February 3, 2026

Joint Application to the Minnesota Public Utilities Commission for a Certificate of Need

for PowerOn Midwest

MPUC Docket No. E002, ET2, ET6675/CN-25-117

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Defined Terms

$	U.S. dollar
AAR	Ambient Adjusted Line Ratings
AC	alternating current
ACSR	aluminum conductor steel reinforced
amps	amperes
ANSI	American National Standards Institute
Applicants	Great River Energy; ITC Midwest LLC; and Northern States Power Company, a Minnesota corporation, doing business as Xcel Energy
Application	Applicants' Joint Certificate of Need Application
BGEPA	Bald and Golden Eagle Protection Act
BMP	best management practice
BWSR	Board of Soil and Water Resources
CAGR	compound annual growth rate
CapX2020	Capacity Expansion Needed by 2020
CN	Certificate of Need
CO_2	carbon dioxide
Commission	Minnesota Public Utilities Commission
CPLANET	Controlled Planning Expansion Tool
dB	decibel
dBA	A-weighted decibel
DC	direct current
Department	Minnesota Department of Commerce
DFAX	distribution factor
DLR	Dynamic Line Ratings
DWSMA	Drinking Water Supply Management Area
ECS	Ecological Classification System
EMF	electric and magnetic field
EPRI	Electric Power Research Institute
ESA	Endangered Species Act
FAA	Federal Aviation Administration
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
G	Gauss

GETs	grid-enhancing technologies
GW	gigawatt
HUC	Hydrologic Unit Code
HVDC	high voltage direct current
HVTL	High-voltage transmission line
IPaC	Information for Planning and Conservation
IRP	Integrated Resource Plan
ITC Midwest	ITC Midwest LLC
JTIQ	Joint-Targeted Interconnection Queue
kcmil	thousand circular mil
kV	kilovolt
kV/m	kilovolt per meter
L_{10}	noise level represents the level exceeded 10 percent of the time,
L_{50}	noise level represents the level exceeded 50 percent of the time,
LCOE	levelized cost of energy
LRTP	Long-Range Transmission Plan
LRTP Tranche 1	Long Range Transmission Plan Tranche 1
LRTP Tranche 2.1	Long Range Transmission Plan Tranche 2.1
LRTP Tranche 2.1 Portfolio	Long Range Transmission Plan Tranche 2.1 Portfolio
MDNR	Minnesota Department of Natural Resources
mG	milliGauss
Minn. Stat. §	Minnesota Statutes Section
Minn. R. Ch.	Minnesota Rules Chapter
MISO	Midcontinent Independent System Operator, Inc.
MnDOT	Minnesota Department of Transportation
MPCA	Minnesota Pollution Control Agency
MRO	Midwest Reliability Organization
MTEP	MISO Transmission Expansion Plan
MTEP24	MISO Transmission Expansion Plan 2024
MVP	Multi-Value Project
MW	megawatts
MWh	megawatt hour
NAC	Noise Area Classifications
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code

NLCD	National Land Cover Database
NLEB	northern long-eared bat
NO_2	nitrogen dioxide
NO_X	oxides of nitrogen
NPC	native plant community(ies)
NPS	National Park Service
NPV	net present value
NRCS	Natural Resources Conservation Service
NRHP	National Register of Historic Places
NSP Companies	Xcel Energy and Northern States Power Company, a Wisconsin corporation
NWR	National Wildlife Refuge
O&M	operations and maintenance
PAD-US	USGS Protected Area Database of the United States
PCE	primary constituent elements
PEM	palustrine emergent
PFO	palustrine forested
PowerOn Midwest	PowerOn Midwest Project
ppb	parts per billion
ppm	parts per million
Project	PowerOn Midwest Project
Project Study Area	Includes all or portions of Lincoln, Pipestone, Rock, Lyon, Murray, Nobles, Redwood, Cottonwood, Jackson, Martin, Faribault, Waseca, Freeborn, Steele, Mower, Dodge, Olmsted, Goodhue, and Dakota County, as shown on Figure 1.8-1.
PSSE	Power System Simulator for Engineering
PWI	Public Waters Inventory
RE	Regional Entity
RIIA	Renewable Integration Impact Assessment
RTO	regional transmission organization
SF_6	sulfur hexafluoride
SIL	surge impedance loading
SMR	small modular nuclear reactors
SNA	Scientific and Natural Area
SOBS	Sites of Biodiversity Significance
SPP	Southwest Power Pool

STATCOM	Static Synchronous Compensator
Studied Projects	The Project and its practical extensions into neighboring states (or the entirety of LRTP numbers 22 through 26) used for the need analysis in this Application
TARA	Transmission Adequacy and Reliability Assessment
TCB	tricolored bat
U.S.	United States of America
USACE	U.S. Army Corps of Engineers
USDA	U.S. Department of Agriculture
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
V	volts
VOLL	value of lost load
WCA	Wetland Conservation Act
WMA	Wildlife Management Area
WPA	Waterfowl Production Area
Xcel Energy	Northern States Power Company doing business as Xcel Energy

1 EXECUTIVE SUMMARY

1.1 Introduction

Great River Energy, ITC Midwest LLC (ITC Midwest), and Northern States Power Company doing business as Xcel Energy (Xcel Energy) (together, the Applicants) submit this joint application (Application) to the Minnesota Public Utilities Commission (Commission) for a Certificate of Need (CN) to construct the PowerOn Midwest Project (the Project or PowerOn Midwest).

The Project consists of 271 miles[1] of new 765 kilovolt (kV) transmission lines across southern Minnesota that will be part of a 765 kV path connecting Minnesota, South Dakota, Iowa, and Wisconsin. The Project includes 69 miles of a new 345 kV second circuit between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation and modifications at all three 345 kV substations. The Project also includes expansions of the existing Lakefield Junction Substation, Pleasant Valley Substation, and North Rochester Substation and new 345 kV transmission line connections to the expanded and existing substations. All Project facilities are expected to be in service in 2034 and are estimated to cost $3.327 billion ($2024) to $4.323 billion ($2024).

The Project was studied, reviewed, and approved as part of the Midcontinent Independent System Operator, Inc. (MISO) Long-Range Transmission Planning (LRTP) Tranche 2.1 Portfolio. MISO is a federally registered regional planning authority and regional transmission organization (RTO). MISO is responsible for planning and operating the transmission system and energy market in parts of 15 states, including Minnesota, and the Canadian province of Manitoba. MISO is an independent not-for-profit entity that has a responsibility, established by the Federal Energy Regulatory Commission (FERC), to identify needed transmission and mandate transmission owners to develop necessary transmission projects to address reliability issues.

The Project is needed to maintain system reliability amid fundamental changes in demand for electricity as well as the type and amount of generation that is interconnected to the grid within the MISO Midwest subregion.[2] In the late 2000s, the level of new generation needing to be

1 Throughout this Application, the Applicants use the mileage presented in the MTEP24 Transmission Portfolio Report, Appendix A. (MISO. MTEP24 Transmission Portfolio Report, Appendix A. The full report is available at: https://www.misoenergy.org/planning/transmission-planning/mtep/#nt=%2Fmtepstudytypenew%3AMTEP%20Reports&t=10&p=0&s=FileName&sd=desc. See "MTEP24.zip)."

2 The MISO Midwest subregion includes MISO transmission customers in Minnesota, Montana, North Dakota, South Dakota, Iowa, Wisconsin, Missouri, Illinois, Indiana, Michigan, and Kentucky.

connected to MISO to meet system needs and renewable portfolio standards was 25 gigawatts (GW). Today, to serve electrical demands, replace retiring generation capacity, and to meet policies and laws like Minnesota's Carbon-Free by 2040 law,[3] 116 GW of new generation must be connected – a four-fold increase from the 2000s. Energy demand is trending up and the type and location of generation resources to serve this demand have fundamentally transformed over the past two decades. The amount of renewable generation interconnecting to the system has dramatically increased, while the amount of fossil-fueled generation on the grid has dramatically decreased. A summary of the factors driving the need for the Project is shown in **Table 1.1-1**.

As generation types and demands for electricity evolve, so too must the transmission grid, which moves electricity from its point of generation to where it is consumed. The Project is necessary to continue to serve customer demand every minute of every day and to ensure the resiliency of the grid, particularly given the rapid pace of retiring baseload generation.

The Applicants and MISO identified that Minnesota requires upwards of 10,000 megawatts (MW) of additional electrical transmission capacity. The Project and the MISO LRTP Tranche 2.1 Portfolio of 24 projects[4] will create a new "transmission backbone" network throughout the Midwest that will ultimately be interconnected with an existing 2,400-mile 765 kV network in the eastern United States. This new transmission backbone network will make Minnesota's connection to the broader Midwest and eastern United States more robust and resilient, enabling Minnesota and the region to meet its electrical demands in a more reliable and cost-effective manner. Additional details on the current and future electricity demand supported by the Project are included in **Chapter 4.**

The Project will enhance the ability of the transmission system to move energy into and out of Minnesota and surrounding areas. This geographic diversity and "reach" to access generation across multiple states (i.e., where the wind is blowing and/or the sun is shining) will allow for a steady flow of electricity to serve communities, so long as the transmission system can efficiently move the energy from where it is produced to where it is consumed.

[3] Minn. Stat. § 216B.1691, subd. 2(g).

[4] The MISO Board of Directors approved the LRTP 2.1. Portfolio on Dec. 12, 2024.

Table 1.1-1
Comparison of Transmission System Needs in 2000s versus 2024

Transmission System Need	2000s	Current
MISO demand needs [a]	1 percent annual growth (trending down)	1 percent annual growth (trending up)
Amount of new MISO generation necessary to be enabled [b]	25 GW (Total MISO GI Queue Size: ~60 GW)	116 GW (Total MISO GI Queue Size: ~270 GW)
MISO fossil-fuel generation retirements [c]	0.4 GW	84 GW
MISO generation mix [d]	Fossil fuels: 83 percent Nuclear: 13 percent Renewable: 0 percent	Fossil fuels: 66 percent Nuclear: 14 percent Renewable: 19 percent
Minnesota policy	25% renewable by 2025	100% carbon-free by 2040
Needed transmission transfer capability [e]	1 - 3 GW	10+ GW
Primary High Voltage Class	345 kV	765 kV

Note: GI = Generator Interconnection

[a] 2000s: MTEP11 Low BAU Future (primary future used to analyze MTEP11 Multi-Value Project Portfolio). Available at: https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf. Page 16.
Current: See **Appendix E.2**. Page 31.
Current demand forecasts do not account for potential data centers and other industrial demands, which MISO predicts could increase growth rates by upwards of three-times the current forecasts. (MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf).

[b] 2000s: MISO. Multi Value Project Portfolio Results and Analyses January 10, 2012.
Current: See **Appendix E.1**. Page 75.
MISO GI Queue. Current values as of November 2025. Available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

[c] 2000s: MTEP11 Low BAU Future (primary future used to analyze MTEP11 Multi-Value Project Portfolio). Available at: https://cdn.misoenergy.org/MTEP14%20MVP%20Triennial%20Review%20Report117061.pdf. Page 16.
Current: See **Appendix E.2**. Page 88.

[d] 2000s: MISO. MISO'S Response to the Reliability Imperative. Available at: https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216. Page 7.
Current: MISO Fact Sheet – September 2025. See **Appendix E.5**. Totals do not sum to 100% due to omission of "other" fuel types.

[e] 2000s: MISO Regional Generator Outlet Study Report – November 2010. Available at: https://puc.sd.gov/commission/dockets/electric/2013/EL13-028/appendixb3.pdf.
Current: See **Chapter 6.**

In addition, these new transmission connections will help ensure reliability 24 hours a day, 7 days a week, and 365 days a year during extreme weather events. During these times, Minnesota may have to rely on neighboring states to provide power to maintain the system. For example, in February 2021 during Winter Storm Uri, it was necessary for MISO to import an unprecedented level of power from the eastern United States to maintain reliability for the MISO region, including Minnesota, and states to the west.[5] The Project will enable utilities to reliably serve existing and additional future demands for electricity.

The Applicants are submitting this Application pursuant to Minnesota Statutes Section (Minn. Stat. § 216B.243 and Minnesota Rules Chapter (Minn. R. Ch.) 7849. To facilitate review, a completeness checklist is included as **Appendix A**, which identifies where in this Application information required by Minnesota statutes and rules is located. The Applicants intend to file Route Permit applications no earlier than the first quarter of 2027.

1.2 Project Description

The following sections describe the Project[6] facilities, including transmission lines and substations.

1.2.1 Transmission Facilities

The Project consists of new 765 kV high-voltage transmission line (HVTL) facilities between the South Dakota/Minnesota state line, Iowa/Minnesota state line, and the North Rochester Substation. The Project also includes a new 345 kV second circuit between the Pleasant Valley Substation, North Rochester Substation, and the Hampton Substation. The Project components are as follows:[7]

- **South Dakota/Minnesota state line to Lakefield Junction 765 kV transmission line:** Construction of a new 92-mile-long 765 kV transmission line from the South Dakota/Minnesota state line to near the existing Lakefield Junction Substation in Jackson County, Minnesota.[8]
- **Lakefield Junction to Iowa/Minnesota state line 765 kV transmission line:** Construction of a new 18-mile-long 765 kV transmission line from the

[5] See **Section 6.6.2** for additional details on resilience and Winter Storm Uri.

[6] Minnesota portions of MISO project numbers 22 through 25: Project 22: Big Stone South - Brookings County - Lakefield Junction 765 kV. Project 23: Lakefield Junction - East Adair 765 kV. Project 24: Lakefield Junction - Pleasant Valley - North Rochester 765 kV. Project 25: Pleasant Valley - North Rochester - Hampton [Corner] 345 kV. See **Appendix E.1**, Page 145).

[7] The Applicants use the mileage presented in the MTEP24 Transmission Portfolio Report, Appendix A. (MISO. MTEP24 Transmission Portfolio Report, Appendix A. The full report is Available at: https://www.misoenergy.org/planning/transmission-planning/mtep/#nt=%2Fmtepstudytypenew%3AMTEP%20Reports&t=10&p=0&s=FileName&sd=desc. See "MTEP24.zip)."

[8] Line connects to the existing Brookings County Substation in Brookings County, South Dakota.

Iowa/Minnesota state line to near the existing Lakefield Junction Substation in Jackson County, Minnesota.[9]

- **Lakefield Junction to Pleasant Valley 765 kV transmission line:** Construction of a new 130-mile-long 765 kV transmission line from near the existing Lakefield Junction Substation in Jackson County, Minnesota to near the existing Pleasant Valley Substation in Mower County, Minnesota.
- **Pleasant Valley to North Rochester 765 kV transmission line:** Construction of a new 31-mile-long 765 kV transmission line from near the existing Pleasant Valley Substation in Mower County, Minnesota to near the existing North Rochester Substation in Goodhue County, Minnesota.
- **Pleasant Valley to North Rochester to Hampton 345 kV line**: A new 69-mile-long 345 kV circuit from the Pleasant Valley Substation in Mower County, Minnesota to the existing North Rochester Substation in Goodhue County, Minnesota (31 miles) and from the North Rochester Substation to the Hampton Substation in Dakota County, Minnesota (38 miles).

The Applicants analyzed multiple 765 kV structure designs – including H-frame and monopole designs – for engineering, regulatory, land-use, and cost considerations. The Applicants propose to construct the 765 kV portions of the Project using four-legged self-supporting lattice structures. The lattice structure design best balances engineering, land-use, and cost considerations, as detailed in **Section 2.2**. The structures will be placed 1,100 to 1,300 feet apart, on average, and will typically be 150 to 175 feet tall. The 765 kV transmission lines will generally require a 250-foot-wide right-of-way.

Between the Pleasant Valley Substation and North Rochester Substation, the Applicants will replace existing single-circuit 345 kV structures (which now only carry one 345 kV circuit) with double-circuit tubular monopole structures (which will carry the existing 345 kV circuit, plus a new 345 kV circuit). The existing single-circuit structures between these substations will be removed. The 345 kV structures will typically be placed 800 to 1,200 feet apart, on average, and will be 90 to 160 feet tall. The 345 kV transmission lines will generally require a 150-foot-wide right-of-way.

Between the North Rochester Substation and Hampton Substation, the Applicants will place the second 345 kV circuit on existing double-circuit-capable 345 kV structures. Approximately

[9] Line connects to a substation in Adair County, Iowa (referred to in the LRTP Tranche 2.1 Portfolio as "East Adair").

three dozen new structures will be required along this portion of the Project as detailed in **Section 2.2.2**.

1.2.2 Substations

As part of the Project, the following existing substations will be expanded nearby for the 765 kV facilities:

- Lakefield Junction Substation in Jackson County;
- Pleasant Valley Substation in Mower County; and
- North Rochester Substation in Goodhue County.

The Project includes modifications to and expansion of the following existing substations to support the new 345 kV facilities:

- Pleasant Valley Substation;
- North Rochester Substation; and
- Hampton Substation in Dakota County.

The expanded substations will be connected to existing substations and each other through six 345 kV transmission line connections.[10] The length of one or more of these 345 kV connections may exceed 1 mile.[11] Accordingly, the Project, and the CN requested in this Application, also includes the following 345 kV transmission lines:

- Lakefield Junction Substation: two 345 kV transmission lines between the Lakefield Junction Substation and the nearby expanded 765 kV Lakefield Junction Substation.
- Pleasant Valley Substation: two 345 kV transmission lines between the existing Pleasant Valley 345 kV Substation and expanded 345 kV Pleasant Valley Substation; and one 345 kV transmission line between the expanded 345 kV Pleasant Valley Substation and the 765 kV Pleasant Valley Substation expansion.

[10] The expanded 765 kV Pleasant Valley Substation will be connected via a 345 kV transmission line to the expanded 345 kV Pleasant Valley Substation.

[11] A CN will be required for each of these connections that exceed one mile. See Minn. Stat. Section 216B.243, subd. 8(a)(4) (exempting HVTLs of one mile or less to connect a new or upgraded substation to a new, existing or upgraded HVTL).

- North Rochester Substation: one 345 kV transmission line between the North Rochester 345 kV Substation and the expanded 345 kV North Rochester Substation.

1.3 Project Ownership

The Applicants in this proceeding are Great River Energy, Xcel Energy, and ITC Midwest.

Great River Energy is a not-for-profit wholesale electric power cooperative based in Maple Grove, Minnesota. Great River Energy provides electricity and related services to approximately 1.7 million people through its 26 member-owner cooperatives and customers. Through its member-owners Great River Energy serves two-thirds of Minnesota and parts of Wisconsin. Great River Energy owns and operates more than 5,100 miles of transmission line and owns more than 100 substations in Minnesota, North Dakota, South Dakota, and Wisconsin.

Xcel Energy is a public utility that generates electrical power and transmits, distributes, and sells power to residential and business customers within service territories assigned by state regulators in parts of Minnesota, Wisconsin, South Dakota, North Dakota, and the upper peninsula of Michigan. Xcel Energy and Northern States Power Company, a Wisconsin corporation (collectively, the NSP Companies), own and operate the five-state integrated NSP System pursuant to the terms of the FERC-approved Interchange Agreement. The NSP Companies have about 1.8 million electricity customers in the upper Midwest.

ITC Midwest is a subsidiary of ITC Holdings Corp., the largest independent electricity transmission company in the U.S. with operations in eight states. ITC Midwest connects a variety of customers at transmission-level voltages. These include large generation and distribution utilities, municipal utility systems, rural electric cooperatives, and large commercial and industrial customers that require high-voltage electricity. ITC Midwest is headquartered in Cedar Rapids, Iowa, and maintains warehouses in Dubuque, Iowa City, and Perry, Iowa, and Albert Lea and Lakefield, Minnesota. ITC Midwest operates more than 6,600 circuit miles of transmission lines in Iowa, Minnesota, Illinois, Missouri, and Wisconsin.

The Applicants will own portions of the transmission line facilities jointly or discreetly as shown in **Table 1.3-1** (765 kV transmission line facilities) and **Table 1.3-2** (345 kV transmission line facilities).

Table 1.3-1
Ownership of 765 kV Transmission Line Facilities

Owner	SD/MN State Line to Lakefield Junction (percent) [a]	Lakefield Junction to IA/MN State Line (percent)	Lakefield Junction to Pleasant Valley (percent)	Pleasant Valley to North Rochester (percent)
Great River Energy	0	0	50	50
Xcel Energy	45	0	0	50
ITC Midwest	55	100	50	0

[a] Final ownership percentages in Minnesota will be dependent on actual costs of the Brookings-Lakefield Junction segment.

Table 1.3-2
Ownership of 345 kV Transmission Line Facilities

Owner	Pleasant Valley to North Rochester (percent)	North Rochester to Hampton (percent)
Xcel Energy	100	64
Dairyland Power Cooperative	0	11
Rochester Public Utilities	0	9
Southern Minnesota Municipal Power Agency	0	13
Wisconsin Public Power	0	3

The substation components will be owned individually as follows:

- ITC Midwest will own the 765 kV substation improvements at the Lakefield Junction Substation.
- Great River Energy will own the 765 kV substation improvements at the Pleasant Valley Substation and the 345 kV substation improvements at the Pleasant Valley Substation.
- Xcel Energy will own the 765 kV substation improvements at North Rochester Substation and the 345 kV substation improvements at North Rochester Substation and Hampton Substation.

1.4 Project Need

The Project is needed to 1) mitigate system overloads to maintain system reliability to meet existing and future energy needs; 2) meet growing electrical demand in a cost-effective manner; and 3) to support the energy transition. As described further in **Section 6.1**, for the purposes of the need analysis in this Application, Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those lines outside of Minnesota). This group of projects is referred to as the "Studied Projects."

The following sections provide a summary of the regional and local Minnesota drivers for the Studied Projects, considering MISO's LRTP efforts and Minnesota-specific factors. Additional details on the need for the Studied Projects are provided in **Chapters 5 and 6**.

1.4.1 Regional Drivers

The MISO region is facing fundamental shifts in how electricity is produced and consumed. The grid must respond to reliably move electricity from the point of generation to where it is consumed. The Project, as part of the overall MISO LRTP Tranche 2.1 Portfolio, is needed to maintain reliability as Minnesota and the Midwest region evolves its energy industry landscape, including new generation resources, consumer demand for low-carbon resources, decentralization of generation, and changing and growing demands for electricity.

Recognizing the complex challenges to electric reliability in the region from the transformational changes in the generation fleet, extreme weather events, and other factors, MISO initiated the LRTP in 2019. The LRTP is a multi-year, multi-phase effort to identify necessary regional transmission grid expansions required to cost-effectively maintain system reliability in the face of greater uncertainty and variability in supply (e.g., greater reliance on wind and solar generation). In short, the LRTP is designed to enable the transmission grid to move more cost-effective electricity, farther distances, and from different generation sources to continue to serve electrical needs 24 hours a day, 7 days a week, 365 days a year.

In 2022, MISO approved the first phase, or "tranche," of the LRTP (LRTP Tranche 1) as the initial step to address Minnesota and the broader Midwest region's evolving reliability needs. The MISO LRTP Tranche 1 consists of 18 transmission projects which will result in approximately 2,000 miles of new and upgraded HVTLs across nine states. The LRTP Tranche 1 includes three projects in Minnesota:

- Big Stone South to Alexandria to Big Oaks Transmission Projects: Commission Docket Numbers CN/22-538, TL-23-159, and TL-23-160;
- Northland Reliability Project: Commission Docket Numbers CN-416 and TL-22-415; and
- Mankato to Mississippi River Project: Commission Docket Numbers CN-22-532 and TL-23-157.

In 2024, MISO approved the next phase of the LRTP (LRTP Tranche 2.1) to establish a new 765 kV transmission backbone across the Midwest. The LRTP Tranche 2.1 includes 24 projects totaling approximately 3,600 miles of new and upgraded transmission in MISO's Midwest subregion (Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, and

Wisconsin). The LRTP Tranche 2.1 builds upon, and is enabled by, the LRTP Tranche 1 and the existing transmission grid, which serves as "entry and exit ramps" for the new LRTP Tranche 2.1 765 kV transmission backbone network. Combined, the existing 765 kV and 345 kV networks work together to move electricity across multiple states to each local community where it is consumed.

MISO followed an extensive stakeholder process, spending more than 40,000 staff hours, facilitating more than 300 meetings, and capturing feedback to arrive at the LRTP Tranche 2.1 Portfolio. MISO concluded that the LRTP Tranche 2.1 Portfolio is needed for:

- **Reliability:** The LRTP Tranche 2.1 Portfolio addresses reliability issues (i.e., points on the transmission grid which require solutions to meet North American Electric Reliability Corporation [NERC] national reliability standards) across the MISO region.[12] The LRTP Tranche 2.1 Portfolio supports energy adequacy so that energy can be delivered where it is needed 24 hours a day, 7 days a week, 365 days a year. The LRTP Tranche 2.1 Portfolio will also maintain system reliability through enabled demand and system stability.
- **Cost Effectiveness/Economic Benefits:** The $21.8 billion LRTP Tranche 2.1 Portfolio has a benefit-to-cost ratio of 1.8 to 3.5 (based on MISO's 2024 analysis). This means that every $1.0 invested in transmission will result in economic benefits of $1.8 to $3.5.[13] For an average electrical consumer, MISO estimates that the LRTP Tranche 2.1 Portfolio is estimated to cost about $5 per 1,000 kWh of energy used while providing $10 to $18 of value over that same amount of usage per month in value.[14]
- **Enabling Generation Transition:** The LRTP Tranche 2.1 Portfolio alleviates congestion and enables interconnection of approximately 116,000 MW of new

[12] The Applicants and MISO are required to ensure the transmission grid meets NERC national reliability standards (i.e., prevent a "violation" of reliability standards). To ensure the transmission grid meets reliability standards, MISO, and the Applicants model how changes in both the production and use of electricity will impact the transmission grid and identify any inadequacies of the existing transmission grid. The Applicants and MISO must identify mitigation plans ("fixes") to each reliability issue as required by NERC. The reliability issues addressed by the MISO LRTP Tranche 2.1 Portfolio are summarized in pages 63 to 69 and detailed in pages 77 through 123 of **Appendix E.1.** The NERC reliability standards are available at: https://www.nerc/globalassets/standards/reliability/tpl/tpl-001-5.1.pdf.

[13] Net savings are 20-year net present value (NPV) in $2024 (Id., Page 125, Figure 2.137).

[14] MISO. Fact Sheet - Long Range Transmission Planning Tranche 2.1. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202.1666573.pdf.

generation resources.[15] These resources will include carbon-free resources to reduce Midwest carbon dioxide (CO_2) emissions by 127 million to 199 million metric tons over 20 to 40 years and help states like Minnesota comply with decarbonization laws.[16]

The Project serves a key role in the MISO LRTP Tranche 2.1 Portfolio by addressing reliability issues specific to southern Minnesota, eastern North Dakota, eastern South Dakota, northern and central Iowa, and western Wisconsin.[17] Additional information on the MISO LRTP Tranche 2.1 Portfolio and process is in **Section 4.6.**

1.4.2 Local Minnesota Drivers

Minnesota's transmission grid has evolved since the Rural Electrification Act of the 1930s that initially brought electricity to most of the state. Several key inflection points - step-changes, or significant buildouts driven by fundamental changes in how electricity was generated and/or consumed – have shaped Minnesota's grid to its present state. The last inflection point in the late 2000s was driven by several transformational factors:

- FERC established RTOs, including MISO, with orders to operate and plan the transmission grid on a multi-state regional basis to improve reliability and cost-efficiency, transforming how the transmission system is used.
- Minnesota passed the Next Generation Energy Act of 2007, which included a Renewable Energy Standard requiring most utilities to generate 25 percent of their electricity (30 percent for Xcel Energy) from renewable sources by 2025.[18] This created the need to interconnect a significant amount of new generating sources.
- Demand for electricity reached new peaks and was forecasted to grow at upwards of 2.49 percentage points annually.[19] Even absent the need to interconnect new generation, the transmission grid began to exceed the limit to which Minnesota transmission owners could make incremental improvements

15 See **Appendix E.1** Page 75.

16 Id., Page 142.

17 Id., Pages 84 and 92.

18 State of Minnesota. Next Generation Energy Act of 2007. Available at: https://www.revisor.mn.gov/laws/2007/0/Session+Law/Chapter/136/2014-06-28%2012:17:06+00:00/pdf.

19 Transmission Planning and CapX2020. Humphrey School of Public Affairs University of Minnesota. Page 21 Table 2. Available at: https://gridnorthpartners.com/wp-content/uploads/2021/03/uofm-humphrey_capx2020_final_report.pdf.

to the lower voltage system to accommodate new and/or shifts in energy usage.

The Capacity Expansion Needed by 2020 (CapX2020) coalition of 11 Minnesota utilities addressed those fundamental changes by proposing and constructing more than 800 miles of HVTLs in Minnesota that are currently in-service.[20]

1.4.2.1 Generation Changes

In 2011, 53 percent of the electricity generated in Minnesota was from coal-fired generation. In 2024, electricity from coal was approximately 20 percent and renewables provided approximately 33 percent of electricity generation in Minnesota.[21] As of January 2025, approximately 7,000 MW of new renewable generation has been installed in Minnesota.[22]

In 2023, the Minnesota Legislature increased the amount of renewable energy that electric utilities were required to acquire. Legislation mandating "100 Percent Carbon-Free by 2040" was signed into law, which requires electric utilities to transition to meet the needs of Minnesota customers with 100 percent carbon-free electricity by the end of 2040. Driven by a combination of economics, consumer preferences, age of existing generation, and regulatory policies, 72,000 MW of new generation is expected to be added, and 16,000 MW of existing generation is expected to be retired over the next 20 years in Minnesota and the surrounding area (within MISO's Local Resource Zone 1).[23] These are baseload generators that have provided round-the-clock energy production for many decades. The retired generators provide more than just energy production, they also provide essential reliability services, which keep electricity safe and stable. As these generators are retired, both the "baseload" nature and essential reliability services of these sources must be replaced.

[20] During the Minnesota regulatory process, given the potential for future expansion to accommodate additional needs, the Commission, at the Department of Commerce's recommendation, approved Minnesota's 345 kV lines built for double circuit optionality. As of 2025, the second circuit has been built or planned for construction on most facilities, allowing a doubling of transmission capacity with minimal impacts and lower cost. (Commission. Surrebuttal Testimony of Dr. Steve Rakow on Behalf of the Minnesota Office of Energy Security. Available at: https://efiling.web.commerce.state.mn.us/documents/%7B3330DBFF-01B4-407D-B195-30774E30DD2A%7D/download. Page 2).

[21] EIA. Electricity Data Browser. Available at: https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=.

[22] EIA. Electric Power Monthly. Table 6.2.B. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b

[23] See **Appendix E.2.** Pages 87 and 88. MISO Local Resource Zone 1 includes the portions of MISO in Minnesota, North Dakota, South Dakota, and western Wisconsin.

1.4.2.2 Increasing Demand

Since 2007, demand growth in the Midwest has remained relatively flat, initially due to the Great Recession from 2007 to 2009 and then from demand efficiency programs absorbing growth. Current forecasts, however, indicate a 1.14 percent annual demand growth rate for Minnesota and the surrounding area, adding approximately 5,000 MW over the next 20 years.[24] Demand forecasts do not include the potential for growth attributed to data centers and other industrial demands beyond what is currently firmly committed, which MISO predicts could increase growth rates by upwards of three times the current forecasts.[25]

1.4.2.3 Transmission Grid Localized Improvement Option Exhausted

The Applicants have a responsibility to implement the right transmission at the right time to maintain reliability. New transmission lines are proposed only after all other options to upgrade existing transmission lines have been exhausted. The Applicants and Minnesota's transmission owners have been at the forefront of "squeezing every drop" of capacity out of the existing transmission grid through uses of new technology to allow transmission line ratings to be adjusted in real-time based on actual weather conditions and upgrading transmission and substation equipment to the latest designs. These incremental changes are insufficient to address the identified transmission system needs.

1.5 How Project Addresses Multiple Needs

1.5.1 Reliability

The Project will maintain system reliability for current and future demands. How the Project supports reliability is measured by NERC compliance, energy adequacy, enabled demand, and system stability.

- **NERC compliance** means the regional transmission system will meet the planning requirements NERC has established.
- **Energy adequacy**[26] means the transmission system will be able to move energy to where it is needed to avoid interruption in service.

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24 MISO. Futures Report, Series 1A. See **Appendix E.2**. Page 32 - MISO Local Resource Zone 1.

25 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

26 Energy adequacy is distinct from resource adequacy which measures the supply of energy available to meet demand.

- **Enabled demand** measures how much additional customer demand can be served.
- **System stability** measures how well the transmission system can transfer large amounts of power between geographic areas.

1.5.1.1 NERC Criteria

NERC defines the reliability standards for which the electrical grid is planned. The Studied Projects eliminate expected reliability overloads of 102 different facilities, 27 of which are 200 kV or higher – addressing 1,313 reliability issues as defined by NERC.[27]

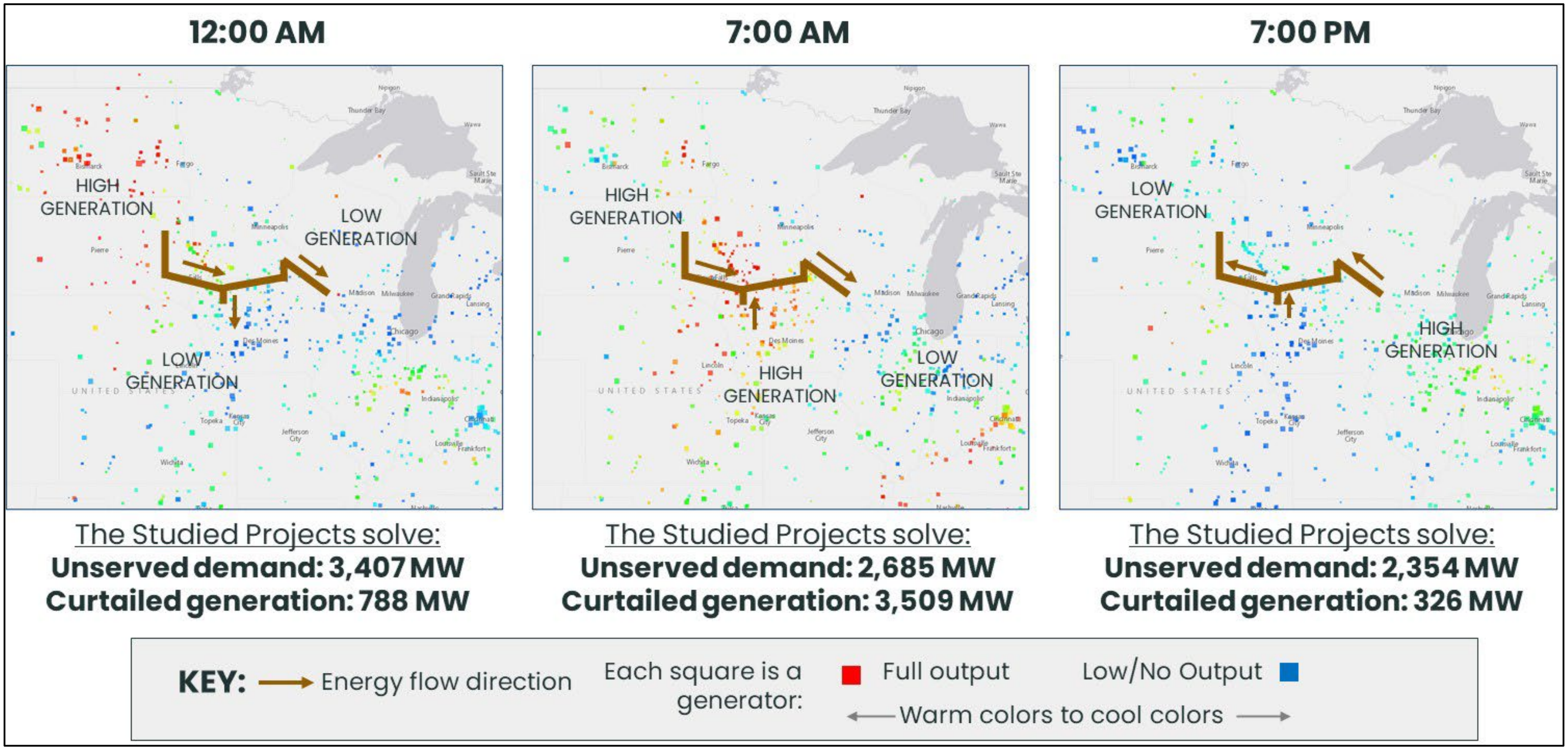
1.5.1.2 Energy Adequacy

The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load 24 hours a day, 7 days a week, 365 days a year. The Studied Projects help enable the transmission grid to take on the role currently served by baseload generation, essentially allowing the transmission grid to function as a super-sized battery, as illustrated on **Figure 1.5-1**.

Figure 1.5-1 shows projected available resources and general power flows across the system in 2042. It displays three different hours of expected generation output and electrical demands under typical and actual weather patterns in winter. The figure shows how, as the weather front moves from east to west, the Studied Projects facilitate moving energy from where it is produced to where it is needed, which changes by the hour. Without the Studied Projects, during these hours, over 2,000 MW of load would not be served, and a similar magnitude of energy generation would be wasted (or, curtailed) because there is inadequate transmission to move it where it is needed. On an annual basis, approximately 1,300,000 megawatt hours (MWh) of load from Minnesota and the surrounding area is at expected risk of not being served without the Studied Projects by 2042. Risk levels are highest during times when electricity demand is highest and during atypical weather conditions (e.g., extreme weather events).

[27] MISO. Details in **Appendix E.4**. **Appendix E.4** contains the full reliability results for Table 2.13 (page 85) and Table 2.102 (page 95) in **Appendix E.1**. In accordance with Minnesota Rules, part 7829.0500, and Minnesota Statutes Chapter 13, Applicants have designated portions of **Appendix E.4** as NONPUBLIC DATA– NOT FOR PUBLIC DISCLOSURE because it contains confidential security information, as defined by Minn. Stat. § 13.37(1)(a). The public disclosure or use of this information creates an unacceptable risk of disruption to the electrical grid. Thus, Applicants maintain this information as nonpublic pursuant to Minn. Rule 7829.0500, subp. 3. Given the need to include nonpublic information, Applicants have prepared and are electronically filing both nonpublic and public versions of **Appendix E.4**.

Figure 1.5-1: Energy Adequacy Provided by the Studied Projects: Typical Winter Day (2042)



1.5.1.3 Enabled Demand

The Studied Projects are needed to serve forecasted demands for electricity. The Studied Projects are also sized appropriately to reliably serve future increases in residential, commercial, and industrial energy demands totaling approximately 6,000 MW over the next 20 years. In addition, the Studied Projects make accommodating approximately 1,600 MW of additional load growth less expensive.

1.5.1.4 System Stability

The Studied Projects will improve system transfer capability and address system instability issues. As the power plants historically relied upon for system stability are retired and are increasingly replaced with inverter-based resources (e.g., wind and solar generators) and demands for electricity become more dynamic, backbone transmission upgrades, like the Studied Projects, are critical to networking the grid to maintain stability.

1.5.2 Cost Effectiveness/Economic Benefits

The Studied Projects are expected to provide $7.7 billion to $25.3 billion in economic benefits to customers and members over the first 20 years of service by reducing congestion and providing access to lower-cost generation resources. The Studied Projects are the most cost-effective alternative to meet Minnesota's growing electrical needs. MISO estimates that the Studied Projects, when coupled with the broader MISO LRTP Tranche 2.1 Portfolio, are expected to provide economic savings of over two times the costs for Minnesota. The Studied Projects reduce congestion in Minnesota by upwards of 11 percent, allowing energy needs to be served with lower-cost energy.

1.5.3 Enabling Generation Transition

The Studied Projects enable aging and/or cost-inefficient generation to retire and be replaced by new generation – including carbon-free generation – which helps meet state policy objectives and satisfy customer demand. The Studied Projects also contribute to more efficient use of existing generation resources. The Studied Projects help enable approximately 24,000 MW of new generation (10,000 MW in Minnesota) to be reliably connected to the transmission grid. While generation is typically interconnected at 345 kV and lower voltages, the Studied Projects enable new generation to interconnect by pulling electricity off the existing lower voltage transmission lines to create transmission capacity to add new generation.

The Studied Projects will enable better/full utilization of carbon-free resources, reducing curtailment by 5.6 million to 7.2 million MWh on an annual basis. Curtailment refers to a condition where a generator can, and economically should, provide power to the grid, but there is insufficient transmission capacity to move the energy generation from the generator to where it is needed to serve demand, or where there is not enough demand or storage resources to use all available generation. While not limited to renewable generation, curtailment occurs primarily at renewable resources which are economically the lowest cost generators from an operating perspective. CO_2 emissions will also be reduced, in support of Minnesota's Carbon-Free by 2040 law. Combined, the Studied Projects will reduce annual CO_2 emissions by 5.4 million to 7.5 million tons.

1.6 Alternatives

The Applicants evaluated multiple system alternatives to the Studied Projects, including alternative voltages, generation and non-wires alternatives, transmission alternatives, combinations of alternatives, and a no-build alternative. None of the alternatives is a more reasonable and prudent alternative to the Studied Projects, as summarized in **Table 1.6-1**. The Applicants also evaluated alternative conductor and structure design as shown in **Table 1.6-1**.

Table 1.6-1
Alternatives Evaluation Summary

Alternative	Reason for Rejection
ALTERNATIVE VOLTAGES	
Lower voltage	**Cost:** Less cost-effective than the Studied Projects. **Impact:** More land-impacts than the Studied Projects.
Higher voltage	**Viability:** No voltages higher than 765 kV are operating in the United States.
GENERATION AND NON-WIRES ALTERNATIVES	
Peaking generation	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Renewable generation	**Need:** Does not address reliability-energy adequacy needs.
Battery energy storage	**Need:** Does not provide transfer capability needed for reliability and efficiency.
Distributed generation	**Need:** Does not address reliability-energy adequacy needs.
Nuclear generation	**Viability:** Does not comply with Minnesota law.
Demand side management/ Conservation	**Viability:** Magnitude of necessary load reduction infeasible.
Reactive power additions	**Need:** Does not address NERC reliability needs.
TRANSMISSION ALTERNATIVES	
Upgrade existing transmission lines	**Cost:** Less cost-effective than the Studied Projects. **Impacts:** Number and scale of upgrades infeasible (at least 1,394 miles of transmission lines and 10 substation upgrades required). **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.

Table 1.6-1 Alternatives Evaluation Summary	
Alternative	**Reason for Rejection**
Alternative endpoints	**Need:** Project endpoints identified and optimized by MISO.[28]
Double circuiting (765 kV/765 kV) and other engineering considerations	**Need:** Single circuit meets current forecasts' needs and proactively accommodates a reasonable level of potential future needs.
High voltage direct current	**Cost:** Less cost-effective than the Studied Projects.
Underground	**Viability:** Underground 765 kV technology is presently not available.
REASONABLE COMBINATION OF ALTERNATIVES	
Lower voltage and upgrading existing lines	**Cost:** Less cost-effective than the Studied Projects. **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.
Lower voltage and peaking generation/storage	**Cost:** Less cost-effective than the Studied Projects. **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.
ALTERNATIVE TRANSMISSION LINE ENGINEERING	
Alternative conductor design	The Applicants studied 17 conductors for the Project. Based on cost, performance, and the Project requirements, Applicants currently propose 1192.5 45/7 ACSR Bunting conductor or similar performing conductor.
Alternative structure design	Applicants considered multiple structure designs, including tubular H-Frame and monopole designs. Based on cost, resiliency and constructability considerations, Applicants determined that the lattice design was the best performing design for the Project.
NO BUILD ALTERNATIVE	
No build alternative	**Need:** Without the Studied Projects, there are consequences to: 1) system reliability (unserved demand, NERC reliability violations, energy adequacy, and system instability); 2) generation plans (increased risk of not complying with Minnesota's Carbon-Free by 2040 law); and 3) economics (less efficient and more expensive piecemeal solution required absent the coordinated regional approach).

The Project does not preclude other technologies but rather enables the development of other technologies to work together with the Project to optimally maintain reliability. Given the complex challenges to regional reliability from the changing generation fleet and electrical demands, an "all of the above" approach is needed. Although the Project is defined by the 765

[28] *See* Minnesota Department of Commerce, Division of Energy Resources Comments on Exemption Requests, at 6 *In the Matter of the Application for a Certificate of Need for the PowerOn Midwest 765 kV and 345 kV High Voltage Transmission Line Project*, Docket No. CN-25-117 (hereinafter, the "PowerOn Midwest Docket") (Oct. 21, 2025) ("The Department agrees with the Applicants that Minnesota Statutes limit the consideration of alternative end points in this matter.…").

kV transmission backbone, the Project is part of a larger system which also includes and/or assumes:

- lower voltage transmission line additions (e.g., 345 kV);
- upgrades of existing transmission lines;
- expansion of demand side management;
- additional distributed generation;
- utility-scale generation additions of multiple fuel-types; and
- expansion in energy storage.[29]

All these technologies, including the Project, are necessary to support future grid reliability. Additional details are provided in **Chapter 7**.

1.6.1 Transmission Line Voltage Alternatives

The Applicants and MISO identified the need to transfer upwards of 10,000 MW more electrical capacity to, through, and out of Minnesota to meet customer demands. The expansion of the transmission system could potentially be accomplished through multiple 345 kV facilities[30] or a combination of 345 kV and 765 kV facilities. Given the magnitude of the capacity required, MISO concluded that 765 kV facilities along a west-east corridor through the Midwest with additional 345 kV transmission line facilities should be constructed. The 765 kV voltage minimizes costs and the amount of right-of-way needed, reducing environmental impacts. In other words, it would require more right-of-way for a 345 kV west-east corridor to create the same capabilities as a single 765 kV right-of-way. The general capacity differences of 765 kV and 345 kV voltages are shown in **Table 1.6-2** and **Figure 1.6-1**.

The Applicants independently considered 765 kV, 500 kV, 345 kV, and existing system alternatives. Like MISO, the Applicants concluded that the 765 kV voltage is best suited to address system reliability needs in a manner which is less costly and less impactful than other alternatives.

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[29] MISO LRTP Tranche 2.1 assumes approximately 3,500 MW of new energy storage will be added in Minnesota and the surrounding area over the next 20 years (See **Appendix E.2**. Page 87, MISO Local Resource Zone 1).

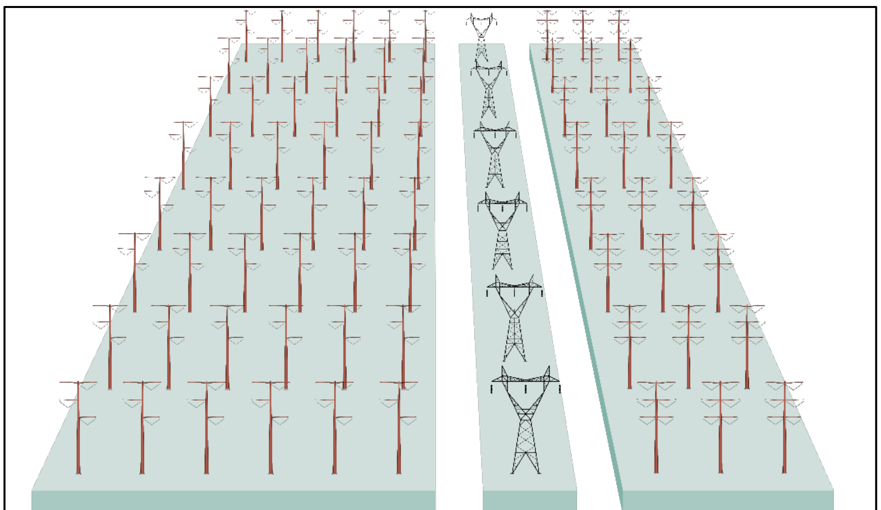
[30] Minnesota's high-voltage transmission network is largely 345 kV with a few 500 kV lines primarily connecting to Manitoba.

Table 1.6-2
Comparison of Land Impacts to Meet Reliability Needs by Voltage Class

Voltage Class	Number of Lines Needed to Provide Equivalent Capability as one 765 kV Line[a]	Approximate ROW Needs for Each Line (feet)	Total ROW Width (feet)	Total Impacted Acreage for 410 Miles[b]
345 kV single-circuit	6	150	900	44,727
345 kV double-circuit	3	150	450	22,364
765 kV (the Project)	1	250	250	12,424

a Source: MISO. See **Appendix E.1.** Page 35.
b Mileage for Minnesota portion of the Studied Projects (MISO LRTP numbers 22 through 26).

Figure 1.6-1: Comparison of Total Right-of-Way Width Based on General Capacities of Each Voltage Class (Not to Scale)[31]



345 kV
SIX
SINGLE CIRCUIT
TOWERS
(900 ft of total right-of-way)

765 kV
ONE
SINGLE CIRCUIT
TOWER
(250 ft of total right-of-way)

345 kV
THREE
DOUBLE CIRCUIT
TOWERS
(450 ft of total right-of-way)

31 **Figure 1.6-1** illustrates total right-of-way width to meet needs for each voltage class. For 345 kV and double-circuit 345 kV, lines may not be located in a single-common right-of-way, as shown for illustrative purposes; however, the total width of all rights-of-way would equal values displayed on **Figure 1.6-1.** See **Table 1.6-1** for additional details.

The 765 kV voltage is also the least-costly option to transfer the necessary level of energy. As shown in **Table 1.6-3**, the cost for 765 kV transmission is less than the 345 kV options.

Table 1.6-3
Comparison of Costs to Meet Reliability Needs by Voltage Class

Voltage Class	Approximate Cost for Each Line [a] ($2024)	Number of Lines Needed to Provide Equivalent Capability as One 765 kV Line [b]	Approximate Total Costs ($2024)
345 kV single circuit	$3.6 million/mile	6	$21.6 million/mile
345 kV double circuit	$6.0 million/mile	3	$18.0 million/mile
765 kV	$5.7 million/mile	1	$5.7 million/mile

[a] MISO. All costs are from MISO's MTEP24 Cost Estimation Guide. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf. Table 4.1-1 and 4.1-2.

[b] MISO. See **Appendix E.1.** Page 35

1.6.2 Non-Transmission Alternatives

The Applicants evaluated generation and non-wires alternatives, including new peaking generation, renewable generation, battery energy storage, distributed generation, nuclear generation, demand-side management and conservation measures, and reactive power additions.

The Studied Projects are needed to maintain NERC reliability standards by addressing system overloads. The Studied Projects increase transfer capability to move electricity from new and existing generation to serve new and existing electrical demands. The ability to transfer more energy is not only needed for reliability but also to efficiently and fully utilize available generating resources (i.e., to avoid curtailment or wasted generation). By its nature, transfer capability is created by transmission solutions, not generation. Adding additional generation does not address the core issues addressed by the Studied Projects of:

- increasing transmission capacity to interconnect with new generation;
- maintaining local reliability by being able to transfer energy into an area during times when local generation is not available; and
- efficiently and fully utilize generation capacity.

Conversely, in most cases, adding additional generation exacerbates the system issues that the Studied Projects seek to address. Nonetheless, the Applicants evaluated adding local generation as a direct alternative to the Studied Projects. Adding additional local capacity does not increase the ability to reliably interconnect new generation or transfer capability – rather it supports energy adequacy by adding additional local generation where existing local generation is insufficient to meet demand and/or the existing grid is not capable of transferring enough energy to meet demand energy.

No generation alternative is a more reasonable and prudent alternative to the Studied Projects.

1.7 Project Schedule and Costs

The Applicants anticipate starting construction on the Project as early as 2029. The target energization for the Project is 2032 for the 345 kV facilities and 2034 for the 765 kV facilities. **Table 1.7-1** summarizes the permitting schedule; more detail on the schedule is provided in **Section 2.6**.

Table 1.7-1
Anticipated Project Schedule

Project Component	SD/MN State line to Lakefield Junction 765 kV	Lakefield Junction to Pleasant Valley and Lakefield Junction to IA/MN State Line 765 kV	Pleasant Valley to North Rochester 765 kV	Pleasant Valley to North Rochester to Hampton 345 kV
Start CN Proceeding	Q1 2026	Q1 2026	Q1 2026	Q1 2026
Start Route Permit Proceeding	Q1 2027	Q1 2027	Q1 2027	Q1 2027
Begin Land Acquisition	Q4 2028	Q4 2028	Q4 2028	Q3 2028
Obtain Permits to Construct	Q2 2029	Q2 2029	Q2 2029	Q2 2029
Start of Construction	Q4 2029	Q4 2029	Q4 2029	Q4 2029
Project Operation	Q2 2034	Q2 2034	Q2 2034	Q3 2032

The schedule is dependent on the anticipated timing of the CN proceeding, Route Permit proceedings, and post-permit requirements that must be completed prior to the start of construction. The schedule is also dependent on the Applicants advancing design work in parallel with the Commission permitting processes. For instance, the Applicants assumed early design work, up to 30 percent completion of the transmission line design, to coincide with the issuance of the Route Permit. In addition, the schedule may be adversely impacted by labor and materials availability at the time of construction.

Estimated costs for the Project are approximately $3.327 billion to $4.323 billion, based on the best available information at the time of filing. A summary of the base cost estimate is presented in **Table 1.7-2**. More detail on costs is provided in **Section 2.4**.

Table 1.7-2 Summary of Project Capital Cost Estimates (Base)					
Project Component	**SD/MN State Line to Lakefield Junction 765 kV ($2024)**	**Lakefield Junction to IA/MN State Line 765 kV ($2024)**	**Lakefield Junction to Pleasant Valley 765 kV ($2024)**	**Pleasant Valley to North Rochester 765 kV ($2024)**	**Pleasant Valley to North Rochester to Hampton 345 kV ($2024)**
Transmission Lines	$582 million	$115 million	$813 million	$197 million	$233 million
Substations	$434 million	N/A	$393 million	$553 million	$7 million
Total	**$1.016 billion**	**$115 million**	**$1.206 billion**	**$750 million**	**$240 million**

1.8 Public Input and Involvement and Notice Area

Each of the Applicants has a long history of working with landowners and local communities to develop energy infrastructure projects in Minnesota. Prior to filing this Application, the Applicants engaged with communities and stakeholders through mailings, meetings, open houses, and other methods to ensure that stakeholders were informed of the Project and had an opportunity to provide comments. Additional information on public input and involvement is included in **Chapter 11**.

The public can review this Application and submit comments on the Project to the Commission. A copy of the Application is available on the Commission's website: https://mn.gov/puc/. A copy of the Application is also available on the Project website at https://poweronmidwest.com.

The public can subscribe to the Project's CN docket and receive email notifications when information is filed in that docket. To learn how to subscribe to the Project's CN docket and to receive email notifications when information is filed in that docket, the public can visit www.mn.gov/puc/edockets/how-to/. To subscribe to this CN docket, follow those instructions and enter docket number 25-117.

To be placed on the Project CN mailing list, email eservice.admin@state.mn.us or call 651-201-2246. You may request to receive notices by email or U.S. Mail. If you send an email or leave a phone message, please include the docket number (25-117), your name, your complete mailing address, and email address.

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

Scott Ek
Planning Director
Minnesota Public Utilities Commission
121 E 7th Place East, Suite 350
St Paul, MN 55101-2147
651-259-5168
scott.ek@state.mn.us
https://mn.gov/puc/

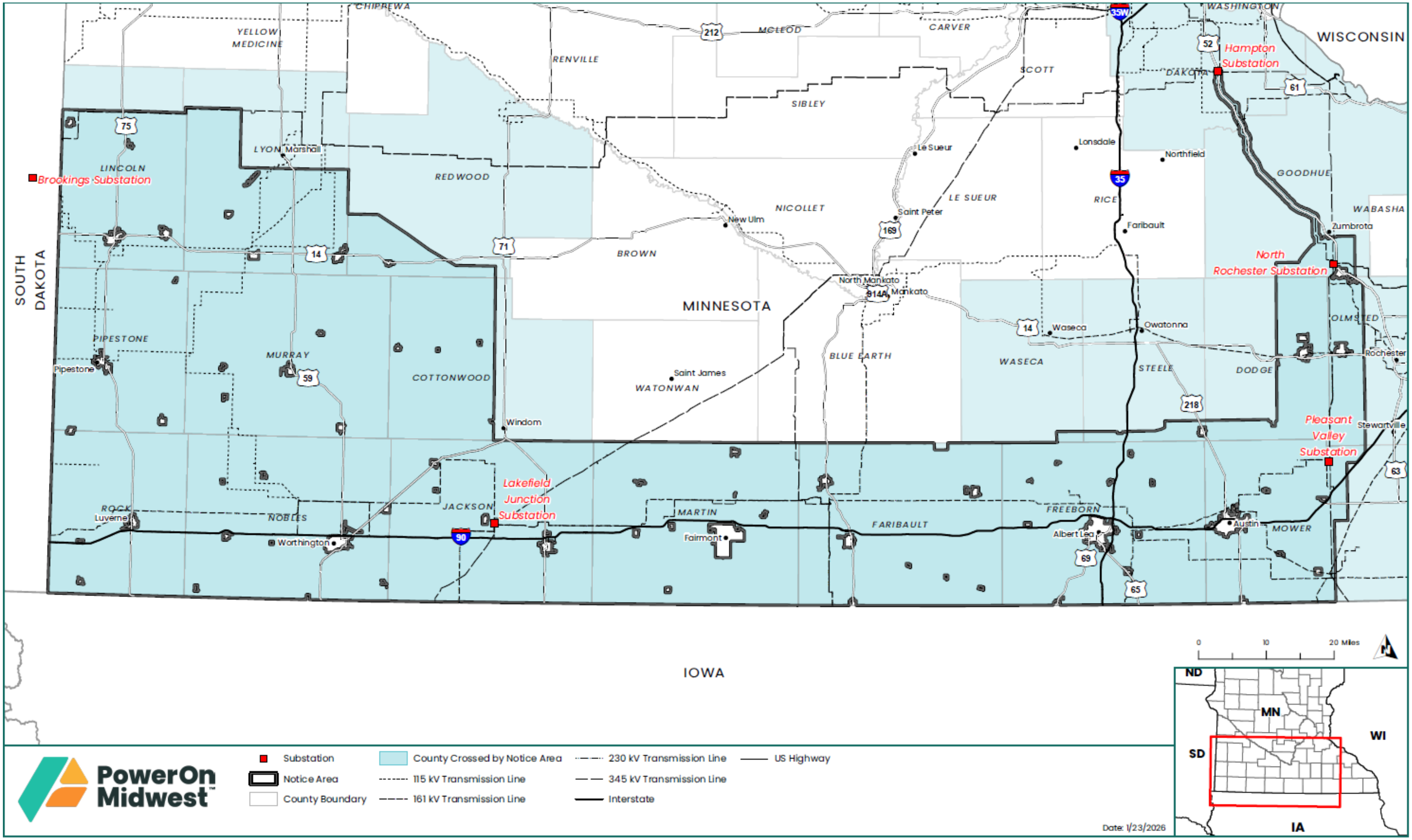
Minn. R. 7829.2550, subp. 1, requires an applicant to file a proposed Notice Plan with the Commission at least three months before filing an application for a CN. This Notice Plan is prepared as an initial step in the CN regulatory process. Preparation of a Notice Plan, and its review and approval by the Commission, ensures that interested persons are aware of the proceeding and have the opportunity to participate. The Applicants filed their proposed Notice Plan on October 1, 2025. The Commission approved the Notice Plan on November 26, 2025. The Commission Order on the Notice Plan is included in **Appendix B**.

The area that was provided notice under the approved Notice Plan (or, the Notice Area) is depicted on **Figure 1.8-1.** Landowners and other stakeholders within the Notice Area were provided notice about the Project in January 2026. The Notice Area includes all or portions of the following counties: Lincoln, Pipestone, Rock, Lyon, Murray, Nobles, Redwood, Cottonwood, Jackson, Martin, Faribault, Waseca, Freeborn, Steele, Mower, Dodge, Olmsted, Goodhue, and Dakota. The Applicants designed the Notice Area to be broad enough to encompass potential future routing corridors, but exclude areas where future routing is unlikely, either because of the presence of routing constraints, and/or because of the Project's geographic requirements.

When developing the Notice Area, the Applicants first identified a larger "Study Area." The Study Area needed to be large enough to encompass multiple potential routing corridors and understand potential constraints. The Applicants gathered publicly available data within the Study Area to identify primary routing constraints and resources across southern Minnesota that were reflective of the Commission's routing criteria.

Next, the Applicants refined the Study Area to exclude portions of counties where routing was unlikely — for example, areas which did not meet the Project's geographic requirements. This refinement reduced the size of the Study Area and resulted in the present exterior boundaries of the Notice Area.

Figure 1.8-1: PowerOn Midwest Notice Area



Once the exterior boundaries of the Notice Area were established, the Applicants generally excluded municipalities with populations exceeding 200 persons from the Notice Area because routing the Project within such municipalities is unlikely. There were some exceptions to this approach if there were existing road or utility corridors within those municipal boundaries, or other potential routing opportunities, which could be considered for Project routing.

The Applicants' broad Notice Area includes several large transportation corridors (U.S. Interstate 90, U.S. Highway 75, U.S. Highway 59, and U.S. Highway 14, along with multiple state highways) and existing utility corridors. For the portion of the Project that would connect the North Rochester Substation to the Hampton Substation in Dakota County, Minnesota, the Notice Area was designed to include 0.5 miles on each side of the existing 345 kV transmission line because Project activities will occur within an existing right-of-way, rather than in a new corridor.

This Notice Area also represents the Project's Study Area further considered in this Application in **Chapter 10**. The Notice Area was developed to ensure that those stakeholders "reasonably likely to be affected by the proposed transmission line"[32] received notice and would have the opportunity to participate in the proceedings.

1.9 Potential Environmental Impacts

Chapter 10 of this Application provides a discussion of the natural environment and land use features in the area reviewed for the Project's Study Area, which is equivalent to the Project Notice Area as shown on **Figure 1.8-1**.

As discussed in further detail in **Chapter 10,** environmental and land use features vary from the western to eastern portion of the Project's Study Area. These variations are reflected in changing patterns of hydrology, vegetation, wildlife, land use, and human settlement. The primary land use within the Project's Study Area is agriculture, with municipalities and rural homesteads scattered throughout. Utility infrastructure, such as transmission and distribution lines and wind and solar generating facilities, are common within the Project's Study Area. Many Project impacts can be avoided and minimized through thoughtful routing, consistent with the Commission's routing criteria. The Applicants will coordinate with federal, state, and local permitting agencies, Tribal governments, and other stakeholders to avoid, minimize, and mitigate potential human and environmental impacts during future routing processes.

[32] Minn. R. 7829.2550, subp. 1.

1.10 Project Meets Certificate of Need Criteria

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a CN. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Minn. R. Ch. 7849.0120 further provides that the Commission grant a CN 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.

Applicants' proposal as summarized in this Chapter and detailed throughout the Application 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 Applicants' customers.

B. A more reasonable and prudent alternative to the Project has not been demonstrated by a preponderance of the evidence.

C. The Project will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments.

D. The Project will comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

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

1.11 Application Organization

The remaining ten Chapters of the Application are organized as follows:

- **Chapter 2**: Project Description
- **Chapter 3**: Coordinated Transmission Development
- **Chapter 4**: Need for Comprehensive Expansion Consistent with Regulatory Authority
- **Chapter 5**: Need Drivers
- **Chapter 6**: How Project Addresses Multiple Defined Needs
- **Chapter 7**: Alternatives to the Project
- **Chapter 8**: Transmission Line Operating Characteristics
- **Chapter 9**: Transmission Line Construction and Maintenance
- **Chapter 10**: Environmental Information
- **Chapter 11**: Public Input and Involvement

1.12 Applicants' Request and Contact Information

For the reasons discussed above and in the remainder of this Application and Appendices, Applicants respectfully request that the Commission find this Application complete and, upon completion of its review, grant a CN for the Project. All correspondence relating to this Application should be directed to:

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2 PROJECT DESCRIPTION

2.1 Project Components

The Project as proposed by the Applicants will include:

- New single-circuit 765 kV HVTL facilities between the following points:
    - The South Dakota/Minnesota state line and the Lakefield Junction Substation in Jackson County, Minnesota;
    - The Lakefield Junction Substation and the Iowa/Minnesota state line;
    - The Lakefield Junction Substation and the Pleasant Valley Substation in Mower County, Minnesota; and
    - The Pleasant Valley Substation and the North Rochester Substation in Goodhue County, Minnesota.
- New 345 kV circuit facilities from the Pleasant Valley Substation to the North Rochester Substation and on to the Hampton Substation in Dakota County, Minnesota.
    - From the Pleasant Valley Substation to the North Rochester Substation, Xcel Energy will remove the existing 345 kV single-circuit structures and replace them with new 345 kV double-circuit structures.
    - From the North Rochester Substation to the Hampton Substation, Xcel Energy will add the new circuit to existing double-circuit capable structures. In approximately three dozen locations, new poles will be required as detailed in **Section 2.2.2**.
- Expansions of the following existing substations for the 765 kV facilities:
    - Lakefield Junction Substation;
    - Pleasant Valley Substation; and
    - North Rochester Substation.
- Modifications to and expansion of the following existing substations to support the new 345 kV circuit:
    - Pleasant Valley Substation;

- North Rochester Substation; and
- Hampton Substation.

