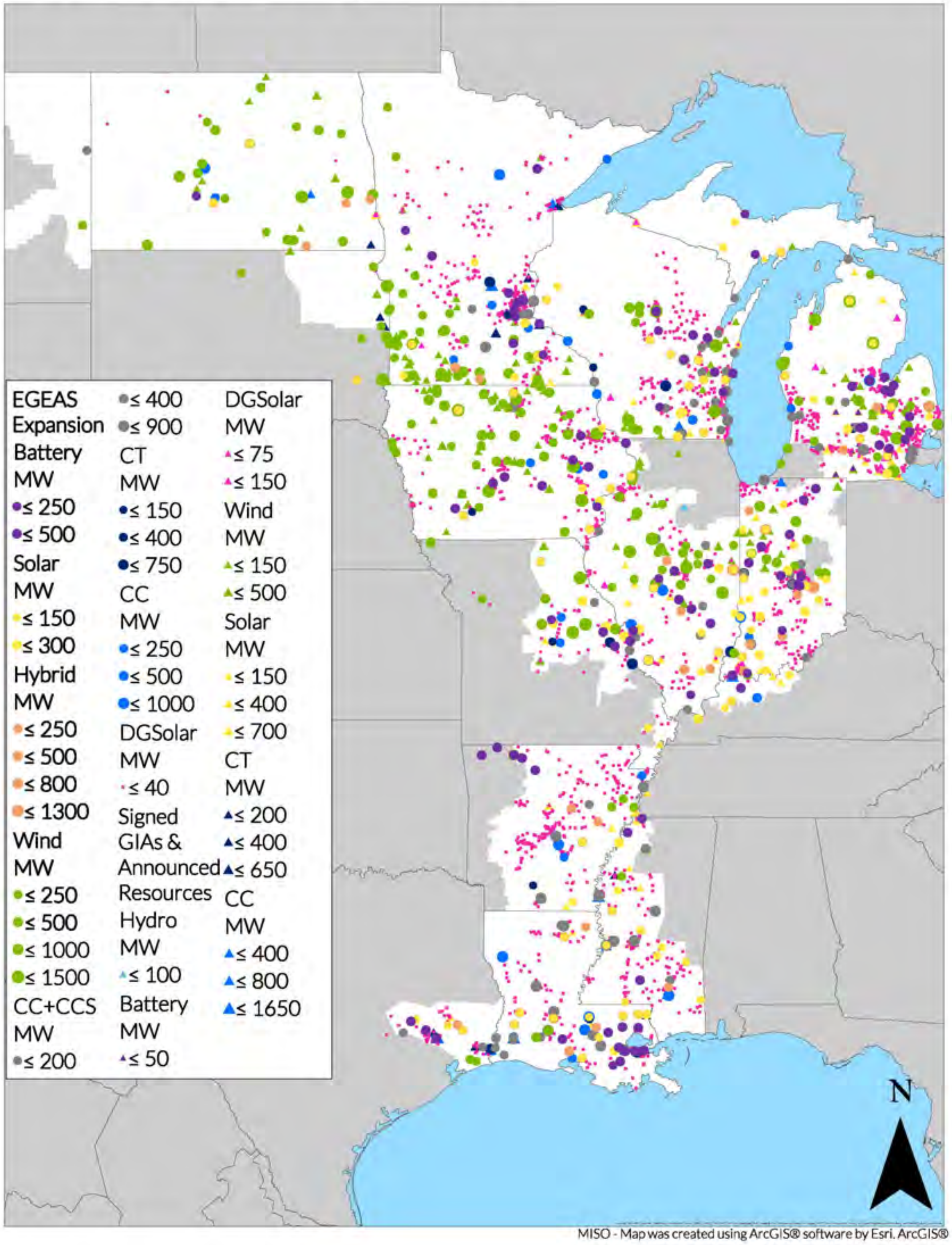


Figure 73: MISO Future 3 Non-EGEAS and EGEAS Expansion Siting

Future 3 Resource Additions (MW) - *Cumulative*											
Zone	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Hydro**	**Totals**
LRZ 1	**2025**	850	2,179	0	7,398	640	0	149	350	0	11,565
	2030	4,766	3,486	0	12,897	2,228	969	606	712	0	25,664
	2035	6,641	6,054	409	25,786	4,728	969	3,635	1,202	0	49,425
	2039	6,731	6,054	3,881	35,848	4,728	969	5,302	1,486	0	64,998
LRZ 2	**2025**	1,686	620	0	949	1,332	0	91	86	0	4,764
	2030	2,762	673	0	2,532	1,991	516	356	275	0	9,105
	2035	4,880	673	0	5,898	2,066	516	2,133	556	0	16,722
	2039	4,880	673	5,363	8,132	2,066	516	3,111	703	0	25,443
LRZ 3	**2025**	311	0	0	5,669	513	0	74	74	0	6,640
	2030	769	92	0	10,102	1,019	264	298	235	0	12,779
	2035	769	92	200	20,874	1,019	264	1,786	475	0	25,479
	2039	769	92	766	29,249	1,019	264	2,605	600	0	35,364
LRZ 4	**2025**	900	0	0	3,768	2,240	0	72	68	10	7,059
	2030	1,612	1,134	0	5,745	2,957	2,122	278	130	10	13,988
	2035	1,612	1,134	459	10,219	2,957	2,122	1,668	221	10	20,403
	2039	1,612	1,134	2,203	13,808	2,957	2,122	2,432	269	10	26,548
LRZ 5	**2025**	64	609	0	1,793	283	0	62	57	0	2,868
	2030	748	1,344	0	3,091	728	251	234	181	0	6,577
	2035	2,114	1,344	266	6,029	791	251	1,402	366	0	12,565
	2039	2,114	1,344	2,117	8,143	805	251	2,045	463	0	17,282
LRZ 6	**2025**	4,659	1,223	0	2,765	2,467	0	142	89	0	11,345
	2030	7,629	2,158	0	3,805	4,259	3,401	566	164	0	21,982
	2035	8,375	2,158	1,661	6,410	4,259	3,401	3,398	277	0	29,940
	2039	8,375	2,158	4,988	8,251	4,259	3,401	4,955	336	0	36,723
LRZ 7	**2025**	3,051	0	0	4,837	1,722	0	159	767	72	10,609
	2030	3,051	153	0	7,079	3,936	1,054	648	841	72	16,832
	2035	3,120	153	1,642	12,888	5,136	1,054	4,087	949	72	29,100
	2039	3,120	153	5,870	16,730	5,736	1,054	6,068	1,006	72	39,808
LRZ 8	**2025**	250	0	0	227	2,544	0	57	59	0	3,137
	2030	1,897	134	0	454	2,753	571	229	188	0	6,226
	2035	1,897	134	122	954	2,753	571	1,377	379	0	8,187
	2039	1,897	134	1745	1,317	2,753	571	2,008	479	0	10,904
LRZ 9	**2025**	6,061	915	0	201	1,031	0	160	64	0	8,432
	2030	8,321	4,215	0	401	2,156	1,529	639	205	0	17,466
	2035	9,953	4,907	726	842	2,356	1,529	3,836	415	0	24,564
	2039	9,953	5,253	10,361	1,163	2,356	1,529	5,594	524	0	36,734
LRZ 10	**2025**	672	0	0	245	627	0	34	37	0	1,616
	2030	672	350	0	291	1,517	123	146	119	0	3,217
	2035	2,472	700	515	390	2,017	123	877	240	0	7,334
	2039	2,472	700	4,707	463	2,017	123	1,280	303	0	12,064
MISO Total	**2025**	18,503	5,546	0	27,853	13,400	0	1,000	1,650	82	68,034
	2030	32,228	13,739	0	46,396	23,544	10,800	4,000	3,049	82	133,837
	2035	41,833	17,349	6,000	90,291	28,082	10,800	24,200	5,081	82	223,719
	2039	41,923	17,695	42,001	123,104	28,696	10,800	35,400	6,168	82	305,869

Table 11: MISO Future 3 Resource Additions by LRZ and Footprint

Future 3 Resource Retirements (MW) - *Cumulative*									
Zone	Milestone	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
LRZ 1	2025	4,324	1,272	0	698	240	0	36	6,569
	2030	6,420	2,635	0	698	519	0	36	10,307
	2035	7,040	3,337	1,092	824	2,946	0	36	15,275
	2039	7,040	3,651	1,092	885	3,572	0	36	16,276
LRZ 2	2025	2,981	604	0	351	11	0	0	3,947
	2030	2,981	2,017	0	351	41	0	0	5,390
	2035	4,173	3,010	0	351	427	0	0	7,961
	2039	4,232	4,906	0	409	617	0	0	10,163
LRZ 3	2025	757	92	448	196	122	0	0	1,615
	2030	776	107	448	275	348	0	0	1,954
	2035	776	135	448	275	1,434	0	0	3,068
	2039	808	702	448	328	2,707	0	0	4,992
LRZ 4	2025	3,118	134	0	117	0	0	0	3,369
	2030	3,118	134	0	117	20	0	0	3,389
	2035	3,118	1,199	0	117	379	0	0	4,813
	2039	3,326	2,794	0	176	1,013	0	0	7,309
LRZ 5	2025	3,893	384	0	345	0	0	0	4,622
	2030	3,893	384	0	345	0	0	0	4,622
	2035	4,899	582	0	345	169	0	0	5,994
	2039	6,132	3,047	0	345	169	0	0	9,692
LRZ 6	2025	11,068	853	0	50	0	0	0	11,970
	2030	11,537	1,398	0	71	0	0	0	13,005
	2035	11,537	3,102	0	71	377	0	0	15,086
	2039	11,537	3,889	0	71	582	21	0	16,100
LRZ 7	2025	2,991	1,697	819	59	0	0	0	5,565
	2030	4,258	1,906	819	59	0	0	0	7,041
	2035	4,878	3,760	819	59	230	0	0	9,745
	2039	8,013	7,134	819	74	565	0	0	16,604
LRZ 8	2025	1,647	788	0	0	0	0	0	2,435
	2030	3,130	788	0	0	0	0	0	3,918
	2035	3,130	882	0	0	0	0	0	4,012
	2039	3,130	3,436	0	0	0	0	0	6,566
LRZ 9	2025	2,746	7,243	0	7	0	0	0	9,996
	2030	2,746	7,243	0	7	0	0	0	9,996
	2035	2,746	9,711	0	7	0	0	0	12,464
	2039	2,746	18,259	0	7	0	0	0	21,012
LRZ 10	2025	0	574	0	0	0	0	0	574
	2030	0	574	0	0	0	0	0	574
	2035	0	3,248	0	0	0	0	0	3,248
	2039	0	3,549	0	0	0	0	0	3,549
MISO Total	2025	33,525	13,640	1,267	1,822	373	0	36	50,663
	2030	38,858	17,185	1,267	1,922	928	0	36	60,196
	2035	42,297	28,965	2,359	2,049	5,960	0	36	81,665
	2039	46,963	51,368	2,359	2,295	9,223	21	36	112,265

Table 12: MISO Future 3 Resource Retirements by LRZ and Footprint

Appendix

EGEAS Modeling

Description

The Electric Generation Expansion Analysis System (EGEAS) is a program developed by EPRI which MISO uses to conduct its expansion analysis studies. The primary function of EGEAS is the creation of a generation expansion plan that meets system requirements specified by several inputs, assumptions, and constraints.

Modeling Procedure

The modeling process can be broken down into three main stages: definition of the model through inputs, computational analysis and solution processing, and consolidation of the results in the output file.

Inputs

Listed below are some of the key input parameters that EGEAS uses when selecting the optimal expansion solution. EGEAS allows users to input a variety of variables however, the inputs below include some of the more important parameters when setting up an economic expansion model.

- Hourly load shape files for the system and NDTs
- Projected peak yearly values of demand and energy
- Planning Reserve Margin (PRM) percentage requirement
- Renewable Portfolio Standard (RPS) percentage trajectories
- Decarbonization trajectories, may be input in short tons or $/short ton
- Existing unit data including planned additions and retirements
- Cost of unserved energy
- Available expansion resources and respective cost and emission data

Computational Analysis

To find the optimal resource expansion plan, EGEAS solves two objective functions:

1. Present value of the revenue requirements
2. The levelized average system rates ($/MWh)

The bulk of the work done by EGEAS is in solving these functions. It is an iterative process that progresses through the study year by year. Retaining only the feasible solutions each year, a single expansion plan that satisfies all input constraints and limitations over the study period is selected after the final year of study.

Output

The final report file is a text output file containing a report on the generic units EGEAS built to meet the system constraints in every year of the study. Metrics such as PRM, RPS, systemwide CO_2 emissions, resource generation, and cost data are also included in the report file.

From this information, MISO staff acquires its resource expansion and sites these resources throughout the footprint based on generator availability and other criteria discussed in the New Resource Addition Siting Process section of this report.

An important metric used in the Futures process is the RPS which EGEAS calculates as the ratio of Renewable Energy Generation (from wind, solar, and solar hybrid resources) to Net System Energy. In this calculation, net system energy is the sum of forecasted and storage charging energy minus energy from demand side management programs. While this may be how EGEAS calculated required contribution from renewable resources when defining an economic expansion, MISO displays these results differently so that energy generation from all resources may be seen. The calculation used by MISO is (Renewable Energy GWh / Total Generation GWh).

Shown below is an example of the EGEAS and MISO calculation to meet the RPS in Future 3 year 2039. MISO values appear less than EGEAS calculated values because total generation includes energy from DSM programs and curtailed renewable energy from low demand periods.

EGEAS Calculation

Forecasted System Energy (GWh)	Storage Charging (GWh)	DSM Energy (GWh)	Net System Energy (GWh)	Renewable Energy Generation (GWh)	RPS %
1,063,465	176,423	56,665	1,183,223	622,241	53%

$$\left(\frac{Renewable}{Forecasted + Storage - DSM}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}063{,}465 + 176{,}423 - 56{,}665}\right) \times 100 = 52.59$$

MISO Calculation

Total Energy Generation (GWh)	Renewable Energy Generation (GWh)	RPS %
1,352,519	622,241	46%

$$\left(\frac{Renewable}{Total\ Generation}\right) \times 100 = RPS\%$$

$$\left(\frac{622{,}241}{1{,}352{,}519}\right) \times 100 = 46.01$$

Additional MISO Assumptions

Futures Assumptions Summary

Table 13 and Table 14 detail Future-specific input assumptions. Many of these variables were direct inputs to the model; however, selected DERs, retirements, and addition totals are results of the analysis.

Variables	Future 1	Future 2	Future 3
Gross Load[29] Total Growth	Low-Base EV Growth 94,275 GWh	30% Total Energy Growth by 2040 196,996 GWh	50% Total Energy Growth by 2040 334,692 GWh
Energy (CAGR) Input/*Result*	0.63% / *0.48%*	1.22% / *1.09%*	1.91% / *1.71%*
Demand (CAGR) Input/*Result*	0.75% / *0.60%*	1.11% / *0.97%*	1.60% / *1.41%*
Electrification Growth & Technologies Growth from Electrification	2% of Total Growth 14,147 GWh	15.2% of Total Growth 109,101 GWh	31.8% of Total Growth 231,513 GWh
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process
Selected DERs DR	0.94 GW	0.94 GW	0.94 GW
EE	7.82 GW	8.05 GW	11.72 GW
DG	3.47 GW	3.47 GW	6.17 GW
Carbon Reduction *(2005 baseline)* MISO Footprint currently at 29%	40% *63% realized in results*	60% *65% realized in results*	80% *81% realized in results*
Wind & Solar Generation Percentage[82]	Resulted in 26% with No Minimum Enforced	Resulted in 35% with No Minimum Enforced	46%
Utility Announced Plans	85% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met	100% Goals Met 100% IRPs Met

Table 13: MISO Futures Assumptions

[29] Total Growth is based on 2039 values due to the study period ending on 12/31/2039.

Variables		Future 1	Future 2	Future 3
Retirement Age-Based Criteria	Coal	46 years[30]	36 years	30 years
	Natural Gas-CC	50 years	45 years	35 years
	Natural Gas-Other	46 years	36 years	30 years
	Oil	45 years	40 years	35 years
	Nuclear	Retire if Publicly Announced	Retire if Publicly Announced	Retire if Publicly Announced
	Wind & Solar - Utility Scale	25 years	25 years	25 years
Retirements	Coal	44.8 GW	45.1 GW	47 GW
	Gas	18.6 GW	21.6 GW	51.4 GW
	Oil	2 GW	2.03 GW	2.3 GW
	Nuclear	2.4W	2.4GW	2.4GW
	Wind	9.2 GW	9.2 GW	9.2 GW
	Solar	0.02 GW	0.02 GW	0.02 GW
	Other	0.04 GW	0.04 GW	0.04 GW
	Total	77.1 GW	80.4 GW	112.3 GW
Additions	CC	37.1 GW	58.7 GW	41.9 GW
	CT	14.1 GW	10.5 GW	17.7 GW
	CC+CCS	0 GW	1.2 GW	42 GW
	Wind[31]	18.7 GW	63.1 GW	123.1 GW
	Solar	34.7 GW	28.7 GW	28.7 GW
	Hybrid	12 GW	1.2 GW	10.8 GW
	Battery	0.6 GW	3.4 GW	35.4 GW
	Hydro	0.1 GW	0.1 GW	0.1 GW
	Total (Including DERs)	129.5 GW	179.4 GW	318.5 GW

Table 14: MISO Futures Assumptions and Expansion Results

[30] EIA Source for Coal Retirement Age, Future 1: https://www.eia.gov/todayinenergy/detail.php?id=40212

[31] All Futures include 9.2 GW of repowered wind and 9.5 GW of wind from signed GIAs.

Capital Costs

MISO used the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB)[32] to calculate the capital costs for all resources except for oil,[33] storage compressed air energy storage (CAES),[34] and internal combustion (IC) renewable[35] costs. MISO utilized moderate cost values within the 2020 ATB, which are in 2018 dollars. These values were converted to 2020 dollars and projected into the 20-year study period to create cost trajectories. For Hybrid unit costs, 2020 ATB Solar PV + Battery costs are included.

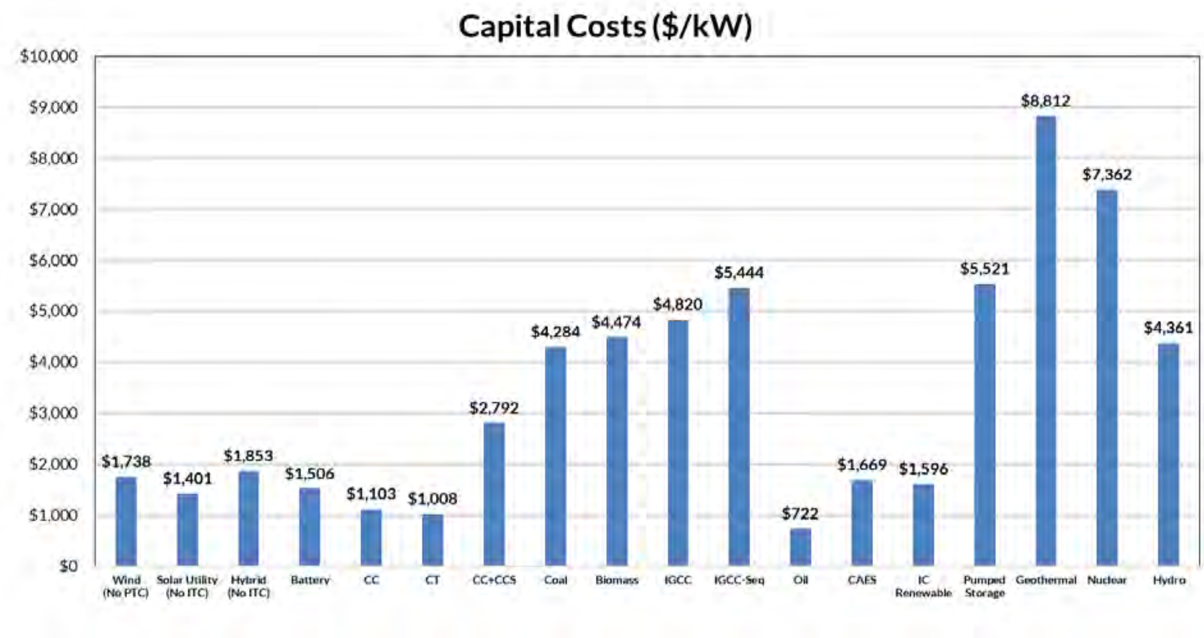


Figure 74: Annual Capital Cost Assumptions by Fuel Type

[32] NREL 2020 ATB: https://atb.nrel.gov/electricity/2020/data.php
[33] EIA costs were used and adjusted for 2020 dollars: https://www.eia.gov/electricity/generatorcosts/
[34] Costs from the DOE Energy Storage Technology and Cost Characterization Report of July 2019: https://www.energy.gov/sites/prod/files/2019/07/f65/Storage%20Cost%20and%20Performance%20Characterization%20Report_Final.pdf
[35] Costs from EIA Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

Production Tax Credits (PTC) and Investment Tax Credits (ITC)

Production Tax Credit (PTC) and Investment Tax Credit (ITC) effects on wind, utility-scale solar PV, and hybrid units are displayed below. Since the battery in the hybrid unit modeled is charged from solar resources 100% of the time, it may qualify for 100% of ITC benefits.[36,37]

Actual and Modeled Schedule of Wind and Solar Tax Credits

Consolidated Appropriations Act of 2016 PTC with 2020 Extensions	2016	2017	2018	2019	2020	2021	2022	2023 & onward
Utility Wind PTC	Full	80%	60%	40%	60%	0%	0%	0%
Utility Solar ITC	30%	30%	30%	30%	26%	22%	10%	10%
Model Representation	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023 & onward**
Utility Wind PTC	Full	Full	Full	Full	Full	Full	Full	0%
Utility Solar ITC	30%	30%	30%	30%	30%	26%	22%	10%
Hybrid ITC (Battery charged by solar 100% of the time)	30%	30%	30%	30%	30%	26%	22%	10%

Table 15: PTC and ITC Schedule

Accreditations of PTC and ITC benefits are seen for wind, solar, and hybrid units since extensions and changes were issued in the spring of 2020. The model representation differs due to the assumed construction time of each of these units, in order to ensure their safe harbor provisions. MISO used the values in the model representation section to build cost trajectories for these resources in EGEAS.

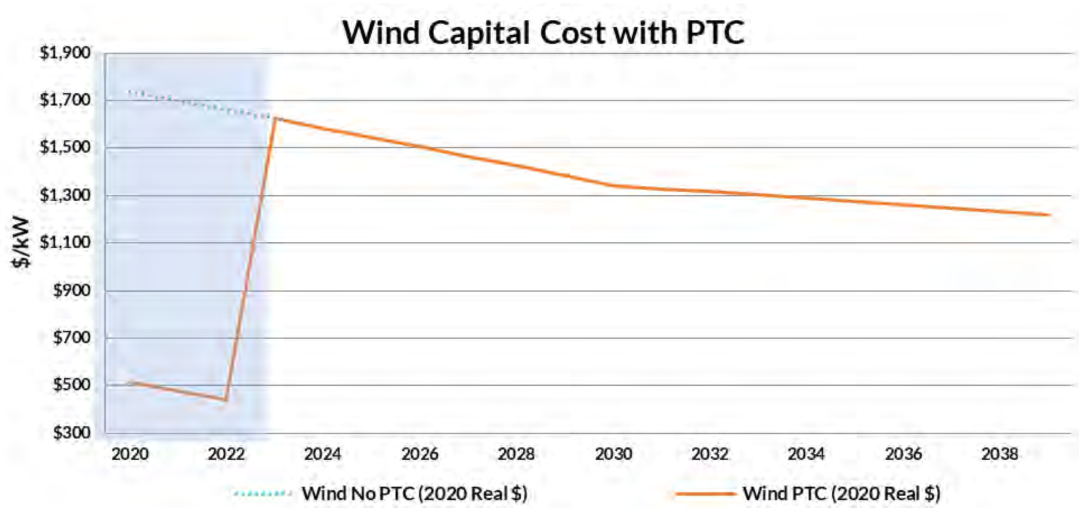


Figure 75: Wind with PTC

[36] Source for PTC and ITC for Wind & Solar PV: https://fas.org/sgp/crs/misc/R43453.pdf

[37] NREL - ITC accreditation for Hybrids: https://www.nrel.gov/docs/fy18osti/70384.pdf

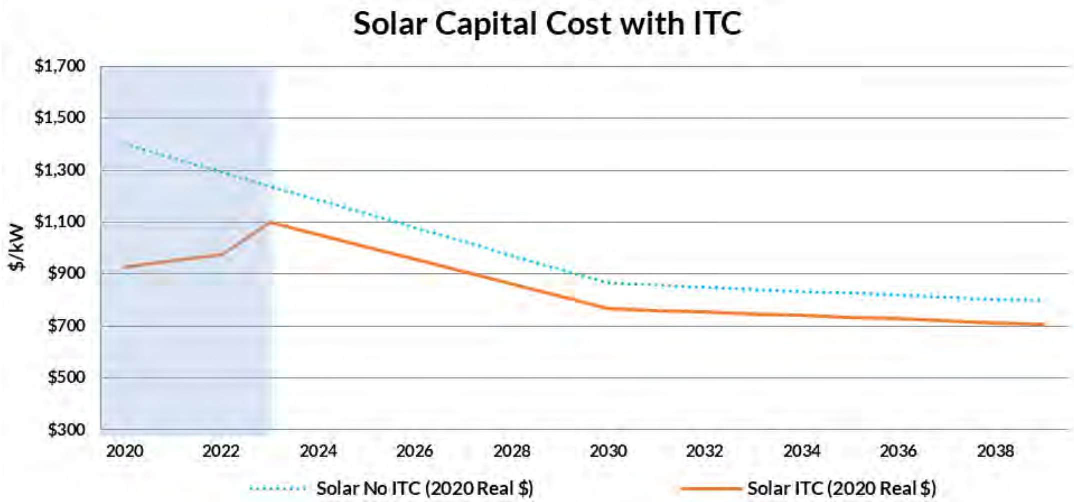


Figure 76: Solar PV with ITC

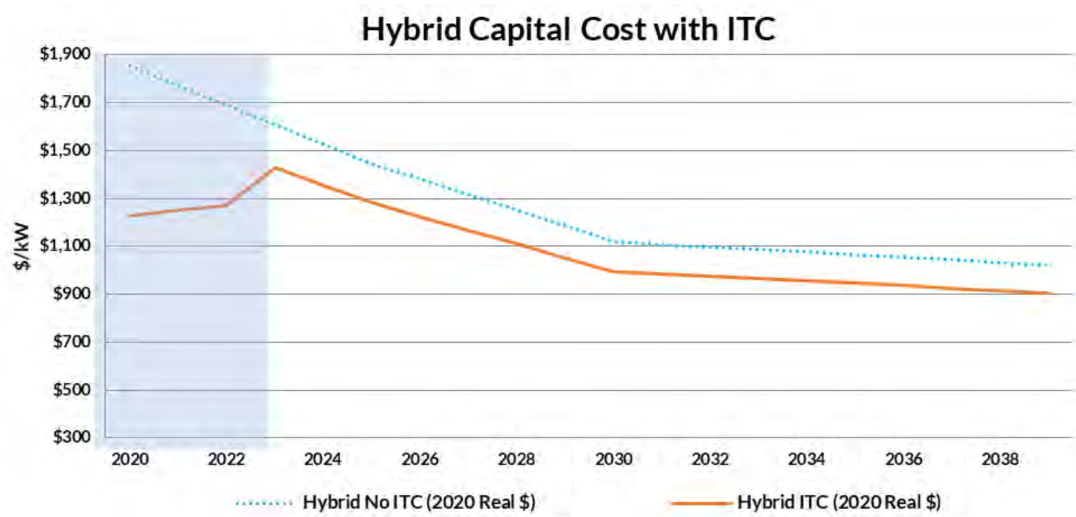


Figure 77: Hybrid with ITC

Electrification and Energy Growth Values

Although the energy growth in Futures 2 and 3 reaches 30% and 50% by 2040 respectively, not all growth is from electrification. Table 16 details the amounts of growth resulting from the reference forecast (SUFG) and electrification (AEG). By the end of the study period (12/31/2039), energy in Futures 1, 2, and 3 increases by 13%, 27%, and 46% respectively. On the following page, Table 17 presents the granular energy values for each technology that was electrified. These numbers represent the total energy growth from electrification in each Future scenario by LRZ.

Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	705,604	716,734	728,773
2039 Reference Growth	80,128	87,895	103,179
Electrification Growth	14,147	109,101	231,513
2039 Energy Forecast	799,879	913,730	1,063,465
Total Energy Increase, 2020-2039	**13%**	**27%**	**46%**
Energy Increase from Reference Forecast	11%	12%	14%
Energy Increase from Electrification	2%	15%	32%
Electrification Technologies	PEVs	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 16: Future-Specific Growth Assumptions (GWh)

Energy Growth by Technology Type from Electrification (GWh)								
F1	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	0	0	0	0	0	0	2,636	2,636
LRZ 2	0	0	0	0	0	0	2,016	2,016
LRZ 3	0	0	0	0	0	0	719	719
LRZ 4	0	0	0	0	0	0	1,237	1,237
LRZ 5	0	0	0	0	0	0	747	747
LRZ 6	0	0	0	0	0	0	1,264	1,264
LRZ 7	0	0	0	0	0	0	4,352	4,352
LRZ 8	0	0	0	0	0	0	238	238
LRZ 9	0	0	0	0	0	0	851	851
LRZ 10	0	0	0	0	0	0	87	87
Total	0	0	0	0	0	0	14,147	14,147
F2	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	3,108	2,556	1,266	4,711	307	0	6,542	18,489
LRZ 2	1,973	1,685	1,262	3,113	200	0	5,004	13,238
LRZ 3	2,076	945	451	2,425	137	0	1,784	7,818
LRZ 4	874	805	428	4,172	319	0	3,071	9,669
LRZ 5	2,307	654	332	1,686	129	0	1,855	6,962
LRZ 6	4,264	1,920	944	4,602	374	0	3,136	15,239
LRZ 7	3,265	2,574	2,085	5,710	316	0	10,802	24,751
LRZ 8	506	528	470	791	73	0	591	2,960
LRZ 9	1,330	1,540	1,114	2,276	387	0	2,112	8,760
LRZ 10	345	172	231	217	35	0	215	1,215
Total	20,048	13,378	8,584	29,702	2,277	0	35,112	109,101
F3	RES_HVAC	RES_DHW	RES_App	C&I_HVAC	C&I_DHW	C&I_Process	PEVs	Total
LRZ 1	6,005	5,289	1,723	6,411	594	2,573	17,078	39,673
LRZ 2	3,812	3,498	1,718	4,237	387	1,834	13,062	28,548
LRZ 3	4,012	1,967	614	3,300	264	1,662	4,657	16,476
LRZ 4	1,690	1,611	583	5,678	616	1,056	8,017	19,250
LRZ 5	4,457	1,334	452	2,295	249	1,303	4,842	14,931
LRZ 6	8,242	3,806	1,284	6,263	722	1,932	8,186	30,437
LRZ 7	6,308	5,301	2,838	7,771	611	2,878	28,198	53,905
LRZ 8	978	1,050	640	1,076	142	1,116	1,543	6,545
LRZ 9	2,570	3,043	1,516	3,098	749	2,340	5,513	18,829
LRZ 10	666	341	315	295	68	674	562	2,921
Total	38,741	27,240	11,683	40,423	4,400	17,368	91,658	231,513

Table 17: Quantification of Electrified Technologies (2020-2039)

Natural Gas Price Forecasting

MISO used the Gas Pipeline Competition Model (GPCM) base price forecast across the three Futures, instead of the Henry Hub price (HH) as in past cycles. GPCM outputs the gas price at a level of monthly granularity and produces unit-specific gas prices. The gas forecast per unit remained the same for all Futures modeled in EGEAS.

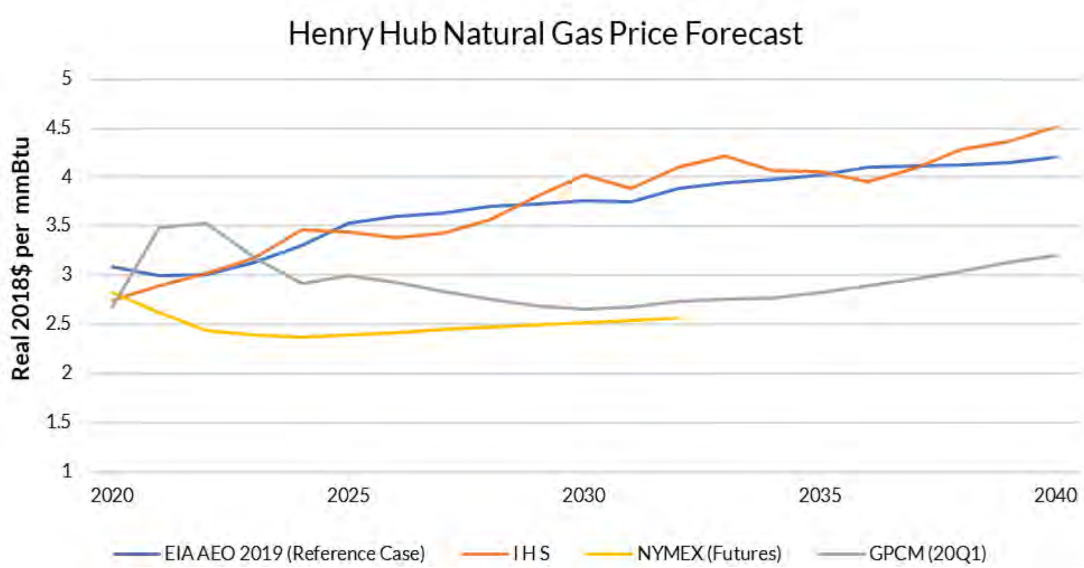


Figure 78: Henry Hub Natural Gas Price Forecast

General Assumptions

Study Period

The study period of the EGEAS resource expansion analysis is 20 years, beginning on 1/1/2020 and ending on 12/31/2039. An extension period of 40 years is added to the end of the simulation, with no new units forecasted during this time. This extension ensures that the generation selected in the last few years of the forecasting period (i.e., Years 15-20) is based on cost of generation spread out over the total tax/book life of the new resources (i.e., beyond Year 20) and does not bias to the cheapest generation in those final years.

Discount Rate

The discount rate of 7.22% is based upon the after-tax weighted average cost of capital of the Transmission Owners that make up the Transmission Provider Transmission System.

MISO Footprint Study Area

The study area for the updated MISO Futures continued to be the entire MISO footprint. However, the Local Clearing Requirement (LCR) for each zone was evaluated during the siting process to ensure each LRZ met their respective LCR as defined in the 2020/2021 Planning Resource Auction (PRA).

External Assumptions and Modeling

General Assumptions

External Footprint Study Area

From an external-to-MISO (External areas) perspective, MISO increased the EGEAS analysis granularity for External areas/pools represented in the MCPS[38] by increasing the number of representative models.

MISO-Created External Regional Model and Future Assumptions			
EGEAS Models	**Future 1**	**Future 2**	**Future 3**
PJM	Yes	Yes	Yes
SPP	No – Use SPP ITP Future 2 and Results[39]	Yes	Yes
TVA-Other *(includes Southeast, TVA, TVA-Other)*	Yes	Yes	Yes
Manitoba Hydro	No	No	No

Table 18: EGEAS External Model Representation

MISO realizes system flows depend on External areas' representations and the above improvements are intended to help align MISO Future assumptions to MISO's neighbors, as well as provide a Future (Future 1) that utilizes SPP Future assumptions. This Future will be used to help bookmark projected External system flows as decided by External Future assumptions.

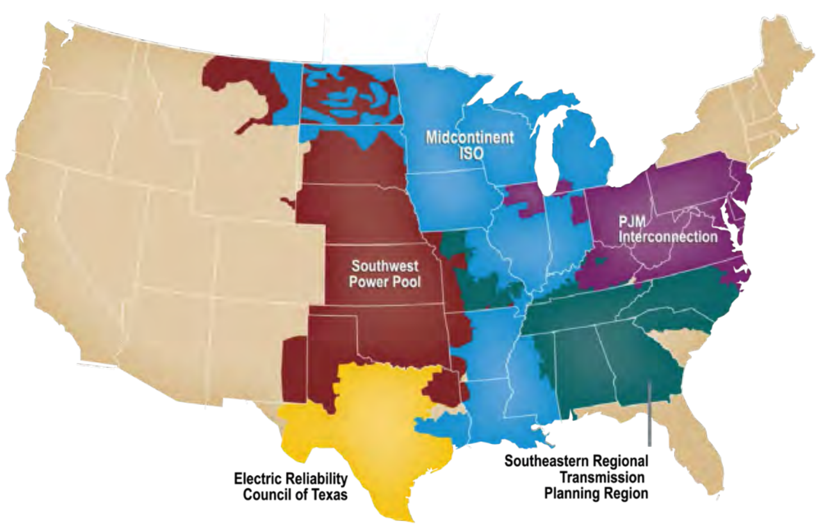


Figure 79: MISO Footprint & Neighboring Systems

[38] MISO Market Congestion Planning Studies (MCPS): https://www.misoenergy.org/stakeholder-engagement/committees/subregional-planning-meeting/market-congestion-planning-studies---south/

[39] https://www.spp.org/documents/61365/2021%20itp%20scope%20mopc%20and%20board%20approved.pdf

External Areas Forecasts Development

The 2019 Merged Load Forecast for Energy Planning forecast did not include External (non-MISO) companies' forecasts, so when available, External areas utilized respective regional model forecasts and when no regional forecast was available, the latest Multiregional Modeling Working Group (MMWG) model was used to create associated forecasts. External forecasts are defined in Table 19 and Future-specific adjustments will follow a similar process as shown in Table 18. Additionally, External areas utilized ABB's Velocity Suite 2018 load shapes.

Peak Load (MW) and Annual Energy (GWh)			
External Area (MCPS-Defined)	**Future 1**	**Future 2**	**Future 3**
PJM	PJM 2020 Long-Term Load Forecast (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
SPP	2021 ITP Future 2 Forecast (40% annual EV growth rate applied to energy only)	2021 ITP Future 1 Forecast + Future-Specific Adjustments	2021 ITP Future 1 Forecast + Future-Specific Adjustments
TVA-Other *(includes Southeast, TVA, TVA-Other)*	2019 MMWG Powerflow Model (Base)	Base + Future-Specific Adjustments	Base + Future-Specific Adjustments
Manitoba Hydro	MTEP20 CFC Forecast[40]	MTEP20 CFC Forecast	MTEP20 CFC Forecast

Table 19: External Area Demand & Energy Forecast Source

[40] 2020 MISO Transmission Expansion Planning (MTEP20): https://www.misoenergy.org/planning/planning/mtep20/

Electrification Assumptions

In addition to the electrification assumptions that were developed for the MISO footprint, a set of similar assumptions were made for External areas with the collaboration of AEG. The load growth in External areas came from electrification assumptions and reference load growth. Each area's growth is detailed in Table 20, electrification growth in Future 1 for SPP and PJM is reflected as zero due to this growth being incorporated in their reference load forecasts. Additionally, Figure 80 through Figure 87 detail the electrification of each technology within each External area.

PJM			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	939,546	946,602	949,301
2039 Reference Growth	111,347	111,347	111,347
Electrification Growth	0	172,086	353,105
2039 Energy Forecast	1,050,893	1,230,036	1,413,753
SPP			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	297,320	299,152	299,964
2039 Reference Growth	69,616	53,481	53,481
Electrification Growth	0	41,795	84,889
2039 Energy Forecast	366,936	394,428	438,334
TVA-Other (Southeast, TVA, TVA-Other)			
Variable/Future	**Future 1**	**Future 2**	**Future 3**
2020 Energy Forecast	698,962	702,206	703,821
2039 Reference Growth	78,303	75,059	73,444
Electrification Growth	7,553	76,817	163,373
2039 Energy Forecast	784,817	854,082	940,638
Electrification Technologies	PEVs (Included in reference forecast for PJM & SPP)	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW	PEVs RES-HVAC RES-DHW RES-Appliances C&I-HVAC C&I-DHW C&I-Process

Table 20: External Area Forecast Growth (GWh)

PJM Electrification

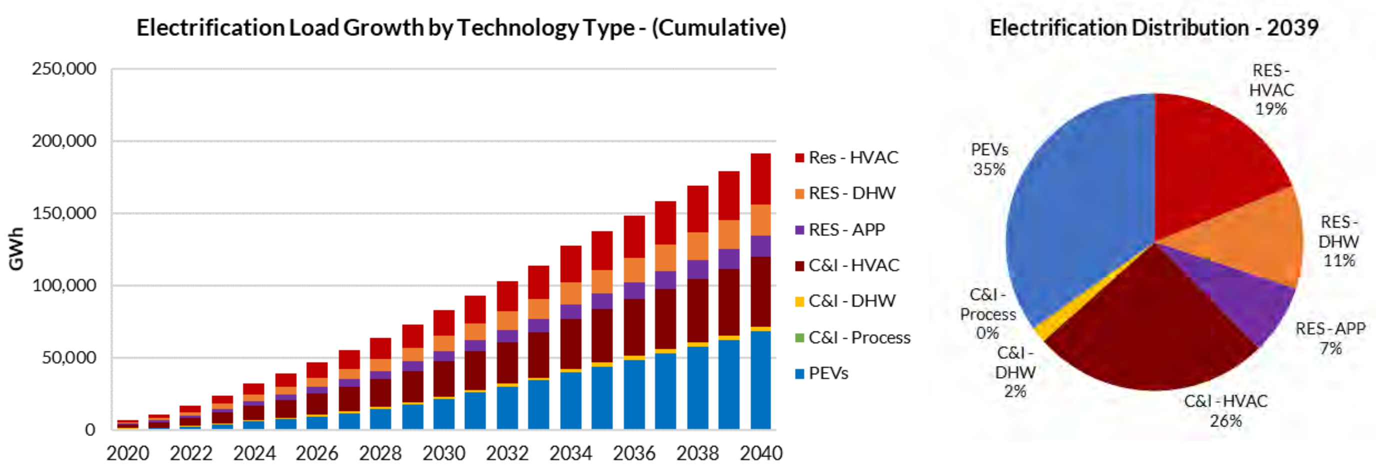


Figure 80: PJM Future 2 Electrification by End-Use

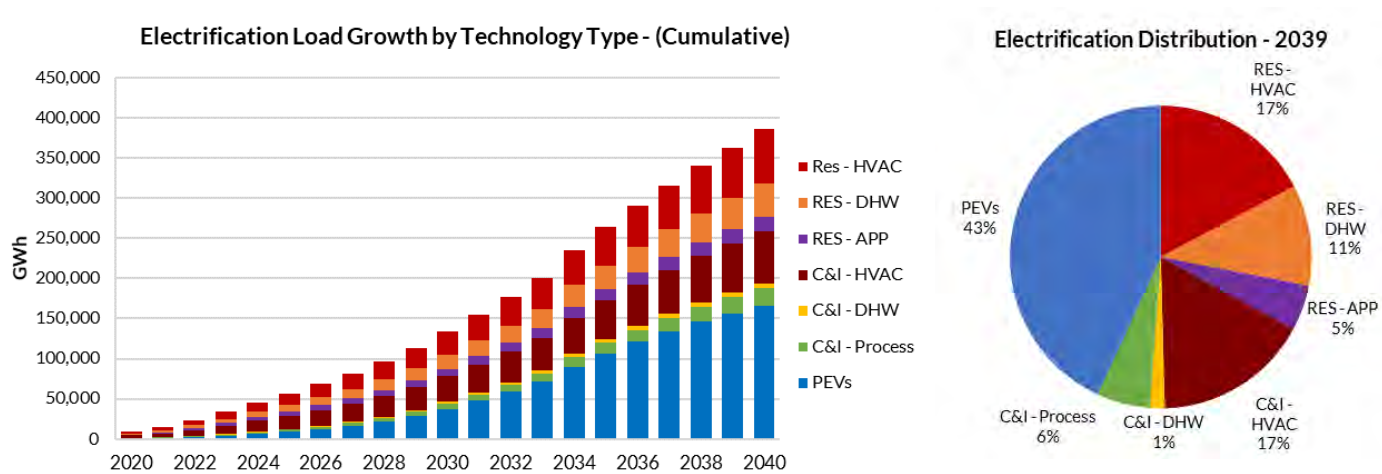


Figure 81: PJM Future 3 Electrification by End-Use

SPP Electrification

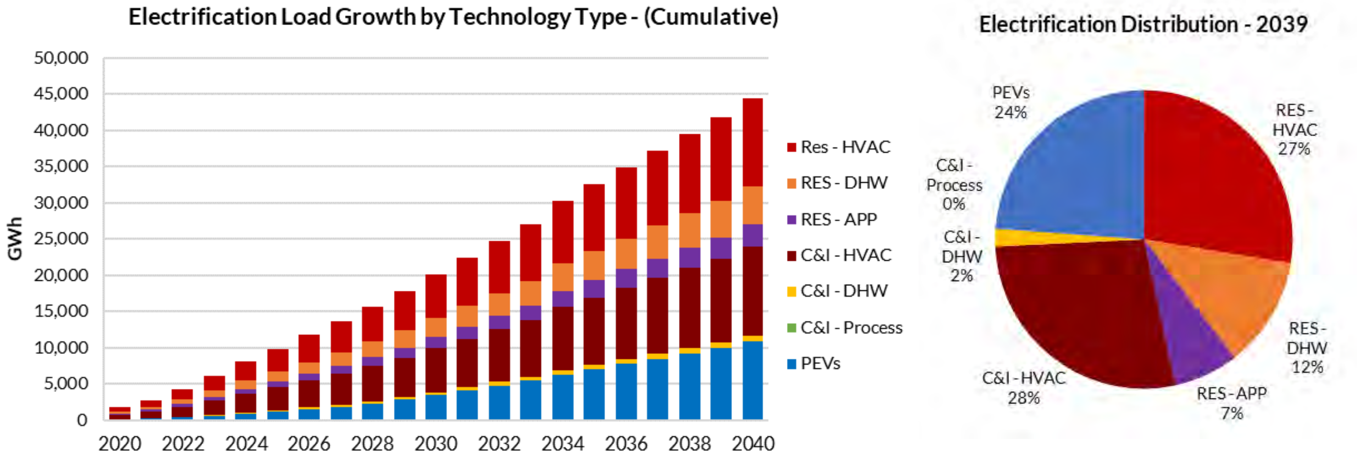


Figure 82: SPP Future 2 Electrification Broken Down by End-Use

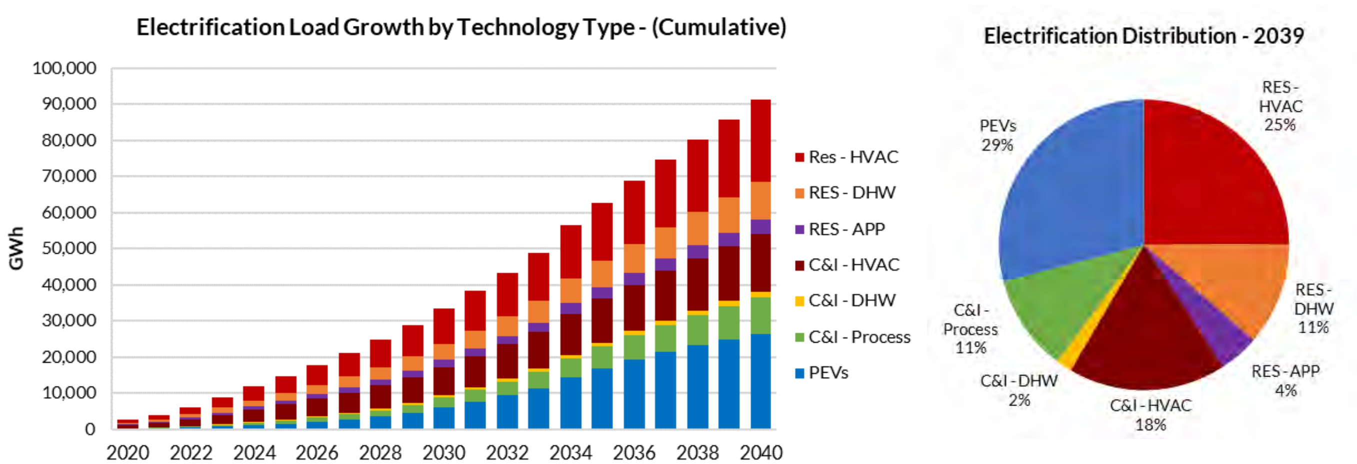


Figure 83: SPP Future 3 Electrification Broken Down by End-Use

TVA-Other Electrification

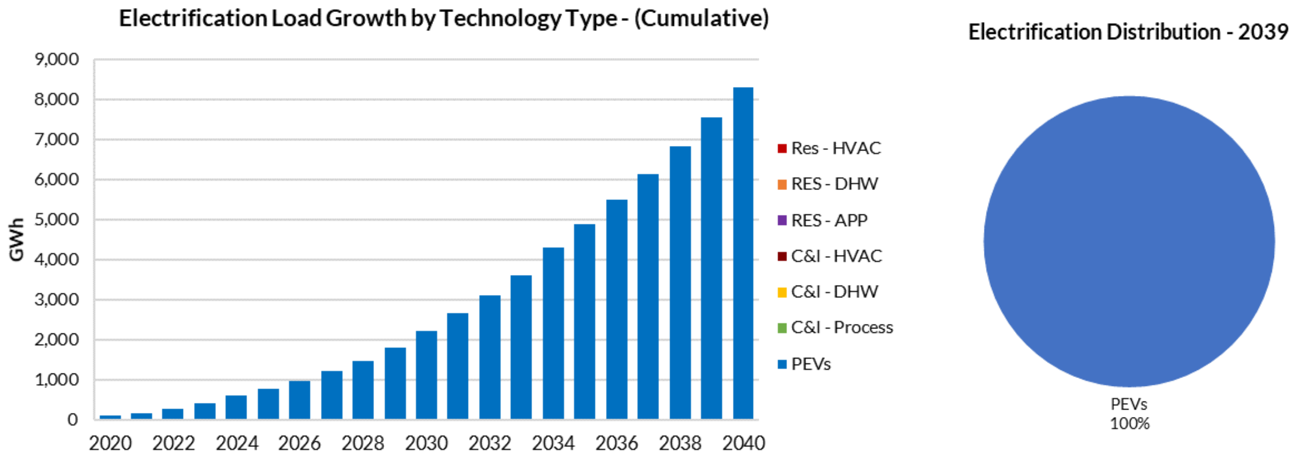


Figure 84: TVA-Other Future 1 Electrification Broken Down by End-Use

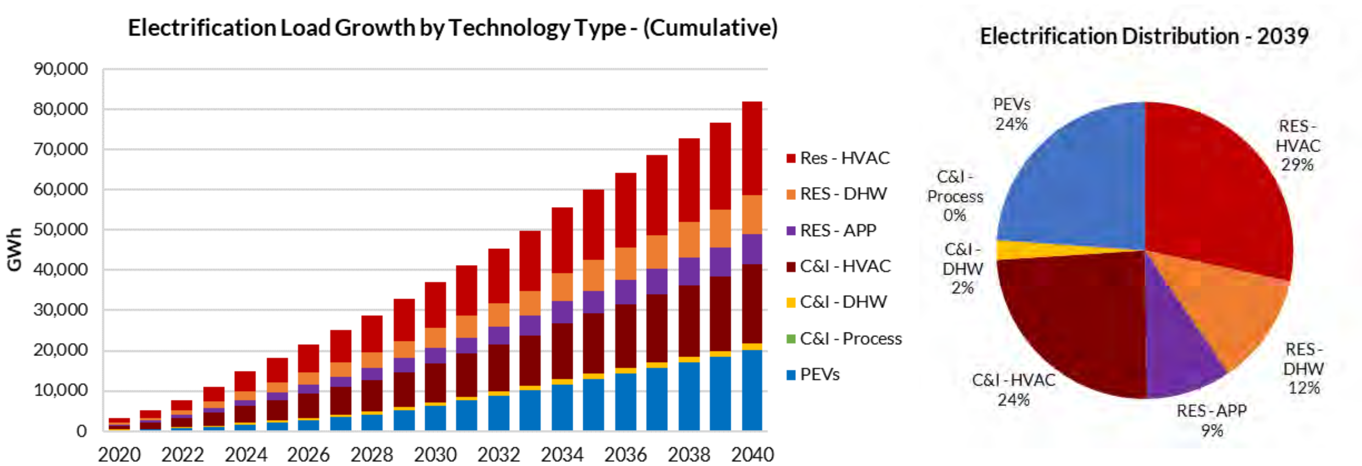


Figure 85: TVA-Other Future 2 Electrification Broken Down by End-Use

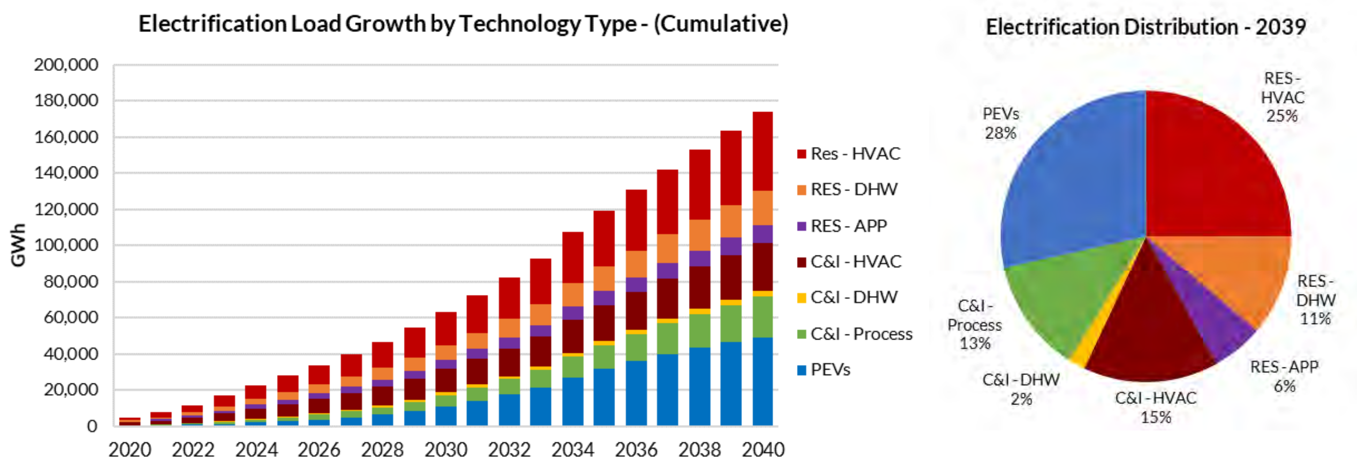
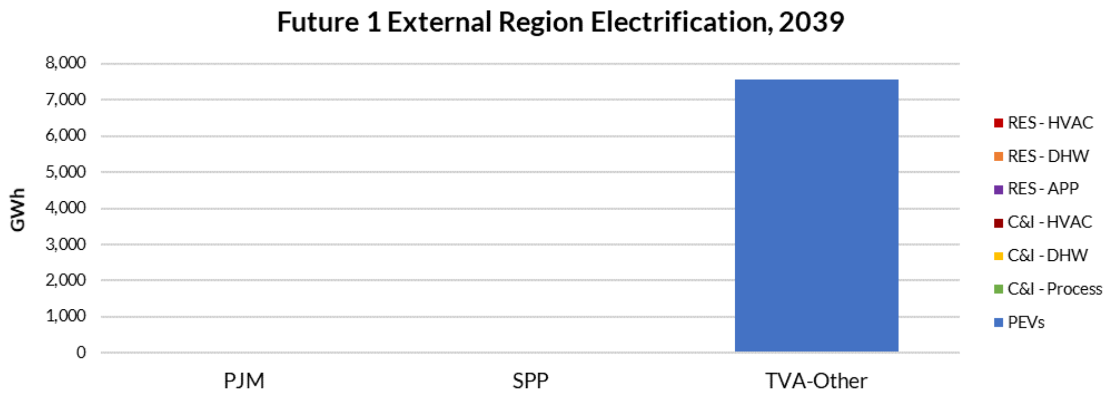
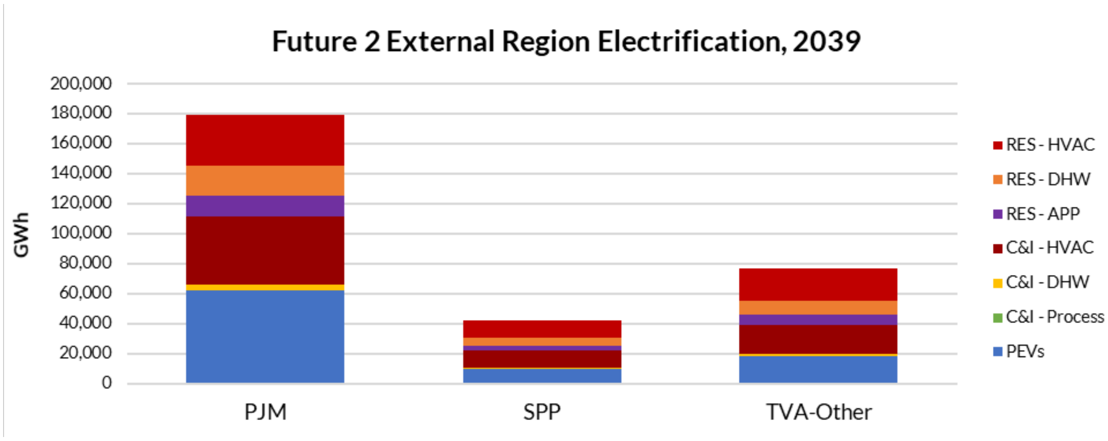


