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

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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.

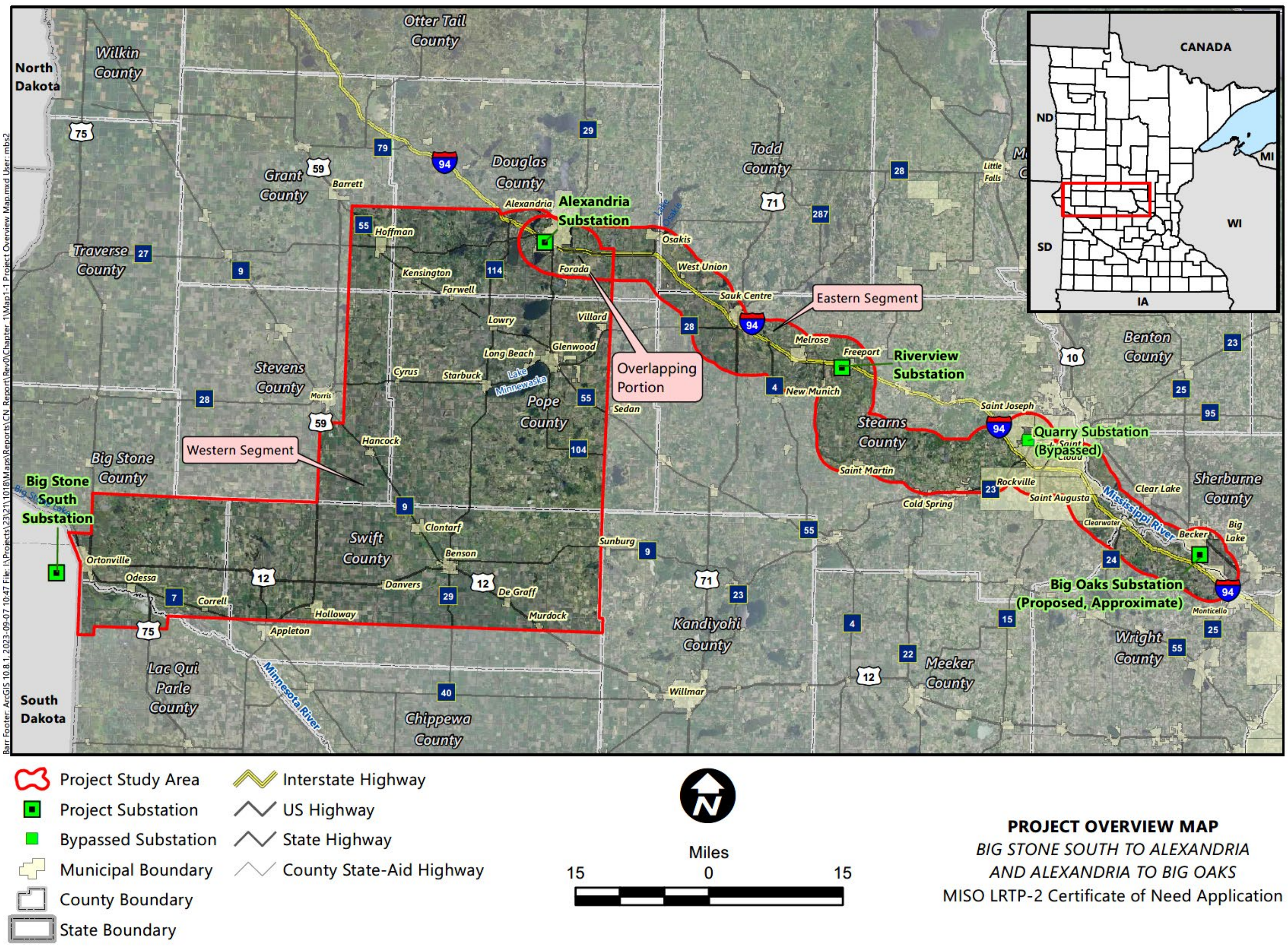
1.2 Project Description

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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Minnesota Department of Commerce EERA
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Website: www.mn.gov/commerce

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

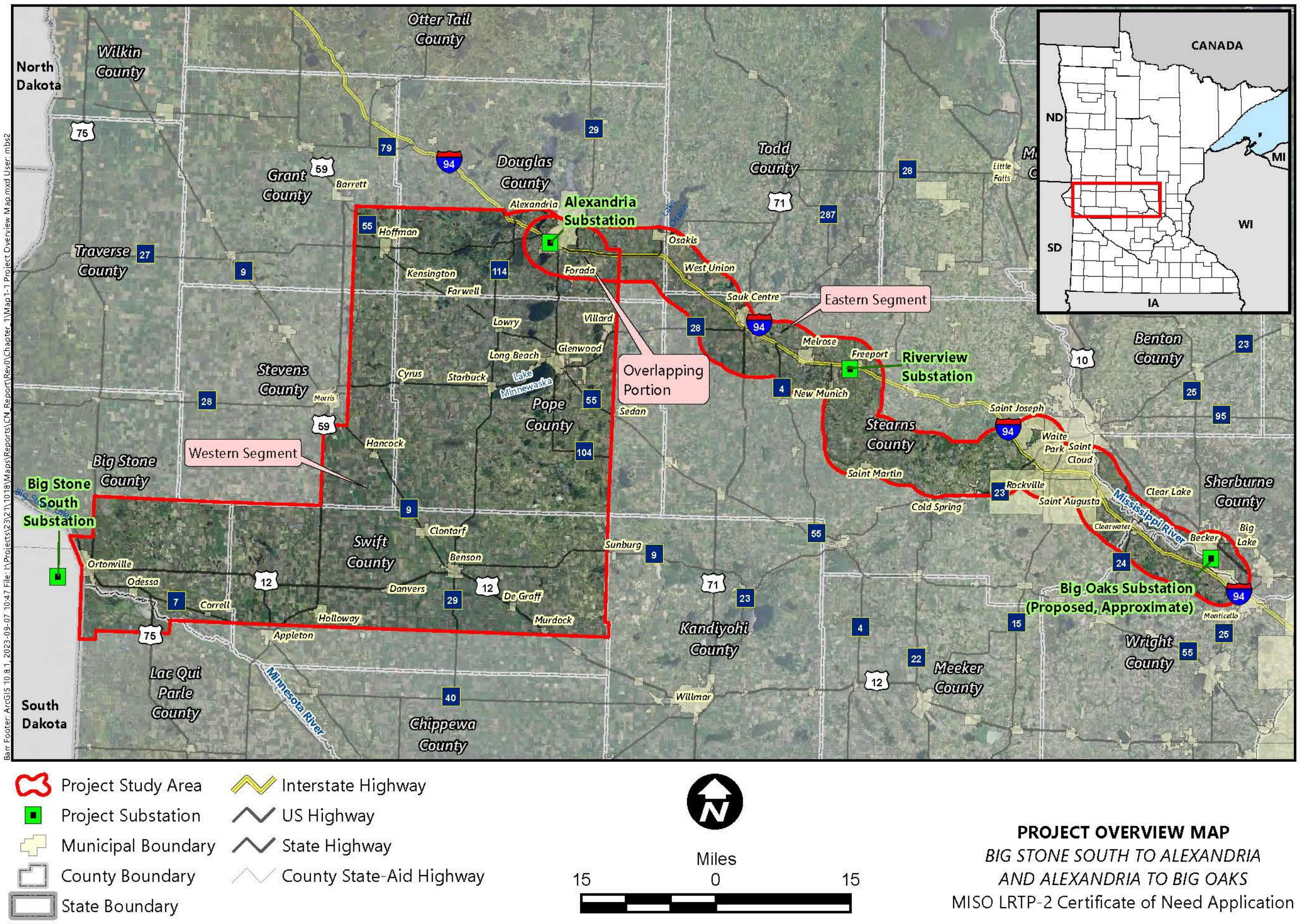
The Applicants propose to construct a new 345 kV transmission line between Grant County, South Dakota and Sherburne County, Minnesota, which will be comprised of two segments:

- 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.

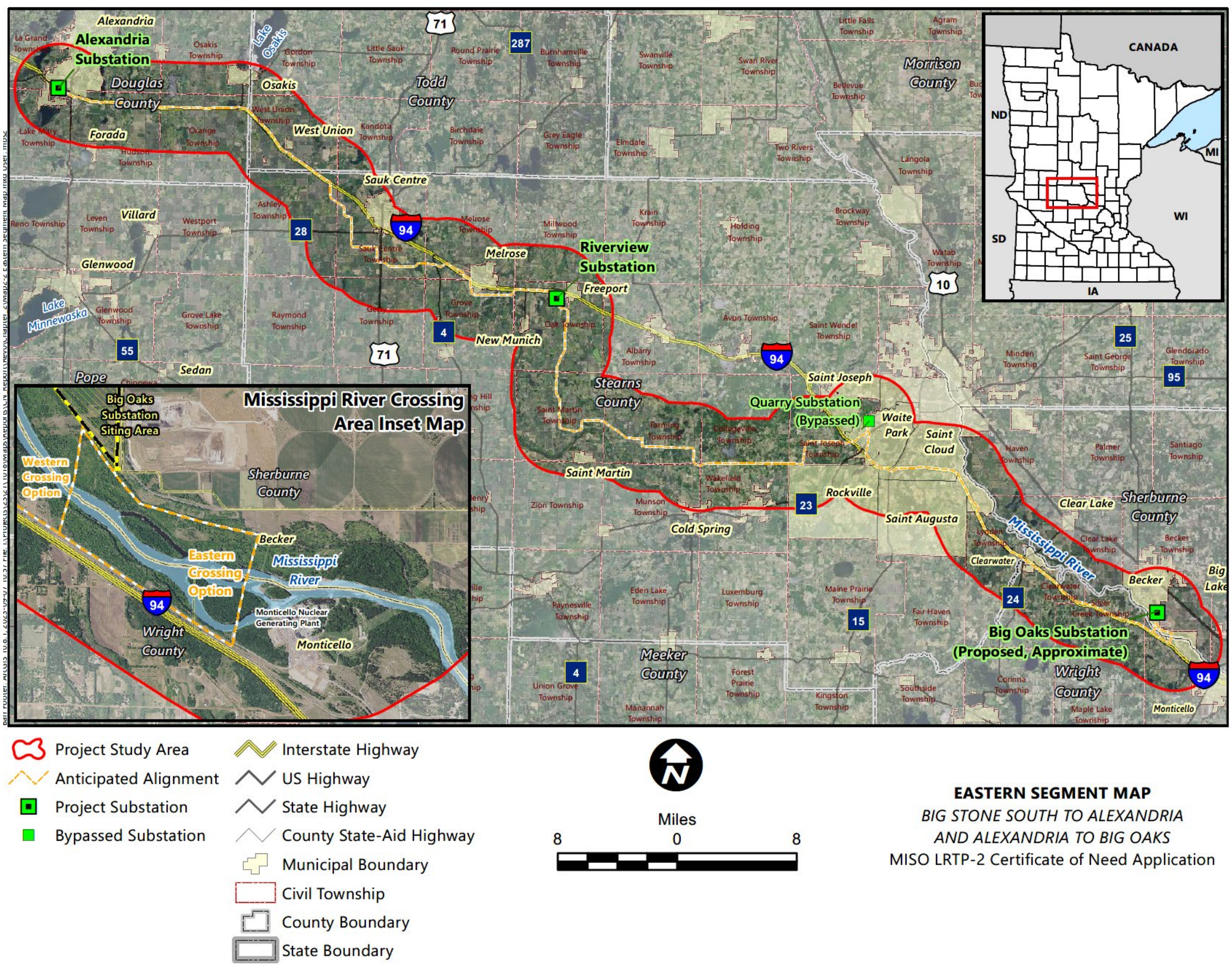
Map 2-1
Project Overview Map



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

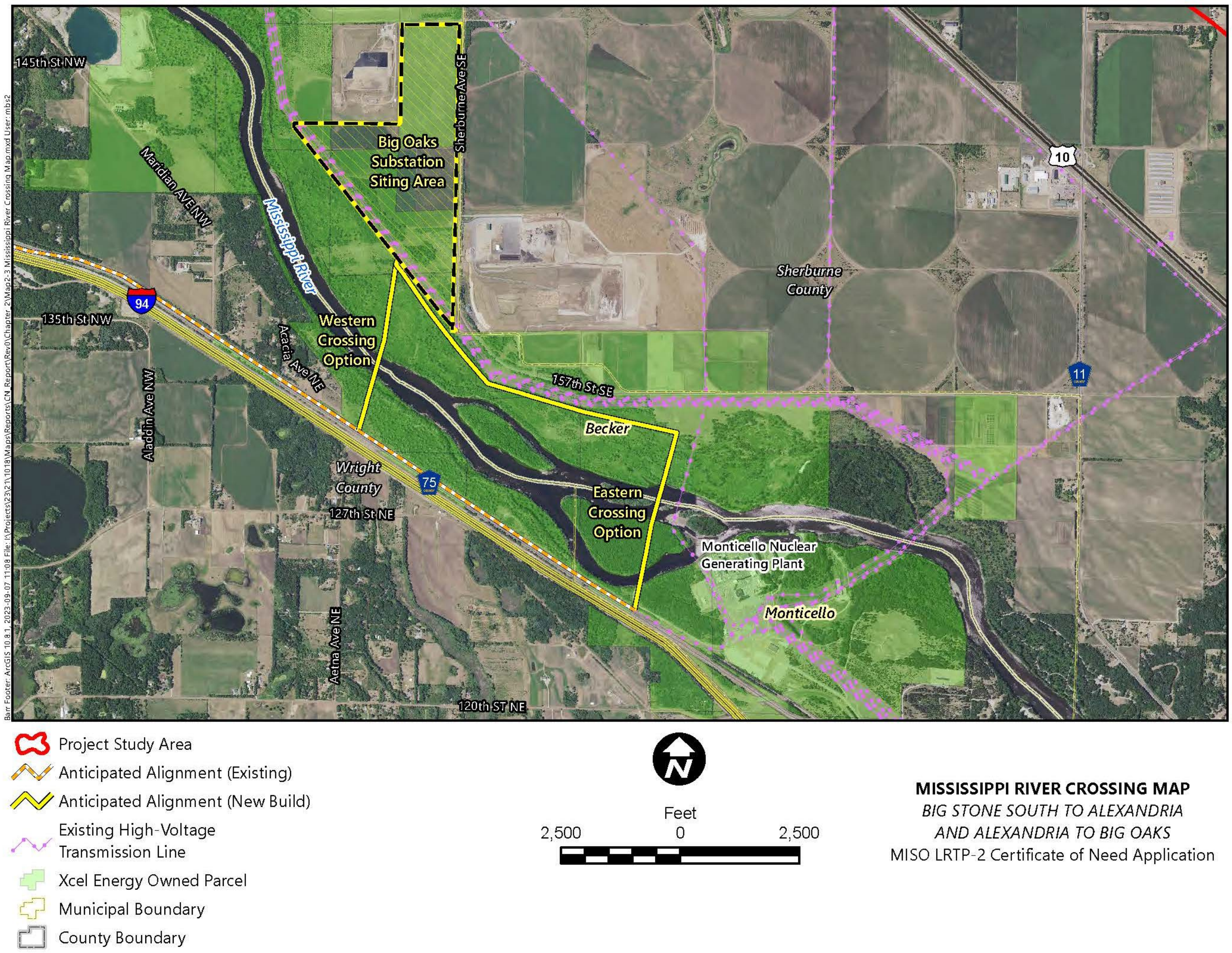
The majority of the Eastern Segment between the Alexandria Substation, Riverview Substation, and the new Big Oaks Substation (approximately 105 to 108 miles long) involves adding a second 345 kV circuit to existing transmission line structures that were constructed as double-circuit capable as part of 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.

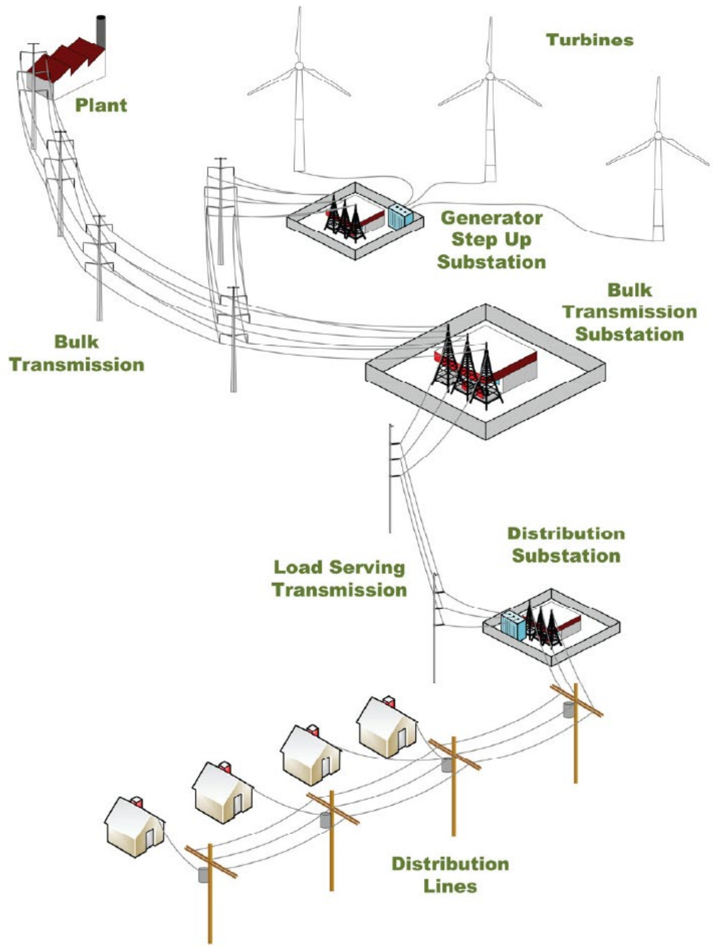
Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant. The electricity is then transported over high voltage transmission lines, often at voltages in excess of one hundred thousand volts (e.g., 115 kV, 230 kV,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

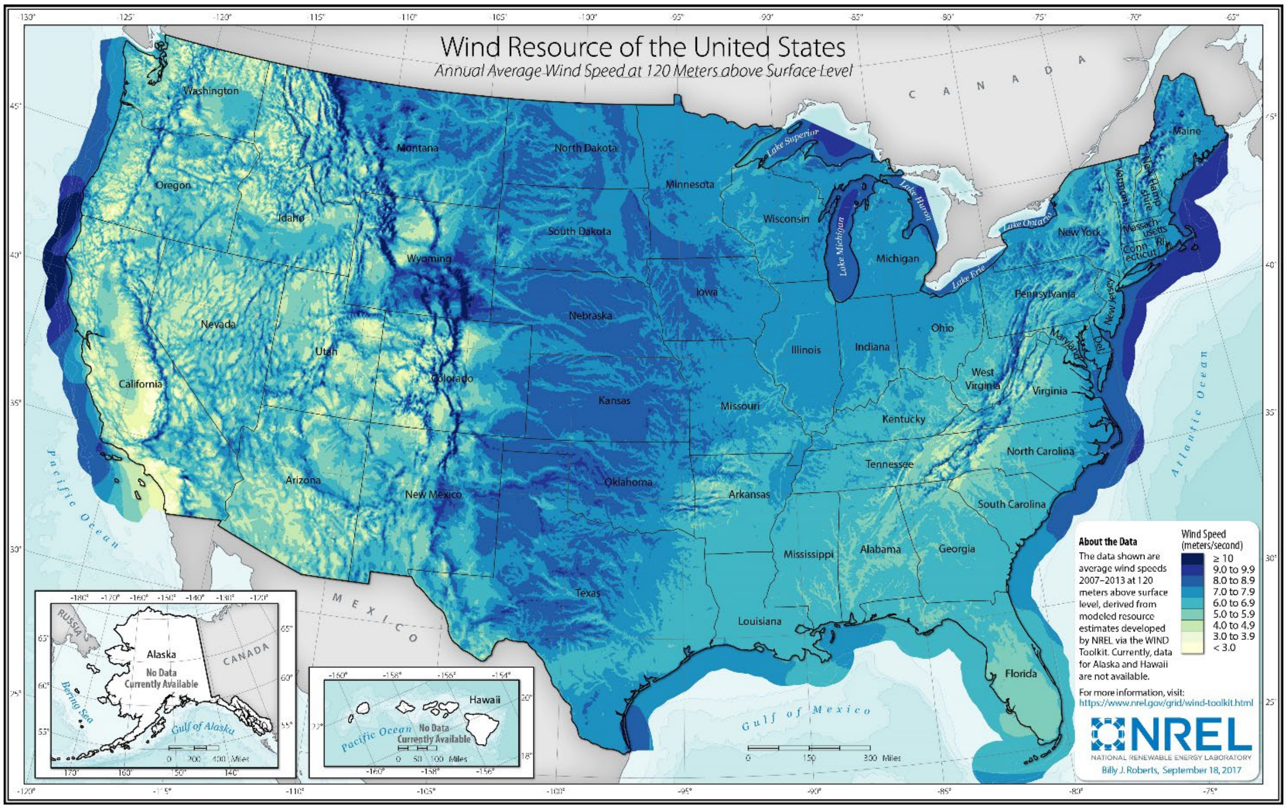
While continuing expansion of renewable energy generation is planned, there is currently not enough transmission capacity on the high-voltage transmission system to accommodate all the renewable energy projects that wish to interconnect. Further, congestion on the high voltage transmission system has 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