The expanded substations will be connected to existing substations and each other through six 345 kV transmission line connections. The length of one or more of these 345 kV connections may exceed 1 mile. Accordingly, the CN requested in this Application also includes the following 345 kV transmission lines:

- Lakefield Junction Substation: two 345 kV lines between the Lakefield Junction Substation and the nearby expanded 765 kV Lakefield Junction Substation.
- Pleasant Valley Substation: two 345 kV transmission lines between the existing Pleasant Valley 345 kV Substation and expanded 345 kV Pleasant Valley Substation; and one 345 kV transmission line between the expanded 345 kV Pleasant Valley Substation and the 765 kV Pleasant Valley Substation expansion.
- North Rochester Substation: one 345 kV transmission line between the North Rochester 345 kV Substation and the expanded 345 kV North Rochester Substation.

2.2 Transmission Line and Structures

2.2.1 Structure Analysis & Selection

The Applicants propose to use four-legged self-supporting lattice structures for the 765 kV facilities and will use tubular steel monopole structures for the new 345 kV double-circuit facilities. The Applicants may use other specialty structures for both the 765 kV and 345 kV facilities depending on site-specific needs and/or conditions.

The Applicants selected a self-supporting lattice tower design from among several 765 kV structure types considered for the Project. The self-supporting lattice tower design best meets the Project requirements based on considerations of cost, engineering, resiliency (can better withstand extreme weather events), and land use impacts. Additional information on structure selection is presented in **Section 7.6.2**.

2.2.2 Structure Descriptions

The proposed 765 kV structures used for the Project will typically range in height from approximately 150 to 175 feet tall. However, where existing transmission lines are crossed, or where topography, environmental constraints, or design needs necessitate, structure heights may be up to 200 feet tall, or greater. If structure heights in excess of 200 feet are necessary, the Applicants anticipate the Federal Aviation Administration (FAA) would issue determinations of no hazard with the expectation that structures be marked and lit. **Appendix C.1** contains a drawing of a typical 765 kV structure.

The typical span length between 765 kV structures will be approximately 1,100 to 1,300 feet, with shorter or longer spans used as needed. The Applicants will generally install the 765 kV structures on drilled pier concrete foundations. Typical foundations will range in size from approximately 5 to 7 feet in diameter and 25 to 65 feet in depth. Actual foundation size will be based on site-specific conditions and detailed engineering design. The 765 kV structures may also require specialty foundations due to geotechnical (soil) conditions or design needs.

The proposed double-circuit 345 kV structures that will replace the existing 345 kV single circuit structures between the Pleasant Valley Substation and the North Rochester Substation will typically range in height from approximately 90 to 160 feet tall. **Appendix C.2** contains a typical 345 kV structure drawing.

The typical span length between 345 kV structures will be between 800 to 1,200 feet. The Applicants will install the 345 kV structures typically on drilled pier concrete foundations, usually approximately 6 feet in diameter and 30 to 40 feet in depth. Actual foundation size will be based on site-specific conditions and detailed engineering design. The 345 kV structures may also require specialty foundations due to geotechnical (soil) conditions or design needs.

The majority of the 345 kV second circuit between the North Rochester Substation and Hampton Substation will be hung on the existing double-circuit capable structures. Approximately three dozen new structures will be required at dead-end and angle locations. Davit arms, insulators, hardware, and conductors will be installed in the second circuit position at all tangent structures. One new angle structure will be needed near the North Rochester Substation.

Table 2.1-1 summarizes the typical structure designs for the new 765 kV and 345 kV structures.

Table 2.1-1
765 kV and 345 kV Transmission Line Structure Characteristics [a]

Line Type	Structure Type	Structure Material	Typical Right-of-Way Width (feet)	Typical Structure Height (feet)	Typical Foundation Diameter (feet)	Typical Span Length Between Structures (feet)
765 kV	Lattice	Galvanized Steel	250	150 - 175	5 - 7	1,110 - 1,300
345 kV Double Circuit	Tubular Monopole	Weathering Steel	150	90 - 160	6	800 – 1,200

[a] Structure sizes may change based on site conditions.

2.2.3 Conductors

A single circuit transmission line carries three phases and separate shield wire(s). A double circuit transmission line carries six phases and two separate shield wires. Each phase can consist of one conductor or multiple "bundled" conductors.

Each 765 kV line will utilize a six-conductor bundle per phase of 1192.5 thousand circular mil (kcmil) 45/7 aluminum conductor steel reinforced (ACSR) Bunting conductor, or a similar performing conductor, with 15-inch subconductor spacing and have a total capacity equal to or greater than 4,000 amperes (amps). The Applicants identified the 1192.5 45/7 Bunting as appropriate for the Project based on a study of 17 conductors. The conductor provides the requisite capacity for the Project, including meeting MISO's ampacity and surge impedance loading (SIL) requirements of 4,000 amps and of 2,400 MW, respectively.[33] Additional information on conductor selection is presented in **Section 7.6.1**.

The 765 kV transmission lines will utilize two shield wires to provide adequate shielding from lightning strikes, thereby providing electrical protection for the lines. The Applicants intend to install optical ground wire (OPGW) as the shield wire type for the Project. The OPGW will not only provide shielding protection, but it will also provide telecommunications capacity for the Applicants. The OPGW will be installed above the phase conductors, near the top of the 765 kV structures.

Each 345 kV line will utilize a twin bundle of twisted pair 636 kcmil ACSR conductor or a similar performing conductor. The 345 kV conductors will have a capacity equal to or greater than 3,000 amps. Twisted pair conductor is the preferred conductor in areas that experience icing with wind which can lead to galloping. Galloping is where conductors oscillate in large vertical motion due to wind or ice loading. Galloping can cause mechanical failures, including outages or damage to insulators. If the galloping action is significant, it can cause phase-to-phase and phase-to-ground faults.

The 345 kV transmission lines will also include two shield wires to provide adequate shielding from lightning strikes. The Applicants may use OPGW for both wires or one OPGW wire and a standard shield wire.

The Applicants will design the Project to meet or surpass relevant local, state, national, and industry requirements, including the National Electric Safety Code® (NESC), as well as the Applicants' own internal standards. The Project will meet applicable standards for construction

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33 In this proceeding, Applicants request authorization to use the Bunting conductor or a similar performing conductor.

and installation, and the Applicants and their contractors will follow safety procedures during design, construction, and after installation.

2.3 Substations

The Project will include expansion of the following existing substations for the 765 kV facilities:

- Lakefield Junction Substation (owned and operated by ITC Midwest);
- Pleasant Valley Substation (owned and operated by Great River Energy); and
- North Rochester Substation (owned and operated by Xcel Energy).

The Project will also include modifications to and expansions of the following existing substations to support the new 345 kV circuit:

- Pleasant Valley Substation;
- North Rochester Substation; and
- Hampton Substation.

Additional information on the substation expansions and modifications is provided in the following sections.

2.3.1 Lakefield Junction 345 kV and 765 kV Substations

The Lakefield Junction Substation is owned and operated by ITC Midwest. The Lakefield Junction Substation will be expanded by approximately 52 acres to accommodate the 765 kV facilities. The 765 kV portion of the Lakefield Junction Substation will be laid out in a double-breaker-double-bus configuration for all interconnecting terminals. Three 765 kV transmission lines will connect to the Lakefield Junction Substation. All three of these 765 kV transmission lines will require reactors. Two 765/345 kV transformer banks will be in the 765 kV portion of the substation. The transformer banks will consist of three in-service single-phase 765/345 kV transformers and one single-phase 765/345 kV transformer shared as a spare between both transformer banks.

The Lakefield Junction Substation will be expanded by approximately 4 acres to accommodate the 345 kV facilities. ITC Midwest will install equipment in the 345 kV portion of the Lakefield Junction Substation to connect two 765/345 kV transformer banks between the 765 kV substation and the 345 kV substation. The transformer interconnection at the 345 kV substation will be a double-breaker-double-bus configuration. Equipment in the expanded substation will be enclosed with high-security fencing.

2.3.2 Pleasant Valley 345 kV and 765 kV Substations

The Pleasant Valley Substation is owned and operated by Great River Energy. The existing 345 kV substation will require replacement of existing 345 kV equipment and a 13-acre expansion for 345 kV facilities, as well as a 60-acre expansion for 765 kV facilities to allow for interconnection of the Project. The expansion will take place entirely on property owned by Great River Energy that is adjacent to and east of the existing Pleasant Valley Substation.

The existing 161/345 kV transformers will remain in the existing Pleasant Valley Substation, and two new 345 kV transmission lines will interconnect with the expanded 345 kV substation. All existing 345 kV transmission lines that terminate in the existing substation will require relocation to terminate in the modified and expanded 345 kV substation. These lines will connect to the modified and expanded 345 kV substation in a breaker-and-a-half topology.

One 345 kV transmission line will connect between the expanded 345 kV substation and the expanded 765 kV substation. This line will connect to the expanded 345 kV substation in a double-breaker-double-bus topology. The 345 kV line will connect to a bank of three energized and one spare single-phase 345/765 kV transformers in the expanded 765 kV substation. There will also be a new 345 kV circuit between the expanded 345 kV substations at the Pleasant Valley and North Rochester substations.

Two 765 kV transmission lines will also interconnect with the expanded 765 kV substation. One transmission line will connect to the Lakefield Junction Substation, and one transmission line will connect to the North Rochester Substation. Both of these transmission lines require reactors. The bank of transformers and two 765 kV transmission lines will connect to the 765 kV substation in a double-breaker-double-bus topology. Equipment in the 345 kV and 765 kV substations will be enclosed with high-security fencing.

2.3.3 North Rochester 345 kV and 765 kV Substations

Xcel Energy owns and operates the North Rochester Substation located near the City of Pine Island. It is the southern endpoint of the new 345 kV second-circuit being added to the existing double-circuit 345 kV transmission line 0964 between the Hampton Substation and North Rochester Substation. It is the northern endpoint of the proposed double-circuit 345 kV transmission line between the Pleasant Valley Substation and North Rochester Substation.

The North Rochester Substation will be expanded by approximately 105 acres to accommodate the 765 kV facilities and approximately 15 acres for the 345 kV facilities. Equipment in the 345 kV and 765 kV substations will be enclosed with high-security fencing.

The expanded 345 kV North Rochester Substation is proposed to include a new breaker row with two new 345 kV, 3,000-amp breakers; three 345 kV disconnect switches; and one new dead-end structure to accommodate the new circuit. The Project will connect North Rochester Substation and the 765 kV substation via the new single circuit 345 kV transmission line.

The 765 kV substation is proposed to include a three-position double breaker double bus configuration to accommodate one 765 kV transmission line to the Pleasant Valley Substation (with reactors). The North Rochester Substation will also include one 765 kV transmission line (with reactors) to interconnect the Gopher to Badger Link Transmission Project (see CN-25-121) and three energized and one spare single-phase 345/765 kV transformers. The design also accommodates two future 765 kV positions for additional lines or transformers, as well as a single-bus 345 kV section with a 345 kV line terminal extending to the existing North Rochester Substation.

2.3.4 Hampton 345 kV Substation

Xcel Energy owns the Hampton Substation, which is located outside the City of Hampton. It is the northern endpoint of the new 345 kV second circuit that will be added to the existing double-circuit-capable 345 kV transmission structures between the North Rochester Substation and Hampton Substation. Xcel Energy will expand the Hampton Substation approximately 1 acre, entirely on Xcel Energy property. Xcel Energy will install a new breaker row with two new 345 kV, 3,000-amp breakers; three 345 kV disconnect switches; and one new dead-end structure to accommodate the second circuit. Equipment in the expanded substation will be enclosed with high-security fencing.

2.4 Project Cost

2.4.1 Construction Costs

Project costs are broken down by the individual Project components in **Table 2.4-1**. All costs are presented in 2024 dollars and include permitting, engineering, materials, land rights and right-of-way, and construction costs including AFUDC (or allowance for funds used during construction). Estimated costs for the Project are approximately $3.327 billion ($2024) (base) to $4.323 billion ($2024) (high-range: base plus contingency).

The Applicants developed the base cost estimate through an extensive due diligence effort. The base estimate was calculated using the Project scope and schedule as presented in this Application and by incorporating the best-available cost estimate information at the time of filing. The Applicants' due diligence included a soils investigation and multiple rounds of bids from contractors and vendors. The Applicants also retained multiple firms to contribute to the engineering design. Further, the Applicants retained independent consultants to support the analysis and validation of the estimates.

The high-range (base plus contingency) cost estimate adds 30 percent to the base cost to account for a reasonable level of potential factors which could impact the final cost of the Project as discussed in more detail below.

Table 2.4-1
Project Cost Estimate by Project Component

Project Component	Base ($2024)	High-Range (Base Plus Contingency) ($2024)
765 KV TRANSMISSION LINES		
MN/SD State Line to Lakefield Junction	$582 million	$756 million
Lakefield Junction to MN/IA State Line	$115 million	$150 million
Lakefield Junction to Pleasant Valley	$813 million	$1.056 billion
Pleasant Valley to North Rochester	$196 million	$255 million
345 KV TRANSMISSION LINES		
Pleasant Valley to North Rochester	$160 million	$207 million
North Rochester to Hampton	$74 million	$96 million
SUBSTATIONS		
Lakefield Junction Substation	$434 million	$564 million
Pleasant Valley Substation	$393 million	$512 million
North Rochester Substation	$553 million	$718 million
Hampton Substation	$7 million	$9 million
PROJECT TOTAL	**$3.327 billion**	**$4.323 billion**

The Applicants will comply with Minn. Stat. § 216I.05, subd. 12(d), which directs the Commission to require the recipient of a route permit to construct an energy infrastructure facility, including contractors and subcontractors, to "pay no less than the prevailing wage rate," as defined in Minn. Stat. § 177.42. These cost estimates assume that the Applicants will pay prevailing wages for applicable positions for the construction of the Project.

The Applicants' high-range (base plus contingency) cost estimate includes a 30 percent contingency adder from the base cost estimate to account for a reasonable level of potential factors which could impact the final cost of the Project. A 30 percent contingency is consistent with industry practices, Applicants' experiences, and MISO guidelines for this stage of project development. The contingency is generic (i.e., a total pool) which accounts for a reasonable level of potential changes attributed but not limited to:

- materials and labor costs (e.g., raw material pricing, substation and transmission line equipment pricing, shortages, taxes and tariffs, etc.);

- routing (e.g., length of the transmission lines, crossings, specialty structures, easement and land costs, etc.); and
- detailed survey, design, and engineering (e.g., topology, soil conditions, final structure designs, final substation designs, etc.).

The MISO Board of Directors approved the LRTP Tranche 2.1 Portfolio on December 12, 2024. MISO's cost estimates for the Project were developed based on a planning-level scope and cost assumptions finalized on May 1, 2024.[34] The Applicants' costs in **Table 2.4-1** are based on detailed engineering (scoping-level) and estimates obtained from equipment manufacturers and construction contractors in late-2025. The Applicants' current cost estimates are higher than the MISO 2024 cost estimates primarily due to the costs to construct the 765 kV substations. The factors driving 765 kV substation costs include but are not limited to:

- major equipment prices based on obtained estimates and bids;
- additional substation equipment (e.g., reactors) necessary to meet reliability and performance requirements; and
- additional site-work needed to prepare the areas for substation construction and operation (e.g., grading).

The Applicants' estimate the Project's 765 kV transmission lines costs to average $6.3 million per mile based on current estimates. Factors which are driving the Project's 765 kV line costs include but are not limited to:

- use of self-supporting lattice structures to lessen potential impacts to agricultural operations as opposed to the use of less-expensive guyed structures – see **Section 7.6.2** for additional details;
- increased foundation costs based on anticipated soil conditions in the Project area;
- use of a larger conductor to meet performance requirements and ensure noise at the edge of the right-of-way does not exceed 50 A-weighted decibels (dBA) under all expected conditions (see **Section 8.3**); and

[34] MISO's MTEP24 Cost Estimation Guide. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf.

- market factors including tariffs, raw material prices, and demand for materials and labor.

As part of the Project's approval and inclusion in the MISO LRTP Tranche 2.1 Portfolio, the Applicants are required to provide MISO with regular updates on the cost and schedule for the Project. If the cost of the Project as reported by the Applicants to MISO exceeds the original baseline estimate by 25 percent or more, MISO Tariff, Attachment FF, Section IX.C.1 requires MISO to undertake a variance analysis. A variance analysis may also be triggered by a schedule delay or inability to complete Project construction.

The process for a variance analysis is set forth in the MISO Tariff. Once a variance analysis has been triggered, (i.e., if the cost of the Project exceeds the original baseline estimate by 25 percent or more), MISO and the Applicants would meet to discuss various Project specifics and details, including the development of supporting facts and documentation. MISO will complete additional investigation into the variance event and relevant facts and factors including the cause or reason for the variance. Once this evaluation is completed, MISO may then elect to: (1) take no action; (2) institute a mitigation plan to alleviate grounds for a variance; or (3) cancel the project.

The Applicants recognize that estimates for the Project currently exceed 25 percent more than MISO's original baseline estimate. It is anticipated that MISO will conduct a variance analysis for the Project. At such time, Applicants will advocate for a mitigation plan to ensure these critical transmission facilities can be constructed.

2.4.2 Operation and Maintenance Costs

Operations and maintenance (O&M) costs for the Project are related to the new transmission lines and the substation expansions and modifications. Relevant O&M considerations for these components are described below.

O&M costs associated with the new transmission lines during the operational phase will be initially driven by controlling regrowth and vegetation within the right-of-way. The Applicants anticipate a post-construction annual maintenance cost of approximately $3,000 to $6,000 per mile. The Applicants also perform other general maintenance on their transmission facilities, such as conducting regular right-of-way patrols and repairing aged or worn equipment or facilities. The specific O&M costs for an individual transmission line vary based on the location of the line, the number of trees located along the right-of-way, the age and condition of the line, the voltage of the line, and other factors.

The Applicants will perform regular inspections at the expanded and upgraded substations and will conduct equipment maintenance and make necessary repairs. The Applicants will service transformers, circuit breakers, batteries, protective relays, and other equipment periodically in accordance with the manufacturers' recommendations. The Applicants will keep the substations free of vegetation and will maintain site drainage. Additional information on maintenance practices is presented in **Section 9.5**.

2.5 Rate Impact

The Commission's rules require an applicant to provide the annual revenue requirements to recover the costs of a proposed project. The Applicants requested an exemption from this rule requirement for Great River Energy and ITC Midwest. Because the Project's costs will be allocated across the MISO footprint, Great River Energy and ITC Midwest instead proposed to provide information regarding the expected Project cost, MISO's cost allocation methodology, and the share that will be allocated to Minnesota utilities' load. Xcel Energy provides a summary of its annual revenue requirement for the capital costs of the Project for a 20-year period below and in greater detail in **Appendix D**.

2.5.1 MISO Cost Allocation

The Project is part of the MISO LRTP Tranche 2.1 Portfolio, which has been determined by MISO to meet the criteria for being designated a Multi-Value Project (MVP) according to the MISO tariff. Therefore, the Project, along with all other projects in the LRTP Tranche 2.1 Portfolio, qualifies for regional cost allocation. MISO has determined that the LRTP Tranche 2.1 Portfolio costs will be allocated to transmission customers in the MISO Midwest subregion[35], where the portfolio is located, and provides proximate benefits. The allocation of the Project's costs to transmission customers is governed by Schedule 26-A, Multi-Value Project Usage Rate, in MISO's tariff. The annual revenue requirement for the Project is determined pursuant to 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, which are assessed based on actual monthly energy consumption by customers. The allocated share of the annual revenue requirement for Minnesota customers is determined by the percent of total MISO energy used by Minnesota utilities, which has been

[35] 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.

estimated at approximately 18 to 24 percent based on MISO's posted 2023 energy withdrawal data.

Table 2.5-1 summarizes the estimated cost allocation for the Project to each local balancing authority area in the MISO Midwest subregion.

Table 2.5-1
Estimated Cost Allocations based on Attachment MM of the MISO Tariff [a]

Local Balancing Authority Area	Cost Allocation Zone	Local Balancing Authority Area Allocation
Alliant East	2	2.8%
Alliant West	3	3.8%
Ameren Illinois	4	8.6%
Ameren Missouri	5	7.1%
Big Rivers Electric Corporation	6	1.4%
Cinergy	6	7.6%
Consumers	7	9.3%
Columbia Water and Light Department	5	0.3%
City Water Light and Power	4	0.3%
Detroit Edison	7	9.8%
Dairyland Power Cooperative	1	1.3%
GridLiance Heartland, LLC	4	0.0%
Great River Energy	1	2.9%
Hoosier Energy	6	0.7%
City of Henderson, Kentucky (d/b/a Henderson Municipal Power & Light)	6	0.1%
Indianapolis Power and Light	6	2.7%
Montana Dakota Utilities	1	0.9%
MidAmerican Energy Company	3	6.7%
Madison Gas and Electric	2	0.7%
Michigan Upper Peninsula	2	0.6%
Minnesota Power	1	2.3%
Muscatine Power and Water	3	0.2%
Northern Indiana Public Service Company LLC	6	3.6%
Northern States Power	1	9.3%
Otter Tail Power	1	3.3%
Southern Indiana Gas and Electric	6	1.1%
Southern Illinois Power Cooperative	4	0.3%
Southern Minnesota Municipal Power Agency	1	0.3%
Upper Peninsula Power Company	2	0.2%
Wisconsin Electric Power Company	2	5.9%

Table 2.5-1 Estimated Cost Allocations based on Attachment MM of the MISO Tariff [a]		
Local Balancing Authority Area	**Cost Allocation Zone**	**Local Balancing Authority Area Allocation**
Wisconsin Public Service Company	2	2.7%
Exports and Wheel-Throughs	N/A	3.0%
[a] MISO. Schedule 26A Indicative Annual Charges. Available at: https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fcdn.misoenergy.org%2FSchedule%252026A%2520Indicative%2520Annual%2520Charges106365.xlsx&wdOrigin=BROWSELINK		

Great River Energy has member load in multiple local balancing authority areas: Great River Energy, Northern States Power, Otter Tail Power, Minnesota Power, Alliant West, and Southern Minnesota Municipal Power Agency. ITC Midwest provides wholesale transmission service to the Alliant West local balancing authority. Xcel Energy has load in multiple local balancing authorities: Great River Energy and Northern States Power. The Applicants calculated the costs allocated to each of the individual Applicants by multiplying each local balancing authority area allocation by each utility's load ratio share.

Great River Energy's allocated cost will be approximately 4.1 percent using allocations from **Table 2.5-1**, above, and the 2025 projected MISO 12CP average load share based on September 2025 MISO zonal rates and determinants file[36] as shown in **Table 2.5-2**, below.

Table 2.5-2 Share of Allocated Costs – Great River Energy			
Pricing Zone	**Project Local Balancing Authority Area Allocation**	**Load Ratio Share per Local Balancing Authority Area**	**GRE Share of Local Balancing Authority Area Allocation**
Great River Energy	2.9%	77.6%	2.3%
Northern States Power	9.3%	9.6%	0.9%
Alliant West	3.8%	4.9%	0.2%
Minnesota Power	2.3%	13.5%	0.3%
Southern Minnesota Municipal Power Agency	0.3%	1.3%	0.0%
Otter Tail Power	3.3%	12.6%	0.4%
TOTAL			**4.1%**

ITC Midwest's allocated cost will be approximately 3.5 percent using allocations from **Table 2.5-1,** above, and 12CP average load share based on September 2025 MISO zonal rates and

[36] MISO. Transmission Settlements and Pricing. Available at: https://www.misoenergy.org/markets-and-operations/settlements/ts-pricing/#nt=%2Ftspricingtype%3AZonal%20Rates&t=10&p=0&s=Updated&sd=desc.

determinants file[37] as shown in **Table 2.5-3**, below. ITC Midwest's load ratio share on the total MISO load includes load that takes wholesale transmission service in Minnesota, Iowa, and Illinois.

Table 2.5-3 Share of Allocated Costs – ITC Midwest			
Pricing Zone	**Project Local Balancing Authority Area Allocation**	**Load Ratio Share per Local Balancing Authority Area**	**ITCM Share of Local Balancing Authority Area Allocation**
Alliant West	3.8%	91.7%	3.5%

Xcel Energy's allocated cost will be approximately 8.5 percent using allocations from **Table 2.5-1,** above, and 12CP average load share based on September 2025 MISO zonal rates and determinants file[38] as shown in **Table 2.5-4**. Xcel Energy's load ratio share is based on total MISO load including load served in Minnesota, Wisconsin, North Dakota, and South Dakota.

Table 2.5-4 Share of Allocated Costs – Xcel Energy			
Pricing Zone	**Project Local Balancing Authority Area Allocation**	**Load Ratio Share per Local Balancing Authority Area**	**Xcel Energy Share of Local Balancing Authority Area Allocation**
Great River Energy	2.9%	5.2%	0.1%
Northern States Power	9.3%	86.6%	8.5%

The Applicants will collectively be allocated approximately 16 percent of the total costs for the Project with the rest of the costs being allocated to load in the remaining MISO Midwest subregion.

2.5.2 Rate Impact – Great River Energy

As a not-for-profit transmission and generation cooperative, Great River Energy's costs are allocated to Great River Energy's 26 member-owner distribution cooperatives based on a Great River Energy Board-approved formula rate methodology. This formula rate methodology allocates power supply and transmission costs by agreed upon applicable billing determinants. Each Great River Energy member-owner distribution cooperative develops their

[37] Id.

[38] Id.

own rates based on individual costs, including allocated costs from Great River Energy, for their member-consumers via the applicable customer rate class.

2.5.3 Rate Impact – ITC Midwest

ITC Midwest requested an exemption from estimating its rate impact because ITC Midwest does not serve retail customers. The Commission granted this exemption.[39]

2.5.4 Rate Impact – Xcel Energy

Instead of the data identified in Minn. R. 7849.0260(C)(5) and Minn. R. 7849.0270, subp. 2(E), Xcel Energy requested an exemption and proposed to provide an annual revenue requirement impact for the capital costs of the Project for a 20-year period. The Commission approved the requested exemption. Accordingly, **Appendix D** provides revenue requirement calculations for Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, which are then adjusted to a Minnesota jurisdictional basis for Northern States Power Company, a Minnesota corporation. 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 individually or jointly owned with the other co-owners as discussed in **Section 1.3**.

2.6 Project Schedule

The anticipated permitting and construction schedule for each transmission line is provided in **Table 2.6-1** through **Table 2.6-5**. These schedules are based on information known as of the date of the filing of this Application and may be subject to change.

Table 2.6-1
SD/MN State Line to Lakefield Junction Substation 765 kV Facilities

Activity	Estimated Dates
Start CN Proceeding	Q1 2026
Start Route Permit Proceeding	Q1 2027
Begin Land Acquisition	Q4 2028
Obtain Permits to Construct	Q2 2029
Start of Construction	Q4 2029
Project Operation	Q2 2034

[39] *See PowerOn Midwest Docket*, Order (regarding Exemption Requests and Notice Plan Petition) (Nov. 26, 2025) (hereinafter, "Order on Initial Filings").

Table 2.6-2 Lakefield Junction to MN/IA State line 765 kV Facilities	
Activity	**Estimated Dates**
Start CN Proceeding	Q1 2026
Start Route Permit Proceeding	Q1 2027
Begin Land Acquisition	Q4 2028
Obtain Permits to Construct	Q2 2029
Start of Construction	Q4 2029
Project Operation	Q2 2034

Table 2.6-3 Lakefield Junction to Pleasant Valley 765 kV Facilities	
Activity	**Estimated Dates**
Start CN Proceeding	Q1 2026
Start Route Permit Proceeding	Q1 2027
Begin Land Acquisition	Q4 2028
Obtain Permits to Construct	Q2 2029
Start of Construction	Q4 2029
Project Operation	Q2 2034

Table 2.6-4 Pleasant Valley to North Rochester 765 kV Facilities	
Activity	**Estimated Dates**
Start CN Proceeding	Q1 2026
Start Route Permit Proceeding	Q1 2027
Begin Land Acquisition	Q4 2028
Obtain Permits to Construct	Q2 2029
Start of Construction	Q4 2029
Project Operation	Q2 2034

Table 2.6-5 Pleasant Valley to North Rochester to Hampton 345 kV Facilities	
Activity	**Estimated Dates**
Start CN Proceeding	Q1 2026
Start Route Permit Proceeding	Q1 2027
Begin Land Acquisition	Q3 2028
Obtain Permits to Construct	Q2 2029
Start of Construction	Q4 2029
Project Operation	Q3 2032

The Applicants developed the overall Project schedule based on the anticipated timing of the CN proceeding and the Route Permit proceedings, while considering the subsequent activities that must be completed prior to the commencement of construction of the Project. Although the Applicants are filing this Application in 2026, years before the in-service dates identified by MISO, the Applicants anticipate that the entirety of this time will be needed to accomplish the processes and tasks that must be completed prior to commencement of construction, and then complete construction.

The Applicants also considered the work that can occur in parallel with the CN proceeding and the Route Permit proceedings. For instance, the Applicants assumed up to 30 percent completion of the transmission line design to coincide with the issuance of the Route Permits. Following the issuance of the Route Permits, the Applicants considered the anticipated time and resources needed for such things as land acquisition, survey, environmental permits, detailed design, procurement of materials, lead time of materials, tree clearing, and above and below grade construction.

Material lead times are largely based on current lead times. However, lead times are likely to increase by the time material orders are placed for the Project, due in large part to the likely increase in demand for materials across the industry during this timeframe. In addition, the material needs for the Project will be sizable, which will likely contribute to increased material lead times. Adding to some of the lead time uncertainty is the likelihood that some materials may need to be sourced internationally, whether for technical reasons, qualified supplier availability, or other reasons.

Similar to material availability, the Applicants believe that personnel resources will be in high demand, perhaps at levels not seen before across the industry, during the anticipated construction timeframe for the Project. Based on early analysis, the Applicants assume that approximately 650 personnel may be needed for construction of the Project, and 10-20 personnel may be needed for operation.

For these reasons, meeting the target in-service date for the Project will be highly dependent on the timely receipt of necessary approvals and permits, the timely execution of tasks that must be completed prior to the start of construction, material availability, and resource availability. There is little flexibility in the schedule to meet the target in-service date for the Project.

The Applicants have spent substantial effort developing the Project schedule and have reviewed ways in which to optimize the schedule. The Applicants believe the schedule currently reflects a best-case scenario in terms of the timing of the overall Project.

3 COORDINATED TRANSMISSION DEVELOPMENT

The Project resulted from coordinated transmission development across the MISO region, which consists of 15 states and the Canadian province of Manitoba. FERC approved MISO as the first RTO on December 20, 2001. Since that time, MISO has overseen comprehensive annual planning processes involving broad stakeholder engagement. To put this Project in the context of the broader coordinated transmission system, this Chapter provides a discussion of the workings of the electric system, the reliability requirements that affect the way the system is developed, and obligations that require utilities, including the Applicants, to provide adequate electric service to all customers. **Chapter 4** describes historical precedents for the present MISO LRTP Tranche 2.1 initiative, the long-range goals and policies supported by a coordinated build-out of the transmission system, and the scope of MISO LRTP Tranche 2.1, which includes the Project.

3.1 Electrical System Overview

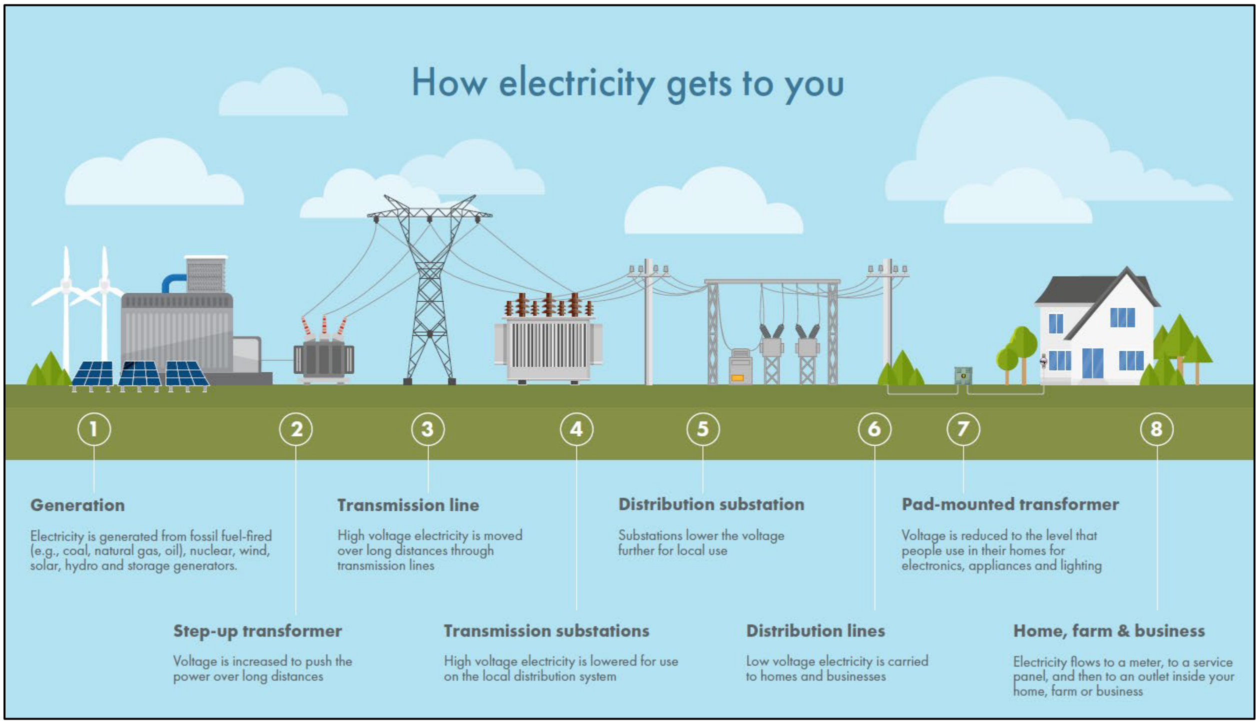
Electric transmission is the process of delivering generated electricity over long distances to the distribution grid. It involves the use of HVTLs, transformers, and the electrical grid to ensure efficient and reliable energy delivery.

By turning on a light switch, a circuit is completed that connects the light bulb with the wires that serve the building. The building wires are connected to a transformer and distribution line outside of the building. Distribution lines, in turn, are connected to substations and larger transmission lines, which comprise the bulk power system that carries electricity from electric generating plants to the areas where the electricity is needed. The bulk power system, or bulk electric system, is a term for the electric generation resources, transmission lines, and interconnections generally operated above 100 kV.

The network of transmission lines which work together to connect places where energy is generated to where it is used is commonly referred to as the electric grid. Over time, the grid has become smarter, more dynamic, and increasingly interconnected due to rising reliability expectations and advancements in technology, along with additional wind, solar, and storage energy resources.

Electricity is produced at generating stations using a variety of sources or fuels, including natural gas, coal, oil, nuclear, and renewable sources (e.g., solar, wind, hydro, biomass, biofuels). Electricity is pushed from generating stations along HVTLs often at voltages in excess of 100,000 volts (e.g., 115 kV, 230 kV, 345 kV, 500 kV, 765 kV). One kV equals 1,000 volts (V). Once the electricity reaches the community in which it will be used, the electricity is “stepped down” to lower, more usable levels at a substation. Then, the electricity is sent along smaller distribution lines to be delivered to neighborhoods and businesses. A diagram showing the transfer of electricity from generator to consumer is shown in **Figure 3.1-1.**

Figure 3.1-1: How Electricity Gets to Consumers[40]



Voltage on transmission lines is higher than what is used by the consumer because transmitting electricity over long distances at higher voltages reduces electrical losses on the system. This means that more of the energy that is generated reaches the ultimate customer. Unlike other consumables where excess product can be easily and economically stored for future use, electricity must largely be generated simultaneously with its consumption, so generators connected to the system must instantaneously adjust their electric output to respond to changes in customer demand. While energy storage technologies (including battery energy storage systems) are advancing, there is not currently a commercially viable large-scale energy storage alternative that could meet the needs of the Project.[41]

40 Great River Energy. How Electricity Gets to You. Available at: https://greatriverenergy.com/cooperatives-articles/how-electricity-gets-to-you/

41 See **Section 7.3.3** for analysis of energy storage as an alternative to the Project.

3.2 Transmission Network

The electric transmission system in the United States is composed of a highly decentralized interconnected network of generating plants, HVTLs, and distribution facilities. Electricity uses all available paths as it flows from generation to consumer. Since electricity from all sources is commingled in the transmission system, it is not possible to know exactly where the electric power came from that lights the room of a home.

More specifically, the bulk electric system is composed of HVTLs which can carry electricity long distances and deliver power to distribution systems to meet customer needs in specific locations, and bulk transformers at 100 kV and above. Transmission lines are made up of conductors, which complete a three-phase circuit and are typically accompanied by a shield wire on top that provides protection from lightning strikes. The shield wire can also include fiber optic cable which provides a communication path between substations for transmission line protection equipment.

Substations are a part of the electric generation, transmission, and distribution system and contain high-voltage electric equipment to monitor, regulate, and distribute electricity. Substations allow transmission lines to connect with other substations and allow power to be transformed from a higher transmission voltage to a lower voltage for distribution. Substation property dimensions depend on the size of the project; anticipated future needs based on the 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 fenced area and the required surrounding areas, including stormwater ponds, grading, parking, access roads, and the transmission line rights-of-way that will enter and exit the substation. The configuration of a substation may change over time to accommodate future load growth or electric system needs.

3.2.1 Nationwide

Today, there are more than 153,000 miles of HVTLs in the United States that transmit electricity at voltages in excess of 200 kV.[42] There are also many thousands of miles of transmission lines between 100 and 200 kV. These facilities include alternating current (AC) transmission lines and direct current (DC) transmission lines. **Table 3.2-1** provides a perspective of the miles of in-service, AC voltage transmission lines operating at over 200 kV in the United States.

[42] ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12

Table 3.2-1 Miles of In-Service AC Voltage Transmission Lines in the United States [a]				
	Under 345 kV	345 kV	500 kV	765 kV
Miles	65,300	55,600	28,100	2,400

[a] ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12. Transmission lines explicitly identified as "Type = DC" are not included here.

The MISO LRTP Tranche 2.1 projects will be the first 765 kV transmission facilities in Minnesota. However, as shown in **Table 3.2-1**, approximately 2,400 miles of 765 kV transmission lines are safely and reliably operating in the United States and have been since the first 765 kV transmission lines were installed in the 1970s. A map of the existing 765 kV lines currently operating in the United States is shown on **Figure 3.2-1**.[43] The 765 kV voltage level is also in use internationally.

Minnesota is not alone in developing new 765 kV transmission lines. Facing similar grid reliability needs, new 765 kV transmission lines are proposed and/or under development in Iowa[44], Illinois[45], Indiana[46], Michigan[47], New Mexico[48], South Dakota[49], Texas[50], Virginia[51], West Virginia[52], and Wisconsin[53]. In 2025 the Southwest Power Pool (SPP) began planning efforts to develop a 765 kV overlay designed to interconnect with MISO's LRTP Tranche 2.1 Portfolio.[54]

43 ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12

44 See **Appendix E.1**. Page 144.

45 Id.

46 Id.

47 Id.

48 SPP Engineering. 2024 Integrated Transmission Planning Assessment Report. Page 147. Available at: https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf

49 See **Appendix E.1**. Page 144.

50 SPP Engineering. 2024 Integrated Transmission Planning Assessment Report. Page 147. Available at: https://www.spp.org/media/2229/2024-itp-assessment-report-v10.pdf

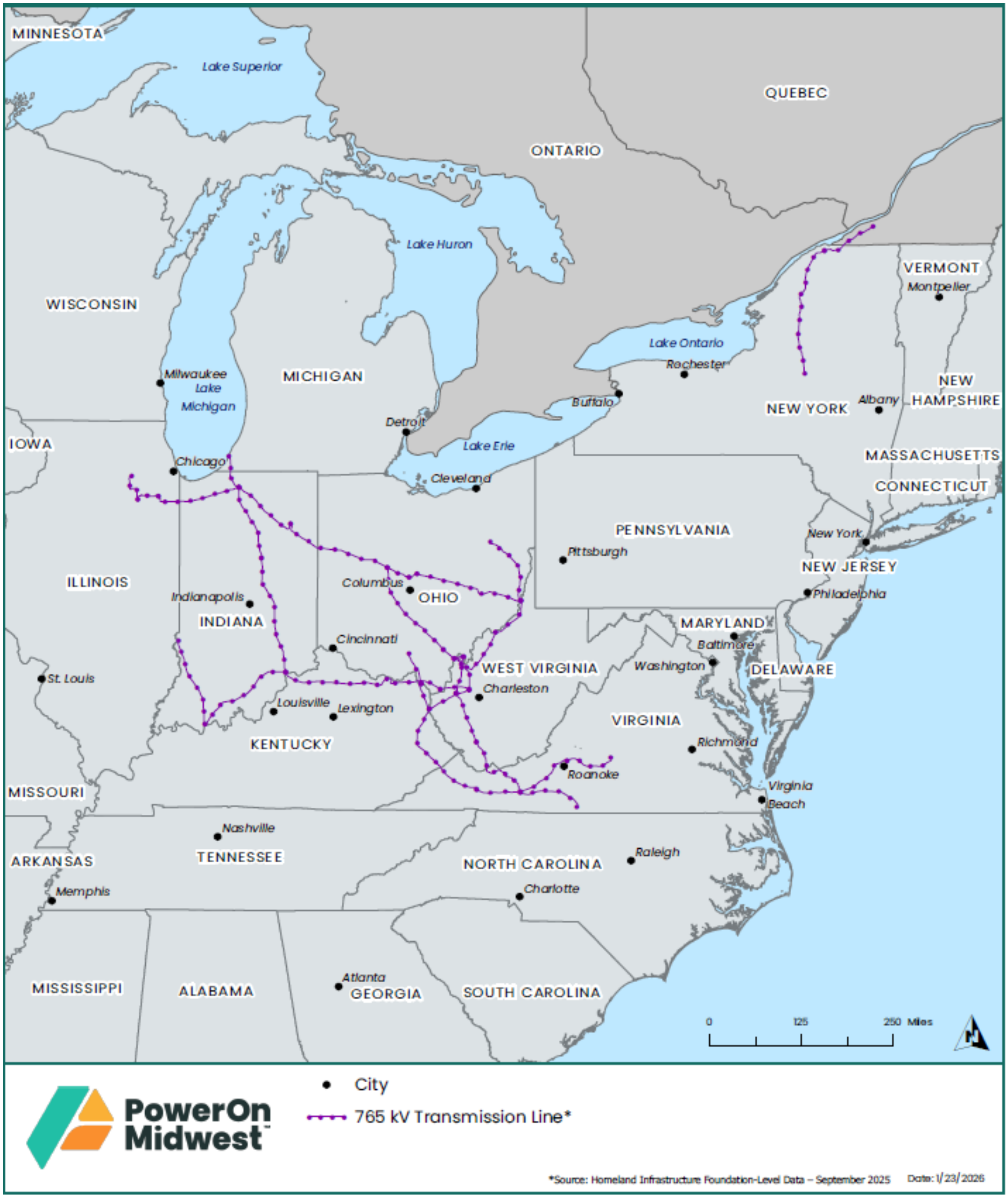
51 PJM. 2024 Regional Transmission Expansion Plan. Page 270. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf

52 Id. Page 295

53 See **Appendix E.1**. Page 144.

54 Southwest Power Pool's 2025 ITP. Available at: https://spp.org/documents/74831/mopc%20education%20session_2025%20itp_20250923.pdf

Figure 3.2-1: Existing 765 kV Transmission Lines in the United States



3.2.2 Eastern Interconnection

The electric transmission grid in the United States (excluding Alaska and Hawaii) is divided into three major subsystems, called interconnections: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas Interconnection. While very little power is exchanged across the interconnections, power is readily transferred within an interconnection.

Minnesota is a part of the largest subsystem, the Eastern Interconnection. This means that Minnesota's electric system is not only interconnected with neighboring states North Dakota, South Dakota, Iowa, and Wisconsin, but also with virtually all the states and Canadian provinces in the eastern two-thirds of North America. The entire electric system in the Eastern Interconnection operates as a single integrated electrical machine. The dynamics of the electrical system are complicated and require the moment-by-moment matching of generation resources and load requirements at the proper voltage across the interconnection. If the load balance or voltage is disturbed by a sudden change in generation output, transmission line availability, or customer usage, the bulk power system provides capacity within the Eastern Interconnection for other connected generation sources to adjust and keep the system in balance. This means that the operation of electrical generators and transmission facilities in Ohio or Nebraska can potentially impact the reliability of electric service to customers in Minnesota, and vice versa.

3.2.3 Minnesota

According to the 2025 Minnesota Transmission Owners Biennial Report, [55] there are more than 19,000 miles of AC transmission lines of 69 kV and higher voltages in Minnesota, including more than 8,500 miles of 69 kV lines, nearly 5,400 miles of 115 kV, 138 kV, and 161 kV lines, approximately 2,100 miles of 230 kV lines, and 3,000 miles of 345 kV and 500 kV lines. In addition, there are almost 230 miles of DC transmission lines in Minnesota.

The Minnesota transmission system connects over a hundred electric generating plants, sized from less than 1 MW to more than 1,700 MW, including fossil fuel-fired (e.g., coal, natural gas, oil), nuclear, wind, solar, hydro, and storage, located both inside and outside the state, to serve the state's more than 5 million residents and businesses. The Minnesota transmission system is also connected to utilities in surrounding states and in Canada. **Figure 3.2-2** shows the transmission system in Minnesota for voltages of 345 kV and greater. [56]

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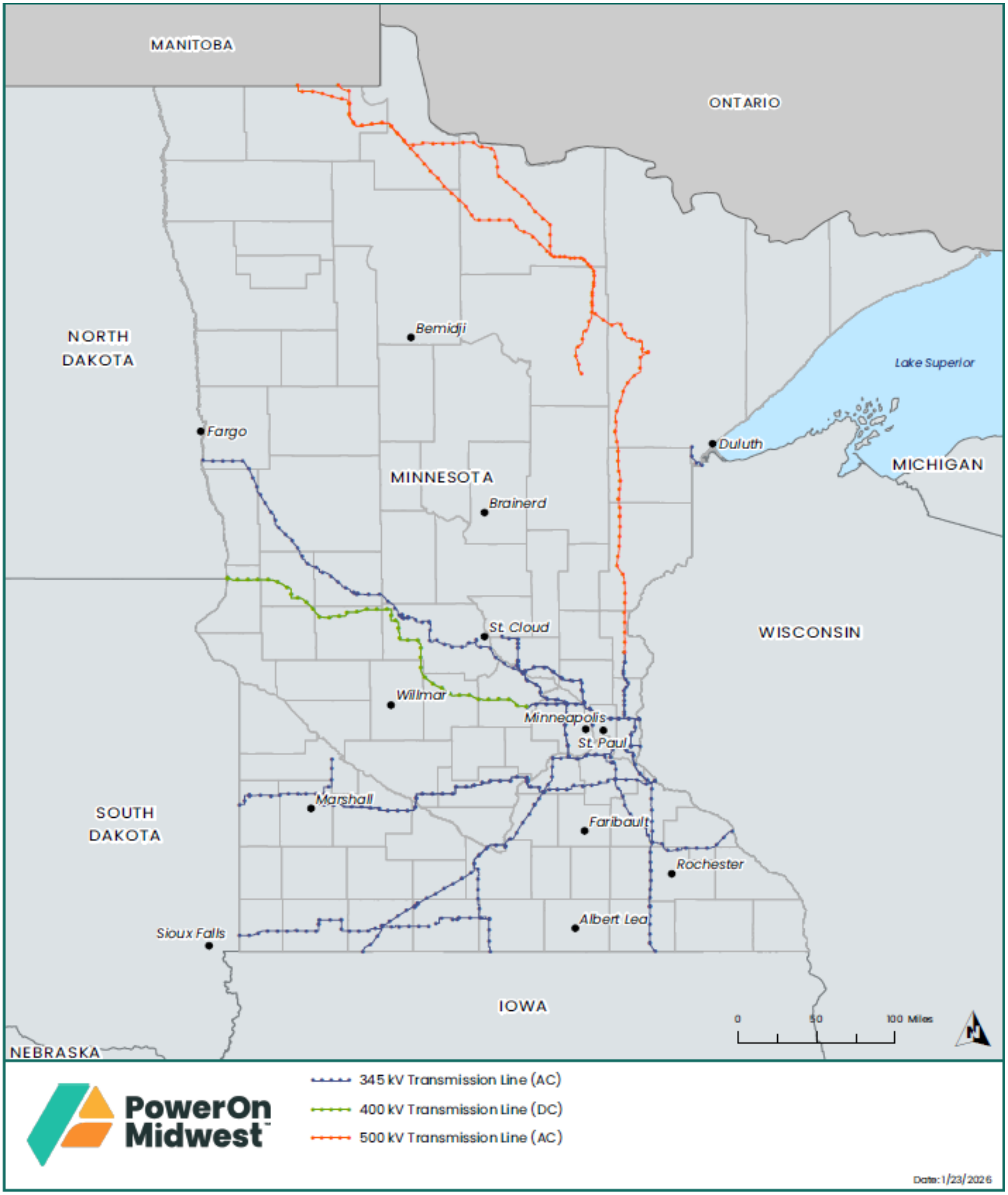
[55] 2025 Minnesota Biennial Transmission Report. Section 7.1. Available at: https://www.minnelectrans.com/report-2025.html.

[56] ESRI. U.S. Electric Power Transmission Lines, Homeland Infrastructure Foundation-Level Data. Data Accurate as of September 30, 2024. Archived as of September 10, 2025. Available at: https://www.arcgis.com/home/item.html?id=d4090758322c4d32a4cd002ffaa0aa12

Figure 3.2-2: Minnesota Transmission Grid



3.3 Regulatory Structure

Load serving utilities in Minnesota have an obligation under Minnesota statutes to serve retail customers within the state, whether residential, commercial, or industrial, located in their assigned retail service territory. In addition, transmission owners have an obligation under federal law to provide reliable transmission services to wholesale customers, such as municipal utilities, connected to their transmission systems. This means that the system must be developed to reliably serve wholesale and retail customers throughout MISO. Fulfilling this important obligation, both now and into the future, requires electric utilities to engage in transmission planning to assess projected growth in customer requirements so as to have adequate lead time to construct new facilities (i.e., generation, transmission, distribution) necessary to serve growing customer demands.

Because of the importance of providing safe, adequate, and reliable service to customers, and the role electric transmission plays in that service, electric transmission is highly regulated. Regulatory oversight of transmission in Minnesota occurs at several levels and by several different regulatory bodies: the Commission, Minnesota Department of Commerce (Department), FERC, MISO, Midwest Reliability Organization (MRO), and NERC.

3.3.1 Minnesota Public Utilities Commission Authority

The Commission provides plenary oversight over many aspects of electric service and construction of new facilities pursuant to state law. For investor-owned public utilities such as Xcel Energy, the Commission has regulatory control over all aspects of the provision of retail electric service to customers. The Commission reviews and approves the rates, charges, and service provisions of public utilities, as well as matters pertaining to the quality of service, integrated resource plans, affiliated interest transactions, and a variety of other types of transactions.

The Commission also has regulatory authority over some aspects of the provision of electric service by other types of electric utilities (such as Great River Energy and ITC Midwest). For example, the Commission has the authority to review and consider CN applications, such as this Application, even if the applicant is not a public utility. In addition, the Commission has the authority to review and accept utility resource plans for non-public utilities and to adjudicate disputes over the retail service area boundaries of the various categories of utilities within Minnesota, regardless of their business form.

3.3.2 Minnesota Department of Commerce

The Department is the leading energy policy agency in the State of Minnesota. The Department plays several roles that are important to the implementation of the State's energy policy, including the development and implementation of new infrastructure. The Department has primary responsibility for the enforcement, investigation, and advocacy of utility matters in Minnesota (Minn. Stat § 216A.07 subds. 2 and 4). The Department takes a leading role in analyzing and evaluating utility proposals, including CN applications.

The Department provides recommendations to the Commission on behalf of customers and ratepayers. As part of its analysis, the Department assesses the needs identified by Applicants. The Department also directly regulates the conservation and demand-side management programs of investor-owned public utilities (e.g., Xcel Energy), which can affect system reliability and the need for new transmission facilities.

3.3.3 Federal Energy Regulatory Commission

Under the Federal Power Act (16 U.S. Code section 824 et seq.), FERC has jurisdiction over the transmission of electricity in interstate commerce. Over the past 25 to 30 years, Congress and FERC have implemented a series of policies designed to provide open access to the transmission grid.

In 1992, Congress enacted the Energy Policy Act of 1992, which authorized expanded competition in the wholesale electric power supply industry, making generation a competitive market subject to FERC's regulatory authority. In addition, under the Federal Power Act, FERC has plenary authority to regulate the interstate electric transmission grid as the nation's electric highway system. Subsequent initiatives by FERC provided further changes to industry structure. In essence, over time, mechanisms were put in place that treat the transmission system like a regulated common carrier that is required to provide "comparable and non-discriminatory" open access to all eligible users of the transmission system.

In 2000, FERC released Order 2000 which encouraged the formation of RTOs, like MISO. In 2001, FERC approved MISO as the RTO for the Midwest. MISO’s tariff, which is essentially a rule book for MISO and its members, is regulated by FERC. When FERC issues a new order, MISO’s tariff and corresponding practices adjust accordingly to comply. Since MISO’s formation, there have been several key orders which have shaped how the transmission grid is planned and operated.

- **FERC Order 693:**[57] FERC establishes Mandatory Reliability Standards for the Bulk-Power System.
- **FERC Order 890:**[58] Mandated a coordinated, open, and transparent transmission planning process, both on a sub-regional and regional level.
- **FERC Order 1000:**[59] Bolsters open and transparent regional planning requirements in FERC Order 890 and added an explicit requirement to plan for public policy (e.g., Minnesota Carbon-Free by 2040 law).
- **FERC Order 1920:**[60] Establishes a minimum 20-year planning horizon for regional transmission planning and defines metrics to measure the economic effectiveness of transmission projects.

While the Commission retains state-law jurisdiction over the construction of new transmission facilities and generation, access to and operation of the transmission system is regulated by FERC. Jurisdictional utilities who own and operate transmission facilities are required to provide comparable access to all qualifying entities requesting access to the system and comply with mandatory NERC reliability standards.

3.3.4 Midcontinent Independent System Operator

MISO is an independent not-for-profit RTO which operates the transmission system and energy market in parts of 15 states and the Canadian province of Manitoba. **Figure 3.3-1** presents a map of MISO's reliability footprint.

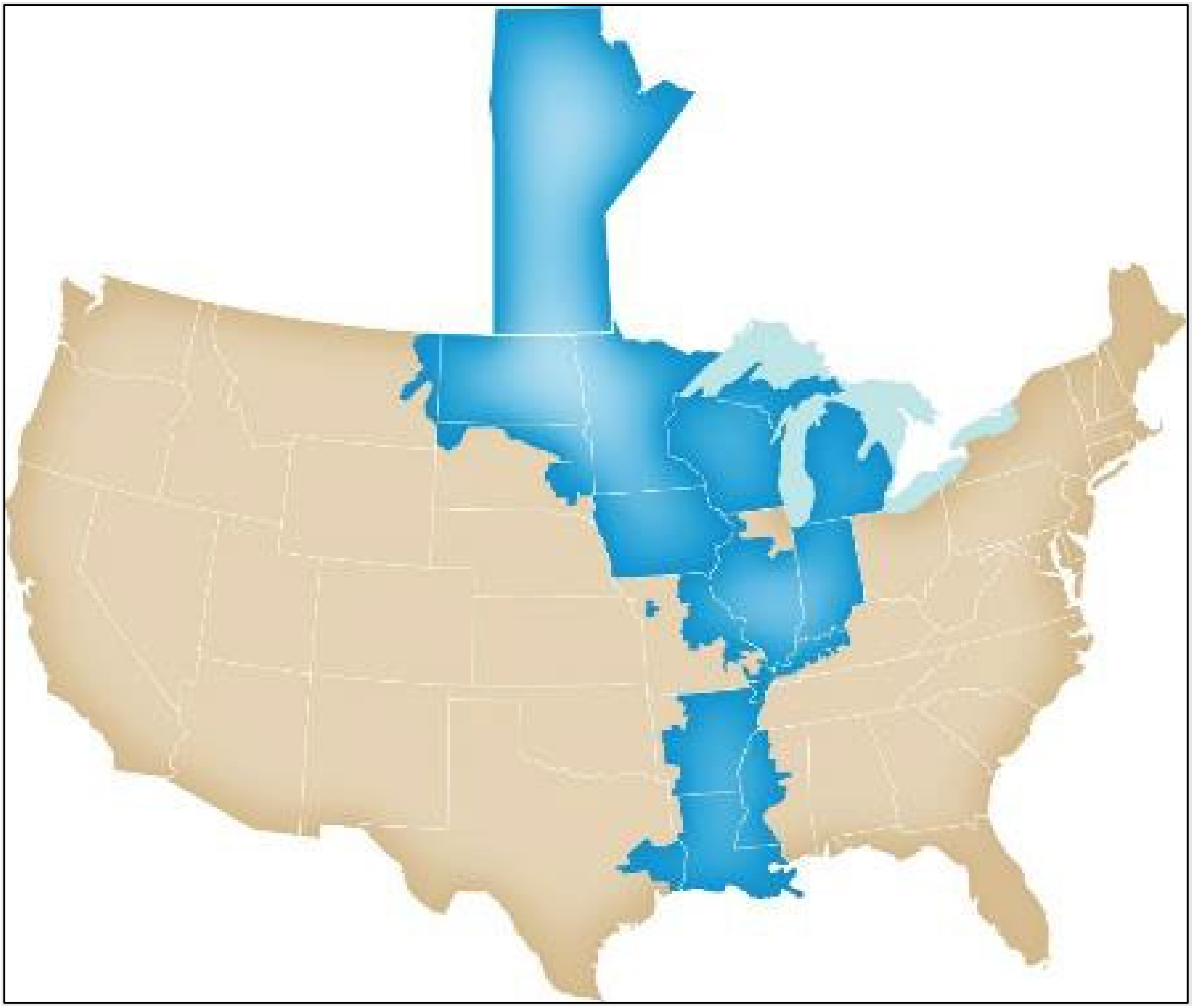
57 FERC. Order No. 693, Mandatory Reliability Standards for the Bulk-Power System. 18 C.F.R. Part 40 (March 16, 2007). Available at: https://www.ferc.gov/sites/default/files/2020-05/E-13_11.pdf

58 FERC. Order No. 890, Preventing Undue Discrimination and Preference in Transmission Service, 18 C.F.R. Parts 35 and 37 (Feb. 16, 2007). Available at: https://ferc.gov/sites/default/files/2020-06/OrderNo.890.pdf.

59 FERC. Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 18 C.F.R. Part 35 (July 21, 2011). Available at: https://www.ferc.gov/sites/default/files/2020-04/OrderNo.1000.pdf.

60 FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

Figure 3.3-1: MISO Reliability Footprint



As a federally registered planning authority and 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. MISO has 56 member-transmission owners, including Great River Energy, ITC Midwest, and Xcel Energy, with more than 79,000 miles of transmission lines under its functional control.[61] MISO members also include 174 non-transmission owners, such as independent power producers and exempt wholesale generators, municipals, cooperatives, transmission-dependent electric utilities, and power marketers and brokers.

[61] MISO Fact Sheet – September 2025. See **Appendix E.5**.

MISO has a responsibility, established by the 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 MTEP in collaboration with member transmission owners 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, 1000, and 1920 in developing the MTEP. These FERC Orders require an open and 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 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.

3.3.5 North American Electric Reliability Corporation

Reliability standards for electric transmission planning are established and enforced by the NERC.[62] NERC is a not-for-profit corporation, whose members include the Regional Entities (REs) across the United States, Canada, and the northern part of Mexico.

Overseen by FERC, NERC is the Electric Reliability Organization for the United States. NERC has the legal authority to enforce reliability standards on all owners, operators, and users of the bulk electric system. NERC has the power to impose a financial penalty up to $1 million per day for any violation of approved NERC reliability standards.[63] To fulfill its mission to ensure the reliability of the bulk electric system in North America, NERC:

- sets standards for the reliable operation and planning of the bulk electric system;
- monitors, assesses, and enforces compliance with reliability standards;
- audits bulk electric system operators to ensure that they are prepared to meet their reliability responsibilities;

[62] NERC. Homepage. Available at: https://www.nerc.com/Pages/default.aspx.

[63] NERC. Sanction Guidelines of the North American Electric Reliability Corporation. Available at: https://www.nerc.com/pa/Stand/Resources/Documents/Appendix_4B_of_the_Rules_of_Procedure_Sanction_Guidelines.pdf.

- supports excellence in electric system operations through the accreditation of operator training programs and certification of system operators and operating organizations;
- provides education and training resources to promote reliability;
- assesses, analyzes, and reports on bulk electric system adequacy and performance; and
- coordinates reliability standards and procedures with the regional entities (such as MRO) and other organizations (such as MISO).

The MRO is the RE that implements the NERC standards for Minnesota and the surrounding region. The MRO is designed to develop standards, monitor compliance, enforce standards, and assess the reliability of the bulk electric system. The MRO operates independently of the entities subject to its jurisdiction, thus ensuring that the reliability standards developed and enforced by the MRO are fair. The REs' members include the Applicants and all segments of the electric industry including rural electric cooperatives; investor-owned utilities; state, municipal and provincial utilities; federal power agencies; independent power producers; power marketers; and end-use customers.

3.3.6 National Electrical Safety Code

The NESC standards contain rules to safeguard employees and the general public during the operation and maintenance of electric supply lines and substations. The Commission requires utilities to comply with the NESC standards when constructing new facilities.[64]

The NESC was well defined by the 1920s and is currently revised every five years following extensive research and review per procedures established by the American National Standards Institute (ANSI).[65] Among other requirements, the NESC specifies the physical clearances, and the mechanical strength of structures and equipment required to ensure safe operation of high-voltage electrical facilities such as transmission lines and substations. The NESC's provisions establish the minimum clearances required from adjacent objects, such as buildings.

The facilities proposed in this Application will comply with all applicable NESC standards.

[64] Minn. R. 7826.0300.

[65] IEEE Standards Association. The National Electric Safety Code. Available at: https://standards.ieee.org/products-programs/nesc/.

3.4 Defining Transmission Needs

Electricity is a critical service and, thus, the transmission grid is planned to stay reliable, resilient, and affordable. Reliability in the most basic sense means "keeping the lights on" 24 hours a day, 365 days a year. To accomplish that task, the transmission system is designed to transport energy from generation to where it is needed, not only during "normal" operating conditions (e.g., a typical day), but also during times when the demand for electricity is highest, such as the hottest summer day when air conditioners are running or conversely the coldest winter day when electric heating is at its maximum. In addition, the transmission system is designed to withstand the outage of a generator, transmission line, transformer, or other transmission system element without major disruption to the overall power supply. Reliability is measured and assessed to federal standards which are set by NERC (see **Section 3.3.5**).

Although the transmission grid is extremely reliable, in recent years, low-probability but high-impact events, like extreme weather and sabotage, have had an increasing impact on the power grid across the United States. As a result, owners and operators of transmission facilities, including the Applicants, are seeking new ways to increase the resilience of the transmission grid to better prevent, withstand, and recover from low-probability but high-impact events. Resilience efforts include the use of stronger transmission structures, conductors which minimize icing, enhanced security measures, and other physical and non-physical improvements.

As a critical service, it is also important that electricity remains cost effective. Due to the magnitude of the investment costs associated with the infrastructure needed to generate and transport electricity (a new transmission line or power plant is often hundreds of millions of dollars), an intensive planning process is undertaken to ensure that any needed addition to the power grid is the best option. The best option not only considers the up-front cost of the project (lower is better) but also the value provided (higher is better). "Value provided" includes the ability to save money on monthly bills by having access to less expensive generators (also known as reducing system congestion), less public or environmental impacts, carbon reduction, lower risk of needing repair, and/or better flexibility to meet potential future power needs.