Figure 86: TVA-Other Future 3 Electrification Broken Down by End-Use

External Region Electrification Summary





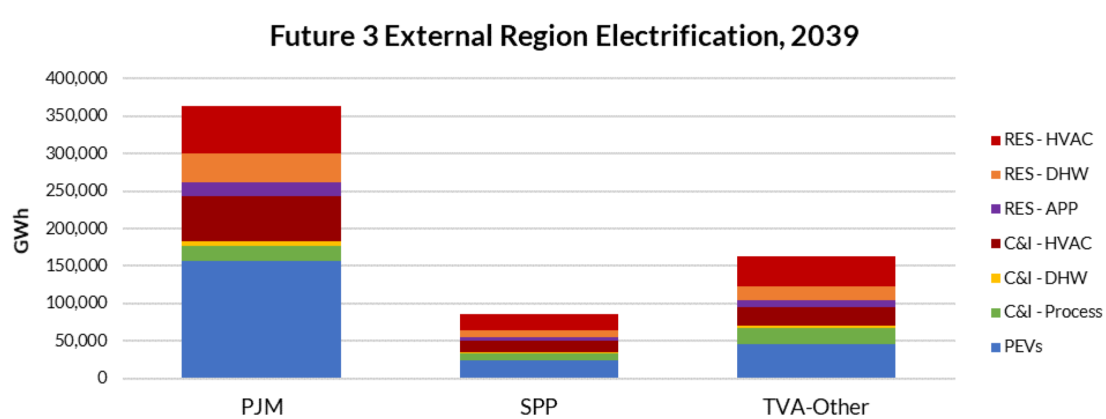


Figure 87: External Region Future Scenario Electrification[41]

[41] The only electrification in Future 1 happens in the external region TVA-Other due to SPP and PJM's Future 1 forecasts already including EVs.

External Expansion Results

While comparing the expansion results of the External regions across each Future scenario, there are several key findings of note:

- All scenarios have very different expansions; this is due to large contrasts among the regions with respect to geography, resource retirements, and current resource mixes.
- Wind, solar, and hybrid resource expansion is largely driven by decarbonization and each underlying load shape. In Future 3 there is significantly more wind than the other two cases; this is primarily due to the increase in load and 80% carbon reduction.
- Battery installation is driven by increased load and decarbonization.
- Age-based retirement assumptions for nuclear, wind, solar, and "other" resources remain the same across scenarios, with the exception of SPP Future 1. In this future, MISO incorporated retirement assumptions in SPP's Future 2. Additionally, all retired wind is repowered and reflected in the resource addition totals.
- In Future 3, the CC+CCS resource proxy units are needed in the later years of the study to serve base load with low CO_2 emissions, while maintaining a high capacity factor.
- Distributed solar (DGPV) and energy efficiency (EE) programs selected by EGEAS for TVA-Other (TVAO) remained the same across all scenarios. SPP Future 2 selected an additional EE program compared with Futures 1 and 3. Lastly, PJM's first two Futures both selected two DGPV and EE programs, while Future 3 selected one of each. A list of EGEAS-offered and selected programs for External regions is found below in Table 22.

Over the course of the following pages (Table 21 through Table 24) the detailed expansion results of each External Future scenario are displayed. Following the figures in each section are resource-specific additions and retirement (R&A) tables, each table details R&A capacities applicable for each region and milestone year.

Future Resource Additions (MW)											
Area	**Future**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**EE**	**Total**
PJM	Future 1	14,400	21,600	0	6,641	3,600	10,800	0	2,954	35,919	95,915
	Future 2	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	38,110	172,106
	Future 3	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	17,291	357,427
SPP	Future 1	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	1,197	58,797
	Future 2	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	3,253	73,009
	Future 3	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	1,332	98,588
TVA-Other	Future 1	16,800	1,200	0	14,405	0	26,400	0	118	346	59,269
	Future 2	16,800	7,200	0	60,005	13,200	25,200	300	118	370	123,193
	Future 3	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	382	274,905

Future Resource Retirements (MW)									
Area	**Future**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Total**
PJM	Future 1	53,068	9,312	0	7,002	6,641	251	0	76,275
	Future 2	54,680	15,348	0	7,136	6,641	251	0	84,055
	Future 3	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP	Future 1	18,361	5,631	0	1,260	0	0	0	25,252
	Future 2	19,842	13,205	0	1,361	9,856	50	0	44,314
	Future 3	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other	Future 1	42,295	7,350	0	1,910	1,205	165	276	53,201
	Future 2	43,840	9,117	0	1,910	1,205	165	276	56,513
	Future 3	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 21: External Resource Additions and Retirements Summary

External Areas Expansion 2020 - 2039

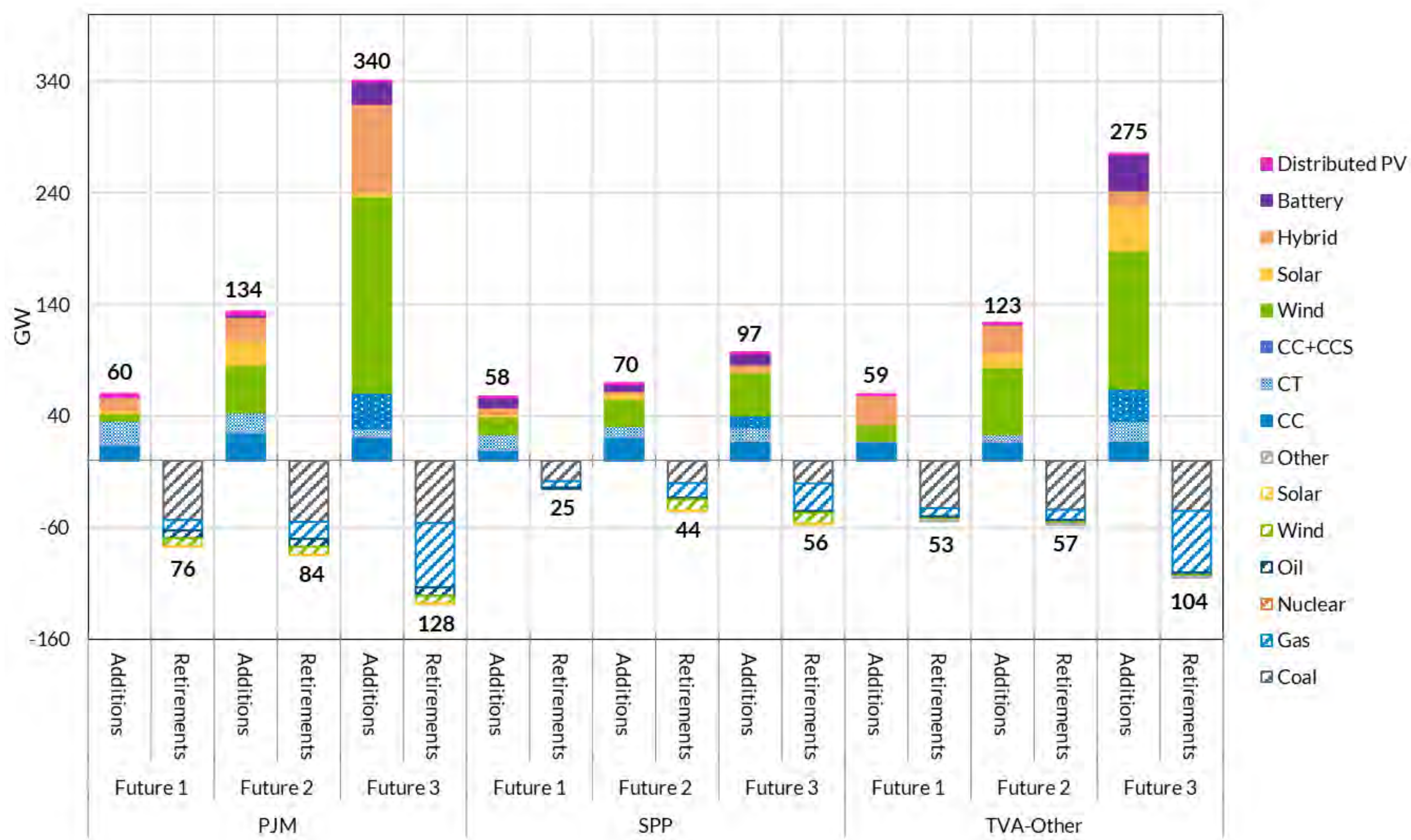


Figure 88: External Region Expansion Summary

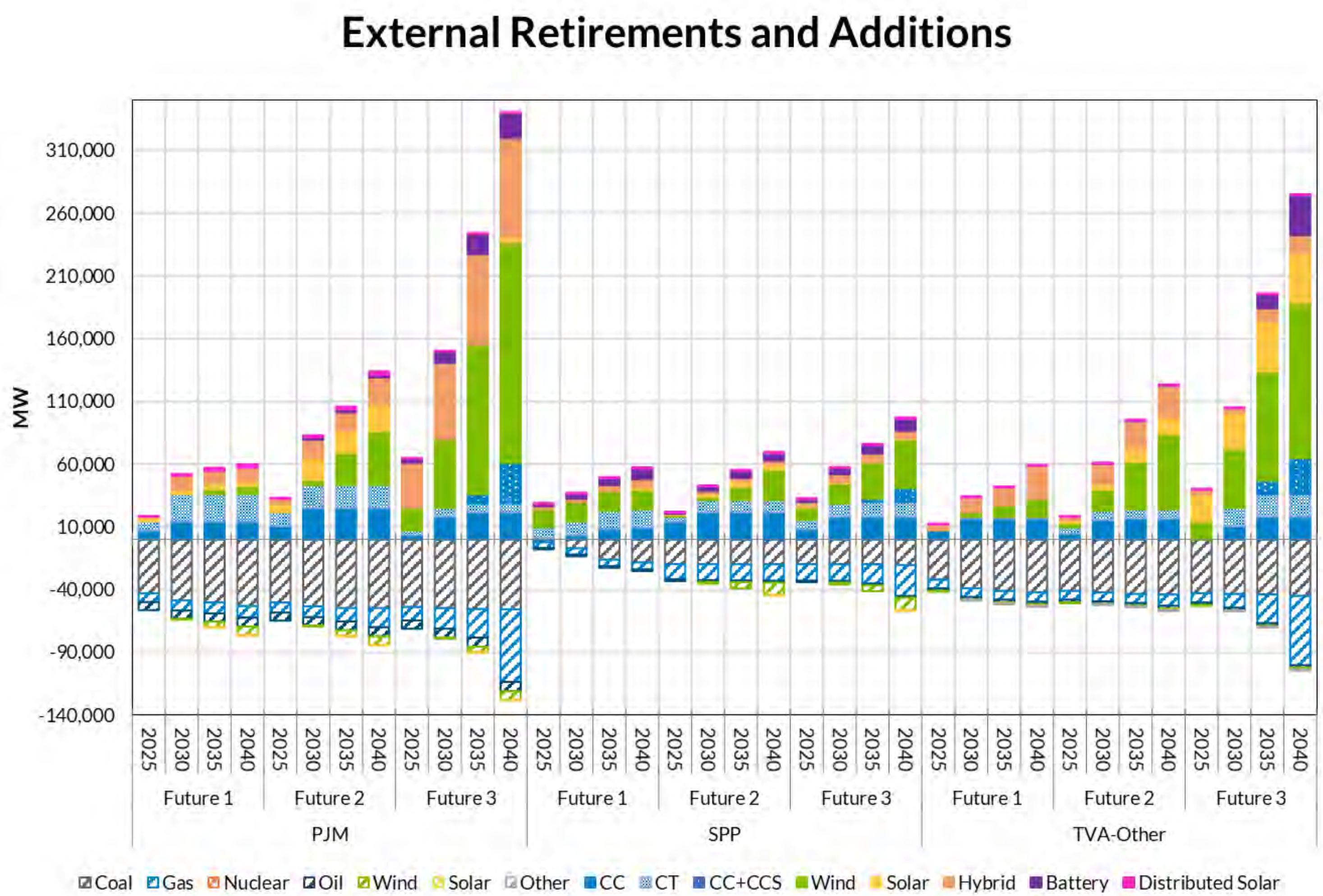


Figure 89: External Resource Additions and Retirements per Milestone Year (Cumulative)

PJM Expansion

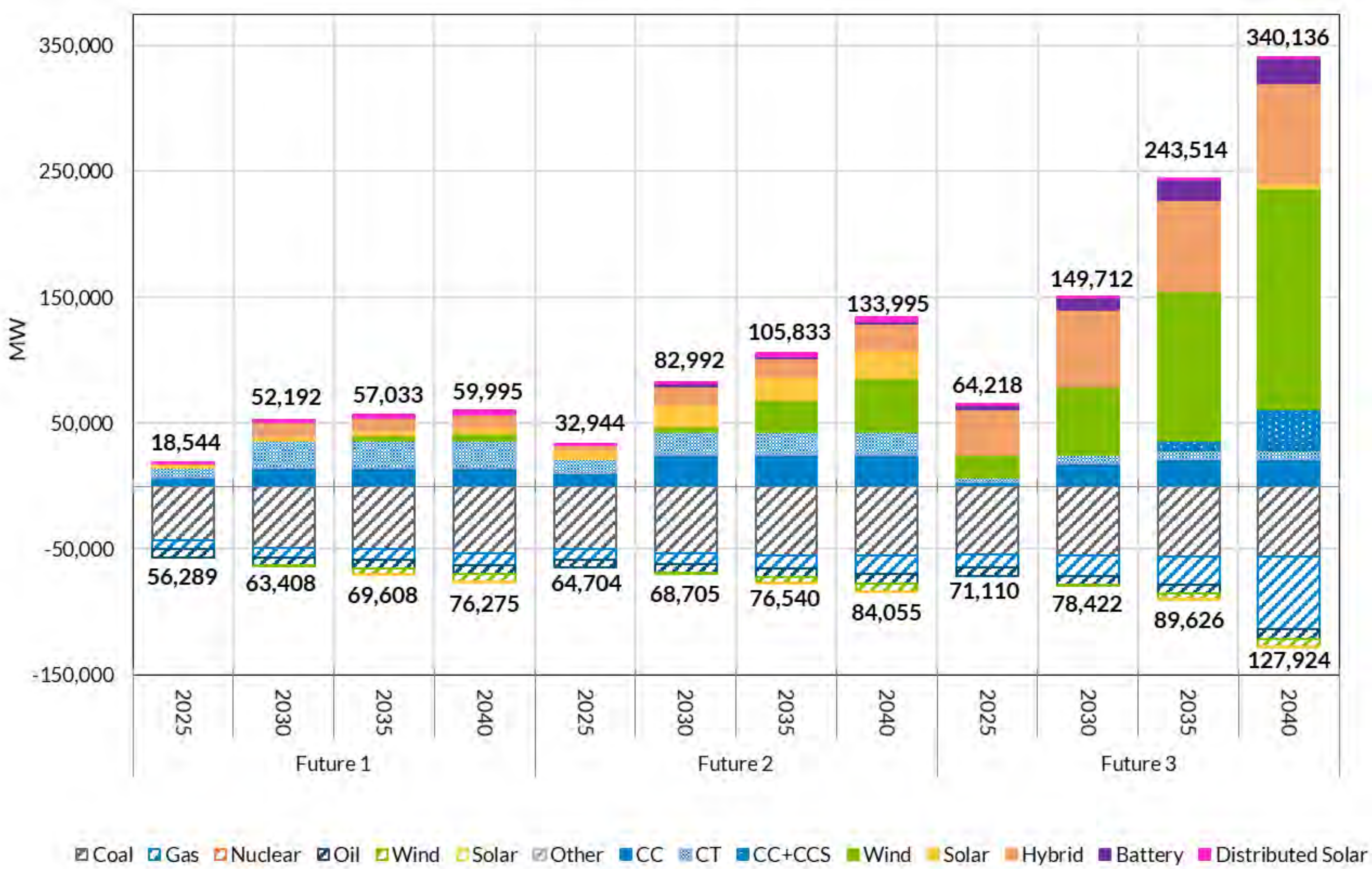


Figure 90: PJM Resource Additions and Retirements per Milestone Year (Cumulative)

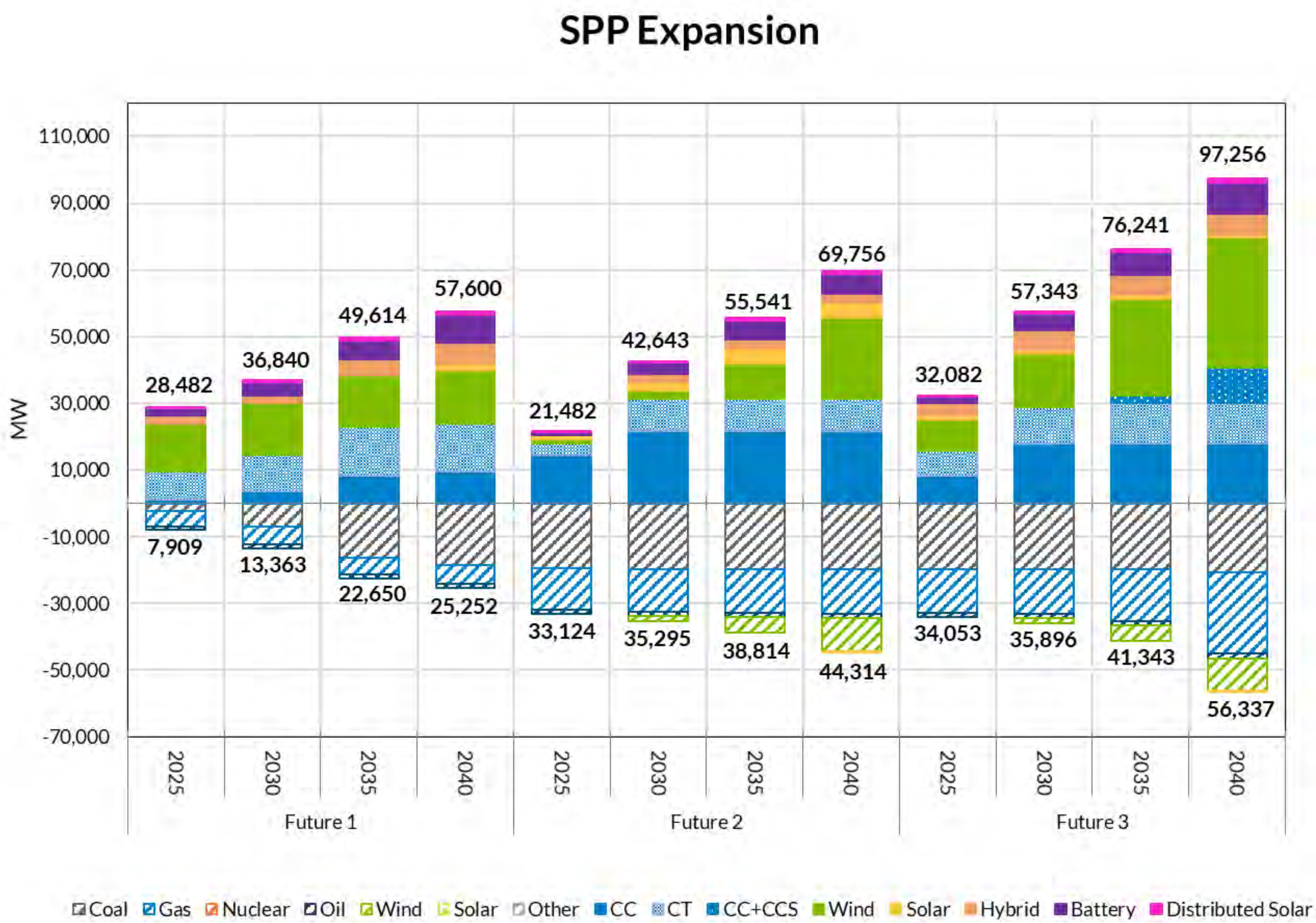


Figure 91: SPP Resource Additions and Retirements per Milestone Year (Cumulative)

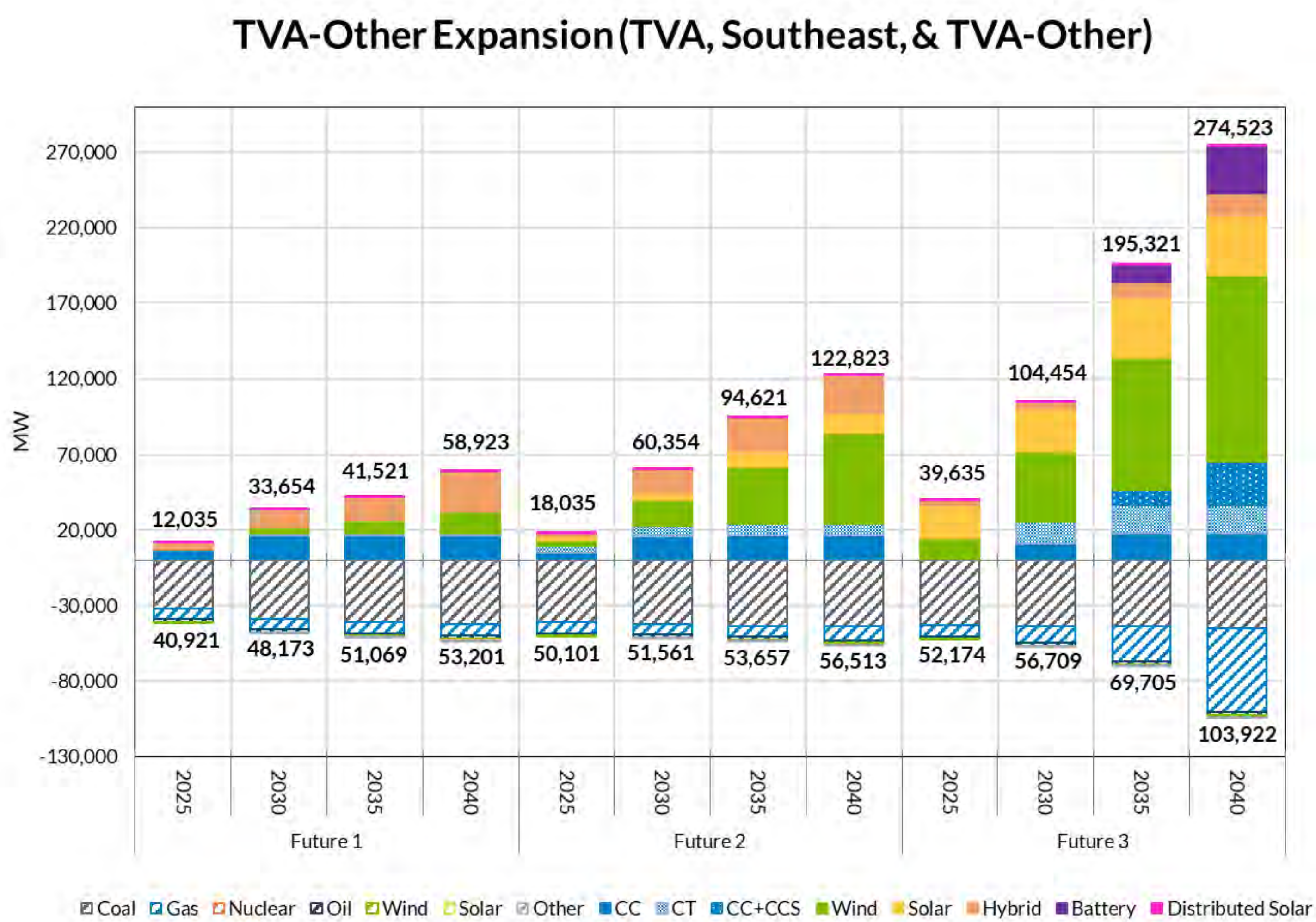


Figure 92: TVA-Other Resource Additions and Retirements per Milestone Year (Cumulative)

External DER Programs: Respective Offerings and Selections

DER Type	EGEAS Program Block	DER Program(s) Included	PJM	SPP	TVAO
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable	*Offered*	*Offered*	*Offered*
DR	C&I Price Response	C&I Price Response	*Offered*	*Offered*	*Offered*
DR	Res. Direct Load Control	Res. Direct Load Control	*Offered*	*Offered*	-
DR	Res. Price Response	Res. Price Response	*Offered*	*Offered*	-
EE	C&I EE	Custom Incentive, Lighting, New Construction, Prescriptive Rebate, Retro commissioning	F1, F2, F3	F2	F1, F2, F3
EE	Res. EE	Appliance Incentives, Appliance Recycling, Behavioral Programs, Lighting, Low Income, Multifamily, New Construction, School Kits, Whole Home Audit	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Customer Solar PV	C&I Customer Solar PV	F1, F2	F1, F2, F3	F1, F2, F3
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	C&I Utility Incentive Solar PV	C&I Utility Incentive Solar PV	F1, F2, F3	F1, F2, F3	-
DG	Res. Customer Solar PV	Res. Customer Solar PV	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Util Incentive Batt Storage	*Offered*	*Offered*	*Offered*
DG	Res. Utility Incentive Solar PV	Res. Utility Incentive Solar PV	*Offered*	*Offered*	-

Table 22: External DER Program Mapping, with Respective Offerings and Selection by Future in EGEAS