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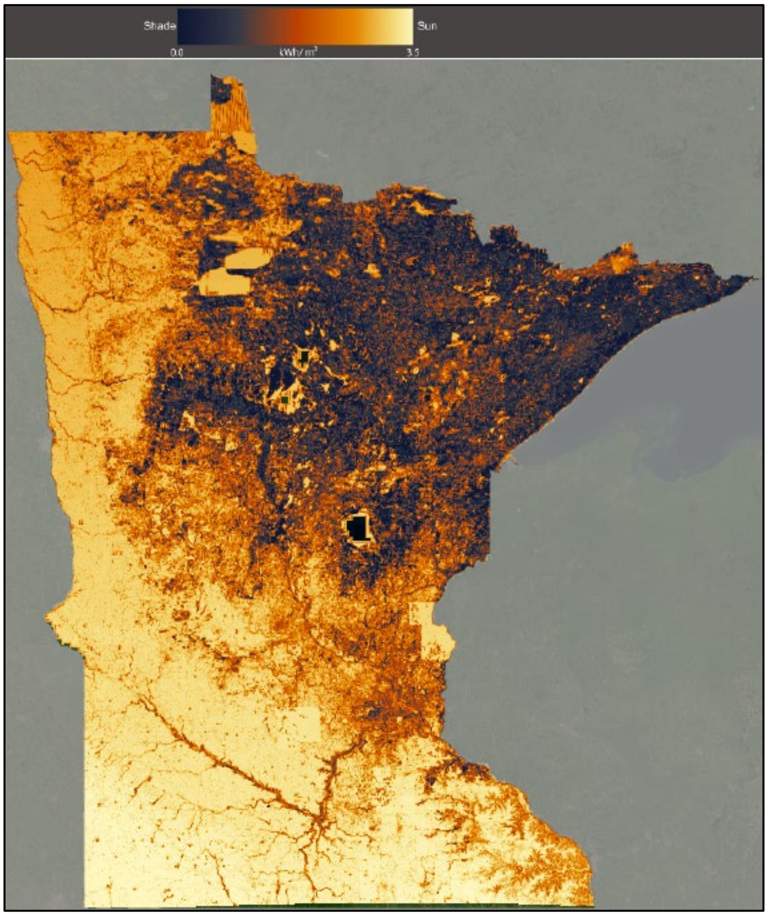
[18] *See* NREL, *Wind Resource Maps and Data*, available at https://www.nrel.gov/gis/wind-resource-maps.html.

[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.

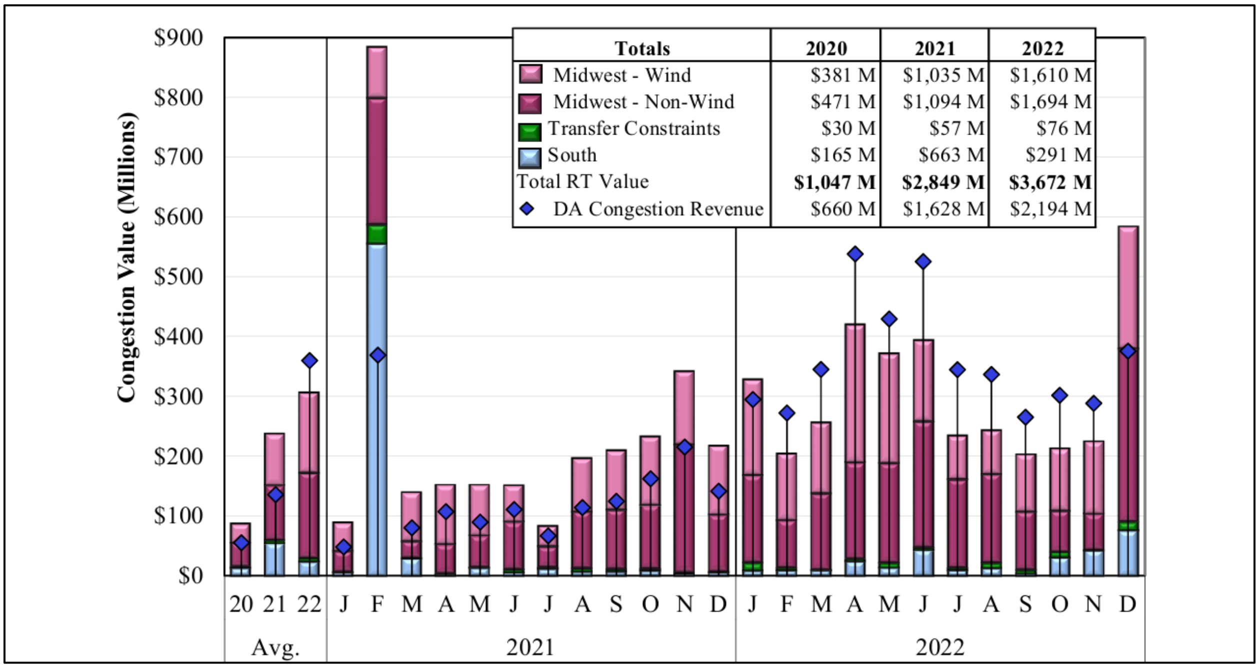
Congestion on the transmission system has been increasing in the past several years due to the increased amount of new generation being added to the transmission system without an equivalent amount of new transmission capacity. One issue contributing to increased congestion costs is how MISO is dispatching 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.

[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).

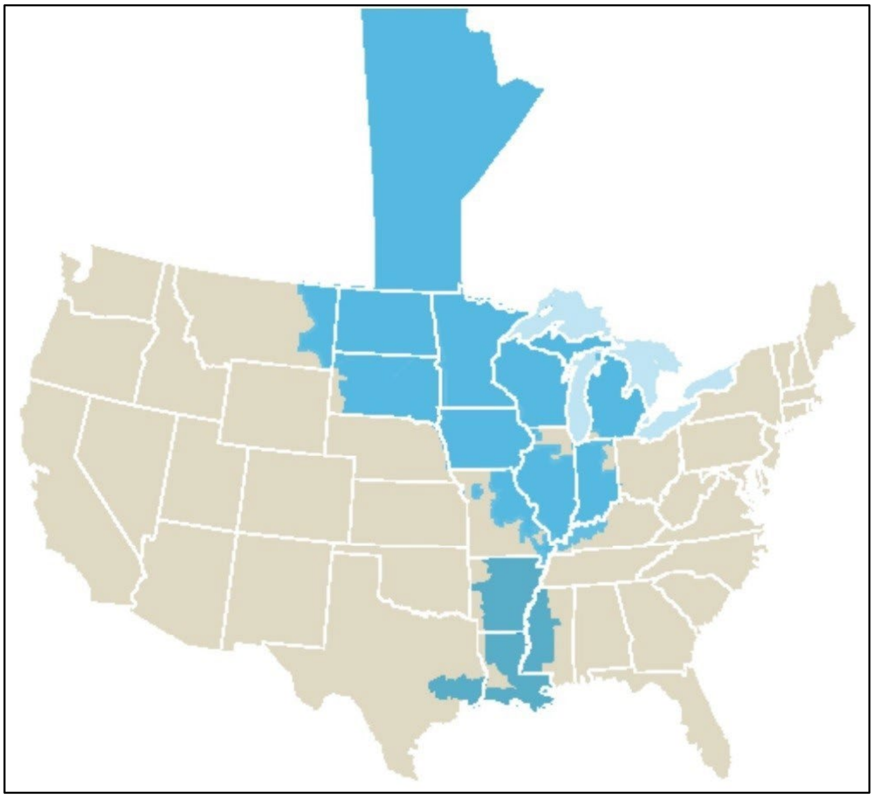
4.2.1 MISO Overview

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.

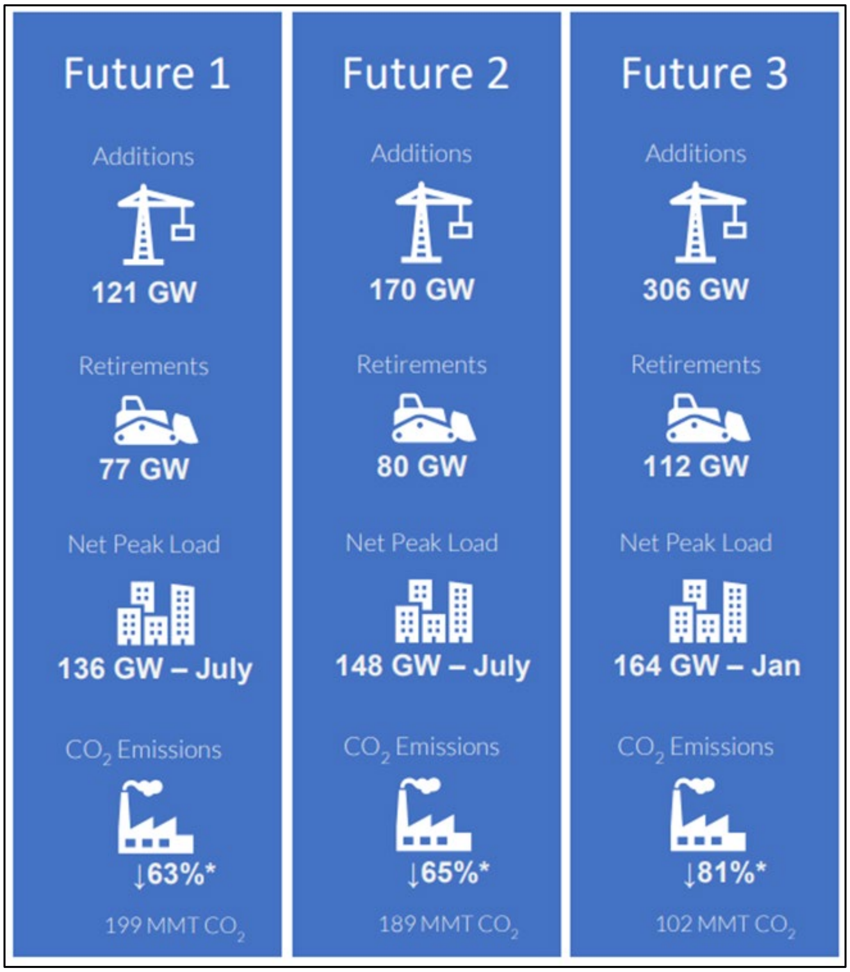
comes to fruition; however, additional generation interconnection requests are also made each year.

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

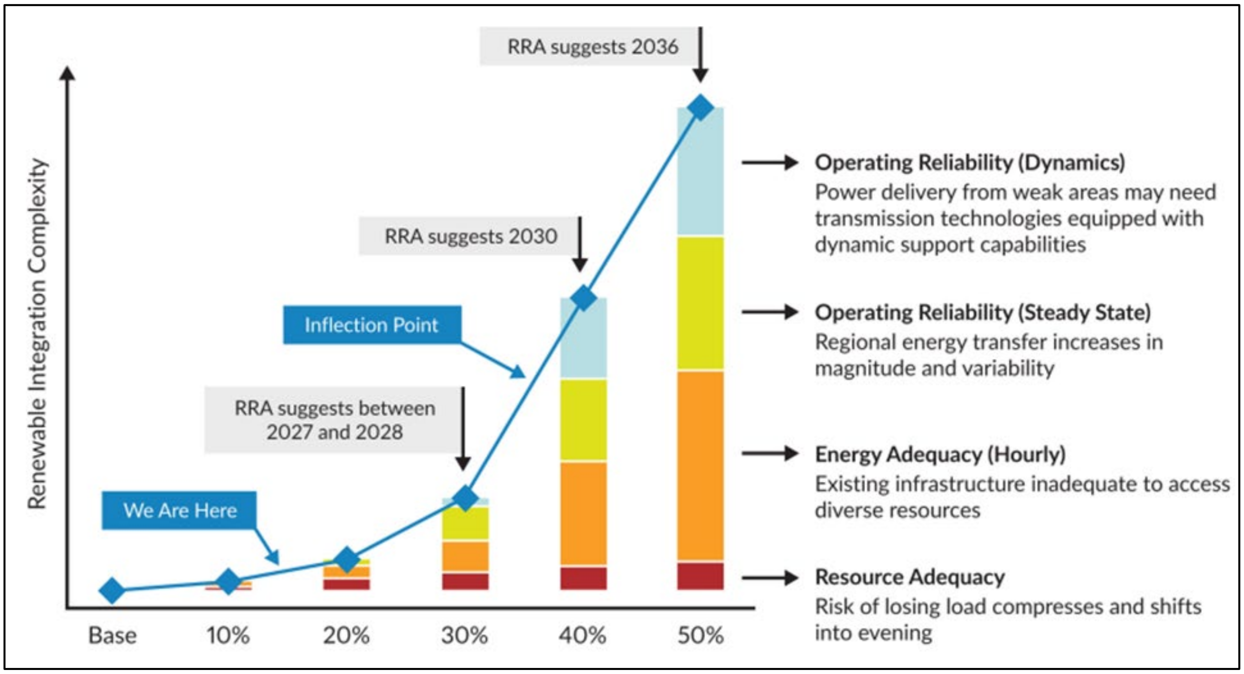
[31] **Appendix E-1** at 26 (MTEP21 Report Addendum).

[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.

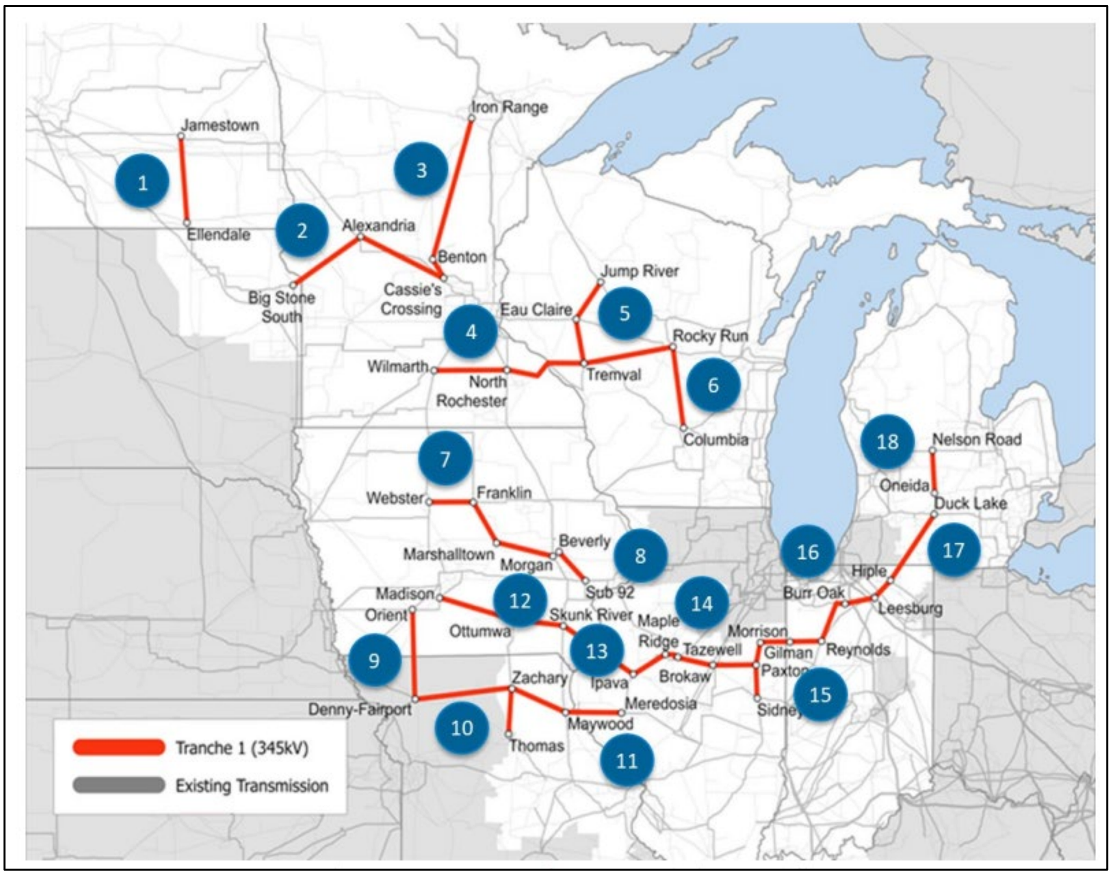
MISO evaluated the LRTP in accordance with MISO's federally approved tariff. For any transmission project to be deemed needed under MISO's tariff, it must meet defined criteria. In MISO's LRTP, MISO and stakeholders worked to identify a transmission plan that simultaneously addresses multiple regional 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]

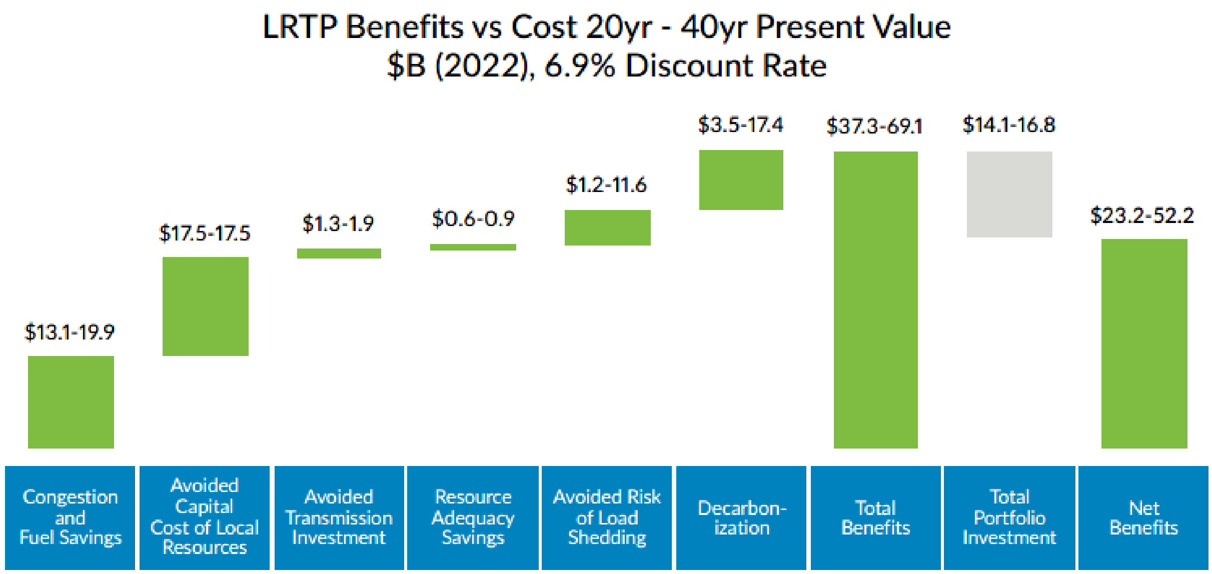


Figure 2: LRTP Tranche 1 Portfolio benefits far outweigh costs (Values as of 6/1/22)*