3.4.1 What is "Reliability?"

Reliability is commonly defined as "keeping the lights on." Because it often requires over a decade to identify and construct infrastructure necessary to ensure reliability, reliability is assessed on a forward basis – commonly 10 to 20 years in the future. A common misconception is assuming that, because the grid is reliable today, improvements are not needed to ensure the grid will be reliable tomorrow. Similarly, the system is reliable today because the correct actions were taken in the previous decade(s).

Reliability is measured by multiple metrics. The reliability need for the Project, as detailed in **Chapter 6.3**, is measured in 11 different metrics, and each is a reliability driver. NERC defines the reliability of the interconnected bulk electric system in two ways: adequacy and security. "Adequacy" is the ability of the electric system to always supply the aggregate electrical demand and energy requirements of customers, considering scheduled and reasonably expected unscheduled outages of system elements (e.g., generators, transmission lines). "Security" is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Most traditionally, reliability is measured against NERC reliability standards (see **Section 3.3.5**). NERC standards establish a minimum level of reliability which must be met by the Applicants and MISO.

NERC's reliability standards apply primarily to the components within the bulk electric system. The bulk electric system must be capable of performing under a variety of expected system conditions and must be planned to withstand forced and maintenance outages and other service interruptions known as contingencies. The standards are designed to keep the interconnected system planned, designed, and operating to withstand a number of contingencies caused by the loss of a generation unit or transmission line, or other system failures.

The NERC reliability standards require that the system be designed so that under system intact conditions or single contingency (or, N-1) conditions (e.g., when a single transmission line, generator, or transformer is out of service) operators can reliably operate the system and serve all connected loads without any ongoing overloads or voltage problems. An overload exists when a transmission line, transformer, or other piece of equipment is subjected to loadings that exceed its applicable rating. Transmission lines and transformers typically have continuous (or, normal) and short-term (or, emergency) ratings. For transmission lines, nominal seasonal ratings are computed for at least each season's conditions. Determination of line ratings involves consideration of the increased conductor sag that occurs at higher current loadings, which impacts the line to ground distances required by NESC, as well as the potential for irreversible metallurgical damage to the conductor. Transformer ratings are based on heat dissipation capability and consideration of insulation degradation that is accelerated at the higher internal temperatures resulting from high loadings.

Each transmission owner establishes loading criteria (also called a facility rating methodology) to avoid operation of transmission facilities at excessively high temperatures which can lead to transmission system damage. Normal ratings are available for continuous operation of the facilities; emergency ratings allow higher flows for a shorter duration of time.

For example, a utility may operate a transmission transformer at the emergency rating level for a short duration (typically less than 30 minutes) to complete transmission circuit breaker switching operations to manage a temporary system condition rather than interrupting service to customers. Designing and operating the system according to prudent loading practices ensures that the transmission system is operated safely and reliably.

The system must also be designed so that if there is a double contingency (or N-1-1) condition, where any two lines, generators, transformers, breakers, or combination thereof, are out of service, the power system will remain in a secure state. However, NERC reliability standards permit interruption of service to customers under double contingency conditions to maintain the safe operation of the electrical system. The NERC reliability standards also require that plans be in place to mitigate the effects of an extreme contingency, where an entire substation, several lines, or an entire generation plant becomes unavailable.

The technical analyses provided and summarized in **Chapter 6.3** of this Application comply with the NERC reliability standards. MISO and the Applicants reviewed the performance of the system with the Studied Projects and determined that the Studied Projects are acceptable for system-intact and outage conditions (i.e., the Studied Projects are needed to maintain NERC reliability standards and do not create new reliability violations due to an outage of the Studied Projects).

3.4.1.1 Energy Adequacy

Energy adequacy is the ability to have energy to serve demand every hour of every day. Historically, with consistently cyclical load patterns and a primarily fossil fuel generation fleet, the system was planned to meet peak demand conditions. The notion was, if generation and transmission capacity were adequate to reliably serve demand during the most stressed conditions (typically summer peak), then there would be adequate generation capacity to meet demand during the other less stressful times of the year.

As demands for electricity become more dynamic, generation output becomes more dependent on weather patterns, and atypical weather becomes more common, it is no longer adequate to plan the grid to only meet peak demand conditions. Rather, "all hours matter." In fact, forecasts detailed in **Chapter 6** of this Application show that the most stressed conditions from a reliability perspective in the next 20 years are not during peak conditions, which is when issues have typically arisen in the past, but, rather, during hours of high power transfers from (atypical) east-to-west (e.g., from Minnesota to South Dakota and North Dakota) or south-to-north flows (e.g., from Iowa and Minnesota to Manitoba). To maintain reliability every hour of every day, the transmission grid must be planned to have the capability and flexibility to move power from where it is produced to where it is needed regardless of the conditions.

Ensuring energy adequacy requires additional analysis and scenarios to ensure the grid can meet all likely future system conditions and demands. While in previous years, the system was planned under a few different scenarios using traditional transmission planning models, now the system is planned considering different scenarios, conditions, generation dispatches, transfers, and loading levels. Multiple tools are used to assess system needs from different perspectives. For example, in this Application, the reliability/energy adequacy need for the Project is assessed using four different loading levels, two different years, and four different transfer scenarios with MISO models (see **Section 6.2.2**). The Applicants further assessed energy adequacy needs under four additional historical but reliability-stressed conditions in **Section 6.3.4**. Finally, MISO and the Applicants assessed 8,760 hourly energy needs under multiple scenarios using Hitachi Energy's production cost model, PROMOD (see **Section 6.3.2**).

In recent years, MISO and FERC have recognized the importance of energy adequacy, as opposed to traditional peak reliability, and have implemented additional precision into how the system is both planned and operated. In 2022, MISO implemented a seasonal resource adequacy construct. MISO's seasonal resource adequacy construct replaces its single annual capacity requirement based on a summer peak with separate requirements and resource accreditations (credit for how well a generator performs in a specific season) for summer, fall, winter, and spring to better ensure reliability across the entire year. Furthermore, in the same year, FERC implemented Order 881, which requires all transmission owners, including the Applicants, to implement ambient adjusted transmission line ratings. Historically, transmission line ratings are fixed (i.e., constant) for each season to ensure the line operates within its engineered parameters. Ambient adjusted ratings provide additional precision to adjust the rating based on real-time temperatures to allow the system to be operated more reliably.

3.4.1.2 Transfer Capability

Transfer capability refers to the maximum amount of electric power that can be moved or transferred between different regions or areas of the grid. This capability is crucial for maintaining reliable electricity flow and ensuring that power can be delivered from where it is generated to where it is needed.

Transfer capability is typically measured across an interface (e.g., a state line or electrical region). Transfer capability is measured differently depending on the specific application. Traditionally, transfer capability is measured by proportionally scaling up generation on one side of the interface and load on the other side of the interface until a reliability overload is identified. The amount scaled immediately before a reliability overload is identified is the transfer capability.

Transfer capability is one of multiple ways to measure grid reliability and an increasingly key reliability metric as the generation fleet evolves. As wind and solar generation output is dependent on weather, there will be times when wind and solar generation within a community or even within much of Minnesota will be unavailable. Conversely, there will be times when there will be more wind and solar generation than can be used within Minnesota or a local area. Transfer capability allows the grid to reliably move power from where it is being produced to where it is needed to serve load every hour of every day. Thus, the ability to transfer energy to follow weather patterns is one part of the answer to the question of "how is reliability maintained when the wind isn't blowing, or the sun isn't shining?" Transfer capability allows the electric grid to perform akin to a super-sized battery.

The Project, and the broader MISO LRTP Tranche 2.1 Portfolio, are specifically designed to increase the ability to transfer bulk power across the MISO region to reliably serve load as discussed in **Sections 4.6**, **6.2, and 6.4** of this Application.

3.4.1.3 System Stability

Stability is a reliability attribute of the power grid. A stable system operates normally under all reasonably expected conditions and can quickly return to a normal state if there is a disturbance to the system. Unanticipated disturbances on the system may be caused by many things, such as a lightning strike on a transmission line, a transmission line structure failing, or a generator tripping offline because of a problem. Without a stable system, otherwise isolated events may lead to cascading and potentially widespread and catastrophic impacts, up to and including blackouts. NERC reliability standards require that the transmission grid be designed to withstand the loss of any single element without disruption. Utilities like the Applicants also typically evaluate the impacts of events involving multiple system elements and planned maintenance outages to prevent or minimize disruptions. As the generation changes where, how, and what kind of energy is produced and transmitted to customers, the stability of the grid must continually be assessed to ensure that the power grid remains reliable.

There are several aspects to stability that must be considered when planning the power grid, including voltage stability and transient stability. Voltage stability simply refers to the ability of the system to recover from an event and rapidly restore voltage within the normal operating range. A voltage collapse occurs when the voltage in some part of the system cannot recover following an event, resulting in extremely low voltages, and possibly causing damage to electrical devices and blackouts. Historically, centralized fossil-fueled baseload generating stations inherently have provided voltage support to the power system to maintain acceptable operating voltages and prevent voltage collapses. As the power system evolves to include a greater variety of generators, new solutions are necessary to ensure that system voltages remain robust, predictable, and stable under all reasonably expected conditions.

Transient stability refers to the short-term response of the grid during the first few seconds after a disturbance (i.e., the transient period). Typical areas of interest in the transient period are voltage and frequency response. Transient stability performance is typically measured by how severe the impact is immediately after the disturbance and how quickly the system voltage and/or frequency recovers from the disturbance. If the system voltage and/or frequency fails to recover to normal operating voltage or frequency, the system is unstable and transmission system elements are likely to begin tripping offline to try to stabilize the system by isolating the disturbance. Depending on the severity of the impacts, this can lead to cascading outages and blackouts.

3.4.2 What is "Enabling Policy?"

Public policy refers to state and/or federal law. As such, the Applicants and MISO must comply with applicable state or federal policy and thus must develop a transmission plan which enables policy. As the transmission grid must also be planned to comply with NERC national reliability standards, the following objective function is used to plan the transmission grid:

> *identify a transmission plan which enables public policy in compliance with national reliability standards in the most cost-effective and least-impactful manner.*

In February 2023, Governor Tim Walz signed the "100 Percent by 2040" legislation into law (or, the Carbon-Free by 2040 law), which, at a high level, directs electric utilities to transition to meet the needs of Minnesota customers with 100 percent carbon-free electricity by the end of 2040.[66] To comply with this legislation, additional sources of emission-free electric energy, like wind and solar, will be added to serve Minnesota's electrical needs. All generation scenarios and conditions used to assess Minnesota's transmission needs in this Application comply with this legislation. Likewise, all alternatives evaluated in this Application are measured for compliance with current Minnesota law.

66 Minn. H.F. 7, sec. 8 (2023); amending Minn. Stat. § 216B.1691, subd. 8(g).

Wind and solar resources are more commonly located in geographically dispersed and remote locations and provide electricity based on weather conditions. Thus, the transmission grid must be expanded to not only provide space to interconnect new carbon-free generators but also to be able to ship power across multiple states to follow weather patterns to ensure a steady-flow of electricity to when and where it is needed by each community (see **Section 5.3**).

In addition, to meet Minnesota law, the grid must be bolstered to maintain reliability after existing fossil-fuel generation retires. As detailed in **Section 3.4.1.3**, fossil-fuel generation not only provides power to the grid, but also key reliability attributes which keep power safe and stable. As those generators retire, the transmission grid must be expanded to take on roles currently served by the current fossil-fuel generation fleet.

As detailed in **Section 6.5** of this application, the Project is a significant step to enabling Minnesota's Carbon-Free by 2040 law.

3.4.3 What is "Cost Effectiveness?"

Electricity is critical to everyday life and, thus, it must be accessible and affordable. Energy infrastructure including power plants, transmission lines, and substations are substantial long-term investments. The Project is expected to have a useful lifespan of at least 50 years. Cost effectiveness refers to the ability of a proposed solution to meet the identified need as compared to the total costs over the life of a project.[67] Total cost considers not only the upfront capital and annual operations and maintenance costs of a project but also cost impacts (typically savings) from greater access to less expensive generation, reduced system losses and lowered generation planning reserve margin.[68]

The process to define the cost effectiveness of a transmission line is similar to the process that a homeowner goes through when purchasing windows for a home. When purchasing new windows not only are the upfront (i.e., capital) costs considered, but also the energy savings from lowered heating and cooling bills. If energy savings offset (i.e., pay for) the more expensive but more energy-efficient window, the window has a lower total cost than the lower capital cost window. In addition, like a transmission line, a purchaser may opt for window features which provide greater lifespan, reliability, safety, and easier maintenance, all of which impact the total costs.

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67 Given the time-value of money and depreciation, cost-effectiveness is typically measured over the first 20 years of a project's service.

68 Planning reserve margin is the amount of generation capacity a utility must possess to reliably serve load. As additional transmission is added, there is potential to decrease the amount each utility must hold as there is more efficient sharing of generation reserves between utilities in the region.

Cost effectiveness for transmission lines is measured in terms of total cost impacts (typically upfront costs, less economic benefits/savings) or a benefit-to-cost ratio (i.e., savings divided by upfront costs). Both measures are designed to provide an "out the door" estimate of total costs.

For projects which are primarily reliability-driven and are needed to comply with national reliability standards, such as the Project, cost-effectiveness is primarily measured as a comparison between alternative solutions to address reliability issues. The most cost-effective solution will address reliability issues for the least total cost.

FERC[69] and MISO[70] have defined and approved consistent metrics to measure societal "out-the-door" economic impacts of transmission lines. MISO and utilities use these metrics to determine the impacts to not only the transmission portion of a monthly electric bill but also the generation portion to determine the total impacts to consumers.

3.4.4 What is "Resiliency?"

Resiliency refers to the ability of the grid to withstand and recover from disruptions, including extreme weather events, equipment failures, and acts of sabotage. It encompasses the capacity to anticipate, adapt to, and quickly recover from disturbances, ensuring a reliable electricity supply even under low-probability, high-impact conditions.

While closely related, resilience differs from reliability. Reliability focuses on the consistent and dependable delivery of electricity under normal and emergency operating conditions and is measured against the NERC reliability standards. Resilience, on the other hand, specifically addresses the ability to withstand and recover from extreme and unusual events. As atypical events become more typical, reliability standards are shifting to encompass more actions which were previously defined as resilience.

Resiliency is considered and weighed in all aspects of planning a power grid. For example, in determining the transfer capability necessary to maintain reliability by the Project, the Applicants considered not only "normal" operating conditions but also lower-probability, historically experienced, increased conditions of grid stress (see **Section 6.3.4**).

The Applicants designed the 765 kV and 345 kV transmission line facilities considering the applicable industry standards, industry best practices, internal practices, and historical

69 FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

70 MISO Tariff Attachment FF Section II.C. Available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

weather events. For instance, the 765 kV transmission line facilities are designed to withstand a 300-year mean recurrence interval (e.g., 30 percent probability the load is exceeded in any one year) extreme wind event and a 500-year mean recurrence interval (e.g., 20 percent probability the load is exceeded in any one year) extreme ice and concurrent wind event, amongst other enhanced reliability load cases. The transmission line facilities have been designed to better withstand extreme weather (see **Sections 2.2.1, 2.2.3, 7.6.1,** and **7.6.2**).

The Applicants designed the 765 kV and 345 kV substation facilities considering applicable industry standards, industry best practices, internal practices, and historical weather events. For instance, the Applicants' equipment will meet or exceed extreme weather ratings of -40 degrees Celsius. The 765 kV substations and associated 345 kV connections will be configured in the highly reliable double-breaker-double-bus topology to ensure uninterrupted power flow through equipment failure. The substation facilities will also adhere to all required NERC/Critical Infrastructure Protection standards to protect cyber and physical assets from nefarious acts.

4 NEED FOR COMPREHENSIVE EXPANSION CONSISTENT WITH REGULATORY AUTHORITY

This Chapter describes historical precedents for MISO LRTP Tranche 2.1, the long-range goals and policies supported by a coordinated build-out of the transmission system, and the scope of the MISO LRTP Tranche 2.1 Portfolio, which includes the Project.

The Applicants, along with all other Minnesota utilities, are obligated to develop, propose, and construct transmission facilities that satisfy all regulatory, policy, and mandatory reliability requirements. These rules and requirements work together to require that Minnesota's electric transmission system be planned, constructed, operated, and maintained in a way that will allow it to operate reliably and in coordination with other interconnected transmission systems throughout the Upper Midwest and the entire Eastern Interconnection. This Application should be reviewed in light of these regulatory requirements.

Among other reasons, and as discussed in more detail in **Chapter 5,** the Project is needed to enable Minnesota to serve electricity demands from new generation sources. In Minnesota, all state-regulated electric utilities, such as Xcel Energy, are required to file an integrated resource plan (IRP) with the Commission every two years. Similar to the objective function used to plan the transmission grid, in each IRP, utilities must identify the generation needs to serve forecasted demand plus a required reserve margin while complying with state laws (e.g., the Minnesota Carbon-Free by 2040 law) for the least total costs. The Commission reviews and ultimately rules on each IRP. The IRP becomes the state-approved plan for generation, and the transmission grid is developed to enable the generation plan in a reliable and least cost manner. The Project and MISO LRTP Tranche 2.1 Portfolio are designed to enable the approved IRPs for Minnesota and the broader Midwest region. Additional information on the Applicants' most recent IRP and generation changes is in **Section 5.3**.

What sets the Project (and broader 765 kV transmission backbone in the MISO LRTP Tranche 2.1 Portfolio) apart is the long-term view to provide a steady supply of reliable electricity for the upcoming decades. The Project is an inflection point in Minnesota's grid. The planning perspective for the Project is similar to the long-term view that resulted in the large regional interconnections in the 1970s and the CapX2020 development in the 2000s. The Project will benefit the overall system and Minnesota customers and businesses for years and decades to come.

4.1 Minnesota Transmission Grid History, Pre-2001

Minnesota's transmission grid has come a long way since the Rural Electrification Act of 1936 initially brought electricity to most of the state. There have been several key inflection points, step-changes, or significant buildouts driven by fundamental changes in how electricity was produced and/or consumed, which have shaped Minnesota's grid to where it is today.

- **1930s:** The Rural Electrification Act provides low-cost federal loans to help rural communities form cooperatives to bring electricity to lower populated areas. Most communities are powered by local diesel generators. Transmission initially extends outward from the Twin Cities area to connect more communities to hydro generation. By the 1940s, local cooperatives are formed, and the start of a grid is established in Northwest Minnesota.
- **1950s:** The 230 kV network is developed across the state to provide an outlet for small coal power plants and to facilitate the initial transfers of energy between utilities.
- **1970s:** The significant development of large centrally located power plants drives a major expansion of the high-voltage transmission grid across the upper Midwest. Grid enhancements in the 1980s and 1990s are comparatively incremental in nature.

The last significant build-out of the grid occurred in the late 2000s and was driven by several transformational factors:

- RTOs (e.g., MISO) were formed under orders from the FERC, empowered by the Federal Power Act, to operate and plan the transmission grid on a multi-state regional basis to improve reliability and cost-efficiency, transforming how the transmission system is used and managed.
- Minnesota passed the Next Generation Energy Act of 2007, which included a Renewable Energy Standard requiring most utilities to generate 25 percent of their electricity (30 percent for Xcel Energy), from renewable sources by 2025. [71] This created the need to interconnect a significant amount of new generating sources.

[71] State of Minnesota. Next Generation Energy Act of 2007. Available at: https://www.revisor.mn.gov/laws/2007/0/Session+Law/Chapter/136/2014-06-28%2012:17:06+00:00/pdf.

- Demand for electricity was growing at an historical rate of a few percentage points annually, and even absent the need to interconnect new generation, the transmission grid was reaching the limit of what Minnesota transmission owners could continue to incrementally expand to accommodate new and/or shifts in energy usage.

To meet these combined needs, an approximately 600-mile 345 kV network was ultimately developed in Minnesota (see **Section 4.3)**.

While the needs of the late 2000s, which drove the last significant expansion of Minnesota grid, were the largest to date, they pale in comparison to the magnitude of today's transmission needs (as described in **Chapter 5)**. To meet modern transmission needs in a reliable and cost-effective manner, a different and longer-term approach was needed. Thus, in 2019, MISO launched the LRTP, a multi-year multi-phase process to identify the transmission expansion necessary to optimally meet the needs of the transmission grid for the next 20 years. Additional information on the LRTP process is found in **Sections 4.4 through 4.7.**

4.2 MISO Transmission Expansion Plan Process, Post-2001

MISO has a responsibility to study the transmission system within its footprint to identify necessary transmission projects to maintain the NERC reliability standards. MISO's planning process, also known as the MISO Transmission Expansion Plan (MTEP) process, is an open and transparent process, and per FERC requirements, considers feedback from all stakeholders including end-use customers, regulatory authorities, environmental advocates, independent power producers, transmission owners, and others.

The MTEP process is performed annually in 18-month overlapping cycles. The results are contained within an MTEP report. Thus MTEP, depending on the context, refers to MISO's planning process or the report and data series used to develop the report and MISO's analysis that identified the need for the Project is the MTEP year 2024 (MTEP24) report. The MTEP process is a top-down, bottom-up process which simultaneously considers both regional needs (top-down) and local needs (bottom-up) and to identify the optimal plan to meet all the MISO region's reliability needs.

Each year as part of the MTEP process, MISO assesses changes in transmission system needs based on changes in demand, generation, and state and federal policy, amongst other factors. Should a change in any one factor result in the grid no longer meeting national reliability standards or policy, MISO, through its stakeholder process, will identify mitigation to ensure the system stays in compliance.

The first MTEP report was released in 2003. Since then, there have been over 20 annual MTEP cycles. In the last 3 MTEP cycles (2022-2024), MISO approved approximately 1,500 transmission projects. Most projects are smaller-scale and incremental in nature – many being replacements of older transmission lines for age and condition purposes. However, in response to fundamental shifts in electricity usage and production, MISO has also identified three regional transmission overlays (portfolios of higher-voltage transmission projects which, when combined, span the footprint): the MVP Portfolio (**Section 4.3**), MISO LRTP Tranche 1 Portfolio (**Section 4.5**), and MISO LRTP Tranche 2.1 Portfolio (**Section 4.6**).

4.3 MVP Projects and CapX2020

In the 2000s, Minnesota's transmission grid was at a point where incremental improvements were exhausted and a step-change was needed to meet the reliability needs described in **Section 5.3**. In 2004, CapX2020, now known as Grid North Partners, formed to develop a long-term vision for the Minnesota power grid to maintain system reliability with these transformational changes. CapX2020 identified the need for, and ultimately developed, an approximately 800-mile 345 kV network across Minnesota and South Dakota. CapX2020's vision for Minnesota was optimized for the entire Midwest via MISO's first regional MVP portfolio, a portfolio of 17 projects, primarily at 345 kV, totaling approximately 2,200 miles across nine Midwest states.[72] All CapX2020 lines were in service as of 2017.

To optimally meet immediate needs with longer-term goals in mind, at the recommendation of the Department[73] and approval of the Commission,[74] the 345 kV CapX2020 projects were upsized and built as single-circuit but double-circuit capable. Today, the second circuit has been or is planned to be added to nearly all the CapX2020 projects, which has allowed Minnesota to double the transmission capacity of each corridor with minimal physical impacts and significantly less costs than would be required for a new stand-alone option.

The scope of the Project in this Application includes the addition of a second circuit of the existing CapX2020 transmission line between North Rochester and Hampton. Despite recent

72 MISO. Regionally Cost Allocated Project Reporting Analysis. 2011 MVP Portfolio Analysis Report. Available at: https://cdn.misoenergy.org/MVP%20Dashboard117055.pdf.

73 Surrebuttal Testimony of Dr. Steve Rakow on Behalf of the Minnesota Office of Energy Security. Available at: https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b3330DBFF-01B4-407D-B195-30774E30DD2A%7d&documentTitle=5320643. Page 21.

74 CapX 2020 Transmission Expansion Initiative. Order Granting Certificates of Need with Conditions. https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7b54C51FAE-B774-4EED-A93C-CAF6ECC5EB52%7d&documentTitle=20095-37752-01. Page 43.

and planned doubling of transmission capacity in the CapX2020 circuits,[75] additional transmission capacity is still needed to meet the needs for the next 20 years.

4.4 MISO Long Range Transmission Plan

In the 2010s and 2020s, more states, like Minnesota, passed mandates to reduce and/or eliminate carbon-emitting generation (additional details in **Section 5.3**). Seeing a fundamental shift in the generation mix towards more renewable (i.e., wind, solar, hydro) generation sources, MISO released a study in 2021 called the Renewable Integration Impact Assessment (RIIA) to understand the implications of an increase in renewable generation entering the system, or renewable penetrations. 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 renewable penetrations will require transformational change in planning, markets, and operations, as shown on **Figure 4.4-1**.

Within the next 20 years, Minnesota's generation mix is expected to be primarily renewable, and MISO is expected to be 83 percent renewable.[76]

In 2024, the MISO system achieved a 19 percent renewable penetration MISO-wide[77] and Minnesota achieved a 33 percent renewable penetration.[78] While incremental transmission expansion has and continues to be developed, the increased stress to efficiently maintain reliability is evident in the increased congestion levels and more frequent use of MISO emergency operating procedures.

Recognizing that transformational changes in the generation fleet require significant changes to the transmission grid to maintain reliability, MISO launched the LRTP in 2019. The LRTP is a multi-year multi-phase study to identify a regional transmission network necessary to cost-effectively maintain reliability and serve MISO future needs.

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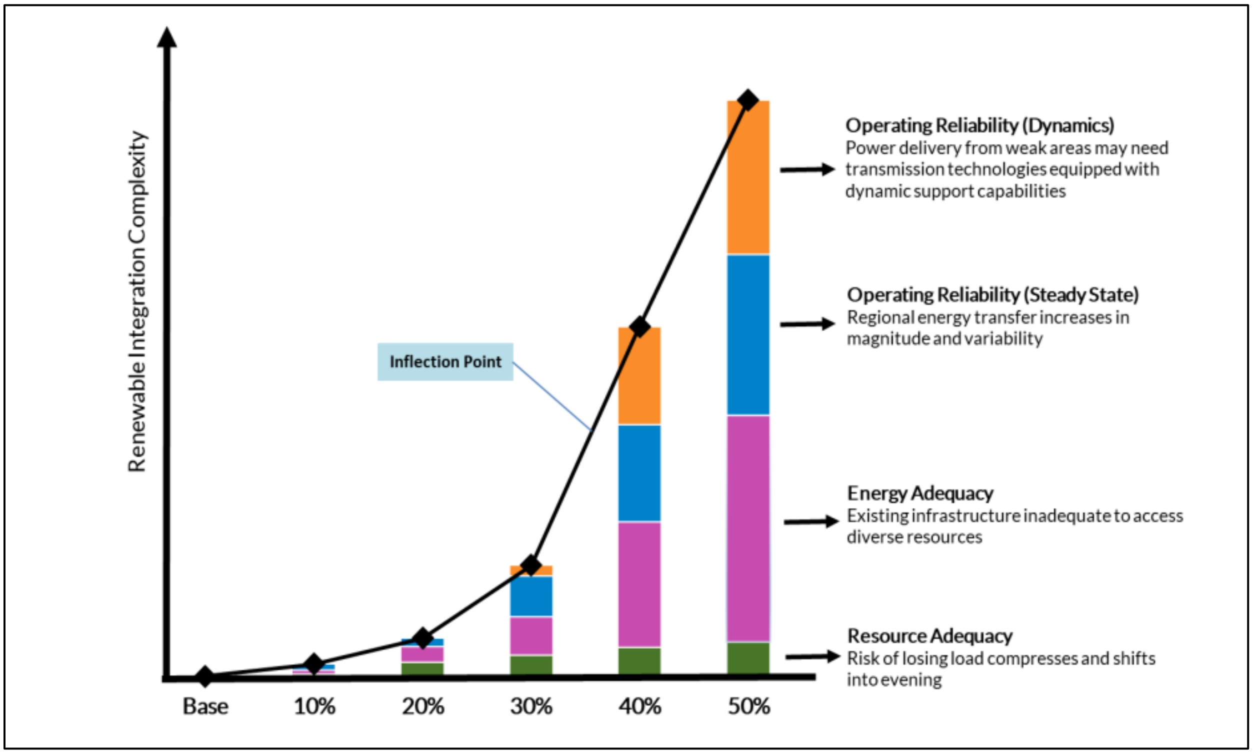
75 Recent completed second-circuit projects include Brookings County to Lyon County and Helena to Hampton. The second-circuit between Alexandria and Monticello (Big Oaks) is expected to be completed in 2026. The second-circuit between Fargo and Alexandria is a project in the MISO LRTP Tranche 2.1 Portfolio. The second circuit between Hampton and North Rochester is proposed in this Application.

76 See **Appendix E.2**. Page 77.

77 MISO Fact Sheet – September 2025. See **Appendix E.5**.

78 EIA. Electricity. Available at: https://www.eia.gov/electricity/data/browser/" \l "/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=. Referenced November 2025.

Figure 4.4-1: Reliability Implications of Increasing Renewable Penetrations[79]



The LRTP is one component of MISO's Reliability Imperative,[80] a shared responsibility of electricity providers (like the Applicants), states, and MISO to address the urgent and complex challenges facing the electric grid in the MISO region. MISO's response to the Reliability Imperative consists of a host of initiatives grouped into four categories: Market Redefinition, Transmission Evolution (i.e., LRTP), System Enhancements, and Operations of the future. The objective of MISO's LRTP is to provide an orderly and timely transmission expansion plan that supports these primary goals:

- **Reliable System** – maintain robust and reliable performance in future conditions with greater uncertainty and variability in supply.
- **Cost Effective** – enable access to lower-cost energy production.

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79 MISO's Renewable Integration Impact Assessment (RIIA). Available at: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf?_t_id=HAcY9Glq5QpaFZ2DUyt_JA%3d%3d&_t_uuid=Ls_331WCSMiJHli_VSQ8lw&_t_q=riia&_t_tags=language%3aen%2csiteid%3a11c11b3a-39b8-4096-a233-c7daca09d9bf%2candquerymatch&_t_hit.id=Optics_Models_Find_RemoteHostedContentItem/520051&_t_hit.pos=3

80 MISO. Reliability Imperative Report. Available at: https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

- **Accessible Resources** – provide cost-effective solutions allowing the future resource fleet to serve load across the footprint.
- **Flexible Resources** – allow more flexibility in the fuel mix for customer choice.

MISO evaluates the projects in the LRTP in accordance with MISO's federally approved tariff. For any 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 an MVP. For a project to be deemed needed by MISO as an MVP it must:

- Reliably and economically enable regional public policy needs;
- Provide multiple types of regional economic value; and/or
- Provide a combination of regional reliability and economic value.

4.5 LRTP Tranche 1

In July 2022, MISO approved the first tranche, or phase, of the LRTP (LRTP Tranche 1). The LRTP Tranche 1 Portfolio consists of 18 transmission projects, totaling approximately 2,000 miles of new and upgraded transmission lines, to enhance connectivity and help maintain adequate reliability for the Midwest by 2030 and beyond. **Figure 4.5-1** depicts the projects in the LRTP Tranche 1 Portfolio.

The LRTP Tranche 1 Portfolio includes three 345 kV projects in Minnesota:

- the Big Stone South to Alexandria to Big Oaks Transmission Project;[81]
- the Northland Reliability Project;[82] and
- the Mankato to Mississippi River Project.[83]

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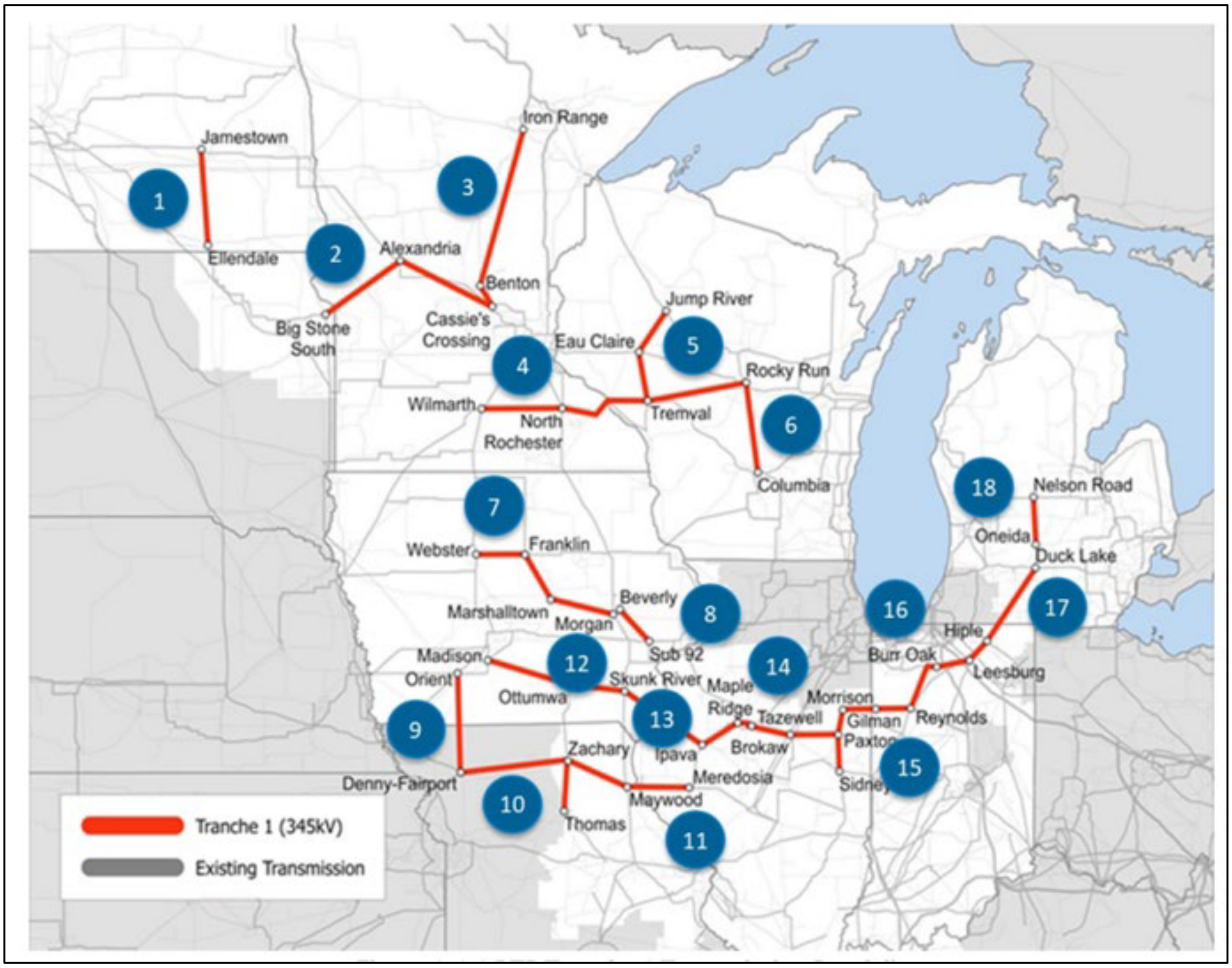
81 Commission Docket Numbers CN/22-538, TL-23-159, and TL-23-160.

82 Commission Docket Numbers CN-416 and TL-22-415.

83 Commission Docket Numbers CN-22-532 and TL-23-157.

Figure 4.5-1: MISO LRTP Tranche 1 Portfolio



LRTP Tranche 1 was intentionally designed as a first step to address immediate reliability needs driven by retiring fossil fuel plants and to increase primarily intra-state, but also inter-state, transfers to meet NERC standards. More specifically, the MISO LRTP Tranche 1 Portfolio:

- Addresses reliability violations as defined by NERC at over 300 different sites across the Midwest. In addition, the portfolio increases 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.
- Provides $23.2 billion in net economic savings over the first 20 years of the LRTP Tranche 1 Portfolio's service, which results in a benefit-to-cost ratio of at least

2.6. This amount increases to $52.2 billion in net economic savings over 40 years, resulting in a benefit-to-cost ratio of 3.8.[84]

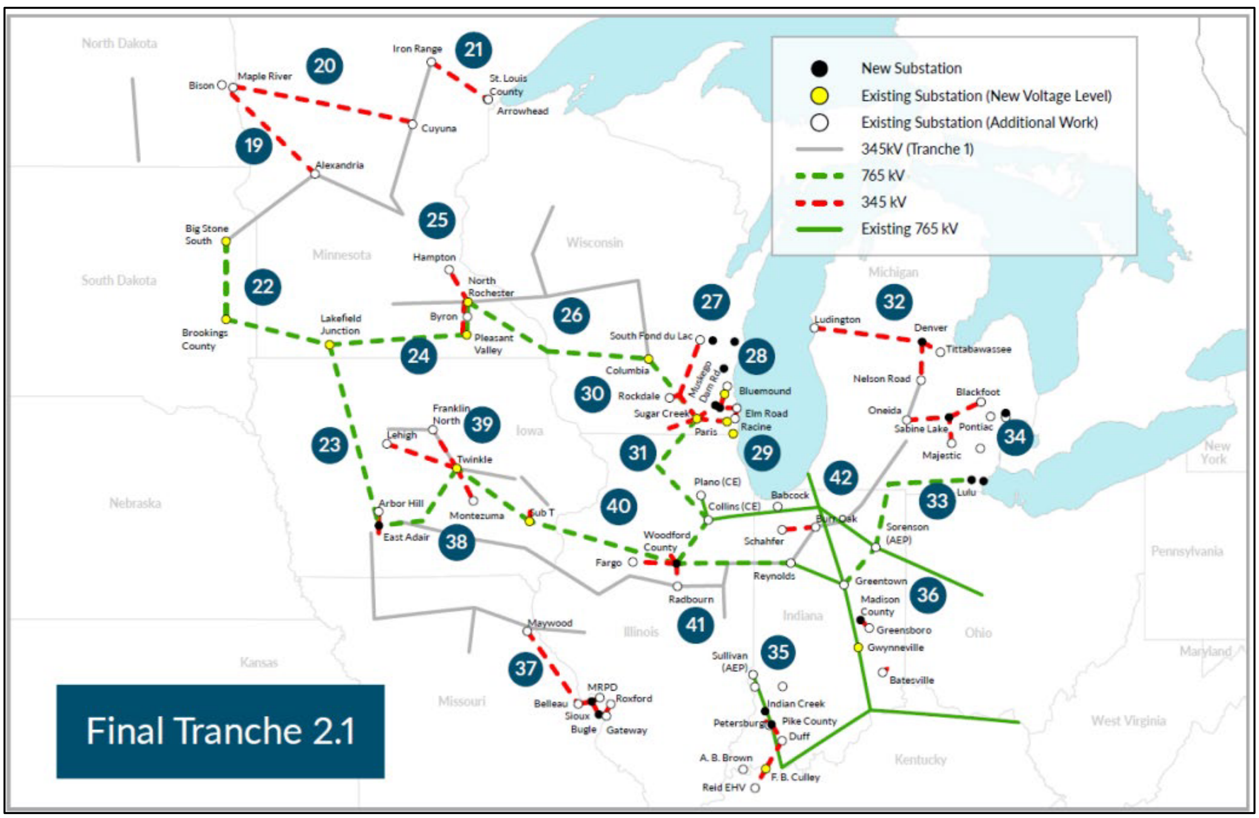
- Supports the reliable interconnection of approximately 43,431 MW in new, primarily renewable, generation capacity across the MISO Midwest subregion, 8,339 MW of which is in Minnesota and the surrounding region.

The LRTP Tranche 1 Portfolio was also designed to bolster the existing 345 kV to position the grid for future LRTP tranches.

4.6 LRTP Tranche 2.1

In 2024, MISO approved the next phase of the LRTP (LRTP Tranche 2.1) which establishes a new 765 kV transmission backbone across the Midwest, as shown on **Figure 4.6-1**.

Figure 4.6-1: MISO LRTP Tranche 2.1 Portfolio[85]



[84] Values as of July 2022. Market forces have driven Project costs to increase since 2022 and the same forces will also cause benefits to increase.

[85] **Appendix E.1**. Page 144

The LRTP Tranche 2.1 Portfolio includes 24 projects totaling approximately 3,600 miles of new and upgraded transmission in MISO's Midwest subregion. The LRTP Tranche 2.1 builds upon and is enabled by the LRTP Tranche 1 and the existing transmission grid, which serves as "entry and exit ramps" for the new LRTP Tranche 2.1 765 kV transmission backbone network, as well as contingency backup to meet NERC reliability standards. Combined, the existing 765 kV and 345 kV networks work together to move electricity across the multiple states to each local community where it is consumed and allow each state to meet their policy and reliability needs in a less costly and impactful manner, as further described in **Section 7.4**. The complete Chapter 2 from the MTEP24 Report ("Regional/Long-Range Transmission Planning") is included as **Appendix E.1**. MISO followed an extensive stakeholder process, spending more than 40,000 staff hours, facilitating more than 300 meetings, and capturing feedback to arrive at the LRTP Tranche 2.1 Portfolio.[86] The LRTP Tranche 2.1 Portfolio meets the following MVP criteria:

- **Reliability** – Addresses reliability violations across the Midwest.[87]
- **Economic Efficiency/Net Benefits** – The $21.8 billion portfolio has a benefit-to-cost ratio of 1.8 to 3.5. This means that every $1.0 invested in transmission will result in economic benefits of $1.8 to $3.5. Per MISO's analysis the LRTP Tranche 2.1 is expected to provide net economic savings of $23.1 billion to $72.4 billion over the first 20 years of service.[88]
- **Policy** – Alleviates congestion and enables interconnection of approximately 116,000 MW of primarily carbon-free resources[89] to reduce Midwest CO_2 emissions by 127 million to 199 million metric tons over 20 to 40 years to help states like Minnesota comply with decarbonization laws.[90] In addition to Minnesota, Illinois[91] and Michigan[92] have enforceable decarbonization

[86] Id. Page 6.

[87] Id. Page 63 through 69 and 77 through 124.

[88] Id. Page 125, Figure 2.13. Net savings are 20-year Net Present Value (NPV) in $2024.

[89] Id. Page 75.

[90] Id. Page 142.

[91] Illinois Climate and Equitable Jobs Act mandates 100% carbon-free power by 2045. Illinois Department of Commerce. Available at: https://dceo.illinois.gov/ceja.html.

[92] Michigan Senate Bill 271 mandates 100 percent carbon-free power by 2040. State of Michigan. Michigan Becomes National Leader in Climate Action with New Legislation. Available at: https://www.michigan.gov/whitmer/news/press-releases/2023/11/28/governor-whitmer-signs-historic-clean-energy-climate-action-package.

standards, and Wisconsin[93] has a decarbonization goal. In addition, many Midwest utilities have decarbonization goals.

The Studied Projects serve a key role in the execution of MISO LRTP Tranche 2.1 by addressing reliability needs specific to southern Minnesota, eastern North Dakota, eastern South Dakota, northern and central Iowa, and western Wisconsin.[94]

4.6.1 Reliability Need

MISO identified the need for the LRTP Tranche 2.1 Portfolio to prevent numerous thermal and voltage reliability issues as summarized on **Figure 4.6-2.** The MISO LRTP Tranche 2.1 Portfolio is needed to ensure that the MISO transmission grid can continue to reliably deliver energy from future generation resources to future load under a range of projected system conditions associated with the Future 2A scenario (see **Section 5.1** for additional details) in the 10-year and 20-year time horizons.

[93] Wisconsin Governor Evers Executive Order #38 established a state goal to reach 100 percent carbon-free electricity by 2050. Available at: https://docs.legis.wisconsin.gov/code/executive_orders/2019_tony_evers/2019-38.pdf.

[94] Id. Pages 84 and 92.

Figure 4.6-2: MISO Summary of Reliability Issues[95]

RELIABILITY ISSUES

WEST

- 20% of the facilities were found to be overloaded
- Annual curtailments exceeded 40%
- Energy losses over transmission lines increased from 2.5% to 11%

kV	Unique overloads	Max loading%
345	66	206
230	41	208
<200	496	263

CENTRAL

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission enabled transfer of regional power
- Needs were refined through transfer sensitivities and multi-element contingencies

kV	Unique overloads	Max loading%
345	21	171
230	13	142
<200	158	191

EAST

- 10% of the facilities were found to be overloaded
- Annual curtailments exceeded 15%
- Transmission supported daily and nightly import / exports

kV	Unique overloads	Max loading%
345	7	113
<200	159	223

4.6.2 Generation Transition and Public Policy

MISO's analysis shows that the LRTP Tranche 2.1 Portfolio supports the reliable interconnection of approximately 115.7 GW of new generation.[96] Of the capacity supported by the LRTP Tranche 2.1 Portfolio, 32.1 GW is in Minnesota and the surrounding region (MISO Local Resource Zone 1).[97] The generation supported by the LRTP Tranche 2.1 Portfolio is expected to reduce CO_2 emissions by 127 million metric tons over the first 20 years of service and 199 million metric tons over the first 40 years of service.[98] Using the Commission's valuation of CO_2 emission reduction,[99] the

95 Id. Page 47. Central, East, and West refer to MISO regions. Minnesota is in the MISO West Region.

96 Id. Page 75.

97 Id. Page 76.

98 Id. Page 142.

99 *In re Establishing an Updated 2020 Estimate of the Costs of Future Carbon Dioxide Regulation on Elec. Generation under Minn. Stat. § 216H.06*, Docket No. E999/DI-19-406, Order Establishing 2020 and 2021 Estimate Of Future Carbon Dioxide Regulation (September 30, 2020).

LRTP Tranche 2.1 Portfolio is expected result in approximately $28 to $39 billion in carbon reduction benefits over the first 20 years across the MISO footprint.[100]

4.6.3 Cost Effectiveness/Net Benefits

MISO's analysis shows that the MISO LRTP Tranche 2.1 Portfolio will provide net economic savings estimated at $23.1 billion to $72.4 billion over the first 20 years of service, as shown on **Figure 4.6-3**.[101] MISO estimates these projected savings will offset the capital cost of the MISO LRTP Tranche 2.1 Portfolio by a ratio of 1.8 to 3.5, meaning that net savings are expected relative to what would be needed without the MISO LRTP Tranche 2.1 Portfolio.[102] For an average electrical consumer, MISO estimates that the LRTP Tranche 2.1 Portfolio is estimated to cost about $5 per 1,000 kWh of energy used while providing $10 to $18 of value over that same amount of usage per month in value.[103]

As shown on **Figure 4.6-3**, MISO quantified the economic savings of the MISO LRTP Tranche 2.1 Portfolio using nine different metrics. The inclusion of each metric is approved in MISO's federally approved tariff and further supported by FERC Order 1920.[104]

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[100] See **Appendix E.1**. Page 143.

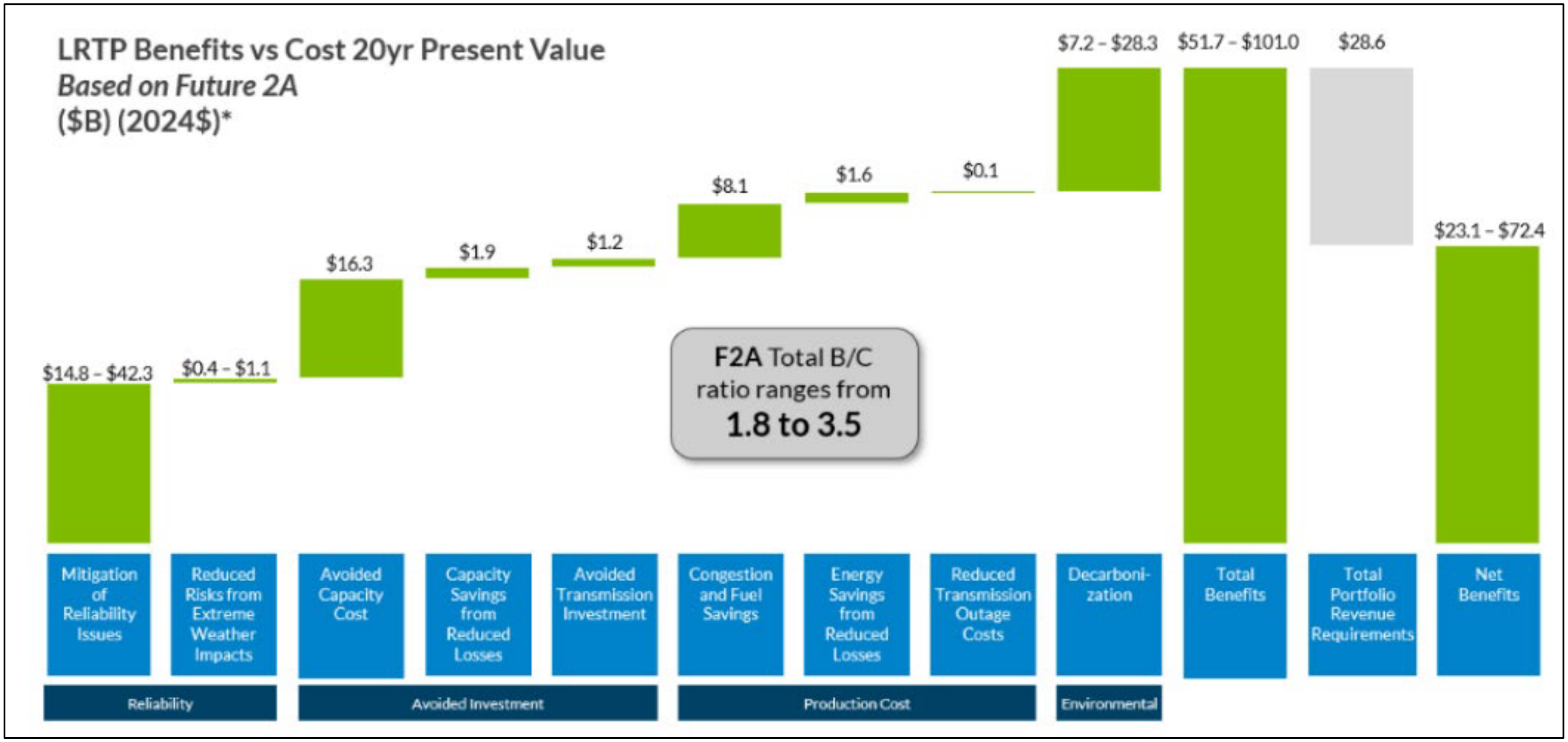
[101] Id. Page 125.

[102] Id. Values based on MISO Future 2A.

[103] MISO. Fact Sheet - Long Range Transmission Planning Tranche 2.1. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202.1666573.pdf

[104] FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

Figure 4.6-3: Economic Savings from the MISO LRTP Tranche 2.1 Portfolio[105]



105 Id. Page 125.

4.6.4 Other Qualitative Benefits

The LRTP Tranche 2.1 Portfolio also provides multiple other qualitative benefits. MISO expects that the addition of the LRTP Tranche 2.1 Portfolio will increase operational flexibility to better allow timely outage scheduling to maintain the reliability of the system; and reduce the economic impact due to congestion caused by outages. The operational flexibility also helps reduce the economic impacts of natural gas price changes by providing access to a broader pool of generation resources.[106]

The LRTP Tranche 2.1 Portfolio also gives more flexibility to better support diverse policy needs. The proactive long-range approach to planning regional transmission provides regulators greater confidence in achieving policy goals by reducing uncertainty around 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.

4.6.5 Studied Projects as Part of MISO LRTP Tranche 2.1

MISO LRTP Tranche 2.1 was developed as a portfolio of projects designed to work together; however, each project group in the portfolio was also justified by MISO based on regional and local needs. MISO identified that the Project is a critical component of the LRTP Tranche 2.1 Portfolio and the best option to meet Minnesota and the Midwest's electrical needs. To identify the optimal LRTP Tranche 2.1 Portfolio, MISO evaluated 97 different alternatives,[107] including multiple alternatives to the Studied Projects.[108] MISO's justification for the Studied Projects is summarized as follows:

> *The 765 kV project in northeastern South Dakota, Southwestern Minnesota and Western Iowa provides an outlet for generation in South Dakota and also connects both west-to-east 765 kV paths developed in the initial portfolio to provide contingency support.[109] The Minnesota – Wisconsin West – Wisconsin East project adds power transfer capability into load centers in Minnesota and Wisconsin….[110] The portfolio resolves most constraints in Southern Minnesota and Western Wisconsin, especially on 200 kV and above facilities.[111] Projects in Southern Minnesota and Wisconsin enable substantially more renewable delivery, particularly from the Eastern Dakotas, Southwestern*

[106] Id. Page 148.

[107] Id. Page 42.

[108] Id. Pages 45 and 52.

[109] Id. Page 93.

[110] Id. Page 84.

[111] Id. Page 84.

Minnesota, and Northern Iowa – locations with some of the strongest wind resources.[112] *This is aided through the loop configuration of the other Tranche 2.1 765 kV west-to-east path which increases the amount of power that can reliably flow over 765 kV facilities.*[113]

Details on MISO and the Applicants' need analysis are presented in **Chapter 6.**

4.7 Minnesota Transmission Owners' Efforts to Expand Existing Grid Capacity

The Applicants have a responsibility to ensure the right transmission upgrades are developed at the right time to maintain reliability. New transmission lines are proposed only after all other options to upgrade existing facilities have been exhausted. The Applicants and Minnesota's transmission owners have been on the forefront of using technology to "squeeze every drop" of capacity out of the existing transmission grid through such recent initiatives as:

- **Ambient Adjusted Line Ratings (AAR):** The Applicants and all MISO transmission owners are implementing ratings on all facilities which are adjusted based on actual temperatures. Temperature is a primary factor in transmission line capacity; generally, the cooler the temperature the more power can safely flow on a transmission line. Previously, line ratings were established on a seasonal basis. This extra precision allows additional capacity when conditions warrant.
- **Dynamic Line Ratings (DLR):** Several Minnesota utilities, including the Applicants, have implemented DLRs at the most impactful sites. DLRs build on the AAR concept by adding additional real-time meteorological data such as wind speed and irradiance to add further precision to enable additional transmission capacity when conditions warrant.
- **Near-Term Congestion Projects:** In 2023, Grid North Partners, an evolution of CapX2020, announced plans to construct 19 projects to help decrease congestion levels over the next several years. The congestion projects are primarily upgrades of existing infrastructure which require little to no new right-of-way. Solutions identified as part of the Grid North Partners study were incremental quick-implementation solutions which help reduce congestion to bridge to longer-term holistic solutions, like the Project and MISO LRTP Tranche

[112] Id. Page 86.

[113] Id. Page 86.

2.1 Portfolio, and help reduce impacts of outages necessary to construct LRTP projects.

- **Grid Enhancing Technologies (GETs):** In 2025, as part of the Minnesota Biennial Transmission Plan, the Minnesota transmission owners, including the Applicants, conducted a second iteration of the near-term congestion study focusing on GETs.[114] GETs are hardware or software that increases the capacity or flexibility of a HVTL, effectively optimizing power flow to reduce congestion and improve the integration of renewable energy. These technologies include, but are not limited to, DLR, advanced power flow controllers, and topology optimization.[115] The 2025 study addresses 30 additional solutions which will be implemented in the near-term to incrementally expand the capacity of the existing transmission grid.

Due to the collective actions taken, the Minnesota transmission grid today is reliable, has enabled Minnesota to meet mandates ahead of schedule (e.g., the renewable portfolio standard)[116], and helps provide electricity costs that are less than the national average.[117] While each effort has resulted in expanded grid capacity, the amount of additional capacity which has been added is a fraction of what is needed to meet Minnesota's projected electrical needs as described in **Chapters 5 and 6**. These actions have also helped bridge the long-term solutions, such as the Project, that are needed to maintain reliability, meet new policy mandates, and remain cost competitive.

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114 2025 Minnesota Biennial Transmission Report. Section 9.3. Available at: https://www.minnelectrans.com/report-2025.html.

115 Grid Enhancing Technologies definition from Minnesota Statute Section 216B.2425.

116 EIA. Electricity Data Browser, Net generation for all sectors, Minnesota, Annual, 2001-23. Available at: https://www.eia.gov/state/analysis.php?sid=MN#29.

117 EIA. Electric Power Annual, Table 2.10: Average Price of Electricity to Ultimate Customers by End-Use Sector. Available at: https://www.eia.gov/electricity/annual/table.php?t=epa_02_10.html.

5 NEED DRIVERS

As the way that our region generates and uses electricity changes, the electric transmission grid must evolve with it. The Project is needed to maintain system reliability amid fundamental changes in how energy is produced and used. This Chapter details the generation and demand forecasts which are driving the need for the Project.

- **Section 5.1 – Need Scenarios:** MISO and the Applicants used a scenario-based approach to analyze the need for the Project to consider a range of potential generation and demand forecasts. MISO's Future 2A, based on approved state integrated resource plans and state and utility goals, is the primary scenario used in this Application.

- **Section 5.2 – Generation Fleet Transformation:** Driven by a combination of economics, consumer preferences, age of existing generation, and regulatory policies, 72 GW of new generation is expected to be added and 16 GW of existing generation is expected to be retired over the next 20 years in Minnesota and the surrounding area (within MISO's Local Resource Zone 1).[118]

  For the broader MISO region, MISO forecasts that by 2042, fossil fuel generation will provide approximately 2 percent of annual energy, compared to 66 percent in 2024. Variable wind and solar generation will provide approximately 73 percent of annual energy, compared to 17 percent in 2024.[119]

- **Section 5.3 – Evolving Electrical Demands:** Peak demand and electrical consumption in Minnesota and within the MISO region is forecasted to increase over the next two decades as a result of new and expanded manufacturing, electrification (e.g., heating and cooling, appliances, agriculture, transportation, etc.), and emerging industries like data centers. Demand forecasts used in this Application do not consider data center and other industry growth potential. However, MISO predicts that these inputs could increase demand by as much as three-fold.

5.1 Need Scenarios

Forecasts of the future generation mix and energy usage are necessary to plan the grid, as transmission grid expansions are long-term decisions. As part of each MTEP cycle, MISO and its

[118] See **Appendix E.2.** Pages 87 and 88.

[119] See **Appendix E.2.** Page 7 (2042 values). 2024 values from MISO Fact Sheet – September 2025. See **Appendix E.5**.

stakeholders 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 range of generation and demand forecasts considering potential 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 ahead, are then used to assess and identify the transmission needed to deliver the necessary energy reliably and efficiently from generation resources to customers. Futures are developed through an iterative and robust stakeholder process which includes representatives from MISO utilities, state regulatory authorities, public consumer advocates, environmental representatives, and independent power producers.

In MTEP24, three Futures were used in MISO's grid planning initiatives: Future 1A, Future 2A, and Future 3A. As of February 2026, the MTEP24 futures, referred to as "Series 1A," published on November 1, 2023, are the latest available. MISO developed these scenarios between 2022 and 2023 and incorporated numerous rounds of stakeholder feedback, policy assessments, and industry trends. MISO's three Futures incorporate varying assumptions about utility and state goals, retirements, distributed energy resource adoption, and electrification, among other factors. All MTEP24 Futures assume that the changes announced through October 2022 in utility IRPs (resource plans for upwards of 10 to 15 years into the future) are realized.[120] A summary of the key assumptions for each MTEP24 Future is shown on **Figure 5.1-1.**

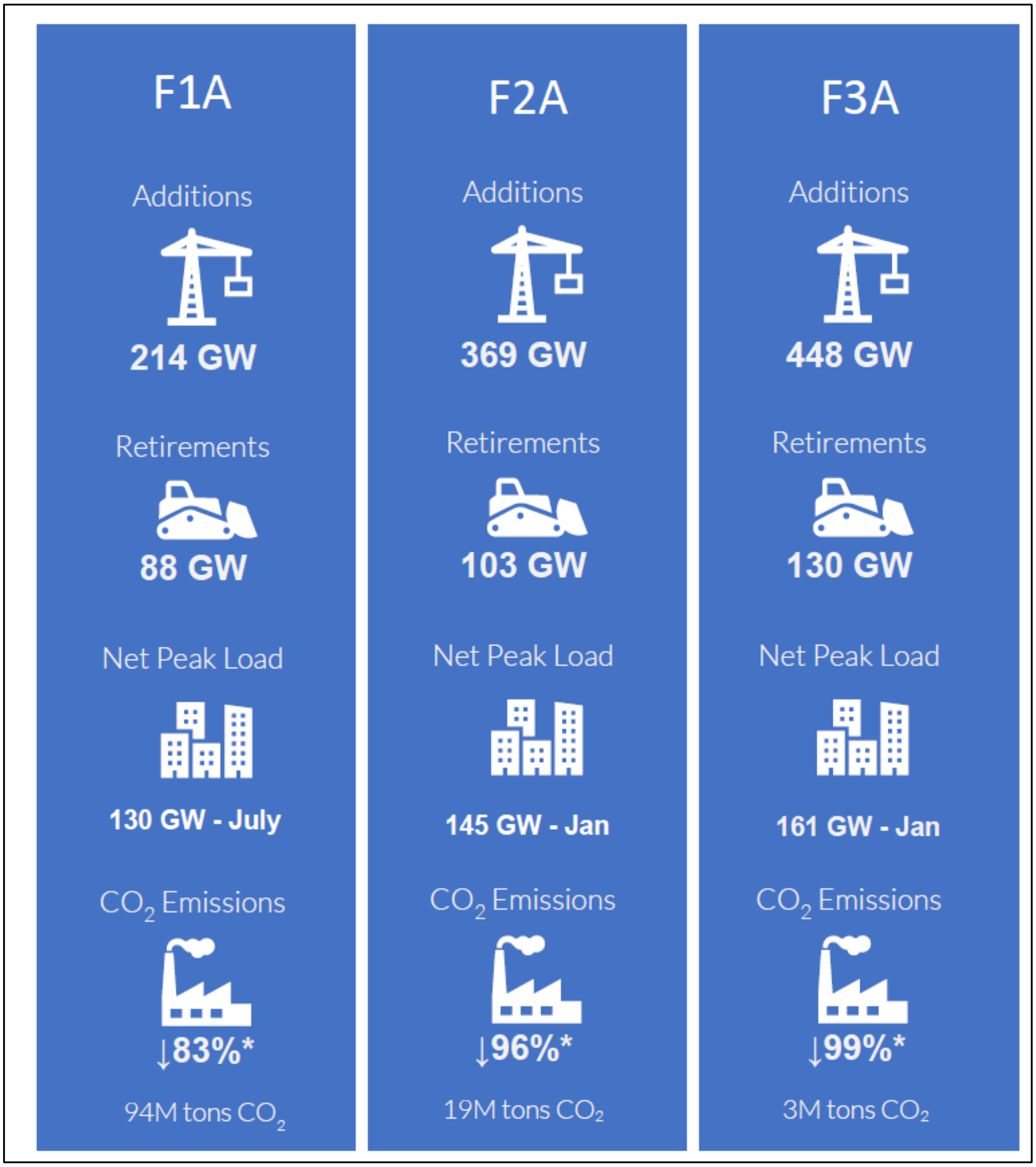
The magnitude of change considered in the MTEP24 Futures is transformational. Future 1A alone, the "least transformational" of the MTEP24 Futures as it assumes only 85 percent of state decarbonization goals as of 2022 are met, anticipates 88 GW of generation retirements and 214 GW of resource additions.[121] For perspective, MISO's current installed capacity is approximately 203 GW.[122]

[120] Id. Page 4.

[121] Id. Page 6.

[122] MISO Fact Sheet – September 2025. See **Appendix E.5**.

Figure 5.1-1: MISO Futures Generation Assumptions – Cumulative Change Through 2042[123]



123 See **Appendix E.2**. Page 4.

Future 2A is MISO's LRTP Tranche 2.1 Portfolio base scenario. Unless noted otherwise, the Applicants' analysis in this Application is performed using Future 2A. Per MISO, "Future 2A is most aligned with an optimized, least-cost expansion that meets member goals."[124] Future 2A incorporates 100 percent of utility IRPs and announced state and utility goals within their respective timelines. MISO also evaluated need under Future 1A – the low bookend scenario - which assumes only 85 percent of announced state and utility goals are met. [125]

Additional details on MISO's MTEP24 Futures can be found in **Appendix E.2**, the MISO Series 1A Futures Report.

5.2 Generation Fleet Transformation

The Project and the MISO LRTP Tranche 2.1 Portfolio enable the interconnection and reliable transfer of more generation across the system, exceeding the capabilities of the existing grid. While the current approved IRPs in Minnesota rely primarily on additional renewable generation,[126] the Project is agnostic to the type of generation which it enables. The Project can move electrons generated by natural gas, coal, hydrogen, energy storage, nuclear, renewables, etc. – providing flexibility for utilities to adjust generation plans as technology, regulatory and company policies, and economics evolve.[127]

The Project and the MISO LRTP Tranche 2.1 Portfolio support reliability for every hour of every day by facilitating the movement of energy to, through, and out of Minnesota, depending on electrical demand and generator availability. The following sections provide details on the generation forecast for Minnesota and the broader MISO region, as the Project's need is not only driven by Minnesota's generation requirements but by those of the broader MISO region.