External Area Resource Additions per Future (MW) - *Cumulative*										
Future/Area	**Milestone**	**CC**	**CT**	**CC+CCS**	**Wind**	**Solar**	**Hybrid**	**Battery**	**Distributed Solar**	**Total**
PJM Future 1	**2025**	7,200	7,200	0	0	3,600	0	0	544	18,544
	2030	14,400	21,600	0	245	3,600	10,800	0	1,547	52,192
	2035	14,400	21,600	0	4,129	3,600	10,800	0	2,504	57,033
	2040	14,400	21,600	0	6,641	3,600	10,800	0	2,954	59,995
PJM Future 2	**2025**	10,800	10,800	0	0	7,200	3,600	0	544	32,944
	2030	25,200	18,000	0	3,845	18,000	14,400	2,000	1,547	82,992
	2035	25,200	18,000	0	25,729	18,000	14,400	2,000	2,504	105,833
	2040	25,200	18,000	0	42,641	21,600	21,600	2,000	2,954	133,995
PJM Future 3	**2025**	3,600	3,600	0	18,000	0	36,000	3,000	18	64,218
	2030	18,000	7,200	0	54,245	0	61,200	9,000	68	149,712
	2035	21,600	7,200	7,200	119,329	0	72,000	16,000	185	243,514
	2040	21,600	7,200	32,400	175,841	3,600	79,200	20,000	295	340,136
SPP Future 1	**2025**	1,200	8,400	0	14,400	0	2,400	2,000	82	28,482
	2030	3,600	10,800	0	15,600	0	2,400	4,000	440	36,840
	2035	8,400	14,400	0	15,600	0	4,800	5,500	914	49,614
	2040	9,600	14,400	0	15,600	2,400	6,000	8,500	1,100	57,600
SPP Future 2	**2025**	14,400	3,600	0	1,200	1,200	0	1,000	82	21,482
	2030	21,600	9,600	0	2,703	2,400	2,400	3,500	440	42,643
	2035	21,600	9,600	0	10,727	4,800	2,400	5,500	914	55,541
	2040	21,600	9,600	0	24,256	4,800	2,400	6,000	1,100	69,756
SPP Future 3	**2025**	8,400	7,200	0	9,600	1,200	3,600	2,000	82	32,082
	2030	18,000	10,800	0	15,903	1,200	6,000	5,000	440	57,343
	2035	18,000	12,000	2,400	28,727	1,200	6,000	7,000	914	76,241
	2040	18,000	12,000	10,800	38,656	1,200	6,000	9,500	1,100	97,256
TVA-Other Future 1	**2025**	7,200	0	0	29	0	4,800	0	7	12,035
	2030	16,800	1,200	0	3,629	0	12,000	0	25	33,654
	2035	16,800	1,200	0	9,055	0	14,400	0	66	41,521
	2040	16,800	1,200	0	14,405	0	26,400	0	118	58,923
TVA-Other Future 2	**2025**	4,800	4,800	0	3,629	2,400	2,400	0	7	18,035
	2030	15,600	7,200	0	16,829	4,800	15,600	300	25	60,354
	2035	16,800	7,200	0	37,855	10,800	21,600	300	66	94,621
	2040	16,800	7,200	0	60,005	13,200	25,200	300	118	122,823
TVA-Other Future 3	**2025**	0	0	0	14,429	21,600	3,600	0	7	39,635
	2030	10,800	14,400	0	46,829	28,800	3,600	0	25	104,454
	2035	18,000	18,000	10,800	87,055	39,600	10,800	11,000	66	195,321
	2040	18,000	18,000	28,800	123,605	39,600	14,400	32,000	118	274,523

Table 23: External Resource Additions by Milestone Year

External Area Resource Retirements per Future (MW) - *Cumulative*									
Future/Area	**Milestone**	**Coal**	**Gas**	**Nuclear**	**Oil**	**Wind**	**Solar**	**Other**	**Total**
PJM Future 1	**2025**	43,061	6,829	0	6,400	0	0	0	56,289
	2030	48,723	7,981	0	6,460	245	0	0	63,408
	2035	50,263	8,569	0	6,604	4,129	43	0	69,608
	2040	53,068	9,312	0	7,002	6,641	251	0	76,275
PJM Future 2	**2025**	50,263	7,981	0	6,460	0	0	0	64,704
	2030	53,287	8,569	0	6,604	245	0	0	68,705
	2035	54,680	10,687	0	7,002	4,129	43	0	76,540
	2040	54,680	15,348	0	7,136	6,641	251	0	84,055
PJM Future 3	**2025**	53,819	10,687	0	6,604	0	0	0	71,110
	2030	54,680	16,495	0	7,002	245	0	0	78,422
	2035	55,469	22,703	0	7,283	4,129	43	0	89,626
	2040	55,737	57,793	0	7,502	6,641	251	0	127,924
SPP Future 1	**2025**	2,318	4,588	0	1,003	0	0	0	7,909
	2030	7,089	5,062	0	1,213	0	0	0	13,363
	2035	16,238	5,200	0	1,213	0	0	0	22,650
	2040	18,361	5,631	0	1,260	0	0	0	25,252
SPP Future 2	**2025**	19,563	12,329	0	1,232	0	0	0	33,124
	2030	19,842	12,649	0	1,301	1,503	0	0	35,295
	2035	19,842	12,938	0	1,307	4,727	0	0	38,814
	2040	19,842	13,205	0	1,361	9,856	50	0	44,314
SPP Future 3	**2025**	19,842	12,938	0	1,273	0	0	0	34,053
	2030	19,842	13,245	0	1,307	1,503	0	0	35,896
	2035	19,842	15,413	0	1,361	4,727	0	0	41,343
	2040	20,524	24,516	0	1,392	9,856	50	0	56,337
TVA-Other Future 1	**2025**	31,981	7,001	0	1,910	29	0	0	40,921
	2030	38,907	7,051	0	1,910	29	0	276	48,173
	2035	41,111	7,051	0	1,910	655	66	276	51,069
	2040	42,295	7,350	0	1,910	1,205	165	276	53,201
TVA-Other Future 2	**2025**	41,111	7,051	0	1,910	29	0	0	50,101
	2030	42,295	7,051	0	1,910	29	0	276	51,561
	2035	43,400	7,350	0	1,910	655	66	276	53,657
	2040	43,840	9,117	0	1,910	1,205	165	276	56,513
TVA-Other Future 3	**2025**	42,885	7,350	0	1,910	29	0	0	52,174
	2030	43,400	11,094	0	1,910	29	0	276	56,709
	2035	43,840	22,878	0	1,990	655	66	276	69,705
	2040	45,040	55,246	0	1,990	1,205	165	276	103,922

Table 24: External Resource Retirements by Milestone Year

Presentation Materials

Futures Workshops & MISO Stakeholder Presentations:

August 15, 2019: MTEP Futures Workshop – Purpose of MISO Futures

September 26, 2019: MTEP Futures Workshop – Drafting of Futures Assumptions

October 17, 2019: MTEP Futures Workshop – Walkthrough of Initial Strawman

December 5, 2019: MTEP Futures Workshop – Detailing Various Assumptions

February 13, 2020: MTEP Futures Workshop – Updated Assumptions

April 27, 2020: MTEP Futures Workshop – Final Assumptions

July 13, 2020: MTEP Futures Workshop – Siting Review

August 12, 2020: PAC Presentation – Draft Expansion and Siting Results

November 11, 2020: PAC Presentation – Final Expansion and Siting Results

September 22, 2021: PAC Presentation – Correction to Futures Resource Expansion

October 13, 2021: PAC Presentation – Revised Future 2 and 3 Expansion Results for MISO

November 10, 2021: PAC Presentation – Revised Futures Siting and External Expansion Results

Full Futures Evolution Material Available at: MISOEnergy.org

misoenergy.org

Appendix F

Energy Conservation and Efficiency Information

TABLE OF CONTENTS

Appendix F-1

Energy Conservation and Efficiency Information

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. The Applicants requested an exemption from this content requirement, and proposed to provide substitute information related either to their conservation programs or to the conservation programs that are available to their members serving load in Minnesota. The Applicants also proposed to provide information regarding how conservation and energy efficiency was considered by MISO in its evaluation of the Project.[1] In response, the Department agreed that the proposed information will better inform the record as to the need for the proposed Project and recommended that the Commission grant the requested exemption with the provision of the proposed alternative data.[2] The Commission approved the Applicants' requested exemption with provision of the alternative data.[3] The required information is provided below.

For decades, Minnesota has been a national leader in energy efficiency. The state's utility-sponsored energy efficiency programs are among the longest-standing in the country, and Minnesota is the only Midwestern state that is consistently ranked in the top ten on the American Council for an Energy Efficient Economy's (ACEEE) State Energy Efficiency Scorecard. Minnesota utilities' energy savings achievements through demand-side management (DSM) have saved billions of dollars for customers and avoided millions of tons of greenhouse gas and other pollutants while creating and supporting jobs in the state.[4] The Applicants provide below information related to their conservation programs, as well as a discussion of how conservation and energy efficiency was

[1] *See* Docket No. E002, E017, ET2, E015, ET10/CN-22-538, *In the Matter of the Application for a Certificate of Need for the Big Stone South – Alexandria – Big Oaks Transmission Project*, Request for Exemption from Certain Certificate of Need Application Content Requirements (Mar. 3, 2023) at 8.

[2] *See* Docket No E002, E017, ET2, E015, ET10/CN-22-538, Comments of the Minnesota Department of Commerce, Division of Energy Resources (Mar. 30, 2023) at 5.

[3] *See* Docket No. E002, E017, ET2, E015, ET10/CN-22-538, Order Approving Notice Plan Petition and Request for Exemption from Certain Certificate of Need Application Content Requirements (Apr. 19, 2023).

[4] The Aggregate Economic Impact of the Conservation Improvement Program 2008-2013, Minnesota Department of Commerce, Division of Energy Resources, Cadmus (Oct. 2015), https://mn.gov/commerce-stat/pdfs/card-report-aggregate-eco-impact-cip-2008-2013.pdf.

considered by the Midcontinent Independent System Operator, Inc. (MISO) in its evaluation and approval of the Project.

A. Xcel Energy's Energy Conservation and Efficiency Programs

Xcel Energy has maintained a consistent and high level of DSM achievement. Between 1994 and 2022, Xcel Energy invested nearly $2.2 billion (nominal) resulting in 11,813 gigawatt hours (GWh) of electric energy savings, 3,733 megawatts (MW) of electric demand savings and an estimated 19.92 million dekatherms (Dth) of natural gas savings.[5] In its 2024-2026 Energy Conservation and Optimization Triennial Plan, dated June 29, 2023 (Xcel Energy's Triennial Plan), Xcel Energy continues to strive to provide customers with a wide variety of options for saving energy. Xcel Energy's Triennial Plan proposed ambitious goals of saving 1,734 GWh, 674 MW, and 3,918,970 Dth over the three-year period at a cost of approximately $530 million.[6] The proposed electric savings goals also aligned with Xcel Energy's DSM commitments in its most recent Integrated Resource Plan (Xcel Energy's IRP).

In its 2022 Conservation Improvement Program (CIP) Status Report, Xcel Energy stated that for more than a decade, its electric DSM portfolio has surpassed the statutory energy savings of 1.5 percent, and in 2022, achieved nearly 648 GWh of electric savings, or 2.33 percent of sales.[7] These savings exceeded the state's new energy savings target of 1.75 percent.[8] In 2022, Xcel Energy spent a total of $124 million to achieve its savings results, including $104 million on electric programs and approximately $20 million on natural gas programs.[9]

[5] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan (June 29, 2023) at 2.
[6] *See* Docket No. E,G002/CIP-23-92, Xcel Energy 2024-2026 Energy Conservation and Optimization Plan (June 29, 2023) at 1.
[7] *See* Docket No. E,G002/CIP-20-473, 2022 CIP Status Report (Mar. 31, 2023) at 4.
[8] The Energy Conservation and Optimization Act of 2021 updated the electrical savings goal to 1.75 percent and the natural gas savings goal to 1.0 percent of annual retail energy sales; utilities filed their first CIP Triennial Plans under this requirement in 2023.
[9] *See* Docket No. E,G002/CIP-20-473, 2022 CIP Status Report (Mar. 31, 2023) at 5.

Likewise, Xcel Energy's initial IRP filing included energy efficiency (EE) and demand response (DR) investments, and Xcel Energy's Supplemental Plan[10] and Alternate Plan[11] continued to reflect those investments. Xcel Energy proposed to seek to achieve EE savings levels ranging from 2 to 2.5 percent annually, achieving average savings of over 780 GWh of energy in each of 2020-2034, and more than 800 MW of additional demand savings by 2034[12] when compared to the 1.5 percent level approved in the Company's prior IRP.[13] In addition, Xcel Energy proposed an incremental 400 MW of DR by 2023.[14]

B. Great River Energy's Energy Conservation and Efficiency Programs

Great River Energy's most recent IRP was filed with the Commission on March 31, 2023.[15] A comment period on that IRP ends on October 2, 2023.[16] Great River Energy's IRP covers the planning period for 2023 through 2037 and provides a comprehensive view of Great River Energy's portfolio plan (the "Plan") for the next 15 years. The Plan builds on changes in Great River Energy's resource portfolio that have already significantly reduced carbon emissions and increased generation from carbon-free resources. The Plan includes additions of only carbon-free resources consisting of wind, solar, and storage. In addition, and as relevant here, the Plan describes recent innovative initiatives regarding energy efficiency and demand response programs. A summary of those efforts is included below; for further detail, see Sections 9 and 10 of Great River Energy's IRP.

Great River Energy operates one of the most robust DR programs in the nation; these programs intentionally change our members' end-users' electric usage patterns from their normal consumption patterns in response to changes in the price of electricity or incentive payments. Great River Energy's energy efficiency programs use an "all of the

[10] *See* Docket No. E002/RP-19-368, IRP Supplement Preferred Plan (Jun. 30, 2020).
[11] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) and Order Approving Plan with Modifications and Establishing Requirements for Future Filings (Apr. 15, 2022) at 10.
[12] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) at 10.
[13] *See* Docket No. E002/RP-15-21, 2016-2030 Upper Midwest Resource Plan (Jan. 2. 2015) and Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (Jan. 11, 2017).
[14] *See* Docket No. E002/RP-19-368, Xcel Energy Reply Comments (IRP Alternate Plan) (Jun. 25, 2021) at 10.
[15] *In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan*, Docket No. ET-2/RP-22-75 (Mar. 31, 2023), eDockets ID 20233-194396-01, 20233-194396-06.
[16] *Id.* at Notice of Comment Period (Apr. 5, 2023).

above" approach to member energy efficiency engagement. The total program is made up of five components:

- **Equipment incentive programs –** These programs provide incentives for members' end users to invest in equipment having greater efficiency than equipment that meets current federal standards. Incentives are based on budget and the current commercial state of the technology. As technologies mature and the market for these technologies transform, the overall rebate for those technologies will be decreased.
- **Consumer behavior programs –** Consumer behavior programs focus on educating end users about their energy use and providing relevant comparisons that seek to illustrate ways in which the member-consumer can reduce their consumption and lower their overall cost of energy. Several of Great River Energy's members have employed tools like SmartHub, which leverages member-owner investments in Advanced Metering Infrastructure to present energy consumption data through an online web portal. In addition, several members have employed direct appeals to their end users to reduce their consumption during the hottest months of the year. These "Beat the Peak" programs ask member-consumers to voluntarily reduce their consumption and are associated with contests that reward end users that realize the greatest reduction in their overall electric consumption.
- **Supply-side efficiency –** Efficiency is a central focus of Great River Energy's culture of business improvement. Recent generation efficiency improvements include combustion turbine tuning to minimize heat rates and major overhauls of several combustion turbines based on operating hours. In addition, Great River Energy has also been actively engaging with third-party wind forecasting developers to identify improvements in day-ahead wind forecasting ability. Additional efficiency gains are being developed with regard to Ambient Adjusted Ratings of Great River Energy's transmission lines which will aid in reducing both congestion charges and renewable energy generation curtailment.

- **Market transformation –** Great River Energy's long history of efficiency engagement with members has resulted in member-consumers who are well versed in the benefits associated with investments in efficiency. As the market share of products that carry labels indicating efficient products (e.g., ENERGY STAR®) have expanded, many members have adopted these technologies without taking advantage of rebate programs.

- **Demand response –** Great River Energy's robust demand response efforts are focused on modifying the load curve during the periods of monthly peak demand, as well as ongoing efforts to shift as many end uses to off-peak periods as possible. The effort to shift end uses to off-peak periods is most pronounced in the areas of electric storage water heating and EV charging efforts.

Great River Energy plans the following energy efficiency program activities throughout the Five-Year Action Plan identified in the IRP:

- Survey members in 2023 regarding key electric end uses within homes and businesses;

- Participate in research to further characterize energy efficiency end use technologies, including the expansion of the efficient fuel switching opportunities under Minnesota's 2021 Energy Conservation and Optimization Act;

- Work with members to identify and market new programs that improve awareness of energy consumption, increase the adoption of efficient end-use technologies where practical, and minimize rate impacts; and

- Further evaluate the efficiency opportunities within our members' service territories.

C. Minnesota Power's Energy Conservation and Efficiency Programs

Minnesota Power filed its 2022 CIP Consolidated Filing with the Commission on April 3, 2023 in Docket No. E015/M-23-135. A copy of the "Summary" section and the "2022 CIP Status Report" section of this filing is provided as **Appendix F-2**.

Minnesota Power filed its 2021 Integrated Resource Plan ("2021 IRP") with the Commission on February 1, 2021 in Docket No. E015/RP-21-33. Appendix B of the 2021 IRP filing contained information regarding Minnesota Power's planning and strategies for demand-side management, Energy Efficiency, and CIP. A copy of Appendix B of the 2021 IRP filing is provided as **Appendix F-3**. Additional information regarding Minnesota Power's conservation and demand-side management programs can be found on Minnesota Power's website at: https://www.mnpower.com/ProgramsRebates.

D. Otter Tail Power's Energy Conservation and Efficiency Programs

Otter Tail Power Company (Otter Tail) has a long history of delivering highly cost-effective demand-side solutions to our customers. Between 1994 and 2022, Otter Tail invested over $117 million (nominal) resulting in 882 gigawatt hours (GWh) of electric energy savings, 272 megawatts (MW) of electric demand. In 2022, Otter Tail achieved over 50 GWh of electric savings, or 2.99 percent of sales[17] while spending $7.7 million to achieve the savings results.

In its 2024-2026 Energy Conservation and Optimization Triennial Plan[18], dated June 30, 2023 (Otter Tail's Triennial Plan), Otter Tail's proposes to achieve over 2.5 percent energy savings, significantly higher than Minnesota's goal of 1.75 percent. In addition, Otter Tail's plan provides a wide breadth of energy solutions for customers, including heating and cooling solutions, water heating, building envelope, lighting, appliances, transportation, load management, renewables, education, and commercial/industrial process solutions.

Otter Tail's Triennial Plan proposed ambitious goals of saving 147 GWh, and 226 MW over the three-year period at a cost of approximately $30 million. The proposed electric

[17] *See* Docket No. E,G002/CIP-20-475, 2022 CIP Status Report (April 3, 2023)
[18] See Docket No. E017/CIP-23-94, Otter Tail Power Company's 2024-2026 Energy Conservation and Optimization Plan (June 30, 2023)

savings goals also align with Otter Tail's conservation commitments filed in its most recent Integrated Resource Plan (Otter Tail's IRP) [19].

In Otter Tail's IRP, the Company filed an Application for Supplemental Resource Plan Approval with the Minnesota Public Utility Commission (MPUC) on March 31, 2023. Consistent with the results of the 2018 Minnesota Energy Efficiency Potential Study[20], the Company included 1.9 percent to 2.0 percent annual savings for conservation efforts made by the Company for the 2024-2026 triennial period in the IRP. For the 2024-2026 Triennial Plan, Otter Tail has proposed energy savings goal at the 2.5 percent level, net of ECO-exempt sales. These aggressive goals go beyond the ECO Act requirement of 1.75 percent and support our Resource Plan objectives.

E. Western Minnesota's Energy Conservation and Efficiency Programs

Western Minnesota Municipal Power Agency owns generation and transmission facilities, the capacity and output of which are sold to Missouri River Energy Services (MRES). MRES provides energy and energy services to its 61 member municipal utilities, and assists member municipalities with their energy efficiency, conservation, and other DSM programs by providing incentives and developing joint programs with members. In its most recent IRP, MRES discussed the comprehensive portfolio of energy efficiency incentives developed by MRES for customers served by its member municipal utilities.[21] In 2020, MRES completed an updated study of the maximum amount of DSM that can be implemented for its members' retail customers, under certain avoided cost assumptions provided by MRES. The study results show an expected potential for DSM of up to 93.9 MW of demand savings by 2036, coincident with the peak demands of the MRES member loads. In 2022, MRES spent nearly $3 million resulting in 5,041 kilowatts (kW) of peak demand savings (not including load control savings and costs).

[19] See Docket No. E017/RP-21-339, Otter Tail Power Company's 2022-2036 Integrated Resource Plan (March 31, 2023)
[20] Minnesota Energy Efficiency Potential Study: 2020-2029, Conservation Applied Research and Development (CARD) Final Report (December 4, 2018)
[21] *See* Docket No. ET10/RP-21-414, Missouri River Energy Services 2022-2036 Resource Plan (July 1, 2021) at 32.

F. MISO's Consideration of Conservation and Energy Efficiency in MTEP21

The Big Stone South – Alexandria – Big Oaks Transmission Project is not needed to support growing peak demand. Rather, the Project is needed to provide additional transmission capacity to transport increasing amounts of renewable generation on the system. More specifically, the existing 230 kV transmission system in eastern North Dakota and South Dakota plays a key role in transporting and delivering energy into Minnesota. The 230 kV system is at its capacity leading to a number of reliability concerns that could affect customers' service. The Project is needed to provide additional transmission capacity, to mitigate current capacity issues, and to improve electric system reliability throughout the region as more renewable energy resources are added to the electric system in and around the region. Given that the need for this Project is not driven by increases in peak demand, the Commission granted the Applicants' request for exemption from certain forecasting data for Applicants' service areas and systems as required by Minn. R. 7849.0270, subp. 2. Instead, Applicants committed to provide forecast information utilized by MISO in studying, planning, and analyzing the Project as part of MISO's 2021 Transmission Expansion Plan (MTEP21).

MISO's annual transmission planning process develops multiple future scenarios to study transmission needs under a variety of economic, policy, and technological possibilities. Each future scenario contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and technological possibilities.

As part of the development of these future scenarios, MISO develops forecasts for conservation, energy efficiency, and demand response, collectively referred to as "Distributed Energy Resources" (DER) by MISO. These forecasts are developed by aggregating each MISO member's load forecasts. To consider a broader range of potential DER outcomes, MISO creates forecasts considering varying adoption rates, technological advancements, and economic factors. MISO's forecasts are developed for each of MISO's 10 Local Resource Zones, to consider regional differences, and then are aggregated to a MISO-wide forecast.

Similar to previous MTEPs, MISO commissioned Applied Energy Group (AEG) to develop new DER technical potential for MTEP21. AEG developed estimates of DER impacts through survey of load-serving entities (LSE) and secondary research.

Based on analysis for MTEP20, with updated utility information and Futures narratives for this cycle, technical potential represents feasible potential under each scenario. To support modeling, AEG compiled DER programs by type and cost into program blocks for use in MISO's Electric Generation Expansion Analysis System (EGEAS) – an integrated resource planning tool.

The DER resources were modeled as program blocks in three main categories: Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). The DER programs also fall into two sectors: Residential and Commercial and Industrial (C&I). A complete list of the DER programs considered by MISO in MTEP21 is provided below in **Table F-1**.

Table F-1
MTEP21 Distributed Energy Resource Programs[22]

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response	C&I Price Response
DR	Residential Direct Load Control	Res. Direct Load Control
DR	Residential Price Response	Res. Price Response
EE	C&I High-Cost EE	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retrocommissioning Low
EE	C&I Mid-Cost EE	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retrocommissioning Mid
EE	Residential High-Cost EE	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV*	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

During the program selection phase for the MTEP21 Futures, each block was offered against supply-side alternatives to determine economic viability. For all three MTEP21 Futures, EGEAS selected the following program blocks, all within the C&I group: Customer PV, Utility Incentive PV, and Low-Cost Energy Efficiency. Additionally, Specific EE programs were grouped by cost into three tiers for C&I and two tiers for Residential.

Announced resources were included in Futures base assumptions. Several stakeholders submitted feedback detailing DERs they intend to add to their systems; these are also included in the totals below. Only selected programs and stakeholder

[22] **Appendix E-1** at 41 (MTEP21 Report Addendum).

additions were implemented in the MTEP21 Futures models. **Table F-2** and **Table F-3** show the total DER technical potential and additions modeled in MTEP21 by Future. The additions are those that were found to be economically superior to other alternatives and thus were included in the MTEP21 Futures. All of the values shown in **Table F-2** and **Table F-3** are in addition to the DER included in MISO LSE base forecasts.

Table F-2

DER Capacity (GW): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Capacity (GW) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	5.2	0.9	5.9	0.9	5.9	0.9
Energy Efficiency (EE)	13.3	7.8	14.5	8.1	14.5	11.7
Distributed Generation (DG)	14.7	3.5	14.7	3.5	21.8	6.2

Table F-3

DER Energy (GWh): 20-Year Technical Potential and Additions in MISO

MTEP21 DERs Energy (GWh) Technical Potential & Added	Future 1		Future 2		Future 3	
	Potential	Added	Potential	Added	Potential	Added
Demand Response (DR)	442	118	498	118	498	118
Energy Efficiency (EE)	86,886	30,801	94,313	31,393	94,313	49,145
Distributed Generation (DG)	26,119	5,709	26,119	5,709	36,934	9,837

Appendix F-2

Minnesota Power 2022 Conservation Improvement Program
Status Report Summary

2022 Consolidated Filing

Conservation Improvement Program

April 3, 2023

Docket No. E-015/M-23-135 | E-015/CIP-20-476.02

30 West Superior Street
Duluth, MN 55802-2093
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minnesota power
AN ALLETE COMPANY

April 3, 2023

Mr. Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Deputy Commissioner Michelle Gransee
Minnesota Department of Commerce
85 Seventh Place East, Suite 500
St. Paul, MN 55101-2198

Re: **2022 Conservation Improvement Program Consolidated Filing**
Docket Nos. E015/M-23-135, E015/CIP-20-476.02

Dear Mr. Seuffert and Ms. Gransee:

Attached please find via eFiling Minnesota Power's 2022 Conservation Improvement Program ("CIP") Consolidated Filing. This submittal includes a CIP Tracker Activity Report, a Financial Incentives Report, a Proposed Conservation Program Adjustment Factor, 2022 CIP Project Evaluations and a compliance with Department of Commerce ("DOC") orders section. Minnesota Power is filing this information pursuant to Minn. Stat. §§ 216B.241, 216B.16, subd, 6c, 216B.2401, and 216B.2411 and in compliance with Minnesota Public Utilities Commission ("MPUC") and DOC rules and orders relating to annual filings associated with Company-sponsored conservation program activities, including Minn. Rule 7690.0550.

Minnesota Power requests that the MPUC review the filed material and approve Minnesota Power's 2022 CIP Tracker Activity, Financial Incentives, proposed Conservation Program Adjustment ("CPA") factor, and a variance of Minn. Rules 7820.3500 and 7825.2600 to permit Minnesota Power to continue to combine the CPA factor with the Fuel Clause Adjustment on customer bills and/or combine the CPA factor with other currently applicable cost recovery riders on bills as the Minnesota Policy Adjustment when final rates in the Company's latest rate case are effective. Further, Minnesota Power requests that the DOC review and approve the evaluations of the various CIP projects included herein and the compliance with prior DOC orders. Minnesota Power has electronically filed this document and copies of this Cover Letter along with the Summary of Filing have been served on the parties on the attached service list.