*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:

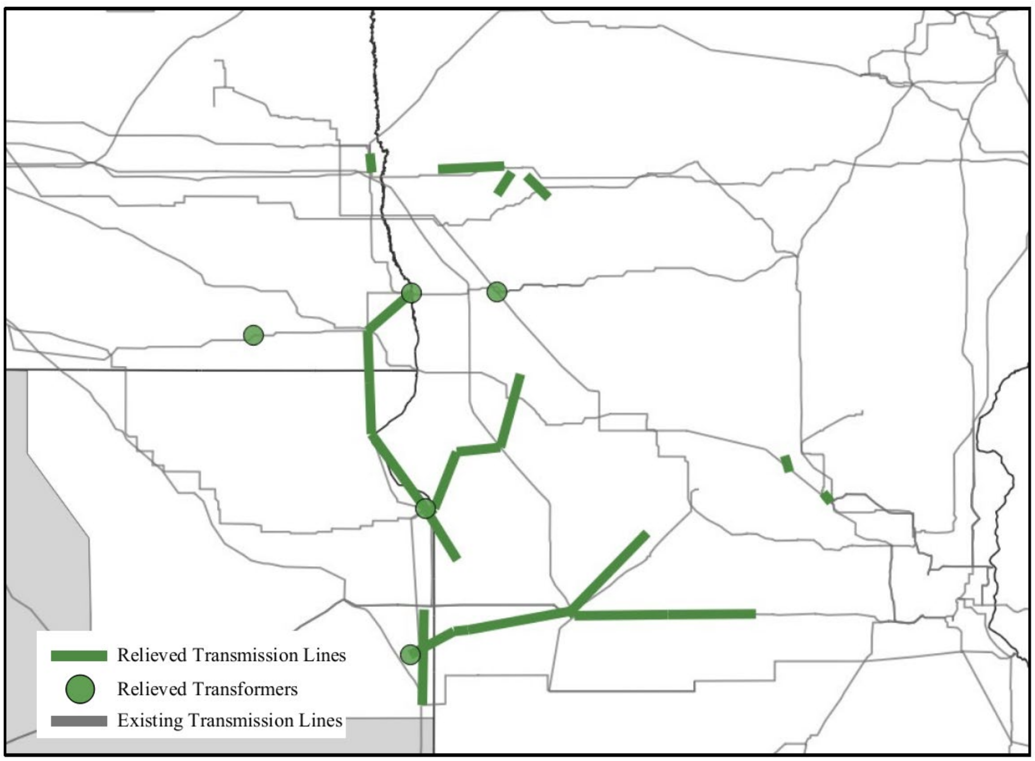
> The Eastern Dakotas and Western/Central Minnesota 230 kV system is heavily constrained for many different seasons through the year. This 230 kV system has been playing a key role in transporting energy across a large geographical area as generation is needing to be transported out of the Dakotas and 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;

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[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.

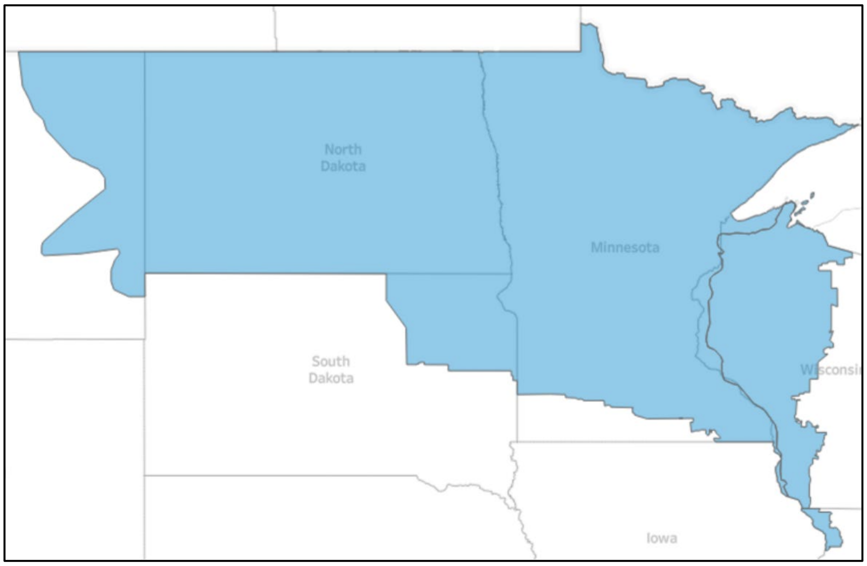
The Applicants conducted two separate analyses:

- 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

- <u>*MISO's MTEP21 Future 2.*</u> 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

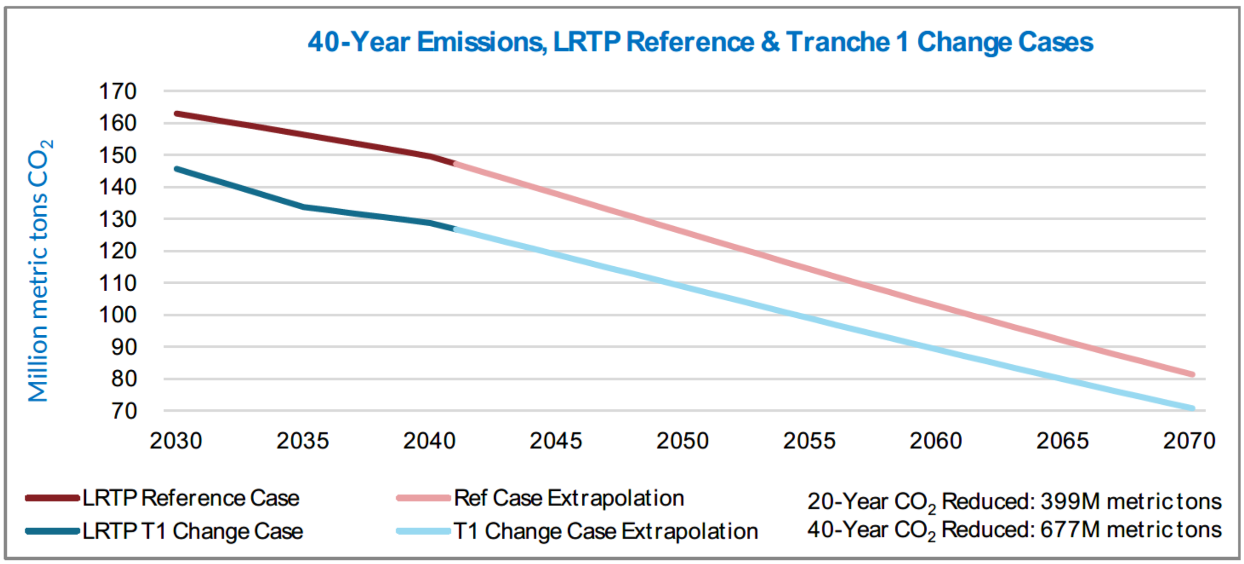
Table 4-11
APC Benefits of the Project under MTEP21 Future 2 Model

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.

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[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.

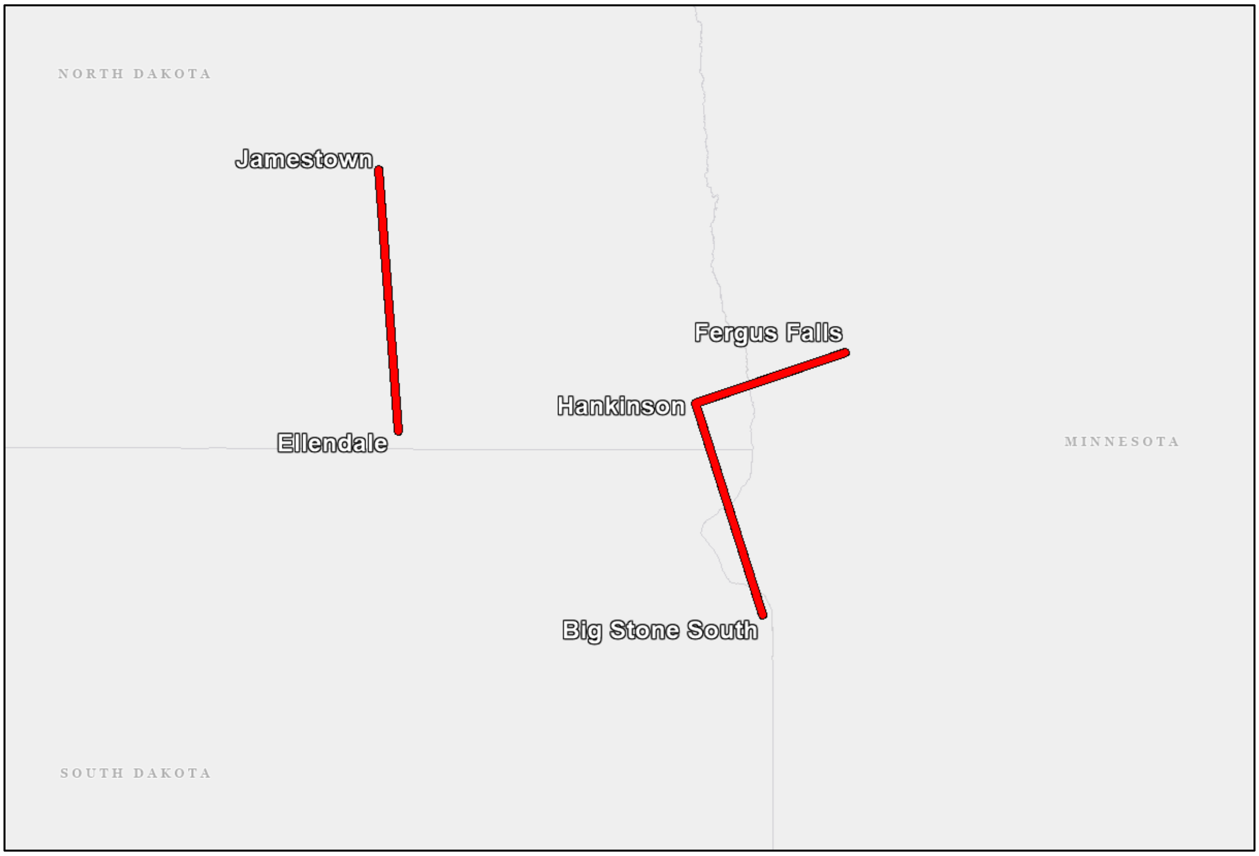
Table 5-2
Thermal Reliability Issues Resulting From Alternative 1

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.

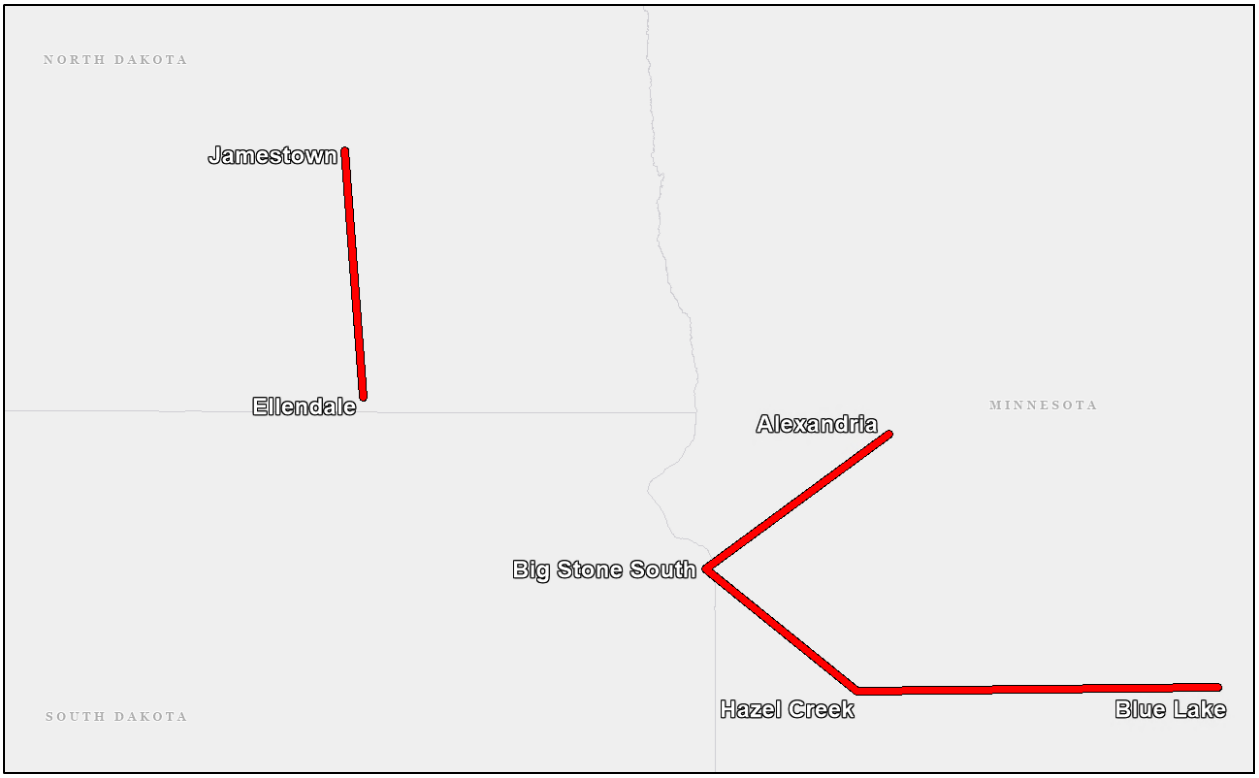
Table 5-4
Thermal Reliability Issues Resulting From Alternative 3

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

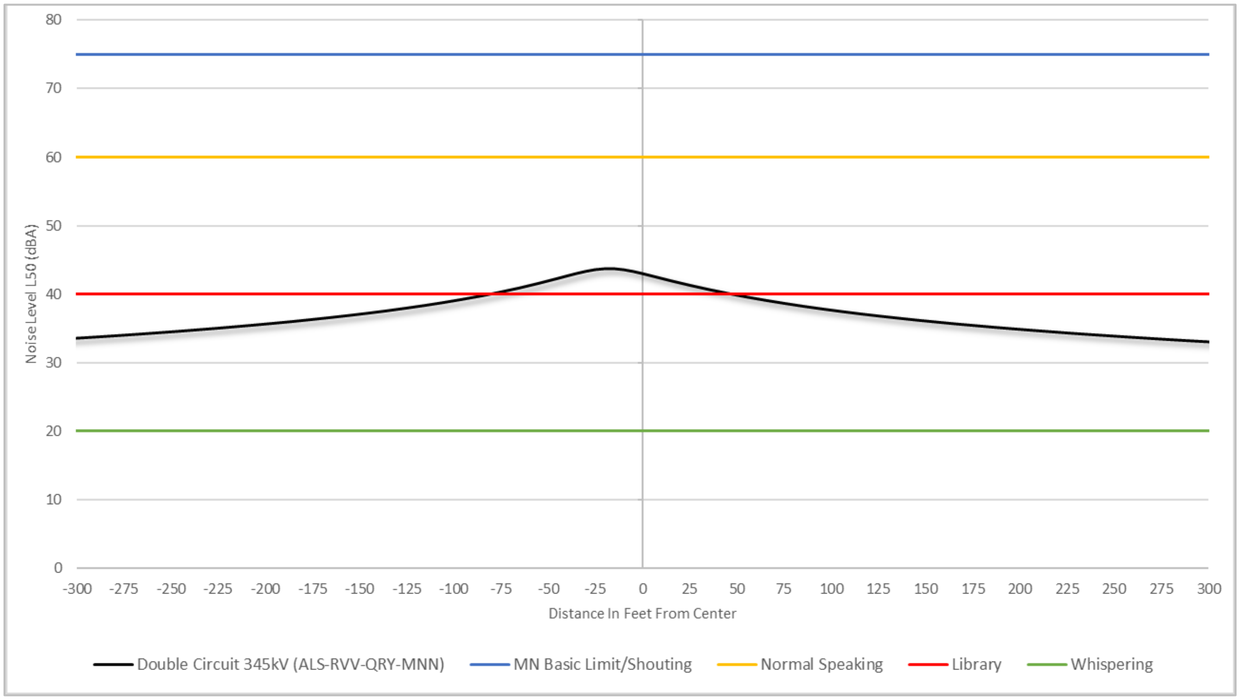


Figure 6-2
Calculated Audible Noise for Single-Circuit 345 kV for Eastern Segment at Nominal System Voltage

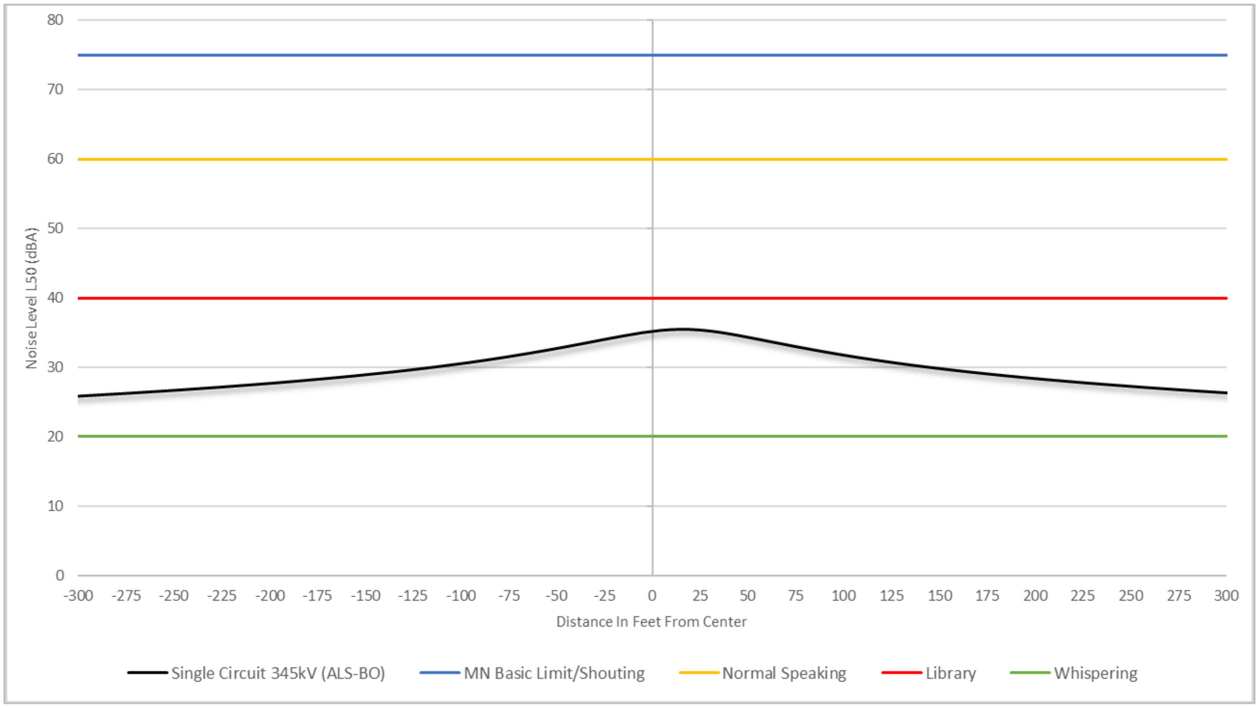
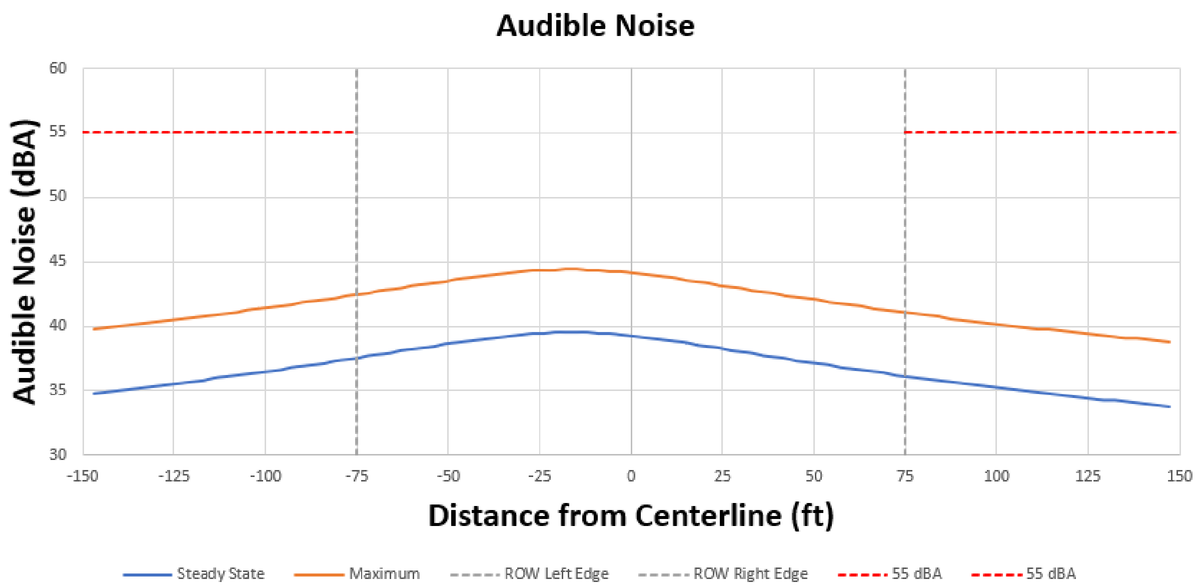