5.2.1 MISO Energy Landscape Transformation

The MISO footprint (see **Figure 3.3-1**) is experiencing a fundamental change in the energy industry landscape due to shifts in generation resources and decentralization of generation.

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. By 2024, coal

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[124] See **Appendix E.1.** Page 10

[125] Id. Page 143.

[126] See **Section 5.3.2.1.**

[127] FERC Order 888 mandates all public utilities to provide open non-discriminatory access to transmission facilities to any generator regardless of owner, fuel-type, etc. FERC. Available at: https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888.

generation had shrunk to approximately 25 percent of MISO's annual energy production, and annual energy from wind and solar generation rose to 17 percent.[128] Since 2001, over 50 GW of renewable resources have been installed across the MISO region.[129] Since 2010, over 30 GW of fossil fuel generation has retired in the MISO region.[130]

The MISO generation evolution is being driven by several factors, including but not limited to economics, age of existing generation, customer and business preferences, state policies, and state and utility goals.

As shown on **Figure 5.2-1**, many states and utilities in MISO have carbon-free and decarbonization targets. **Figure 5.2-2** displays the levelized cost of energy (LCOE), a measure of the lifetime cost to deliver an equivalent amount of energy by generation type. As shown on **Figure 5.2-2,** the LCOE for utility scale wind without federal tax subsidies is $37 to $86 per MWh, utility scale solar without federal tax subsidies is $38 to $78 per MWh, natural gas combustion turbine is $149 to $251 per MWh, and natural gas combined cycle is $48 to $109 per MWh, as of June 2025.

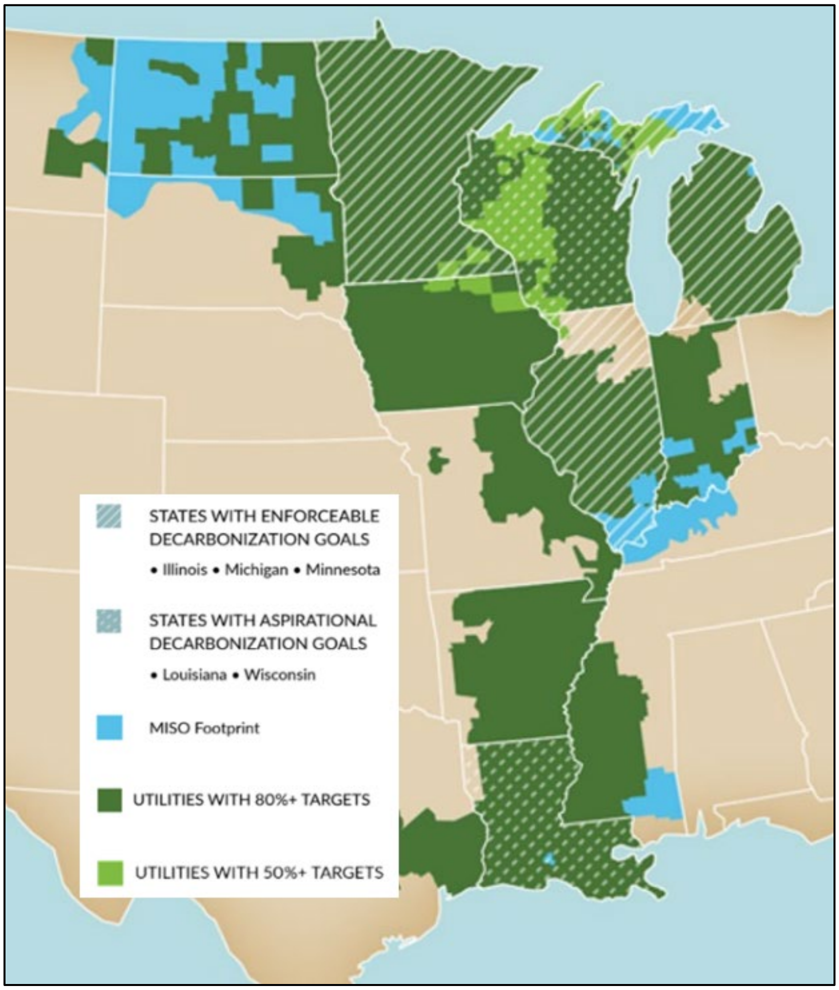
MISO forecasts generation trends, including the retirement of legacy fossil-fuel generation and replacement with wind, solar, and other new technologies, to continue and potentially accelerate over the next 20 years. This is based primarily on state-approved IRPs – MISO Future 2A. MISO forecasts that nameplate generation capacity will roughly double by 2042 as shown on **Figure 5.2-3**.

128 MISO. Fact Sheet – September 2025. See **Appendix E.5**.

129 Id. Installed wind and solar capacity.

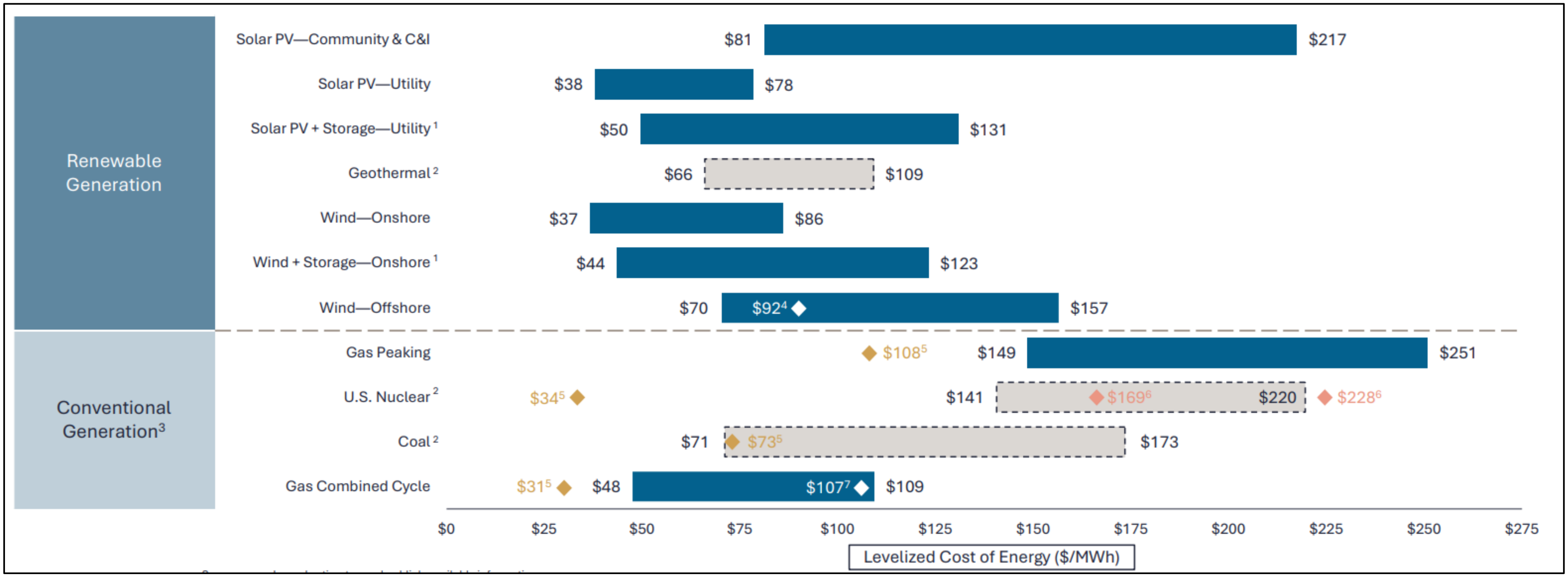
130 MISO. MTEP 23, Chapter 2: Portfolio Evolution. Available at: https://cdn.misoenergy.org/Recommended%20MTEP23%20Chapter%202%20-%20Portfolio%20Evolution630591.pdf. Page 5.

Figure 5.2-1: Decarbonization or Clean Energy Goals Across the MISO Footprint as of September 2025[131]



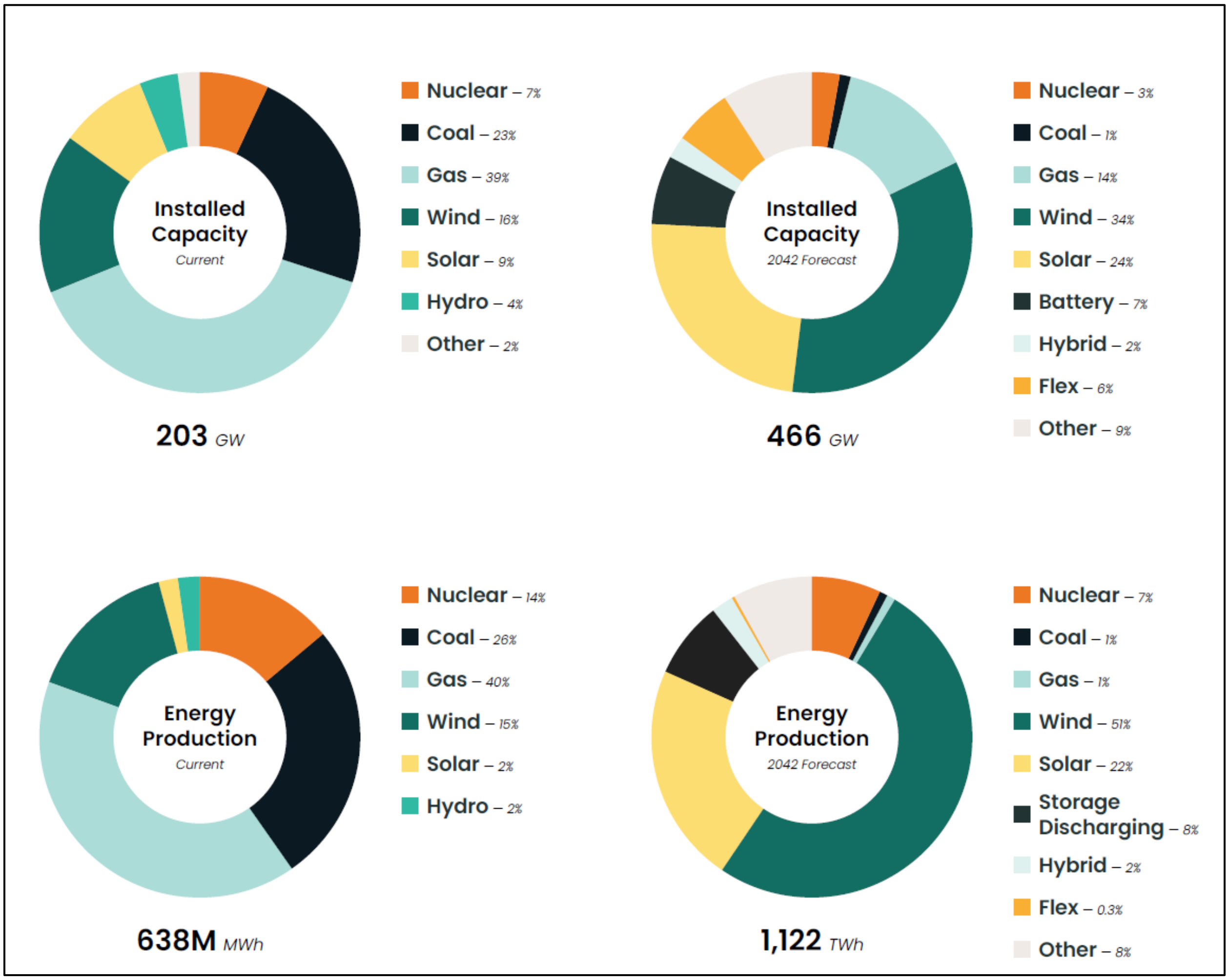
[131] MISO. MTEP Futures Redesign Workshop, September 2025.

Figure 5.2-2: Levelized Cost of Energy by Generation Type – Wind and Solar Photovoltaic, <u>Excluding</u> Federal Tax Subsidies[132]



[132] Lazard. Levelized Cost of Energy. Available at: https://www.lazard.com/media/eijnqja3/lazards-lcoeplus-june-2025.pdf.

Figure 5.2-3: MISO Region Forecasted 2042 Generation Energy and Capacity[133]



5.2.2 Minnesota Energy Landscape Transformation

Minnesota's generation transition is consistent, but accelerated, relative to the overall generation transition occurring within the MISO footprint. This accelerated transition is due to a combination of economics, consumer and commercial preferences, age of existing generators, and Minnesota's Carbon-Free by 2040 law.[134] The Project and the MISO LRTP Tranche 2.1 Portfolio is needed to enable the generation transition in a reliable manner by providing transmission capacity to interconnect additional generation (see **Section 6.5.1**),

[133] See **Appendix E.2.** Page 7 (2042 values). Current values (2024) from MISO Fact Sheet – September 2025. See **Appendix E.5**.

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

transfer generation from where it is available to where it is needed (see **Section 6.3.2**), and efficiently use all available generation capacity (see **Sections 6.4.2 and 6.5.2**).

In 2011, over half of the electricity generated in Minnesota came from coal-fired generation. In 2024, electricity from coal was reduced to approximately 20 percent and renewables provided over 33 percent of electricity generation statewide.[135] As of June 2025, approximately 7,000 MW of new renewable generation has been installed in Minnesota to meet electrical needs.[136] Meanwhile, many of the traditional baseload generators that have provided round-the-clock energy production for decades are retiring. Based on the information contained within IRPs, Minnesota's active remaining baseload fossil-fuel generators are planned to retire and/or cease coal-fired operations as follows:

- Sherburne County Generating Station Unit 1 - 2026[137]
- Sherburne County Generating Station Unit 3 – 2030[138]
- Allen S. King – 2028[139]
- Clay Boswell Energy Center – 2035[140]

MISO forecasts the generation mix trends in Minnesota and the surrounding area (MISO Local Resource Zone 1)[141] to continue over the next 20 years, based on the information primarily contained within IRPs. MISO forecasts that by 2042, over 50,000 MW of wind and solar generation will be added in Local Resource Zone 1, providing much of the annual energy, with other technologies including natural gas, battery storage, and demand response[142] providing the remainder, as shown on **Figure 5.2-4.**

135 EIA. Electricity. Available at: https://www.eia.gov/electricity/data/browser/" \l "/topic/0?agg=2,0,1&fuel=vvg&geo=000004&sec=g&freq=A&start=2001&end=2024&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=. Referenced November 2025.

136 EIA. Electric Power Monthly. Table 6.2.B. Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_6_02_b. Referenced November 2025.

137 Xcel Energy. 2024-2040 Integrated Resource Plan. Available at: https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002YCQL/2EQNYnEG7hBohut31h0nHs5yppYhY.lwg_GbUZK8t6w.

138 Id.

139 Id.

140 Minnesota Power. 2025 Integrated Resource Plan. Available at: https://www.mnpower.com/IRP2025.

141 MISO Local Resource Zone 1 includes the MISO footprint in most of Minnesota, North Dakota, South Dakota, Montana, and western Wisconsin.

142 Demand response encompasses multiple forms of peak shaving and load reduction programs, such as interruptible loads, load management (e.g., residential air conditioner saver switch) and dual fuel programs.

Figure 5.2-4: Minnesota and Surrounding Area (Local Resource Zone 1) Current to Future 2A Generation Forecast – Resource Additions and Retirements[143]

Zone	Milestone	Battery	CC	CT Gas	Demand Response	DGPV	IC Gas	Solar	Hybrid	ST Coal	ST Gas	Wind	Flex	EE	UDG	Totals
LRZ 1	2027	20	100	981	1,446	375	0	4,867	0	163	0	4,651	2,123	804	18	15,548
	2032	540	100	2,103	1,533	925	0	7,200	70	163	0	23,444	2,123	1,579	42	39,822
	2037	1,616	100	3,225	1,807	1,675	0	10,264	219	163	595	34,388	2,123	2,128	115	58,418
	2042	3,493	100	4,029	1,919	2,675	0	13,654	219	163	595	40,125	2,123	2,559	376	72,030

Future 2A Resource Retirements (MW) - *Cumulative*									
Zone	Milestone	Coal	Gas	Nuclear	Oil	Wind	Solar	Other	Totals
LRZ 1	2027	3,612	1,604	0	325	123	0	962	6,625
	2032	5,355	2,141	0	570	1,772	0	996	10,834
	2037	5,844	2,362	0	584	3,178	24	1,014	13,005
	2042	5,844	2,988	0	678	5,274	470	1,014	16,268

[143] See **Appendix E.2**. Pages 87 and 88. Report published November 1, 2023. As of January 2026, this is the latest information available.

5.2.2.1 Applicants' Minnesota Integrated Resource Plans

In Minnesota, all state-regulated electric utilities, such as Xcel Energy, are required to file IRPs with the Commission every two years. In addition, though not state-regulated, Great River Energy files an informational IRP which is similarly reviewed by the Commission every two years. In each IRP, utilities must identify the generation needs to serve forecasted demand plus a required reserve margin while complying with state laws for the least total costs. ITC Midwest is an electric transmission company which does not own generation or serve end-consumers; ITC Midwest does not file an IRP.

The Commission reviews and ultimately rules on each IRP. The IRP becomes the state-approved plan for generation, and the transmission grid is developed to enable the generation plan in a reliable and cost-effective manner. The Project and the MISO LRTP Tranche 2.1 Portfolio are designed to enable the approved IRPs for Minnesota and the broader Midwest region.

Xcel Energy's most recent 2024-2040 IRP was approved by the Commission on February 20, 2025.[144] The approved IRP includes:

- extending the use of the Prairie Island and Monticello nuclear plants into the 2050s and retiring all coal facilities by 2030;
- adding new renewable resources by 2030, including 3,200 MW of wind and 400 MW of solar;
- adding 600 MW of battery storage by 2030;
- adding approximately 2,100 MW of peaking and dispatchable resources by 2029, roughly half of which will come from wind, solar, and battery resources, and half from a new gas peaking plant (Lyon County) and two existing gas power purchase agreements. Xcel Energy's proposed Lyon County plant is being reviewed in a CN proceeding[145]; and
- integrating over 1,800 MW of additional distributed energy resources (e.g., distributed solar, energy efficiency, and demand response) by 2030.

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[144] *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, Docket No. E-002/RP-24-67, Order Approving Settlement Agreement with Modifications (Apr. 21, 2025).

[145] *Northern States Power Company, a Minnesota corporation doing business as Xcel Energy, has submitted a Combined Application to the Minnesota Public Utilities Commission (Commission) for the proposed Lyon County Generating Station Project. This application seeks multiple approvals, including a Certificate of Need, Site Permit, Transmission Line Route Permit, and Pipeline Routing Permit, as well as a Partial Exemption for routing the pipeline.* Docket No. 25-145.

Great River Energy's most recent 2023-2037 IRP was accepted by the Commission on March 7, 2024.[146] The 2023-2037 IRP includes plans to procure or construct more than 1,200 MW of wind power, 200 MW of energy storage, and 200 MW of solar energy capacity by 2037.[147] Great River Energy will file its next IRP in April 2026 and will analyze a much wider range of future power supply scenarios due to the current uncertainties in load growth, federal and state energy policies, resource costs, and procurement timelines.

5.2.3 Impact of Federal Policies on Midwest Generation Trends

Utilities consider many factors when determining generation plans to meet demand needs. These factors include costs, performance, and state and federal policies over a planning horizon of 15 or more years. As described in **Section 3.4.2**, utilities such as the Applicants must comply with all enacted policies. In addition, because generation plans are long-term decisions, utilities must consider the potential for future policy changes.

In 2025, the U.S. Congress enacted the One Big Beautiful Bill Act, and the U.S. Secretary of Energy issued several orders. The One Big Beautiful Bill sunsets federal tax credits for wind and solar generations,[148] prevented certain power plants in Michigan[149] and Pennsylvania[150] from closing, and exempted compliance with the Mercury and Air Toxics Standards for two years for specific coal power plants in Ohio, Illinois, and Colorado[151], amongst others.

Each presidential administration enacts policies to reflect its priorities and energy policies. **Figure 5.2-5** displays some of the key policies and priorities impacting generation plans during the past four presidential administrations. As shown on **Figure 5.2-5**, despite changes in parties, policies and orders, generation trends across the Midwest have been generally consistent over the past four federal administrations. Key policy changes are highlighted on bottom timeline.

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146 *In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan*, Docket No. ET-2/RP-22-75 (Order Accepting 2023-2037 Resource Plan and Setting Future Filing Requirements).

147 Great River Energy. 2023 – 2027 Integrated Resource Plan. Available at: https://greatriverenergy.com/wp-content/uploads/2023/03/2023-IRP-FINAL.pdf

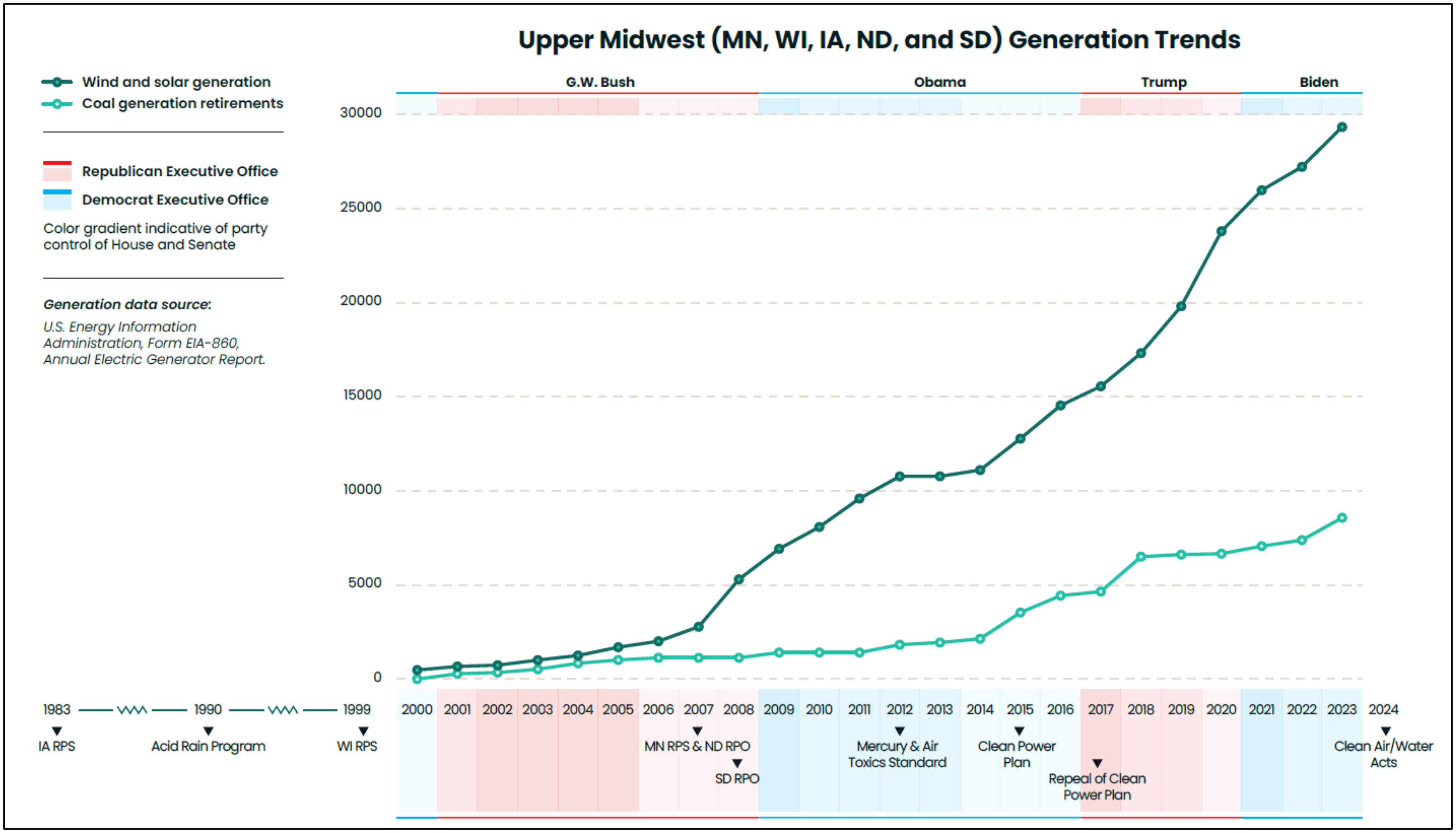
148 H.R. 1, Public Law No. 119-21.

149 United States Department of Energy. Order No. 202-25-3. Available online at: https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

150 United States Department of Energy. Order No. 202-25-4. Available online at: https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf

151 The White House. July 17, 2025, Proclamation: Regulatory Relief for Certain Stationary Sources to Further Promote American Energy. Available online at: https://www.whitehouse.gov/presidential-actions/2025/07/regulatory-relief-for-certain-stationary-sources-to-further-promote-american-energy/

Figure 5.2-5: Upper Midwest Generation Historical Trends by Federal Administration



The generation forecasts used in this Application are primarily based on state-approved IRPs and comply with Minnesota and other states' enacted policies and announced state and utility goals (see **Section 5.1** for additional details on MISO Future 2A). Nonetheless, MISO evaluated need under a scenario which considers a deceleration of generation evolution trends,[152] and found the MISO LRTP Tranche 2.1 Portfolio, which includes the Project, provides benefits in excess of costs.[153]

5.3 Evolving Electrical Demands

The Project is driven by the need to reliably serve existing, expanding, and new electrical demands from the changing generation fleet. As need for the Project is not only driven by Minnesota's demand forecast but the broader MISO region, the following sections provide details on generation forecast for Minnesota and the MISO region.

5.3.1 Base MISO Region Peak Demand and Energy Forecast

Since the late 2000s, demand growth in the Midwest has in aggregate remained relatively flat. This was initially due to the Great Recession from 2007 to 2009, then from energy efficiency programs absorbing growth, and finally, due to the COVID-19 pandemic, as shown on **Figure 5.3-1**.

Prior to 2019, MISO load forecasting relied heavily on econometric-based evaluations of gross load, using standard economic indicators such as gross domestic product, population, and employment rates. These methods, while useful, rest on the premise that historical trends and relationships between economic variables and electricity demand will persist into the future. During times of economic instability or periods of rapid industry transformation, these relationships no longer hold, requiring the development of new load forecast methodologies. In 2019, MISO developed a new set of forward-looking future scenarios to guide the LRTP and other planning studies. This effort considered a range of possible economic, political, and technological outcomes to project load growth over a 20-year study period.[154]

Current MISO forecasts (published in November 2023) indicate a 1 to 2 percent compound annual growth rate (CAGR) for the next 20 years. MISO-wide base peak gross demand and annual energy forecasts used for analysis in this Application assume a 1.14 percent and 1.25

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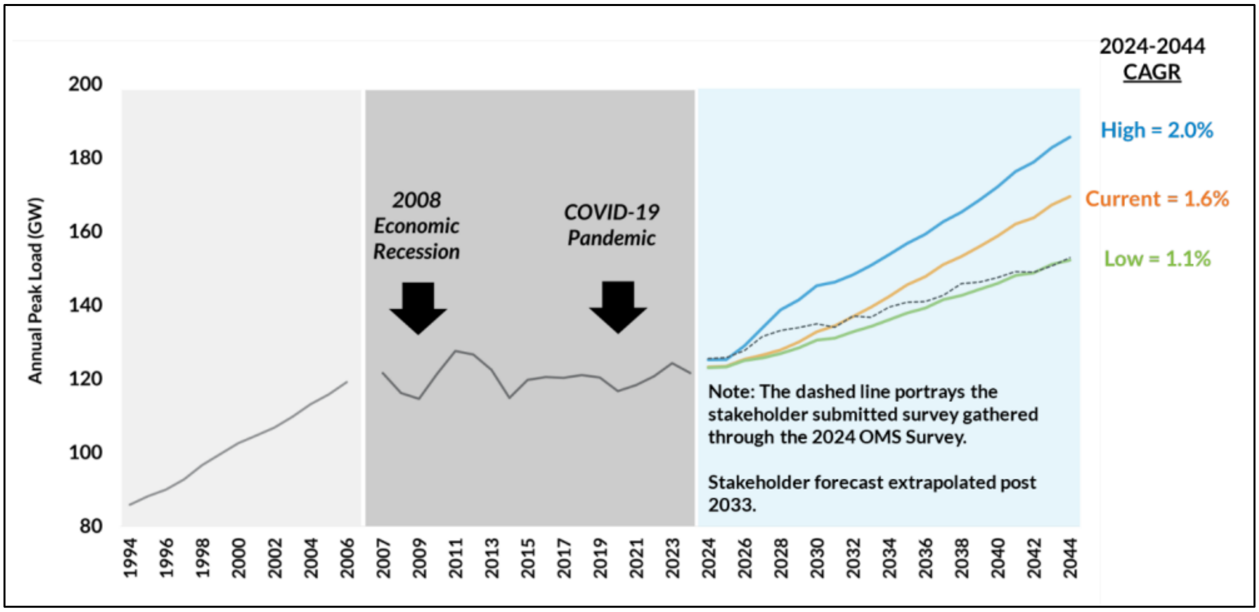
152 Details on MISO's Future 1A can be found in **Appendix E.2.**

153 The MISO LRTP Tranche 2.1 Portfolio has a benefit to cost ratio of 1.2 to 2.2 under MISO Future 1A. See **Appendix E.1**. Page 143.

154 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf. Page 8.

percent CAGR, respectively, growing MISO gross coincident peak demand by approximately 25 percent of current levels and gross annual energy by 28 percent over the next 20 years.[155]

Figure 5.3-1: MISO Region Net Peak Load Expectations Over Time (1994 to 2044)[156]



For Minnesota and the surrounding region (Local Resource Zone 1), MISO forecasts total load to peak at approximately 24 GW in 20 years; compared to a 2023 peak load of approximately 19.4 GW.[157] The load growth rate is consistent with the Organization of MISO States Survey as shown on **Figure 5.3-1**.

Demand forecasts do not include the potential for growth attributed to data centers and other industrial demands beyond what was firmly committed in 2023. MISO predicts that the addition of these inputs could increase demand by as much as three-fold.[158] Base forecast demand growth is driven by multiple factors including:

- growth and expansion of existing residential, commercial, agriculture, and industrial electricity use;
- new and expanded manufacturing;

155 See **Appendix E.2**. Page 31, Figures 25 and 26.

156 Id. Page 4.

157 Id**.** Page 32. MISO Local Resource Zone 1. 2023 peak demand from MISO production cost models.

158 MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

- the electrification of heating and cooling, appliances, transportation and additional devices in homes and businesses; and
- the initial start of emerging industries like data centers and artificial intelligence applications.

The development of data centers is substantially impacting the transmission system. In 2025, multiple data center projects were publicly announced in the vicinity of the Project including but not limited to Meta's UMore Park,[159] Project Skyway,[160] and the Nobles County Powered Data Park.[161] The Applicants and other Minnesota transmission owners continue to process these and additional requests from large commercial loads, ranging from tens of MWs to over 1,000 MW each. While not all will come to fruition, for perspective, if even one large load (e.g., 1,000 MW) is interconnected, it would increase state demand levels by more than 5 percent. These potential large load additions are not included in the MISO base demand forecast used to justify the need for the Project but are examples of the type and scale of potential future load additions.

MISO's base demand forecast starting point is developed by aggregating each MISO member's forecasts. Great River Energy's most recent peak demand and annual forecast may be found in Great River Energy's 2024 Annual Electric Utility Forecast Report filed on July 1, 2024,[162] which is provided in **Appendix F.1.** Xcel Energy's most recent peak demand and annual forecast may be found in Xcel Energy's 2024 Annual Electric Utility Forecast Report filed on July 1, 2024,[163] which is provided in **Appendix F.2**.

5.3.2 MISO Demand and Energy Forecast Ranges

To consider a broader range of potential outcomes to bookend uncertainty, MISO creates multiple demand and energy forecasts from the base forecast in the Futures (see **Section 5.1** for details on MISO's Futures). The load forecasts used in MISO's Futures consider different adaptation rates for demand response, energy efficiency, and distributed generation (e.g.,

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159 Minnesota Employment and Economic Development. Governor Walz Announces Meta Will Build New Data Center in Rosemount. Available online at: https://mn.gov/deed/newscenter/press-releases/?id=1045-614051#:~:text=PAUL%2C%20MN%5D%20%E2%80%93%20Governor%20Tim%20Walz%20today,million%2C%20715%2C000%2Dsquare%2Dfoot%20data%20center%20in%20Rosemount%2C%20supporting.

160 Project Skyway. Available online at: https://pineislandskyway.com/.

161 Geronimo Power. Nobles County Powered Data Park. Available online at: https://geronimopower.com/in-development/nobles-county-powered-data-park/.

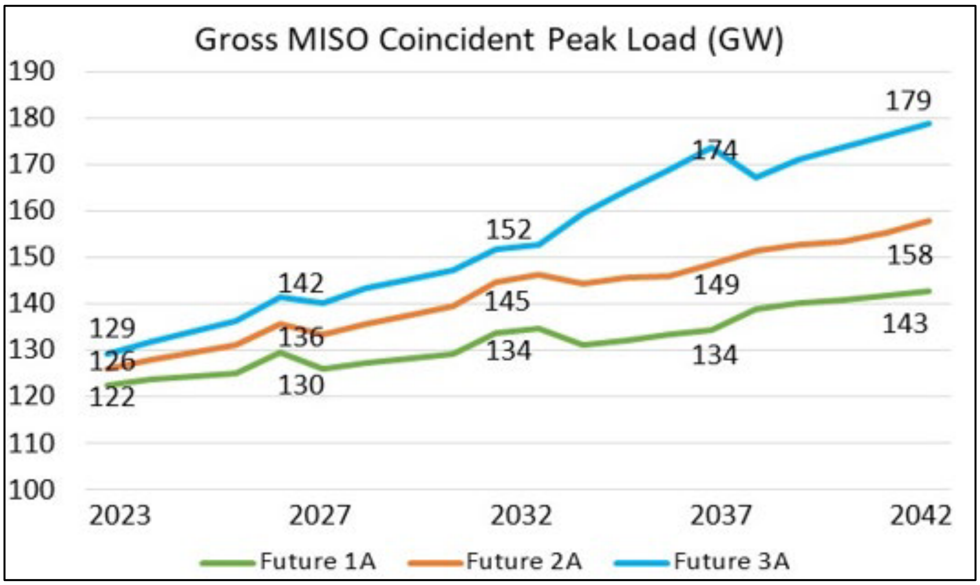
162 Id.

163 Docket No. E999/PR-23-11.

behind-the-meter generation) and differing impacts of 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.

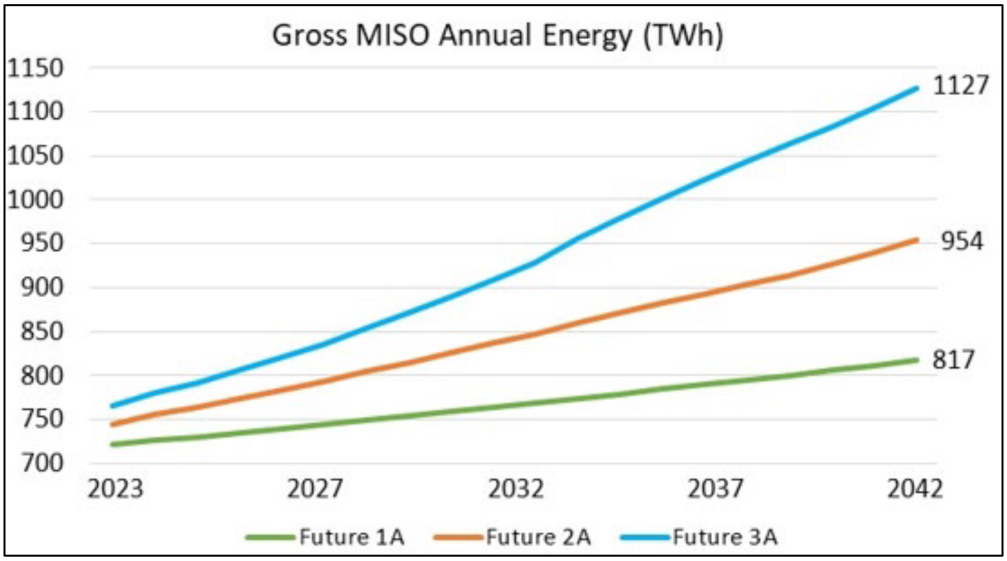
The MTEP24 Futures' gross peak demand and annual energy forecast for the MISO Market Footprint are provided on **Figure 5.3-2** and **Figure 5.3-3**, respectively.

Figure 5.3-2: MISO Market Footprint MTEP24 Futures Gross Coincident Peak Load Forecast [164]



[164] See: **Appendix E.2.** Page 31.

Figure 5.3-3: MTEP24 Futures MISO Market Footprint Annual Energy Forecast [165]



The associated peak demand and annual energy CAGR are provided in **Table 5.3-1**.

Table 5.3-1 MTEP24 Futures 20-Year CAGR[166]		
MTEP24 Future	**Annual Gross MISO Coincident Demand 20-Year CAGR (percent)**	**MTEP24 Future**
Future 1A	0.77	0.63
Future 2A	1.14	1.25
Future 3A	1.63	1.95

MISO's demand forecast used in planning modeling is a gross forecast. It does not include the net reductions from demand response or distributed generation as is provided in the Applicants' Annual Forecast Reports. MISO's planning process explicitly models demand response and distributed generation as a supply-side resource. MISO estimates that the Future 2A demand and energy CAGR, net of demand response and distributed generation (i.e., indicative of load that will be realized at the meter), is approximately 0.8 percent.[167]

165 Id.

166 Id. Page 27

167 Id. Page 27.

Details on how conservation and energy efficiency was considered by MISO in the evaluation of the Project can be found in **Appendix G**. Additional details on MISO's MTEP24 load forecast can be found in **Appendix E.2**, the MISO Series 1A Future Report.

6 HOW PROJECT ADDRESSES MULTIPLE DEFINED NEEDS

The Studied Projects[168] enable the transmission grid to move more energy farther distances and to-and-from more locations than the existing transmission grid's capabilities. As described in this Chapter, the Studied Projects reliably increase the capacity of the grid in a cost-effective manner while, at the same time, supporting the generation transition driven in part by state policy. This Chapter discusses the engineering and analyses undertaken to demonstrate how the Studied Projects meet these three needs.

- **Section 6.3 - Reliability Need:** The Studied Projects mitigate projected reliability overloads of the existing transmission grid to satisfy NERC reliability standards, to enable the regional transfer of the energy needed today and into the future, and to serve customer and member electricity demands every hour of every day.
- **Section 6.4 - Cost-Effectiveness/Economic Benefits:** The Studied Projects provide economic benefits to customers and members by reducing transmission congestion and providing access to lower-cost generation.
- **Section 6.5 - Enabling Generation Transition:** The Studied Projects enable aging generation to retire and be replaced by new generation, including carbon-free generation which helps meet state policy objectives. The Studied Projects also contribute to more efficient use of existing generation resources.

Table 6.0-1 summarizes the metrics demonstrating how the Studied Projects enhance reliability, provide economic benefits, and support state policy.

Table 6.0-1
How the Studied Projects [a] Meet Reliability, Economic, and State Policy Needs

Category	Measure	Description
Reliability Need (**Section 6.3**)	Solves reliability issues of 102 different facilities – addressing 1,313 NERC reliability violations	Ability to maintain NERC reliability standards [b] and reliably transfer energy across the region to serve load.
	1,300 GWh mitigated unserved demand	Demand over a year no longer at high risk of not being served.
	3,010 MW load enabled	Load included in "base" forecast which would not be reliably served without the Studied Projects.
	Addresses multiple dynamic stability instability issues	Ability of the system to reliably transfer energy and recover after an unexpected event.

[168] As discussed in **Section 1.4**, the Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those LRTPs outside of Minnesota). This group of projects is referred to as the "Studied Projects."

Table 6.0-1
How the Studied Projects [a] Meet Reliability, Economic, and State Policy Needs

Category	Measure	Description
Cost Effectiveness/ Economic Benefits (**Section 6.4**)	$7.7 billion to $25.3 billion in economic savings over first 20 years of service	Savings from decreasing congestion, providing access to lower cost generation, carbon reductions, and avoided reliability needs.
	2 percent to 11 percent system congestion relief	Reduction in transmission system "bottlenecks" which improves system reliability and access to lower cost generating resources.
Enabling Generation Transition (**Section 6.5**)	5.6 TWh to 7.2 TWh reduced curtailment (annual)	Reduction in "wasted" energy from generators which safeguards system reliability, improves system efficiency, and reduces emissions.
	Enabled generation: 24 GW	New carbon-free generation which with the Studied Projects can be reliably interconnected to the grid.
	Reduction in CO_2 emissions = 3.6 million tons (annual)	Studied Projects-enabled generation interconnections and reduced curtailment helps utilities to meet Minnesota's Carbon-Free by 2040 law.

[a] The Studied Projects definition used for the need analysis is LRTP Numbers 22 through 26, see **Section 6.1** for additional information.
[b] NERC. Reliability Standards. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL001-5.pdf.

The Studied Projects are a "step-change" in the transmission grid that is warranted given the magnitude of the reliability needs of the regional grid and Minnesota's energy demand and generation resources. For context, the Studied Projects:

- mitigate reliability overloads of 102 different transmission facilities – even one overload is not acceptable per NERC standards and would require mitigation;[169]
- enable approximately 3,010 MW of forecasted load to be reliably interconnected and served in Minnesota and the surrounding region[170] over the next 20 years – Minnesota's peak demand in 2024 was approximately 10,790 MW and is expected to grow to 12,455 MW by 2042;[171] and
- support the reliable interconnection of approximately 24 GW of new nameplate generation in Minnesota and the surrounding region – approximately 18 GW of

[169] See **Section 6.3.1** for additional details.

[170] The Studied Projects enabled demand to be reliably served in Minnesota, Iowa, South Dakota, North Dakota, and Wisconsin.

[171] MISO Future 2A models – Load growth assumptions included in **Appendix E.2**.

nameplate generation is installed in Minnesota as of 2023 and is expected to increase to 34.5 GW by 2042.[172]

The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load every hour of every day. As Minnesota and other states increasingly rely on weather-dependent generation resources and load becomes more variable, the ability to transfer energy to follow weather patterns is critical to system reliability. To meet projected reliability needs with the expected generation fleet, Minnesota needs to transfer upwards of 10 GW more energy, as shown on **Figure 6.0-1** and **Figure 6.0-2**.

As detailed in **Section 4.6**, the Studied Projects, in conjunction with the MISO LRTP Tranche 2.1 Portfolio, help provide the necessary transfer capability needs to support reliability. The Project and the MISO LRTP Tranche 2.1 Portfolio will create a network of transmission backbone connections throughout the Midwest that will ultimately be interconnected with the existing 765 kV network (see **Figure 3.2-1**), allowing Minnesota to meet its electrical needs. Additionally, the Project's 765 kV voltage provides the transfer capability needed in a manner which is more cost-effective and less impactful in terms of land-use than other alternatives (see **Section 7.2**).

[172] Current generation level source: EIA. State Electricity Profiles – Minnesota. Available at: https://www.eia.gov/electricity/state/minnesota/. Future generation level source: MISO Future 2A, see: **Appendix E.2.**

Figure 6.0-1: Map of Maximum Transfer Needed

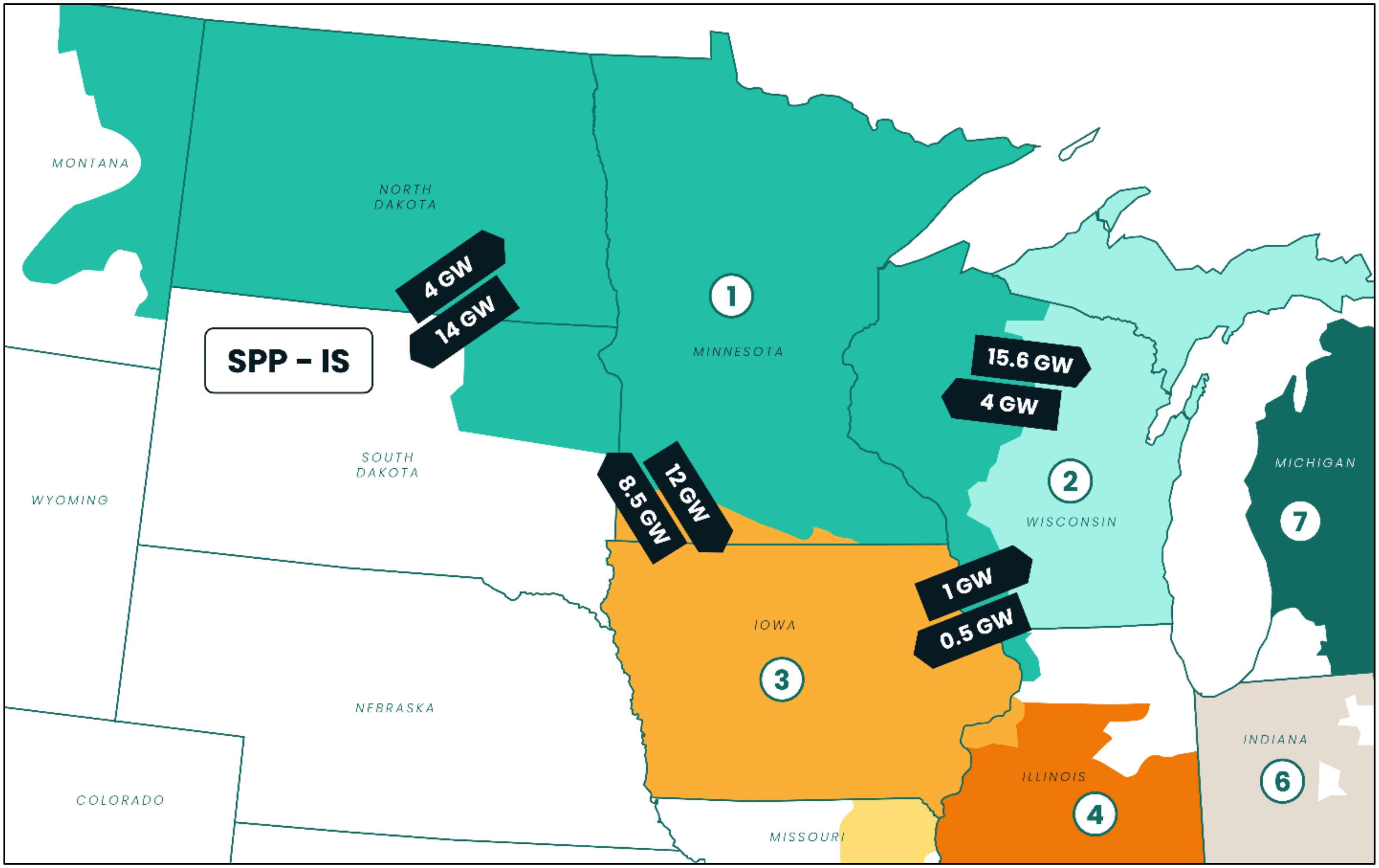
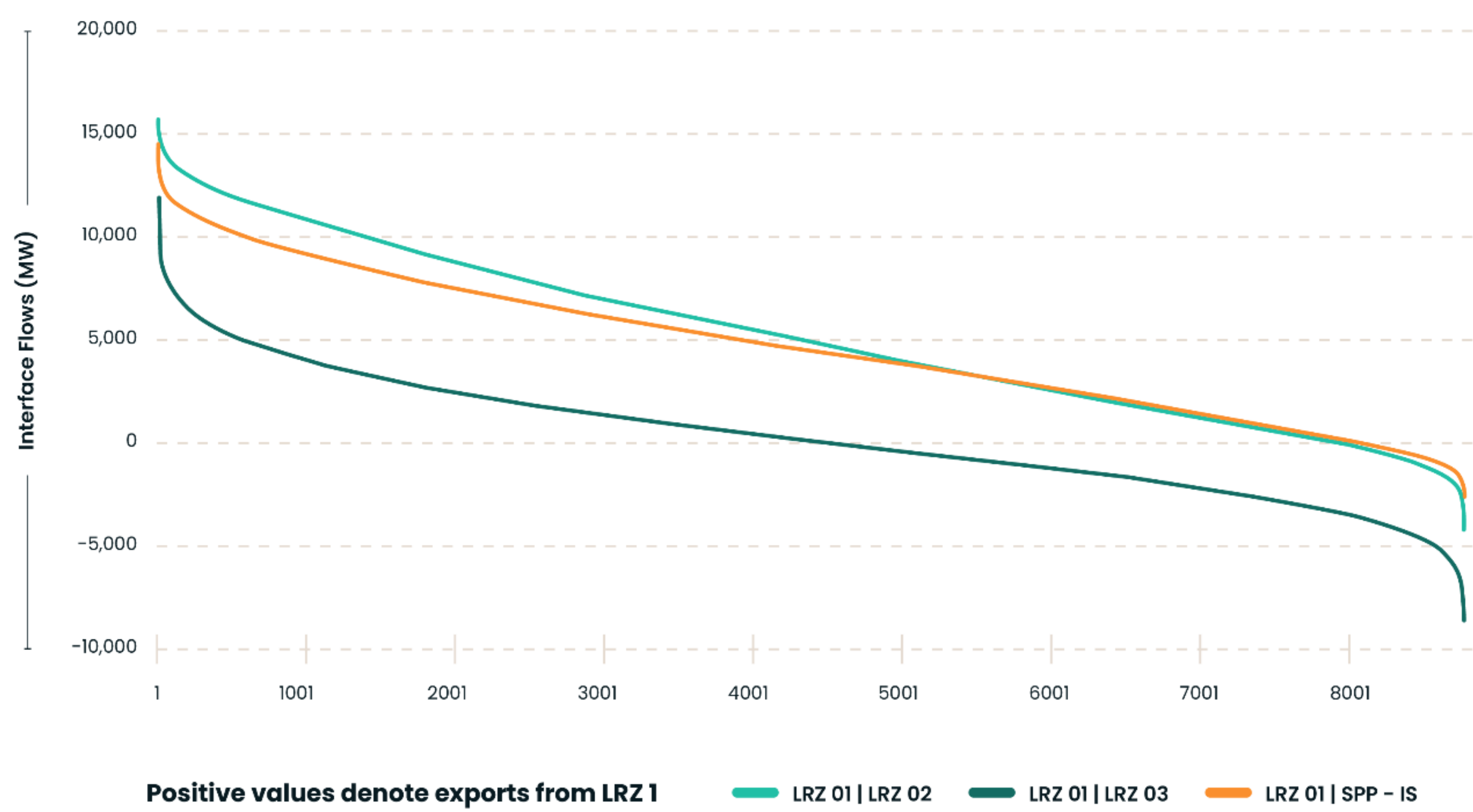


Figure 6.0-2: Annual Duration Curve of Transfer Needed



6.1 Scope of Analysis

This Application seeks a CN for the Minnesota portions of MISO LRTP Tranche 2.1 project numbers 22, 23, 24, and 25.[173] Electricity flows freely across state lines, and one of the primary drivers for the Project is to be able to move energy across multiple states, including but not limited to Minnesota, Iowa, South Dakota, and Wisconsin. Thus, to quantify the reliability benefits of the Project, it is necessary to study the Project and its practical extensions into neighboring states. For the purposes of the need analysis in this Application, Applicants studied the entirety of LRTP numbers 22 through 26 (including the portions of those transmission lines outside of Minnesota). As noted, this group of projects is referred to as the "Studied Projects."

The Studied Projects create a contiguous transmission path with on and off ramps at existing 345 kV high-voltage hubs in Minnesota. Combined with the rest of the LRTP Tranche 2.1 Portfolio, this provides connections between generation and load. Eliminating any segment would create a break in the high capacity 765 kV paths between these 345 kV hubs.

Each Studied Projects segment is needed and is necessary because the LRTP projects work together to address system needs.

- **LRTP 22:** The westernmost line, from South Dakota to Lakefield Junction in Minnesota, is needed to tap into high-potential generation areas in southwest Minnesota, South Dakota, and North Dakota, and to transfer excess generation to load areas to the east. Conversely, this segment enables energy to flow to South Dakota and North Dakota from Minnesota from other points east when local generation is not available to serve the local load.
- **LRTP 23:** The connection from Minnesota to Iowa provides connections to high-potential generation areas. Additionally, this line creates a loop across central Iowa, which serves as contingency backup for the Studied Projects as required by NERC reliability standards. Likewise, the Studied Projects serve as a backup in the event of an outage of one of the MISO LRTP Tranche 2.1 765 kV projects in central Iowa to central Illinois.
- **LRTP 24:** The east-west 765 kV line across southern Minnesota from Lakefield to Pleasant Valley, and then north to North Rochester is the primary "artery" for the

[173] See **Appendix E.1.** Page 75. LRTP 22: Big Stone South (South Dakota) – Brookings County (South Dakota) - Lakefield Junction 765 kV. LRTP 23: Lakefield Junction - East Adair (Iowa) 765 kV. LRTP 24: Lakefield Junction - Pleasant Valley - North Rochester 765 kV. LRTP 25: Pleasant Valley - North Rochester - Hampton [Corner] 345 kV.

Studied Projects, connecting Minnesota's high-voltage hubs to both generation sources and load sinks.

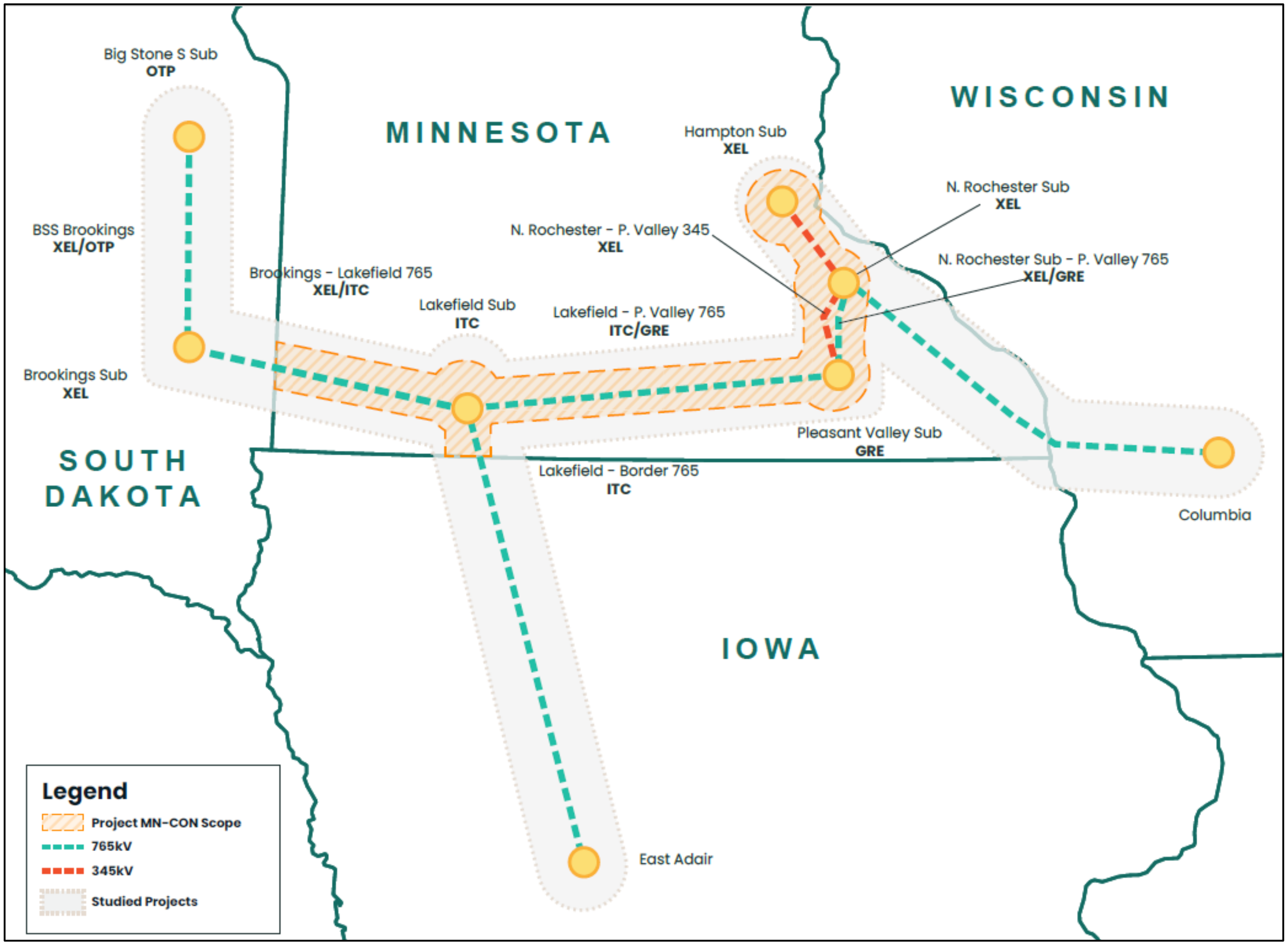
- **LRTP 25:** The double-circuit 345 kV line between Pleasant Valley and North Rochester is needed to meet NERC reliability standards as a contingency backup when the parallel 765 kV line between Pleasant Valley and North Rochester is out of service. The North Rochester to Hampton double-circuit 345 kV line connects the 765 kV grid to the greater Twin Cities electrical network.
- **LRTP 26:** Commission approval of LRTP 26 (i.e., North Rochester to Columbia, Wisconsin) is being sought in a separate CN application.[174] LRTP 26 works with LRTP 22 through 25 (i.e., the Project) to move energy between high-renewable generation areas in Minnesota, South Dakota, and Iowa to eastern demand centers. Conversely, LRTP 26 enables power to move from Wisconsin and eastern generation sources to Minnesota and South Dakota when local generation is not available.

MISO studied LRTP 22 through 26 together. Consistent with MISO's analysis, the need analysis performed by the Applicants in support of this Application includes LRTP 22 through 26, the Studied Projects, as shown in the grey buffered lines on **Figure 6.1-1**.[175]

[174] North Rochester – Columbia 765 kV Transmission Project. LRTP 26. Docket No. ET3, E002/CN-25-121.

[175] See **Appendix E.2**. Page 144.

Figure 6.1-1: Studied Projects Definition for Need Analysis



6.2 Study Methodology

The Applicants performed the need analysis for the Studied Projects based on industry-standard practices that are consistent with MISO's federally approved tariff.[176] The following sections detail the study processes, key assumptions, and methodology used to both identify and quantify the need for the Studied Projects.

6.2.1 Study Assumptions

The analysis used to determine and quantify the need for the Studied Projects was performed comparing two different cases:

- **Project case:** All MISO-approved projects (including the MISO LRTP Tranche 2.1 Portfolio).
- **Pre-Project case:** All MISO-approved projects, less the Studied Projects.

Because the only difference between each case is the addition of the Studied Projects, all resulting changes in system performance are directly attributed to the Studied Projects.

The underlying transmission topology used for the Applicants' analyses includes all transmission projects approved by MISO as of January 1, 2025, including the MISO LRTP Tranche 2.1 Portfolio and Joint-Targeted Interconnection Queue (JTIQ) projects.[177] The JTIQ Portfolio includes:

- Bison – Hankinson – Big Stone South 345 kV;
- Lyon Country – Lakefield 345 kV;
- Raun – S3452 345 kV;
- Auburn – Hoyt 345 kV; and
- Sibley 345 kV Bus Reconfiguration.

MISO's analysis of the MISO LRTP Tranche 2.1 Portfolio was performed prior to MISO's approval of the MTEP24 projects, including the JTIQ projects and, therefore, MISO's analysis did not include the JTIQ projects in the Project and Pre-Project case. MISO performed a sensitivity analysis including the JTIQ projects and found that the MISO LRTP Tranche 2.1 Portfolio's need is

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176 MISO Tariff Attachment FF. Available at: https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

177 MISO. Joint Targeted Interconnection Queue Study. Available at: https://cdn.misoenergy.org/JTIQ%20Report623262.pdf.

independent of the JTIQ projects (i.e., needed regardless of the JTIQ portfolio's status) and that the JTIQ projects complement the MISO LRTP Tranche 2.1 Portfolio.[178]

Unless otherwise noted, the Applicants performed all analyses using MISO's Future 2A scenario assumptions, as detailed in **Section 5.1**. Future 2A assumptions are based on known and state-approved policies and integrated resource plans. Load forecasts are based on a mid-level growth rate, which includes only known firm load additions from data centers. No speculative data center additions are included in the demand forecasts. Mid-level demand forecasts are based on the utility demand and conservation forecasts, which for the Applicants are described in **Section 5.3**. MISO's Future 2A assumptions were developed through an open and transparent stakeholder process, as prescribed in MISO's federally approved tariff and FERC Orders 890 and 1000.

6.2.2 Studies Undertaken to Demonstrate How Project Meets Reliability Needs

Applicants used multiple models and processes, each designed to assess different necessary system attributes. Models and processes are generally grouped into three primary categories, the details of each are further described in the subsequent sections:

- **Steady-State Reliability -** Assesses potential overloads of the transmission grid (i.e., line flows or voltage levels outside physical capabilities). Analysis is detailed but is limited to a single snapshot in time (e.g., 1 hour of the year). Multiple cases (e.g., hours), each looking at a different "worst case" scenario, are used to provide a representative sample of system conditions, helping ensure reliability is maintained for the entire year.
- **Production Cost** – Simulates an 8,760 hourly dispatch of load and generation over a year to determine both reliability implications (e.g., inability to fully serve a load at a specific time) and market economics (e.g., costs to serve load). Production cost models assess system needs for all hours of a year but not to the same level of detail as steady-state models.
- **System Stability** – Assesses sub-minute and sub-second reliability implications of the system. Models determine the ability of the system to come back to a state of equilibrium in terms of frequency and voltage following an event (e.g., loss of the generator or a transmission line). Models are extremely detailed but are limited in what can be monitored (i.e., assessed) and are a single snapshot

[178] **Appendix E.1.** Page 39.

in time. Similar to steady-state reliability models, stability analysis is performed using multiple cases, each looking at a different “worst case” scenario, to provide a representative sample of system conditions, helping ensure reliability is maintained for the rest of the year.

As each model is designed to analyze different system reliability attributes, the combination of results not only most accurately quantifies the need for the Project but is the best indication of system performance that will be experienced by the operators of the grid.

Models used by the Applicants are consistent with MISO’s base models, tools, and assumptions. Unless otherwise noted, the primary difference between the Applicants’ analysis and MISO’s analysis is that the Applicants’ analysis is specific to the Studied Projects. MISO’s analysis is based on the combined MISO LRTP Tranche 2.1 Portfolio.

6.2.2.1 Steady-State Reliability Analysis Methodology

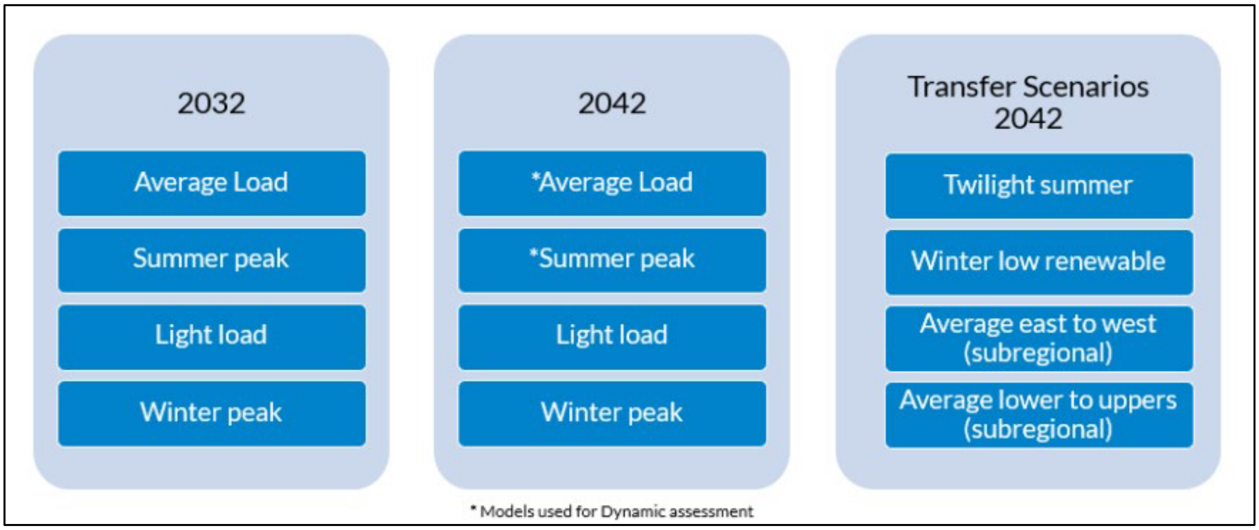
MISO, as well as the Applicants in this Application, conducted the steady-state reliability analysis for forecast years 2032 and 2042, under four different load levels and generation levels and four different transfer scenarios, as shown on **Figure 6.2-1**. Per MISO: “these broad base models encompassed multiple uncertainties around variable renewable energy output, load profiles, and seasons, thus providing the platform to perform a wide range of reliability studies.”[179] Unless otherwise noted, reported mitigated reliability issues are the sum total of unique issues mitigated under all scenarios.