If you have any questions regarding this filing, please contact me at (218) 355-3602 or avang@mnpower.com.

Sincerely,

Analeisha Vang
Senior Public Policy Advisor

AMV:th
Attach.

Summary

Minnesota Power
2022 Conservation Improvement Program ("CIP") Consolidated Filing

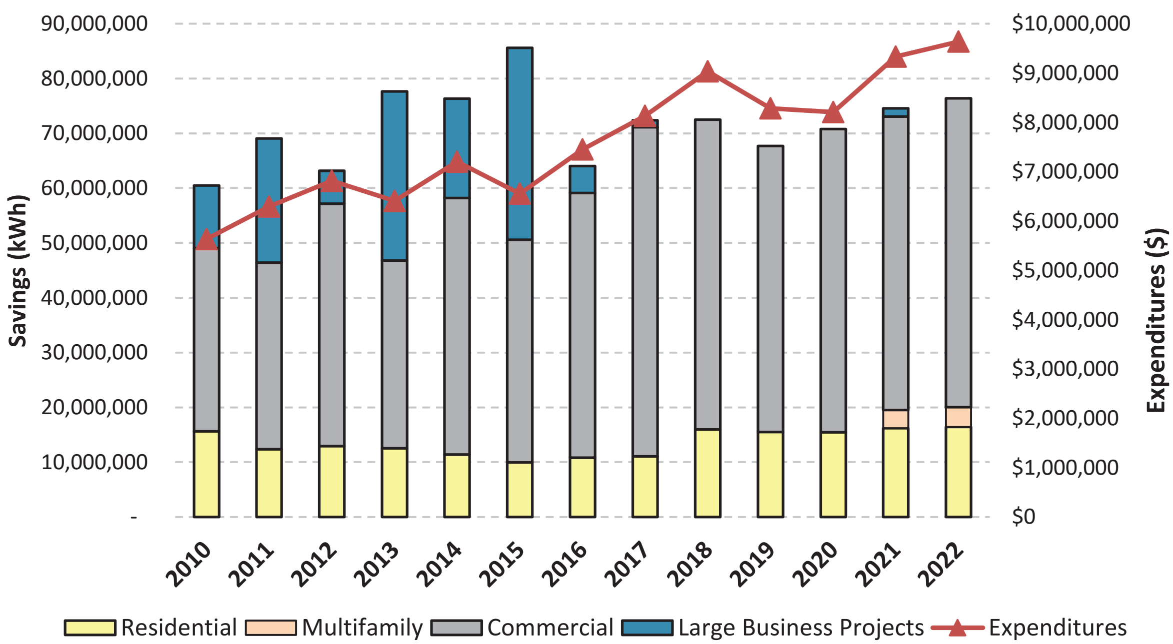
EXECUTIVE SUMMARY

Minnesota Power (or, "the Company") is pleased to report its 2022 energy conservation program results:

- Minnesota Power achieved energy savings of **2.9%** of gross annual retail energy sales,[1] well above the 1.5% energy-savings goal set in the 2021-2023 Triennial Order, and the 1.75% goal in the 2021 Energy Conservation and Optimization Act.[2]
- The Company achieved energy savings totaling **76,400,068 kilowatt hours ("kWh")**, which is **115%** of the approved energy-savings goal for the year. The Company also achieved demand savings of **8,195 kilowatts ("kW")**, which is **82%** of the approved demand-savings goal. The proposed energy-savings target for 2022 was well above the state 1.5% energy-savings goal for CIP.
- Expenditures totaled **$9,635,730**, which was **90%** of the approved budget for 2022.

The figure below illustrates historical and recent kWh energy-savings achievements, along with CIP expenditures. While Minnesota Power continues to have a successful track record of exceeding the state energy savings goal, the cost of delivering on these goals continues to increase. The Company anticipates the trend of increasing costs will continue as inflation impacts the cost of both products and labor and more cost-effective measures reach market saturation. Cost-effectiveness is also being impacted by lower avoided costs. While Minnesota Power's CIP portfolio continues to be cost-effective overall, higher cost programs – especially those serving income-qualified customers – are becoming increasingly less cost-effective.

Minnesota Power's 2005–2022 CIP Achievements



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[1] In accordance with Minnesota Rules part 7690.1200, weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2021–2023 Triennial Plan.

[2] While the Energy Conservation and Optimization Act (ECO Act) passed in 2021 with a higher savings goal, the energy savings goal for the 2022 Consolidated is based on the November 24, 2020 Order in Docket No. 20-476.

Minnesota Power's 2022 CIP Expenditures and Energy Savings

2022	*Expenditures*	*Energy Savings (kWh) at busbar*
Direct Savings Programs:		
Residential		
Energy Partners (Low Income)	$488,578	1,203,774
Home Efficiency (Residential)	$2,054,644	15,214,197
Multifamily		
Multifamily Direct Install	$156,743	351,955
Custom Multifamily Efficiency	$267,636	3,251,017
Commercial		
Prescriptive Business Efficiency	$59,247	1,013,699
Custom Business Efficiency (Business/Commercial/Industrial/Agricultural)	$4,474,126	55,365,426
Indirect Savings Programs:		
Customer Engagement	$640,290	
Energy Analysis	$700,495	
Research & Development	$148,909	
Evaluation & Program Development	$467,870	
Regulatory Charges	$177,191	
Total	**$9,635,730**	**76,400,068**

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 2022 Conservation Improvement Program Consolidated Filing	Reporting on CIP Tracker Account Activity, Financial Incentives Report, Proposed CPA Factors and 2022 Project Evaluations Docket No. E-015/M-23-135 E-015/CIP-20-476.02

SUMMARY OF FILING

Minnesota Power (or, "the Company") hereby files with the Minnesota Public Utilities Commission ("MPUC" or "Commission") and the Department of Commerce, Division of Energy Resources ("Department") its annual Conservation Improvement Program ("CIP") Consolidated Filing in compliance with Minn. Stat. § 216B.241. Minnesota Power requests approval of the following:

- Recovery of the 2022 CIP Tracker Account activity year-end balance of $1,321,045.
- A revised Conservation Program Adjustment ("CPA"), to be first implemented without proration on July 1, 2023, of $0.000306/kilowatt hour ("kWh").
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the continued combination of the Conservation Program Adjustment with the Fuel and Purchased Power Clause Adjustment on customer bills, until final rates from Minnesota Power's latest rate case are implemented.[3]
- A variance of Minn. Rules 7820.3500 and 7825.2600 to permit the combination of the Conservation Program Adjustment with other currently applicable cost recovery riders (Rider for Transmission Cost Recovery, Rider for Renewable Resources, and Rider for Solar Energy Adjustment), on bills as the Minnesota Policy Adjustment when final rates are effective as detailed in the February 28, 2023 Order in Minnesota Power's latest rate case.[4]

Minnesota Power submits its Conservation Improvement Program Consolidated Filing via eFiling with the Department of Commerce, Division of Energy Resources to comply with annual CIP project evaluation filing requirements.

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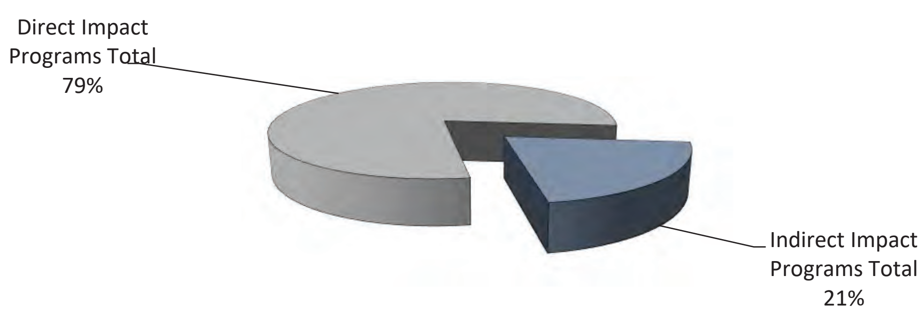
[3] *Minnesota Power's 2021 Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E015/GR-21-335.
[4] From the docket above, see the February 28, 2023 Order at Order Point 43 and the September 1, 2022 ALJ's Findings of Fact, Conclusions of Law, and Recommendations at pp. 129-31.

Status Report

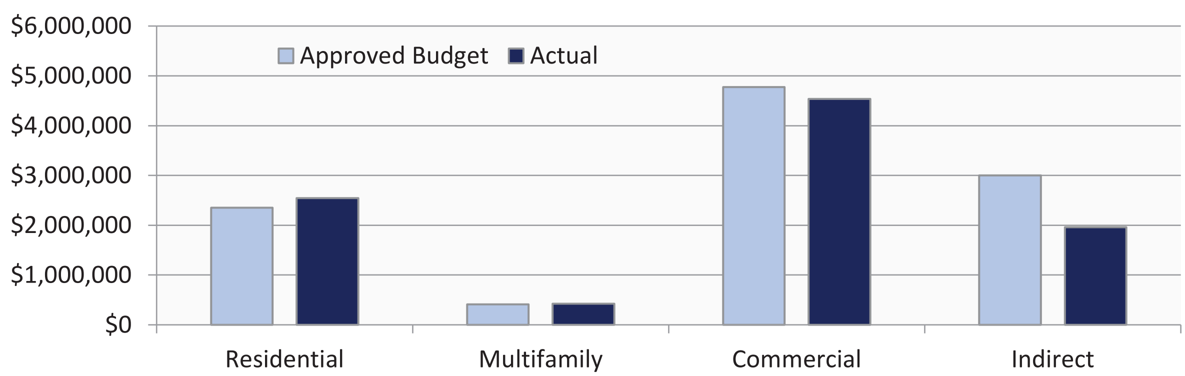
2022 CIP Status Report

Minnesota Power's energy conservation strategy provides a wide variety of program offerings to best serve its diverse customer mix. Each customer is unique in both their motivations for pursuing energy efficiency opportunities and their ability to engage in different offerings. With this knowledge, Minnesota Power provides a combination of traditional programs and innovative delivery strategies designed to address the needs and barriers of each customer segment including residential, multifamily and business. Minnesota Power's CIP portfolio includes a combination of "direct savings" and "indirect savings" programs that complement each other and provide for a balanced and meaningful customer experience.

2022 Program Spending By Direct and Indirect Savings Programs

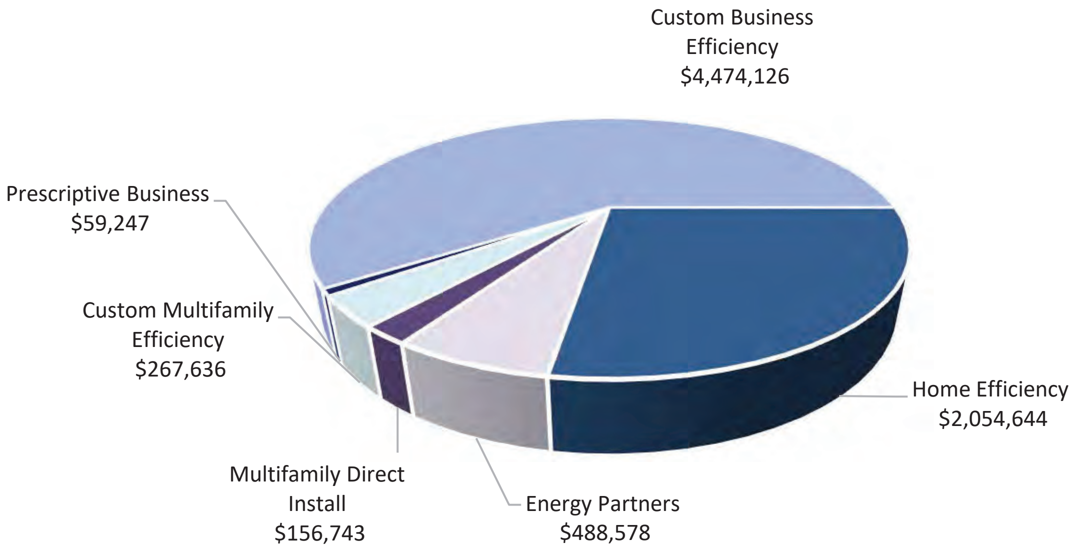


2022 Approved Budgets & Actual Spending Per Segment

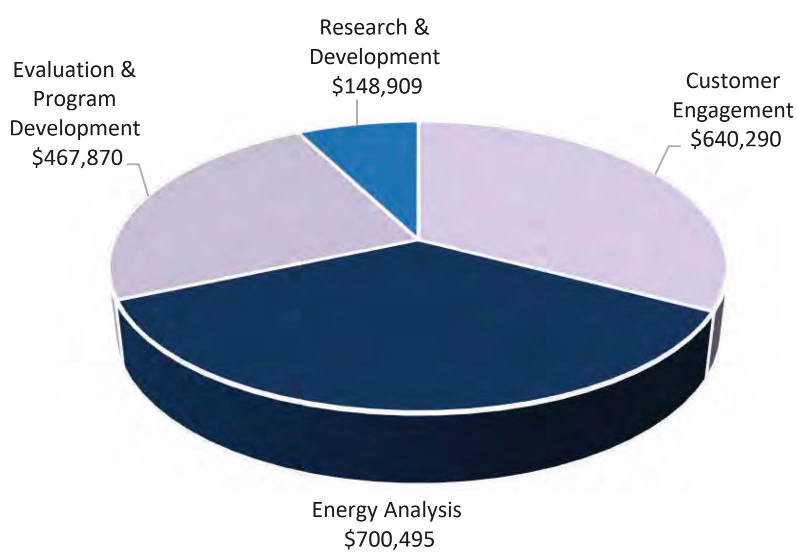


Investing in a range of programs is essential to keep Minnesota Power's program portfolio strong well into the future. Minnesota Power added three new programs to its CIP portfolio in the 2021-2023 Triennial Plan to better serve all customer segments. See the figures below for a breakdown of spending by program.

2022 Direct Savings Program Spending Breakdown

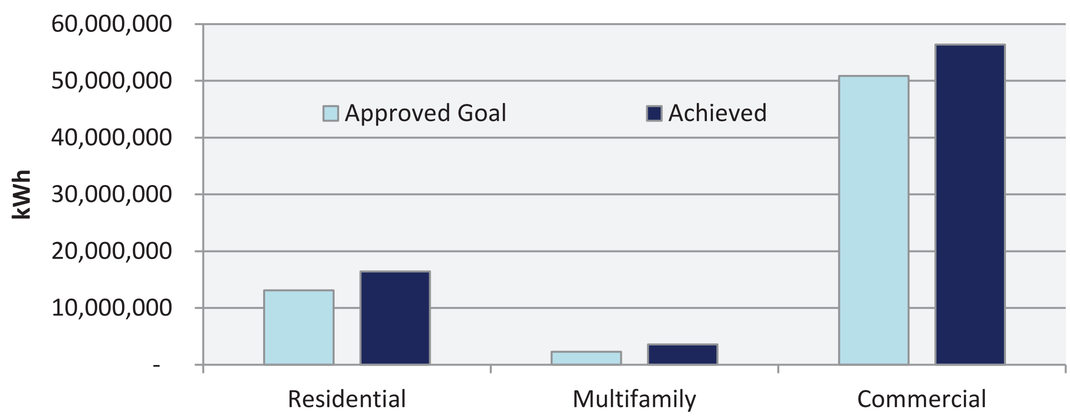


2022 Indirect Savings Program Spending Breakdown



Minnesota Power met or exceeded the energy savings goal in each segment of its CIP portfolio, as shown in the chart below. Two programs within those segments, Multifamily Direct Installation and Energy Partners, did not achieve the approved energy savings goal for various reasons as described in detail in the specific program descriptions. Minnesota Power continues to work with customers, stakeholders and delivery partners to identify opportunities to refine these offerings going forward.

2022 Approved Savings Goals & Achievements per Segment



For further context regarding Minnesota Power's energy conservation programs and the impact they have on customers, see the Successes section of this filing. These case studies highlight people, businesses and communities taking ownership of their energy usage and demonstrate how Minnesota Power connects with customers through conservation.

Looking Forward

There are many factors influencing the energy efficiency environment in Minnesota, including rising delivery costs, evolving state and federal policy, and changes in cost effectiveness. Minnesota Power has worked closely with customers, contractors, stakeholders, and regulators to ensure that programs are flexible and responsive to the evolving industry and has taken steps to modify programs as needed. However, additional actions will be required to ensure Minnesota Power's CIP portfolio continues to meet customer needs and encourages equitable access to customer programs as the environment continues to evolve.

Program delivery costs have increased significantly in recent years. The combination of inflation, supply chain disruptions, and economic uncertainty have impacted customers' ability to make capital improvements to their homes and businesses. Additionally, attracting and retaining talent in northern Minnesota has continued to create challenges for customers, delivery partners, and the Company. Encouraging customers to make energy-efficient investments has required higher incentives, more costly equipment and more resources than have historically been required.

In addition, the Company anticipates that recent federal and state policy changes will have a significant impact on Minnesota Power's CIP portfolio in the coming years. Initial guidance related to the ECO Act passed by the Minnesota legislature in 2021 was provided on March 15, 2022 as the result of a significant Department-led stakeholder working group.[17] This guidance will enable utilities to begin exploring new types of offerings including efficient fuel switching and load management activities. As utilities and stakeholders begin to utilize this guidance, further discussion and additional guidance will likely be needed. Meanwhile, the passage of the Inflation Reduction Act ("IRA") has introduced a significant amount of federal funding that will be available in the form of both rebates and tax credits on the purchase of energy efficient equipment and services. It will be critical for utilities and the Department of Commerce to coordinate on the design and implementation of these programs to ensure that customers are able to maximize the benefits of both CIP and IRA programs. While effective coordination and implementation of these funds could help address the rising costs of utility conservation programs, there is significant uncertainty around actual impacts.

Meanwhile, as the result of a robust series of Department-led working group efforts which included utilities, stakeholders, and industry experts, significant changes to the CIP/ECO evaluation framework and calculations have been proposed. Changes include the addition of a new primary screening test referred to as the Minnesota Cost Test ("MCT"), a test designed to reflect the State's energy policy goals and objectives, inclusion of new utility system and non-utility system impacts within the tests, and potential standardization of various existing impacts that historically have been utility specific. These changes, along with rising delivery costs and the new IRA programs described above, will make it difficult to predict the overall cost-effectiveness of CIP portfolios going forward. Flexibility to update and modify programs and portfolios will be more critical than ever going into the next Triennial.

Minnesota Power will continue to work with customers, stakeholders and regulators to ensure that programs are well-positioned to address challenges and opportunities associated with the rapidly evolving energy efficiency and optimization landscape into the future. Minnesota Power remains committed to providing sustainable, inclusive, and cost-effective energy-efficiency programs, with ongoing program development and increased efforts to raise program awareness and participation.

[17] Docket No. E,G999/CIP-21-837

Minnesota Power's 2022 CIP Expenditures & Achievements

2022	*Expenditures*				*Energy Savings (kWh @ Busbar)*				*Demand Savings (kW @ Busbar)*				*Participation*			
Direct Impact Programs	*Filed Budget*	*Approved Budget*	*Actual*	*Percent of Approved*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*	*Filed Goal*	*Approved Goal*	*Achieved*	*Percent to Goal*
Home Efficiency	$ 1,985,398	$ 1,985,398	$ 2,054,644	103%	11,847,171	11,847,171	15,214,197	128%	1,309	1,309	1,735.3	133%	225,559	225,559	309,430	137%
Energy Partners	$ 366,961	$ 366,961	$ 488,578	133%	1,246,050	1,246,050	1,203,774	97%	132	132	133.4	101%	14,126	14,126	12,735	90%
Multifamily Direct Install*	$ 247,228	$ 106,131	$ 156,743	148%	1,025,640	401,482	351,955	88%	112	43	39.9	92%	12,294	3,868	2,904	75%
Custom Multifamily Efficiency*	$ 140,588	$ 307,643	$ 267,636	87%	1,092,769	1,912,346	3,251,017	170%	184	350	628.4	179%	45	68	82	121%
Prescriptive Business Efficiency*	$ 123,323	$ 119,422	$ 59,247	50%	1,102,604	603,964	1,013,699	168%	123	88	173.4	198%	1,178	1,015	6,059	597%
Custom Business Efficiency	$ 4,651,797	$ 4,651,797	$ 4,474,126	96%	50,267,374	50,267,374	55,365,426	110%	8,101	8,101	5,484.9	68%	1,365	1,365	1,437	105%
Direct Impact Programs Total	**$ 7,515,295**	**$ 7,537,352**	**$ 7,500,974**	**100%**	**66,581,608**	**66,278,387**	**76,400,067.6**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**254,567**	**246,001**	**332,647**	**135%**
Indirect Impact Programs																
Customer Engagement	$ 864,900	$ 864,900	$ 640,290	74%									100,750	100,750	103,470	103%
Energy Analysis	$ 1,018,077	$ 1,018,077	$ 700,495	69%									6,145	6,145	5,771	94%
Evaluation & Program Development	$ 731,472	$ 731,472	$ 467,870	64%												
Research & Development	$ 384,600	$ 384,600	$ 148,909	39%												
Indirect Impact Programs Total	**$ 2,999,049**	**$ 2,999,049**	**$ 1,957,564**	**65%**	-	-	-						**106,895**	**106,895**	**109,241**	**102%**
Regulatory Charges	$ 200,000	$ 200,000	$ 177,191	89%												
Total	**$ 10,714,344**	**$ 10,736,401**	**$ 9,635,730**	**90%**	**66,581,608**	**66,278,387**	**76,400,068**	**115%**	**9,962.1**	**10,023.0**	**8,195.2**	**82%**	**361,462**	**352,896**	**441,888**	**125%**

*Approved budgets and goals for these programs reflect program modifications as filed and approved in Docket No. E015/CIP-20-476.

Appendix F-3

Minnesota Power Integrated Resource Plan, Appendix B

APPENDIX B: DEMAND SIDE MANAGEMENT

This Appendix of the 2021 Integrated Resource Plan ("2021 IRP") contains information regarding Minnesota Power's planning and strategies for demand side management ("DSM"), Energy Efficiency ("EE") and Conservation Improvement Programs ("CIP"). Minnesota Power's performance and planning outlooks for DSM, EE and CIP are broken into two parts in this Appendix:

1. Minnesota Power's Energy Efficiency Resource Alternatives and Conservation Program Strategy; and
2. Order Point 14 Considerations, Potential energy-efficiency competitive-bidding process.

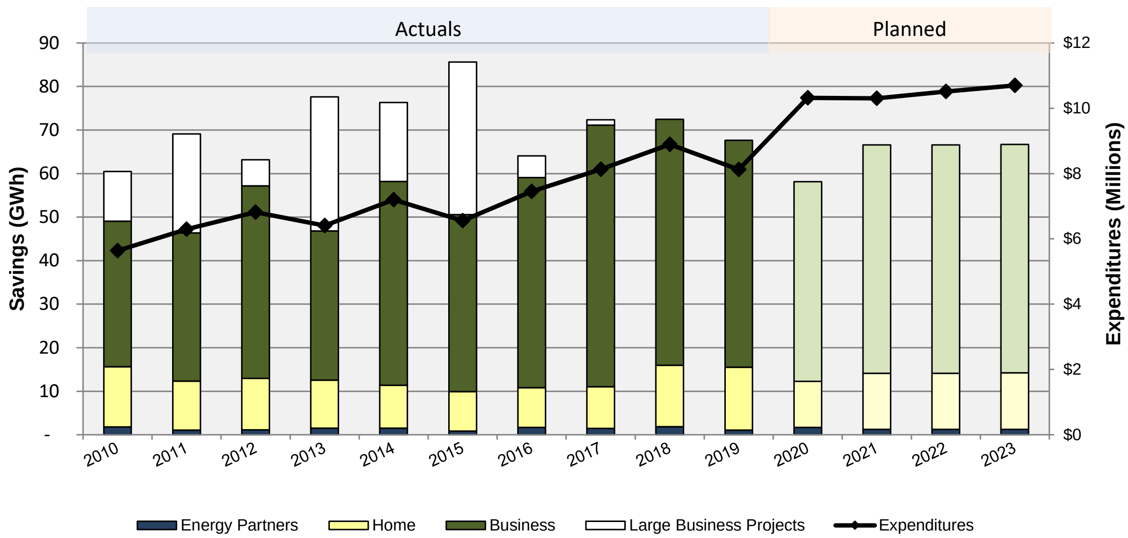
Part 1: Minnesota Power's Energy Efficiency Resource Alternatives and Conservation Program Strategy

Minnesota Power (or the "Company") is committed to providing sustainable energy-efficiency programs, as demonstrated by its strong historical CIP achievements. Since the Minnesota Next Generation Energy Act of 2007 ("NGEA"), Minnesota Power has been refining and expanding upon its proven conservation program platform to deliver cost-effective savings and customer value. The Company remains dedicated to continuous program improvement and views ongoing CIP initiatives as part of its broader *Energy**Forward*** resource strategy; a strategy designed to provide a safe, reliable and affordable power supply while identifying sustainable solutions for reducing carbon emissions further. Part 1 discusses the development of the Company's energy conservation targets included in the 2021-2023 CIP Triennial Plan filing[1] and the 2021 IRP baseline assumptions, as well as two increased EE alternative resource scenarios.

Figure 1 below reflects historical (first year) savings achievements and the proposed savings goals for 2021-2023, as filed in the 2021-2023 CIP Triennial Plan. Minnesota Power, together with its customers, community stakeholders and trade allies, has achieved success through its energy conservation programs, delivering energy savings at or above the state's 1.5 percent energy-savings goal since 2010 when the goal went into effect, all while maintaining focus on targeted program objectives – quality installations, informed decisions, EE and safety. The proposed goal for 2021-2023 and the assumed EE in the baseline forecast reflect the Company's intent to continue achieving savings of 2.5 percent which is well above the state's 1.5 percent goal.

[1] Docket No. E015/CIP-20-476.

Figure 1: Minnesota Power Historical CIP Achievements and 2021-2023 Goal



2021 IRP Baseline Assumptions and the 2021-2023 CIP Triennial

For purposes of both CIP Triennial planning and 2021 IRP modeling, Minnesota Power started with the 2020-2029 Minnesota State Demand Side Management Potential Study ("Potential Study") funded by the Department of Commerce and led by the Center for Energy and Environment ("CEE")[2]. The energy savings goals filed in the 2021-2023 CIP Triennial Plan are largely aligned with the Potential Study "Program", which will be referred to as the Baseline scenario (adjustments were made and discussed below and in Appendix A). Additionally, to align resource planning EE assumptions and modeling with CIP planning, the Company used the adjusted Baseline scenario that informed the CIP Triennial goals as the baseline EE assumption built into the custom demand forecast. These savings targets are well above the State of Minnesota's 1.5 percent energy-savings goal for CIP,[3] which equates to roughly 40 GWh on Minnesota Power's system. The adjusted Baseline scenario assumes roughly 65 GWH in 2021-2023 and ranges from 73 GWh in 2024 to 80 GWh by 2029. The average annual savings in the period after the current CIP Triennial (2024-2029) is roughly 77 GWh. This is in line with the Minnesota Public Utilities Commission's Order Point 12 from the Company's integrated resource plan ("IRP") filed in 2015,[4] which directed the Company to assume a planning goal of 76.5 GWh of EE. The savings goals in the CIP Triennial Plan and the efficiency levels assumed in the baseline assumptions for the IRP are aggressive, but the Company believes these are achievable. However, it is important to note that the significant impact of the COVID-19 pandemic, including a disruption in program services in the EE industry and potential long-term impacts, was not known or accounted for in the Baseline or alternative energy savings

[2] https://mn.gov/commerce-stat/pdfs/mn-energy-efficiency-potential-study.pdf
[3] Minn. Stat. § 216B.241, subd. 1c(b) ("Each individual utility and association shall have an annual energy-savings goal equivalent to 1.5 percent of gross annual retail energy sales unless modified by the commissioner under paragraph (d). The savings goals must be calculated based on the most recent three-year weather-normalized average.").
[4] Order Approving Resource Plan with Modifications, Docket No. E015/RP-15-690 (July 18, 2016) ("Minnesota Power's average annual energy savings goal is set at 76.5 GWh.").

scenarios. Therefore, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty.