Figure 6-3
Calculated Audible Noise for Single-Circuit 345 kV for Western Segment at Nominal and Maximum System Voltage



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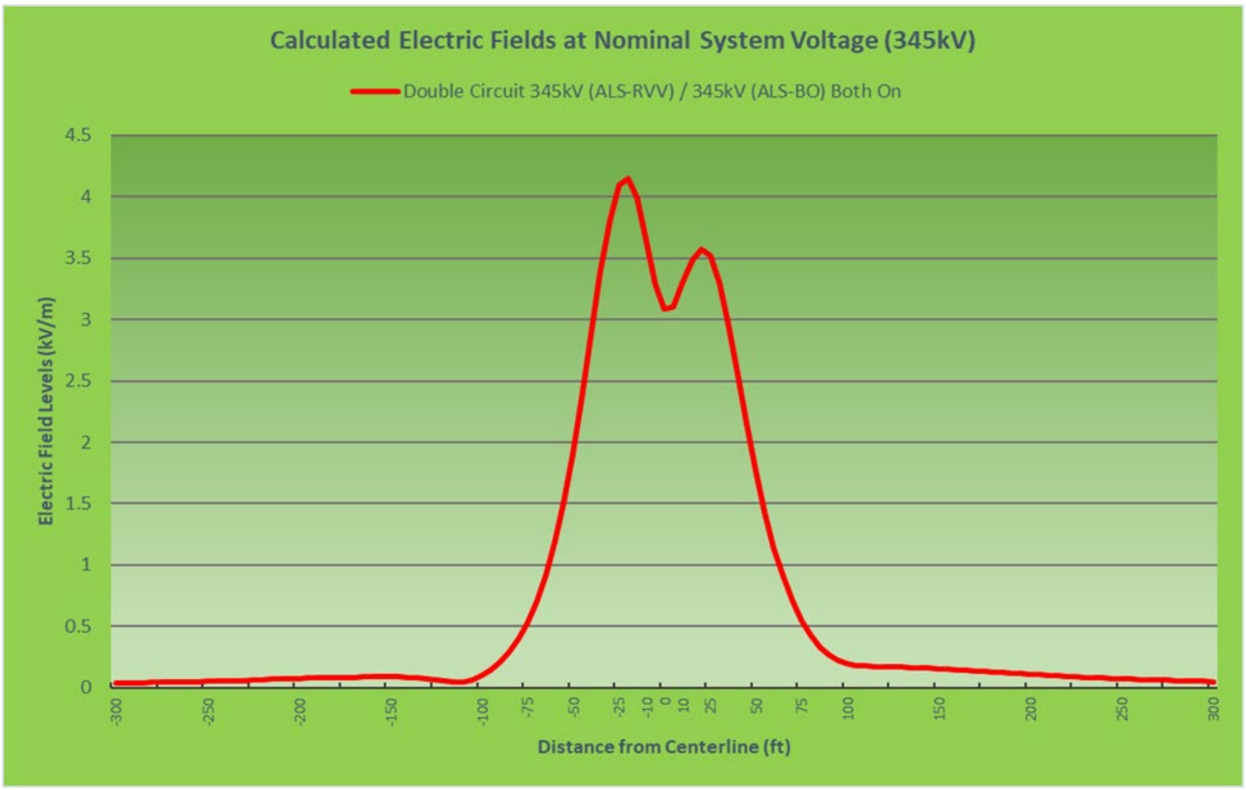
[77] *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton, Minn.,* Docket No. ET2/TL-08-1474, ORDER GRANTING ROUTE PERMIT (Sept. 14, 2010) (adopting the Administrative Law Judge's Findings of Fact, Conclusions, and Recommendation at Finding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

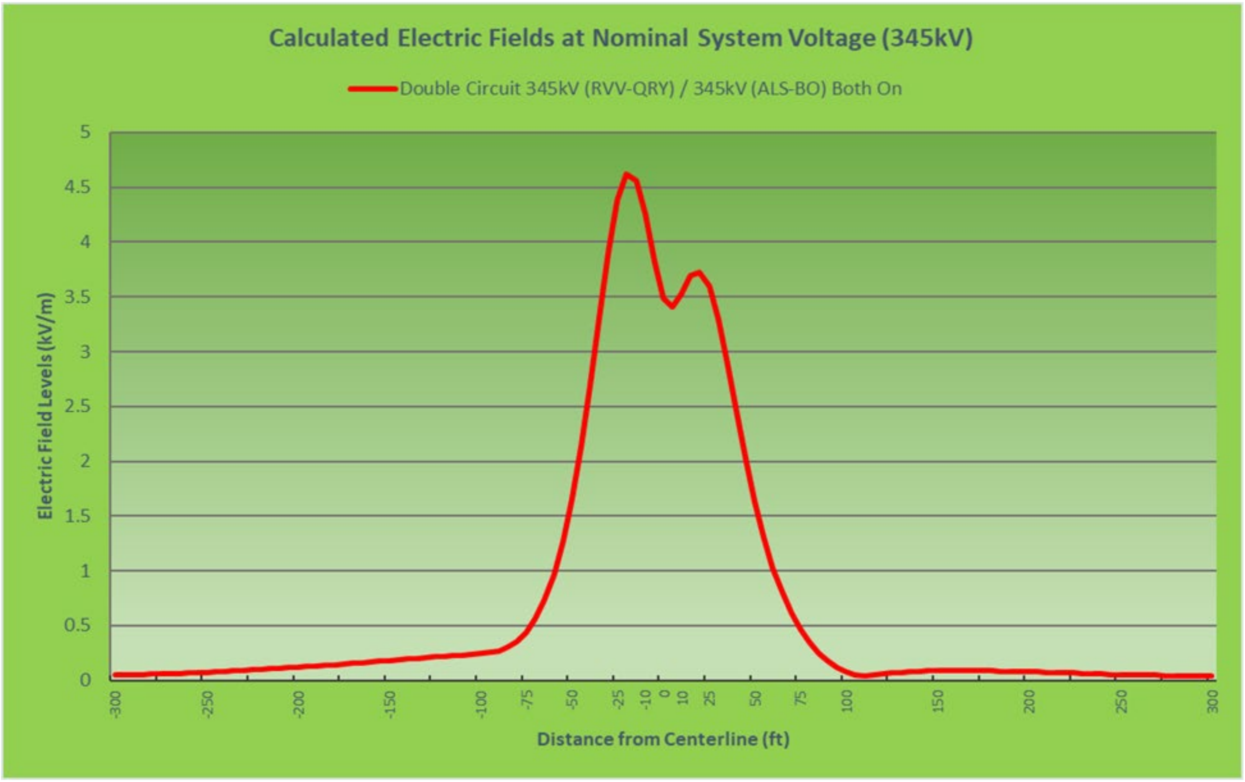
[78] Electric field calculations are not provided for Project substations because Project substations will not be accessible to the public, and electric fields associated with the substations are anticipated to be similar to the 345 kV lines and thus, well below the Commission's electric field limit.

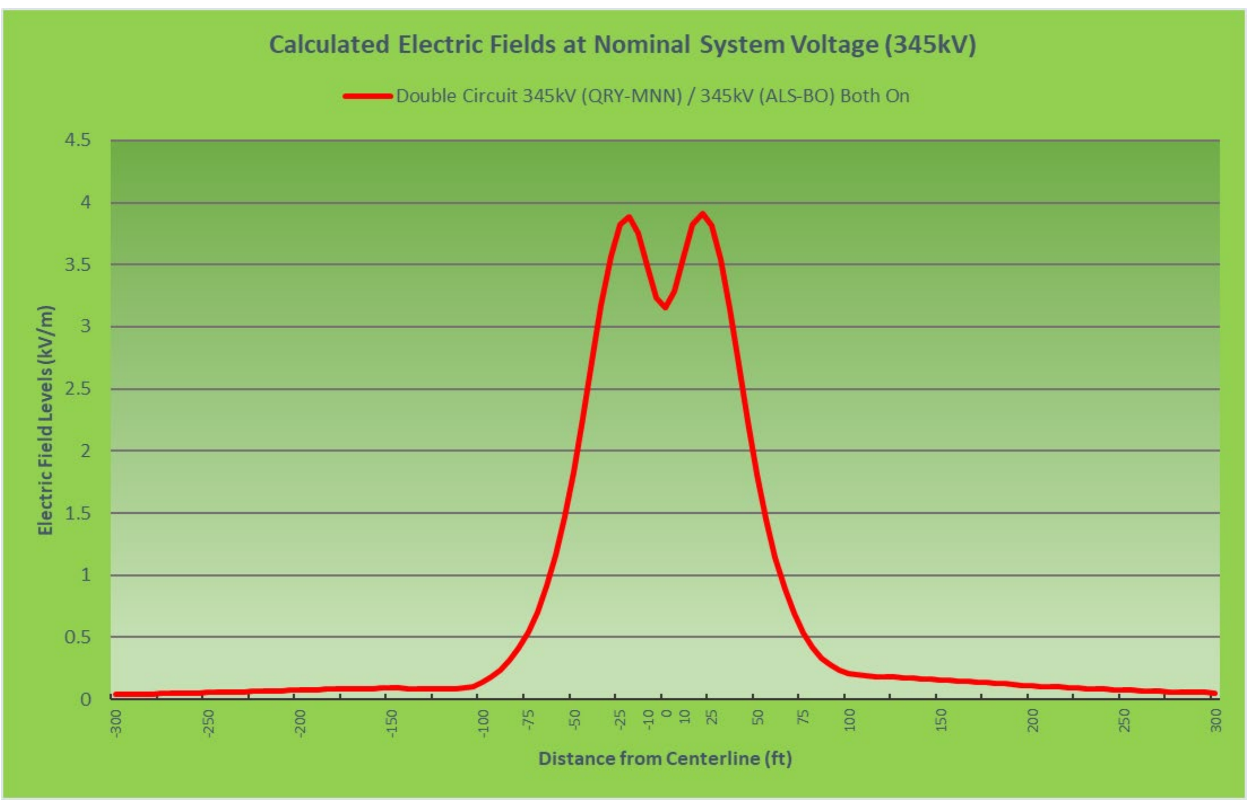
Table 6-2
Electric Field Calculations Summary

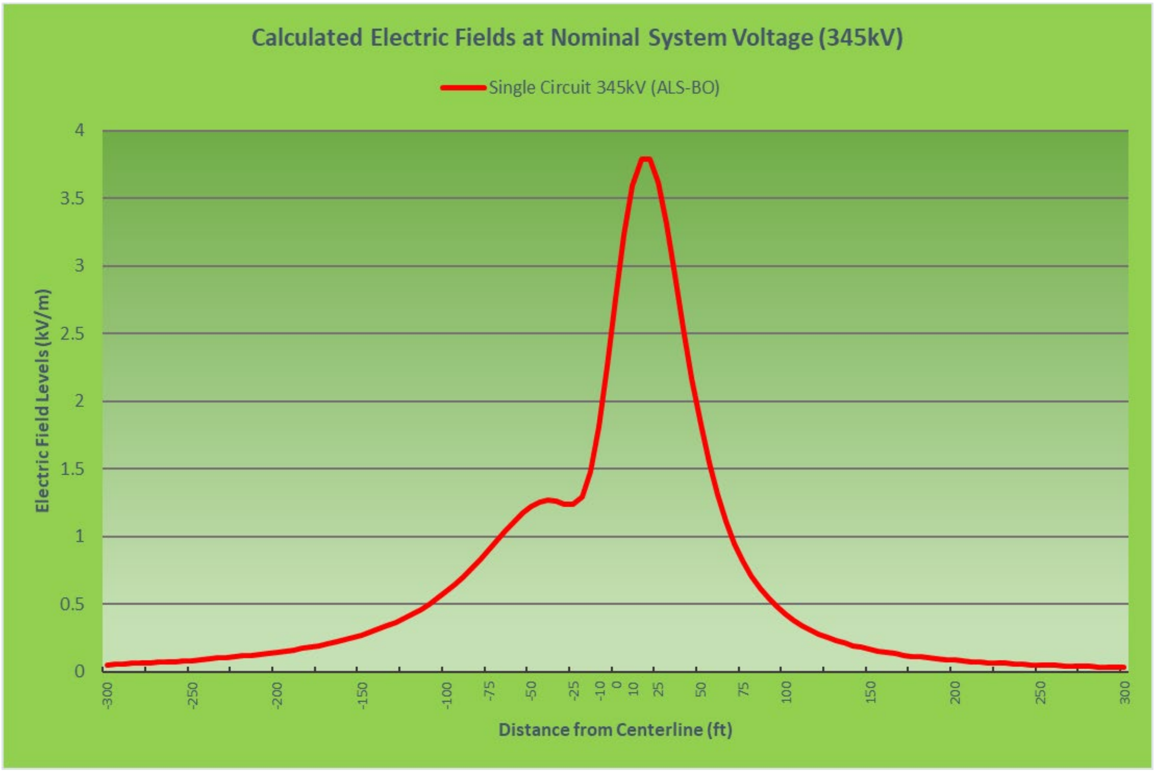
Structure Type	Circuits Present	Maximum Voltage	Distance to Proposed Centerline (feet)												
			-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit on Double-Circuit Capable Monopole	Big Stone South – Alexandria	379.5 kV	0.07	0.15	0.21	0.33	1.8	5.7	4.6	1.2	0.12	0.16	0.19	0.10	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)
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)
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)

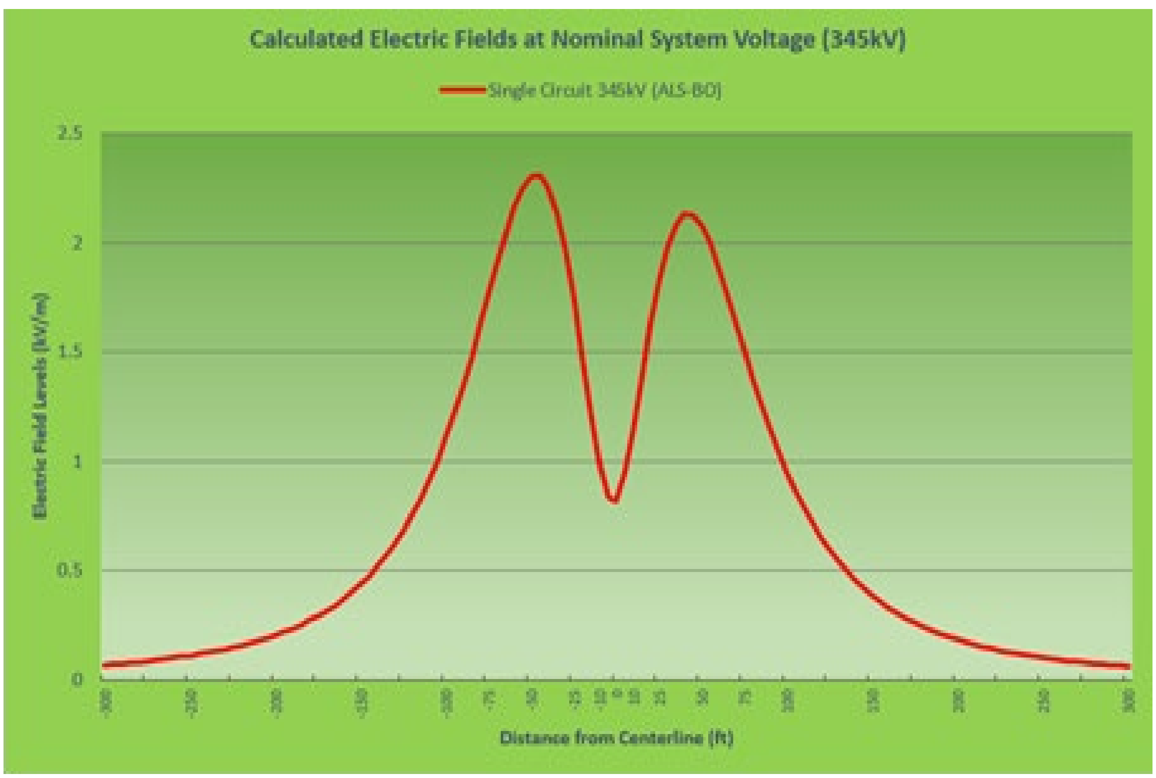
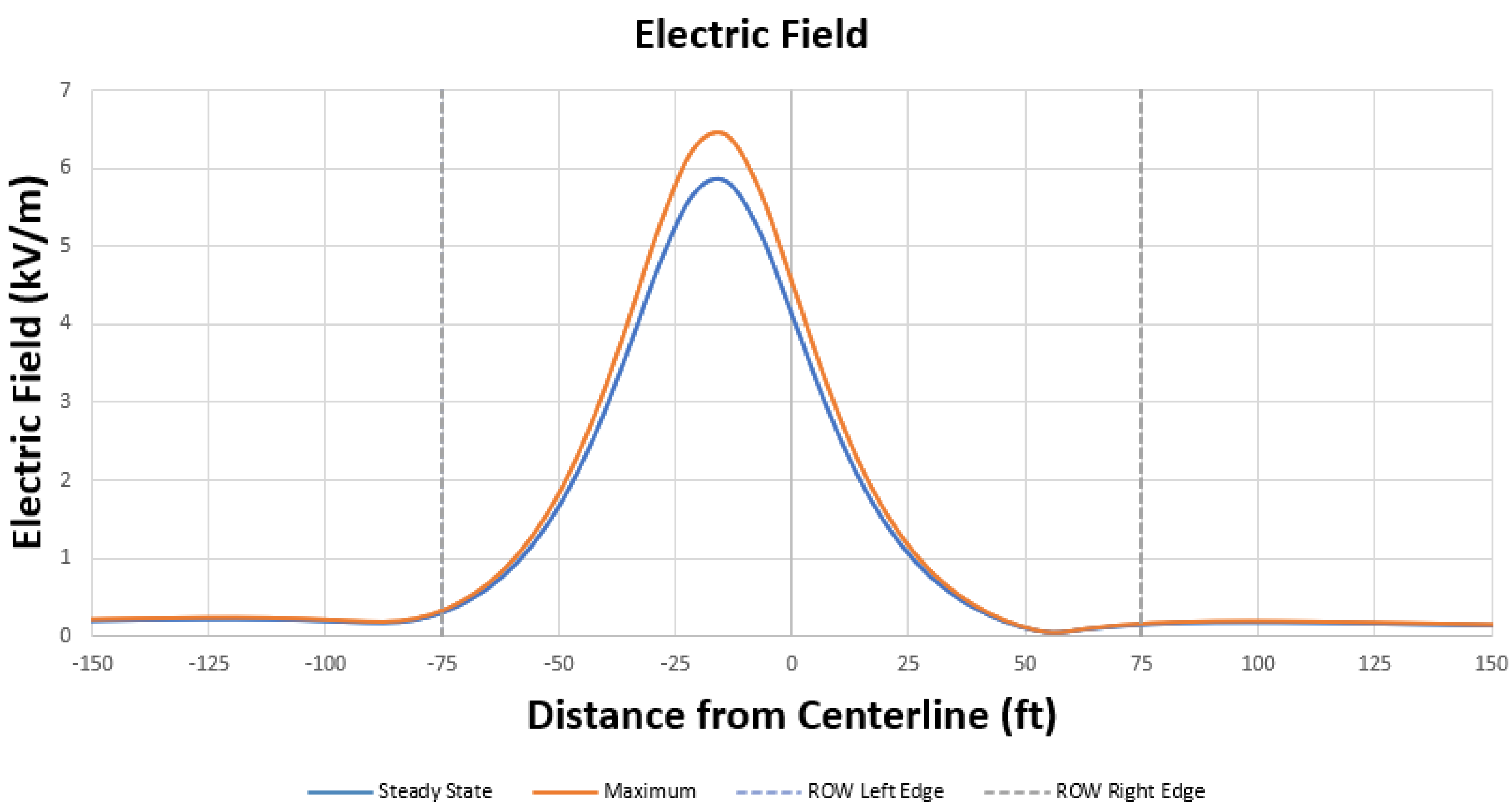

Calculated Electric Fields at Nominal System Voltage (345kV)
Single Circuit 345kV (ALS-BO)
Electric Field Levels (kV/m)
Distance from Centerline (ft)

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.