The Applicants conducted steady-state reliability modeling using Power System Simulator for Engineering (PSSE) and Transmission Adequacy and Reliability Assessment (TARA) – both industry standard reliability software packages.

To develop non-wire alternative solutions to steady-state reliability issues, the Applicants used the Electric Power Research Institute’s (EPRI) Controlled Planning Expansion Tool (CPLANET). EPRI is an independent, nonprofit organization that conducts research and development related to the generation, delivery, and use of electricity. CPLANET is a reliability optimization tool which inputs a reliability case and determines optimal (e.g., minimum) generation additions or load reductions necessary to mitigate reliability issues.

[179] **Appendix E.2**. Page 14.

Figure 6.2-1: MISO Reliability Model Scenarios[180]



The Applicants used a steady-state reliability analysis to quantify the following for the Studied Projects:

- Mitigated NERC reliability violations (MISO-performed): **Section 6.3.1.**
- Load enabled (Applicants-performed): **Sections 6.3.3** and **6.6.2.**
- Reduced reliability impacts due to lower-probability high-impact events (Applicants-performed): **Section 6.3.4.**
- Enabled generation (MISO- and Applicants-performed): **Section 6.5.1.**
- Reduced system losses (Applicants-performed): **Section 6.6.3.**

6.2.2.2 Production Cost Analysis Methodology

MISO, and the Applicants in this Application, conducted production cost analyses using PROMOD for forecast years 2037 and 2042 using MISO's Future 2A. PROMOD is an industry standard production cost model which uses a security constrained economic commitment and dispatch algorithm, similar to the MISO market operations, to project 8,760 hourly generation outputs and line flows in compliance with NERC single contingency (or, N-1) standards.

The Applicants conducted post-processing of PROMOD data (e.g., calculation of adjusted production costs savings) consistent with MISO's defined processes and industry standards.

[180] Id. Page 14, Figure 2.8.

MISO and the Applicants' economic benefit calculations excluded federal tax incentives for renewable generation (e.g., production tax credits).[181] The Applicants used production cost analysis in this Application to quantify the following for the Studied Projects:

- Reduction in unserved demand (Applicants-performed): **Section 6.3.2.**
- Congestion and fuel savings (Applicants-performed): **Section 6.4.2.**
- Reduction in generation curtailment (Applicants-performed): **Section 6.5.2.**
- CO_2 emissions reduction (Applicants-performed): **Section 6.5.3.**

6.2.2.3 Stability Analysis Methodology

The Applicants conducted the voltage and dynamic stability analysis in this Application. As further detailed in **Appendix E.3**, the stability analysis used four different planning scenarios for the planning year 2042. These planning scenarios considered different system load conditions, generation portfolio mix, and transmission interface levels:

- The Light Load scenario represents off-peak system conditions, characterized by a high proportion of renewable energy serving the MISO load.
- The Peak Summer Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during summer months.
- The Peak Winter Load scenario represents a scenario with the highest load and highly stressed conditions expected to occur during winter months.
- The Average Load scenario represents a highly stressed scenario characterized by the highest angular separation across the system, lowest inertia (because of lowest conventional generation, both in absolute terms and by percentage), lowest short circuit current contribution, and highest renewable penetration (meaning that renewables are serving most of MISO load and is the most severe case due to the required transfers of generation across long distances to serve load).

The Applicants created a sensitivity scenario for each of the planning scenarios above, with the generation portfolio shifted from renewable resources to conventional synchronous generation-based resources.

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[181] See **Appendix E.2**. Page 136.

The starting point for the cases used in this analysis was the Average, Light Load, Summer, and Winter 2042 cases that MISO created for LRTP Tranche 2.1 Portfolio analysis. The Voltage Security Assessment Tool 24.0 and the Transient Security Assessment Tool, both industry standard tools, were used to analyze voltage and dynamic stability.

The Applicants used stability analysis in this Application to quantify the following for the Studied Projects:

- Improvement in stability margin (Applicants-performed): **Section 6.3.5**.

6.3 Reliability Need

The Studied Projects are needed to mitigate overloads of the transmission grid to comply with NERC's TPL-001 reliability standards and to continue to serve customer and member demands every hour of everyday. The following sections detail and quantify how the Studied Projects are needed to support system reliability by:

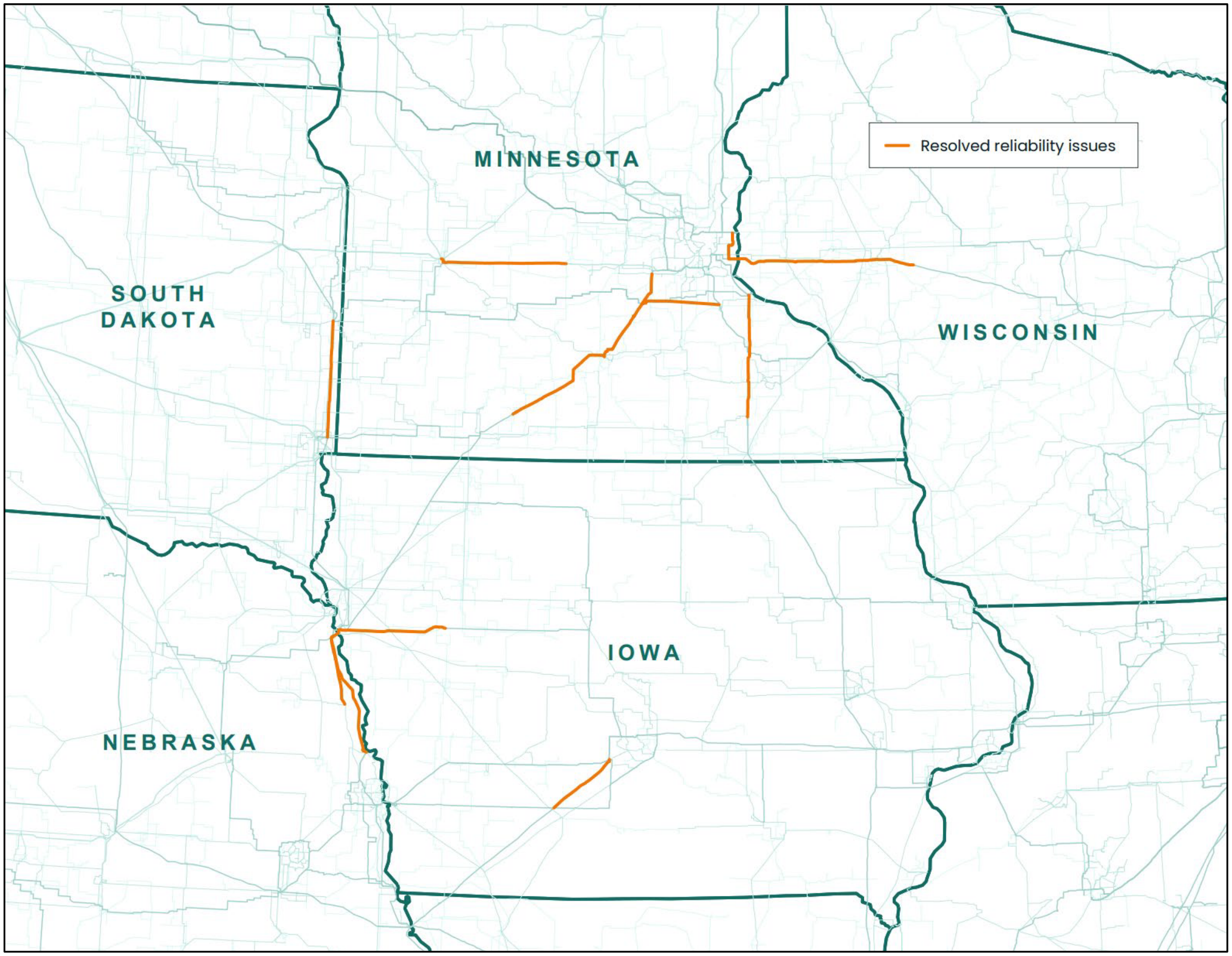
- **NERC Reliability:** Mitigates transmission system overloads of 102 different system facilities as defined by NERC reliability standards **(Section 6.3.1)** and overloads of 24 additional transmission system facilities under lower-probability high-impact events **(Section 6.3.4)**;
- **Energy Adequacy:** Allows approximately 1,305,000 MWh of Minnesota load to no longer be at expected risk of being unserved in the future **(Section 6.3.2)**;
- **Enabled Demand:** Enables approximately 3,010 MW of forecasted demand to be reliably served **(Section 6.3.3)**; and
- **System Stability:** Improves transfer capability and address system instability issues **(Section 6.3.5)**.

6.3.1 NERC Reliability Analysis

The electrical grid is planned to meet NERC reliability standards. The Studied Projects eliminate expected reliability overloads of 102 different facilities, 27 of which are 200 kV or higher – addressing 1,313 reliability issues as defined by NERC.[182] The most significant NERC steady-state reliability overloads addressed by the Studied Projects are shown in **Figure 6.3-1**.

[182] MISO. Details in **Appendix E.4**. **Appendix E.4** contains the full reliability results for Table 2.13 (page 85) and Table 2.102 (page 95) in **Appendix E.1** (MTEP24 Chapter 2: Regional/Long Range Transmission Planning). **Figure 6.3-1** combines Figure 2.89 (Page 86) and Figure 2.103 (Page 96) in **Appendix E.1**.

Figure 6.3-1: Map of Top Steady-State Reliability Issues Mitigated by the Studied Projects



NERC national reliability standards require appropriate mitigation for each reliability issue, also referred to as a violation. Reliability is most stressed when there are large geographic differences in generation output (e.g., high generation output in South Dakota and western Minnesota, but low generation output in Wisconsin and to the east – and vice versa) leading to high transfers in summer average load and winter conditions. Under those conditions, the existing transmission grid is incapable of moving the necessary amounts of energy, resulting in overloads of the existing east-west transmission paths in the Studied Projects area, for contingencies of lines in the same area.

The Studied Projects mitigate these reliability issues by creating a new high-capacity path to move power to, through, and out of Minnesota and into the broader Midwest region. Without the Studied Projects, the existing 345 kV grid is simultaneously facilitating both intra- and inter-state transfers. The Studied Projects create a new low impedance path which pulls power from the 345 kV and lower-voltage grid, avoiding overloads, and allows the existing grid to collect, move, and distribute power primarily intra-state, while the 765 kV facilities facilitate long-distance bulk power transfers to adjacent states and beyond.

In addition, the Studied Projects play a key role in the broader MISO LRTP Tranche 2.1 Portfolio, which eliminates NERC reliability issues across the Midwest as discussed in **Section 4.6.1**.

While the Applicants have designed the Project to be in-service at all times, NERC reliability standards require that the transmission grid be able withstand a loss (e.g., outage) of any transmission line, including the transmission lines that are part of the Studied Projects. When a 765 kV transmission line from the Studied Projects is out of service, the existing and planned 345 kV grid (to include the 345 kV circuit between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation) will serve as a required contingency backup to maintain system reliability standards.

6.3.1.1 Supporting Local Reliability in Southern Minnesota

The Project supports reliability for the Midwest region and southern Minnesota alike. The Studied Projects are needed to address the reliability issues of the grid detailed in **Section 6.3.1** – to move generation from where it is being produced to where it is needed – including southern Minnesota. The Project establishes a new transmission backbone connection at three substations spread across southern Minnesota. MISO optimally selected these substations because each is a hub – meaning each substation has strong connections to the 345 kV, 230 kV, and lower voltage transmission lines which directly serve the communities in the vicinities of these substations. Each Project substation serves as a collection point for sending generation to other areas and serving local demand. Whether a Project substation is importing (i.e., serving local load) or exporting (i.e., sending excess generation) can change by the moment based on system conditions.

Many of the communities where the Project is located have vast generation resources, including wind, solar, and natural gas peaking plants. Wind and solar generation are variable in nature, meaning output is dependent on weather patterns. On average, wind and solar generators are outputting roughly half of the time; typical capacity factors range from 35 percent to 55 percent. Natural gas peaking plants are dispatchable resources that can be called upon in an instant to serve demand but are typically the highest-cost resource in the MISO market. By design and economics, these generators typically produce electricity less than 10 percent of the year. When these local generators are not producing energy, power is being shipped into southern Minnesota from different areas – increasingly from many states away. This shared pool of generation helps ensure a steady flow of electricity in a cost-efficient manner.

Electricity demands in southern Minnesota are also evolving. Southern Minnesota has a diverse array of industries including agriculture, manufacturing and industrial, commercial, and medical, many of which are increasingly electrifying (i.e., increasing electrical usage). Other emerging industries such as data centers have potential to further increase electrical demands.

In the next decade, as the Midwest generation fleet continues to evolve and demands for electricity grow, the existing grid is not capable of moving the necessary amounts of power into southern Minnesota when local generation is not available. The system overloads impacting area reliability are shown on **Figure 6.3-1**. It should be noted that system overloads impacting an area's reliability are commonly not located in that area, as the grid is a network in which the "weakest link" can prevent generation from being imported from another area.

Likewise, when southern Minnesota has generation output in excess of what is needed locally, the existing grid is incapable of fully exporting that energy so it can be sold to other areas. The result is this excess energy is currently curtailed (or, wasted) at times.[183] The inability to fully export excess energy has economic consequences for southern Minnesota through the inability to sell a product and potential reliability consequences for other areas who need power to serve their load.

The Studied Projects address both congestion and curtailment issues as described in **Section 6.4.2** and **Section 6.5.2**, respectively. The Studied Projects expand the grid's capacity to

[183] The Commission examined generation curtailment and transmission congestion in southern Minnesota (Nobles County). Docket No. E999/CI-24-316.

continue to provide reliable service to southern Minnesota for today’s and tomorrow's electrical needs.

6.3.2 Energy Adequacy – 8,760 Reliability

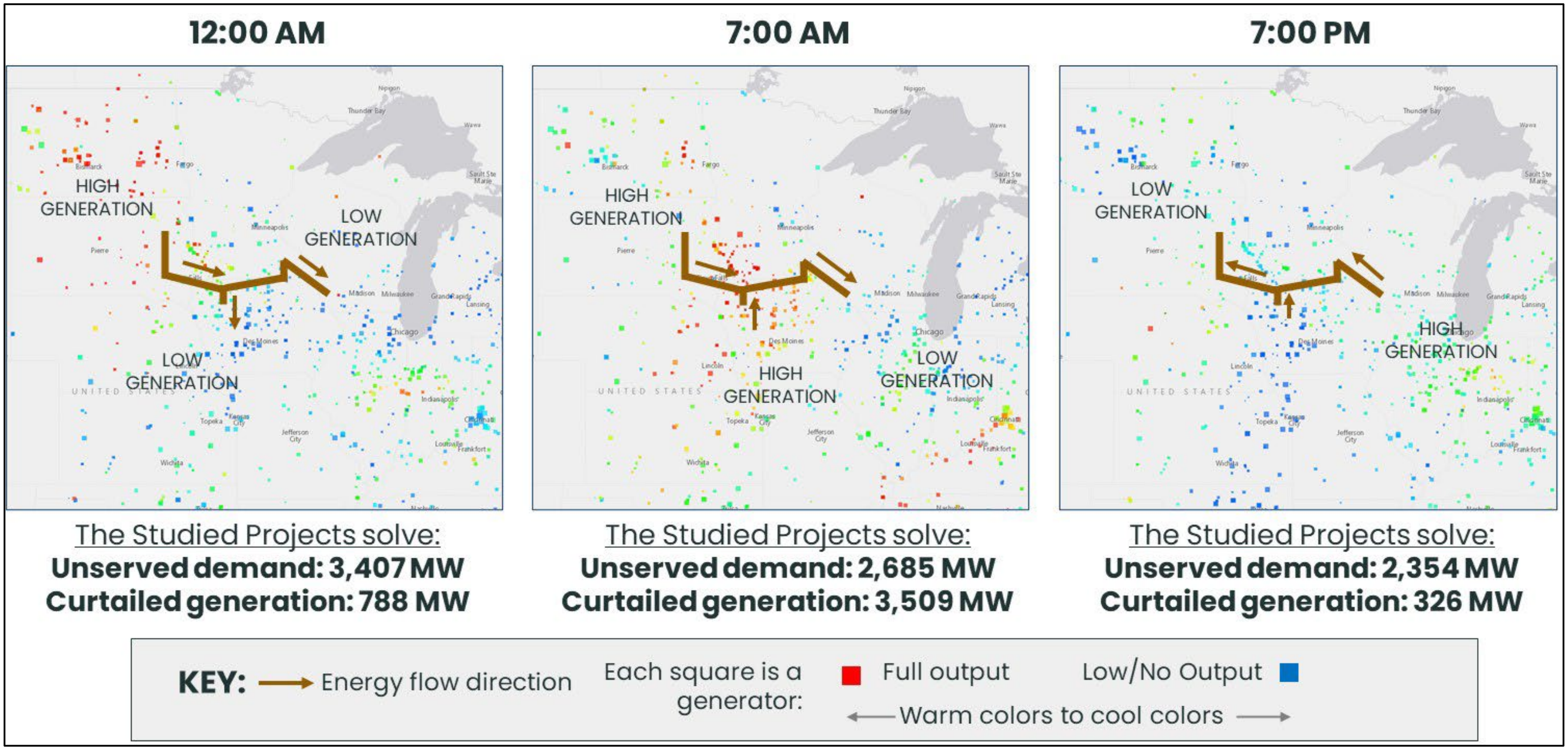
The Studied Projects provide the ability to transfer bulk energy to, through, and out of Minnesota to continue to serve load 24 hours a day, 7 days a week, 365 days a year. The Studied Projects’ transfer capability[184] helps enable the transmission grid to take on the role currently served by baseload generation, essentially allowing the transmission grid to function as a super-sized battery. **Figure 6.3-2** displays three different hours of expected generation output and electrical demands in 2042 under a typical, and actual, weather pattern in winter. The figure shows how, as the weather front moves from west to east, the Studied Projects facilitate moving energy from where it is produced to where it is needed, which changes by the hour.

Without the Studied Projects, during these three hours, over 2,000 MW of load is not being served, and a similar magnitude of generation is being wasted (i.e., curtailed) because there is inadequate transmission to move (i.e., transfer) energy from where it is being produced to where it is needed. On an annual basis, approximately 1,300,000 MWh of Minnesota load is at expected risk of not being served without the Studied Projects by 2042. Risk levels are highest during times when electricity is needed most and during atypical weather conditions.

As illustrated on **Figure 6.3-2**, the transfer capability enabled by the Studied Projects is multi-directional. This means that the Studied Projects enable a west to east transfer (e.g., from South Dakota into Minnesota) and at other times an east to west transfer (e.g., from Minnesota to South Dakota). Similarly, the Studied Projects enable north to south and south to north transfers, depending on generation availability and electrical demands.

[184] See **Section 3.4.1.2** for additional details on how transfer capability is defined.

Figure 6.3-2: Energy Adequacy Need for Studied Projects –Typical Winter Day (2042)



The multi-directional nature of the grid is not new but has been increasing in magnitude and volatility in terms of frequency of flow direction changes. For example, historically, transfer between the Dakotas and Minnesota was nearly always transferring power energy from west to east (measured using "NDEX," a long-standing interface system operators use to measure total flows between Minnesota and North Dakota). Since 2022, NDEX transfers have been nearly equally split between west to east and east to west.[185]

Applicants have completed an analysis of transfer capability and the resulting unserved demand (see **Section 6.2.2** for additional details on methodology). The Applicants' analysis looked at every hour of the year and determined if the grid can transfer the needed energy from where it is being produced to where it is needed to serve load at that hour. **Figure 6.3-2** shows three representative hours of the 8,760 hours evaluated by the Applicants.

Unserved demand means there is inadequate power available to completely serve a specific load at a specific time. To prevent a voltage-drop (i.e., a collapse, which could damage equipment and consumer appliances, etc.), the grid operator will systematically shed load (i.e., "turn off the lights") to maintain a safe and adequate voltage for the rest of the system. Unserved demand is caused by either a lack of generation available or inadequate transmission capacity to move generation to a specific demand site. The Applicants' analysis quantifies the amount of demand that would be at risk of being unserved without the Studied Projects, or demand that would need to be served by a future-new dispatchable generation technology at that site. MISO models quantify unserved demand as the sum of "emergency energy" and "flex output.[186]

The Applicants' quantification of load at risk of being unserved is likely conservative because, unlike actual operations, planning models have perfect foresight of load levels, generation availability, and weather patterns, and, thus, can perfectly plan and optimize to minimize risk.

6.3.3 Enabled Demand Analysis

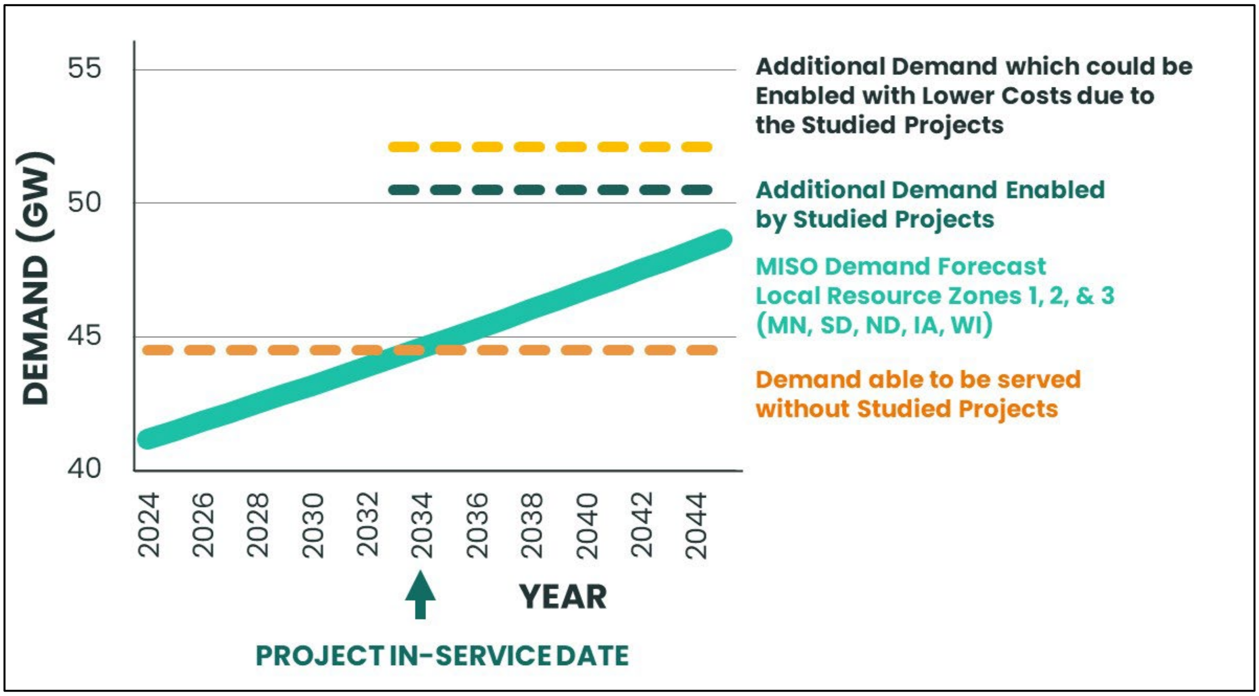
Without the Studied Projects, the grid will be unable to reliably serve the base demand forecast. The Studied Projects help enable 3,010 MW of the base forecast demand growth to be reliably served over the next 20 years as shown on **Figure 6.3-3**. As reported in **Section 5.3**, the base demand forecast only includes firm large-load additions and does not include potential/speculative large spot-load (e.g., data center) additions.

[185] From August 2022 to April 2025, NDEX transfers were 50.4 percent from Minnesota to North Dakota and 49.6 percent from North Dakota to Minnesota.

[186] MISO "flex" output is defined in **Appendix E.2**. Page 20.

The Studied Projects are needed to serve the current forecasted demands for electricity; however, the Studied Projects also leave capacity to reliably serve potential future increases in residential, commercial, and industrial energy demands totaling an additional approximately 3,000 MW over the next 20 years, as shown in **Figure 6.3-3** and further detailed in **Section 6.6.1.**

Figure 6.3-3: Demand Growth Enabled by the Studied Projects



To interconnect new load to the transmission grid, utilities (like the Applicants) and MISO perform analysis to ensure that the new load will not harm the reliability of the grid (i.e., that both the new and existing load can be reliably served). Should adding the new load result in violating a NERC reliability standard, an upgrade or expansion of the transmission grid is required for that new load to be interconnected.[187]

The Applicants' analysis captures load in the base forecast that could not be reliably interconnected but for the Studied Projects using EPRI's CPLANET tool (see **Section 6.2.2.1** for details on methodology). The load enabled by the Studied Projects is the minimum amount of load additions over the next 20 years that had to be reduced to eliminate the reliability issues mitigated by the Studied Projects.

[187] MISO's planning procedures detailed in MISO Tariff Attachment FF.

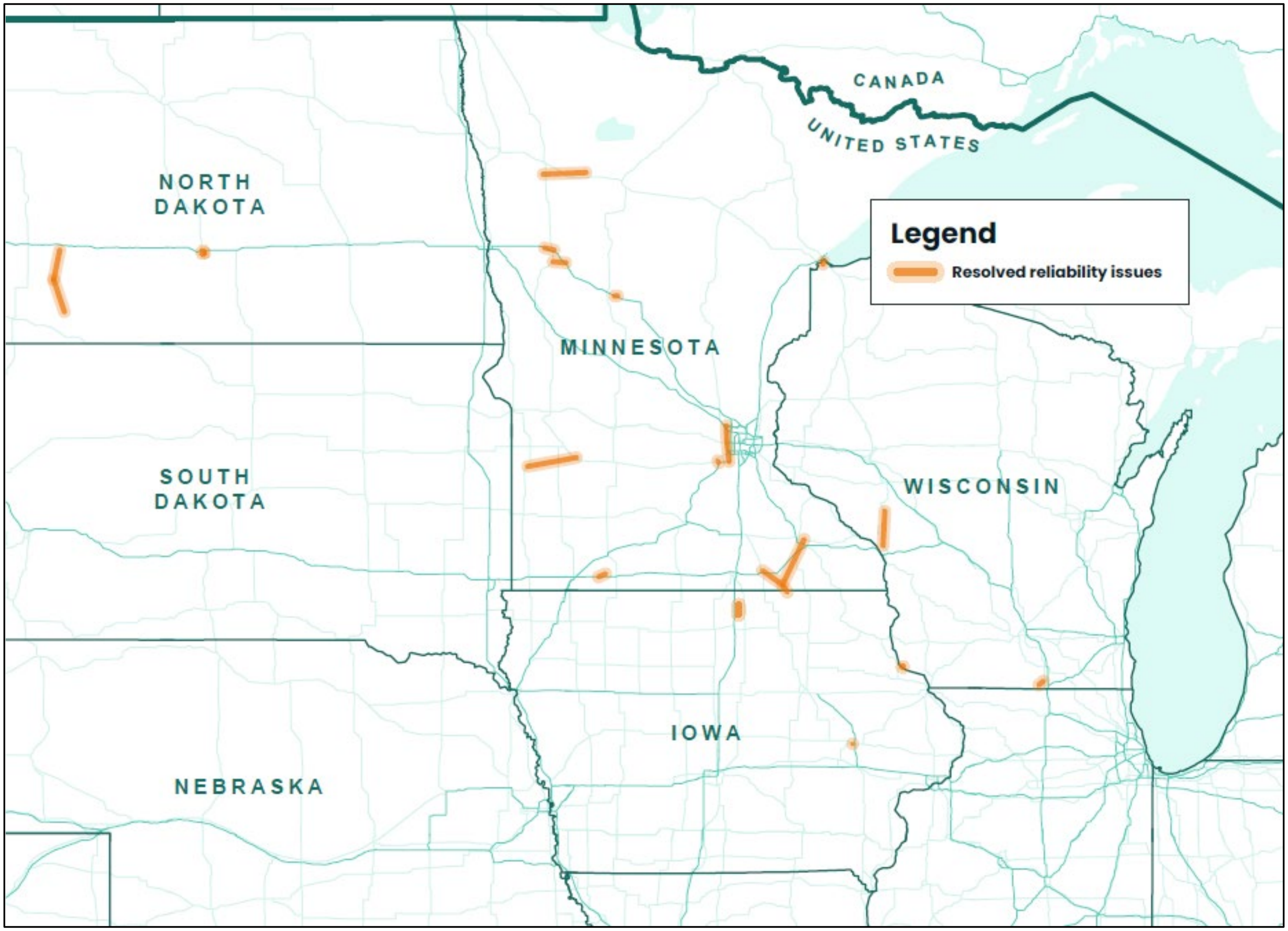
6.3.4 Sensitivity Analysis for Serving Load in Lower-Probability High-Impact Events

The Studied Projects also help maintain reliability under lower-probability, high-impact events such as extreme weather and multiple system outages. As the scenarios used in **Section 6.3.1** modeled only typical stress conditions (e.g., summer and winter peak) to understand the reliability impacts during additional conditions of higher grid stress, the Applicants modeled four additional scenarios, each based on an hour of actual historical weather in 2018. Under the additional modeled stressed conditions, the Studied Projects eliminate 50 additional reliability issues (13 above 200 kV) at 24 different sites, shown on **Figure 6.3-4**. Only those reliability issues mitigated by the Studied Projects that are not already captured under **Section 6.3.1** are included on **Figure 6.3-4**.

Over the last decade, the number of extreme events has been on the rise. MISO did not declare a single grid emergency between its founding in 2001 to 2016. Between 2019 and August 2025, MISO declared 56 grid emergencies, many during non-traditional times of grid stress. MISO declares grid emergencies when there is an elevated risk of the system not being able to serve the demand.

While historically the most stressed conditions have been extreme cold (e.g., Winter Storm Uri) or extreme heat, with increased reliance on variable and weather-dependent generating resources, the most stressed conditions in the future could be widespread wind and solar droughts, atypical wind and/or solar patterns, multiple outages, and/or dramatic changes in demand.

Figure 6.3-4: Additional Reliability Issues Mitigated under Lower-Probability High-Impact Events



Reliability impacts of lower-probability, high-impact events were identified by the Applicants using the following load and generation scenarios:

- **Highest west to east flow:** Conditions experienced on February 23, 2018, at 22:00.
- **Highest 24-hour flow change:** Conditions experienced on February 24, 2018, at 13:00.
- **High load and low resource availability:** Conditions experienced on July 13, 2018, at 20:00.
- **Highest east to west flow:** Conditions experienced on February 28, 2018, at 13:00.

Each additional scenario is based on actual experienced load and weather patterns. Simply put, the scenarios capture the reliability impacts if tomorrow's generation fleet and electricity demands occurred with yesterday's weather patterns. Apart from the generation dispatch and load-level, all other assumptions, modeling, and analysis are consistent with MISO models and analysis used in **Section 6.3.1.**

Under current NERC reliability standards, these additional scenarios are deemed extreme and, thus, the same mitigation requirements do not apply. While these additional reliability issues mitigated by the Studied Projects could be defined as resiliency needs, as opposed to reliability needs, given each scenario is based on actual experienced conditions, the Applicants have included these as a component of the reliability need.

6.3.5 System Stability Analysis

The Studied Projects add a significant component to the overall transmission grid resulting in improvements to the stability of the grid, both from a voltage and transient aspect as well as lowering probability of a cascading event. System stability is an increasingly important attribute for the grid due to the changing generation mix and more dynamic load patterns. Historically, system stability was maintained by large centrally located power plants. The large rotating mass of those power plants helped the grid remain stable during a system event (e.g., unexpected outage of a transmission line or power plant). As the power plants historically relied upon for system stability are retired and are increasingly replaced with inverter-based resources (e.g., wind and solar generator) and demands for electricity become more dynamic, backbone transmission upgrades, like the Studied Projects, are critical to networking the grid to maintain stability.

When comparing analysis with and without the Studied Projects, the performance of the grid is significantly enhanced in transferring power through Minnesota. Transfer capability is measured using both steady-state and stability studies. As transfer capability is determined by the most limiting measure, which can be different depending on specific conditions, the Applicants have evaluated each measure (steady-state and stability). In summary, under each metric, the Studied Projects enable a significant increase in the ability to reliably transfer energy from generation to load.

The voltage stability results show that the Studied Projects provide a significant increase in transfer capability of generation within Minnesota and neighboring states to load centers. As detailed in **Appendix E.3**, the Studied Projects increase the transfer capability from a voltage stability perspective by upwards of 4 GW. The Studied Projects' backbone nature enables the needed increases in system stability and allows the potential for further increases in system stability through incremental system reactive power devices.

More significantly, the Applicants' stability analysis shows that without the Studied Projects, an outage of select parallel or downstream 765 kV or 345 kV paths can create system instability. Specifically:

- Without the Studied Projects, the loss of (i.e., outage of) the parallel MISO LRTP Tranche 2.1 Portfolio east-west transmission line from central Iowa to Illinois (Sub T to Woodford County – LRTP project numbers 38 and 40) triggered major voltage oscillations in the Average Load scenario with high wind generation conditions.
- Similarly, without the Studied Projects, the loss of the 765 kV transmission line between Twinkle and Sub T in Iowa triggered significant angle instability conditions in the Light Load scenario with high wind generation conditions.
- The loss of the 345 kV transmission line between Alexandria and Big Oaks in Minnesota (MISO LRTP Tranche 1) or the loss of the 345 kV transmission line between Iron Range and St. Louis in Minnesota triggered voltage oscillations and generator angle instability conditions without the Studied Projects for the Average Load scenarios.

A full copy of the stability analysis report is included in **Appendix E.3**.

6.4 Cost-Effectiveness/Economic Benefits

While primarily driven by reliability, the Project provides economic benefits to customers and members which allows Minnesota to meet its reliability needs in a cost-effective manner. As discussed in **Chapter 7**, the Studied Projects are the most cost-effective alternative to meet reliability needs. The Studied Projects reduce system-wide congestion in Minnesota by upwards of 11 percent, allowing energy needs to be served with lower cost energy resulting in economic savings to consumers and members. As detailed in the following sections, the Studied Projects are expected to provide economic savings totaling $7.7 billion to $25.3 billion over the first 20 years of service based on four metrics. MISO, in their evaluation of the LRTP Tranche 2.1 Portfolio, quantified nine benefit metrics. The Applicants quantified three MISO benefit metrics - the omission of the other benefit metrics does not imply that those metrics are not provided by the Studied Projects, only that they were not quantified. The Applicants quantified a fourth benefit metric (avoided asset renewal).

6.4.1 Economic Savings

The Studied Projects are expected to provide $7.7 billion to $25.3 billion in economic benefits over the first 20 years of service as shown on **Figure 6.4-1**.[188]

As shown on **Figure 6.4-1**, the Studied Projects' economic savings are the total of four benefit metrics: mitigation of reliability issues,[189] reducing CO_2 emissions,[190] congestion and fuel savings,[191] and avoided asset renewals. These metrics are approved in MISO's federally approved tariff and further recognized in FERC Order 1920.[192] The Applicants' valuation method for each metric is consistent with MISO's tariff defined methodology and models. Consistent with MISO's assumptions, the value of reducing CO_2 emissions is quantified using a range which considers the 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.[193]

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[188] Net savings consider financing fees and the time value of money.

[189] See **Appendix E.1.** Page 127.

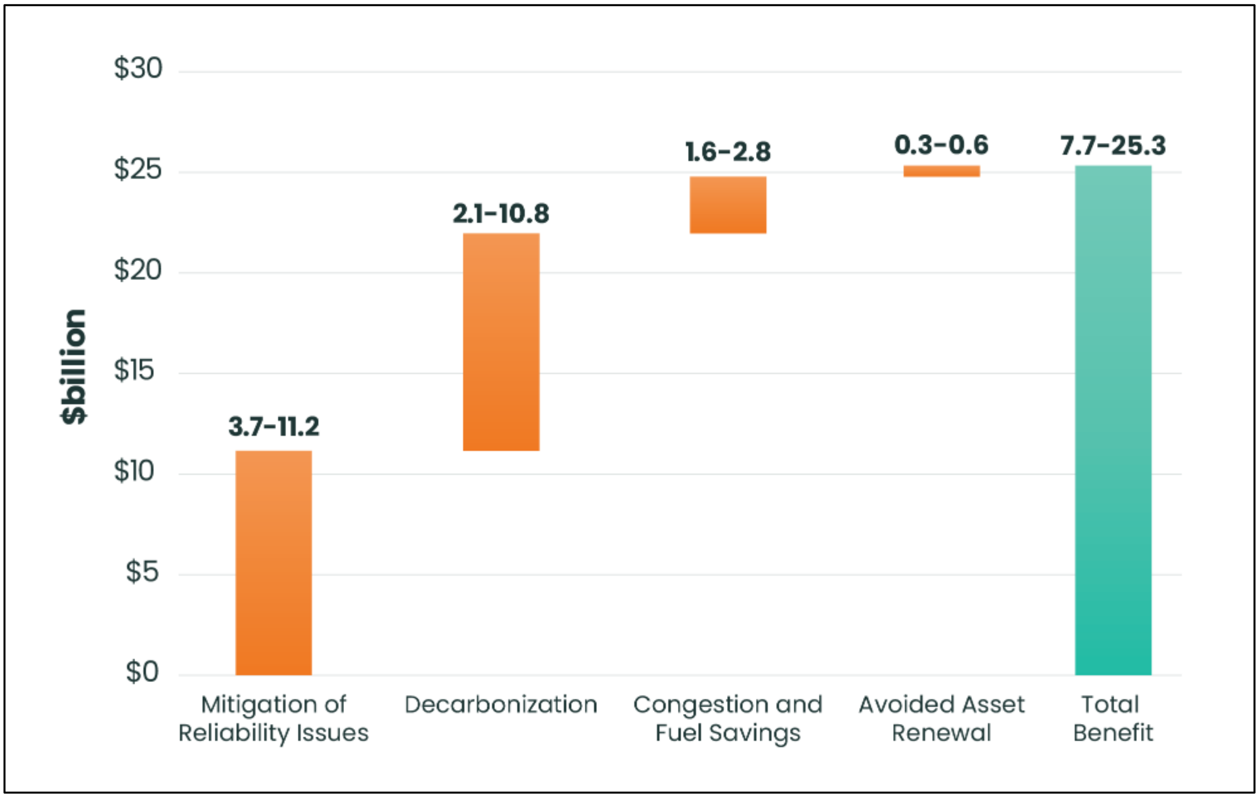
[190] See **Appendix E.1**. Page 142. The reduction of CO_2 emissions due to the Studied Projects is detailed in **Section 6.5.3.**

[191] See **Section 6.4.2.**

[192] FERC. Order 1920-A and 1920-B, Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 18 C.F.R. Part 35 (November 21, 2024, and April 11, 2025). Available at: https://cms.ferc.gov/media/e-1-rm-21-17-001 and https://cms.ferc.gov/media/order-1920-b.

[193] MISO. LRTP Tranche 2 Business Case Metrics Methodology Whitepaper. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf. Page 31.

Figure 6.4-1: Project Economic Savings



Avoided asset renewal benefits are associated with the upgrade of 137 miles of 161 kV transmission lines in LRTP 26 – which is also included in the scope of the Studied Projects. The existing 161 kV transmission lines are on wooden H-frame structures that are reaching the end of their useful lives. Replacement of these lines in conjunction with the Studied Projects avoids the otherwise necessary asset renewal costs.

As detailed in **Section 4.6.3**, the MISO LRTP Tranche 2.1 Portfolio, which includes the Studied Projects, is expected to provide $23 billion to $72 billion in net economic savings over the first 20 years of service. MISO quantified nine different benefit metrics. The Applicants quantified three of MISO's nine benefit metrics for the Studied Projects because they can most reasonably be calculated on a Project-specific basis. The Applicants quantified a fourth benefit metric (avoided asset renewal). The omission of the other benefit metrics in the Studied Projects' economic benefits does not imply that those metrics are not provided by the Studied Projects, only that they were not quantified.

It should be noted that the models and assumptions used to quantify the economic benefits for the Studied Projects were developed in 2022 and early 2023.[194] Since 2023, costs for materials, labor, production, etc. have continued to rise. As economic benefits reflect the value of avoided costs (e.g., fuel cost savings, avoided transmission and generation investment, etc.) it is expected that benefits will likewise increase with costs. Thus, the Studied Projects' benefits estimated in **Figure 6.4-1** are likely lower than expected.

6.4.2 Congestion and Fuel Savings

One of the key measures of economic savings is congestion reduction. Congestion has been a focus in recent years in Minnesota[195] and is one of four benefit metrics quantified for the Studied Projects on **Figure 6.4-1**. Congestion is a limitation, or bottleneck, on the transmission grid, which prevents the lowest cost-generation from serving load. The Studied Projects are expected to reduce system congestion in Minnesota and the surrounding area, providing access to lower cost generation and resulting in $321 million to $660 million in cost savings over the first 20 years of the Studied Projects' service, as shown in **Table 6.4-1**. The reduction in congestion not only provides greater flexibility to efficiently serve load, but the resulting economic savings help offset the capital cost of the Studied Projects.

Table 6.4-1
Congestion and Fuel Savings from the Studied Projects

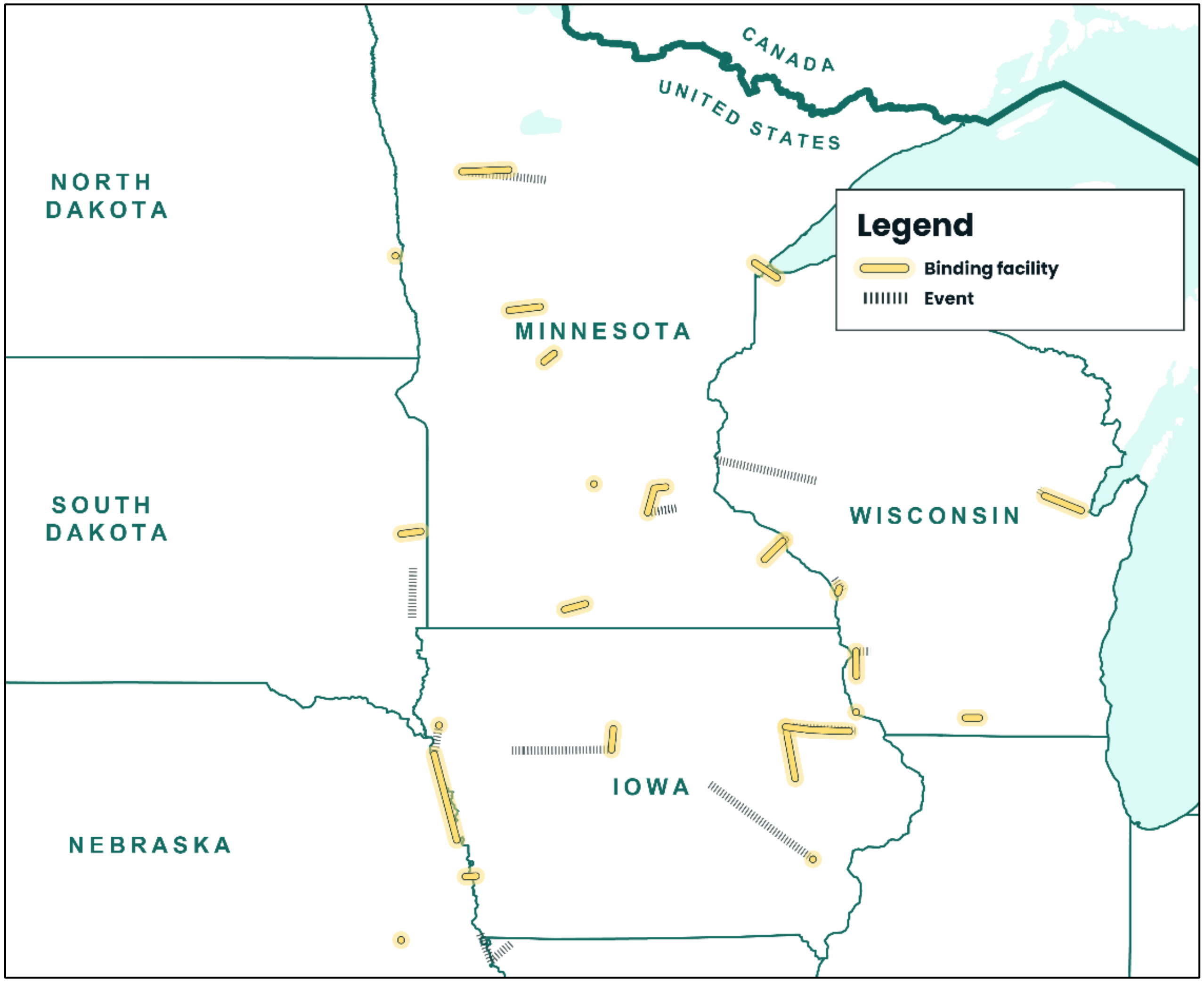
Period	**20-year NPV ($M)**		**40-year NPV ($M)**	
Discount Rate	7.1 percent	3.0 percent	7.1 percent	3.0 percent
MISO Midwest	$1,558	$2,814	$2,013	$4,603
Minnesota and surrounding region (Local Resource Zone 1)	$321	$660	$601	$1,802

The Studied Projects reduce total system congestion in Minnesota and surrounding states by approximately 2 percent to 11 percent, with the range dictated by conditions/year. More importantly, the Studied Projects address congestion on the most difficult (i.e., expensive, largest-scale, and longest to construct) transmission elements in southern Minnesota, shown on **Figure 6.4-2**. With the largest elements mitigated, enabling additional congestion reduction with smaller scale and quicker implementation solutions, such as what has been done through Grid North Partners' recent efforts (see **Section 4.7**), can more easily be done in the future.

194 See **Appendix E.2**. At the time of filing this Application, the MISO Series 1A futures are the latest models available.

195 Recent proceedings in Minnesota involving congestion include Nobles County congestion analysis, 2025 grid enhancing technologies study, and the 2022 Grid North Partners near-term congestion study detailed in the 2025 2025 Minnesota Biennial Transmission Report. *See, e.g., In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation,* Docket No. E-999/CI-24-316; Minn. Laws 2024, Ch. 127, H.F. 5247; *2025 Biennial Transmission Projects Report,* Docket No. E999/M-25-99, 2025 Biennial Transmission Projects Report, Ch. 9 (Oct. 31, 2025).

Figure 6.4-2: Map of Top Congested Elements Mitigated by the Studied Projects



6.5 Enabling Generation Transition

As described in **Section 5.2**, driven by a combination of economics, age and condition, consumer preferences, utilities goals, and policies, the generation fleet in Minnesota and the broader Midwest region is evolving. Within the next 10 to 15 years, most fossil fuel generators will be retired and replaced primarily with wind and solar generation. The existing fossil fuel resources not only support reliability by providing energy (i.e., MWs), but also key reliability attributes that keep the grid stable and ensure reliability every hour of every day (i.e., energy adequacy). While wind and solar technologies continue to advance, by nature, their output is dependent on weather conditions. At the same time, demand usage is also evolving in magnitude, location, and profile. System changes are needed to allow the new variable generation fleet to serve the evolving demand; specifically, to provide a consistent flow of electricity every hour of every day (i.e., energy adequacy), interconnect new generation capacity at different locations, and to replace retiring reliability attributes. While technologies such as energy storage[196] are part of the solution, transmission infrastructure like the Studied Projects address the bulk of the needs. The Studied Projects help enable the energy transition by:

- **Enabling generation:** The Studied Projects help enable approximately 24 GW of new generation (10 GW in Minnesota) to be reliably interconnected to the transmission grid to replace retiring generation capacity and to serve load (**Section 6.5.1**).
- **Reducing curtailment:** The additional transmission capacity provided by the Studied Projects allows better and fuller utilization of existing generation resources, reducing curtailment (i.e., wasted energy) by upwards of 7.2 million MWh on an annual basis (**Section 6.5.2**).
- **Reducing CO_2 emissions:** The reduced curtailment, enabled generation, and reduced congestion provided by the Studied Projects decreases CO_2 emissions by 3.6 million to 4.5 million tons annually to help comply with Minnesota's Carbon-Free by 2040 law (**Section 6.5.3**).

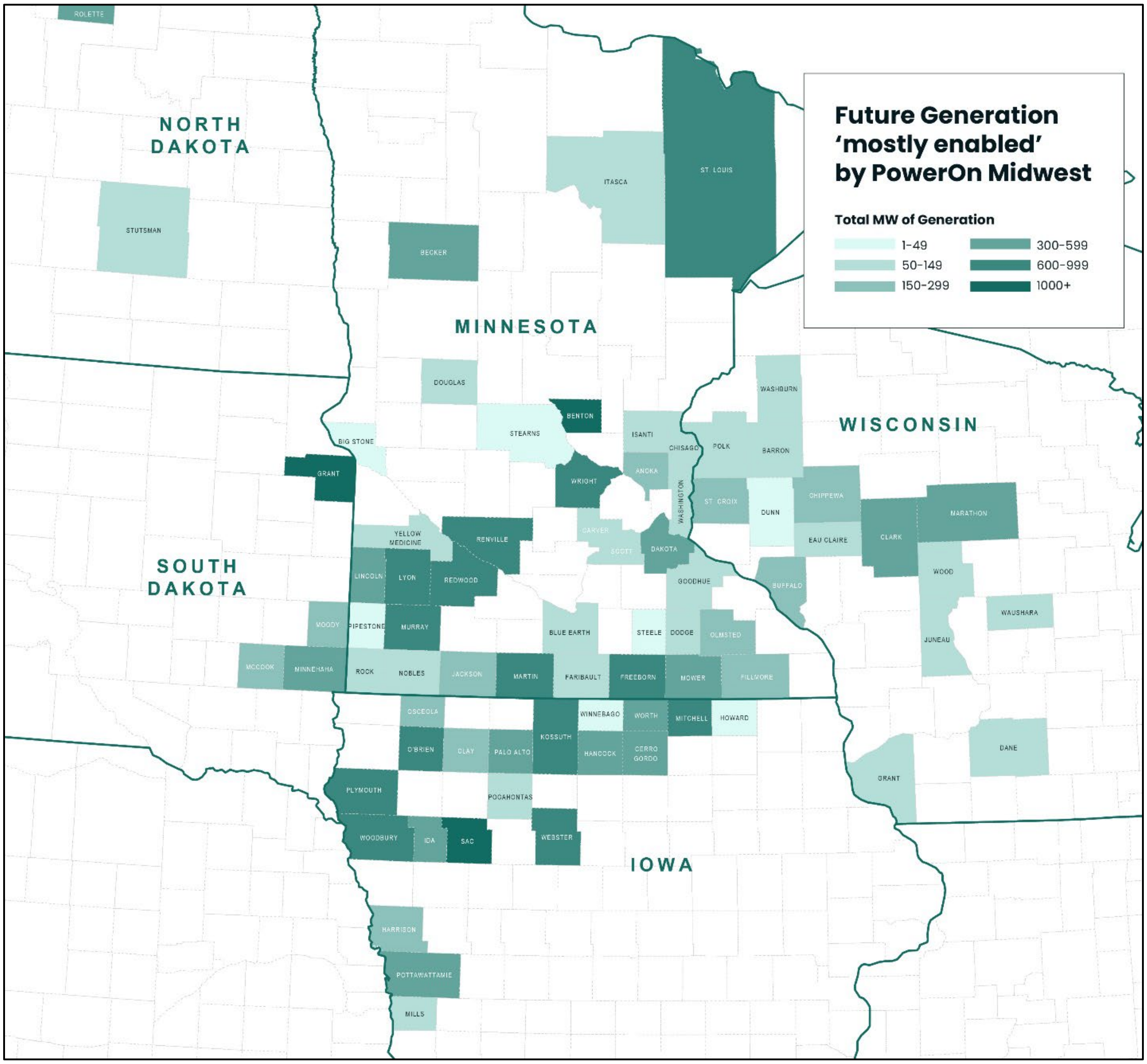
6.5.1 Enabled Generation

The Studied Projects help enable approximately 24 GW of generation to be reliably interconnected to the transmission grid as shown on **Figure 6.5-1.** While generation is typically

[196] See **Section 7.1** for additional details on how the Project is one technology of many that are needed to enable the energy transition.

interconnected at the 345 kV and lower voltages, the Studied Projects pull electricity off the existing lower voltage transmission lines to create transmission capacity to add new generation.

Figure 6.5-1: Generation Enabled by the Studied Projects



To interconnect a new generator to the transmission grid, a generation developer must go through the MISO Generator Interconnection Queue. MISO performs a study to ensure that the connecting generator(s) does not cause a reliability issue to the transmission grid. If the generation addition causes a reliability issue/overload, the transmission grid must be upgraded to mitigate the reliability issue(s) to interconnect the new generator.[197]

MISO's federally approved tariff requires that if a new generator causes a five percent or more reliability issue impact (referred to as a distribution factor, or DFAX), that generator cannot fully interconnect until there is a plan in place to mitigate that reliability violation.[198]

As detailed in **Section 4.6.2**, the MISO LRTP Tranche 2.1 Portfolio, which includes the Studied Projects, helps enable approximately 116 GW of new generation to be interconnected across the Midwest.[199] Without the MISO LRTP Tranche 2.1 Portfolio, the 116 GW of generation has more than a five percent DFAX on a reliability constraint and, thus, would not be able to interconnect without alternative mitigation.[200]

To isolate the generation enabled by the Studied Projects, the Applicants filtered MISO's data to generators which have a five percent or more DFAX on reliability constraints mitigated specifically by the Studied Projects. Because the Studied Projects are part of a broader portfolio, which intentionally provides overlapping reliability needs (i.e., the Studied Projects and another project in the MISO LRTP Tranche 2.1 Portfolio may both contribute to addressing a single reliability constraint), the Applicants calculated the generation enabled in multiple definitions:

- **10.2 GW**: Generators which are exclusively enabled by the Studied Projects (i.e., no other project in the LRTP Tranche 2.1 Portfolio addresses the necessary reliability mitigations).
- **45.0 GW**: Generators which are enabled by the Studied Projects in combination with other LRTP Tranche 2.1 Portfolio projects (i.e., multiple projects work together to mitigate the reliability issue to enable the generation addition).
- **24.5 GW**: Generators which are mostly enabled by the Studied Projects. Includes generators which are exclusively enabled by the Studied Projects and those which the most significant reliability constraint(s) is addressed by the Studied Projects.

[197] MISO's generator interconnection procedures detailed in MISO Tariff Attachment X.

[198] MISO Tariff Attachment X Section 3.7.1 and 3.8.

[199] See **Appendix E.1.** Page 75.

[200] Id. Page 27.

The Studied Projects can enable generation nameplate totals greater than the transmission line's rated physical capacity due to the network nature of the grid (i.e., creating new capacity and unlocking capacity in the existing grid).

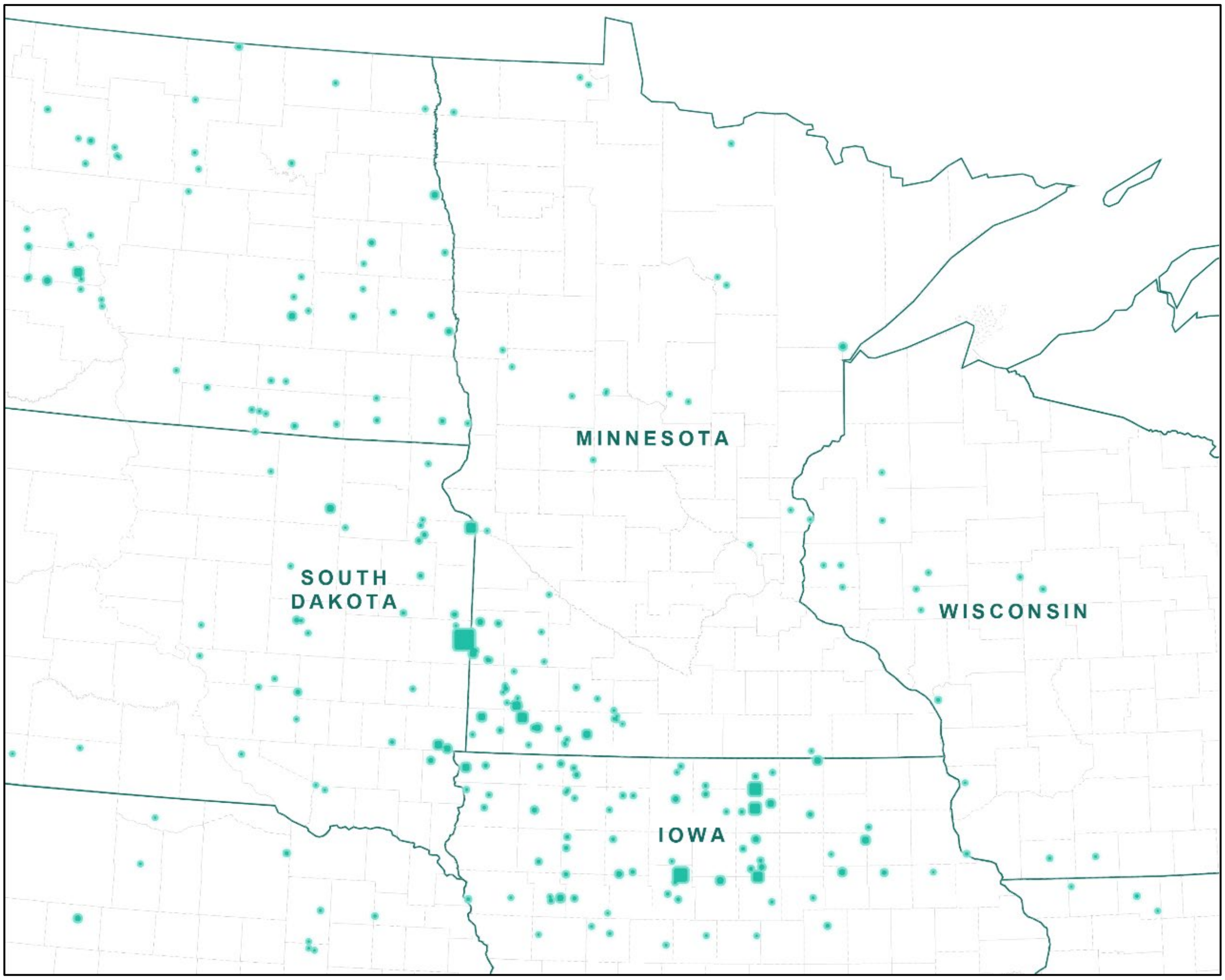
6.5.2 Curtailment Analysis

Curtailment refers to a condition where a generator can, and economically should, provide power to the grid, but there is insufficient transmission capacity to move the energy generation from the generator to where it is needed to serve demand (i.e., there is congestion), or there is not enough demand or storage resources to use all available generation. While not limited to renewable generation, curtailment occurs primarily at renewable resources which are economically the lowest cost generators from an operating perspective.

Curtailment is a reliability, economic, and policy issue. Curtailment results in an inability to access the least-cost generation, which is needed to serve load. Curtailment also often results in higher costs as the energy is wasted and must be replaced by other often more expensive and potentially carbon emitting generation. The curtailed renewable generation therefore would not contribute to carbon-free goals. The Studied Projects and the MISO LRTP Tranche 2.1 Portfolio reduce curtailment by directly mitigating insufficient transmission capacity, but also by enabling generation by providing connections to reach loads across MISO (and, even beyond MISO).

The Studied Projects reduce renewable generation curtailment (i.e., generation which is wasted and cannot used to serve electrical needs) by 5.6 million to 7.2 million MWh on an annual basis. Much of the reduced curtailment is in southern Minnesota. However, given the regional nature of the Studied Projects, the Studied Projects reduce generation curtailment across a five-state Upper Midwest region (see **Figure 6.5-2**).

Figure 6.5-2: Reduction in Generation Curtailment from the Studied Projects
(Dot size indicative of magnitude of curtailment reduction)



6.5.3 Carbon Reduction – Socially Beneficial Uses of Facility Output

The Studied Projects are needed to maintain transmission reliability for the state and the broader MISO region as the region undergoes a transition from fossil fuel generation resources to cleaner energy resources. The Studied Projects reduce annual CO_2 emissions by 3.6 million to 4.5 million tons, as shown in **Table 6.5-1**, supporting public policy goals such as Minnesota's Carbon-Free by 2040 law and its interim targets.

Table 6.5-1 Carbon Emission Reduction from Reduced Congestion and Curtailment	
Year	**Carbon Emission Reduced by Studied Projects (tons)**
2032	4,556,816
2037	4,362,798
2042	3,609,815

The Studied Projects reduce annual CO_2 emissions by reducing renewable curtailments (see **Section 6.5.2**) and decreasing congestion (see **Section 6.4.2**).

As detailed in **Section 4.6.2,** MISO estimates that the addition of the broader MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, is projected to result in a reduction of 127 million to 199 million metric tons of CO_2 emissions.

In addition, as discussed in **Section 6.5.1**, the Studied Projects directly support the reliable interconnection of approximately 24 GW of new carbon-free generation, which also decreases CO_2 emissions by offsetting more expensive carbon emitting resources in the dispatch. The carbon reductions from the additional generation enabled by the Studied Projects are not captured in **Table 6.5-1** and, thus, carbon reduction totals are conservative.

6.6 Additional Project Benefits

The Project provides additional benefits to Minnesota and the broader region. This section provides an overview of the analysis of the Project's beneficial impacts on ability to serve load beyond the base load forecast, flexibility and resiliency, and reduced system losses.

6.6.1 Enabled Demand Growth Beyond the Base Load Forecast

Given the critical nature of electricity and length of time needed to develop infrastructure, it is necessary to consistently be a step ahead of needs. While the Studied Projects are needed to meet today's forecasted demand needs as detailed in **Section 6.3.3**, the Studied Projects also help enable upwards of approximately 3,000 MW of additional load growth beyond the base forecast to be reliably interconnected. The additional load enabled is agnostic to type, industry, and timing and could be used to accommodate residential, commercial, and/or industrial growth. As detailed in **Section 5.3**, the current demand forecasts do not include potential for load growth from data center development, which MISO predicts could increase demand by as much as three-fold.[201]

[201] MISO. December 2024 Demand Forecast Whitepaper. Available at: https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf).

Reliability impacts for new load interconnections are dependent on multiple factors, the largest being the location of new load, co-location with generation (i.e., is load "offset" by on-site generation), and the hourly profile. As a conservative measure, the Applicants assumed that new load has a 100 percent load factor (i.e., it is "always on") and is not co-located with new generation. To consider a range of potential locations for the future load, the Applicants analyzed two different scenarios:

- **Spread across the State of Minnesota:** Where all existing load is scaled-up on a pro-rata basis; and
- **Directly located on the Project:** Where new load is spread equally at the Lakefield Junction Substation, Pleasant Valley Substation, and North Rochester Substation.

In the future, with the generation mix primarily composed of wind, solar, and storage, the most stressed reliability conditions (i.e., limiting case) for the grid to serve the state's load are the times when all local wind and solar is offline and storage is depleted. Under this situation, reliability is dependent on the grid's transfer capability. To determine the amount of additional load which could be interconnected with the Studied Projects, the Applicants analyzed this limiting case, where serving existing, forecasted, and potential additional load is done by transferring energy from outside of Minnesota. Additional load enabled by the Studied Projects is calculated as the difference in transfer capability needed to serve the base demand and the total transfer capability provided by the Studied Projects.

To determine the total transfer capability provided by the Studied Projects, the Applicants incrementally increased the transfer levels until a system overload was identified. While the Studied Projects enable the bulk of the increased transfer, as transfer is increased there are lower-voltage facilities (i.e., underlying facilities) which overload. Upgrading lower-voltage/underlying facilities is typical and identified in the annual MTEP planning process. As such, these violations were cataloged, but the Applicants continued to increase the transfer until there was a violation of a higher-voltage, more-significant facility which would require more than a typical annual MTEP system upgrade to mitigate. The transfer level immediately before the higher-voltage violation is the total transfer enabled by the Studied Projects.

The cost to mitigate each reliability violation is calculated using MISO's Cost Estimation Guide by assuming the monitored element is upgraded.[202] As shown on **Figure 6.6-1**, the Project

[202] MISO. Cost Estimation Guide / Workbook for MTEP 24. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.

enables 3,140 MW of additional load beyond the base forecast. **Figure 6.6-1** details the additional load enabled by the Studied Projects assuming new load is spread across the entire state. Should new load be located directly at the Project substations, the Studied Projects enable additional load. As shown on **Figure 6.6-1**, approximately $500 million in transmission system upgrades, spread across multiple transmission facilities, are required to meet this load level in addition to the Studied Projects; however, each of these upgrades is small scale and in the range of a "typical" (i.e., non-LRTP) annual load serving project.