Summary of Alternative Energy Efficiency Scenarios

Based on the aforementioned Potential Study, current CIP strategy, and analysis of historic performance and future opportunities, Minnesota Power provided two alternative EE scenarios with additional energy and capacity savings above the Baseline scenario (built into the base/expected 2020 Annual Electric Utility Forecast Report ("AFR2020") forecast). The Company further developed cost projections consistent with each outlook. The two alternative energy efficiency scenarios evaluated in the IRP analysis are:

1. "High" Scenario: modeled to reflect the midpoint between "Very High" and "Baseline" scenario (Program scenario from the Potential Study) scenarios, and
2. "Very High" Scenario: modeled after the adjusted Potential Study "Max Achievable" scenario.

Minnesota Power worked closely with CEE to update the original assumptions used in the Potential Study for the Minnesota Power-specific projections, in order to accurately capture the Company's specific territory, customer base, system, and historical experience with CIP.

The process of updating the CEE potential projections and method used to incorporate them into the load forecast are documented in the Company's AFR2020, included as Appendix A. These scenarios were incorporated in the EnCompass modeling process as supply side alternatives in the capacity expansion plan analysis.

The alternative efficiency scenarios ("High" and "Very High") considered in the IRP analysis begin in year 2024. These alternatives were not modeled as an option for 2021-2023 in light of currently-approved levels and due to limited ability to significantly increase EE above the approved 2021-2023 CIP Triennial Plan in the short-term. The potential study projected energy savings for the years 2021-2029. All three EE scenarios therefore assume new program implementation (and new savings) each year through 2029, after which no new saving programs were assumed. For the purposes of modeling the alternative scenarios in the 2021 IRP, only the additional costs and additional first year GWh/GW savings above the baseline are included. A high-level summary of the baseline EE (assumed in the forecast) and the increased efficiency scenarios modeled in the resource plan are shown in Table 1 and includes the following:

- % of Sales: Represents the level of 2024 savings under each scenario as a percentage of average weather normalized 2017-2019, non-CIP exempt retail sales—the baseline for the 2021-2023 CIP Triennial Plan.[5]
- Energy: Total estimated first year energy savings associated with each scenario for the year 2024.
- Energy Above Base: The additional GWh associated with each scenario in terms of first year savings as compared to the baseline plan (EE assumed in forecast).
- Summer Peak: Estimated first year GW demand savings coincident with Midcontinent Independent System Operator ("MISO") summer peak for the year 2024.

[5] In accordance with Minnesota Rules part 7690.1200, 2017-2019 weather-normalized average retail energy sales were used to calculate the electric savings goal for Minnesota Power's 2021-2023 Triennial CIP. This equated to 2,646,854,358 kWh, net of CIP exempt customers at the time of the Triennial Filing. Savings as a percent of sales in Table 1 were calculated using this figure.

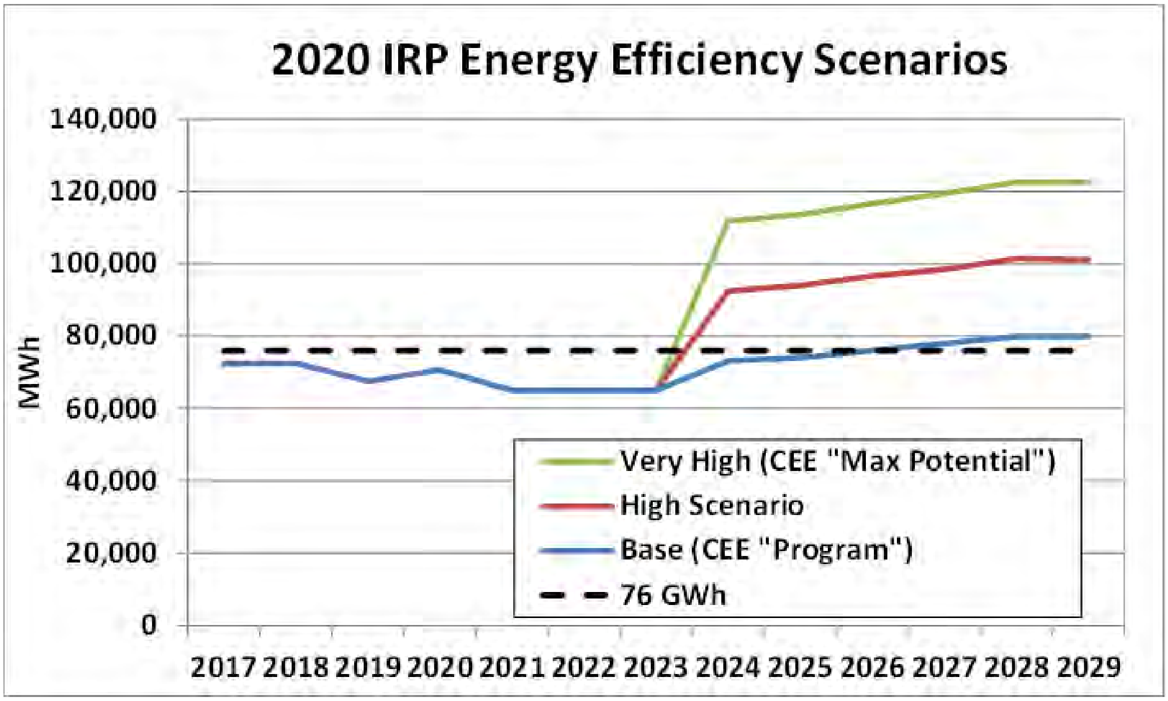
- Summer Peak Reduction Above Base: The additional first year GW demand savings associated with the scenario as compared to the baseline plan.
- Incentives: Rebates to incentivize customers to install/complete an efficiency measure.
- Non-Incentives: All other costs incurred by the Company to implement the 2024 EE plan.
- Total Cost: The estimated total program costs assumed to achieve the level of savings associated with each scenario in the year 2024.
- Total Cost Above Base: The estimated additional spending needed to achieve the incremental savings as compared with the existing plan for the year 2024.

Table 1: Summary of Energy Efficiency Scenarios

Scenarios		*First Year Annual Savings at the Generator (Energy: GWh/ Peak: MW)				First Year Program Costs (Million $)			
Plan	% of Sales** (Rounded)	Energy	Energy Above Base	MP Summer Peak	Summer Peak Reduction Above Base	Incentives	Non-Incentive	Total	Total Cost Above Base
Adjusted Base (CEE "Program")	2.76%	73.2	–	6.4	–	$10.42	$5.41	$15.81	$0
High	3.49%	92.5	19.3	8.1	1.7	$17.16	$6.86	$24.02	$8.19
Adjusted Very High (CEE "Max Achievable")	4.22%	111.8	38.7	9.7	3.3	$31.97	$8.31	$40.28	$24.45

Figure 2 below reflects the first year EE savings (measured at the generator) assumed in each year through 2029 for each of the three scenarios.

Figure 2: 2020 IRP Energy Efficiency Scenarios



Energy Efficiency Scenario Development and Assumptions

As previously noted, the Minnesota statewide Potential Study was the starting point for developing the baseline and alternative EE scenarios. As part of the Potential Study, CEE developed and defined two "achievable" potential scenarios. The following excerpt from the Final Report defines these two scenarios:

"In addition to total economic potential (i.e., the total potential if all possible measures were installed that meet cost-effectiveness criteria), two program scenarios were calculated:

- *Maximum achievable potential: This is the subset of economic potential that is achievable considering market barriers, given the most aggressive program scenario possible. This study assumed financial incentives would cover 100 percent of the incremental cost of each measure, along with very aggressive marketing and program designs to achieve maximum market penetration of the measures.*
- *Program potential: The program potential is a subset of the maximum achievable, given constraints in implementation. This study assumed that financial incentive levels are dropped to 50 percent of the incremental cost of each measure, which is a typical scenario used for planning purposes in Minnesota, and a good benchmark for aggressive programs nationally. The project team still assumed aggressive marketing and program designs for this scenario."*

Savings Targets and Contributions

The goal of the Potential Study was to produce a statewide EE potential report, and while some regional and investor-owned utility ("IOU"-specific) inputs were used in the methodology, other major inputs were developed at the statewide level. CEE leveraged the load forecast file in the Company's most recent prior IRP (2015), which was a 2014 vintage and fairly optimistic in its outlook for customer demand growth. The Company recognized this likely resulted in an inflated estimate of kWh savings potential relative to its current, more moderate outlook, and conferred with CEE on reasonable methods for updating the potential savings estimates. The Company worked with CEE to update its model with the most current customer outlook and CIP exemptions to produce a more accurate estimate of Minnesota Power's potential savings. Once the savings potential was updated for the Baseline and Very High (Max Potential) scenarios, a third scenario was created (High scenario) with a target savings level at the mid-point between the adjusted Baseline (Program) and Very High levels.

Additionally, the Minnesota Power-specific savings contributions by class and technology included in the original Potential Study were evaluated and ultimately modified to better reflect Minnesota Power's history and anticipated opportunities based on experience and internal analysis. As a result of this process, for 2021-2023, these contributions were modified to reflect historical patterns, accounting for changes that impact measure and savings opportunities, including market penetration and updates to approved measures and savings calculations as defined in the Technical Reference Manual ("TRM").[6] Updated avoided costs and net benefit estimates were also taken into account to evaluate changes in cost-effectiveness for various technologies compared to in the past. The most significant change to the assumed measure contributions for 2021-2023 was an increase in lighting measures. The Potential Study originally assumed changes to lighting standards would significantly impact savings opportunity from lighting in CIP portfolios as early as 2022. However, the TRM used for the 2021-2023 CIP Triennial Plan was not updated to reflect changes in the calculation of lighting savings, allowing for utilities to maintaining higher levels of planned savings through lighting measures.

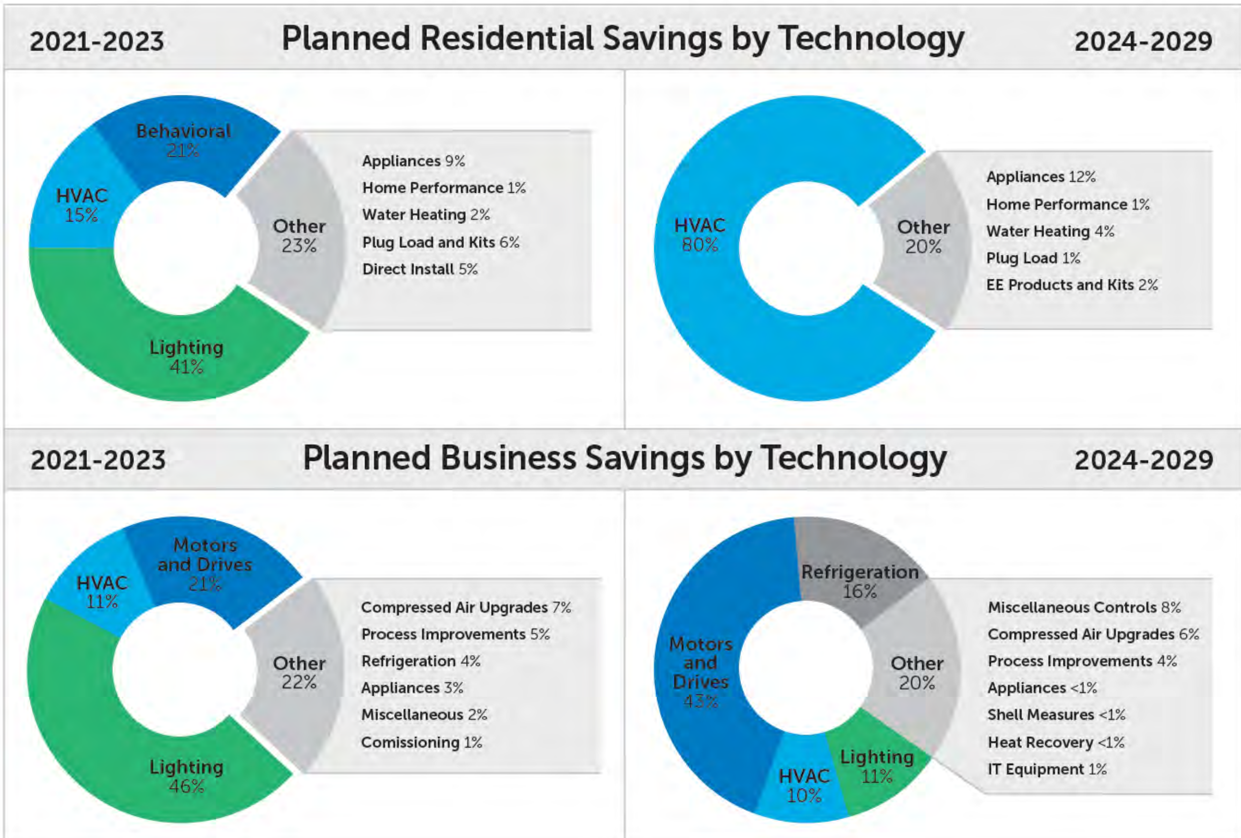
Beyond 2023, in the Baseline scenario, Minnesota Power updated the savings contributions by technology in each class to reflect anticipated reductions in lighting savings opportunity, which for both residential and commercial/industrial ("C/I") classes have historically accounted for the majority of the savings achievements. For residential, this resulted in a significant shift to Heating Ventilation & Air Conditioning ("HVAC") savings and for C/I this resulted in a noticeable shift away from lighting into other evolving technologies such as motors and Heating Ventilation Air Conditioning & Refrigeration ("HVACR").

For the alternative savings scenarios (High and Very High) – all measures in the Baseline scenario were scaled by the same percentage to achieve the targeted levels for each.

The graphs in Figure 3 below reflect Baseline savings contributions by technology for the 2021-2023 period and for 2024 and beyond:

[6] State of Minnesota Technical Reference Manual for Energy Conservation Improvement Programs (Jan. 20, 2020), https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={D0CDC86F-0000-C832-A29A-F7752BF4A0D9}&documentTitle=20201-159365-02.

Figure 3: Planned Savings by Technology



Scenario Cost Development

Cost assumptions were developed for each scenario for 2024 through 2029. For use in the 2021 IRP analysis, the costs associated with the High and Very High scenarios are incremental to the Baseline scenario. All costs were estimated for the year 2024 and escalated each year proportional to the change in energy savings.

Baseline Scenario

2024 cost assumptions for the Baseline scenario were developed to serve as the baseline costs against which the costs for the two higher scenarios would be compared. These costs were developed using the assumptions defined in the potential study and therefore reflect:

- Customer incentives (rebates) equal to 50 percent of the measures incremental cost where incremental cost is the difference between the cost of the standard efficiency product or action, or sometimes purchasing nothing/taking no action, compared to the cost of the efficient product or action.
- Aggressive program design and marketing. Non-incentive costs increase linearly with savings.

High Scenario

There is no equivalent scenario from the statewide Potential Study for this scenario, as it represents the midpoint between the adjusted Baseline scenario and the adjusted Very High (max achievable) scenario. The Company assumed:

- Customer incentives (rebates) would be set at 65 percent of incremental measure costs. This is roughly halfway between recent historical rebate levels and the max scenario (100 percent).
- Aggressive program design and marketing. Non-incentive costs increase linearly with savings.

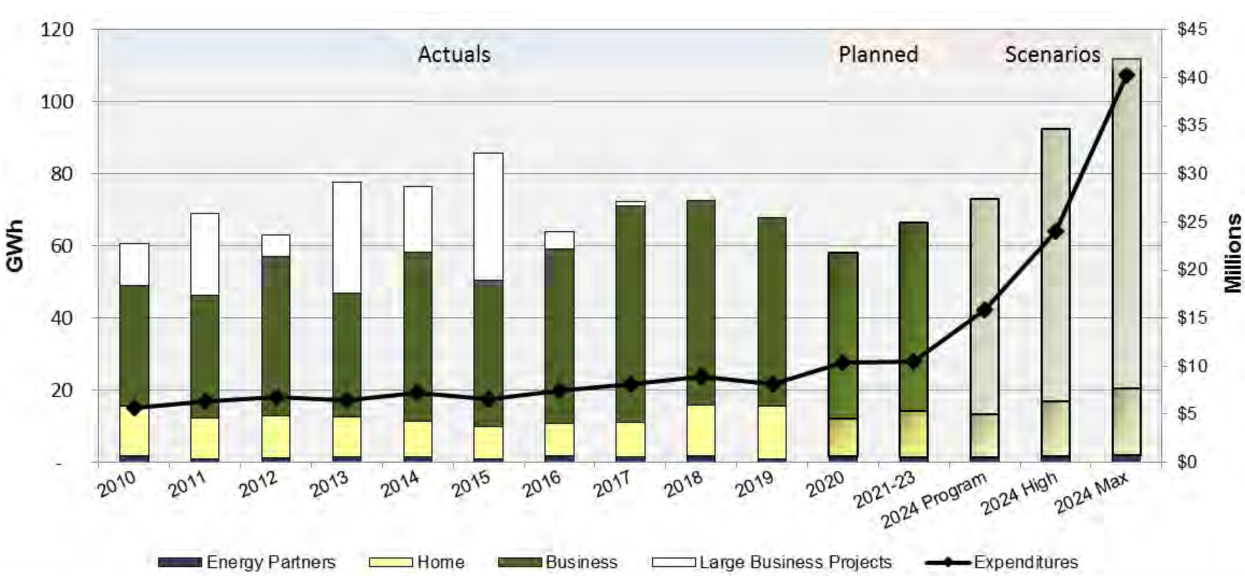
Very High (Max Achievable) Scenario

Like the Baseline scenario, Minnesota Power based incentive costs for the Very High scenario on the potential study scenario description:

- Customer incentives (rebates) are assumed at 100 percent of incremental measure costs.
- Aggressive program design and marketing. Non-incentive costs scale linearly with savings.

Figure 4 below expands on the Minnesota Power Historical CIP Performance graph (Figure 1) to include the planned costs and savings for 2020 and 2021-2023 (as filed in the respective triennial plans), and 2024 costs and savings as modeled for the Baseline and two alternative scenarios used in the 2021 IRP analysis:

Figure 4: Historical, Planned, and Modeled CIP Energy Savings (First Year) and Costs

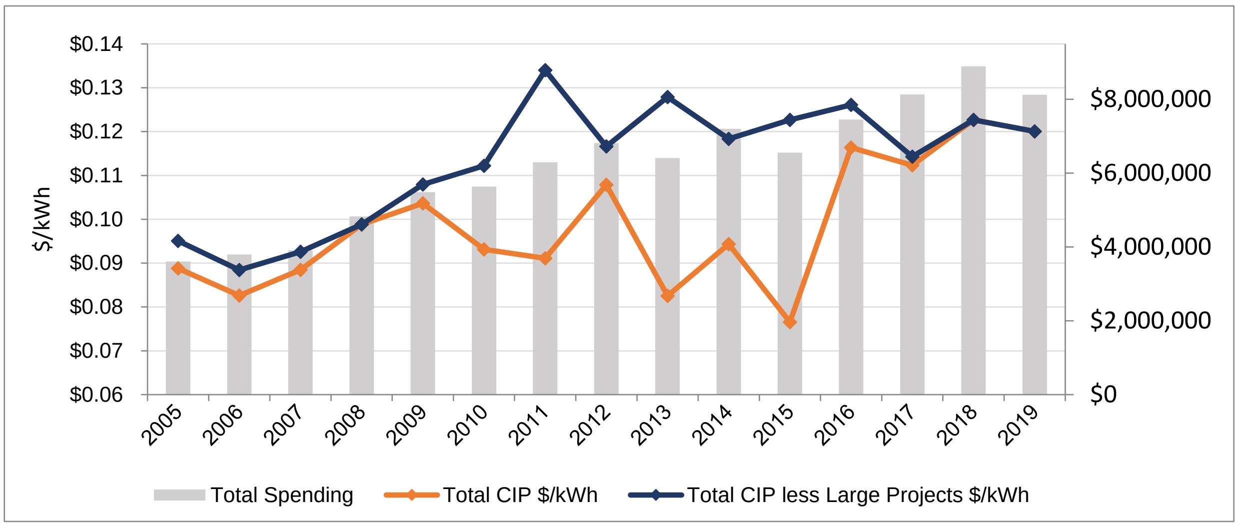


Discussion of Increasing Costs

Minnesota Power largely drew from the Potential Study assumptions to determine scenario costs for the 2021 IRP. The Company's own analysis of historical and anticipated cost trends indicates strong alignment with and support of the Potential Study assumptions. Specifically, stronger incentive levels and more aggressive program development and marketing will be critical to deliver at the levels discussed in the 2021 IRP.

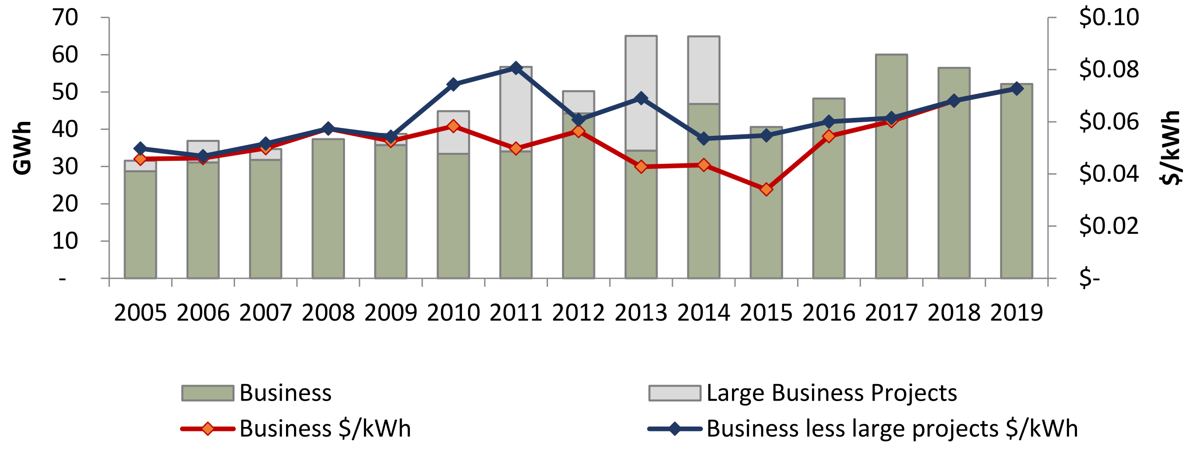
Further, costs have been increasing steadily over the past several years, in part due to the loss of large project opportunities. Between 2010 and 2015, such opportunities accounted for about 30 percent of total savings and only 4 percent of total spending. Figure 5 below reflects the (first year) cost per kWh saved trend between 2005 and 2019. Between 2010 and 2015, where significant large project savings were realized, the average cost per kWh saved was \$0.09/kWh – compared to an average of \$0.12/kWh between 2016 and 2019 when opportunities for these types of projects were no longer available.

Figure 5: Total Spending and Cost per kWh Trending



C/I savings have historically comprised the vast majority of the Company's savings achievements. Between 2005 and 2019, C/I savings accounted for approximately 80 percent of CIP savings – ranging from 73 percent to 88 percent in any given year. Similarly, C/I costs are a significant driver of overall costs. Figure 6 below shows how C/I costs per kWh have trended over time. Over the last three years, C/I costs per kWh saved have steadily increased even as savings have decreased. This suggests that in order to achieve higher savings goals, the cost per kWh saved will not only continue to trend up, it will increase more significantly with higher levels of EE. This increase will likely be further compounded as the opportunity for cost-effective lighting projects decreases.

Figure 6: Commercial and Industrial Cost per kWh (First-year Savings)



With the absence of large C/I projects, costs have increased over the last several years. However, cost-effective, efficient lighting products and projects across all customer sectors made their way to the forefront of Minnesota Power's CIP programs. Lighting measures became an obvious and easy energy saving option for customers to identify and adopt, especially as they also became increasingly cost-effective for consumers. Customer awareness and acceptance increased as LEDs became the primary option on the market. These factors, in combination with strategic program design, resulted in lighting making up the majority (over 50 percent) of savings over the last several years, helping to keep program costs lower despite the loss of large C/I projects.

However, with changing codes and standards impacting lighting measure baselines and significant market saturation of commercial efficient lighting, beginning in 2024 the majority of additional lighting opportunity is expected to go away. The Company will need to find ways to replace the most cost-effective and prevalent measure in its existing portfolio, which in 2019 accounted for nearly 37 GWh in savings (54 percent of total 2019 savings). The types of technologies that will need to replace those savings will be more costly measures that customers may not be as ready (or financially able) to adopt without significant education and incentives to do so. Increased education and outreach, along with higher rebate levels drive the increase in costs assumed in the 2024 Baseline scenario as compared to the 2021-2023 (filed) budgets.

Scenario Details

The following tables include the plan parameters for each scenario (savings, costs, participation for Baseline, High, and Very High scenarios).