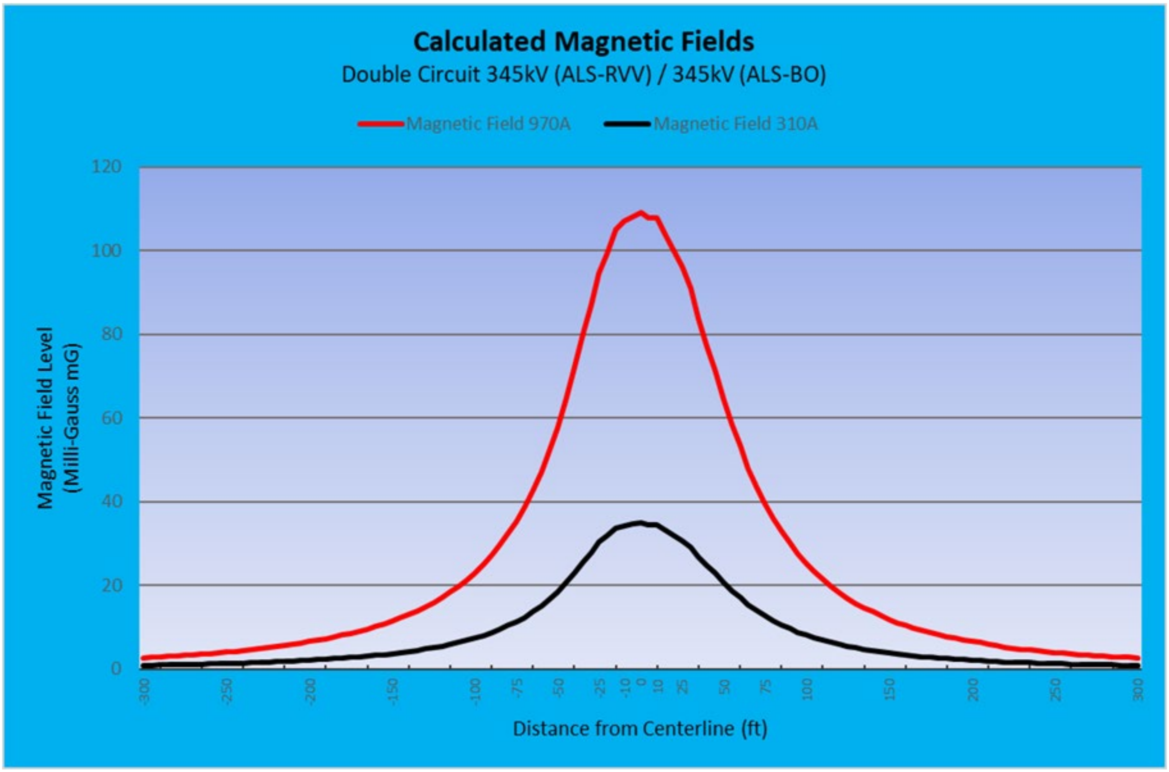
Magnetic field calculations for the Project substations are not provided here because the specific physical design of a substation is required to calculate representative magnetic fields, and that level of design is not yet available for the Project substations. Magnetic fields associated with the Project's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

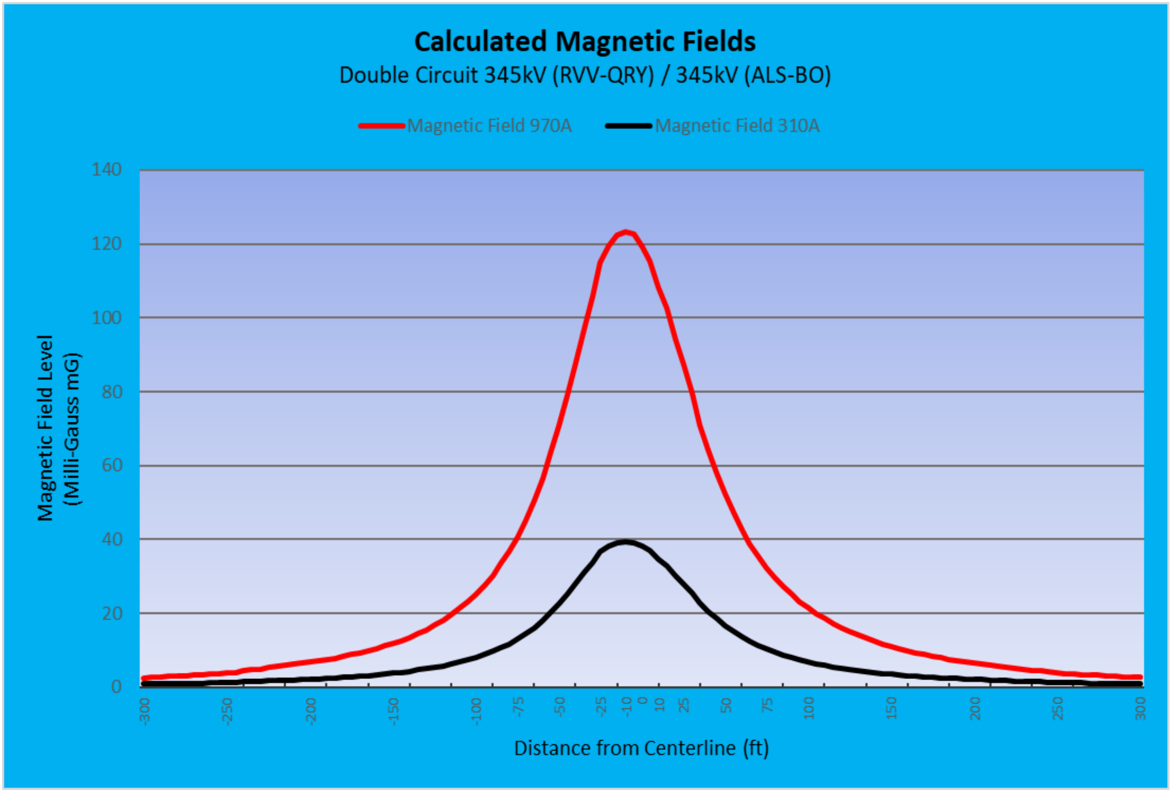
Table 6-3
Magnetic Field Calculations Summary

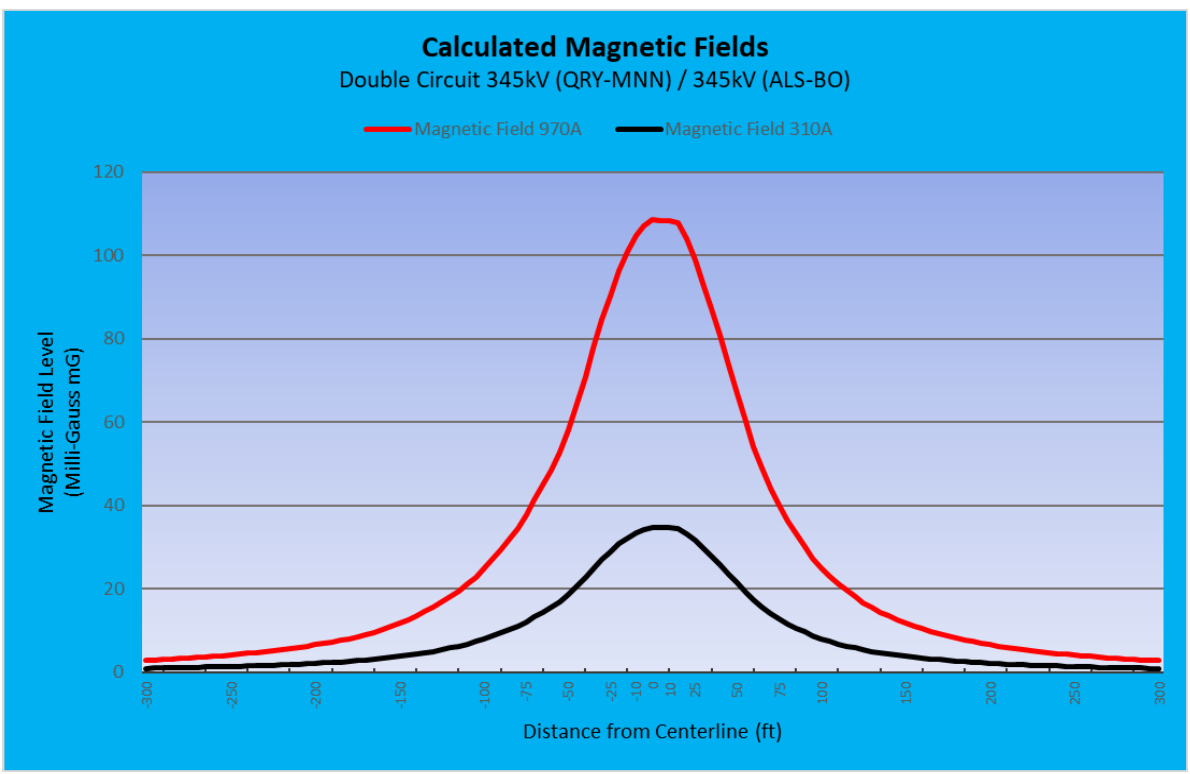
Structure Type	Circuits Present	System Condition	Current (Amps)	Distance to Proposed Centerline (feet)												
				-300	-200	-100	-75	-50	-25	0	25	50	75	100	200	300
345 kV Single-Circuit on Double-Circuit Capable Monopole	Big Stone South – Alexandria	Peak System Energy Demand	1,434/1,434	5	11	41	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

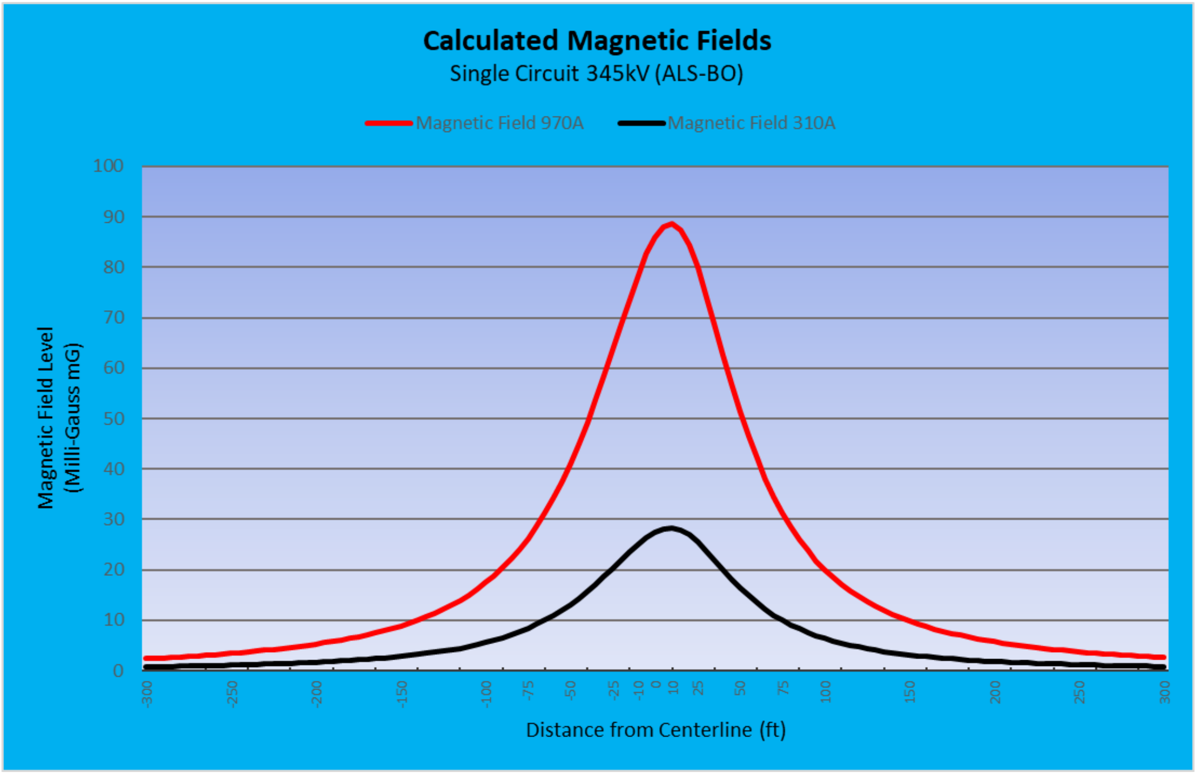
345 kV Single-Circuit Monopole	Alexandria (ALS) – Big Oaks	Peak System Energy Demand (580 MVA)	970	2.4	5.3	17	26	41	64	86	80	51	31	20	5.8	2.6
	Alexandria (ALS) – Big Oaks	Average System Energy Demand (185 MVA)	310	0.8	1.7	5.6	8.4	13	20	27	26	16	10	6.4	1.8	0.8
345 kV Single-Circuit H-Frame	Alexandria (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)
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)
Distance from Centerline (ft)


Calculated Magnetic Fields
Single Circuit 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
Distance from Centerline (ft)

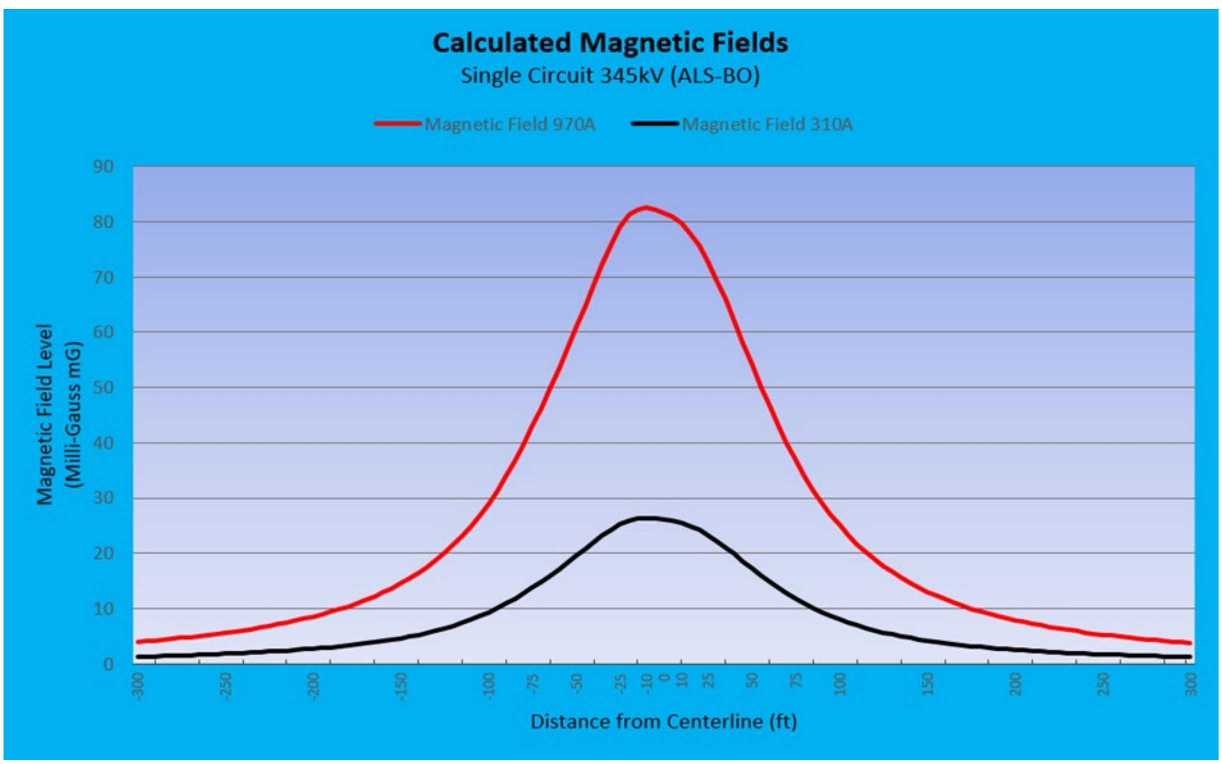
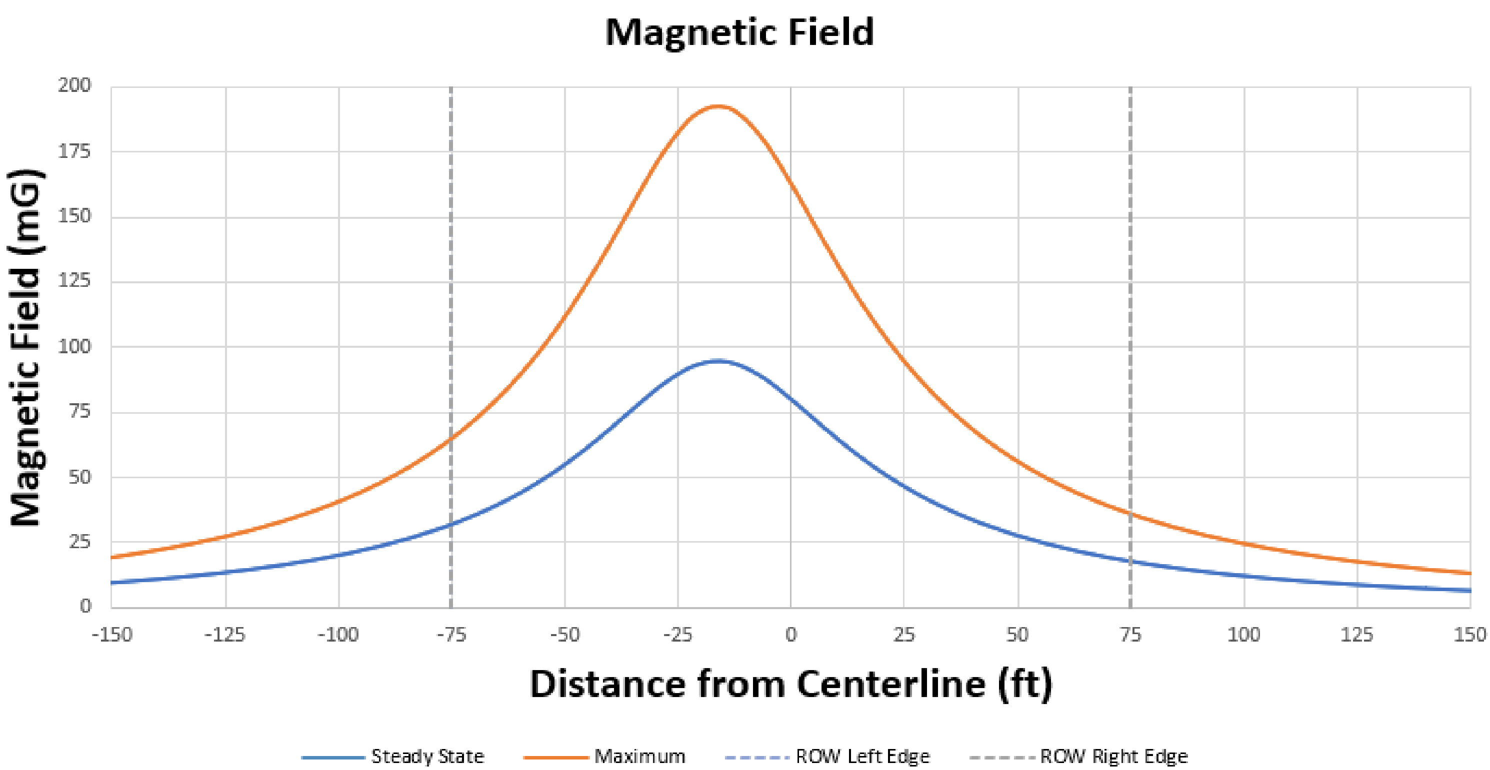