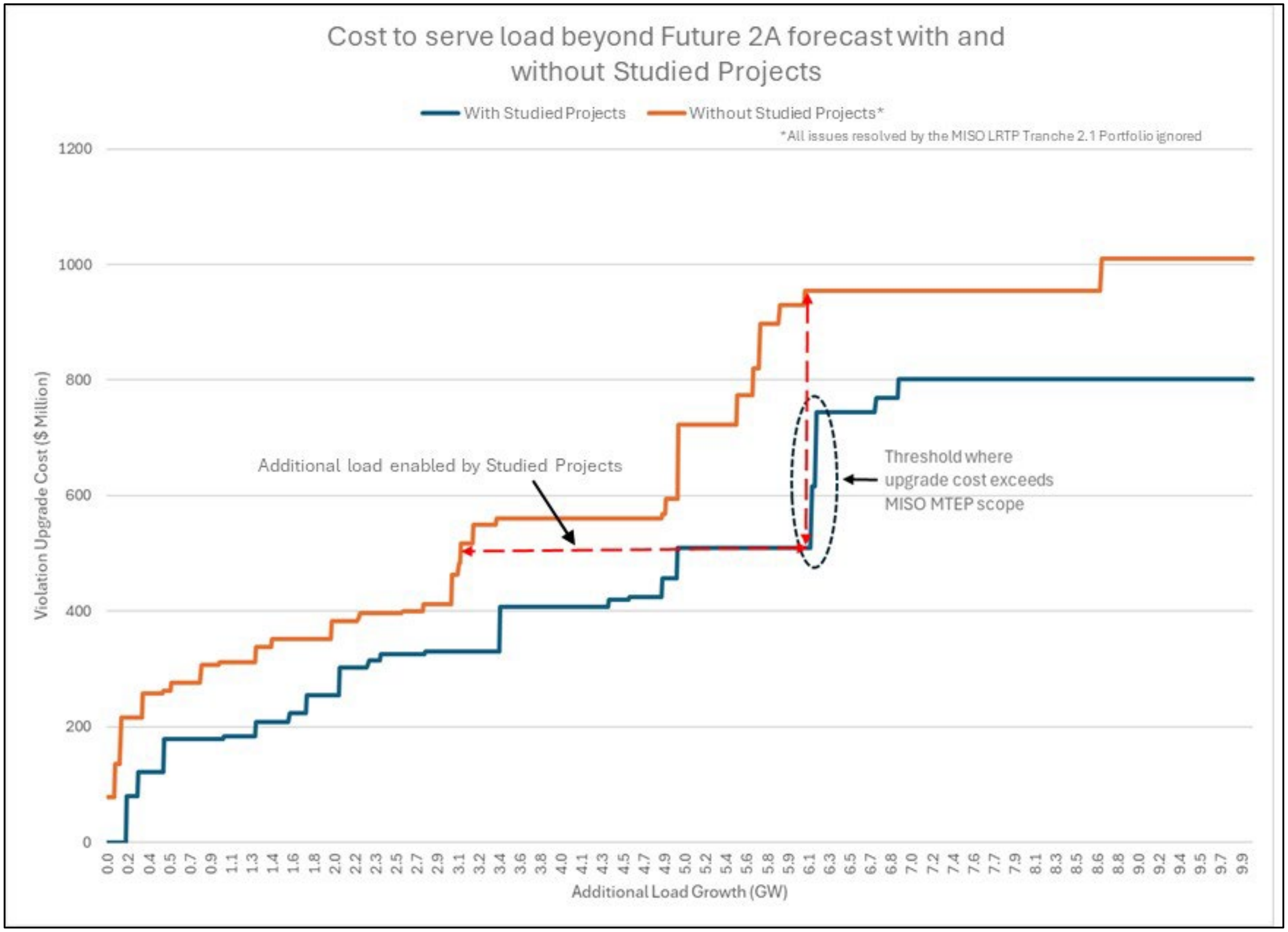
As detailed in **Section 6.3.3**, without the Studied Projects the base demand forecast is not reliably served. Thus, without the Studied Projects, there is no additional enabled load. To isolate the additional load enabled by the Studied Projects versus the additional lower-voltage mitigation, the Applicants performed similar analysis on a non-Project case with the same lower-voltage mitigation. As shown on **Figure 6.6-1**, the difference between these cases is the amount specifically enabled by the Studied Projects.

Additional load of 3,140 MW is the equivalent of increasing the annual net growth rate for MISO load in Minnesota, South Dakota, North Dakota, Iowa, and Wisconsin (MISO Local Resource Zones 1, 2, and 3) from 0.8 percent to 1.2 percent over the next 20 years.

Additionally, as shown on **Figure 6.6-1**, the Studied Projects decrease the costs to enable additional load growth beyond the level enabled by the Studied Projects by approximately $500 million to $900 million. To interconnect load growth beyond the load growth enabled by the Studied Projects, approximately 1,600 MW, larger-scale reliability overloads on the 345 kV grid must be addressed, in addition to the overloads on the lower voltage system. The Studied Projects proactively address some of the 345 kV overloads that need to be resolved, thereby reducing the costs to expand the system beyond 1,600 MW.

Figure 6.6-1: Additional Load Enabled by the Studied Projects

(Assumes new load is geographically spread across Minnesota)



6.6.2 Flexibility and Resiliency

The Project establishes a strong, low-impedance, and high-capacity path which not only facilitates bulk transfers between Minnesota, South Dakota, Iowa, and Wisconsin, but also with much of the Eastern Interconnection, in the eastern part of the United States. When combined, the projects within the MISO LRTP Tranche 2.1 Portfolio create a new transmission backbone network, allowing Minnesota to meet its electrical needs in a more reliable and cost-effective manner. In addition to directly supporting daily reliability, the transmission backbone network provides flexibility to respond to extreme weather and other low-probability high-impact events.

In **Section 6.3.4**, the Applicants showed that the Studied Projects enable the system to be reliable even under stressed conditions. The modeled stress conditions were based on actual experienced weather conditions from 2018; however, there is potential for different and/or more extreme weather conditions in the future. Transmission enhancements, like the MISO LRTP Tranche 2.1 Portfolio and the Project, provide flexibility to be able to respond to these types of events.

Winter Storm Uri in February 2021 was an example of the regional transmission expansion providing flexibility beyond modeled scenarios. Winter Storm Uri was a widespread rare Category 3 “Major” winter storm in which Midwest temperatures dropped as low as -30 degrees Fahrenheit. There was an unprecedented need to transfer high amounts of power from the east to the west to maintain reliability during the storm. At that time, most of the MISO MVP Portfolio, the first regional (i.e., LRTP) transmission portfolio approved by MISO, had been recently constructed. The MVP Portfolio was primarily designed to facilitate power transfers from west to east. However, during Winter Storm Uri, to support reliability, PJM — the MISO-equivalent organization in the eastern United States — at one point exported approximately 13,000 MW of energy to MISO, which was used to support SPP, the MISO-equivalent organization to the west of MISO.[203] This level of transfer to maintain reliability would not have been possible without the MVP Portfolio, and was well beyond the scenarios/conditions for which the MVP Portfolio was specifically planned and analyzed. Similarly, the Project and MISO LRTP Tranche 2.1 Portfolio provide significantly more grid flexibility than currently available to be able to respond to the next unprecedented event.

[203] MISO: The February Arctic Event Report. Available at: https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf.

6.6.3 Reduced System Losses

Losses are a measure of the energy flow across the system that is converted into heat due to impedance within the elements of the transmission system. More simply, losses are wasted energy. It is necessary for utilities to provide enough generation to serve their respective system demands (plus reserves), considering the loss of energy before it can be usefully consumed. When system losses are reduced or minimized, electrical energy is delivered to end users more efficiently, helping to defer the need to add more generation resources to a utility's portfolio. Therefore, system loss reduction results in monetary savings in the form of less fuel required to meet the system demand plus potentially delayed capital investment in generation plant construction.

Generally, the higher the voltage, the lower the transmission system losses. Diminishing losses at higher voltages is one of the primary reasons the transmission grid is operated at voltages higher than what is both generated and consumed. The Studied Projects reduce system losses by pulling system flows off lower voltage facilities which have higher losses, and onto the higher-voltage Studied Projects, which have lower losses.

Each new transmission line that is added to the electric system affects the losses of the system. In determining the losses associated with a particular transmission project, it is not reasonable to consider only the Studied Projects' transmission facilities and calculate losses directly from operation of those new transmission facilities. Rather, it is necessary to look at the total losses of the system that result with and without the Studied Projects. The losses were therefore studied using the larger MISO system. In its Exemption Order, the Commission authorized the Applicants to provide line loss data for the system as a whole, rather than line loss data specific to an individual transmission line.[204]

The Applicants used power flow software to calculate the losses using MISO's eight defined scenarios. In each case, system line losses due to the Studied Projects were compared between a case with the Studied Projects and a case without the Studied Projects (see **Section 6.2** for additional detail). Annual losses were calculated by weighing each of the scenarios shown in **Table 6.6-1** based on the approximate percentage of the year the scenario best represents. For example, the average loading as compared to the other scenarios best represents the hourly conditions for approximately 22 percent of the year. Similar weights were calculated for all

[204] *See* Order on Initial Filings.

scenarios. Weights were determined by comparing each's scenario assumptions to 8,760 hourly load and generation levels.[205]

As shown in **Table 6.6-1**, the Studied Projects are expected to reduce transmission system losses by approximately 450 MW during conditions of highest losses. Over a year, the Studied Projects are expected to reduce system losses by approximately 1.6 million MWh.

Table 6.6-1
Change in System Transmission Line Losses from the Studied Projects

Scenario [a] (Approximate Percentage of Year Scenario Represents)	Reduction in System Line Losses from the Studied Projects
Average Loading (22 percent)	452.6 MW
Average East to West (10 percent)	36.9 MW
Average Lowers to Uppers (12.5 percent)	385 MW
Light Load (5 percent)	372.5 MW
Summer Peak (2 percent)	170.8 MW
Twilight Summer (1 percent)	101.7 MW
Winter Peak (2.5 percent)	352.8 MW
Winter Low Renewables (45 percent)	8.7 MW
Annual Sum (100 percent)	1,634,001 MWh

[a] Scenario definitions based on MISO MTEP24 reliability models – see **Section 6.2.2** for additional information.

6.7 Impact of Delay

If the Project is delayed, there will be both regional and local reliability consequences. The MISO LRTP Tranche 2.1 Portfolio assumes the 765 kV portions of the Project will be in service in 2034, and that the 345 kV portion will be in service in 2032. Delay of the Project would degrade the performance of the broader portfolio, which was optimized to work together to maintain reliability across the Midwest. The loss in performance would increase the risk of reliability events and unserved demand and could jeopardize Minnesota and other MISO states in meeting clean energy policy objectives. In addition, as the NERC standards require MISO and the Applicants to plan and implement solutions to meet reliability standards, MISO and the Applicants would have to implement temporary solutions until the Project is in-service. Given the volume and magnitude and reliability needs addressed by this Project as detailed in

[205] MISO. LRTP Tranche 2 Business Case Metrics Methodology Whitepaper. Available at: https://cdn.misoenergy.org/LRTP%20Tranche%202%20Business%20Case%20Metrics%20Methodology%20Whitepaper633738.pdf

Section 6.3, depending on the length of the delay, a temporary solution would be expensive at best and infeasible at worst (see **Section 7.4.1**).

In addition to the regional impacts, a delay in the Project will also have local impacts. The Project is needed to support reliability in Minnesota as aging power plants transition or retire. The transition of these aging plants and replacement with new generation sources is a key component of Minnesota utilities' IRPs, which have been reviewed and approved by the Commission. In addition, a delay will also delay the curtailment reductions discussed in **Section 6.5.2** above.

6.8 Effect of Promotional Practices

The Applicants have not conducted any promotional activities or events that have triggered the need for the Project. Rather, the Project is driven by regional reliability issues related to the clean energy transition and meeting public policy objectives.

6.9 Effect of Inducing Future Development

The Project is not intended to induce future development, but it is needed to serve demand arising from future economic development that otherwise would not be possible if the Project and the MISO LRTP Tranche 2.1 Portfolio were not constructed as discussed in **Sections 6.3.3** and **6.6.2**.

7 ALTERNATIVES TO THE PROJECT

An applicant is required to consider various alternatives to the Project in any CN proceeding for a proposed transmission line project. Minn. Stat. § 216B.243, subd. 3(6) states that, in assessing need, the Commission shall evaluate "possible alternatives for satisfying the energy demand or transmission needs including but not limited to potential for increased efficiency and upgrading of existing energy generation and transmission facilities, load-management programs, and distributed generation." The Commission's rules likewise require an application to discuss the following alternatives:

(1) New generation of various technologies, sizes, and fuel types;

(2) Upgrading of existing transmission lines or existing generating facilities;

(3) Transmission lines with different design voltages or with different numbers, sizes, and types of conductors;

(4) Double-circuiting of existing transmission lines;

(5) If the proposed facility is for DC (AC) transmission, an AC (DC) transmission line;

(6) If the proposed facility is for overhead (underground) transmission, an underground (overhead) transmission line; and

(7) Any reasonable combinations of the alternatives listed in subitems (1) to (6).[206]

Minn. R. 7849.0340 further requires an applicant to analyze not building the proposed facility (or, the no-build alternative).

This Chapter discusses the Applicants' evaluation of multiple system alternatives to the Studied Projects, including alternative voltages, generation and non-wires alternatives, transmission alternatives, combinations of alternatives, and a no-build alternative. None of the alternatives is a more reasonable and prudent alternative to the Studied Projects, as summarized in **Table 7.0-1**. This Chapter also discusses the Applicants' evaluation of alternative conductor and structure design, as summarized in **Table 7.0-1**.

Table 7.0-1
Alternatives Evaluation Summary

Section	Alternative	Reason for Rejection
ALTERNATIVE VOLTAGES		
7.2.1	Lower-Voltage	**Cost:** Less cost-effective than Studied Projects. **Impact:** More land impacts than Studied Projects.

[206] Minn. R. 7849.0260.

Table 7.0-1 Alternatives Evaluation Summary		
Section	**Alternative**	**Reason for Rejection**
7.2.2	Higher-Voltage	**Viability:** No voltages higher than 765 kV are operating in the United States.
GENERATION AND NON-WIRES ALTERNATIVES		
7.3.1	Peaking Generation	**Need:** Does not provide transfer capability needed for reliability and efficiency.
7.3.2	Renewable Generation	**Need:** Does not address reliability-energy adequacy needs.
7.3.3	Battery Energy Storage	**Need:** Does not provide transfer capability needed for reliability and efficiency.
7.3.4	Distributed Generation	**Need:** Does not address reliability-energy adequacy needs.
7.3.5	Nuclear Generation	**Viability:** Does not comply with Minnesota law.
7.3.6	Demand Side Management/ Conservation	**Viability:** Magnitude of necessary load reduction infeasible.
7.3.7	Reactive Power Additions	**Need:** Does not address NERC reliability needs.
TRANSMISSION ALTERNATIVES		
7.4.1	Existing System Upgrades	**Cost:** Less cost-effective than the Studied Projects. **Impacts:** Number and scale of upgrades infeasible (at least 1,394 miles of transmission line and 10 substation upgrades required). **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.
7.4.2	Alternative Endpoints	**Need:** Project endpoints identified and optimized by MISO.[207]
7.4.3	Double Circuiting (765 kV/765 kV) and Other Engineering Considerations	**Need:** Single circuit meets current forecasts' needs and proactively accommodates a reasonable level of potential future needs.
7.4.4	High Voltage Direct Current	**Cost:** Less cost-effective than the Studied Projects.
7.4.5	Underground	**Viability:** Underground 765 kV technology is presently not available.
REASONABLE COMBINATION OF ALTERNATIVES		
7.5.1	Lower-Voltage and Existing System Upgrades	**Cost:** Less cost-effective than the Studied Projects. **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.
7.5.2	Lower-Voltage and Peaking Generation/Storage	**Cost:** Less cost-effective than the Studied Projects. **Optionality:** Does not allow for any future growth or expansion beyond the amount studied.

[207] *See PowerOn Midwest* Docket, Minnesota Department of Commerce, Division of Energy Resources Comments on Exemption Requests, at 6 (Oct. 21, 2025) ("The Department agrees with the Applicants that Minnesota Statutes limit the consideration of alternative end points in this matter….").

Table 7.0-1 Alternatives Evaluation Summary		
Section	**Alternative**	**Reason for Rejection**
ALTERNATIVE TRANSMISSION LINE ENGINEERING		
7.6.1	Alternative Conductor Design	The Applicants studied 17 conductors for the Project. Based on cost, performance, and the Project requirements, Applicants currently propose 1192.5 45/7 ACSR Bunting conductor or a similar performing conductor.
7.6.2	Alternative Structure Design	The Applicants considered multiple structure designs, including tubular H-Frame and monopole designs. Based on cost, resiliency, and constructability considerations, the Applicants determined that the lattice design was the best performing design for the Project.
NO BUILD ALTERNATIVE		
7.7	No Build Alternative	**Need:** Without the Studied Projects, there are consequences to: 1) system reliability (unserved demand, NERC reliability violations, energy adequacy, and system instability); 2) generation plans (increased risk of not complying with Minnesota's Carbon-Free by 2040 law); and 3) economics (less efficient and more expensive piecemeal solution required absent the coordinated regional approach).

7.1 Analysis of Alternatives

The evaluation of alternatives implies substitution for the Studied Projects, or an "or" (e.g., transmission or generation; 345 kV or 765 kV). In actuality, all technologies are needed to work together to optimally maintain reliability. The Studied Projects do not preclude other technologies evaluated but rather enable these technologies to work synergistically with the Studied Projects. Given the complex challenges to regional reliability from the changing generation fleet and electrical demands, an "all of the above" approach is needed. The Studied Projects work as part of a larger system which also includes and/or assumes:

- lower-voltage transmission line additions (e.g., 345 kV);
- upgrades of existing transmission lines;
- expansion of demand side management;
- additional distributed generation;
- utility-scale generation additions of multiple fuel-types; and

- expansion in energy storage.[208]

All these technologies, including the Studied Projects, are necessary to support future grid reliability.

7.1.1 Alternative Evaluation Criteria

To be an alternative to the Studied Projects, an alternative (or combination of alternatives) must, at a minimum, address the primary needs for the Studied Projects detailed in **Chapter 6**. Because there are multiple needs, needs were prioritized and alternatives screened based on the following criteria.

A viable alternative must:

- Address the NERC reliability violations mitigated by the Studied Projects (see **Section 6.3.1**);
- Maintain energy adequacy (serve load at all hours, every day) by eliminating an equivalent level of unserved demand as the Studied Projects (see **Section 6.3.2**);
- Comply with state law (see **Section 3.4.2**); and
- Have similar cost impacts as the Studied Projects – considering both upfront capital costs and economic impacts (e.g., congestion and fuel savings; see **Section 2.4** and **Section 6.4**).

The Applicants further evaluated the alternatives that met these criteria on additional factors: flexibility to meet future needs, curtailment reduction, carbon emission reductions, resiliency, and land and community impacts.

7.1.2 Alternative Evaluation Methodology and Cost Assumptions

The Applicants compared the electrical performance of each alternative to the Studied Projects based on practices which are industry standard and consistent with MISO's federally approved tariff. All analysis and assumptions are consistent with need methodology detailed in **Section 6.2.**

To evaluate generation and non-wire alternatives, the Applicants used EPRI's CPLANET tool (see **Section 6.2.2**). To evaluate transmission alternatives, the Applicants directly replaced the Studied Projects with other potential transmission solution. The Applicants also studied

[208] MISO LRTP Tranche 2.1 assumes approximately 3,500 MW of new energy storage will be added in Minnesota and the surrounding area over the next 20 years. See **Appendix E.2.** Page 87 for MISO Local Resource Zone 1.

combinations of alternatives. Because the Project as evaluated (i.e., the Studied Projects) extends beyond Minnesota into South Dakota, Iowa, and Wisconsin,[209] the Applicants did not limit the geographic scope of alternatives to Minnesota.

The Applicants used consistent "planning-level" scope and cost assumptions to have "apples to apples" costs to compare against alternatives. **Section 2.4.1** of the Application includes the Applicants' cost estimates and describes the diligence conducted by the Applicants to prepare the cost estimates. An equivalent level of detail is not available for each alternative. For consistency, the Applicants compared the Studied Projects and each alternative using planning-level scopes and MISO's MTEP24 cost-estimation guide, or equivalent, for non-wire alternatives. When comparing costs between alternatives, the focus is the relative relationship between the Studied Projects and the alternatives (i.e., a higher cost or lower cost) using a common set of cost assumptions, rather than the absolute magnitude of each cost. The Studied Projects' estimated cost of $6.008 billion ($2024), used for comparison with alternatives, is provided in **Table 7.1-1**.

Table 7.1-1
Studied Projects Cost Estimate for Comparison with Alternatives[210]

Segment	Estimated Cost ($2024)
Project: Minnesota Portions of LRTP 22 – 25	$2.244 billion
South Dakota portion of LRTP 22	$724 million
Iowa 765 kV portions of LRTP 23	$1.116 billion
Minnesota portion of LRTP 26	$821 million
Wisconsin portion of LRTP 26	$1.103 billion
TOTAL [a]	**$6.008 billion**

[a] The Studied Projects 20-year NPV cost using a 7 percent discount rate is $5.919 billion.

7.2 Alternative Voltages - Why 765 kV? Why Now?

The Applicants and MISO identified the need to transfer more than 10,000 MW more electrical capacity to, through, and out of Minnesota to meet future demands (see **Figure 6.0-1** and **Figure 6.0-2)**. The expansion of the transmission system technically could be accomplished through 345 kV facilities[211] or a combination of 345 kV and 765 kV facilities. However, given the magnitude of the capacity required, MISO concluded that 765 kV facilities along a west-east corridor with additional 345 kV transmission line facilities should be constructed.

[209] See **Section 6.1.**

[210] Cost estimates based on MISO MTEP24 approved scope and costs. See **Appendix E.1**. Page 145.

[211] Minnesota's high-voltage network is largely 345 kV with a few 500 kV lines primarily connecting to Manitoba.

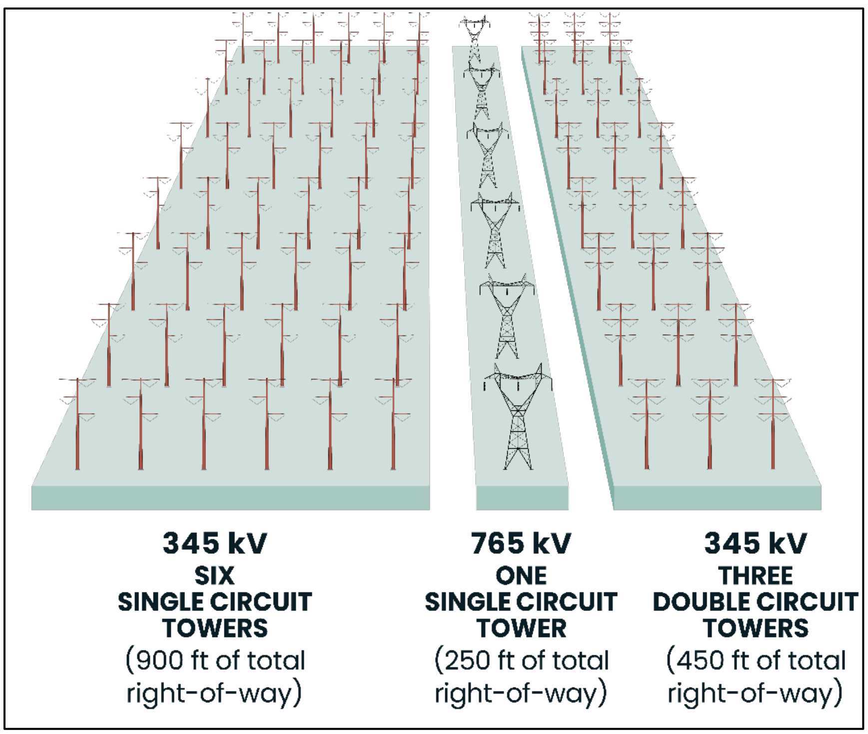
Use of the 765 kV voltage minimizes costs and the amount of right-of-way needed, which minimizes environmental impacts. It would require multiple 345 kV corridors resulting in more right-of-way to create the same capabilities as a single 765 kV right-of-way, as shown in **Table 7.2-1** and **Figure 7.2-1**.

Table 7.2-1
Comparison of Land Impacts to Meet Reliability Needs by Voltage Class

Voltage Class	Number of Lines Needed to Provide Equivalent Capability as One 765 kV Line[a]	Approximate ROW Needs for Each Line (feet)	Total ROW Width (feet)	Total Impacted Acreage for 410 Miles[b]
345 kV Single-Circuit	6	150	900	44,727
345 kV Double-Circuit	3	150	450	22,364
765 kV (Project)	1	250	250	12,424

a MISO. See **Appendix E.1.** Page 35.
b Mileage for Minnesota portion of the Studied Projects (MISO LRTP numbers 22 through 26).

Figure 7.2-1: Comparison of Total Right-of-Way Width Based on General Capacities of Each Voltage Class (Not to Scale) [212]



[212] **Figure 7.2-1** illustrates total right-of-way width to meet needs for each voltage class. 345 kV and double-circuit 345 kV lines may not be located in a single-common right-of-way, as shown for illustrative purposes; however,

The 765 kV voltage is also the least-cost option to transfer the necessary level of energy. As shown in **Table 7.2-2**, 765 kV transmission costs are half the costs of single- or double-circuit 345 kV options that have the equivalent capability.

Table 7.2-2
Comparison of Costs to Meet Reliability Needs by Voltage Class

Voltage Class	Approximate Cost for Each Line [a] ($2024)	Number of Lines Needed to Provide Equivalent Capability as one 765 kV Line [b]	Approximate Total Costs ($2024)
345 kV Single-Circuit	$3.6 million/mile	6	$21.6 million/mile
345 kV Double-Circuit	$6.0 million/mile	3	$18.0 million/mile
765 kV (the Project)	$5.7 million/mile	1	$5.7 million/mile

a MISO. MTEP24 Cost Estimation Guide. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf. Table 4.1-1 and 4.1-2.
b MISO. See **Appendix E.1.** Page 35

While the Project is the first 765 kV line in the Upper Midwest, approximately 2,400 miles of 765 kV lines have been safely and reliably operating in the United States for decades (see **Section 3.2.1**). 765 kV transmission technology has been included in long-term plans for the Upper Midwest since 2009. Previous evaluations of 765 kV in the Upper Midwest include:

- **Green Power Express:** Approximately 3,000 miles of 765 kV across 7 states proposed by ITC in 2009 to enable the interconnection of approximately 60 GW of generation. The Green Power Express did not move forward due to an insufficient underlying system and lack of cost allocation mechanism.
- **MISO MVP & Precursor Studies:** In the 2000s, MISO conducted multiple studies considering 345 kV, 765 kV, and high voltage direct current (HVDC) overlays. MISO selected a primarily 345 kV overlay, with some 765 kV, as it met system needs at the time for the least costs.[213]
- **MISO LRTP Tranche 1:** MISO's long-term view consistently included transmission greater than 345 kV including 765 kV.[214] MISO LRTP Tranche 1 did not include 765

the total width of all rights-of-way would equal values displayed on **Figure 7.2-1**. See **Table 7.2-1** for additional details.

213 MISO Regional Generator Outlet Study. Available at: https://cleangridalliance.org/_uploads/_media_uploads/_source/RGOS_Overview.pdf.

214 MISO. MTEP 21 Report Addendum: Long Range Transmission Planning Tranche 1 Executive Summary. https://cdn.misoenergy.org/MTEP21%20Addendum-LRTP%20Tranche%201%20Report%20with%20Executive%20Summary625790.pdf. Page 17.

kV because the underlying system at that time could not support the higher voltage, and the 345 kV voltage could meet the system needs.

Today, each of the conditions necessary for 765 kV is present, including:

- **Need:** Best option considering technical performance, cost, impacts, etc.
- **Sufficiently robust underlying system to:**
  - **Meet NERC reliability criteria**: National standards require that the system be capable of maintaining reliability should there be an outage of a transmission line.
  - **Fully utilize the Project**: Underlying system has capacity to move power to and from the 765 kV network.
- **Mechanisms to share costs:** Regional buildouts require significant capital and approval from affected utilities to pay their share. The Project, as part of the MISO LRTP Tranche 2.1 Portfolio, is part of a coordinated buildout which allows each state to maintain reliability more cost-effectively.

7.2.1 Lower-Voltage Alternative

The Applicants evaluated a lower-voltage double-circuit 345 kV transmission line with the same endpoints to determine if it could meet the need for the Studied Projects (referred to as the Lower-Voltage Alternative).[215] The Lower-Voltage Alternative replaced the 765 kV facilities in the Studied Projects with double-circuit 345 kV facilities and included the 345 kV circuit between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation that is part of the Project. The Applicants' evaluation of the Lower-Voltage Alternative tested MISO's conclusion that multiple 345 kV transmission lines would be required to provide the same capabilities as the 765 kV transmission line proposed as part of the Project.

The Applicants estimate that the cost of the Lower-Voltage Alternative is $5,022 million ($2024).[216] The Applicants evaluated the electrical performance of the Lower-Voltage Alternative using steady-state, production cost, and stability analysis. Unless noted, all analyses and assumptions for the Lower-Voltage Alternative are consistent with the Project's analysis detailed in **Section 6.2**.

[215] The Applicants also considered but did not evaluate in detail a 500 kV alternative, as 500 kV has similar electrical capacity and similar costs as a double-circuit 345 kV.

[216] Cost per mile shown in **Table 7.2-2.**

As detailed in the following sections, the Applicants' analysis concluded that a single double-circuit 345 kV line was inadequate to meet the needs identified in **Section 7.1.1**. This means that multiple double-circuit 345 kV facilities would be required to provide transmission capacity equivalent to the Studied Projects' single 765 kV circuit facilities. Even two double-circuit 345 kV circuits are more costly and impact more land than the single 765 kV circuit Studied Projects' facilities as shown in **Tables 7.1-1 and 7.1-2**. Consequently, an alternative of multiple double-circuit 345 kV facilities was considered but rejected.

Section 7.5 describes the Applicants' evaluation of pairing the Lower-Voltage Alternative with existing system upgrades and non-wire alternatives.

7.2.1.1 Lower-Voltage Alternative Reliability Analysis

As shown in **Table 7.2-3**, the Lower-Voltage Alternative does not fully address the NERC steady-state reliability violations mitigated by the Studied Projects.[217] The Lower-Voltage Alternative does not adequately "pull" flows off the underlying system during high transfer conditions and thus violations remain at each of the "weakest" points across Minnesota and the surrounding area.

Table 7.2-3
Steady-State Reliability Analysis: Lower-Voltage Alternative Comparison
Count of Unique System Facilities where all Steady-State Reliability Issues are Solved

Solution	All	>200 kV
Studied Projects (765 kV)	80	25
Lower-Voltage Alternative (double-circuit 345 kV)	67	23

The Applicants also compared the ability to maintain energy adequacy (ability to serve load every hour of every day) between the Lower-Voltage Alternative and the Studied Projects. As shown in **Table 7.2-4**, the Lower-Voltage Alternative does not mitigate the same level of load at risk of being unserved as the Studied Projects.

[217] The count of reliability issues mitigated by the Studied Projects shown in **Table 7.2-3**, differs from the count in **Section 6.3.1** due to the treatment of the Joint Targeted Interconnected Queue (JTIQ) projects. In **Table 7.2-3**, the JTIQ projects are included in both the pre- and post-case in the Applicants' analysis of the Studied Projects and the Lower-Voltage Alternative. The JTIQ projects are included in the Applicants' analysis because they were approved by MISO in 2024. The count in **Section 6.3.1**, provided by MISO, excludes the JTIQ projects in both the pre- and post-case as when MISO performed their analysis the JTIQ projects were not MISO approved. In both cases, the only difference between the pre- and post-case is the Studied Projects or alternative. Both counts consistently highlight the need for the Studied Projects to mitigate NERC reliability issues.

Table 7.2-4 Unserved Demand [a] Analysis: Lower-Voltage Alternative Comparison – Year 2042 Future 2A		
Solution	**Mitigated Unserved Demand (MWh)**	**Difference in Mitigated Unserved Demand Compared to Studied Projects (MWh)**
Studied Projects (765 kV)	1,305,782	-
Lower-Voltage Alternative (double-circuit 345 kV)	552,233	753,549
[a] Unserved demand is caused by either a lack of generation available or inadequate transmission capacity to move generation to a specific demand site. The Applicants' analysis quantifies the amount of demand that would be at risk of being unserved without the Project, or demand that would need to be served by a future-new dispatchable generation technology at that site. MISO models quantify unserved demand as the sum of "emergency energy" and "flex" output.		

The Lower-Voltage Alternative also does not mitigate generation curtailment (wasted energy) to the same level as the Studied Projects as shown in **Table 7.2-5**.

Table 7.2-5 Wind and Solar Generation Curtailment Analysis: Lower-Voltage Alternative Comparison – Year 2042 Future 2A		
Solution	**Reduction in Curtailed Generation from Solution (MWh)**	**Difference in Curtailed Generation Compared to Studied Projects (MWh)**
Studied Projects (765 kV)	7,207,981	-
Lower-Voltage Alternative (double-circuit 345 kV)	4,605,138	2,602,843

7.2.1.2 Lower-Voltage Alternative Stability Analysis

As summarized in **Table 7.2-6**, the Lower-Voltage Alternative does not fully address instability issues addressed by the Studied Projects.

Table 7.2-6 Dynamic Stability Analysis Comparison: Lower-Voltage Alternative		
System Stability Maintained with Outage of:	**Studied Projects (765 kV)**	**Lower-Voltage Alternative (double-circuit 345 kV)**
Parallel path 765 kV lines in Iowa and Illinois (Twinkle to Sub T or Sub T to Woodford County 765 kV)	Yes	No
King to Eau Claire 345 kV line	Yes	No
One Alexandria to Bison 345 kV line	Yes	No

The projects in the MISO LRTP Tranche 2.1 Portfolio were designed and optimized to work together to meet the needs of the region. The Studied Projects serve as a "contingency back-up" to maintain system stability when other projects in the MISO LRTP Tranche 2.1 Portfolio are out of service, namely the parallel east-west paths in Iowa to Illinois and the path from Fargo to the Twin Cities. As shown in **Table 7.2-6**, the Lower-Voltage Alternative is not capable of addressing dynamic stability issues during outages of these transmission lines.

Additional details on the stability comparative analysis are included in **Appendix E.3**.

7.2.1.3 Lower-Voltage Alternative Economic Analysis

The Applicants compared the Lower-Voltage Alternative and the Studied Projects' ability to reduce system congestion. As shown in **Table 7.2-7**, the Lower-Voltage Alternative does not provide the same magnitude of congestion and fuel savings as the Studied Projects.

Table 7.2-7
Congestion and Fuel Savings Comparison: Lower-Voltage Alternative, MISO Region 20-year net present value
Future 2A – 7% Discount Rate

Solution	Congestion and Fuel Savings – MISO Midwest Footprint ($2024)	Difference in Savings ($2024)
Studied Projects (765 kV)	$1.600 billion	-
Lower-Voltage Alternative (double-circuit 345 kV)	$966 million	($634 million) (less savings)

7.2.2 Higher-Voltage Alternatives

765 kV is currently the highest AC voltage class in production and operating in the United States. Thus, higher-voltage AC alternatives are not a viable alternative to the Project.

7.3 Generation and Non-Wires Alternatives

The Applicants evaluated generation and non-wires alternatives, including new peaking generation, renewable generation, battery energy storage, distributed generation, nuclear generation, demand-side management and conservation measures, and reactive power additions.

As detailed in **Chapter 6**, the Studied Projects are needed to maintain NERC reliability standards by addressing system overloads. The Studied Projects increase transfer capability to move electricity from new and existing generation to serve new and existing electrical demands. The ability to transfer more energy is not only needed for reliability but also to efficiently and fully utilize available generating resources (i.e., to avoid curtailment or wasted generation). By its nature, transfer capability is created by transmission solutions, not generation. Adding additional generation does not address the core issues addressed by the Studied Projects of:

- increasing transmission capacity to interconnect with new generation;

- maintaining local reliability by being able to transfer energy into an area at times when local generation is not available; and
- efficiently and fully utilizing generation capacity.

Conversely, in many cases, adding additional generation without adding transmission grid capacity to fully interconnect new generation ("generation outlet") exacerbates system issues such as curtailment.

Nonetheless, in the following sections, the Applicants evaluated adding local generation as a direct alternative to the Studied Projects. Adding additional local capacity does not increase generation outlet or transfer capability; rather, it addresses energy adequacy issues by adding additional local generation to address times where existing local generation is insufficient to meet demand; and/or the existing grid is not capable of transferring enough energy to meet demand; and/or it provides a counter-flow to push back on new generation to avoid a reliability overload.

While the Applicants only evaluated and quantified generation alternatives for Minnesota and the areas bordering Minnesota, this generation alternative approach would also require MISO to adopt a similar strategy, as other states would be unable to rely on Minnesota generation when their local generation is not available to serve their load.

As detailed in the following sections, no generation alternatives are a more reasonable and prudent alternative to the Studied Projects.

7.3.1 Peaking Generation

The Applicants considered peaking generation as an alternative to the Studied Projects. Peaking generation, in this context, means local dispatchable generation that is interconnected to the transmission system and can run continuously and whenever called upon. The Applicants considered both natural gas and hydrogen as peaking generation fuel sources. The Applicants considered three general configurations for peaking generation: reciprocating internal combustion engines, combustion turbines, and combined cycle generation. The Applicants assumed that each peaking generation addition could be sized exactly to meet system needs.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify the peaking generation additions necessary to address the NERC steady-state reliability needs. The Applicants analysis identified that peaking generation additions alone were incapable of addressing all the NERC steady-state reliability needs that are addressed by the Studied Projects. Peaking generation additions totaling 5,172 MW spread amongst 12 locations were able to solve approximately a third of the steady-state reliability needs of the Studied Projects (or, 23 of 80 facilities addressed by the Studied Projects). The estimated cost for those peaking units based on available technology is as follows:

- **Reciprocating Internal Combustion Engine:** Total estimated capital cost: $6.454 billion ($2024);[218]
- **Combustion Turbines (natural gas):** Total estimated capital cost: $4.282 billion ($2024);[219]
- **Combustion Turbines (hydrogen):** Total estimated capital cost: $4.458 billion ($2024);[220] or
- **Combined Cycle Generation:** Total estimated capital cost: $4.401 billion ($2024).[221]

In addition to the generation additions, it would be necessary to upgrade 57 different transmission elements, estimated to cost approximately $1.655 billion, summarized in **Table 7.3-1**, to address the NERC steady-state reliability issues not resolved through the peaking generation additions.

Table 7.3-1
System Upgrades in Addition to Peaking Generation Needed to Address NERC Reliability Needs

Scope	Number (unique locations)	Total Miles	Estimated Cost ($2024)
Peaking generation alternative (natural gas CT)	12	-	$4.282 billion
345 kV line upgrade	7	203	$869 million
230 kV line upgrade	3	59	$111 million
161 kV line upgrade	7	106	$190 million
138 kV line upgrade	9	82	$146 million
115 kV line upgrade	23	156	$268 million
Transformer upgrade	6	-	$63 million
Additional transformer	2	-	$19 million
TOTAL	**69**	**604**	**$5.947 billion** [a]

[a] Twenty-year NPV cost using a 7 percent discount rate is $6.255 billion.

[218] EIA. Construction Cost Data for Electric Generators Installed in 2023. Available at: https://www.eia.gov/electricity/generatorcosts/.

[219] EIA. Annual Energy Outlook 2025 at Table 4 ("MISW" region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

[220] Id.

[221] Id.

Each peaking generation solution, combined with necessary transmission upgrades, may be designed to mitigate the identified NERC reliability issues and for a similar construction cost as the Studied Projects. However, when considering total costs including fuel, congestion, generation curtailment (wasted energy), and emissions, the peaking generation alternative is significantly more costly than the Studied Projects, as shown in **Table 7.3-2**.

It should be noted that to provide the necessary reactive power support, the peaking plants would have to be built and operated to provide reactive power when not outputting real power (MWs) and/or additional reactive power equipment (e.g., capacitors, reactors, and Static Synchronous Compensators [STATCOMs]) would be necessary. As the total cost for the peaking generation alternative already exceeded the cost of the Studied Projects the Applicants did not further evaluate the necessary reactive additions.

Table 7.3-2
Total Cost Effectiveness of the Studied Projects Versus Peaking Generation Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)

	Capital Cost [a]	Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				Total Costs
		Congestion and Fuel	**Avoided Reliability**	**Asset Renewal**	**Decarbonization**	
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion - $6.222 billion	($5.927 billion) – ($1.832 billion) [c]
Peaking generation alternative (natural gas combustion turbines)	$6.255 billion	$47 million	$3.705 billion	-	($440 million) - ($1.265 billion)	$2.944 billion to $3.768 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 value of lost load (VOLL). Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative value denotes a total cost reduction (savings exceed upfront costs).

In addition to a higher total cost, the peaking generation alternative does not allow for future growth or expansion beyond the amount studied – as detailed in **Section 6.6.1** the Studied Projects proactively enable load growth beyond the base forecast. In addition, peaking generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied Projects as discussed in **Section 6.6.2.** Peaking generation alternatives which utilize fossil fuels also do not help meet the state's Carbon-Free by 2040 law. In addition, timing and permitting uncertainty is a concern as each of the 12 generators would need to go through the MISO generator interconnection queue processes and federal, state, and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3**, peaking generation does not address the core issues of generation outlet and transfer capability, which are addressed by the Studied Projects.

The addition of new peaking generation is not a more reasonable and prudent alternative to the Studied Projects.

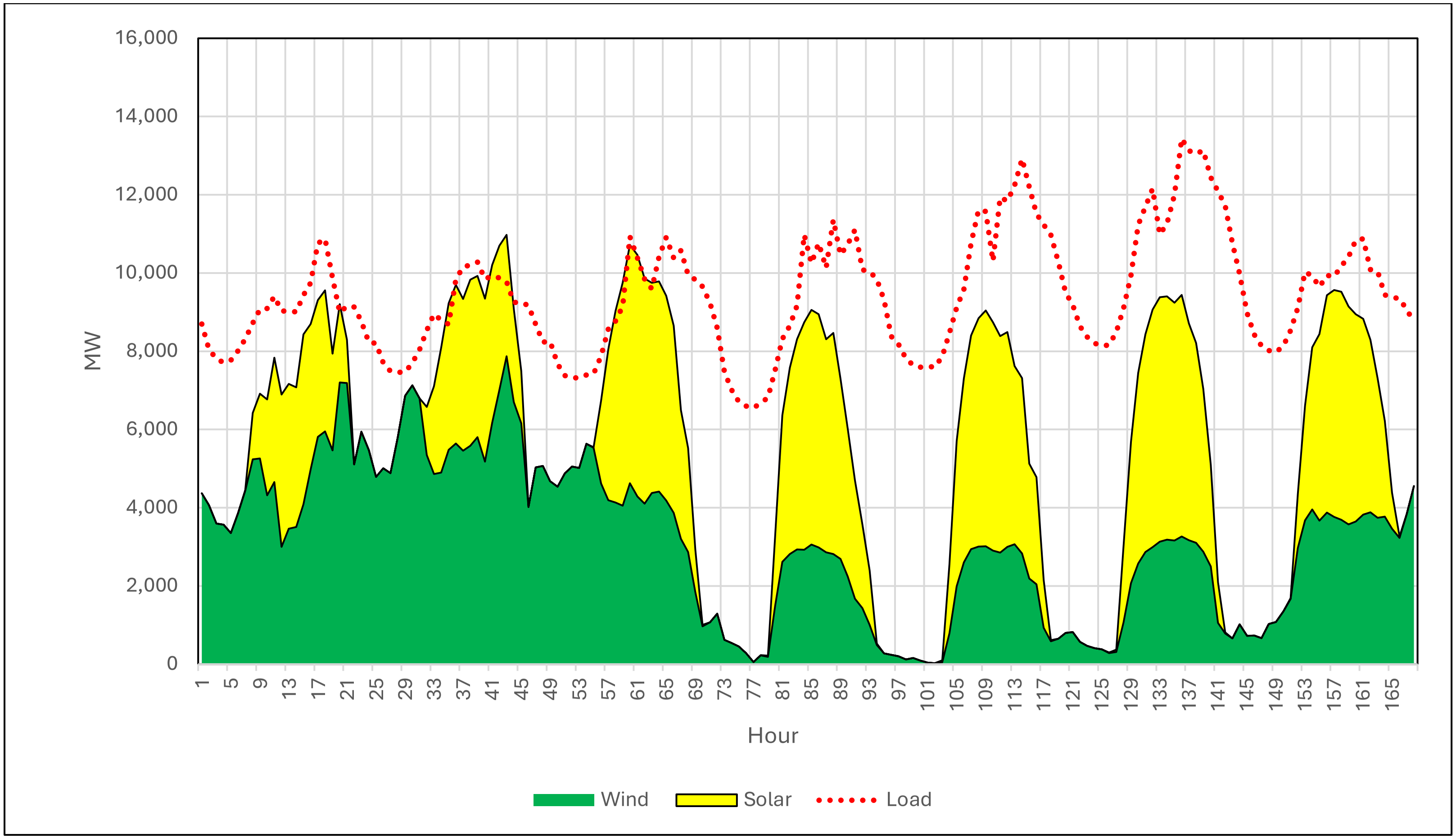
7.3.2 Renewable Generation

The Applicants considered renewable generation (i.e., solar and wind generation) as an alternative to the Studied Projects. The renewable generation may be interconnected at a single location on the transmission system or at multiple locations on the transmission or distribution system.

The Studied Projects help maintain system reliability every hour of every day (energy adequacy) by providing the ability to transfer (import) regional and diverse energy when local generation is not available. As such, a viable generation alternative to the Studied Projects must always be available locally to meet reliability needs. Because renewable generation is dependent on natural events, such as sunlight or wind speed, and cannot be dispatched if those natural conditions are not present, neither wind nor solar generation alone is a viable alternative to the Studied Projects.

As shown on **Figure 7.3-1**, without the multi-state geographic diversity enabled by the Studied Projects and MISO LRTP Tranche 2.1 Portfolio, there are hours where there is practically no in-state wind or solar output, and thus no reasonable amount of additional renewable generation will meet the reliability need of the Studied Projects.

Figure 7.3-1: Minnesota Hourly Total Renewable Output During Last Week of July 2018



The Studied Projects are needed to reliably serve load in Minnesota, when local wind and solar levels are at their lowest. During these hours, the Studied Projects facilitate importing generation to Minnesota from other parts of the MISO footprint. Replacing the Studied Projects with additional local renewable generation, subject to the same weather patterns versus geographically diverse renewables, is not viable as it does not address the issue of local generation being unavailable.

The addition of new renewable generation is not a viable alternative to the Studied Projects. The combination of renewable generation with energy storage is discussed in **Section 7.3.3**.

7.3.3 Battery Energy Storage

Energy storage, in this context, means a local battery or some other energy storage technology capable of being charged and discharged when called upon. The Applicants considered and evaluated both 4- and 8-hour energy storage options. Each energy storage option assumes lithium-ion battery technology per the U.S. Department of Energy's National Renewable Electric Laboratory. Any longer-duration storage solutions will be significantly more costly to implement.

Energy storage locations were optimized to meet reliability needs with the minimum amount of storage additions (i.e., lowest capital costs). As such, energy storage locations considered co-location with renewables including wind and solar, demand sources (representative of either utility-scale at load or a collection of distributed storage units), and other strategic places on the transmission system. If storage additions were limited to only one of these locations, the amount of storage necessary to address the reliability needs of the Studied Projects would at-best be more expensive or at-worst be non-viable, as the alternative would address less of the reliability needs of the Studied Projects. The Applicants also considered adding both additional generation and energy storage together. The option was rejected for further study, because even with the energy storage alternative and no additional generation, there is generation curtailment (excess energy which is wasted). Adding additional generation would increase curtailment and capital costs.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify energy storage additions necessary to address the NERC steady-state reliability needs. The Applicants' analysis identified that energy storage additions alone were incapable of reasonably addressing all the NERC steady-state reliability needs addressed by the Studied Projects. Energy storage additions totaling 7,527 MW spread amongst 30 locations were able to solve approximately half of the steady-state reliability needs of the Studied Projects (or, 42 of 80 facilities addressed by the Studied Projects). The estimated cost based on available technology is as follows:

- **Energy Storage:** 7,527 MW total at 30 locations. Total estimated capital cost: $12.879 billion ($2024) for 4-hour batteries or $25.691 billion ($2024) for 8-hour batteries.[222]

In addition to the energy storage additions, it is necessary to upgrade 38 different transmission elements estimated to cost approximately $1.227 billion to address reliability issues which could not be efficiently resolved through storage additions, as shown in **Table 7.3-3**. It should be noted that to provide the necessary reactive power support, the energy storage additions would have to be built and operated to provide reactive power.

Table 7.3-3
System Upgrades in Addition to Energy Storage Additions to Address NERC Reliability Needs

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
Energy Storage Alternative • 4-Hour Batteries • 8-Hour Batteries	30	-	$12.879 billion $25.691 billion
345 kV Transmission Line Upgrade	5	143	$651 million
230 kV Transmission Line Upgrade	3	59	$111 million
161 kV Transmission Line Upgrade	4	78	$141 million
138 kV Transmission Line Upgrade	6	57	$96 million
115 kV Transmission Line Upgrade	15	98	$172 million
Transformer Upgrade	4	-	$44 million
Additional Transformer	1	-	$11 million
TOTAL – 4-Hour Batteries	**68**	**435**	**$14.106 billion** [a]
TOTAL – 8-Hour Batteries	**68**	**435**	**$26.918 billion** [b]

[a] Twenty-year NPV cost using a 7 percent discount rate is $15.089 billion.
[b] Twenty-year NPV cost using a 7 percent discount rate is $28.896 billion.

Both 4-hour battery and 8-hour battery energy storage options, combined with necessary transmission upgrades, may be designed to mitigate the NERC steady-state reliability issues but each technology offers tradeoffs between upfront costs and economic savings (e.g., congestion and fuel savings); thus, each were further evaluated using production cost models

[222] U.S. Department of Energy's National Renewable Electric Laboratory. 2024 Annual Technology Baseline (4-hour and 8-hour battery – moderate maturity curve). Available at: https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

in **Table 7.3-4**. As shown in **Table 7.3-4**, each energy storage alternative has a significantly higher total cost than the Studied Projects.

Table 7.3-4
Total Cost Effectiveness of the Studied Projects Versus Battery Energy Storage Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)

	Capital Cost [a]	Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				Total Costs
		Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) – ($1.832 billion) [c]
4-Hour Batteries Alternative	$15.089 billion	$383 million	$3.705 billion	-	$231 million - $495 million	$10.506 billion - $10.770 billion
8-Hour Batteries Alternative	$28.896 billion	$461 million	$3.705 billion	-	$364 million - $591 million	$24.139 billion - $24.366 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative value denotes a total cost reduction (savings exceed upfront costs).

In addition to a higher total cost, the energy storage generation alternative does not allow for any future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1**, the Studied Projects proactively enable load growth beyond the base forecast. In addition, peaking generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2.** Timing and permitting uncertainty are a concern as each of the 30 battery energy storage locations would need to go through the appropriate MISO processes as well as federal, state, and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3**, energy storage does not address the core issues of generation outlet and transfer capability, which are addressed by the Studied Projects.

The addition of energy storage is not a more reasonable and prudent alternative to the Studied Projects.

7.3.4 Distributed Generation

Distributed generation is typically smaller-scale generation that is connected to the local distribution system. Distributed generation can be dispatchable generation, which is able to run continuously when called upon, most likely on diesel, natural gas, or other fossil fuels. Distributed generation can also be renewable and/or battery energy storage.

Dispatchable distributed and renewable generation have the same fundamental limitations as transmission-connected peaking, renewable generation, and battery energy storage, as discussed in **Sections 7.3.1, 7.3.2, and 7.3.3,** but at a greater cost.[223] Therefore, the addition of new dispatchable or renewable distributed generators is not a more reasonable and prudent alternative to the Studied Projects.

7.3.5 Nuclear Generation

Minnesota currently has a nuclear power moratorium in place, preventing the construction of new nuclear power facilities.[224] Thus nuclear is not a viable alternative to the Project. Nonetheless, given public interest in potential new nuclear technologies, the Applicants evaluated nuclear options.

Nuclear generation, in this context, is a thermal power station in which the power source is a nuclear reactor. The Applicants considered two general configurations for nuclear generation: utility-scale nuclear plants and small modular nuclear reactors (SMRs). SMRs are an emerging technology. In the United States, SMRs are in the research and prototype phase and not in wide commercial deployment.[225] For analysis purposes, the Applicants assumed each SMR can be sized exactly to meet reliability needs. The Applicants assumed that each utility-scale nuclear plant was 1,000 MW. Each nuclear generator (utility-scale or SMR) was assumed to have a minimum generation dispatch of 25 percent of nameplate capacity.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify nuclear generation additions necessary to address the NERC steady-state reliability needs. The following SMR nuclear generation additions were able to solve approximately a third of the steady-state reliability needs of the Studied Projects (or, 23 of 80 facilities addressed by the Studied Projects). The estimated cost based on available technology is as follows:

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[223] A distributed peaking generation has a construction cost of $1,929/kW ($2024) compared to $828/kw for a utility-scale combustion turbine. Source: U.S. Energy Information Administration, Annual Energy Outlook 2025 at Table 4 ("MISW" region). EIA. Assumptions to the Annual Energy Outlook 2025: Electricity Market Module. Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

[224] Minn. Stat. § 216B.243, subdivision 3b.

[225] U.S. Department of Energy. Advanced Small Modular Reactors. Available at: https://www.energy.gov/ne/advanced-small-modular-reactors-smrs

- **SMR:** 5,172 MW total at 12 locations. Total estimated capital cost: $49.284 billion ($2024).[226]

The Applicants considered but rejected a utility-scale nuclear plant option to address reliability needs. As each utility-scale nuclear plant is assumed to have a minimum capacity size of 1,000 MW, adding 12,000 MW of nuclear generation (one unit per site) is not a reasonable or prudent alternative

In addition to the SMR nuclear additions, it would be necessary to upgrade 57 different transmission elements, estimated to cost approximately $1.655 billion, summarized in **Table 7.3-5**, to address the NERC steady-state reliability issues not resolved through nuclear generation additions.

Table 7.3-5
System Upgrades in Addition to Nuclear Generation Needed to Address NERC Reliability Needs

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
SMR Nuclear Alternative	12	-	$49.289 billion
345 kV Transmission Line Upgrade	7	203	$869 million
230 kV Transmission Line Upgrade	3	59	$111 million
161 kV Transmission Line Upgrade	7	106	$190 million
138 kV Transmission Line Upgrade	9	82	$146 million
115 kV Transmission Line Upgrade	23	156	$268 million
Transformer Upgrade	6	-	$63 million
Additional Transformer	2	-	$19 million
TOTAL	**69**	**604**	**$50.949 billion** [a]

[a] Twenty-year NPV cost using a 7 percent discount rate is $54.754 billion.

Nuclear generation additions, combined with necessary transmission upgrades, may be designed to mitigate the identified NERC reliability issues and further reduce CO_2 emissions; however, at a significantly higher cost than the Studied Projects, as shown in **Table 7.3-6**.

[226] EIA. Annual Energy Outlook 2025 at Table 4 ("MISW" region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

Table 7.3-6 Total Cost Effectiveness of the Studied Projects Versus SMR Nuclear Generation Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)						
		Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				
	Capital Cost [a]	Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	Total Costs
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
SMR nuclear alternative	$54.754 billion	$854 million	$3.705 billion	-	$2.868 billion - $8.385 billion	$41.810 billion- $47.327 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2emissions.

[c] Negative value denotes a total cost reduction (savings exceed upfront costs).

In addition to a higher total cost, the nuclear generation alternative does not allow for any future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1**, the Studied Projects proactively enable load growth beyond the base forecast. In addition, nuclear generation alternatives do not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2**. Even if Minnesota's nuclear moratorium where lifted, timing and permitting uncertainty is a concern as each of the 12 generators would need to go through the MISO queue processes and federal, state, and local permitting (as appropriate). Most importantly, as discussed in **Section 7.3.5**, nuclear generation does not address the core issue addressed by the Studied Projects – generation outlet and transfer capability.

The addition of new nuclear generation is not a more reasonable and prudent alternative to the Studied Projects.

7.3.6 Demand Side Management/Conservation

The Applicants considered demand-side management/conservation as an alternative to the Studied Projects. In this context, demand side management/conservation is assumed to encompass all forms of peak shaving and load reduction programs, such as interruptible loads and dual fuel programs, as well as more general energy conservation programs, such as energy-efficiency rebates. It should be noted that MISO's models assume implementation of current demand side management and conservation plans and an expected forecast for program growth as detailed in **Appendix G**. This alternative considers adding additional demand side management and conservation beyond the base forecast to attempt to address NERC reliability needs. The demand side management/conservation alternative is sized as the minimal amount of load which would have to be reduced to avoid NERC reliability issues without the Studied Projects.

As discussed in **Section 7.1.2**, the Applicants used the EPRI CPLANET tool to identify demand side management/conservation programs necessary to address the NERC steady-state reliability needs. The Applicants' analysis identified that demand side management/conservation alone was incapable of addressing all the NERC steady-state reliability needs addressed by the Studied Projects. Demand side management/conservation program additions totaling 5,122 MW were able to solve approximately a third of the steady-state reliability needs of the Studied Projects (or, 28 of 80 facilities addressed by the Studied Projects). In addition to the demand side management/conservation additions, at a minimum, it would be necessary to upgrade the transmission grid to address each of the outstanding NERC reliability issues.

Although conservation programs will continue to be implemented in the area of the Studied Projects to encourage efficient use of electricity, it is unrealistic for these programs to reach the significant levels of load reduction required to maintain grid reliability. For these reasons, solutions involving demand-side management/conservation are not a more reasonable and prudent alternative to the Studied Projects.

7.3.7 Reactive Power Additions

The Applicants considered implementing additional reactive power additions to support reliability. Reactive power additions, in this context, mean transmission technology capable of providing reactive power and voltage support to the system through the use of traditional electromechanical devices such as switched capacitor banks and reactors, flexible AC transmission system devices such as static volt-amperes reactive compensators or STATCOMs, or synchronous condensers. Unlike generation or energy storage solutions, reactive power additions do not produce any active or real power (i.e., MWs) for consumption by end-use customers, meaning this alternative is not capable of providing real power support when local generation is not available, as discussed for previous generation and non-wires alternatives. Instead, reactive power solutions enable increased interface transfer capability by providing voltage support where needed to prevent voltage collapse.

While a reactive power addition may contribute to resolving or reducing the severity of the reliability issues, reactive power additions alone cannot satisfy all the needs of the Studied Projects. This is because existing transmission lines become overloaded when transferring power to, through, or out of Minnesota. Reactive power additions alone cannot mitigate these steady-state overloads on the transmission line, meaning that the additional existing system upgrades described in **Sections 7.3 and 7.4** would also be required. For these reasons, solutions involving only reactive power additions are not a more reasonable and prudent alternative to the Studied Projects.

7.4 Transmission Alternatives

7.4.1 Existing System Upgrades

The Applicants considered upgrading existing transmission facilities as an alternative to the Studied Projects (the Existing System Upgrades Alternative). For this analysis, existing system upgrades consisted of rebuilding overloaded transmission lines and facilities to a higher capacity and adding capacitor banks. Upgrading of existing transmission implies the installation of new conductors and/or equipment on existing transmission structures; however, as this definition did not meet reliability needs provided by the Studied Projects, the Applicants also considered a rebuild of existing transmission lines (including structures) to higher capacity and voltage levels.

The Existing System Upgrades Alternative was developed in an iterative fashion to resolve the NERC steady-state reliability violations and energy adequacy issues described in **Sections 6.3.1, 6.3.2, and 6.3.5**. Where transmission line overloads were identified, the existing transmission lines were upgraded to higher capacity. If the higher-capacity line was not sufficient to mitigate the reliability issue, the line was rebuilt as a double-circuit or at the next higher voltage level. Reactive power additions (e.g., capacitors, reactors, and STATCOMs) were added to provide the equivalent level of reactive power support as the Studied Projects. The Applicants continued the analysis iteratively until all steady-state reliability issues mitigated by the Studied Projects were resolved. The resulting Existing System Upgrades Alternative is detailed in **Table 7.4-1**.

Table 7.4-1
Existing System Upgrades Alternative Scope

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
345 kV Transmission Line Upgrade	15	735	$2.800 billion
230 kV Transmission Line Upgrade	3	47	$89 million
161 kV Transmission Line Upgrade	17	230	$458 million
138 kV Transmission Line Upgrade	10	87	$154 million
115 kV Transmission Line Upgrade	42	294	$504 million
Transformer Upgrade	6	-	$63 million
Additional Transformer	4	-	$45 million

Table 7.4-1 Existing System Upgrades Alternative Scope			
Scope	**Number (Unique Locations)**	**Total Miles**	**Estimated Cost ($2024)**
Reactive Support (Capacitors, STATCOMs)	-	-	$1.261 billion
TOTAL	**97**	**1,394**	**5.376 billion** [a]
[a] Twenty-year NPV cost using a 7 percent discount rate is $5.297 billion.			

Based on MISO's Transmission Cost Estimate Guide for MTEP24,[227] the Applicants estimate the cost for these upgrades to be at least $5.376 billion. Timing and constructability are a concern for the Existing System Upgrades Alternative, as it would require extended, coordinated outages on 87 individual transmission lines as well as shorter bus outages at multiple substations which can result in extended market congestion and marginal system reliability. In addition, prior to construction each upgrade would need to go through MISO's planning process and then be engineered and permitted by federal, state, and local agencies (as applicable).

If constructability and timing concerns could be managed, existing system upgrades may be designed to mitigate the identified NERC reliability issues. However, when considering total costs including congestion, generation curtailment (wasted energy), and generation dispatch costs, the Existing System Upgrades Alternative costs more than the Studied Projects, as shown in **Table 7.4-2**.

Table 7.4-2 Total Cost Effectiveness of the Studied Projects Versus Existing System Upgrades Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)						
		Savings Relative to "Do Nothing" [b] ***Positive value denotes a cost savings***				
	Capital Cost [a]	**Congestion and Fuel**	**Avoided Reliability**	**Asset Renewal**	**Decarbonization**	**Total Costs**
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
Existing System Upgrades Alternative	$5.297 billion	$178 million	$3.705 billion	-	$326 million - $952 million	$463 million - $1.088 billion

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative value denotes a total cost reduction (savings exceed upfront costs).

[227] MISO. Cost Estimation Guide / Workbook for MTEP 24. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf.

It should be emphasized that while the Existing System Upgrades Alternative addresses the minimum NERC reliability requirements, it does not provide the same level of operational reliability. As detailed in **Section 6.3.4**, in addition to the core steady-state overloads, the Studied Projects address overloads of 24 additional facilities under lower-probability higher-impact events. As the total costs of the Existing System Upgrades Alternative already exceeded the cost of the Studied Projects, the Applicants did not quantify the incremental upgrades necessary to provide an equivalent level of operational reliability as the Studied Projects.

In addition, the Existing System Upgrades Alternative does not provide the same level of future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the Existing System Upgrades Alternative would be "full" on "Day 1" whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The Existing System Upgrades Alternative does not allow for future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1**, the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.
- The Existing System Upgrades Alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2**.

For all these reasons, upgrading of existing facilities is not a more reasonable or prudent alternative to the Studied Projects.

7.4.2 Alternative Endpoints

The Applicants did not consider alternative transmission line endpoints for the Studied Projects. Pursuant to Minn. Stat. § 216B.243, subd. 3(6),[228] the Applicants are not required to evaluate alternative endpoints for a HVTL qualifying as a large energy facility unless the alternative end points are (i) consistent with end points identified in a federally registered planning authority (i.e., MISO) transmission plan; or (ii) otherwise agreed to for further evaluation by the applicant.

[228] "[T]he commission must not require evaluation of alternative end points for a high-voltage transmission line qualifying as a large energy facility unless the alternative end points are (i) consistent with end points identified in a federally registered planning authority transmission plan, or (ii) otherwise agreed to for further evaluation by the applicant".