Table 2: Year 2024 Energy and Demand Savings (MISO Summer Peak)

	Program	High	Very High	Program	High	Very High
	kWh - Generator	kWh - Generator	kWh - Generator	kW - Generator	kW - Generator	kW - Generator
Residential	12,019,394	15,202,866	18,423,077	1,377.1	1,742.9	2,111.2
HVAC	9,653,139	12,212,160	14,794,019	1,133.8	1,434.8	1,737.9
Home Performance	85,203	99,404	127,805	3.4	4.0	5.2
Energy Efficiency Products and Kits	272,032	344,568	417,620	23.8	30.1	36.5
Water Heating	449,076	569,730	690,423	37.2	47.2	57.2
Appliances	1,491,432	1,890,102	2,288,021	171.1	216.8	262.5
Plug Load	68,512	86,901	105,188	7.8	9.9	12.0
Admin Costs	0	0	0	0.0	0.0	0.0
Low Income	1,319,275	1,666,899	2,031,465	139.0	176.3	213.4
HVAC	50,927	58,157	83,974	13.4	16.9	20.4
Water Heating	535,470	678,921	822,080	44.4	56.3	68.2
Appliances	360,715	457,940	553,927	40.3	51.2	61.9
Energy Efficiency Products and Kits	372,162	471,881	571,483	40.9	51.9	62.9
Admin Costs	0	0	0	0.0	0.0	0.0
Business	59,826,687	75,624,419	91,373,241	4,866.8	6,143.8	7,395.2
Lighting	6,617,469	8,241,744	9,995,622	883.8	1,103.5	1,340.2
Refrigeration	9,621,879	12,232,833	14,838,140	655.2	829.3	1,002.9
Motors and Drives	25,946,629	32,872,342	39,949,432	946.9	1,195.5	1,443.4
HVAC	6,075,527	7,642,025	9,208,522	1,468.1	1,850.3	2,232.6
Compressed Air Upgrades	3,679,508	4,785,381	5,660,022	158.1	204.7	242.0
Process Improvements	2,253,887	2,575,871	3,219,838	163.2	186.6	233.2
Appliances	207,143	263,613	313,837	48.3	61.3	73.1
Shell Measures	269,540	394,856	402,419	1.7	2.0	2.4
Heat Recovery	170,483	230,992	250,778	86.8	130.3	130.3
Miscellaneous Controls	4,525,664	5,715,246	6,827,273	368.5	462.7	554.1
IT Equipment	458,959	669,518	707,358	86.2	117.6	140.9
Admin Costs	0	0	0	0.0	0.0	0.0
Indirect Impact	0	0	0	0.0	0.0	0.0
Grand Total	**73,165,356**	**92,494,183**	**111,827,783**	**6,383.0**	**8,062.9**	**9,719.8**

Table 3: Year 2024 Participation

	Program Participants	High Participants	Very High Participants
Residential (Measures)	9,439	11,962	14,489
HVAC	2,328	2,949	3,572
Home Performance	6	7	9
Energy Efficiency Products and Kits	698	884	1,071
Water Heating	3,006	3,812	4,617
Appliances	2,845	3,605	4,366
Plug Load	556	705	854
Admin Costs	0	0	0
Low Income (Measures)	6,409	8,125	9,840
HVAC	94	118	144
Water Heating	2,707	3,431	4,155
Appliances	622	790	956
Energy Efficiency Products and Kits	2,986	3,786	4,585
Admin Costs	0	0	0
Business (Projects)	968	1,226	1,482
Lighting	121	152	185
Refrigeration	78	100	121
Motors and Drives	366	465	564
HVAC	264	333	402
Compressed Air Upgrades	29	38	45
Process Improvements	7	8	10
Appliances	37	47	56
Shell Measures	9	11	13
Heat Recovery	9	11	13
Miscellaneous Controls	45	57	68
IT Equipment	3	4	5
Admin Costs	0	0	0
Indirect Impact	0	0	0
Grand Total	**16,816**	**21,313**	**25,811**

Table 4: Year 2024 Costs

	Program	High	Very High
Residential	$2,559,353.02	$3,883,875.36	$6,511,717.62
HVAC	$1,553,904.76	$2,560,462.35	$4,770,536.21
Home Performance	$25,410.89	$41,871.06	$78,012.24
Energy Efficiency Products and Kits	$5,865.83	$9,665.49	$18,008.30
Water Heating	$15,358.79	$25,307.62	$47,151.97
Appliances	$76,151.80	$125,479.92	$233,788.43
Plug Load	$6,072.98	$10,006.81	$18,644.23
Admin Costs	$876,587.97	$1,111,082.11	$1,345,576.24
Low Income	$291,046.68	$425,437.51	$674,977.75
HVAC	$17,026.96	$28,056.36	$52,273.33
Water Heating	$8,953.71	$14,753.57	$27,488.19
Appliances	$100,274.73	$165,228.71	$307,846.55
Energy Efficiency Products and Kits	$22,418.33	$36,940.04	$68,824.98
Admin Costs	$142,372.95	$180,458.83	$218,544.70
Business	$10,130,018.60	$16,103,811.76	$28,725,696.97
Lighting	$841,029.45	$1,385,814.80	$2,581,986.70
Refrigeration	$1,816,645.37	$2,993,395.86	$5,577,158.07
Motors and Drives	$2,523,251.68	$4,157,713.61	$7,746,461.57
HVAC	$1,405,354.45	$2,315,687.09	$4,314,482.13
Compressed Air Upgrades	$261,445.31	$430,799.16	$802,645.28
Process Improvements	$479,785.07	$790,570.73	$1,472,955.18
Appliances	$32,908.50	$54,225.33	$101,030.14
Shell Measures	$28,227.85	$46,512.74	$86,660.40
Heat Recovery	$152,354.21	$251,043.21	$467,732.22
Miscellaneous Controls	$959,192.95	$1,580,519.94	$2,944,752.36
IT Equipment	$83,405.00	$137,431.42	$256,055.94
Admin Costs	$1,546,418.76	$1,960,097.87	$2,373,776.98
Indirect Impact	$2,845,049.47	$3,606,122.45	$4,367,195.43
Grand Total	**$15,825,467.77**	**$24,019,247.08**	**$40,279,587.77**

Table 5: Baseline Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$5,410,429.15	$10,415,038.65	$15,825,467.80	12,939	6,383	6,180	73,165,356	12,939	6,383	6,180	73,165,356
2025	$5,512,787.14	$10,612,077.08	$16,124,864.22	13,083	6,433	6,238	73,992,182	26,021	12,816	12,418	147,157,537
2026	$5,643,574.95	$10,863,842.70	$16,507,417.65	13,432	6,607	6,391	76,103,887	39,450	19,422	18,806	223,248,792
2027	$5,776,670.66	$11,120,051.03	$16,896,721.69	13,783	6,772	6,556	77,977,293	53,141	26,145	25,284	300,733,290
2028	$5,944,155.48	$11,442,458.15	$17,386,613.64	14,143	6,953	6,720	79,906,922	67,190	33,048	31,924	380,137,737
2029	$5,941,977.80	$11,438,266.12	$17,380,243.91	14,142	6,953	6,720	79,905,018	81,235	39,950	38,562	459,528,328
2030	$0.00	$0.00	$0.00	0	0	0	0	81,137	39,898	38,478	459,001,824
2031	$0.00	$0.00	$0.00	0	0	0	0	80,995	39,826	38,360	458,245,514
2032	$0.00	$0.00	$0.00	0	0	0	0	80,529	39,550	37,949	455,706,460
2033	$0.00	$0.00	$0.00	0	0	0	0	80,152	39,321	37,615	453,650,748
2034	$0.00	$0.00	$0.00	0	0	0	0	79,301	38,782	36,921	448,165,605
2035	$0.00	$0.00	$0.00	0	0	0	0	78,435	38,234	36,213	442,598,403
2036	$0.00	$0.00	$0.00	0	0	0	0	76,566	36,685	34,622	430,246,558
2037	$0.00	$0.00	$0.00	0	0	0	0	74,684	35,126	33,024	417,837,180
2038	$0.00	$0.00	$0.00	0	0	0	0	73,092	33,733	31,689	406,972,381
2039	$0.00	$0.00	$0.00	0	0	0	0	63,276	28,593	28,172	345,400,838
2040	$0.00	$0.00	$0.00	0	0	0	0	53,836	23,720	24,993	286,577,308
2041	$0.00	$0.00	$0.00	0	0	0	0	44,160	18,746	21,759	226,194,881
2042	$0.00	$0.00	$0.00	0	0	0	0	33,069	13,997	17,361	163,447,735
2043	$0.00	$0.00	$0.00	0	0	0	0	21,746	9,142	12,899	99,380,815
2044	$0.00	$0.00	$0.00	0	0	0	0	9,908	3,991	8,127	33,904,849
2045	$0.00	$0.00	$0.00	0	0	0	0	7,014	2,898	5,669	23,777,119
2046	$0.00	$0.00	$0.00	0	0	0	0	4,047	1,779	3,150	13,393,670
2047	$0.00	$0.00	$0.00	0	0	0	0	1,063	650	619	2,958,141
2048	$0.00	$0.00	$0.00	0	0	0	0	531	325	309	1,478,688

Table 6: High Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$6,857,761.25	$17,161,485.81	$24,019,247.06	16,362	8,063	7,813	92,494,183	16,362	8,063	7,813	92,494,183
2025	$6,976,564.68	$17,458,790.31	$24,435,354.99	16,629	8,196	7,953	94,059,438	32,991	16,259	15,766	186,553,621
2026	$7,139,531.26	$17,866,612.72	$25,006,143.98	17,074	8,412	8,150	96,619,127	50,062	24,669	23,914	283,156,772
2027	$7,302,400.68	$18,274,191.98	$25,576,592.67	17,395	8,583	8,323	98,410,169	67,340	33,190	32,137	380,942,274
2028	$7,513,916.18	$18,803,507.62	$26,317,423.80	17,917	8,831	8,556	101,428,868	85,138	41,958	40,592	481,735,556
2029	$7,507,429.90	$18,787,275.74	$26,294,705.64	17,879	8,827	8,547	101,174,504	102,894	50,720	49,036	582,259,545
2030	$0.00	$0.00	$0.00	0	0	0	0	102,770	50,654	48,930	581,593,691
2031	$0.00	$0.00	$0.00	0	0	0	0	102,591	50,563	48,780	580,636,908
2032	$0.00	$0.00	$0.00	0	0	0	0	102,000	50,214	48,260	577,420,840
2033	$0.00	$0.00	$0.00	0	0	0	0	101,524	49,924	47,838	574,820,361
2034	$0.00	$0.00	$0.00	0	0	0	0	100,469	49,253	46,970	568,065,110
2035	$0.00	$0.00	$0.00	0	0	0	0	99,356	48,549	46,063	560,889,411
2036	$0.00	$0.00	$0.00	0	0	0	0	96,992	46,592	44,049	545,258,616
2037	$0.00	$0.00	$0.00	0	0	0	0	94,612	44,601	41,997	529,515,369
2038	$0.00	$0.00	$0.00	0	0	0	0	92,598	42,820	40,276	515,722,358
2039	$0.00	$0.00	$0.00	0	0	0	0	80,140	36,281	35,781	437,534,740
2040	$0.00	$0.00	$0.00	0	0	0	0	68,135	30,061	31,706	362,741,808
2041	$0.00	$0.00	$0.00	0	0	0	0	55,822	23,715	27,553	286,063,076
2042	$0.00	$0.00	$0.00	0	0	0	0	41,838	17,713	21,987	206,958,437
2043	$0.00	$0.00	$0.00	0	0	0	0	27,499	11,568	16,332	125,712,436
2044	$0.00	$0.00	$0.00	0	0	0	0	12,551	5,050	10,297	42,955,125
2045	$0.00	$0.00	$0.00	0	0	0	0	8,891	3,668	7,190	30,146,320
2046	$0.00	$0.00	$0.00	0	0	0	0	5,134	2,250	4,000	16,998,416
2047	$0.00	$0.00	$0.00	0	0	0	0	1,358	823	796	3,793,798
2048	$0.00	$0.00	$0.00	0	0	0	0	679	412	398	1,896,517

Table 7: Very High Scenario Cumulative Effects

year	Administration	Incentives	Total	kW	Summer Coin kW	Winter Coin kW	kWh	kW	Summer Coin kW	Winter Coin kW	kWh
2024	$8,305,093.35	$31,974,494.41	$40,279,587.76	19,758	9,720	9,439	111,827,783	19,758	9,720	9,439	111,827,783
2025	$8,440,342.21	$32,495,200.64	$40,935,542.86	20,088	9,899	9,595	113,621,147	39,846	19,619	19,034	225,448,930
2026	$8,635,487.58	$33,246,507.59	$41,881,995.17	20,618	10,176	9,882	116,648,550	60,460	29,793	28,913	342,077,974
2027	$8,828,130.71	$33,988,180.97	$42,816,311.68	21,099	10,422	10,099	119,397,418	81,417	40,140	38,891	460,718,885
2028	$9,083,676.88	$34,972,030.22	$44,055,707.10	21,675	10,682	10,356	122,595,685	102,948	50,746	49,124	582,545,801
2029	$9,072,882.00	$34,930,470.05	$44,003,352.05	21,668	10,680	10,350	122,571,522	124,468	61,347	59,349	704,330,413
2030	$0.00	$0.00	$0.00	0	0	0	0	124,317	61,267	59,221	703,526,200
2031	$0.00	$0.00	$0.00	0	0	0	0	124,101	61,157	59,040	702,368,931
2032	$0.00	$0.00	$0.00	0	0	0	0	123,386	60,735	58,411	698,477,555
2033	$0.00	$0.00	$0.00	0	0	0	0	122,809	60,384	57,900	695,330,534
2034	$0.00	$0.00	$0.00	0	0	0	0	121,535	59,566	56,844	687,158,206
2035	$0.00	$0.00	$0.00	0	0	0	0	120,238	58,736	55,769	678,866,523
2036	$0.00	$0.00	$0.00	0	0	0	0	117,359	56,331	53,286	659,790,040
2037	$0.00	$0.00	$0.00	0	0	0	0	114,449	53,887	50,774	640,488,029
2038	$0.00	$0.00	$0.00	0	0	0	0	112,014	51,738	48,690	623,796,477
2039	$0.00	$0.00	$0.00	0	0	0	0	96,964	43,854	43,268	529,097,753
2040	$0.00	$0.00	$0.00	0	0	0	0	82,443	36,361	38,371	438,583,478
2041	$0.00	$0.00	$0.00	0	0	0	0	67,604	28,713	33,365	346,171,372
2042	$0.00	$0.00	$0.00	0	0	0	0	50,640	21,432	26,612	250,315,647
2043	$0.00	$0.00	$0.00	0	0	0	0	33,293	13,993	19,761	152,169,633
2044	$0.00	$0.00	$0.00	0	0	0	0	15,163	6,103	12,439	51,891,028
2045	$0.00	$0.00	$0.00	0	0	0	0	10,739	4,434	8,683	36,410,539
2046	$0.00	$0.00	$0.00	0	0	0	0	6,190	2,718	4,820	20,490,213
2047	$0.00	$0.00	$0.00	0	0	0	0	1,636	996	957	4,563,879
2048	$0.00	$0.00	$0.00	0	0	0	0	818	498	478	2,281,557

Summary of Findings

Minnesota Power has a proven track record of successful CIP performance and anticipates continuing this trend into the future, as indicated by the aggressive goals set forth in the 2021-2023 Triennial Plan and assumed in the 2021 IRP baseline forecast. However, the Company acknowledges that the current EE environment is rapidly evolving in ways that will continue to present new challenges. Changing baselines, uncertain economic conditions (whether related to the current pandemic in the near term, or resulting from other, unknown events that may occur over the longer term), and decreased avoided costs will all contribute to Minnesota Power's ability to offer cost-effective, meaningful programs to customers. While Minnesota Power continues to build on the successes of its existing programs and adapting to challenges through unique and innovative program offerings and delivery strategies, achieving this higher level of savings through less cost-effective measures will be more resource intensive. Additionally, long-term EE savings require customers to take specific actions year after year, which introduces uncertainty regarding whether or not these savings will materialize. For these reasons, among others, it is important to take a reasonable approach to long-term EE assumptions to minimize risk and uncertainty. The Company has done so, while also testing what could be achieved by including alternative scenarios in its IRP analysis.

Part 2: Order Point 14, Potential Energy-Efficiency Competitive Bidding Process

In the Order approving Minnesota Power's 2015 Integrated Resource Plan ("2015 Plan"),[1] the Minnesota Public Utilities Commission (or "Commission") required that for its next resource plan, the Company must "investigate the potential for an energy-efficiency competitive-bidding process to supplement its existing conservation improvement program, open to both CIP-exempt and non-CIP-exempt customers, and shall summarize its investigation and findings in its next resource plan." This portion of Appendix B addresses this Commission requirement.

Specifically, Minnesota Power investigated the potential for an energy-efficiency competitive-bidding process to supplement its existing conservation-improvement program by researching best practices and examining how large customers who are exempt from CIP focus on conservation efforts within their operations. The Company's research and analysis, discussed below, indicated that many of the bidding programs available for review had the following characteristics that set the programs up for success: a dedicated funding source, bidding platform, and a process for customer communications. Conversely, the Company was not able to identify specific direction in either Minnesota policy or statutes that provided direction on how the Company might recover costs of a competitive-bidding process from either CIP-exempt or non-CIP exempt customers. The lack of explicit cost recovery authorization presents an important barrier to all potential stakeholders. Additionally, the Company has already demonstrated an outstanding CIP achievement record for non-exempt customers, along with aggressive future goals. For these reasons the Company does not feel that a competitive-bidding process would add value at this time. Nevertheless, the Company summarizes here its investigation and findings.

The first section below provides details on the Company's investigative research that has been completed with respect to energy-efficiency competitive-bidding processes. The second section focuses on energy-efficiency efforts of CIP-exempt customers, along with additional considerations.

Energy-Efficiency Competitive-Bidding Process Research

Minnesota Power identified the following competitive-bidding programs to assess best practices, potential outcomes, and possible barriers to success for any program Minnesota Power might initiate. Each program is discussed in turn, and includes a combination of deregulated, regulated and a statewide efficiency program not run by the individual utilities.

Energize Missouri Industries program, is an initiative of the Missouri Department of Natural Resources ("Missouri DNR"). Between 2010 and 2011, the Missouri DNR provided grants to energy efficiency ("EE") companies that competitively bid for EE incentives through a reverse auction. The overall goal of the online reverse auction was to provide industries and commercial entities with an opportunity to realize measurable energy savings that would result in reduced energy costs and increased market competitiveness. The online reverse auction allowed pre-qualified providers to bid on $3 million in incentives on a $/kWh saved basis for expected EE projects. Available incentive dollars were allocated based on a lowest-price obtained, thus increasing the cost-effectiveness of the program and allowing the Missouri DNR to spread the dollars further. The program was funded by a $3 million grant from the American Recovery and Reinvestment Act of 2009 ("ARRA").

[1] Order Approving Resource Plan with Modifications, Docket No. E015/RP-15-690 (July 18, 2016).

Focus on Energy is a company that partners with Wisconsin utilities on an efficiency bidding program. Bids are submitted through an online auction where business incentive program customers and/or trade allies bid for additional financial incentives above current prescriptive and custom levels. Customers who qualify for the business incentive program include commercial and industrial ("C/I") businesses who average less than 1,000 kW per month. Typical businesses include, but are not limited to, banks, hotels, grocery stores, breweries, food processing, and manufacturing. Customers and trade allies can submit bids, using an online auction platform, which identifies the unit price needed to deliver the estimated kWh or therms savings from the EE project.

The Focus on Energy efficiency auction is a type of reverse auction in which the role of the buyer and seller are reversed. The pre-qualified bidders compete by offering rates on a price per annual kWh or a price per therms reduced basis until no pre-qualified bidder is willing to make a lower bid. During the live auction, pre-qualified bidders will be logged into an online platform and will actively submit bids to compete for the EE incentives. The auctions will start at an established bid ceiling price and pre-qualified bidders will bid down on this price at predefined increments. Pre-qualified bidders will be able to see live results and their position for an auction. At the end of the auction, the bidders with the lowest price per annual kWh or therms reduced bids are considered the winners of the auction and are then tasked with implementing their energy-saving project(s). The winning bidder is provided a financial incentive, which is limited to $200,000 per project and $400,000 per customer per calendar year for all Focus on Energy Incentives. The funding comes from Focus on Energy partnership with 107 utilities throughout Wisconsin. Each participating utility pays in either a portion of their revenue or a set amount by meter. Focus on Energy then uses that funding to provide cost-effective programs that support EE projects.

Bid4Efficiency is a reverse auction program run by American Electric Power Ohio. In the reverse auction program, interested customers (nonresidential customers that use more than 200,000 kWh per year) respond to a request for qualifications ("RFQ"). As part of the pre-qualification process customers or service providers are required to attend training and mock auctions. After customers respond to the RFQ, these large C/I customers are eligible to become prequalified bidders. The bidders then send in bids to an online live auction platform in the form of price per annual kWh or watts reduced for energy-efficiency projects such as process-improvement initiatives or compressed-air systems costing more than $25,000. C/I customers as well as trade allies can bid for planned and unplanned projects. Starting at the bid ceiling price, prequalified bidders compete with one another to determine who can submit the lowest $/kWh saved for their specific project. The bidder with the lowest price per annual kWh (or price per watts reduced) is granted an award from $25,000 to $500,000 to complete their project. Additional details of the reverse auction include: bidders can only win one auction, non-winning bidders are offered a default incentive rate 10-20 percent lower than the lowest winning bid, and winners that achieve 80 percent or more of the total awarded auction incentive amount receive a $0.005 per kWh bonus.

Kansas City Power and Light (now Evergy) historically offered a block bidding program, which featured separate auctions for C/I customers and for trade allies. The auctions consisted of two blocks: one for projects in excess of $100,000 and one for those exceeding $400,000. To participate in the program, potential bidders responded to the request for quotation for the auction and attend a webinar to learn how the auction process would work. If the request for quotation was approved for the customer's project, that customer was then allowed to participate in the online auction. Projects that were eligible to receive the program incentives were required to save more than 1 million kWh annually and have a minimum payback of at least two years.

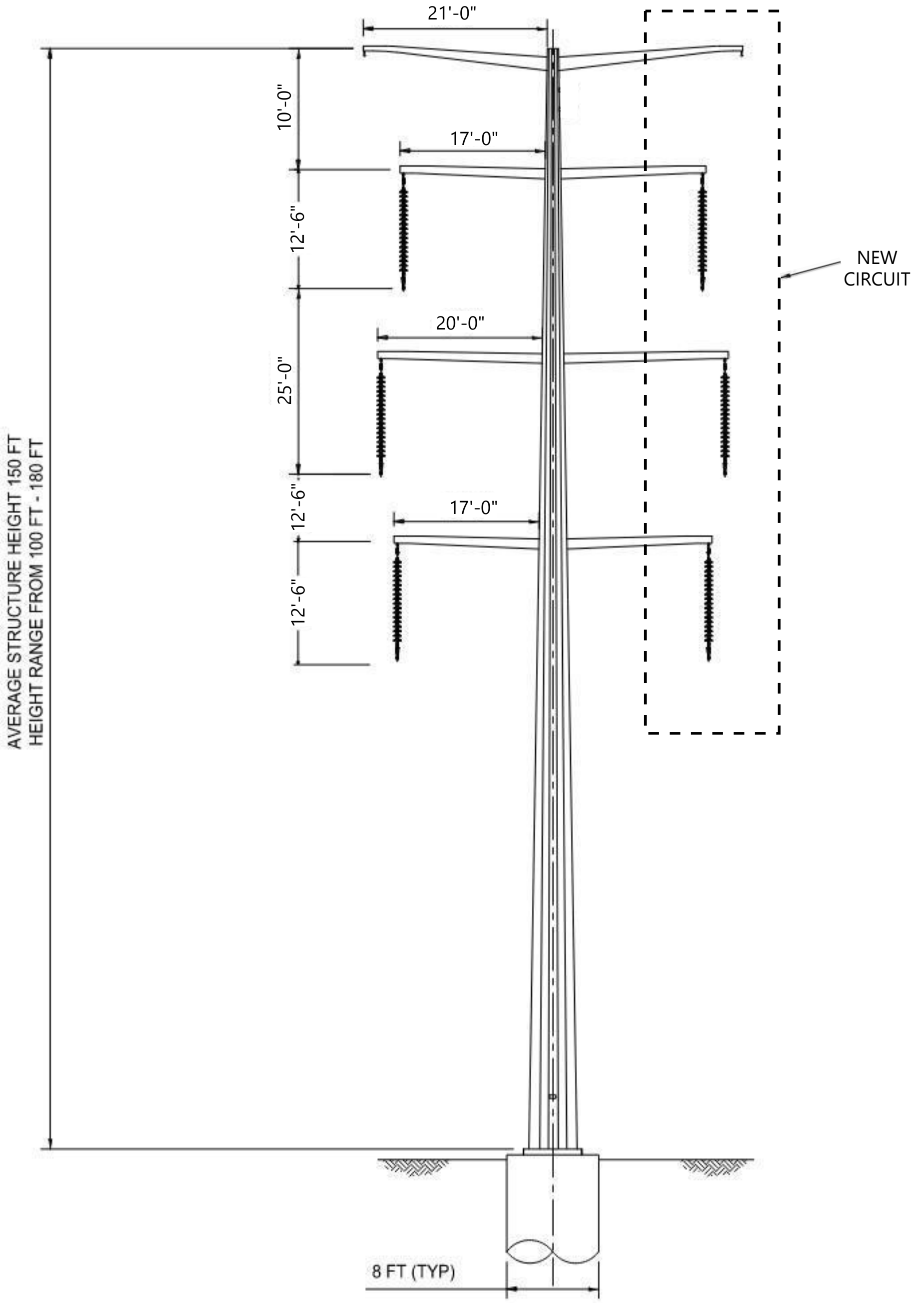
Energy-Efficiency Competitive-Bidding for CIP-Exempt Customers

Minnesota Power's CIP-exempt group is comprised of large industrial customers that have identified through a state legislative designation to be considered "exempt" from the conservation program established in Minnesota. CIP exceptions are defined by Minnesota Statutes § 216B.241, subd. 1a(b), which states in part: "The owner of a large customer facility may petition the commissioner to exempt both electric and gas utilities serving the large customer facility from the investment and expenditure requirements [of CIP]" and "[t]he filing must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate, and implement energy conservation and efficiency improvements." Under this statute, customers seeking an exemption are required to file with the commissioner of the Minnesota Department of Commerce and must prove that they are implementing energy conservation and efficiency improvements. They also must show there is no need for additional incentives to manage, complete, and address EE measures. Exempt customers must provide a filing every five years to the commissioner explaining measures that they are already taking to be efficient. However, a large customer facility that is, under an order from the commissioner, exempt from the investment and expenditure requirements as of December 31, 2010, is not required to submit a report to retain its exempt status, except with respect to ownership changes.

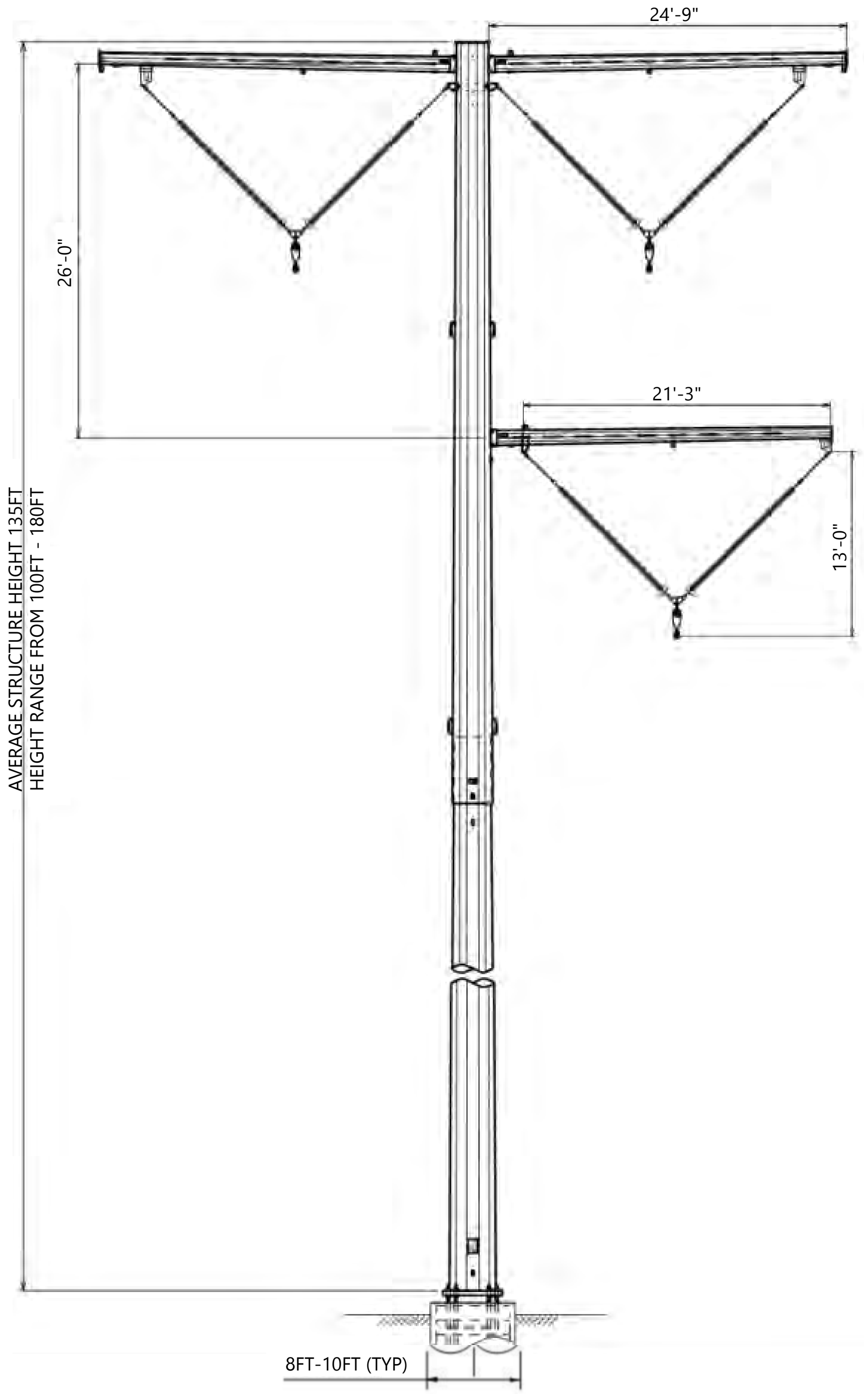
There are approximately 14 Minnesota Power customers at the time of this filing that fall under the CIP-exempt classification, most of whom have submitted multiple reports to the Department of Commerce detailing efforts to implement EE and energy conservation strategies. These CIP-exempt customers compete in global markets and in industries that have an advantage because of other nations' favorable tax policies, trade laws, health care costs, environmental compliance or other subsidies. CIP-exempt customers are naturally incentivized to pursue all efficiency improvements to keep their product costs as low as possible, including any and all economically viable efficiency improvements related to energy.