Calculated Magnetic Fields
Single Circuit 345kV (ALS-BO)
Magnetic Field 970A
Magnetic Field 310A
Magnetic Field Level (Milli-Gauss mG)
Distance from Centerline (ft)

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

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[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

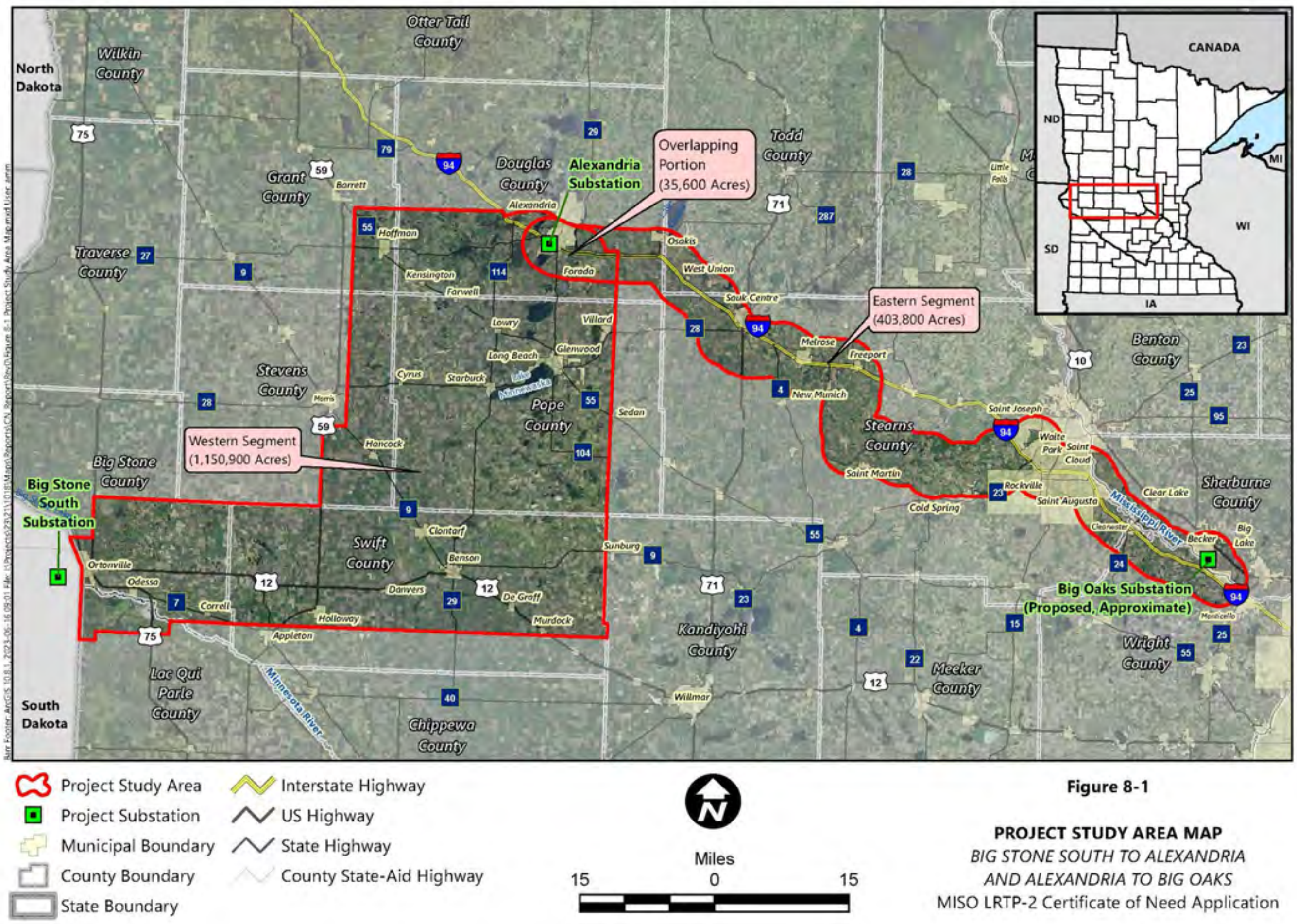
This section provides a general description of the environmental setting, land use and human settlement, land-based economies, archeological and historical resources, hydrological features, vegetation and wildlife, and rare and unique natural resources that are known to occur or may potentially occur 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

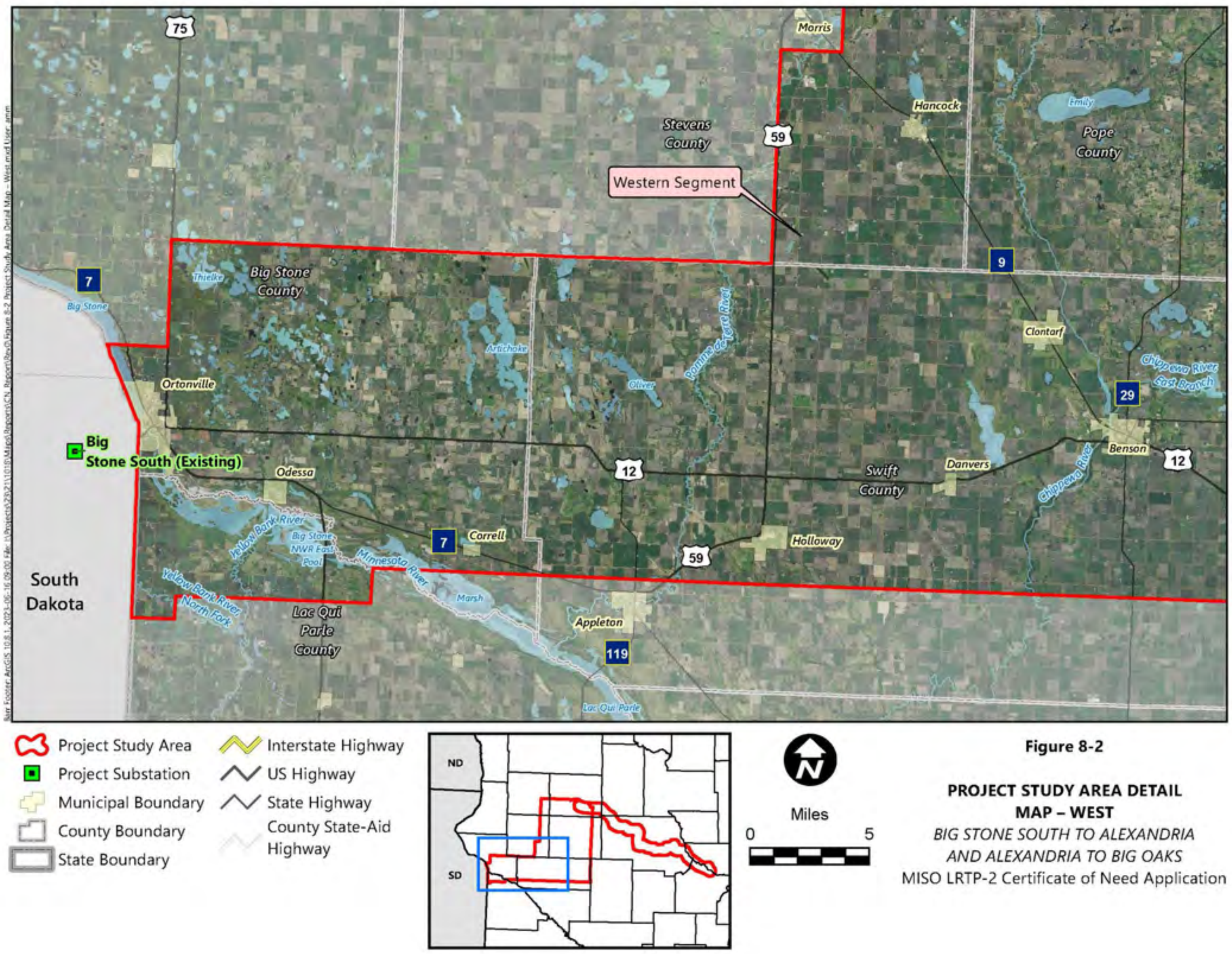
The overall Project Study Area measures approximately 1,519,100 acres and includes portions of Big Stone, Douglas, Grant, Lac Qui Parle, Pope, Sherburne, Stearns, Stevens, Swift, Todd, and Wright counties (**Map 8-1**). The Project Study Area is divided into two segments: the Western Segment and the 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.

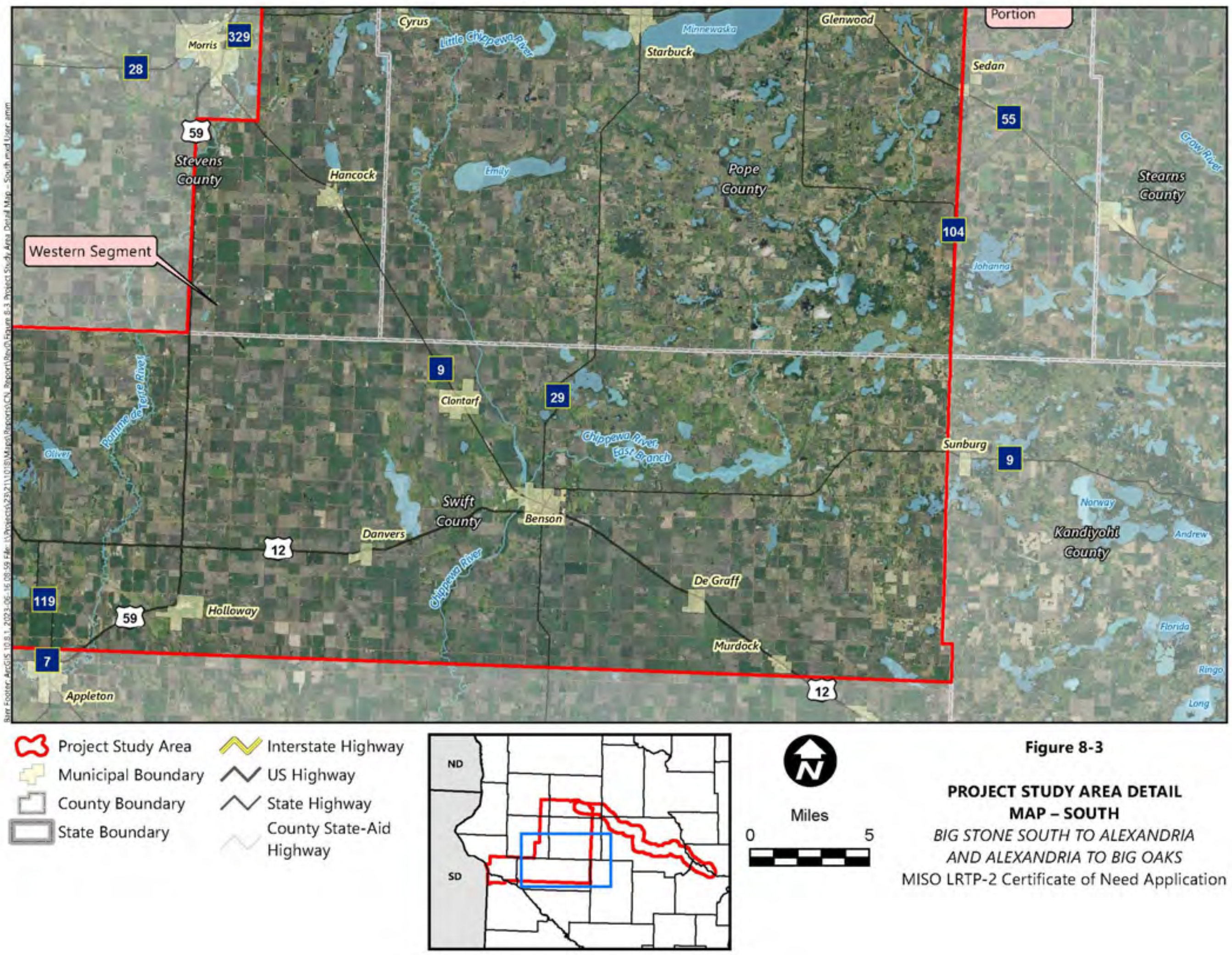
Map 8-1
Project Study Area



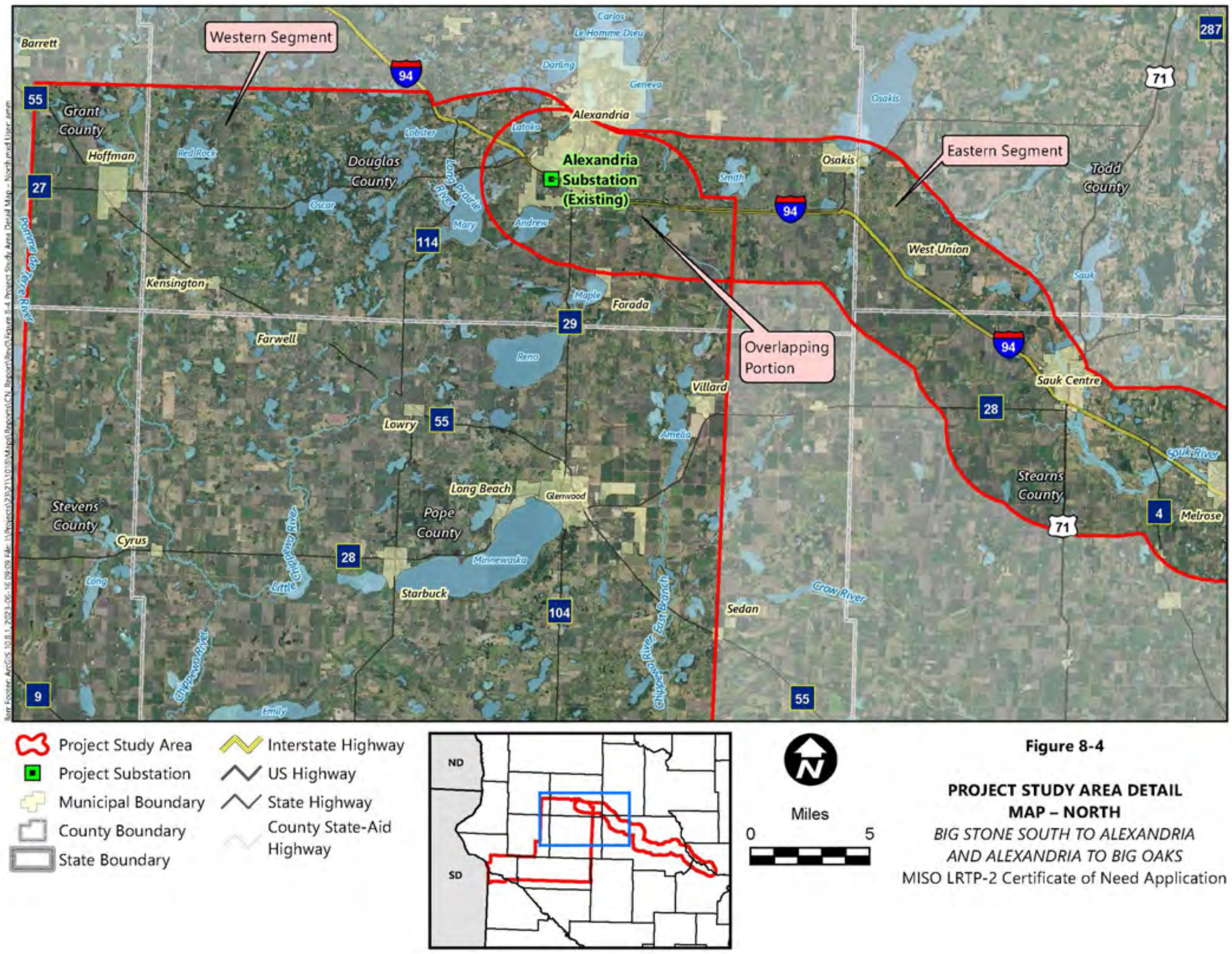
Map 8-2
Project Study Area Detail Map – West



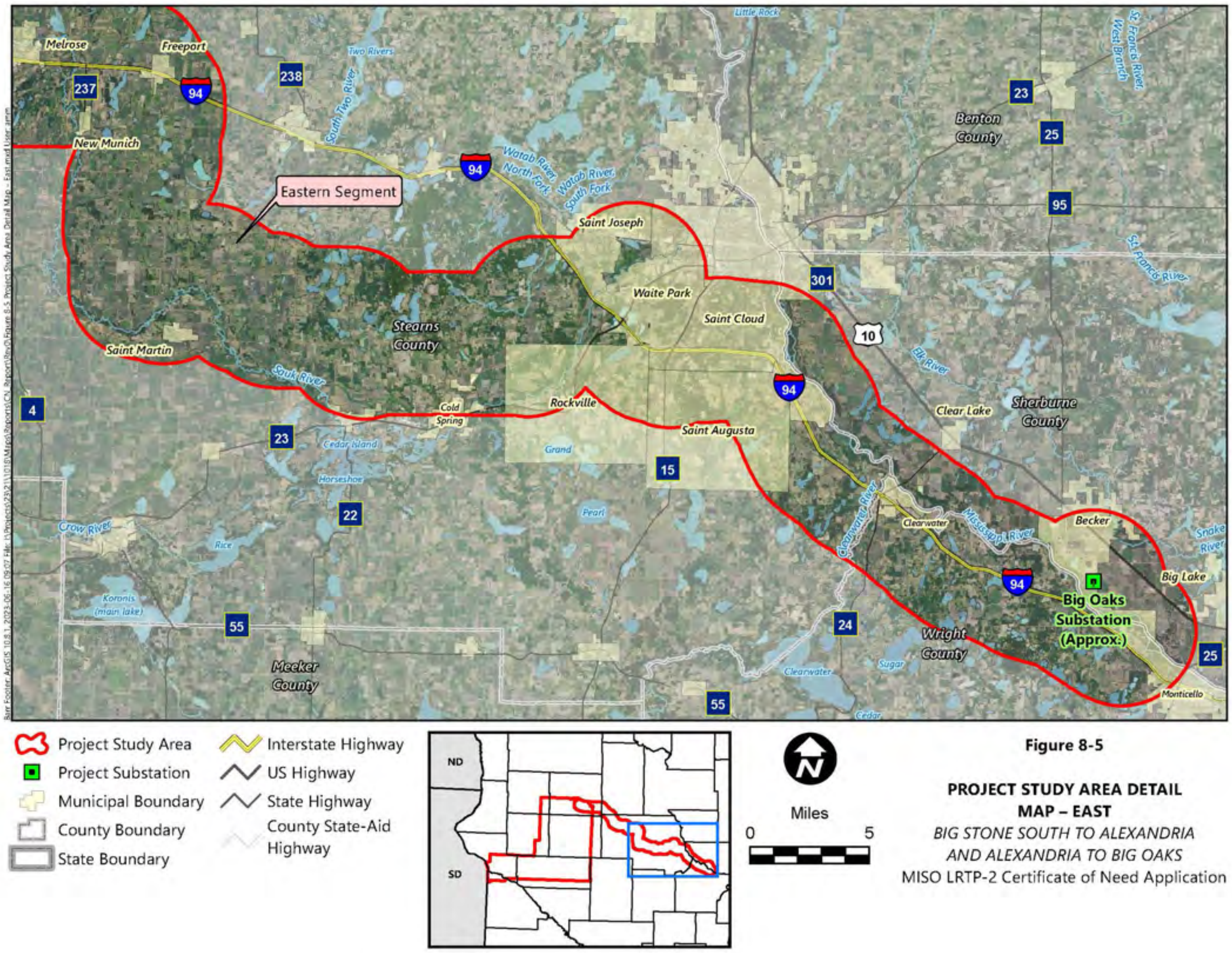
Map 8-3
Project Study Area Detail Map – South



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.