MISO, in its identification of the Studied Projects and the LRTP Tranche 2.1 Portfolio, considered multiple configurations and endpoints. After multiple rounds of analysis, MISO selected the Studied Projects and LRTP Tranche 2.1 Portfolio as the optimal configuration to meet regional system needs. Additional information on MISO's evaluation of alternative system endpoints can be found in **Appendix E.1**.[229]

7.4.3 Double Circuiting Considerations

Double-circuiting is the construction of two separate transmission circuits (three phases per circuit) on the same structure. Placing two transmission circuits on common structures generally reduces right-of-way requirements, which potentially reduces human and environmental impacts.

The Project will involve upgrades of the single-circuit 345 kV transmission lines between the Pleasant Valley Substation, North Rochester Substation, and Hampton Substation to double-circuit 345 kV transmission lines, effectively doubling capacity.

The 765 kV portions of the Project are proposed as a single circuit to meet MISO's identified needs. As discussed in **Section 6.6.1**, the Project is proactively designed to support a reasonable amount of future system needs. Unlike other voltage classes (e.g., 345 kV) where double-circuit transmission structures are common, all existing 765 kV structures in the United States are single-circuit. Double-circuiting 765 kV transmission lines presents reliability, maintenance, and practical challenges.

- **Reliability challenges:** Reliability standards established by NERC require that the transmission system be planned to be able to withstand potential contingencies, including the loss of all circuits on a common structure. For a double-circuit 765 kV line, the remaining transmission system would need to be planned to maintain reliability during the simultaneous outage of two 765 kV lines. As two 765 kV lines carry the equivalent capacity of multiple double-circuit 345 kV lines,[230] the underlying system would need to be significantly expanded to provide adequate contingency back-up.
- **Maintenance challenges:** When multiple circuits are constructed on common towers, typically all circuits sharing the common tower must be deenergized for the maintenance period for worker safety, or specialized "live line" procedures

[229] See **Appendix E.1**. Page 42.
[230] See **Appendix E.1**. Page 35.

and precautions must be planned and followed. As MISO coordinates outages to ensure ongoing system reliability, trying to schedule simultaneous outages involving multiple circuits on a common tower is more difficult than if each circuit could be maintained separately without taking the others out of service at the same time. The backbone nature of 765 kV increases the difficulty and criticality of trying to schedule outages. In addition, taller or more specialized structures required for the double-circuit may require specialized equipment and maintenance practices.

- **Practical siting challenges:** The Project's single circuit 765 kV is configured with the phases horizontally aligned to minimize structure heights and comply with all applicable state and federal safety and engineering standards. Double-circuit structures require lines to have the phases either be configured vertically or multiple horizontal elevations. Regardless of design, given the necessary clearances, double-circuit structure heights would likely exceed 200 feet and require lighting in accordance with FAA guidance.[231] In addition to taller heights, the additional conductor and arms weight will result in more robust (i.e., more steel) and costly structures.

Co-locating the proposed 765 kV portions of the Project with other voltages has similar challenges.

7.4.4 High Voltage Direct Current

HVDC lines are typically proposed for transmitting large amounts of electricity over long distances because line losses are less than an AC line. HVDC lines require converter stations at each delivery point because the DC power must be converted to AC power before customers can use it. A single 600 kV or 640 kV HVDC converter station can be upwards of $750 million to $900 million, respectively.[232] The converter station costs do not include nor obviate the need for line construction and AC substation upgrades. Such converter stations would add significantly to the cost of the Project, as the Project has three 765 kV delivery points (i.e., substations) in Minnesota, and three additional delivery points outside of Minnesota.

[231] The first double circuit 765 kV line in South Korea has an average height of 95 meters (312 feet). T&D World. Korea's First 765 kV Double Circuit Line. Available at: https://www.tdworld.com/overhead-transmission/article/20969243/koreas-first-765-kv-double-circuit-line.

[232] MISO. Cost Estimation Guide / Workbook for MTEP 2024. Available at: https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf Table 4.3

HVDC lines are typically proposed for large regional transmission projects that involve hundreds of miles of new transmission line between two delivery points. As a general rule, HVDC becomes a cost-effective alternative to AC transmission when the line length is greater than 260 miles and high transfer capability is needed.[233] As detailed in **Section 1.2.1**, the Project is made up of a series of individual facilities, each providing delivery points between generation and demand. The Project's longest segment is between the Lakefield Junction Substation and the Pleasant Valley Substation. MISO estimated this segment to be 130 miles, which is much shorter than the threshold for which HVDC is cost effective.

HVDC is not a more reasonable and prudent alternative for the Project.

7.4.5 Underground

Undergrounding has not been used for 765 kV transmission lines. Underground 765 kV cable is not currently available from cable manufacturers. Development of a new voltage class of cable system takes several years through design, prototypes, and qualification testing.

Even if an underground design were feasible, the construction cost of placing the entire length of the Project's proposed transmission line underground is currently unknown, as this would involve the engineering and construction of an unprecedented voltage level that has never been developed or placed underground before. However, based on existing cost comparisons for 345 kV and 500 kV lines, underground installation is expected to be more than five times as expensive per mile as compared to the proposed overhead construction.

The largest AC voltage underground transmission lines that are in service today are 500 kV. In the United States, the most comparable project is the Tehachapi Renewable Transmission Project in Chino Hills, California.[234] The Tehachapi Renewable Transmission Project undergrounded an approximately 3.5-mile segment of a 500 kV line. The cost for undergrounding the 3.5-mile 500 kV segment was estimated at $247 million, or approximately $70 million per mile in 2014.[235] For reference, the Project's 765 kV overhead transmission lines

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[233] MISO. Discussion of Legacy, 765 kV, and HVDC Bulk Transmission. Available at: https://cdn.misoenergy.org/20230308%20PAC%20Item%2007%20Discussion%20of%20765%20kV%20and%20HVDC628088.pdf. Slide 6.

[234] T&D World. Engineering a 500 kV Underground System. Available at: https://www.tdworld.com/intelligent-undergrounding/article/20969593/engineering-a-500-kv-underground-system.

[235] *See In the Matter of the Application of Southern California Edison Company (U 338-E) for a Certificate of Public Convenience and Necessity Concerning the Tehachapi Renewable Transmission Project (Segments 4 through 11)*, Docket No. A0706031, Decision Granting the City of Chino Hill's Petition for Modification of Decision 09-12-044 and Requiring Undergrounding of Segment 8A of the Tehachapi Renewable Transmission Project, at 2-3, 22, 47 (July 11, 2013); Decision Granting, in part, the Petition of SCE for Modification of Decision 13-07-018, at 10 (Jan. 16, 2014).

are estimated to cost approximately $6.3 million per mile.[236] It should be emphasized that the Tehachapi Renewable Transmission Project is also at a lower voltage level than the Project.

The installation of an underground 765 kV transmission line is not a feasible, reasonable, or prudent alternative for any portion of the Project.

7.5 Any Reasonable Combination of Alternatives

The Applicants also considered combinations of generation/non-wire and transmission alternatives to the Studied Projects. The Applicants analyzed two combinations of alternatives:

- Lower-Voltage Alternative with existing system upgrades; and
- Lower-Voltage Alternative with peaking generation or storage.

The Applicants analyzed these two combinations to represent the optimized combinations of the Lower-Voltage Alternative and transmission and generation alternatives (respectively). It should be noted that in the evaluation of generation and non-wire alternatives in **Section 7.3** the Applicants considered the combination of generation alternatives and existing system upgrades.

As detailed in the following sections, none of the combined alternatives is a more reasonable and prudent alternative to the Studied Projects.

7.5.1 Combination of Lower-Voltage Alternative and Existing System Upgrades

The Applicants evaluated combining the Lower-Voltage Alternative and existing system upgrades. The scope of the combined alternative was developed by starting with the Lower-Voltage Alternative described in **Section 7.2.1** and then adding existing system upgrades to mitigate the remaining NERC reliability violations using the iterative process described in **Section 7.4.1.** The scope of the resulting combined alternative is shown in **Table 7.5-1**.

Table 7.5-1
Combined Lower-Voltage Alternative and Existing System Upgrades Alternative Scope

Scope	Count (unique locations)	Total Miles	Estimated Cost ($2024)
Lower-Voltage Alternative (*see* **Section 7.2.1**)	-	840	$5.022 billion
230 kV Transmission Line Upgrade	2	31	$59 million

[236] Escalation range based on Handy-Whitman Index of Public Utility Construction Costs for 2014 (Pacific Region) to 2025 (Central Region). Range indicative of escalation of total transmission plan (low end) and underground conductor, conduit, and devices (high end). The Handy-Whitman Index of Public Utility Construction Costs, a semi-annual publication by Whitman, Requardt and Associates that tracks and quantifies the escalation of costs for construction, materials, and equipment in the public utility industry.

Table 7.5-1 Combined Lower-Voltage Alternative and Existing System Upgrades Alternative Scope			
Scope	**Count (unique locations)**	**Total Miles**	**Estimated Cost ($2024)**
161 kV Transmission Line Upgrade	1	17	$30 million
138 kV Transmission Line Upgrade	2	17	$44 million
115 kV Transmission Line Upgrade	6	53	$80 million
Transformer Upgrade	1	-	$8 million
Additional Transformer	2	-	$21 million
Reactive Support (Capacitors, STATCOMs)	-	-	$1.106 billion
TOTAL	**14 + Lower-Voltage Alt**	**957**	**$6.370 billion**
[a] Twenty-year NPV cost using a 7 percent discount rate is $6.276 billion.			

This alternative may be designed to mitigate the identified NERC reliability issues and provide equivalent reactive support as the Studied Projects; however, at a higher total cost than the Studied Projects, as shown in **Table 7.5-2**.

Table 7.5-2 Total Cost Effectiveness of the Studied Projects Versus Combined Lower-Voltage Alternative and Existing System Upgrades Alternative: 20-year Net Present Value – 7 percent discount rate ($2024)						
		Savings Relative to "Do Nothing" [b] ***Positive value denotes a cost savings***				
	Capital Cost [a]	**Congestion and Fuel**	**Avoided Reliability**	**Asset Renewal**	**Decarbonization**	**Total Costs**
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) - ($1.832 billion) [c]
Combined Lower-Voltage Alternative and Existing System Upgrades Alternative	$6.276 billion	$904 million	$3.705 billion	-	$1.399 billion - 4.088 billion	($2.421 billion) [c] - $268 million

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative value denotes a total cost reduction (savings exceed upfront costs).

It should be emphasized that while the combined alternative addresses the minimum NERC reliability requirements in the current forecast, it provides no future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the alternative would be "full" on "Day 1" whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The alternative does not allow for future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1,** the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.
- The alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects, as discussed in **Section 6.6.2**.

For all these reasons, the combined alternative is not a more reasonable or prudent alternative to the Studied Projects.

7.5.2 Combination of Lower-Voltage Alternative and Peaking Generation/Storage

The Applicants evaluated combining the Lower-Voltage Alternative and peaking generation/storage. Natural gas peaking generation (**Section 7.3.1**) and battery energy storage (**Section 7.3.3**) were the lowest-cost non-wire alternatives. As discussed in these sections, adding additional local capacity does not increase generation outlet or transfer capability; rather, it addresses energy adequacy issues by adding generation to address times where local generation is not available and energy cannot be transferred from outside a local area to meet demand by the existing grid; and/or provides a counter-flow to "push back" on new generation to avoid a reliability overload.

The Applicants developed the scope of the combined alternatives by starting with the Lower-Voltage Alternative described in **Section 7.2.1** and then adding peaking generation or battery energy storage using the processes described in **Section 7.3.1** and **Section 7.3.3**, respectively, to mitigate the remaining NERC reliability violations issues. The scope of the resulting combined alternatives is as follows:

- **Lower-Voltage Alternative and Natural Gas Peaking Generation Alternative:** $6.431 billion ($2024).
    - **Lower-Voltage Alternative:** $5.022 billion ($2024).

    - **Natural Gas Peaking Generation:** 1,540 MW total at seven locations: $1.275 billion ($2024).[237]
    - **Existing System Upgrades:** Upgrades totaling $134 million were necessary to solve the remaining steady-state reliability issues.

- **Lower-Voltage Alternative and Battery Energy Storage Alternative:** $6.209 billion for 4-hour batteries and $7.257 billion for 8-hour batteries ($2024).
    - **Lower-Voltage Alternative:** $5.022 billion ($2024).
    - **Battery Energy Storage:** 615 MW total at nine locations: $1.053 billion for 4-hour batteries and $2.100 billion for 8-hour batteries ($2024).[238]
    - **Existing System Upgrades:** Upgrades totaling $134 million were necessary to solve the remaining steady-state reliability issues ($2024).

Peaking or storage additions alone were incapable of addressing each reliability issue even when combined with the Lower-Voltage Alternative; thus, additional existing system upgrades were also required as detailed in **Table 7.5-3.**

Table 7.5-3
Combined Lower-Voltage Alternative, Peaking Generation/Storage, and Existing System Upgrades Alternative Scope

Scope	Number (Unique Locations)	Total Miles	Estimated Cost ($2024)
Non-Wire Alternatives: • Natural Gas CT, • Energy Storage (4-Hour Batteries), or • Energy Storage (8-Hour Batteries).	7 9 9	-	$1.275 billion $1.053 billion $2.100 billion
Lower-Voltage Alternative (*see* **Section 7.2.1**)	-	840	$5.022 billion
230 kV Transmission Line Upgrade	1	28	$54 million
161 kV Transmission Line Upgrade	1	17	$30 million
138 kV Transmission Line Upgrade	1	9	$16 million
115 kV Transmission Line Upgrade	2	23	$34 million
TOTAL- Natural Gas CT	12 + Lower-Voltage Alt.	917	$6.431 billion [a]
TOTAL- Energy Storage (4-Hour Battery)	14 + Lower-Voltage Alt.	917	$6.209 billion [b]
TOTAL- Energy Storage (8-Hour Battery)	14 + Lower-Voltage Alt.	917	$7.257 billion [c]

[237] EIA. Annual Energy Outlook 2025 at Table 4 ("MISW" region). Available at: https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

[238] U.S. Department of Energy's National Renewable Electric Laboratory. 2024 Annual Technology Baseline (4 and 8-hour battery – moderate maturity curve). Available at: https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

Table 7.5-3 Combined Lower-Voltage Alternative, Peaking Generation/Storage, and Existing System Upgrades Alternative Scope			
Scope	**Number (Unique Locations)**	**Total Miles**	**Estimated Cost ($2024)**
[a] Twenty-year NPV cost using a 7 percent discount rate is $6.454 billion.			
[b] Twenty-year NPV cost using a 7 percent discount rate is $6.215 billion.			
[c] Twenty-year NPV cost using a 7 percent discount rate is $7.343 billion.			

These alternatives may be designed to mitigate the identified NERC reliability issues; however, at a higher total cost than the Studied Projects, as shown in **Table 7.5-4**.

Table 7.5-4
Total Cost Effectiveness of the Studied Projects Versus Combined Lower-Voltage Alternative and Generation Additions:
20-year Net Present Value – 7 percent discount rate ($2024)

		Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				
	Capital Cost [a]	**Congestion and Fuel**	**Avoided Reliability**	**Asset Renewal**	**Decarbonization**	**Total Costs [c]**
Studied Projects	$5.919 billion	$1.600 billion	$3.705 billion	$319 million	$2.127 billion – $6.222 billion	($5.927 billion) – ($1.832 billion)
Combined Lower-Voltage Alternative and Natural Gas Peaking Generation	$6.454 billion	$1.270 billion	$3.705 billion	-	$966 million - $2.826 billion	($1.347 billion) - $513 million
Combined Lower-Voltage Alternative and Battery Energy Storage: 4-Hour Batteries	$6.215 billion	$1.251 billion	$3.705 billion	-	$1.192 billion - $3.488 billion	($2.229 billion) - $67 million
Combined Lower-Voltage Alternative and Battery Energy Storage: 8-Hour Batteries	$7.343 billion	$1.283 billion	$3.705 billion	-	$1.219 billion - $3.564 billion	($1.209 billion) - $1.136 billion

Table 7.5-4
Total Cost Effectiveness of the Studied Projects Versus Combined Lower-Voltage Alternative and Generation Additions:
20-year Net Present Value – 7 percent discount rate ($2024)

		Savings Relative to "Do Nothing" [b] *Positive value denotes a cost savings*				
	Capital Cost [a]	Congestion and Fuel	Avoided Reliability	Asset Renewal	Decarbonization	Total Costs [c]

[a] See **Section 7.1.2** for cost details. For consistency, the Studied Projects and alternatives are each compared using MISO's planning-level scopes and MISO's MTEP24 cost-estimation guide or equivalent for non-wire alternatives.

[b] See **Section 6.4.1** for metric definitions. Avoided reliability assumes $3,500 VOLL. Decarbonization range based on 45Q federal tax credit (low-end) and the Minnesota Public Utilities Commission established (high-end) cost of CO_2 emissions.

[c] Negative values denote a total cost reduction (savings exceed upfront costs).

The peaking plants and energy storage additions would have to be built and operated to provide reactive power and/or additional reactive power equipment (e.g., capacitors, reactors, and STATCOMs) to provide the necessary reactive power support. As the total cost for the alternative already exceeded the cost of the Studied Projects the Applicants did not further evaluate the necessary reactive additions.

Finally, it should be emphasized that while the combined alternative addresses the minimum NERC reliability requirements in the current forecast, it provides no future flexibility or optionality. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as the "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs. In simple terms the alternative would be "full" on "Day 1" whereas the Studied Projects would still have space to accommodate future changes and options for further expansion. More specifically:

- The alternative does not allow for any future growth or expansion beyond the amount studied. As detailed in **Section 6.6.1,** the Studied Projects proactively enable load growth beyond the base forecast. Future load growth or additional changes on the system would continue to drive additional incremental upgrade needs for the foreseeable future.

- In addition, the alternative does not provide similar regional flexibility and resiliency benefits as the Studied Projects as discussed in **Section 6.6.2**.

For all these reasons, this alternative is not a more reasonable or prudent alternative to the Studied Projects.

7.6 Alternative Transmission Line Engineering

As the Project is the first 765 kV transmission line in Minnesota, significant engineering went into developing a 765 kV transmission voltage class standard which enables MISO's determined electrical performance requirements, meets all applicable state and federal standards for noise and safety, is resilient to Minnesota's weather conditions, and minimizes cost, human, and environmental impacts. The Project configuration detailed in **Section 2.2** is the result of over a year of engineering evaluation. The following sections detail alternative conductor and structure configurations considered for the Project.

7.6.1 Alternative Conductor Design

The Applicants propose to utilize a six-conductor bundle of 1192.5 kcmil 45/7 ACSR Bunting conductor per phase with 15-inch sub-conductor spacing, or a conductor with similar performance, for each 765 kV transmission line. The Applicants initially studied both four-conductor bundle and six-conductor bundle conductor configurations. However, the four-conductor bundle configuration was immediately determined to not to be an acceptable option due to its higher noise profile. After evaluating more than a dozen conductors, the Applicants determined that the 1192.5 45/7 ACSR Bunting would provide the requisite capacity for the Project, including meeting or exceeding MISO's requirements of 4,000 amps and 2,400 MW SIL.

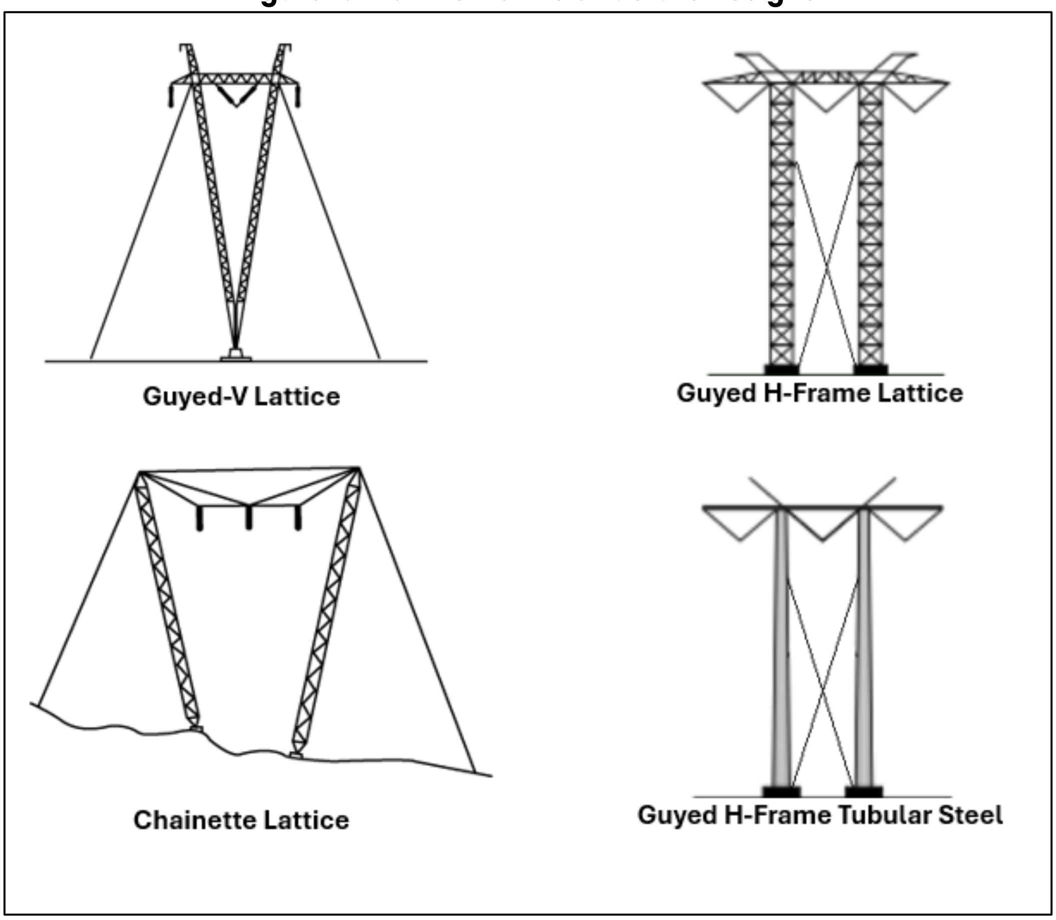
Each 345 kV line will utilize a twin bundle of twisted pair 636 kcmil ACSR or a similar performance conductor. The conductors will have a capacity equal to or greater than 3,000 amps. This type of conductor is the preferred conductor in areas of icing with wind that can lead to galloping, which is further discussed in **Section 2.2.3**.

7.6.2 Alternative Structure Design

The Project's proposed 765 kV structures are a self-supporting lattice design that will typically range in height from approximately 150 to 175 feet tall. Lattice structures are the most common structure type for existing 765 kV transmission lines across the United States. The structures will typically be installed on drilled pier concrete foundations, with typical foundations ranging in size from approximately 5 to 7 feet in diameter and 25 to 65 feet in depth. Actual foundation size will be based on site-specific conditions and detailed engineering design. Typical span lengths, meanwhile, will range from 1,110 to 1,300 feet. **Appendix C.1** contains a typical 765 kV structure drawing. The Applicants selected a self-supporting lattice tower design from among several structure types considered for the Project. The self-supporting lattice tower design was determined to best meet the Project needs based on considerations of cost, engineering, resiliency, and land-use impacts.

The Applicants considered several different structure types for the Project. Several were immediately rejected as acceptable options. For instance, based on land-use types within the Project's Notice Area, which are primarily agricultural areas, the Applicants determined that any structures requiring the use of guy wires and anchors would not be feasible for the Project. As such, structure types such as guyed-V lattice, chainette lattice, guyed H-frame lattice, and guyed H-frame tubular steel were removed from consideration. Images of these structure types are presented in **Figure 7.6-1**.[239]

Figure 7.6-1: Alternative Structure Designs



[239] Guyed-V lattice and chainette lattice (see guyed cross-rope suspension tower) from: Hydro Quebec. Power Transmission Towers. Available at: https://www.hydroquebec.com/learning/transport/types-pylones.html. Guyed H-frame lattice and guyed h-frame tubular steel (as modified) from: SaVRee. Electrical Transmission Towers Explained. Available at: https://www.savree.com/en/encyclopedia/electrical-transmission-towers.

The Applicants determined that the structure footprint of such structure types, along with the risk associated with third party damage to guyed structures, was unacceptable.

In addition to self-supporting lattice, the Applicants evaluated tubular steel H-frame and tubular steel monopole structure types as being potential options to consider for the Project. The Applicants first identified the general structure geometry and line characteristics for each structure type. The design of the tubular H-frame structure was based on similar line characteristics as the self-supporting lattice tower, including overall structure height, phase spacing, and span length, amongst other items. In addition, the design of the tubular H-frame structure type was based on the structure being mounted to drilled pier concrete foundations. In comparison, the tubular steel monopole structure was based on the conductors being arranged in a delta configuration, putting the conductor in a stacked vertical alignment. Given this configuration, and an assumed ruling span of 1,100 feet, the Applicants determined the typical height of a tubular steel monopole structure would be approximately 200 feet. As with the self-supporting lattice and tubular H-frame, the Applicants based the design of the tubular steel monopole on the use of a drilled pier concrete foundation.

To compare the three structure types, the Applicants performed a comprehensive structure selection analysis and comparison of each.

Based on the analysis, the Applicants determined that the tubular steel H-frame structure type could potentially be a technically feasible 765 kV structure option, but screened it from further consideration based on costs, constructability, technical considerations, and the ability of the structures to withstand extreme weather events. The weight of the tubular H-frame structure required to meet the engineering needs of the Project was determined to be significantly greater than the weight of the self-supporting lattice structure, thereby contributing to additional material handling challenges during construction. Further, the Applicants determined that the tubular steel H-frame structures were approximately 20 percent more costly per mile as compared to self-supporting lattice structures.

Based on the results of the structure selection analysis, the Applicants determined that tubular steel monopole structures were an unreasonable alternative for the Project. Although the Applicants determined that tubular steel monopoles could likely support 1,100-foot span lengths, the Applicants found that the structure heights and weights needed to support such spans would be excessive. The Applicants further determined that if span lengths were reduced to 800 feet, structure heights could be maintained below 200 feet, the height at which FAA lighting and marking would be recommended, the quantity of structures required on a given Project section would increase by up to 40 to 50 percent as compared to using self-supporting lattice structures. For these reasons, tubular steel monopole structures were also found to be approximately 40 percent more costly per mile than self-supporting lattice structures. A summary of the alternative structure types considered, and the associated conclusion is presented in **Table 7.6-1**.

Table 7.6-1
Alternative 765 kV Structure Types Considered for the Project

Structure	Spans	Heights	Cost (Material plus Labor)	Analysis
Guyed-V lattice, chainette lattice, guyed H-frame lattice, and guyed H-frame tubular steel	1,100 to 1,300 feet	150 to 175 feet	Not evaluated	Screened from detailed analysis because footprints of such structure types would cause greater impacts to existing land use than self-supporting structures. Guyed structures also have a greater risk of third-party damage.
Tubular steel monopole	800 feet	Under 200 feet	Approximately 40 to 50 percent more per mile than self-supporting lattice	Not selected because of costs, quantity of structures required, and live-line maintenance considerations caused by delta configuration with two phases stacked on one side of the structure. Constructability was also a consideration.
Tubular steel H-frame	1,100 to 1,300 feet	150 to 175 feet	Approximately 20 percent more per than self-supporting lattice	Not selected because less resilient compared to the self-supporting lattice structure. Significantly greater steel weights than self-supporting lattice structure. Design would also have a higher cost and present constructability challenges.

The 345 kV second circuit between the North Rochester Substation and the Hampton Substation will require approximately three dozen new structures at dead-end and angle locations. For tangent structures, the second circuit will be hung on the existing double-circuit capable structures. As such, alternative structure designs were not considered for the 345 kV line between the North Rochester Substation and the Hampton Substation. The 345 kV double-circuit line between the Pleasant Valley Substation and North Rochester Substation will utilize Xcel Energy's standard 345 kV design, similar to what is installed from the North Rochester Substation to the Hampton Substation. As such, no alternative structure designs were considered.

7.7 No Build and Consequences of Delay

As required by Minn. R. 7849.0340, the Applicants also considered the no-build alternative; that is, no new transmission would be constructed to meet the identified reliability needs. As detailed in **Section 7.2** through **Section 7.5**, no alternative is more prudent and/or reasonable than the Studied Projects. Should the Studied Projects be delayed and/or not constructed, there would be local and regional reliability, policy, and economic consequences.

As detailed in **Section 6.3.1**, the Studied Projects address 1,313 reliability issues on 102 different facilities. Per NERC, each of these issues requires a corrective action plan; doing nothing is not a reasonable option. Should the Studied Projects (the regional coordinated solution) not move forward, utilities would need to develop smaller-piecemeal solutions which as detailed in **Section 7.4.1** will at best be more expensive and at worst would be infeasible to develop in a reasonably timely manner. These smaller piecemeal solutions also do not allow for future growth or expansion and thus addressing potential future needs would also likely be more expensive and inefficient. The MISO LRTP Tranche 2.1 Portfolio, including the Studied Projects, was intentionally designed as a new "foundation" to not only meet today's system needs, but to be built upon to more efficiently meet potential future needs.

As detailed in **Section 6.5.1**, the Studied Projects and MISO LRTP Tranche 2.1 Portfolio are needed to enable generation in state approved IRPs. Planned generation in Minnesota's IRPs is currently in various stages of the MISO Generator Interconnection Queue, MISO Expedited Resource Addition Study, and/or planning – all of which assume the MISO approved LRTP Tranche 2.1 Portfolio will move forward as scheduled. Should the Project not move forward as planned, there would be a cascading impact which would likely delay and/or alter generation additions needed to serve new, expanding, and existing demands for electricity. Additionally, the planned generation additions in the state-approved IRPs will further support compliance with Minnesota's Carbon-Free by 2040 law. Should the Project not move forward or be delayed, there are state law compliance risks.

Other states would also be adversely impacted. This Project is a key component of a broader regional portfolio. The coordinated and regional approach enabled through the portfolio helps each MISO Midwest state meet reliability needs and goals in a more efficient and effective manner. The portfolio has been designed and optimized by MISO to work together - meaning the Project supports other states' needs and likewise other projects in the MISO LRTP Tranche 2.1 Portfolio support Minnesota's needs. A delay or cancellation of the Project not only increases risks of not meeting Minnesota's needs but also other states' needs.

8 TRANSMISSION LINE OPERATING CHARACTERISTICS

8.1 Overview

The major components of the Project will include (1) steel lattice structures (for the 765 kV) and monopole steel structures (for the 345 kV); (2) the wires attached to the structure and carrying the electricity, called conductors; (3) insulators and associated hardware connecting the conductors to the structures to provide structural support and electrical insulation; (4) shield wires which protect the line from direct lightning strikes; (5) OPGW for communications; (6) ground rods located below ground and connected at each structure; and (7) foundations to adequately support the structures.

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 human-made structure in the landscape. Due to the physics of how electricity functions, noise may be generated in some circumstances; interference with electromagnetic signals can occur; and electrical and magnetic fields are created around the conductors. Each of these operating characteristics are considered when designing the transmission line to prevent any significant impacts to its operation and to the overall environment.

8.2 Corona

Corona discharges occur on transmission line conductors when the electric field intensity at the conductor's surface is above a certain critical value. High levels of electric field give rise to a chain of ionization events in the surrounding air that culminates in the formation of corona discharges. The corona on conductors can produce a number of effects, such as power loss, electromagnetic interference, audible noise, gaseous effluents, and light. Some of these corona effects have important implications for the electrical design of transmission lines, particularly in the choice of conductor size.[240]

Oxidants such as ozone and various oxides of nitrogen (collectively known as NO_X) contribute to atmospheric air pollution. Ozone is also formed in the lower atmosphere from lightning discharges and from reactions between solar ultraviolet radiation and air pollutants. 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 natural production of ozone. The formation of ozone at ground level is mainly due to the action of ultraviolet radiation on the

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240 P. Sarma Maruvada (EPRI). EPRI AC Transmission Line Reference Book, 200 kV and Above, Third Edition, 2005. Sections 8.1 and 11.9.

gaseous emissions of combustion processes. For example, photochemical reactions taking place in automobile exhaust gases are known to generate ozone and contribute to increased pollution in urban areas. Ozone is a very reactive form of oxygen molecules and combines readily with other elements and compounds in the atmosphere. Because of its reactivity, it is relatively short-lived.

The rapid growth of HVTLs in the early 1970s raised some concerns of the possibility of ozone generation by corona discharges on transmission line conductors and the impact on ambient air quality. Laboratory studies and measurements near transmission lines have clearly shown, however, that transmission lines do not make any significant contribution to ambient atmospheric ozone levels.[241]

Both the state and federal governments currently have regulations regarding permissible concentrations of ozone and oxides of nitrogen. The National Ambient Air Quality Standard for ozone is 0.070 parts per million (ppm) on an 8-hour averaging period.[242] The Minnesota state standard for ozone is also 0.070 ppm on an 8-hour averaging period. The national and Minnesota state standard for nitrogen dioxide (NO_2), one of several oxides of nitrogen, is 100 parts per billion (ppb) on a 1-hour average and 53 ppb annual mean. Minnesota is currently in compliance with the national standards for ozone and NO_2. The operation of the Project's transmission lines would not create any potential for the concentration of these pollutants to exceed ambient air standards.

The most significant contributor to greenhouse gases is CO_2, followed by methane, nitrous oxide, and fluorinated gases (hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride [SF_6], and nitrogen trifluoride). Other greenhouse gases include nitrogen oxides, volatile organic compounds, and other gases produced through human activities. In Minnesota, CO_2 is the primary greenhouse gas emitted by human activities. CO_2 is most frequently produced through the combustion of hydrocarbon fuels to operate vehicles and equipment, generate electricity, and provide heat for homes and industrial processes.[243]

The Project will produce greenhouse gas emissions during pre-construction, construction, and restoration activities through the use of cranes, bulldozers, bucket loaders, personal employee vehicles, and other heavy equipment associated with Project construction and maintenance. During operations, some negligible operational greenhouse gas emissions are anticipated as

[241] Id.

[242] EPA. NAAQS Table. Available at: https://www.epa.gov/criteria-air-pollutants/naaqs-table.

[243] MPCA. January 2025 Report to the Legislature. Greenhouse Gas Emissions in Minnesota, 2005-2022. Available online at https://www.pca.state.mn.us/sites/default/files/lraq-3sy25.pdf.

a result of the use of maintenance vehicles (e.g., cars, trucks, helicopters) or substation equipment (i.e., SF_6 production). The emission of SF_6, when it occurs, would originate from substations as releases occur due to cracks in seals in certain substation equipment. The Applicants would track SF_6 and would maintain equipment to minimize unanticipated releases.

8.3 Noise

Noise is defined as unwanted sound. It may be composed of 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, the most noticeable frequencies of sound are given more "weight" in most measurement schemes. The dBA scale corresponds to the sensitivity range for human hearing by applying more weight to frequencies a person hears clearly and less weight to frequencies a person does not hear as well. A noise level change of 3 dB is barely perceptible to a person with healthy hearing organs in an ideal listening environment (i.e., an audiology booth). A 5-dB change in noise level is clearly noticeable for that same person in the same listening environment. **Table 8.3-1** shows noise levels associated with common, everyday sources, providing context for the transmission line and substation noise levels discussed later in this section.

Table 8.3-1
Decibel Levels of Common Noise Sources [a]

Sounds Pressure Levels (dBA)	Common Indoor and Outdoor Noises
110	Rock band at 5 meters
100	Jet flyover at 300 meters
90	Chainsaw at 1 meter
85	Typical construction activities
80	Food blender at 1 meter
70	Vacuum cleaner at 3 meters
60	Normal speech at 1 meter
50	Dishwasher in the next room
40	Library
30	Bedroom
20	Quiet rural nighttime

[a] MPCA. A Guide to Noise Control in Minnesota, Figure 3. Available at: https://www.pca.state.mn.us/sites/default/files/p-gen6-01.pdf.

Table 8.3-2 provides the Minnesota Pollution Control Agency (MPCA) daytime and nighttime noise standards organized by Noise Area Classifications (NACs) (Minn. R. Ch. 7030.0400 and 7030.0500). NACs are categorized by the type of land use activities at a location and the sensitivity of those activities to noise. Residential-type land use activities including residences, churches, camping and picnicking areas, and hotels are included in NAC-1. Commercial-type land use activities such as transit terminals, retail, and business services are included in NAC-2. Industrial-type land use activities are included in NAC-3. MPCA noise standards are expressed using the L_{50} and L_{10} statistical descriptors. The L_{50} noise level represents the level exceeded 50 percent of the time, or for 30 minutes in an hour. The L_{10} noise level represents the level exceeded 10 percent of the time, or for six minutes in an hour.

Table 8.3-2
MPCA Noise Limits by Noise Area Classification [a]

Noise Area Classification	Description	Daytime (dBA)		Nighttime (dBA)	
		L_{10}	L_{50}	L_{10}	L_{50}
1	Residential-type land use activities	65	60	55	50
2	Retail-type land use activities	70	65	70	65
3	Manufacturing-type and agricultural land use activities	80	75	80	75

[a] Minn. R. Ch. 7030.0400 and 7030.0500

The Project Notice Area is composed of multiple land uses types, but predominantly consists of agricultural land use, which has a NAC-3 classification and a daytime and nighttime L_{50} limit of 75 dBA.

Audible noise will occur as part of the construction and operation phases of the Project. Noise-sensitive land uses in the vicinity of the Project primarily include residences and neighborhoods, recreational areas, cemeteries, churches, office and retail buildings, restaurants, and parks.

During construction, the main sources of noise will be the operation of heavy equipment and vehicle traffic. Construction noise will be temporary and primarily limited to daytime hours. Instances such as outages, operational limitations, customer schedules, or other factors may cause construction to occur outside of daytime hours or on weekends. Heavy equipment will also be equipped with sound attenuation devices such as mufflers to minimize the daytime noise levels. Mitigation may be proposed for activities that occur during nighttime hours.

During operation, corona discharges can occur on transmission line conductors (see **Section 8.2**). Corona occurs when the electric field intensity on the conductor exceeds the breakdown strength of air and the air within a few centimeters of the conductor becomes ionized. This ionization produces a “crackling” sound. Typically, corona discharge levels on transmission lines, and therefore noise levels, are higher in wet or humid conditions. During heavy rain, the background noise level of the rain is usually greater than the corona 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, and sometimes snow and other high-humidity conditions, it is easier to hear corona noise because it is not being masked by the sound of rain. Several other factors, including voltage, conductor shape and diameter, and surface irregularities such as scratches, nicks, dust, or water drops can affect a conductor’s electrical surface gradient and, therefore, its corona noise discharge level. The way conductors are arranged also affects corona noise production.

The Applicants calculated corona noise levels using the Bonneville Power Administration Corona and Field Effects Program audible noise module, a corona noise model created by the Bonneville Power Administration. This program calculates audible noise levels due to corona at different distances from the transmission line centerline, expressed as L_{50} noise levels in A-weighted decibels. Calculated audible noise levels associated with the proposed 765 kV and 345 kV transmission lines, measured at the edge of the right-of-way (125 feet from the 765 kV transmission line centerline and 75 feet from the 345 kV transmission line centerline) will be below the NAC-1 noise standard. The L_{50} level for the 765 kV transmission line at the edge of the right-of-way is calculated at 48.9 dBA. The L_{50} level for the 345 kV transmission line at the edge of the right-of-way is calculated as 40 dBA.

Because audible noise is primarily related to the electric field, and electric fields are particularly dependent on the voltage of the transmission line, the values were calculated at the transmission lines’ maximum continuous operating voltage. Maximum continuous operating voltage is generally defined for the Project as the nominal voltage plus 5 percent (or, a 1.05 overvoltage). In this case, the model used a maximum continuous operating voltage of 803.3 kV for 765 kV transmission lines and 362.3 kV for 345 kV transmission lines. Modeling results indicate that audible noise from the transmission lines will be within the most stringent MPCA noise standards.

At substations, the transformers, reactors, and switchgear are among the primary noise sources. Noise emissions from this equipment have a tonal character that sometimes sounds like a hum or a buzz, which corresponds to the frequency of the alternating current. Transformers are among the largest noise sources, and the core of a transformer will expand and contract as it is magnetized and demagnetized at a rate that is based on the frequency of the alternating current. This type of noise does not have much low frequency content and, therefore, blends into background noise levels with increasing distance away from the source without being too intrusive off-site. The Applicants will design substations to ensure compliance with state noise standards.

8.4 Radio, Television, and GPS Interference

Generally, transmission lines do not cause interference with radio, television, or other communication signals and reception. While it is rare in everyday operations, four potential sources for interference do exist, including gap discharges, corona discharges, shadowing effects, and reflection effects.

Gap discharge interference is the most commonly noticed form of interference with radio and television signals, and also typically the most easily fixed. Gap discharges are usually caused by hardware defects or abnormalities on a transmission or distribution line causing small gaps to develop between mechanically connected metal parts. As sparks discharge across a gap, they create the potential for electrical noise, which can cause interference with radio and television signals in addition to audible noise. The degree of interference depends on the quality and strength of the transmitted communication signal, the quality of the receiving antenna system, and the distance between the receiver and the transmission line. Gap discharges are usually a maintenance issue, since they tend to occur in areas where gaps have formed due to broken or ill-fitting hardware (e.g., clamps, insulators, brackets). Because gap discharges are a hardware issue, they can be repaired relatively quickly once the issue has been identified.

Corona from transmission line conductors can also generate electromagnetic noise at the same frequencies that radio and television signals are transmitted. The air ionization caused by corona generates audible noise, radio noise, light, heat, and small amounts of ozone as noted in **Section 8.2.** The potential for radio and television signal interference due to corona discharge relates to the magnitude of the transmission line-induced radio frequency noise compared to the strength of the broadcast signals. Because radio frequency noise, like electric and magnetic fields, becomes significantly weaker with distance from the transmission line conductors, very few practical interference problems related to corona-induced radio noise occur with transmission lines. In most cases, the strength of the radio or television broadcast signal within a broadcaster's primary coverage area is great enough to prevent interference.

If interference from transmission line corona associated with the Project does occur for an AM radio station within a station's primary coverage area, where good reception existed before the Project was built, satisfactory reception can be obtained by appropriate modification of, or addition to, the receiving antenna system. The situation is unlikely, however, because AM radio frequency interference typically occurs immediately under a transmission line and dissipates rapidly with increasing distance from the line.

FM radio receivers are not affected by 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 interference rejection properties inherent in FM radio systems make them virtually immune to amplitude type disturbances.

The potential for television interference due to radio frequency noise caused by transmission lines is now substantially reduced because the United States has completed the transition from analog to digital broadcasting. Digital reception is, in most cases, considerably more tolerant of noise than analog broadcasts. Due to the higher frequencies of television broadcast signals (i.e., 54 megahertz and above) a transmission line seldom causes reception problems within a station's primary coverage area.

Shadowing and reflection effects are typically associated with large structures, such as tall buildings, and may cause reception problems by disturbing broadcast signals and leading to poor radio and television reception. Although the occurrence is rare, a transmission structure or the conductor can create a shadow on adjoining properties that obstructs or reduces the transmitted signal. Structures may also cause a reflection or scattering of the signal. Reflected signals from a structure result in the original signal breaking into two or more signals. Multipath reflection or scattering interference can be caused by the combination of a signal that travels directly to the receiver and a signal reflected by the structure that travels a slightly longer distance and is received slightly later by the receiver. If one signal arrives with significant delay relative to the other, the picture quality of digital television broadcast signals may be impacted. With digital broadcasts, the picture can become pixelated or freeze and become unstable. The most significant factors affecting the potential for signal shadow and multipath reflection are structure height above the surrounding landscape and the presence of large flat metallic facades. Television interference due to shadowing and reflection effects is rare but may occur when a large transmission structure is aligned between the receiver and a weak distant signal, creating a shadow effect.

In the rare situation where the Project may cause interference within a station's primary coverage area, the problem can usually be corrected with the addition of an outside antenna. If television or radio interference is caused by or from the operation of the proposed facilities in those areas where good reception was available prior to construction of the Project, Applicants will evaluate the circumstances contributing to the impacts and determine the necessary actions to restore reception to the prior level, including the appropriate modification of receiving antenna systems if necessary.

8.5 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.

The Project will be equipped with protective devices (e.g., circuit breakers and relays located in substations where transmission lines terminate) to safeguard the public in the event of an accident, or if a structure or conductor falls to the ground. The protective equipment will de-energize the transmission line should such an event occur.

8.6 Electric and Magnetic Fields

Electric and magnetic fields (EMF) are invisible forces that are present anywhere electricity is produced or used, including around electric appliances and any wire that is conducting electricity. The term EMF typically refers to electric and magnetic fields that are coupled together. However, for lower frequencies associated with distribution or transmission lines, electric and magnetic fields are relatively decoupled and should be described separately. Electric fields are the result of electric charge, or voltage, on a conductor. The intensity of an electric field is related to the magnitude of the voltage on the conductor and is typically described in terms of kV per meter (kV/m). Magnetic fields are the result of the flow of electricity, or current, traveling through a conductor. The intensity of a magnetic field is related to the magnitude of the current flow through the conductor and is typically described in units of magnetic flux density expressed as Gauss (G) or milliGauss (mG).

8.6.1 Electric Fields

Voltage on any wire produces an electric field in the area surrounding the wire. The voltage on the conductors of a transmission line produces an electric field extending from the energized conductors to other nearby objects, such as the ground, structures, vegetation, buildings, and vehicles. The intensity of transmission line electric fields is proportional to the voltage of the line and rapidly decreases with distance from the transmission line conductors. The presence of trees, buildings, or other solid structures nearby can also significantly reduce the magnitude of the electric field. Because the magnitude of the voltage on a transmission line is near-constant, the magnitude of the electric field will be near-constant for each of the proposed configurations, regardless of the power flowing on the line.

When an electric field reaches a nearby conductive object, such as a vehicle or a metal fence, it induces a voltage on the object. The magnitude of the induced voltage is dependent on many factors, including, but not limited to, the object's capacitance, shape, size, orientation, location, resistance with respect to ground, and the weather conditions. If the object is insulated or semi-insulated from the ground and a person touches it, a small current would pass through the person's body to the ground. This might be accompanied by an electrical discharge and mild shock, similar to what can occur when a person walks across a carpet and touches a grounded object, like a doorknob, or another person.

The main concern with induced voltage is not the magnitude of the voltage induced, but the current that would flow through a person to the ground should the person touch the object. To ensure that any such spark discharge associated with transmission line induced voltage does not reach unsafe levels, the NESC requires that any discharge be less than 5 milliamperes (mA). The Applicants will design the Project consistent with this NESC requirement.

There is no federal standard for transmission line electric fields. The Commission, however, has historically imposed a maximum electric field limit of 8 kV/m measured at 1 meter above ground for new transmission projects.[244] As demonstrated in **Table 8.6-1**, the electric fields associated with the Project will be within the Commission's 8 kV/m limit.

Table 8.6-1
Electric Field Calculation Summary for the Project (kV/m)

Maximum Continuous Operating Voltage	Distance from Proposed Centerline (feet)										
	-125	-100	-75	-50	-25	0	25	50	75	100	125
803.3 kV (765 kV)	2.93	4.73	6.98	7.47	5.24	4.96	5.24	7.47	6.98	4.73	2.93
362.3 kV [a] (345 kV)	-	-	0.33	1.44	4.14	2.76	3.51	1.36	0.33	-	-

[a] The right-of-way for the 345 kV transmission line is 150 feet, so greater distances were not included in the analysis.

8.6.2 Magnetic Fields

Current passing through any conductive material, including a wire, produces a magnetic field in the area around the material. The current flowing through the conductors of a transmission line produces a magnetic field that extends from the energized conductors to other nearby objects. The intensity of the magnetic field associated with a transmission line is proportional to the amount of current flowing through the transmission line's conductors and rapidly decreases with the distance from the conductors. Unlike electric fields, magnetic fields are not significantly impacted by the presence of trees, buildings, or other solid, non-ferromagnetic

[244] *In the Matter of the Route Permit Application for a 345 kV Transmission Line from Brookings County, S.D. to Hampton*, 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).

structures nearby. However, they are impacted by structures made of ferromagnetic materials. Because the actual power flow on a transmission line could potentially vary widely throughout the day depending on electrical system conditions, the actual magnetic field level in the vicinity of the transmission line could also vary widely from hour to hour.

There are currently no Minnesota regulations pertaining to magnetic field exposure. The Commission has acknowledged that Florida, Massachusetts, and New York have established standards for magnetic field exposure.[245] Magnetic fields calculated for the Project are presented in **Table 8.6-2**.

Table 8.6-2
Magnetic Field Calculation Summary for the Project (mG) [a]

Transmission Line Voltage	Current (Amps)	Distance to Proposed Centerline (feet)										
		-125	-100	-75	-50	-25	0	25	50	75	100	125
765 kV	2,264	75.7	108.6	155.8	203.9	225.3	225.0	225.3	203.9	155.8	108.6	75.7
345 kV [b]	1,850	-	-	45	90	161	237	167	95	45	-	-

[a] Both transmission line voltages were analyzed using a system condition of highest loading – system intact.
[b] The right-of-way for the 345 kV transmission line is 150 feet, so greater distances were not included in the analysis.

Magnetic field levels associated with some common household electric appliances are provided in **Table 8.6-3** to provide context for the calculated magnetic field levels associated with the Project.

Table 8.6-3
Table of Magnetic Fields of Common Electric Appliances (mG)

Appliance	6 Inches from Source	1 Foot from Source	2 Feet from Source
Hair Dryer	300	1	-
Electric Shaver	100	20	-
Can Opener	600	150	20
Electric Stove	30	8	2
Television	-	7	2
Portable Heater	100	20	4
Vacuum Cleaner	300	60	10
Copy Machine	90	20	7
Computer	14	5	2

[245] In the Matter of the Route Permit Application for the North Rochester to Chester 161 kV Transmission Line Project, Docket No. E-002/TL-11-800, ORDER at 20 (Sept. 12, 2012).

Table 8.6-3 Table of Magnetic Fields of Common Electric Appliances (mG)			
Appliance	**6 Inches from Source**	**1 Foot from Source**	**2 Feet from Source**
Source: USEPA. EMF in Your Environment. Magnetic Field Measurements of Everyday Electrical Devices. Available at: https://nepis.epa.gov/Exe/tiff2png.cgi/000005EP.PNG?-r+75+-g+7+D%3A%5CZYFILES%5CINDEX%20DATA%5C91THRU94%5CTIFF%5C00000191%5C000005EP.TIF			

EMFs from power lines, and their effects on health, have been studied for more than 40 years by governmental bodies, public health organizations, and government-appointed scientific panels all over the world. Initially, there were concerns of a possible association between childhood leukemia and magnetic fields of transmission lines. Subsequent research failed to demonstrate a causal relationship between transmission lines and any health risk. The World Health Organization (WHO) and other health agencies have concluded that, at the levels of EMF exposure found near transmission lines, there are no known health consequences.

8.7 Stray Voltage and Induced Voltage

Stray voltage is typically caused by a lower voltage service system serving a customer, usually a farm, but it can also be caused by customer equipment. Questions concerning stray voltage are usually best addressed by the electric distribution utility that serves the farm directly. Transmission lines can, however, induce voltage on objects parallel to and immediately under the transmission line. Appropriate measures will be taken to prevent induced voltage problems when the Project parallels or crosses objects.

8.8 Farming Operations, Vehicle Use, and Metal Buildings Near Transmission Lines

The Applicants will comply with the NESC with respect to grounding objects and fences within the right-of-way and will work with landowners to resolve issues that arise because of the Project.

Farm equipment, passenger vehicles, and trucks may be safely used under and near transmission lines. The Project will be designed to meet or exceed minimum clearance NESC requirements with respect to roads, driveways, cultivated fields, and grazing lands.

Vehicles or other conductive equipment under high-voltage transmission lines may become electrically charged due to induced voltage from the transmission lines. Without a continuous grounding path, this charge can provide a nuisance shock. Such nuisance shocks are typically rare, as vehicles are generally effectively grounded through tires or other means. Modern tires are produced using carbon black, a good conductor of electricity, thus providing an electrical path to ground. Additionally, metal components of farming equipment are often in contact with the ground when in operation. Therefore, unless vehicles or equipment have unusually old tires or are parked on dry rock, plastic, or other surfaces that insulate them from the ground, any induced charge on vehicles or equipment will normally flow continuously to ground.

Buildings are permitted near transmission lines but are generally not permitted within the right-of-way, as a structure under a transmission line may interfere with the safe operation of the transmission facilities. In addition, the NESC establishes minimum electrical clearance zones from transmission lines to various objects, including buildings, for the safety of the general public. The Applicants will acquire easement rights that provide the necessary area to operate and maintain the Project. The Applicants may permit encroachment into these easements for specific activities when they can be deemed safe and still meet the NESC minimum requirements.

Metal buildings near the right-of-way may have unique concerns due to induction. For example, per NESC requirements, conductive buildings near transmission lines of 170 kV or greater must be properly grounded. Any person with questions about new or existing metal buildings or structures may contact the Applicants for further information about proper grounding requirements.

9 TRANSMISSION LINE CONSTRUCTION AND MAINTENANCE

9.1 Engineering Design and Regulatory Approvals

Detailed transmission line and substation engineering design work generally begins after the Commission designates a route and issues a route permit. The Applicants will refine the design of the transmission lines as more site-specific information is gathered for properties along the approved route. Throughout the process, the Applicants will work with landowners and ensure that all permit conditions are satisfied. The Applicants will prepare plan and profile documents which provide a detailed description of the facilities, including structure placement, spans, and wire heights, and will prepare a site layout for each expanded and modified substation.

9.2 Land Rights Acquisition

The Applicants will work with landowners to acquire easements for an approximately 250-foot-wide corridor for the 765 kV transmission lines across the Project and an approximately 150-foot-wide corridor for the 345 kV double circuit transmission line between the Pleasant Valley Substation and North Rochester Substation. Xcel Energy does not anticipate the need to acquire new easements for the North Rochester to Hampton transmission line. In some areas, the width may vary depending on span length and other design requirements. The Applicants will review and make these modifications on a case-by-case basis.

The Applicants will address land rights and related matters with landowners and other stakeholders throughout the permitting proceedings. The Applicants intend to contact landowners to obtain rights-of-entry agreements to support the Applicants' survey efforts as early as 2027. It is anticipated that the more detailed land rights acquisition discussions with landowners will occur in conjunction with the Applicants' survey efforts and will continue throughout the permitting and post-permitting periods. In those discussions, the Applicants will describe the Applicants' survey, construction, and access plans, as well as potential impacts on the land, mitigation opportunities, and restoration. The land rights evaluation and acquisition process will include title search, contact with the landowner, survey, real estate document preparation, discussion and negotiation, and completion of land rights agreements, including permanent easements, temporary easements, and/or other agreements as necessary to support the initial survey needs of the project and construction, operation, and maintenance of the Project.

The Applicants may discuss special considerations such as temporary or permanent gates, fencing, and access accommodations. The Applicants' experience with easement discussions is that, in most cases, they are able to work with landowners to address their concerns and reach an agreement for the purchase of the necessary land rights. In all cases, the Applicants will use fair market value data to try in good faith to reach agreements with landowners on a voluntary basis. In some cases, agreements cannot be reached. In those cases, the Applicants may be required to obtain the necessary rights for the Project by exercising their right of eminent domain under Minnesota law. The process of exercising the right of eminent domain is called condemnation. Minnesota law establishes a common process – through Minn. Stat. Ch. 117 – for condemnation actions. Minnesota has a well-developed body of law for determining valuation issues to ensure that landowners receive just compensation.

Typically, before commencing a condemnation proceeding, a condemning authority obtains an appraisal and provides it to the property owner, along with the condemning authority's offer of compensation. To start the formal condemnation process, a utility (or other condemning authority) files a petition in the district court where the property is located and serves that petition on all owners of interests in each of the properties identified in the petition. At or around the date the petition is filed, the utility also issues a notice to the owners that identifies the date on which the utility is asking the district court to grant the utility title to and possession of the land rights pursuant to Minnesota's quick take process.

If the court grants the petition, the court appoints a three-person condemnation commission that will determine the just compensation for the easement. The three people must be knowledgeable of applicable real estate issues. The commissioners schedule a viewing of the property and then schedule a valuation hearing where the utility and landowners can testify as to the fair market value of the easement or fee. As part of the valuation process, the landowner typically also obtains an appraisal and has certain rights of reimbursement in connection with the costs of obtaining an appraisal. At the commissioners' hearing on valuation, the parties offer their evidence, such as testimony by appraisers or the landowners, about the fair market value impacts the acquisition has on the property's value. The condemnation commission then makes an award in an amount representing just compensation and that award is filed with the court. Each party has the right to appeal the award to the district court for a trial. In the event of an appeal, the jury or judge 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.

In addition, the Project is subject to Minnesota's Buy the Farm law (Minn. Stat. § 216I.21, subd. 4). Under the Buy the Farm law, when a utility files condemnation petition to obtain the easement rights necessary to support the Project, certain landowners of certain classes of land have the right to elect that the utility acquire the owners' fee interest in the property instead of the easement sought by the utility. The eligible classes of property include agricultural and non-agricultural homestead, non-homestead agricultural land, rental residential property, and commercial and non-commercial seasonal residential recreational property. Owners who make Buy the Farm elections may also be entitled to relocation assistance. The Applicants intend to communicate with landowners early in the acquisition process to make clear the options that are available if a landowner wants to further explore or pursue a Buy the Farm transaction. As part of the discussions, the Applicants will also provide landowners resources regarding the relocation assistance that may be available to them.

9.3 Construction Procedures

Work on each construction spread[246] will begin after all required federal, state, and local approvals are obtained, property and necessary land rights are acquired, and final design is completed. The precise timing of construction will consider various requirements that may be in place due to permit conditions, system loading issues, and available workforce.

Applicants will notify and/or coordinate with landowners prior to the start of the construction phase of the Project, including an update on the Project schedule and other related construction activities.

The first phase of construction activities for the new structures will involve survey staking of the transmission line centerline, easement boundaries, and/or structure locations, then removal of all trees and other vegetation from the full width of the easement area.

As a general practice, low-growing brush may be allowed to reestablish at the outer limits of the easement area after all vegetation has initially been cleared. The NESC states that "vegetation that may damage ungrounded supply conductors should be pruned or removed." Trees beyond the easement area that are in danger of falling into the energized transmission line (or, danger trees) will be removed or trimmed to eliminate the hazard, as allowed by the terms in the given acquired easement. Danger trees generally are those that are dead, weak, diseased, or leaning towards the energized conductors. While clearing typically occurs immediately prior to the installation of structures and their associated foundations, there are instances where clearing must occur before the overall line design and structure placements are finalized. This is often the result of calendar restrictions to avoid vulnerable timeframes in

[246] Construction spreads refer to a specific area under construction. Construction spreads are determined by the utility based on multiple factors, such as engineering, labor, materials, and permitting needs.

the life cycle of particular flora or fauna species. In those situations, the Applicants would proceed with clearing in parallel with final design efforts.

All material resulting from the clearing operations will either be chipped on site and spread on the easement area, stacked in the easement area for use by the property owner, or removed and disposed of as otherwise agreed to with the property owner during easement negotiations.

The Applicants will design the transmission line structures for installation at the existing ground elevations. Where terrain requires (typically on slopes exceeding 10 percent), construction work areas may be graded or leveled with fill. If acceptable to the landowner, the Applicants will leave these areas as-modified after construction for use during future maintenance activities. If not acceptable to the landowner, the Applicants will, to the extent practicable, 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. To the extent practicable, construction crews will attempt to use equipment that minimizes impacts to lands.

The Applicants will use construction staging areas/laydown yards for the staging of personnel and equipment and the storage of materials necessary to construct the new transmission line facilities. The Applicants estimate that construction of the Project will likely include staging areas/laydown yards every 40 to 80 miles, ranging from 20 to 60 acres in size.

The Applicants will evaluate construction access opportunities by identifying existing transmission line easements, roads, or trails that run near the approved route. When feasible, the Applicants will limit construction activities to the easement area. In certain circumstances, additional off-easement access or workspace may be required.

New access routes, or improvements to existing access roads, may be required to accommodate construction equipment. The Applicants will obtain permits for new access from local road authorities when needed.

Structure and foundation installation will begin after clearing and access route preparation are complete. **Section 2.2.2** describes the types of foundations proposed for the 765 kV structures and 345 kV structures. The actual diameter and depth of a foundation and associated excavation will depend on structure and foundation design and the soil conditions that are determined during geotechnical exploration. Once the excavation is prepared, the Applicants will place a steel rebar cage in the excavation, along with an anchor bolt cage or stub angle, depending on the design of the structures. Concrete is then brought to the site from a local concrete batch plant or portable, onsite batch plant and is placed in the excavation.

Structure components will then be transported from staging areas and delivered to the appropriate foundation locations once the concrete has properly cured. The Applicants will assemble and erect the structures in sections. The structure base will be bolted to the foundation via the anchor bolts or stub angles, and then insulators and associated hardware will be attached to the structure.

Conductor and shield wire stringing is the last major component of transmission line construction. Where the Project crosses streets, roads, highways, or other energized conductors or obstructions, the Applicants may install temporary guard structures before conductor stringing. The temporary guard structures ensure that conductors will not obstruct traffic or contact existing energized conductors or other cables during stringing operations and also protect the conductors from damage.

Stringing setup areas are dependent on the line design and configuration. However, it is anticipated that stringing sites will typically be located at approximately 20,000-foot intervals. These sites are located within the Applicants' transmission easement areas when possible. When necessary, the Applicants will acquire temporary construction easements. Stringing operations require access to each structure to secure the conductor and shield wire to the insulators and clamps, respectively, once final conductor sag, compliant with the Applicants' procedures and minimum code clearances, is established. This access may be conducted via crane or helicopter.

Conductor accessories will be installed as required after conductor installation is complete. These accessories may include vibration dampers, spacer-dampers, bird flight diverters, or aerial navigation markers. The Applicants will work with the appropriate agencies to identify locations where marking devices will be installed.

Certain soil conditions and environmentally sensitive areas may require special construction techniques. To the extent possible, the Applicants will attempt to place structures outside of such areas, so as to minimize any environmental impacts. 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 practicable, construction will be scheduled during frozen ground conditions.

- When construction during frozen conditions is not practicable, 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 areas and waterways. These construction practices help prevent soil erosion and ensure that fuel and lubricants do not enter waterways or impact environmentally sensitive areas.
- Various best management practices (BMPs) will be identified in the Project's Stormwater Pollution Prevention Plan, including the use of silt fences, bio logs, erosion control blankets with embedded seeds, hydromulch, 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 agricultural drain tile.

9.4 Restoration and Clean-up Procedures

Once construction is completed in an area, the Applicants will restore disturbed areas to their original condition to the maximum extent feasible. Some areas may require temporary restoration before the completion of construction per MPCA construction stormwater permit requirements.

A Project representative will contact the property owner to discuss any damage that has occurred as a result of the Project after construction activities are complete. This contact may not occur until after the start of restoration activities. The Applicants will repair (or reimburse the landowner to repair) damage to fences, drain tile, or other property damaged by construction of the Project.

The Applicants will compensate farmers for crops damaged during construction. The Applicants will measure the damaged area, determine the yield estimate in consultation with the farmer, and pay compensation at current market rates or other appropriate rates (i.e., contract prices). The Applicants may also make a payment for future crop loss due to potential or assumed soil compaction. In addition, farmers will be compensated for their expense to deep rip compacted areas. The Applicants will provide this service if a landowner does not have access to deep ripping equipment.

The ground-level vegetation disturbed or removed during construction will typically reestablish naturally to pre-construction conditions. The Applicants may need to provide additional assistance in reestablishing vegetation and controlling soil erosion in areas where significant soil compaction or other disturbance from construction activities occurred. In these areas, the Applicants will use seed that is noxious weed free to reestablish vegetation.

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

9.5 Maintenance Practices

The Applicants will design and maintain the transmission lines in accordance with the NESC and the Applicants' standards. In general, transmission lines are highly reliable, with unplanned outages typically being limited. The average annual availability of transmission infrastructure is very high, in excess of 99 percent. Transmission facilities have decades-long estimated service lives but, practically speaking, HVTLs are seldom retired. Regular maintenance and asset renewal of transmission line components is necessary for longer term reliable operation.