Appendix G

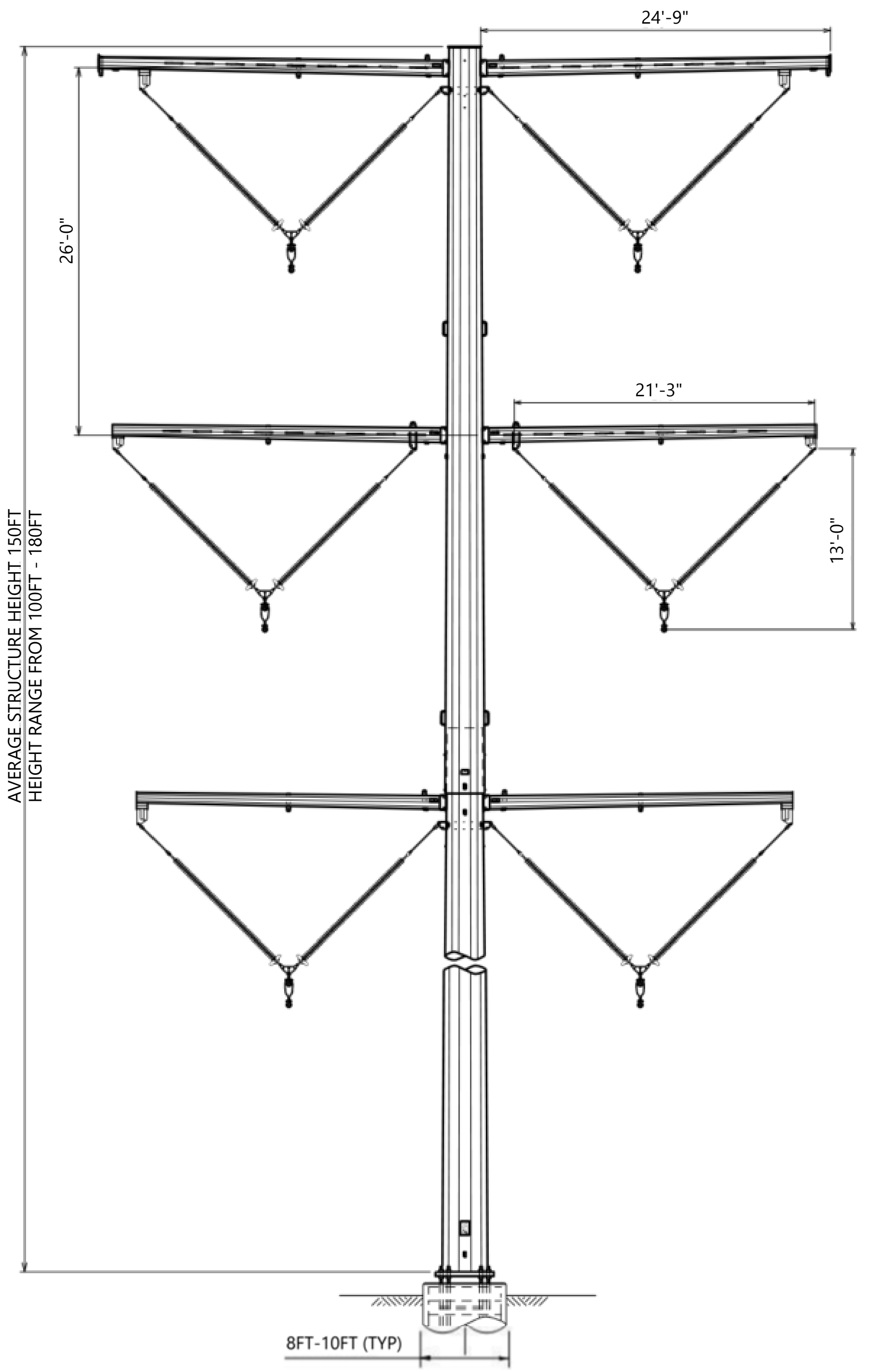
Technical Diagrams of Typical 345 kV Structures



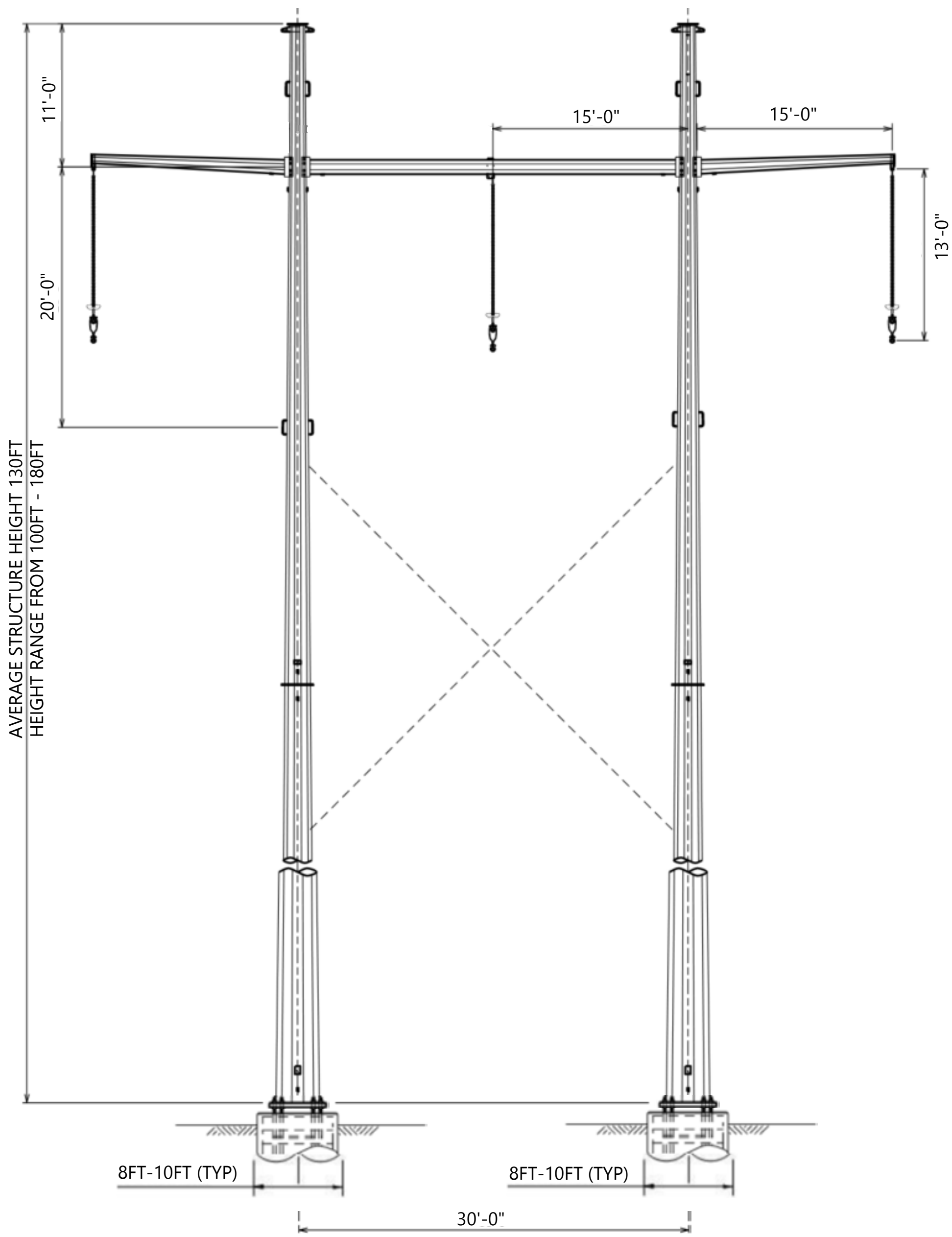
LOOKING AHEAD
EXISTING DOUBLE-CIRCUIT
MONOPOLE TANGENT STRUCTURE
STANDARD SPAN



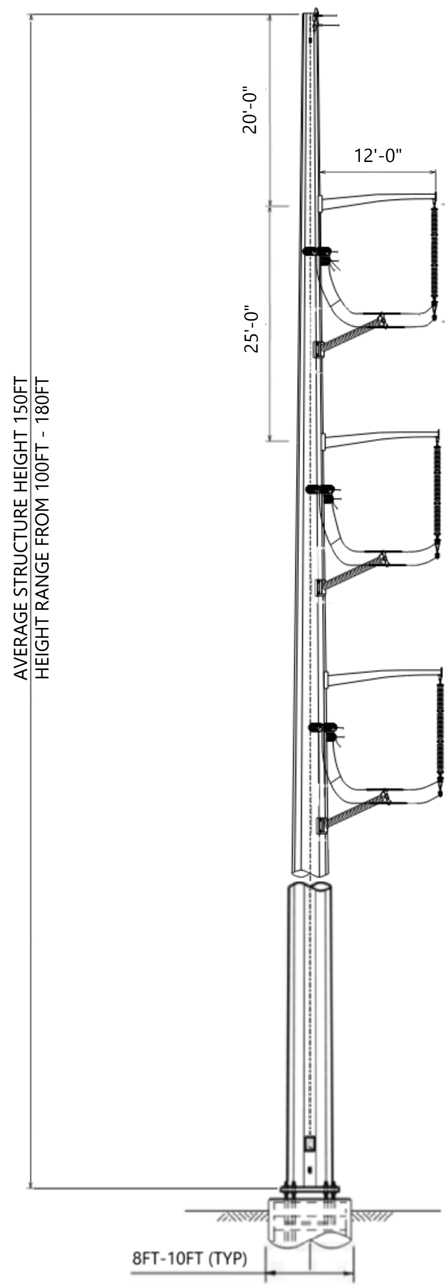
LOOKING AHEAD
SINGLE-CIRCUIT MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
DOUBLE-CIRCUIT MONOPOLE
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
SINGLE-CIRCUIT H-FRAME
TANGENT STRUCTURE
STANDARD SPAN



LOOKING AHEAD
MONOPOLE
DEAD END STRUCTURE
STANDARD SPAN

Appendix H

Xcel Energy Rate Impact Calculations

LRTP2 - Years 1 thru 20

Amounts in dollars

Line No.		Line (A)	Subs (B)	Total
1	**LRTP2 - Revenue Requirement**	**90,755,344**	**145,146,185**	**235,901,530**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%
6				
7	**Net cost to MN Jurisdiction**	**65,938,800**	**105,456,768**	**171,395,568**

NOTE: Tax assumptions include 21% corp Fed tax rate

LRTP2 - Year 1 Revenue Requirement

Line No.	Amounts in dollars	Line (A)	Subs (B)	Total
1	**LRTP2 - Revenue Requirement**	**5,921,759**	**9,376,996**	**15,298,755**
2				
3				
4	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%
5	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%
6				
7	**Net cost to MN Jurisdiction**	**4,302,487**	**6,812,909**	**11,115,396**

NOTE: Tax assumptions include 21% corp Fed tax rate

LRTP2 - Total

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	**Project Spend**								
2	Line	47,254,900							
3	Sub	76,300,000							
4	**Total**	123,554,900							
5									
6	Revenue Requirement								
7	Line		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439
8	Sub		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636
9									
10	**Total Revenue Requirements - NSP**		15,298,755	14,903,010	14,451,105	14,027,675	13,629,873	13,255,327	12,897,074
11									
12	FERC Interchange Agreement allocator to NSPM		83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction		86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
14									
15	**Total Revenue Requirements - MN Jurisdiction**		11,115,396	10,827,865	10,499,531	10,191,885	9,902,860	9,630,731	9,370,441
16									
17									
18	**Discount Rate =**	0.06349334							
19									
20	**Present Value of Revenue Requirements - NSP**	139,175,804	14,385,379	13,176,633	12,014,252	10,965,959	10,018,852	9,161,821	8,382,002
21									
22									
23									
24			12.38%	12.06%	11.70%	11.35%	11.03%	10.73%	10.44%

LRTP2 - Total

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	**Project Spend**									
2	Line									
3	Sub									
4	**Total**									
5										
6	Revenue Requirement									
7	Line	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949	4,137,239	3,997,529	3,857,819	3,735,958
8	Sub	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333	6,640,853	6,427,373	6,213,893	6,029,233
9										
10	**Total Revenue Requirements - NSP**	12,544,043	12,190,853	11,837,663	11,484,473	11,131,283	10,778,092	10,424,902	10,071,712	9,765,191
11										
12	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%	86.6%
14										
15	**Total Revenue Requirements - MN Jurisdiction**	9,113,944	8,857,332	8,600,720	8,344,107	8,087,495	7,830,883	7,574,271	7,317,659	7,094,954
16										
17										
18	**Discount Rate =**									
19										
20	**Present Value of Revenue Requirements - NSP**	7,665,832	7,005,209	6,396,144	5,834,834	5,317,750	4,841,610	4,403,370	4,000,200	3,646,904
21										
22										
23										
24		10.15%	9.87%	9.58%	9.30%	9.01%	8.72%	8.44%	8.15%	7.90%

LRTP2 - Total

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	**Project Spend**				
2	Line				
3	Sub				
4	**Total**				
5					
6	Revenue Requirement				
7	Line	3,649,855	3,581,600	3,513,346	3,445,091
8	Sub	5,902,309	5,804,204	5,706,100	5,607,995
9					
10	**Total Revenue Requirements - NSP**	9,552,163	9,385,804	9,219,445	9,053,086
11					
12	FERC Interchange Agreement allocator to NSPM	83.9%	83.9%	83.9%	83.9%
13	Demand Allocator - MN Jurisdiction	86.6%	86.6%	86.6%	86.6%
14					
15	**Total Revenue Requirements - MN Jurisdiction**	6,940,177	6,819,308	6,698,439	6,577,570
16					
17					
18	**Discount Rate =**				
19					
20	**Present Value of Revenue Requirements - NSP**	3,354,367	3,099,171	2,862,491	2,643,024
21					
22					
23					
24		7.73%	7.60%	7.46%	7.33%

LRTP2 - Subs
Based on 56 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve		(1,545,115)	(3,090,231)	(4,635,346)	(6,180,462)	(7,725,577)	(9,270,693)	(10,815,808)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(652,365)	(2,291,518)	(3,722,348)	(4,966,786)	(6,042,373)	(6,964,460)	(7,814,182)
5			74,102,520	70,918,252	67,942,305	65,152,752	62,532,050	60,064,847	57,670,010
6									
7	Average Rate Base		75,201,260	72,510,386	69,430,278	66,547,529	63,842,401	61,298,449	58,867,428
8									
9	Debt Return		1,571,706	1,515,467	1,451,093	1,390,843	1,334,306	1,281,138	1,230,329
10	Equity Return		3,654,781	3,524,005	3,374,312	3,234,210	3,102,741	2,979,105	2,860,957
11	Current Income Tax Requirement		821,652	(217,880)	(69,931)	59,958	175,785	279,421	304,135
12									
13	Book Depreciation		1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax		652,365	1,639,153	1,430,831	1,244,438	1,075,587	922,087	849,722
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		3,815,000	7,248,500	6,523,650	5,875,100	5,287,590	4,753,490	4,501,700
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22									
23	Total Revenue Requirements - NSP		9,376,996	9,137,236	8,862,796	8,605,940	8,364,911	8,138,242	7,921,636
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	85,546,670	8,817,165	8,078,771	7,368,285	6,727,585	6,148,758	5,624,993	5,148,390
28									
29	**Level Annual Revenue Requirement**	**5,610,224**							
30									
31	**57 Year Life LARR %**	**7.35%**							

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(12,360,924)	(13,906,039)	(15,451,154)	(16,996,270)	(18,541,385)	(20,086,501)	(21,631,616)	(23,176,732)	(24,721,847)
3	Removal Expense	-	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,663,905)	(9,515,820)	(10,365,542)	(11,217,458)	(12,067,180)	(12,919,095)	(13,768,818)	(14,620,733)	(14,823,561)
5		55,275,172	52,878,141	50,483,303	48,086,272	45,691,435	43,294,404	40,899,566	38,502,535	36,754,592
6										
7	Average Rate Base	56,472,591	54,076,656	51,680,722	49,284,788	46,888,854	44,492,919	42,096,985	39,701,051	37,628,564
8										
9	Debt Return	1,180,277	1,130,202	1,080,127	1,030,052	979,977	929,902	879,827	829,752	786,437
10	Equity Return	2,744,568	2,628,125	2,511,683	2,395,241	2,278,798	2,162,356	2,045,913	1,929,471	1,828,748
11	Current Income Tax Requirement	257,194	208,039	163,269	114,114	69,344	20,188	(24,581)	(73,737)	534,728
12										
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	849,722	851,915	849,722	851,915	849,722	851,915	849,722	851,915	202,828
15	ITC Flow Thru	-	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	4,501,700	4,509,330	4,501,700	4,509,330	4,501,700	4,509,330	4,501,700	4,509,330	2,250,850
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376	1,131,376
22										
23	Total Revenue Requirements - NSP	7,708,254	7,494,773	7,281,293	7,067,813	6,854,333	6,640,853	6,427,373	6,213,893	6,029,233
24										
25	Discount Rate =									
26										
27	Present Value of Revenue Requirements	4,710,617	4,306,709	3,934,239	3,590,894	3,274,522	2,983,128	2,714,855	2,467,983	2,251,675
28										
29										
30										
31										

LRTP2 - Subs
Based on 56 YEAR LIFE

Line No.	Rate Analysis	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	76,300,000	76,300,000	76,300,000	76,300,000
2	Depreciation Reserve	(26,266,962)	(27,812,078)	(29,357,193)	(30,902,309)
3	Removal Expense	-	-	-	-
4	Accumulated Deferred Taxes	(14,379,495)	(13,935,429)	(13,491,363)	(13,047,296)
5		35,653,543	34,552,493	33,451,444	32,350,395
6					
7	Average Rate Base	36,204,067	35,103,018	34,001,969	32,900,919
8					
9	Debt Return	756,665	733,653	710,641	687,629
10	Equity Return	1,759,518	1,706,007	1,652,496	1,598,985
11	Current Income Tax Requirement	1,153,700	1,132,119	1,110,537	1,088,956
12					
13	Book Depreciation	1,545,115	1,545,115	1,545,115	1,545,115
14	Annual Deferred Tax	(444,066)	(444,066)	(444,066)	(444,066)
15	ITC Flow Thru	-	-	-	-
16	Tax Depreciation & Removal Expense	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-
18	AFUDC Expenditure	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-
20	Avoided Tax Interest	-	-	-	-
21	Property Tax @ 1.4828%	1,131,376	1,131,376	1,131,376	1,131,376
22					
23	Total Revenue Requirements - NSP	5,902,309	5,804,204	5,706,100	5,607,995
24					
25	Discount Rate =				
26					
27	Present Value of Revenue Requirements	2,072,673	1,916,535	1,771,653	1,637,239
28					
29					
30					
31					

LRTP2 - Line
Based on 63 YEAR LIFE

Cost Assumptions			
Capital Structure	Rate	Ratio	Weighted Cost
Long Term Debt	4.4000%	47.0800%	2.0700%
Short Term Debt	4.1700%	0.4200%	0.0200%
Preferred Stock	0.0000%	0.0000%	0.0000%
Common Equity	9.2500%	52.5000%	4.8600%
Required Rate of Return			6.9500%
Tax Rate (MN)	28.7400%		

Line No.	Rate Analysis		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
1	Plant Investment		47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve		(1,074,986)	(2,149,972)	(3,224,958)	(4,299,945)	(5,374,931)	(6,449,917)	(7,524,903)
3	Removal Expense		-	-	-	-	-	-	-
4	Accumulated Deferred Taxes		(370,102)	(1,351,351)	(2,203,581)	(2,940,371)	(3,572,588)	(4,109,737)	(4,602,068)
5			45,809,812	43,753,576	41,826,361	40,014,584	38,307,382	36,695,247	35,127,929
6									
7	Average Rate Base		46,532,356	44,781,694	42,789,969	40,920,472	39,160,983	37,501,314	35,911,588
8									
9	Debt Return		972,526	935,937	894,310	855,238	818,465	783,777	750,552
10	Equity Return		2,261,473	2,176,390	2,079,592	1,988,735	1,903,224	1,822,564	1,745,303
11	Current Income Tax Requirement		541,977	(103,486)	(13,505)	65,290	135,376	197,913	211,570
12									
13	Book Depreciation		1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax		370,102	981,250	852,229	736,790	632,216	537,149	492,331
15	ITC Flow Thru		-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense		2,362,745	4,489,216	4,040,294	3,638,627	3,274,765	2,943,980	2,788,039
17	Tax Depreciation on Easements		-	-	-	-	-	-	-
18	AFUDC Expenditure		-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating		-	-	-	-	-	-	-
20	Avoided Tax Interest		-	-	-	-	-	-	-
21	Property Tax @ 1.4828%		700,696	700,696	700,696	700,696	700,696	700,696	700,696
22									
23	Total Revenue Requirements - NSP		5,921,759	5,765,773	5,588,309	5,421,735	5,264,963	5,117,085	4,975,439
24									
25	Discount Rate =	0.06349334							
26									
27	Present Value of Revenue Requirements	53,629,134	5,568,215	5,097,861	4,645,967	4,238,373	3,870,093	3,536,828	3,233,612
28									
29	**Level Annual Revenue Requirement**	**3,477,024**							
30									
31	**63 Year Life LARR %**	**7.36%**							

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(8,599,889)	(9,674,875)	(10,749,861)	(11,824,847)	(12,899,834)	(13,974,820)	(15,049,806)	(16,124,792)
3	Removal Expense	-	-	-	-	-	-	-	-
4	Accumulated Deferred Taxes	(5,094,399)	(5,588,089)	(6,080,420)	(6,574,110)	(7,066,441)	(7,560,131)	(8,052,462)	(8,546,152)
5		33,560,612	31,991,936	30,424,618	28,855,943	27,288,625	25,719,949	24,152,632	22,583,956
6									
7	Average Rate Base	34,344,270	32,776,274	31,208,277	29,640,281	28,072,284	26,504,287	24,936,291	23,368,294
8									
9	Debt Return	717,795	685,024	652,253	619,482	586,711	553,940	521,168	488,397
10	Equity Return	1,669,132	1,592,927	1,516,722	1,440,518	1,364,313	1,288,108	1,211,904	1,135,699
11	Current Income Tax Requirement	180,849	148,757	119,381	87,288	57,912	25,820	(3,556)	(35,649)
12									
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	492,331	493,690	492,331	493,690	492,331	493,690	492,331	493,690
15	ITC Flow Thru	-	-	-	-	-	-	-	-
16	Tax Depreciation & Removal Expense	2,788,039	2,792,765	2,788,039	2,792,765	2,788,039	2,792,765	2,788,039	2,792,765
17	Tax Depreciation on Easements	-	-	-	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696	700,696	700,696	700,696
22									
23	Total Revenue Requirements - NSP	4,835,789	4,696,079	4,556,369	4,416,659	4,276,949	4,137,239	3,997,529	3,857,819
24									
25	Discount Rate =								
26									
27	Present Value of Revenue Requirements	2,955,215	2,698,500	2,461,904	2,243,941	2,043,228	1,858,483	1,688,514	1,532,217
28									
29									
30									
31									

LRTP2 - Line
Based on 63 YEAR LIFE

Line No.	Rate Analysis	Year 16	Year 17	Year 18	Year 19	Year 20
1	Plant Investment	47,254,900	47,254,900	47,254,900	47,254,900	47,254,900
2	Depreciation Reserve	(17,199,778)	(18,274,764)	(19,349,750)	(20,424,736)	(21,499,723)
3	Removal Expense	-	-	-	-	-
4	Accumulated Deferred Taxes	(8,637,842)	(8,328,891)	(8,019,940)	(7,710,989)	(7,402,038)
5		21,417,280	20,651,245	19,885,210	19,119,175	18,353,139
6						
7	Average Rate Base	22,000,618	21,034,262	20,268,227	19,502,192	18,736,157
8						
9	Debt Return	459,813	439,616	423,606	407,596	391,586
10	Equity Return	1,069,230	1,022,265	985,036	947,807	910,577
11	Current Income Tax Requirement	339,543	721,243	706,228	691,213	676,198
12						
13	Book Depreciation	1,074,986	1,074,986	1,074,986	1,074,986	1,074,986
14	Annual Deferred Tax	91,690	(308,951)	(308,951)	(308,951)	(308,951)
15	ITC Flow Thru	-	-	-	-	-
16	Tax Depreciation & Removal Expense	1,394,020	-	-	-	-
17	Tax Depreciation on Easements	-	-	-	-	-
18	AFUDC Expenditure	-	-	-	-	-
19	Book Depreciation Cleared to Operating	-	-	-	-	-
20	Avoided Tax Interest	-	-	-	-	-
21	Property Tax @ 1.4828%	700,696	700,696	700,696	700,696	700,696
22						
23	Total Revenue Requirements - NSP	3,735,958	3,649,855	3,581,600	3,513,346	3,445,091
24						
25	Discount Rate =					
26						
27	Present Value of Revenue Requirements	1,395,229	1,281,694	1,182,636	1,090,838	1,005,785
28						
29						
30						
31						

Key Inputs

Line No	Capital Structure			
1			2024	
2	Capital Structure	Cost	Ratio	WACC
3	Long Term Debt	4.4000%	47.0800%	2.07%
4	Short Term Debt	4.1700%	0.4200%	0.02%
5	Preferred Stock	0.0000%	0.0000%	0.00%
6	Common Equity	9.2500%	52.5000%	4.86%
7	**Required Rate of Return**			6.95%
8	(Rates and Ratios from Settlement in Docket E002/GR-21-630)			
9				
10	**Property Tax Rates**			
11	Property Tax Rate			1.4828%
12	(percentage based on last TCR filing in Docket No. E002M-21-814)			
13				
14	**Income Tax Rates**			
15	Federal Tax Rate			21.00%
16	StateTax Rate			9.80%
17	State Composite Income Tax Rate			28.7420%
18				
19	**Allocators (2024 Estimate)**			
20	MN 12-month CP demand (Electric Demand)			86.6326%
21	NSPM 36-month CP demand (Interchange Electric)			83.8663%
22	Jurisdictional Allocator			72.6556%
23				
24	**Book Depreciation Lives**			
25	Land			0.00
26	Line			63.28
27	Sub			56.43
28				
29	**Net Salvage %**			
30	Land			0.00%
31	Line			-43.95%
32	Sub			-14.26%
33				
34	**Book Depreciation Rates**			
35	Land			0.00%
36	Line			2.2749%
37	Sub			2.0251%