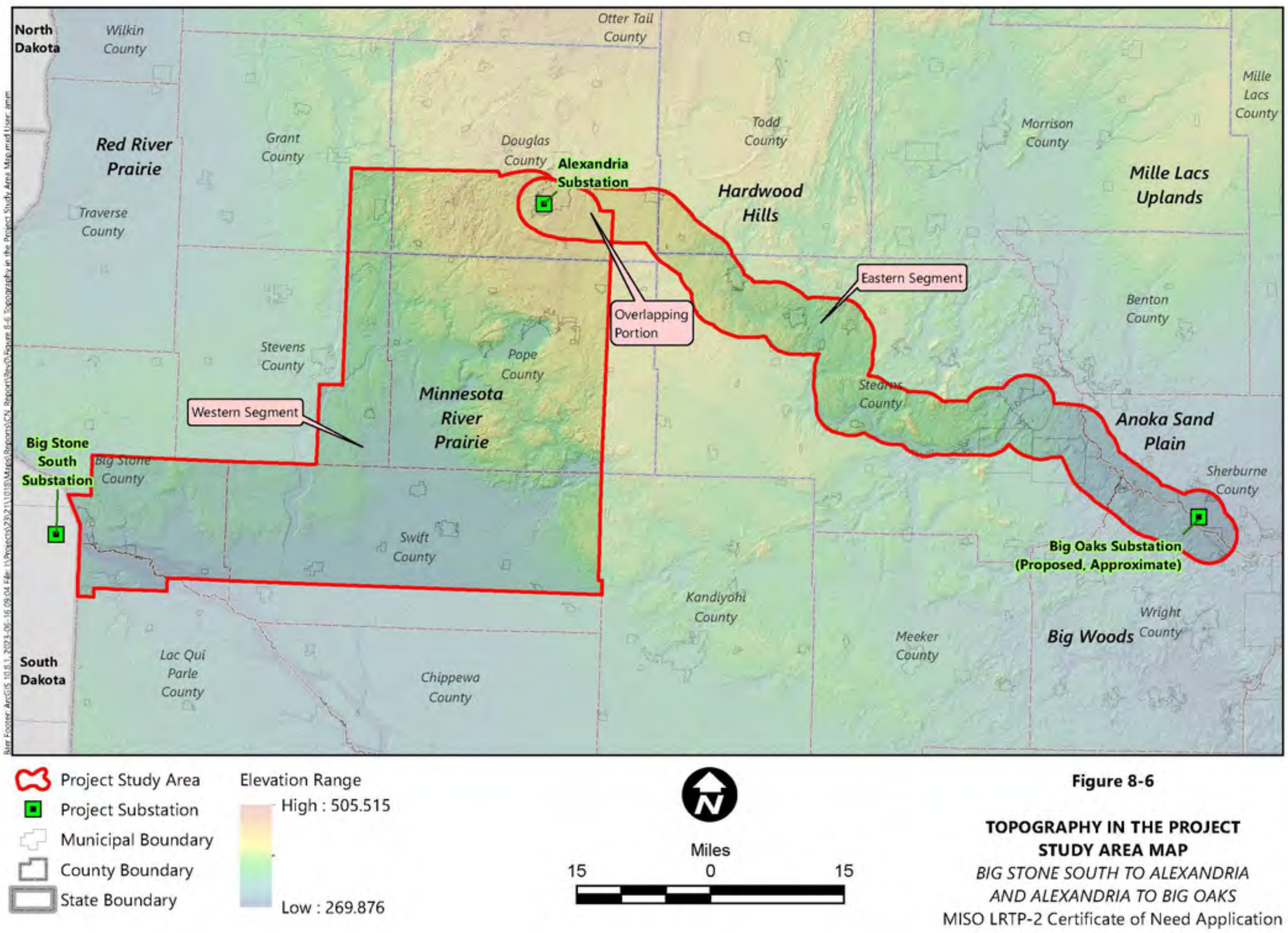
8.1.2 Geomorphology and Physiography

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

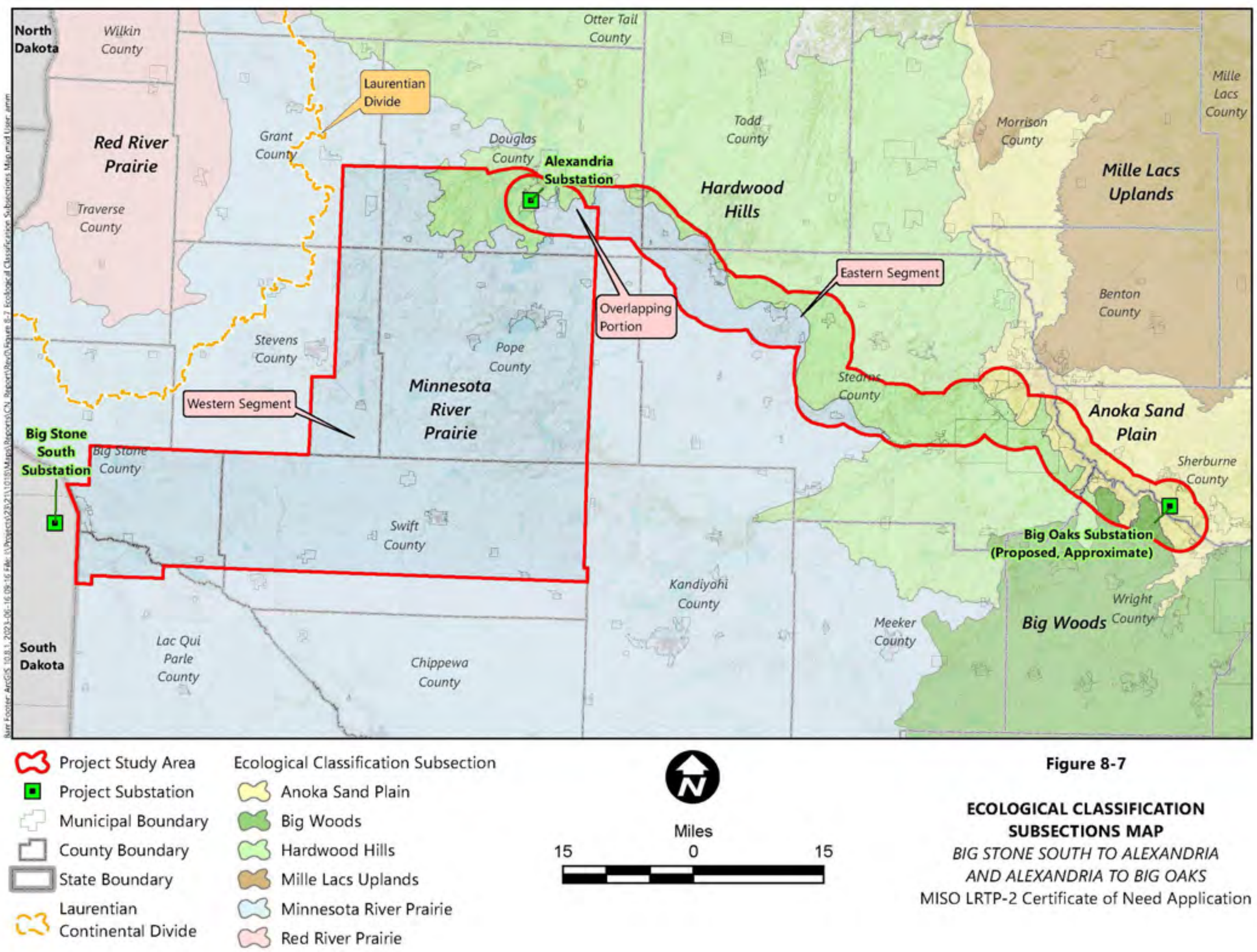


Table 8-1
ECS Subsections in the Project Study Area

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.

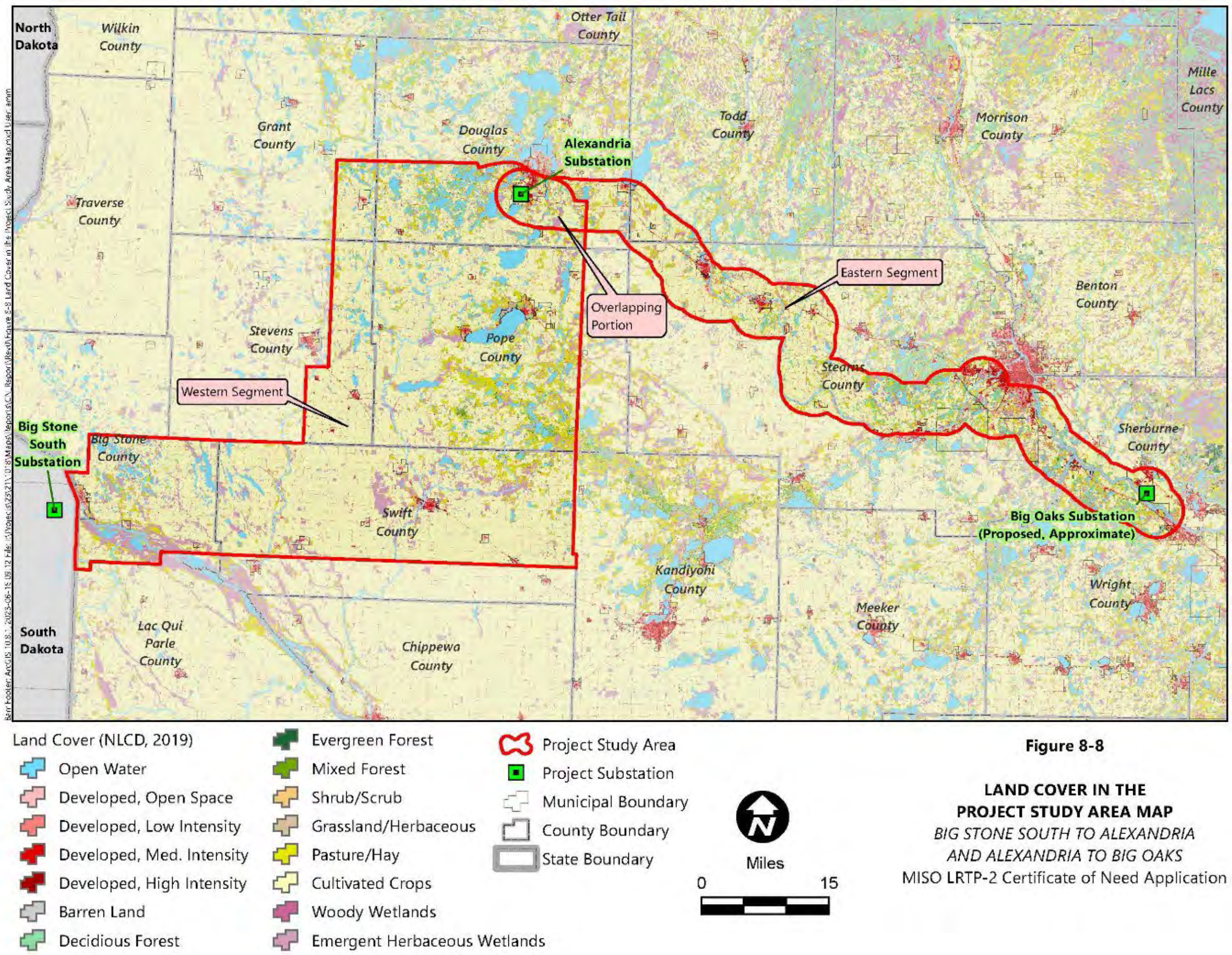
8.1.3 Human Settlement

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**).

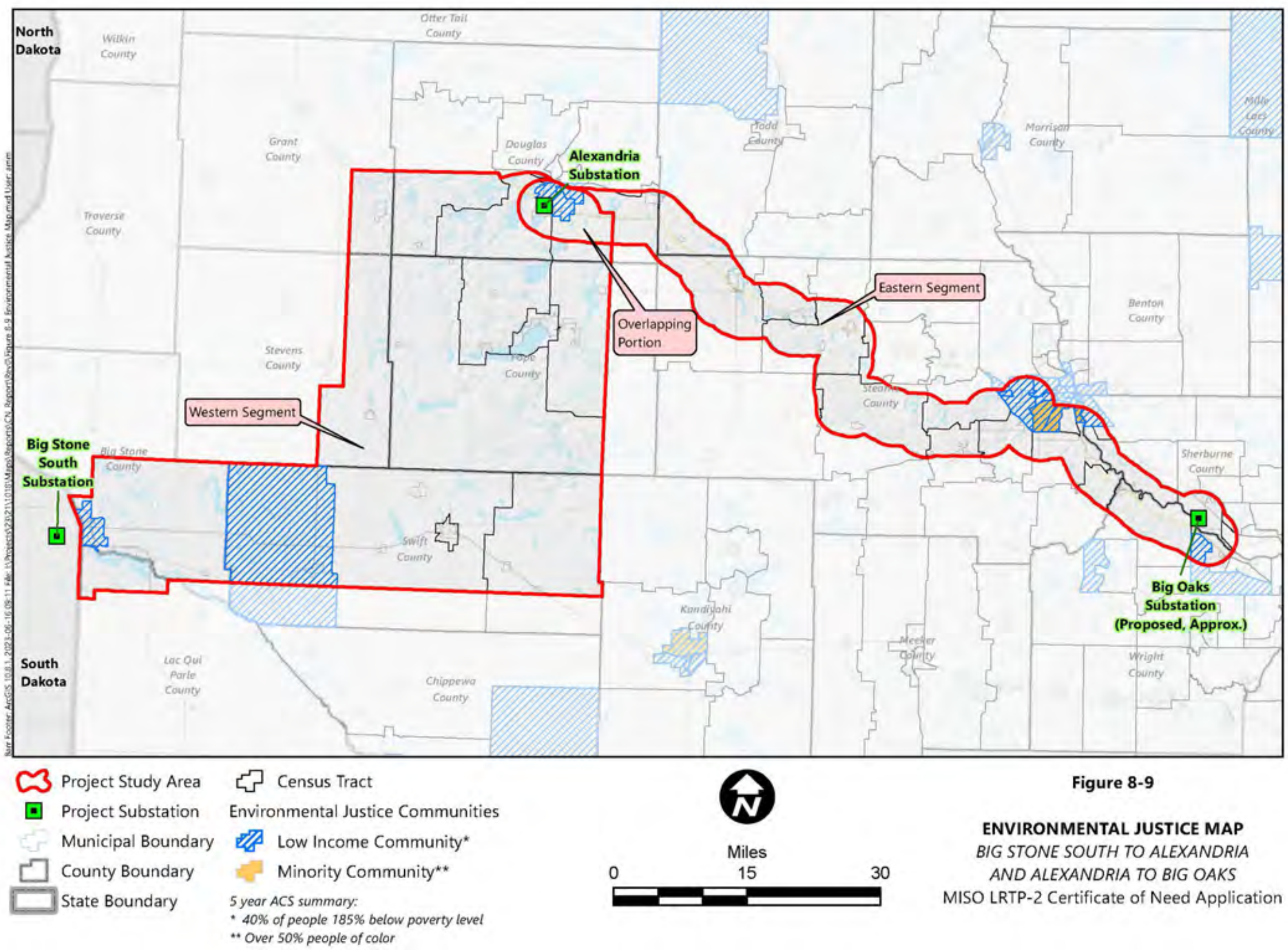
There are two state trails located within the Project Study Area: the Minnesota River State Trail (TRA00750) and the Central Lakes State Trail (TRA00757) (**Map 8-10**). The Minnesota River State Trail is located along the far western end of the Western Segment. The Central Lakes State Trail is located 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**).

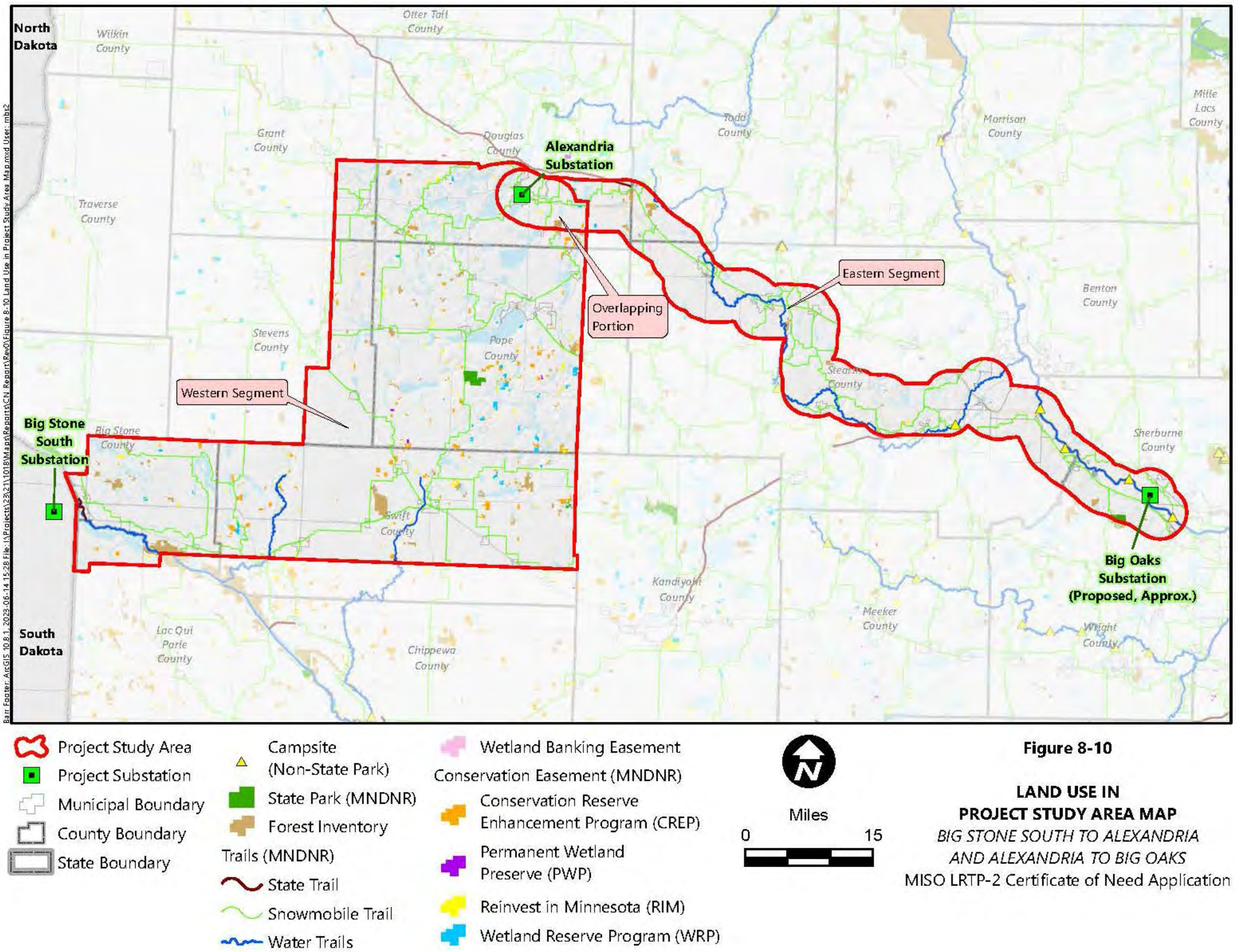
Snowmobile trails are found throughout the Project Study Area and generally follow existing county and township roads, though many state parks and hiking trails also allow snowmobiling during the winter months. In total, there are approximately 720 miles of snowmobile trails within the Project Study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

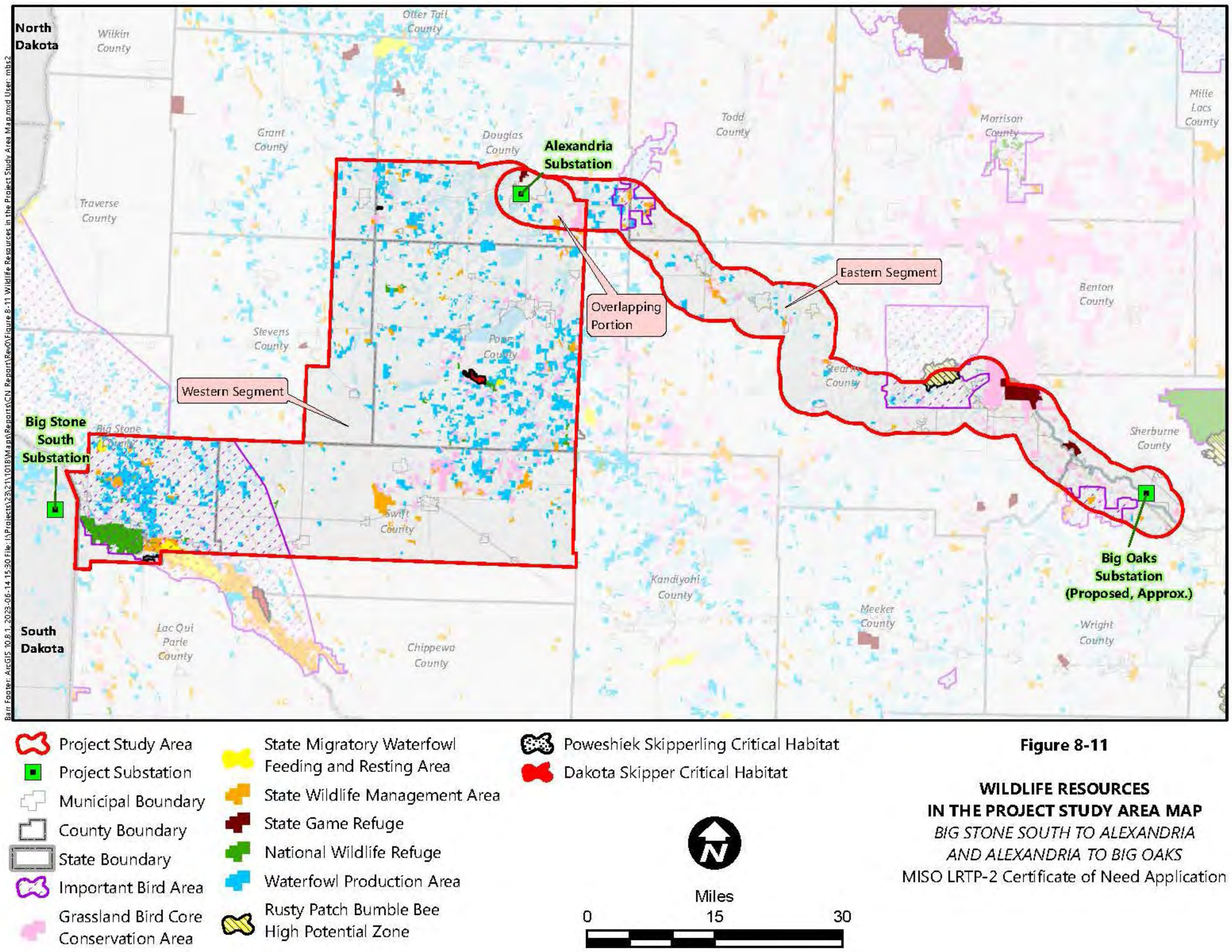
Map 8-9
Environmental Justice Map



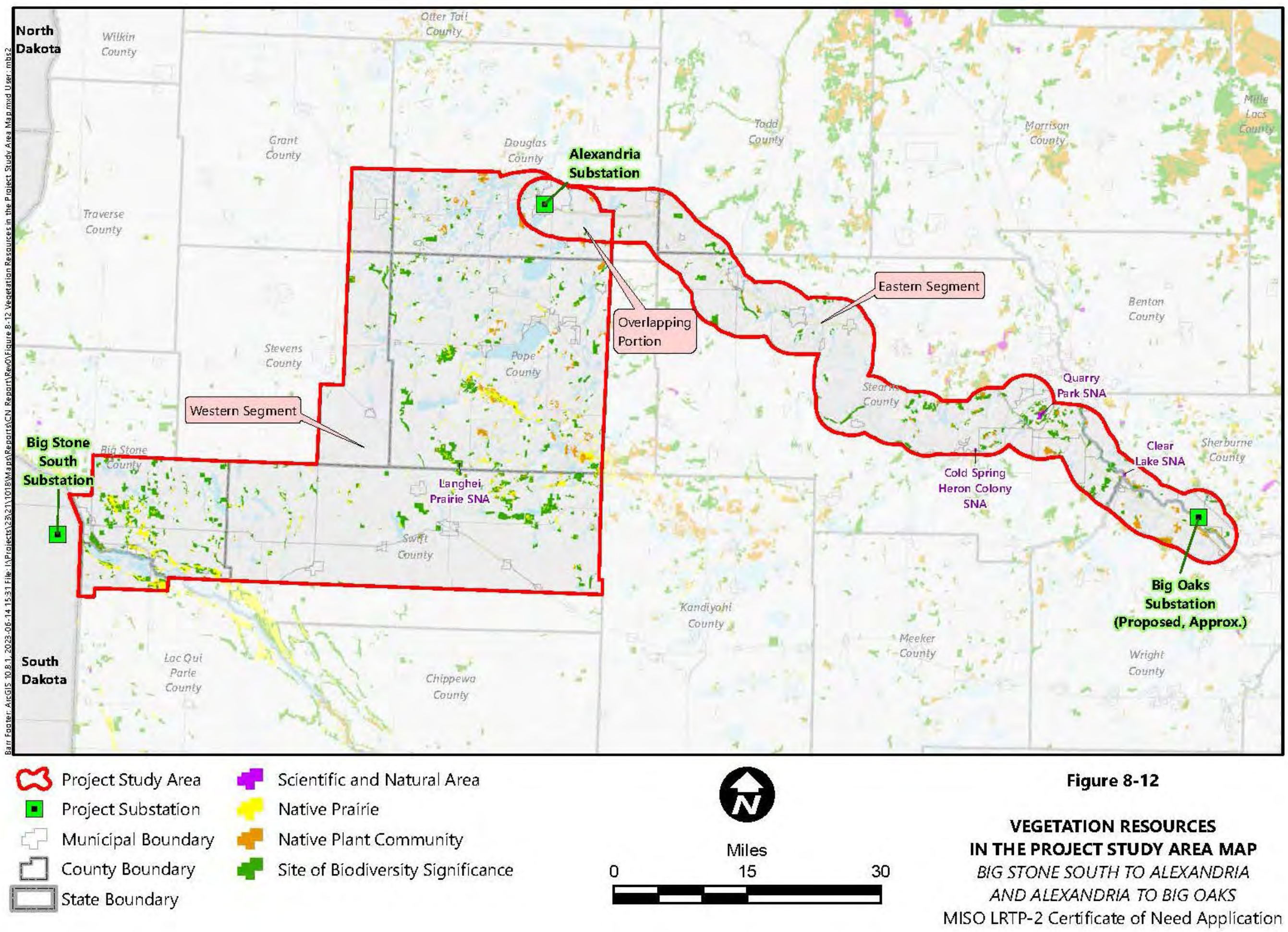
Map 8-10
Land Use in the Project Study Area Map



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.

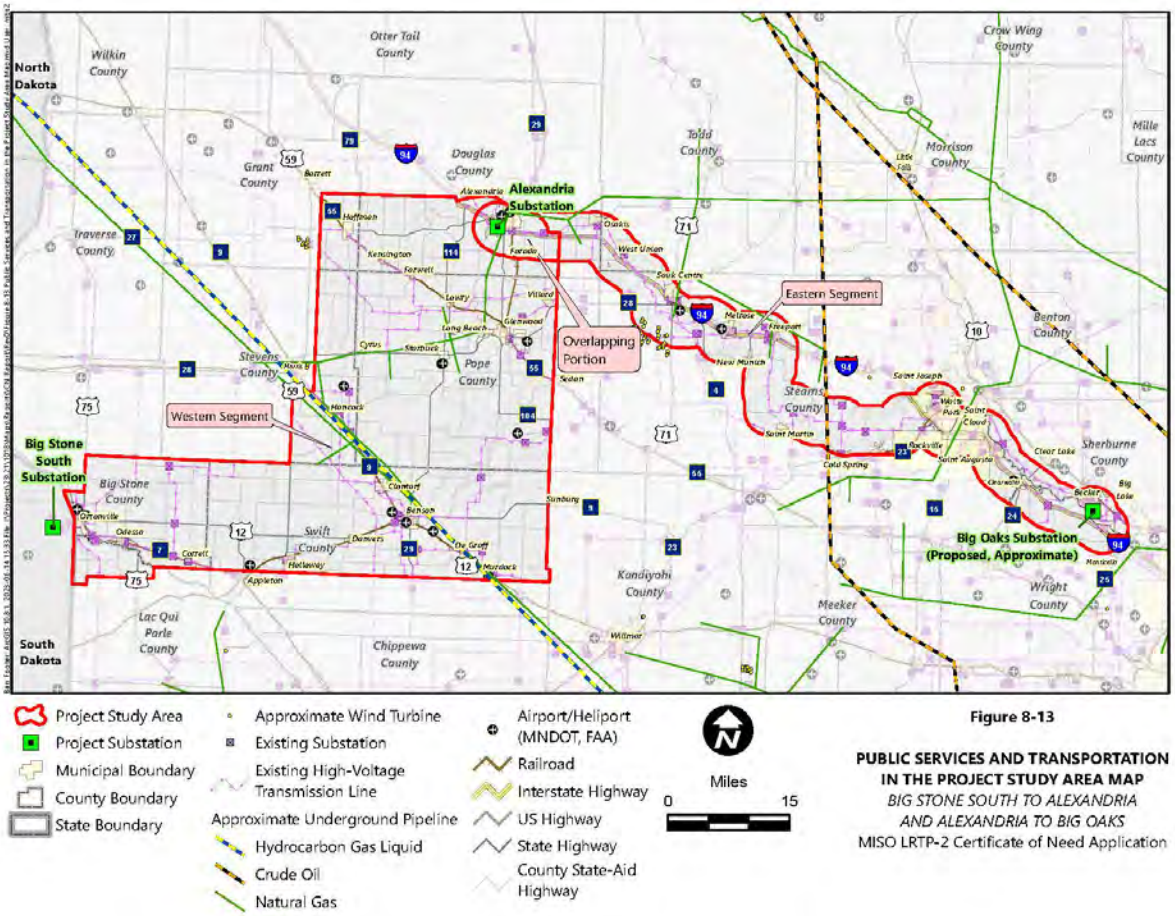
There are 19 airports located within the Project Study Area including nine private airports and 10 public airports (**Map 8-13**; **Table 8-6**). In general, the public airports are located in medium to larger municipalities in the Project Study Area such as

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

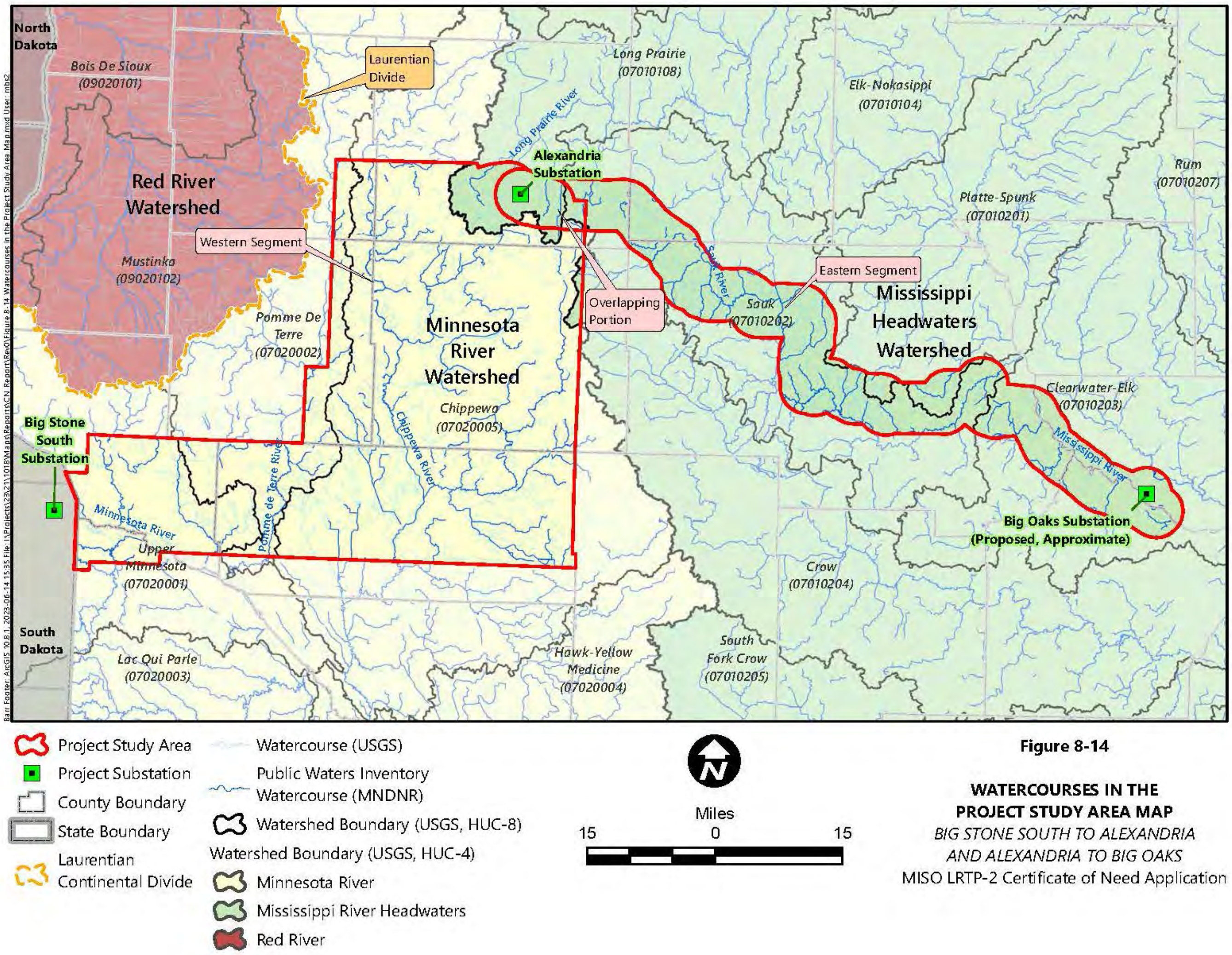
There are eight major watershed basins (HUC-04) and 81 major surface water watersheds (HUC-08) covering Minnesota. The Western Segment is predominantly located within the Minnesota River Watershed (HUC-4), and the Eastern Segment is located within the Mississippi River Headwaters Watershed (HUC-04). 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

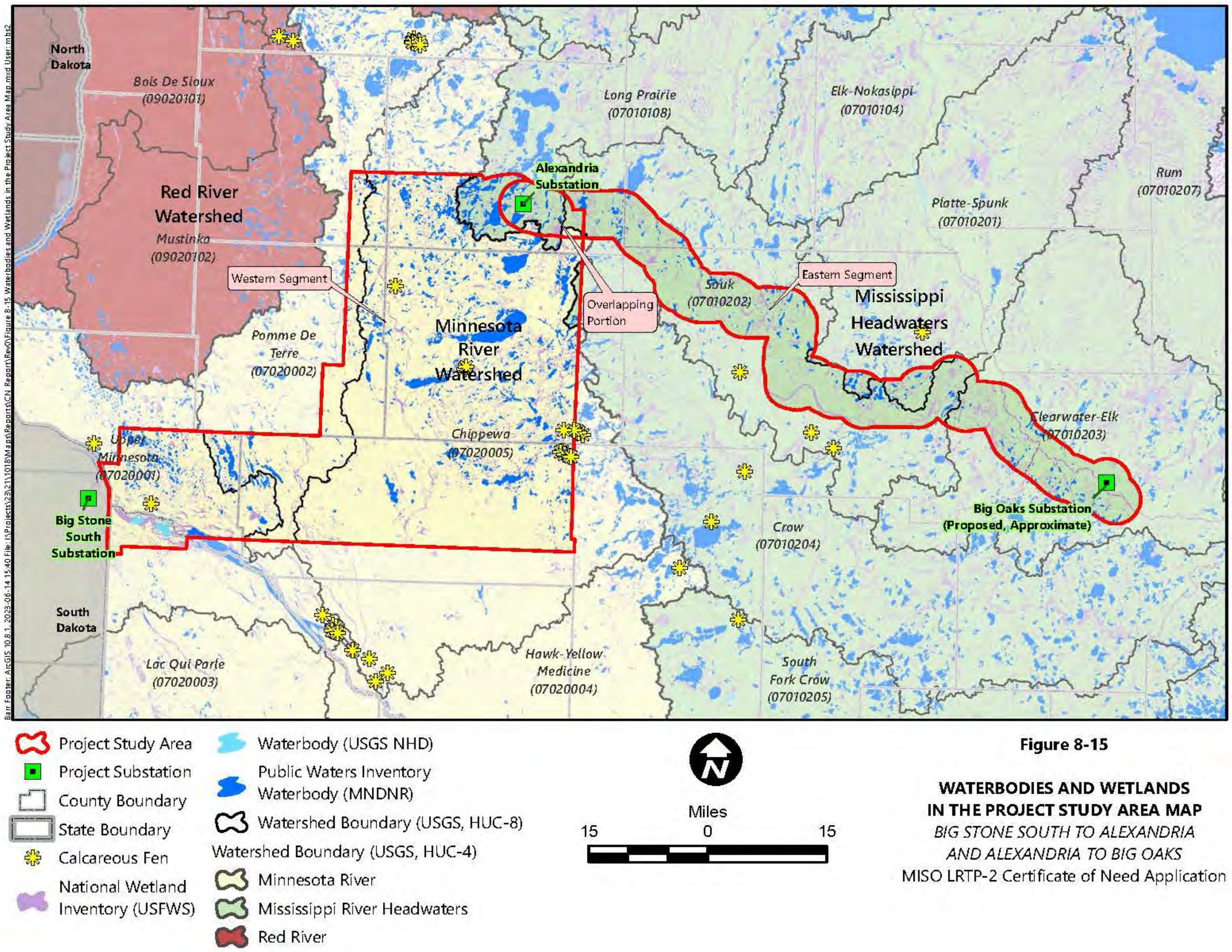


Table 8-9
National Wetland Inventory Wetlands Within the Project Study Area

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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