The Applicants will require access to the transmission lines to periodically conduct inspections, perform maintenance, and repair damage that may occur. Generally, the Applicants will inspect the Project at least once by air and once by ground annually. These inspections will be limited to the defined easement areas and through other access easement areas where obstructions or terrain dictate. If maintenance concerns are identified during inspection, repairs will be performed, as necessary. Should any damage occur during this work, the Applicants will restore the affected area and/or compensate the landowner for damages pursuant to the terms of the easements. The annual inspections are a fixed annual cost for maintaining and operating transmission facilities. The aerial inspections cost approximately $35 to $55 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 Applicants will manage their easement areas to control any encroachments that may interfere with the operation of the transmission line, including removal of vegetation that interferes with the operation and maintenance of the transmission line. Native shrubs that will not interfere with the safe operation and maintenance of or access to the transmission line will often be allowed to reestablish in the outer edge the right-of-way. Right-of-way clearing practices include a combination of mechanical and hand clearing, with herbicide application where allowed, to remove or control vegetation growth.

9.6 Storm and Emergency Response and Restoration

Transmission infrastructure has few mechanical elements and is built to withstand weather extremes that are normally encountered in the region. With the exception of outages due to severe weather such as tornadoes, extreme winds, and heavy ice storms, transmission lines rarely fail.

In the event of a fault on the transmission system, protective relaying equipment is designed to immediately detect the fault and automatically remove the transmission line from service. Such interruptions are usually only momentary. Scheduled maintenance outages are also infrequent.

However, unplanned outages of transmission facilities can happen for a variety of reasons. Unplanned outages can occur due to such things as mechanical failures or severe weather such as heavy ice, wind, or a combination of ice and wind. If a storm or emergency outage were to occur, the Applicants have the necessary infrastructure and crews in place in central and southern Minnesota to respond quickly and safely to return the line to service. The Applicants will deploy first responders to the lines as quickly as possible to patrol the line and assess the damage. Once the damage has been assessed, the first responder will immediately relay the following information back:

- magnitude of damage;
- isolation requirements for switching;
- material required for restoration;
- number of line crew needed; and
- equipment needed.

Based on the assessment of the first responder, the Applicants will develop a plan to restore the damaged facilities. The goal of the repair is to place the transmission system back into service as quickly and safely as possible to minimize the impact to the transmission system.

In addition to line crews, the Applicants also have experienced internal engineering departments that can assist in the event of unplanned outages. If a storm or emergency outage were to occur, on-call engineers can be notified to assist in identifying an appropriate repair. The engineer will assess the situation based on feedback from onsite personnel and design an appropriate solution for any damaged infrastructure. Based on the scale of the damage, additional engineering resources can be requested as needed.

10 ENVIRONMENTAL INFORMATION

The Applicants gathered environmental information to characterize conditions within the Project Study Area. The Project Study Area is equivalent to the Project Notice Area as described in **Section 1.8** and as shown on **Figure 1.8-1**. The Project Study Area includes all, or portions of, Cottonwood, Dakota, Dodge, Faribault, Freeborn, Goodhue, Jackson, Lincoln, Lyon, Martin, Mower, Murray, Nobles, Olmsted, Pipestone, Redwood, Rock, Steele, and Waseca Counties, Minnesota.

The intent of this Chapter is to describe the major features present within the Project Study Area. Throughout this Chapter, information about existing resources is presented from the western portion to the eastern portion of the Project Study Area as appropriate.

10.1 Physiographic Regions

The landscape across the Project Study Area transitions from the northwest to the southeast due to historical glacial processes. These variations are reflected in the changing patterns of hydrology, vegetation, wildlife, land use, and human settlement.

Level topography, prairie remnants, and agricultural fields dominate the western portions of the Project Study Area. Progressing east, the terrain transitions to predominantly level to slightly undulating landforms. In the south-central portion of the Project Study Area, the landscape is characterized by a higher density of lakes and wetlands. The eastern portion of the Project Study Area is characterized by an increase in areas of hardwood forests, bedrock outcrops, and rolling topography.

The Minnesota Department of Natural Resources (MDNR) and the U.S. Forest Service developed an Ecological Classification System (ECS) to support ecological mapping and landscape classification across Minnesota.[247] The ECS helps define large areas that share relatively consistent ecological characteristics to assist in resource management decisions. At the highest level, the State of Minnesota is broken down into four provinces. Within these provinces there are 10 sections, which contain a total of 26 subsections.

The Project Study Area is located within two of the four statewide provinces. Within these two provinces, the Project Study Area is located within three sections. Finally, within these three sections, the Project Study Area is located within six subsections. **Table 10.1-1** provides the

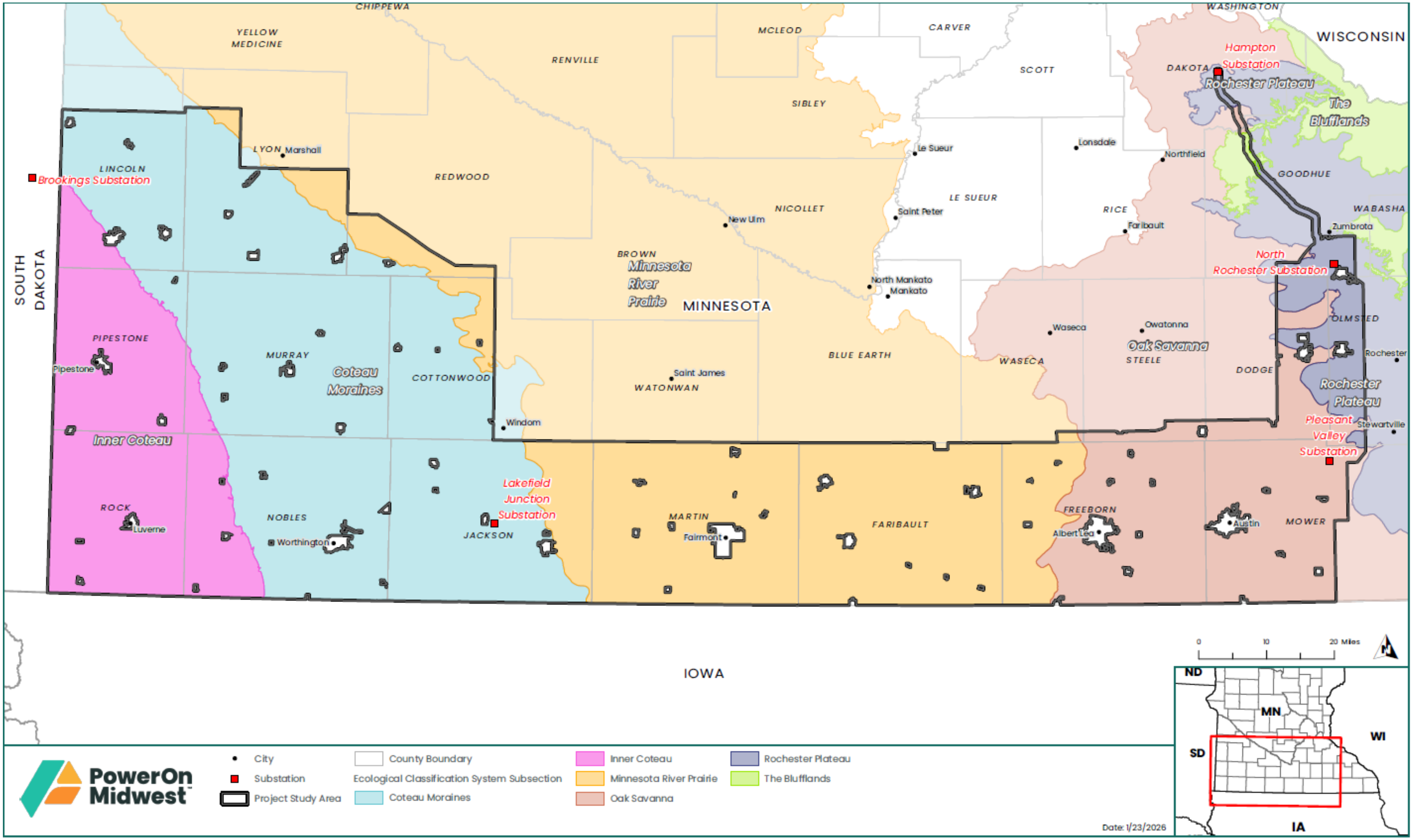
[247] MNDR. Ecological Classification System. Available at: https://www.dnr.state.mn.us/ecs/index.html.

acreage and associated percentage of the Project Study Area within each ECS subsection. **Figure 10.1-1** depicts the ECS subsections within the Project Study Area.

Table 10.1-1 ECS Subsections in the Project Study Area			
ECS Subsection [a]	**Counties within the Notice Area**	**Acres in Project Study Area**	**Percentage of Project Study Area**
Inner Coteau	Lincoln, Pipestone, Murray, Rock, Nobles	766,845	16.1
Coteau Moraines	Lincoln, Lyon, Pipestone, Murray, Cottonwood, Nobles, Jackson	1,835,325	38.4
Minnesota River Prairie	Lyon, Redwood, Cottonwood, Jackson, Martin, Faribault, Freeborn, Waseca	1,275,757	26.7
Oak Savanna	Freeborn, Waseca, Steele, Mower, Dodge, Goodhue, Dakota	740,129	15.5
Rochester Plateau	Dodge, Olmsted, Goodhue, Dakota	157,235	3.3
The Blufflands	Goodhue	3,214	<0.1
PROJECT TOTAL		**4,778,505**	**100.0**
[a] 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 ECS. Source: MDNR. Ecological Sections of Minnesota. Available at: https://gisdata.mn.gov/dataset/geos-ecological-class-system			

The Applicants chose to present much of the information in this Chapter by ECS subsection because ECS subsections share environmental features common to a general area and are a tool to understand greater resource themes. Geopolitical boundaries are used to communicate impacts when appropriate. The following sections describe the ECS subsections within the Project Study Area from west to east.

Figure 10.1-1: ECS Subsections within the Project Study Area



10.1.1 Inner Coteau Subsection

Approximately 16 percent of the Project Study Area is within the Inner Coteau Subsection, including portions of Lincoln, Pipestone, Murray, Rock, and Nobles Counties. Cities within this subsection include, but are not limited to, Pipestone, Luverne, and Edgerton. Edgerton is home to the 1960 State High School Basketball Tournament champs.

This subsection is part of a high glacial landform occupying southwestern Minnesota, southeastern South Dakota, and northwestern Iowa. The high elevation is caused by deposits of glacial till up to 800 feet thick. Loamy, well-drained soils with thick dark surface horizons are dominant. Both dry prairie and moist prairie soils are present.[248] Wind farms are prevalent along Buffalo Ridge due to constant, high prevailing winds.

10.1.2 Coteau Moraines Subsection

Approximately 38 percent of the Project Study Area is within the Coteau Moraines subsection, including portions of Lincoln, Lyon, Redwood, Pipestone, Murray, Cottonwood, Nobles, and Jackson Counties. Cities within this subsection include, but are not limited to, Worthington and Lakefield.

This subsection is also part of a high glacial landform occupying southwestern Minnesota, southeastern South Dakota, and northwestern Iowa. A steep escarpment cut by several streams within narrow, straight ravines marks the northeast edge of the subsection but fades and becomes indistinct as it reaches Iowa. The subsection is generally characterized by rolling and hilly moraine ridges in some portions and steeply rolling and hilly terminal and end moraines in others. The depth of glacial till typically ranges between 600 feet to 800 feet. Soil types include dry and wet prairie soils.[249]

10.1.3 Minnesota River Prairie Subsection

Approximately 27 percent of the Project Study Area is within the Minnesota River Prairie subsection, including all or portions of Lyon, Redwood, Cottonwood, Jackson, Martin, Faribault, Freeborn, and Waseca Counties. Cities within the subsection include, but are not limited to, Fairmont and Blue Earth.

The subsection is characterized by large till plains bisected by the Minnesota River, formed by Glacial River Warren that drained Glacial Lake Agassiz. Topography outside of the Minnesota

[248] MDNR. Inner Coteau Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Bc/index.html.

[249] MDNR. Coteau Moraines Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Bb/index.html.

River Valley, which is to the north and outside of the Project Study Area, consists of level to gently rolling ground moraines. The depth of glacial till generally ranges between 100 feet and 400 feet deep. Soils within the Project Study Area are primarily well- to moderately well-drained loams, with some clayey, sandy, and gravelly soil types also present. The subsection has 150 lakes greater than 160 acres in size, many of which are shallow, perched lakes.[250]

10.1.4 Oak Savanna Subsection

Approximately 16 percent of the Project Study Area is located within the Oak Savanna Subsection in Freeborn, Waseca, Steele, Mower, Dodge, Goodhue, and Dakota Counties. Cities include, but are not limited to, Albert Lea, Austin, Byron, and Kasson.

The subsection consists of gently rolling ridges to the west with hardwood hills to the east. Steep slopes are often present to the west. Glacial drift is typically less than 100 feet thick within the subsection, with a maximum thickness of about 200 feet. Some limestone, sandstone, and shale are locally exposed, particularly in the dissected stream valleys at the eastern edge of the subsection. Soils are predominantly wet or well-drained soils developed under prairie or forest vegetation. The subsection contains few lakes, and most are on the western edge. [251]

10.1.5 Rochester Plateau Subsection

Approximately 3 percent of the Project Study Area crosses the Rochester Plateau Subsection in Mower, Dodge, Olmsted, Goodhue, and Dakota Counties. Cities within the subsection include, but are not limited to, Zumbrota and Pine Island.

This subsection consists of an old plateau covered by loess sediments along the eastern border and pre-Wisconsin age glacial till in the central and western parts. In the west there is a gently rolling glacial till plain. Loess deposits range from 30 feet thick on broad ridgetops, to under a foot on valley walls. Depth of drift over bedrock ranges from 100 feet to 200 feet in the west to 10 feet to 100 feet in the east. Where there is little to no drift, bedrock exposures are common, and consist primarily of dolomite, limestone, sandstone, and shale. Oak openings and barrens are interspersed with agricultural land use. There are some lakes in this subsection.[252]

[250] MDNR. Minnesota River Prairie Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Ba/index.html.

[251] MDNR. Oak Savanna Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Me/index.html.

[252] MDNR. Rochester Plateau Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Lf/index.html.

10.1.6 The Blufflands Subsection

Less than 0.1 percent of the Project Study Area is within The Blufflands Subsection, in Goodhue County. Most of the land within this subsection is concentrated along the Mississippi River, though some parts of the subsection extend further to the west along major river valleys, such as the portion of the Study Area south of Cannon Falls.

This subsection consists of an old plateau covered by loess sediments that have been extensively eroded along rivers and streams. It is characterized by highly dissected landscapes associated with major rivers. Bluffs and deep stream valleys are common. Oak openings and barrens are more common than in the Rochester Plateau subsection to the west. Half of this subsection is woodland. [253]

10.2 Hydrologic Features

In the southwestern portion of the Project Study Area, virtually all of the Inner Coteau Subsection drains southwest, out of Minnesota and into the Missouri River basin system. A small part drains northeast towards the Minnesota River. There are few lakes and a well-established, dendritic or "tree-like" drainage network. The Coteau Moraines subsection primarily drains northeast into the Minnesota River system, or southeast towards Iowa.

In south-central portion of the Project Study Area, in the Minnesota River Prairie subsection, streams and small rivers drain into the Minnesota River or the Upper Iowa River, though drainage networks are poorly developed due to topography. There are 150 lakes greater than 160 acres in size throughout, though many are shallow and perched.

In the southeastern portion of the Project Study Area, drainage is fairly well developed throughout the Oak Savanna subsection. There are a few lakes present along the western edge of the subsection. The drainage network within the Rochester Plateau subsection is well developed and dendritic in nature, with few lakes present. The headwaters of the Root, Whitewater, Zumbro, and Cannon Rivers are located here. Drainage within The Blufflands subsection is also well developed and dendritic in nature. The major waterway within the portion of the subsection crossed by the Project Study Area is the Cannon River.[254]

10.2.1 Major Basins

Hydrologic Unit Codes (HUCs) are used nationwide to differentiate drainage areas with a series of numbers. HUC 2 is the largest classification level in the U.S. Geological Survey's (USGS)

[253] MDNR. Blufflands Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Lc/index.html.

[254] MDNR. Ecological Classification System. Available at: https://www.dnr.state.mn.us/ecs/index.html.

classification system. The Project Study Area is within two major HUC 2 regions: the Missouri Region and the Upper Mississippi Region.[255] The majority of the Project Study Area lies within the Upper Mississippi Region.

HUC 8 indicates a subbasin within the larger HUC 2 region. There are 23 HUC 8 subbasins within the two HUC 2 regions within the Project Study Area. **Table 10.2-1** summarizes the major HUC 2 and HUC 8 drainage areas relative to the ECS subsections and the Project Study Area. These areas are shown on **Figure 10.2-1**.

Table 10.2-1
HUC-2 and HUC-8 Drainage Areas by ECS Subsection within the Project Study Area

Region (HUC 2) / Subbasin (HUC 8)	Inner Coteau	Coteau Moraines	Minnesota River Prairie	Rochester Plateau	Oak Savanna	The Blufflands
	Acres within Project Study Area					
MISSOURI REGION						
Little Sioux River	-	198,120	-	-	-	-
Lower Big Sioux River	316,713	5,589	-	-	-	-
Rock River	425,161	155,127	-	-	-	-
Upper Big Sioux River	23,420	3,007	-	-	-	-
UPPER MISSISSIPPI REGION						
Blue Earth River	-	4,836	674,092	-	-	-
Cannon River	-	-	-	7,562	30,574	3,201
Cedar River	-	-	-		417,156	-
Cottonwood River	-	312,850	107,574	-	-	-
Des Moines River - Headwaters	64	763,374	2,120	-	-	-
East Fork Des Moines River	-	189	128,257	-	-	-
Lac Qui Parle River	-	12,340	-	-	-	-
Le Sueur River	-	-	218,367	-	9,841	-
Lower Des Moines River	-	35,546	19,598	-	-	-
Minnesota River - Mankato	-	1,446	4,717	-	-	-
Minnesota River - Yellow Medicine River	737	144,766	6,360	-	-	-
Mississippi River - Lake Pepin	-	-	-	2,526	-	-
Redwood River	751	195,777	7,374			
Root River	-	-	-	3,366	63,547	-
Shell Rock River	-	-	12,359	-	134,443	-
Upper Wapsipinicon River	-	-	-	-	2,886	-
Watonwan River	-	2,358	60,701	-	-	-

[255] MDNR. Subregions of Minnesota. Available at: https://www.dnr.state.mn.us/watersheds/subregions.html.

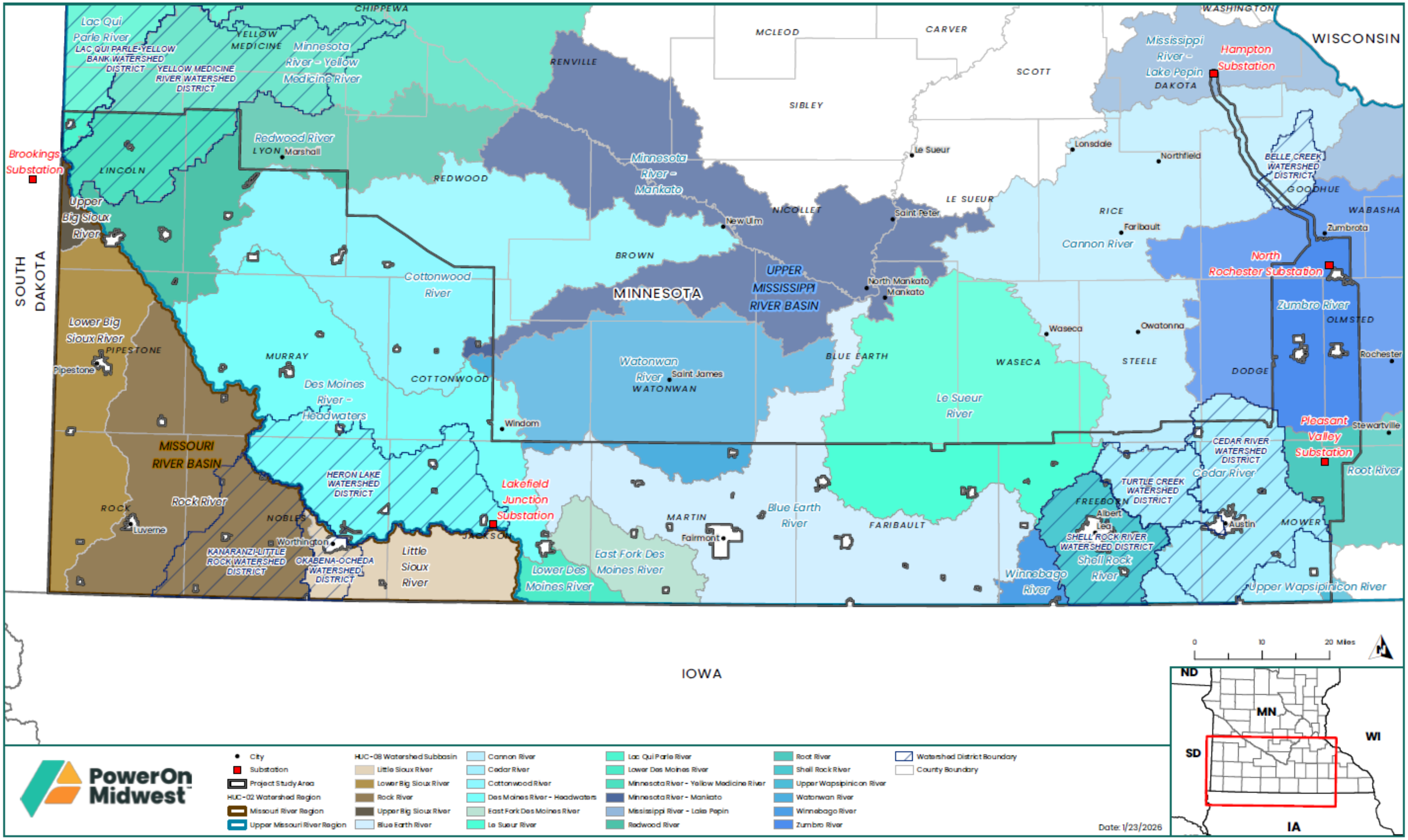
Table 10.2-1
HUC-2 and HUC-8 Drainage Areas by ECS Subsection within the Project Study Area

Region (HUC 2) / Subbasin (HUC 8)	Inner Coteau	Coteau Moraines	Minnesota River Prairie	Rochester Plateau	Oak Savanna	The Blufflands
	Acres within Project Study Area					
Winnebago River	-	-	34,236	-	10,901	-
Zumbro River	-	-		143,781	70,782	13
PROJECT TOTAL	**766,845**	**1,835,325**	**1,275,757**	**157,235**	**740,129**	**3,214**

[a] ECS boundaries do not conform to watershed boundaries. As such, portions of each watershed listed may be within multiple ECS.

Source: MN Watershed Suite. Available at : https://gisdata.mn.gov/dataset/geos-dnr-watersheds.

Figure 10.2-1: HUC-2 and HUC-8 Drainage Areas within the Project Study Area



10.2.2 Watershed Districts

There are nine Minnesota Watershed Districts within the Project Study Area. Minnesota Watershed Districts assist with land use planning, flood control, and conservation projects, and are governed by a board of managers appointed by county commissioners within the district.[256] Minnesota Watershed Districts are depicted on **Figure 10.2-1**. These include the following:

- Lac Qui Parle – Yellow Bank;
- Yellow Medicine River;
- Kanaranzi – Little Rock;
- Okabena – Ocheda;
- Heron Lake;
- Shell Rock River;
- Turtle Creek;
- Cedar River; and
- Belle Creek.

10.2.3 Rivers, Streams, and Lakes

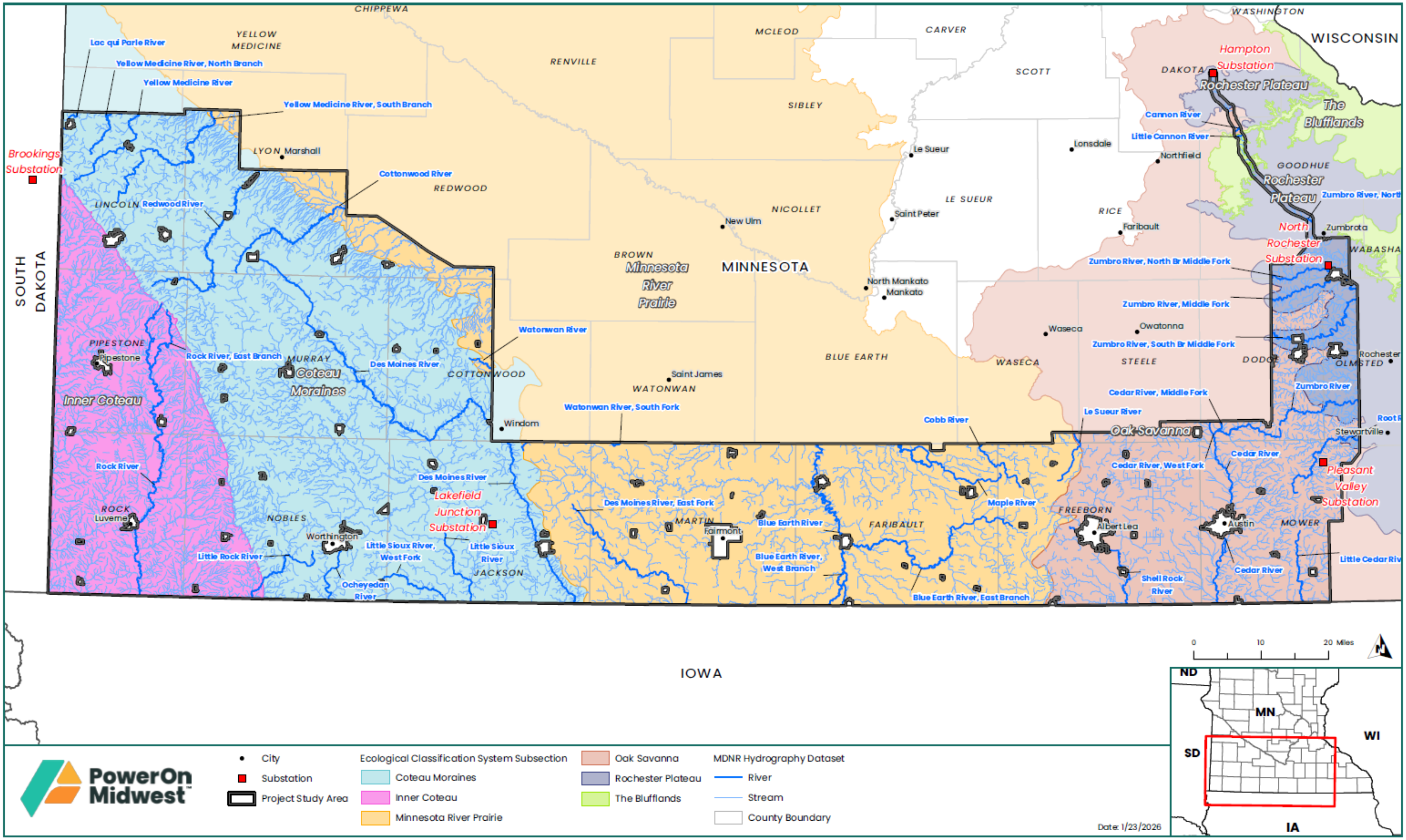
Rivers, streams, and ditches are prevalent throughout the Project Study Area. Lakes are scattered throughout the Project Study Area; the south-central portion of the Project Study Area is characterized by a higher density of lakes. The counties of Mower, Olmstead, Pipestone, and Rock have no natural lakes.[257]

The MDNR's Hydrography Dataset is a collection of the "best available" spatial data representing Minnesota surficial hydrology. Hydrography features within the Project Study Area are shown on **Figure 10.2-2**. There is a greater density of streams and rivers in the westernmost and easternmost portions of the Study Area, although surface water features are common throughout.

[256] Minnesota Board of Water and Soil Resources (BWSR). Watershed Districts. Available at: https://bwsr.state.mn.us/watershed-districts.

[257] MDNR. Lakes, Rivers, and Wetlands Facts. Available at: https://www.dnr.state.mn.us/faq/mnfacts/water.html.

Figure 10.2-2: Hydrography Features within the Project Study Area



The Des Moines River is the largest river in the Project Study Area (present in Lyon, Murray, Cottonwood, and Jackson Counties). The Des Moines River is a Section 10 water regulated by the U.S. Army Corps of Engineers (USACE).[258] Other major rivers in the Project Study Area include the Cottonwood, Blue Earth, Cannon, Cedar, Root, and Zumbro Rivers. The largest lake in the Project Study Area is Heron Lake (over 6,400 acres when the northern and southern portions are combined). Other lakes over 2,000 acres include Lake Shetek, Lake Benton, Freeborn Lake, Geneva Lake, and Albert Lea Lake.[259] Chains of lakes, such as the Fairmont Chain of Lakes, are common features moving west-east across the Project Study Area.

The MDNR maintains the Minnesota Public Waters Inventory (PWI), which is a list of watercourses (e.g., streams, rivers), basins, and wetlands which meet the definition of a public water in state statute. Public waters are held in trust by the state for the benefit of all Minnesotans.[260] The MDNR issues Utility Licenses and Work in Public Waters permits for projects which impact public waters. As shown in **Table 10.2-2**, 1,385 public water features are present within the Project Study Area, with the majority occurring in the Des Moines River - Headwaters Watershed, which is within the Coteau Moraines, Inner Coteau, and Minnesota River Prairie subsections.

Table 10.2-2
Public Waters within the Project Study Area

Region (HUC 2) / Subbasin (HUC 8)	PWI Watercourse	PWI Basins and Wetlands	Total
MISSOURI REGION			
Little Sioux River	28	49	77
Lower Big Sioux River	77	2	79
Rock River	146	14	160
Upper Big Sioux River	6	-	6
UPPER MISSISSIPPI REGION			
Blue Earth River	83	71	154
Cannon River	14	1	15
Cedar River	67	14	81
Cottonwood River	70	54	124
Des Moines River - Headwaters	136	156	292
East Fork Des Moines River	14	22	36

258 Section 10 waters are defined by the Rivers and Harbors Act as navigable waters subject to the ebb and flow of tides and waters used to conduct interstate and foreign commerce.

259 MDNR. Public Waters Inventory (PWI) Maps. Available at: https://www.dnr.state.mn.us/waters/watermgmt_section/pwi/maps.html.

260 MDNR. Public Waters Inventory Program. Available at: https://www.dnr.state.mn.us/waters/watermgmt_section/pwi/index.html.

Table 10.2-2
Public Waters within the Project Study Area

Region (HUC 2) / Subbasin (HUC 8)	PWI Watercourse	PWI Basins and Wetlands	Total
Lac Qui Parle River	2	4	6
Le Sueur River	38	26	64
Lower Des Moines River	14	-	14
Minnesota River - Mankato	1	-	1
Minnesota River - Yellow Medicine River	24	42	66
Redwood River	31	53	84
Root River	12	-	12
Shell Rock River	25	19	44
Upper Wapsipinicon River	1	-	1
Watonwan River	13	9	22
Winnebago River	3	3	6
Zumbro River	41	-	41
PROJECT TOTAL	**846**	**539**	**1,385**

Source: MDNR. Public Water Basin and Watercourse Delineations. Available at: https://gisdata.mn.gov/dataset/water-mn-public-waters.

The Project will cross waterbodies regulated by the USACE, MDNR, and local Minnesota Watershed Districts. Waterbody features can often be avoided by spanning the feature to avoid work within the water. The Applicants will submit permit applications for the Project later in the routing and permitting process. Permit applications will contain information on how the Applicants will construct and operate the Project to minimize impacts.

10.2.4 Floodplains

Floodplain zones within the Project Study Area are concentrated along many river corridors where Federal Emergency Management Agency (FEMA) floodway designations are in effect. These floodways align predominantly with the 100-year floodplain boundaries, as delineated in FEMA's Flood Insurance Rate Maps.[261] In addition to these zones, 200-year floodplain extents occur beyond riverine environments into agricultural landscapes and the margins of urbanized zones. The Applicants will review the Project for floodplain permitting needs later in the routing and permitting process. Permit applications, if needed, will contain information on how the Applicants will construct and operate the Project to minimize impacts in floodplains.

[261] FEMA Flood Hazard Layer. Available at: https://hazards-fema.maps.arcgis.com/apps/webappviewer/index.html?id=8b0adb51996444d4879338b5529aa9cd.

10.2.5 Wetlands

MDNR's National Wetland Inventory Data for Minnesota classifies approximately 7 percent, or 321,772 acres, of the land within the Project Study Area as wetland.[262] Of these acres, 200,092 acres, or 42 percent, are palustrine emergent (PEM) wetlands, and 26,709 acres, or 8 percent, are palustrine forested (PFO) wetlands. Wetlands within the Project Study Area are depicted on **Figure 10.2-3. Table 10.2-3** presents the location of wetlands within each ECS subsection in the Project Study Area.

Table 10.2-3
Wetland Acreage by ECS Subsection within the Project Study Area

ECS Subsection	Wetland (acres)	Percent of Wetlands within the Project Study Area
Inner Coteau	44,579	13.9
Coteau Moraines	154,005	47.9
Minnesota River Prairie	73,696	22.9
Oak Savanna	40,082	12.5
Rochester Plateau	9,260	2.9
The Blufflands	150	<0.1
PROJECT TOTAL	**321,772**	**100.0**

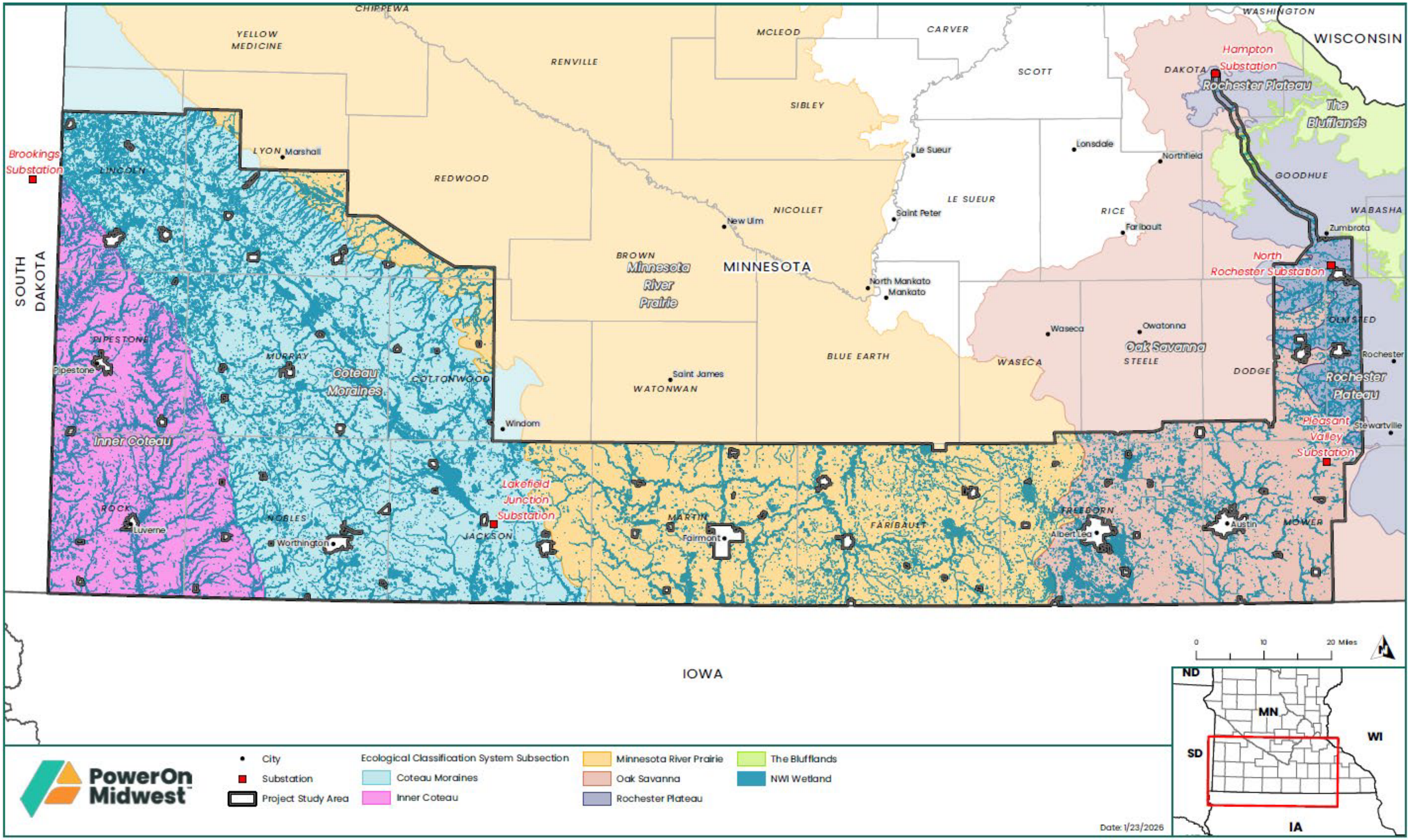
Note: Total percentage does not add, due to rounding.
Source: MDNR. National Wetland Inventory for Minnesota. Available at: https://gisdata.mn.gov/dataset/water-nat-wetlands-inv-2009-2014.

Almost half of the wetlands within the Project Study Area are in the Coteau Moraines subsection, due to the size of this subsection relative to the others within the Project Study Area. Many of the wetlands are located near the Des Moines River and adjacent prairies and are dominated by PEM wetlands. Only 4 percent of the wetlands within this subsection are PFO wetlands. A similar percentage of PFO wetlands occur in the other western subsections – the Inner Coteau (2 percent) and the Minnesota River Prairie (13 percent).

The percentage of PFO wetlands increases in the eastern portion of the Project Study Area. Approximately 68 percent of the 150 acres of wetlands within the Blufflands province are PFO. The Rochester Plateau subsection has more than 42 percent of the wetlands classified as PFO.

[262] MDNR. National Wetland Inventory for Minnesota. Available at: https://gisdata.mn.gov/dataset/water-nat-wetlands-inv-2009-2014.

Figure 10.2-3: Wetland Features within the Project Study Area



Several agencies regulate impact wetlands in Minnesota. The USACE issues Section 404 wetland permits for discharges of dredged or fill material into Waters of the United States. The MPCA issues Section 401 water quality certifications. Finally, the Minnesota Board of Water and Soil Resources (BWSR) coordinates the state Wetland Conservation Act (WCA). The Applicants will design the final Project routes to avoid and minimize potential temporary and permanent impacts to wetlands to the extent practicable and will work with regulatory agencies to obtain necessary permits and approvals prior to construction of the Project.

10.2.6 Groundwater

Groundwater in Minnesota is divided into six aquifer provinces based on glacial geology and bedrock.[263] Four of these provinces are located within the Project Study Area. Generally, groundwater is provided through surficial aquifers, buried sand aquifers, and bedrock aquifers. Groundwater provinces are shown on **Figure 10.2-4.**

In the western portion of the Project Study Area (generally, the area west of Martin County), most of the area is within Province 5 (Western). Here, there are limited surficial and buried sand aquifers within the loam/clay loam glacial sediment. The underlying Cretaceous and Precambrian bedrock also contains limited aquifers. Limited portions of the western Project Study Area are within Province 6 (Arrowhead/Shallow Bedrock), which has even more limited aquifer potential due to exposed or shallow bedrock.

From Martin County to the east, most of the area is within Province 2 (South-Central). Here, thick glacial sediment contains limited surficial and buried sand aquifers, but there are extensive bedrock aquifers. The far eastern portion of the Project Study Area is part of Province 3 (Karst), which is characterized by thin glacial sediment overlying thick bedrock prone to karst features like sinkholes and caves. Surficial and buried sand aquifers are limited, but bedrock aquifers provide good groundwater availability.

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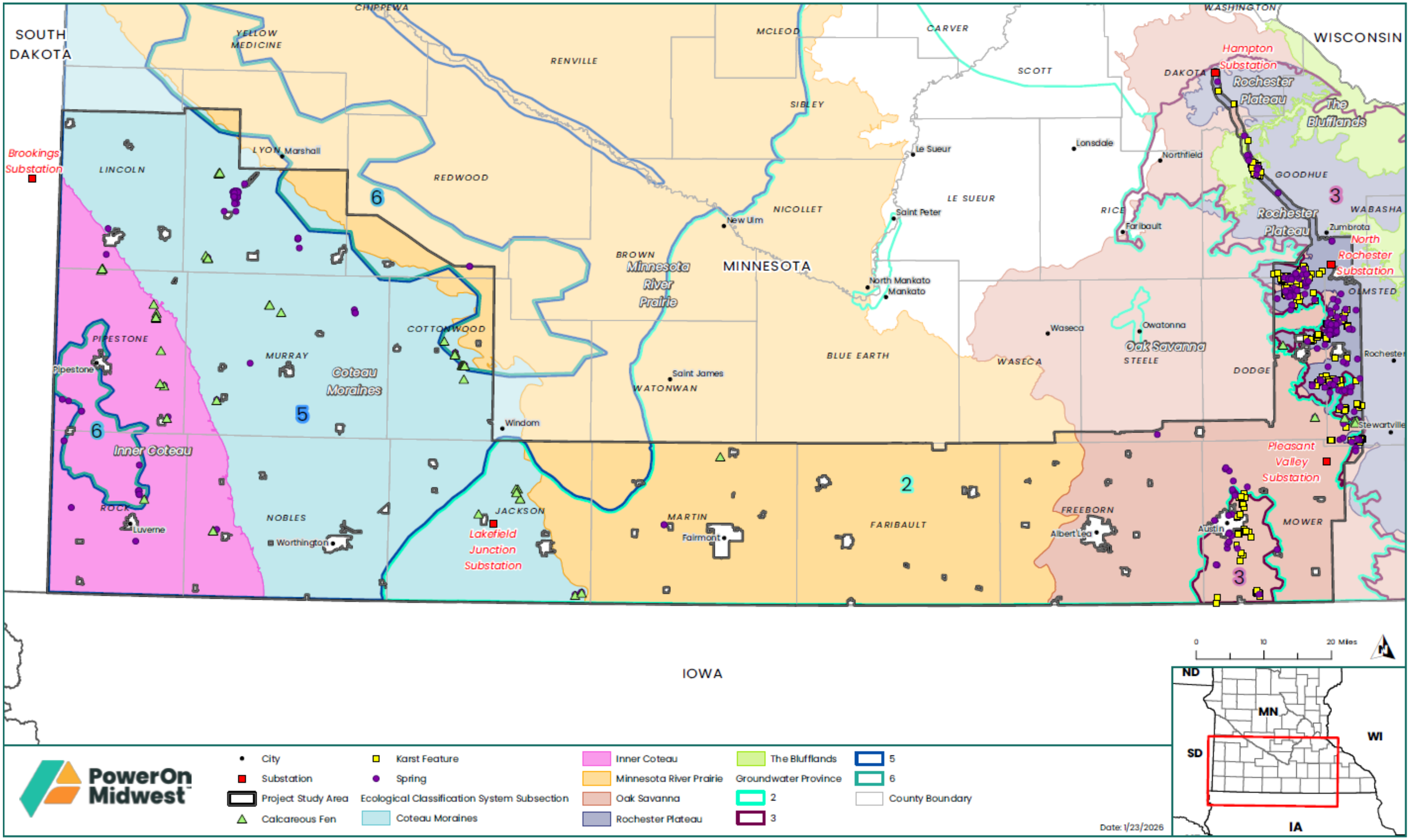
[263] Minnesota Groundwater Provinces 2021. Available at: https://files.dnr.state.mn.us/waters/groundwater_section/mapping/provinces/2021-provinces.pdf.

Figure 10.2-4: Groundwater Features within the Project Study Area



10.2.7 Calcareous Fens

Calcareous fens are rare habitats created by upwelling groundwater that occur on slopes with high concentrations of calcium carbonate and low nutrient availability. Fens support rich biodiversity, including rare plants, and are susceptible to surface disturbing activities. Federal- and state-protected plant species are often found in calcareous fen habitats.[264] MDNR regulates potential impacts to calcareous fens.[265]

The MDNR maintains a list of known calcareous fens.[266] There are 33 listed calcareous fens within the Project Study Area. The majority are located within the Coteau Moraines subsection (17), followed by the Inner Coteau subsection (11), owing to the greater concentration of fens in the southwestern part of the state. **Table 10.2-4** presents the number of calcareous fens in each subsection. Calcareous fen locations are also shown on **Figure 10.2-4**. The Applicants will carefully consider the location of these features when routing the Project to avoid and minimize impacts.

Table 10.2-4
Calcareous Fens by ECS Subsection within the Project Study Area

ECS Subsection	Number of Fens
Inner Coteau	11
Coteau Moraines	17
Minnesota River Prairie	1
Rochester Plateau [a]	2
Oak Savanna [a]	2
The Blufflands	0
PROJECT TOTAL	**33**

[a] One fen is present in both the Rochester Plateau and Oak Savanna ECS and is not double-counted.
Source: MDNR. Calcareous Fens – Source Feature Points. Available at: https://gisdata.mn.gov/dataset/biota-nhis-calcareous-fens.

10.2.8 Karst and Springs

Southeastern Minnesota is a region composed of rolling hills, bluffs, and valleys, where shallow levels of sediment cover Paleozoic carbonate and sandstone bedrock. Over time, the

[264] MDNR. Calcareous Fens. Available at: https://files.dnr.state.mn.us/natural_resources/water/wetlands/calcareous_fen_fact_sheet.pdf.

[265] Minn. R. 8420.0935, subp. 2.

[266] MDNR. Identification List of Known Calcareous Fens. Available at: https://files.dnr.state.mn.us/eco/wetlands/calcareous_fen_list.pdf.

carbonate minerals in the rock are dissolved by rain and groundwater, creating karst. Karst is characterized by sinkholes, caves, springs, and underground drainage dominated by rapid conduit flow.[267] The MDNR maintains the Karst Features Inventory, which contains both reported and verified karst features like sinkholes, caves, stream sinks, and karst springs.[268] The location of springs is also maintained by the MDNR as the Minnesota Spring Inventory.[269] Several isolated springs have been reported in the Inner Couteau and Couteau Moraine subsections in the western portion of the Project Study Area. A north-south line of karst and spring features is present to the east of the city of Austin in Mower County in the Oak Savanna subsection. Then, further to the east, karst and spring features become more common in the Rochester Plateau and The Blufflands subsections in Dodge, Olmsted, Goodhue, and Dakota Counties. These features are shown on **Figure 10.2-4**.

The Applicants will use best management practices to prevent surface runoff and sedimentation and will conduct geotechnical analyses where appropriate to evaluate whether karst is present at structure locations. Structure foundation design will account for the presence of karst, as needed.

10.3 Natural Vegetation and Wildlife

10.3.1 Vegetation

Pre-European contact and present-day vegetation vary across the Project Study Area due to the characteristics and land use patterns of each ECS subsection. ECS subsections are shown on **Figure 10.1-1**. **Table 10.3-1** summarizes existing vegetative cover in the Project Study Area by ECS subsection.

267 MDNR. Springs, Springsheds, and Karst. Available at: https://www.dnr.state.mn.us/waters/groundwater_section/mapping/springs.html.

268 MDNR. Karst Feature Inventory Points. Available at: https://gisdata.mn.gov/dataset/geos-karst-feature-inventory-pts.

269 MDNR. Minnesota Spring Inventory. Available at: https://arcgis.dnr.state.mn.us/portal/apps/webappviewer/index.html?id=560f4d3aaf2a41aa928a38237de291bc.

Table 10.3-1
Vegetative Cover by ECS Subsection in the Project Study Area (acres)

Land Use Category	ECS SUBSECTION						Total
	Inner Coteau Moraines	Coteau Moraines	Minnesota River Prairie	Oak Savanna	Rochester Plateau	The Blufflands	
Deciduous Forest	2,661	18,468	7,341	14,114	20,993	1,306	**64,883**
Emergent Herbaceous Wetlands	10,407	65,059	25,485	11,045	1,085	6	**113,087**
Evergreen Forest	2	26	3	24	74	20	**149**
Grassland/ Herbaceous	11,525	19,693	287	339	80	31	**31,955**
Mixed Forest	19	76	51	143	245	26	**560**
Pasture/Hay	72,111	123,272	22,705	34,808	19,913	608	**273,417**
Shrub/Scrub	<0.1	7	4	15	11	1	**38**
Woody Wetlands	64	2,875	13,532	6,932	2,681	65	**26,149**
PROJECT TOTAL	**96,790**	**229,478**	**69,408**	**67,420**	**45,082**	**2,064**	**510,238**

Note: Some totals may not add due to rounding.

Source: National Land Cover Database, 2019. Available at: https://www.sciencebase.gov/catalog/item/5f21cef582cef313ed940043. Does not include the categories of barren land, cultivated crops, developed (all types), or open water.

In the westernmost part of the Project Study Area, the Inner Coteau subsection was mostly covered by tallgrass prairie. Wet prairies were uncommon and found only along narrow stream edges. Forests were also rare and mainly grew in deep valleys along the Rock and Redwood Rivers. The prairies in this area tended to be drier than in other parts of Minnesota, which led to more plants that are typical of the midgrass prairies found farther west. Dry prairies were especially widespread in Pipestone and Rock counties, where the soil is thin and lies close to bedrock. Today, farming is the main use of the land in this region and very little of the original prairies and forested valleys remain.[270]

In the Coteau Moraines subsection, vegetation consisted largely of tallgrass prairies, with wet prairies and forests being restricted to stream margins and riparian ravines. Land in this subsection is currently used for agricultural production and little pre-European contact vegetation remains.[271]

Moving east, vegetation in the Minnesota River Prairie subsection was predominantly tallgrass prairie interspersed by many islands of wet prairie and areas of deciduous forest, floodplains, and other small streams. While wetlands were common within this subsection, most have been drained to establish cropland.[272]

The Oak Savanna subsection previously consisted of bur oak savanna with areas of tallgrass prairie and maple-basswood forest. Bur oak savanna developed on rolling moraine ridges at the western edge of the subsection and in dissected ravines at the eastern edge. Tallgrass prairie occurred in level to rolling areas, while forest was constrained to ravines or waterways where the frequency or severity of fires was lower. Current land use is agricultural in nature; urban development has been increasing within this subsection.[273]

On the eastern edge of the Project Study Area, vegetation in the Rochester Plateau subsection was composed primarily of tallgrass prairie and bur oak savanna. Fire was important in upland prairie and oak savanna dominated communities. Land use in this subsection is now dominated by agricultural activities, with some small areas of oak barrens remaining.[274]

In the northeast portion of the Project Study Area, tallgrass prairie and bur oak savanna were the major vegetation types on ridge tops and dry upper slopes in The Blufflands subsection.

[270] MDNR. Inner Coteau Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Bc/index.html.

[271] MDNR. Coteau Moraines Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Bb/index.html.

[272] MDNR. Minnesota River Prairie Subsection. Available at: https://www.dnr.state.mn.us/ecs/251Ba/index.html.

[273] MDNR. Oak Savanna Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Me/index.html.

[274] MDNR. Rochester Plateau Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Lf/index.html.

Red oak-white oak-shagbark hickory-basswood forests were present on moister slopes and red oak-basswood-black walnut forests were found in protected valleys. Prairie was restricted mostly to broad ridge tops. Currently, approximately 50 percent of this subsection is in crops or pastureland, and 50 percent is woodland.[275]

10.3.1.1 Native Plant Communities and Sites of Biodiversity Significance

The MDNR classifies native plant communities (NPCs) in Minnesota by considering a variety of features, including hydrology, vegetation, soils, topography, and natural disturbance regimes (e.g., fire, floods, drought). This classification system is meant to, "provide a framework and common language for improving our ability to manage vegetation, survey natural areas for biodiversity conservation, identify research needs, and promote study and appreciation of native vegetation in Minnesota."[276] NPCs are ranked for their degree of ecological integrity. The Project Study Area crosses 12 native plant ecological systems. Within these ecological systems there are 29 unique NPC classes. NPCs within these classes are further categorized by NPC type and subtype. NPCs within the Project Study Area are ranked between S1 to S5. NPCs ranked between S1-S3 are of higher quality than those ranked S4-S5.

Through the Minnesota Biological Survey, MDNR systematically collects, interprets, and delivers baseline data on the distribution and ecology of rare plants, rare animals, NPC classes, and functional landscapes and designates sites which exhibit these characteristics as Sites of Biodiversity Significance (SOBS). SOBS are assigned one of four ranks based on the relative significance of biodiversity of the site at a statewide level: Outstanding, High, Moderate, or Below. SOBS are present throughout the Project Study Area, distributed across all ECS subsections. The Project Study Area contains 43 sites ranked as Outstanding and 112 sites ranked as High. Most of the sites ranked High and Outstanding are present in the Coteau Moraines and Inner Coteau subsections. [277]

The Applicants will consider the location of highly-ranked NPCs and SOBS as routing for the Project is refined. The Applicants will work with the appropriate agencies regarding BMPs for work in or near these resources.

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275 MDNR. Blufflands Subsection. Available at: https://www.dnr.state.mn.us/ecs/222Lc/index.html.

276 MDNR. Native Plant Community Classification. Available at: https://www.dnr.state.mn.us/npc/classification.html.

277 MDNR. MBS Sites of Biodiversity Significance. Available at: https://gisdata.mn.gov/dataset/biota-mcbs-sites-of-biodiversity.

10.3.1.2 Native Prairie

The MDNR has developed the Minnesota Prairie Conservation Plan to preserve existing prairie habitats, identify areas in need of conservation, and build cooperation between federal and state agencies and conservation organizations. A primary strategy to protect remaining native prairie resources is to maintain habitat through conservation easements on public and private lands.[278] A review of the MDNR's 2018 Native Prairie Bank Easement Boundaries identified native prairie bank easements and prairie corridors within the Project Study Area, all within the Inner Couteau, Couteau Moraines, and Minnesota River Prairie subsections.[279] In addition to these formal prairie bank easements, upland and wetland NPCs are present within all of the ECS subsections.[280]

As shown in **Table 10.4-1,** roughly 82 percent of land in the Project Study Area is categorized as cultivated cropland. Native prairies are generally found in small, scattered pockets along waterbodies where agricultural activities have not displaced native vegetation, or along railroad rights of way as prairie remnants.

The Applicants will carefully consider the location of these features when routing the Project and will work with agencies to develop the appropriate BMPs, as needed.

10.3.2 Wildlife

Given the predominance of cropland and developed cover types in the Project Study Area (see **Section 10.4**), terrestrial habitat suitability for wildlife is largely limited to common and generalist species. Areas in and around agricultural and developed land use are generally inhabited by species such as white-tailed deer (*Odocoileus virginianus*), raccoons (*Procyon lotor*), voles (*Microtus* spp.), European starlings (*Sturnus vulgaris*), American crows (*Corvus brachyrhynchos*), and house sparrows (*Passer domesticus*). Waterbodies and wetlands provide aquatic habitat for fish, amphibians, reptiles, birds, and invertebrates. Trout streams are present in the Coteau Moraines, Oak Savanna, and Rochester Plateau subsections.[281]

The potential for suitable habitat for more diverse species is higher in the other cover types crossed by the Project, such as grassland, forest, and wetland (see **Section 10.3.1**). Lands managed for recreation and wildlife, including those described in **Section 10.4.1**, also provide

278 MDNR. Minnesota Prairie Conservation Plan. Available at: https://www.dnr.state.mn.us/prairieplan/index.html.

279 MDNR. Minnesota Native Prairie Bank. Available at: https://files.dnr.state.mn.us/destinations/snas/NPBstatemap.pdf.

280 MDNR. Native Prairies. Available at: https://gisdata.mn.gov/dataset/biota-dnr-native-prairies.

281 MDNR. State Designated Trout Streams. Available at: https://gisdata.mn.gov/sv/dataset/env-trout-stream-designations.

habitat for a greater variety of species. Depending on the species and their life histories, individuals may utilize terrestrial, aquatic, or a combination of habitats throughout an annual cycle.

10.3.3 Federally Listed Species

The Applicants used the USFWS' Information for Planning and Consultation[282] (IPaC) website to obtain information regarding federally listed threatened or endangered species, candidate species, and designated critical habitat that may be present within the Project Study Area. Information about these species and associated habitat is presented in **Table 10.3-2**.

Table 10.3-2
Federally Listed Species Potentially Present in the Project Study Area

Scientific Name	Common Name	Federal Designation	County
Myotis septentrionalis	Northern long-eared bat	Endangered	Dakota, Dodge, Faribault, Freeborn, Goodhue, Jackson, Martin, Mower, Lincoln, Lyon, Nobles, Olmsted, Pipestone, Rock, Steele, Waseca
Perimyotis subflavus	Tricolored bat	Proposed Endangered	Dakota, Dodge, Goodhue, Jackson, Mower, Nobles, Olmsted, Rock, Steele
Calidris canutus rufa	Rufa red knot	Threatened	Lincoln, Pipestone, Rock
Grus americana	Whooping crane	Experimental / non-essential	Dakota, Dodge, Goodhue, Freeborn, Mower, Olmsted, Steele
Notropis topeka	Topeka shiner	Endangered	Lincoln, Murray, Nobles, Pipestone, Rock
		Final Designated Critical Habitat	Lincoln, Murray, Nobles, Pipestone, Rock
Lampsilis higginsii	Higgins Eye (pearlymussel)	Endangered	Dakota
Simpsonaias ambigua	Salamander mussel	Proposed Endangered	Dodge, Goodhue, Faribault, Freeborn, Martin, Mower, Nobles, Pipestone, Rock
Hesperia dacotae	Dakota skipper	Threatened	Lincoln, Pipestone
		Final Designated Critical Habitat	Lincoln, Murray, Pipestone
Danaus plexippus	Monarch butterfly	Proposed Threatened	All
Bombus affinis	Rusty patched bumble bee	Endangered	Dakota, Dodge, Freeborn, Goodhue, Jackson, Mower, Olmsted
		Proposed Designated Critical Habitat	Dakota, Olmsted
Bombus suckleyi	Suckley's cuckoo bumble bee	Proposed Endangered	Cottonwood, Jackson, Lincoln, Lyon, Murray, Nobles, Pipestone, Redwood, Rock

282 USFWS. Information for Planning and Consultation. Available at: https://ipac.ecosphere.fws.gov/.

Table 10.3-2
Federally Listed Species Potentially Present in the Project Study Area

Scientific Name	Common Name	Federal Designation	County
Argynnis idalia occidentalis	Western regal fritillary	Proposed Threatened	All
Erythronium propullans	Minnesota dwarf trout lily	Endangered	Goodhue, Rice, Steele
Lespedeza leptostachya	Prairie bush-clover	Threatened	Cottonwood, Dakota, Dodge, Goodhue, Jackson, Martin, Mower, Nobles, Olmsted, Pipestone, Rock
Platanthera praeclara	Western prairie fringed orchid	Threatened	Dodge, Freeborn, Jackson, Lincoln, Martin, Mower, Murray, Nobles, Pipestone, Rock
Oarisma poweshiek	Poweshiek skipperling [a]	Final Designated Critical Habitat	Cottonwood, Lincoln, Lyon, Murray, Pipestone

[a] Although the Poweshiek skipperling is listed as Endangered, IPaC did not indicate its presence in counties within the Project Study Area, despite the presence of Final Designated Critical Habitat.

The Applicants will continue to review listings under the Endangered Species Act (ESA) as Project planning progresses. The Applicants will work with the appropriate agencies as routing for the Project is refined to develop avoidance and minimization measures related to federally listed species, as needed.

10.3.3.1 Northern Long-eared Bat

The northern long-eared bat (NLEB) (*Myotis septentrionalis*) is a federally endangered bat that stretches across much of the eastern and midwestern United States. Approximately 3.0 to 3.7 inches in length with a wingspan of 9 to 10 inches, the species derives its name from oversized ears relative to other members of the genus *Myotis.*[283] In summer, the species roosts in both live trees and snags, and can be found roosting alone or in colonies under loose bark or in crevices and hollows. A habitat generalist, roost tree selection appears to be opportunistic; the species uses a variety of tree sizes and species, typically greater than or equal to 3 inches diameter at breast height.

The species is generally associated with intact, interior forested habitats, including mesic hardwood, floodplain, and fire-dependent forests, particularly those near water sources. Occasionally, the species will use smaller forest patches connected by shelterbelts; however, this habitat is usually within 1,000 feet of other forested or wooded habitat as the species tends

[283] USFWS. Northern Long-eared Bat. Available at: https://www.fws.gov/species/northern-long-eared-bat-myotis-septentrionalis.

to stay close to more densely forested areas while foraging. Males and non-reproductive females may also roost in cooler places such as caves and mines. The species has also been found, rarely, roosting in structures such as barns and sheds. The species overwinters in small crevices or cracks in hibernacula (e.g., caves and mines with constant temperatures, high humidity, and no air currents).[284]

The primary threat to the NLEB is white-nose syndrome. Other sources of mortality such as collisions with wind turbines, loss of summer habitat, and changes which alter the microhabitat of hibernacula have not been observed to produce significant population declines; however, as white-nose syndrome impacts more populations, impacts from these activities may become more pronounced.[285]

On April 2, 2015, the USFWS listed the NLEB as threatened under the ESA and simultaneously published an interim 4(d) rule. The USFWS issued a final rule reclassifying the species from threatened to endangered on November 30, 2022, with an effective date of March 31, 2023, nullifying the 4(d) rule for the species.

Potential impacts on individual NLEBs may occur if clearing or construction takes place in its summer habitat when the species is breeding, foraging, or raising pups. Bats might be injured or killed if occupied trees are cleared during this active window, and the species might be disturbed during clearing or construction activities due to noise or human presence. Tree clearing activities conducted when the species is in hibernation and not present on the landscape could result in indirect impacts due to removal of suitable foraging and roosting habitat.

In Minnesota, the species is most likely to be found in forested wetlands and riparian areas. However, individual trees, fence rows, or small wooded lots (less than 10 acres) that are greater than 1,000 feet from forested/wooded areas are considered unsuitable for the species, as are pure stands of less than 3-inch diameter-at-breast-height trees that are not mixed with larger trees and trees found in highly developed urban areas. Potentially suitable roosting and foraging habitat is present in the Project Study Area.

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[284] USFWS. Range-wide Indiana Bat and Northern Long-eared Bat Survey Guidelines. Available at: https://www.fws.gov/sites/default/files/documents/2025-05/2024_usfws_rangewide_ibat-nleb_survey_guidelines.pdf.

[285] USFWS. Northern Long-eared Bat. Available at: https://www.fws.gov/species/northern-long-eared-bat-myotis-septentrionalis.

10.3.3.2 Tricolored Bat

The tricolored bat (TCB) (*Perimyotis subflavus*) is one of the smallest bat species native to North America and ranges from the eastern and central United States into portions of southern Canada, Mexico, and into Central America. On September 13, 2022, the USFWS published a proposed rule listing the TCB as federally endangered under the ESA. Proposed species are not protected under the ESA. However, federal agencies are required to confer with the USFWS on agency actions that may be likely to jeopardize the continued existence of a proposed species.

TCB are one of the first bat species to enter hibernation in the fall, and one of the last to leave in the spring.[286] The species overwinters in caves and mines where available; however, throughout much of its range in the southern United States, roadside culverts, tree cavities, and abandoned water wells may also serve as suitable overwintering habitat. During the active season, the species may be found roosting among leaf clusters (live and dead) on living or recently dead deciduous hardwood trees. The species has also been observed roosting in eastern red cedar trees and pine needles as well as within human-made structures such as barns and bridges.[287]

Like the NLEB, tree clearing and construction may impact individual TCBs if the work takes place when the species is breeding, foraging, or raising pups in its summer habitat. Bats may be injured or killed if occupied trees are cleared during the species' active season.

10.3.3.3 Rufa Red Knot

The rufa red knot is a medium-sized shorebird that was ESA-listed as threatened in 2014. The species is known for its long-distance migration between breeding grounds in the Canadian Arctic and several wintering areas in the southern hemisphere. A majority of rufa red knots follow migration routes along the east and west coasts of the United States, but small numbers of this species have been documented along an inland migration route across the Midwest during spring and fall migrations. Sightings are typically concentrated along the Great Lakes. This species is a rare migrant through Minnesota. A small portion of western Minnesota (south of Fergus Falls to the Iowa state line) and northeast Minnesota near Duluth transect the rufa red knot range.[288]

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[286] USFWS, Tricolored Bat Frequently Asked Questions. Available at: https://www.fws.gov/story/2022-09/tricolored-bat-frequently-asked-questions.

[287] USFWS. Range-wide Indiana Bat and Northern Long-eared Bat Survey Guidelines. Available at: https://www.fws.gov/sites/default/files/documents/2025-05/2024_usfws_rangewide_ibat-nleb_survey_guidelines.pdf.

[288] USFWS. Rufa Red Knot. Available at: https://www.fws.gov/species/rufa-red-knot-calidris-canutus-rufa.

10.3.3.4 Whooping Crane

The historic range of the whooping crane extended from the Arctic coast south to central Mexico, and from Utah east to New Jersey, into South Carolina, Georgia, and Florida. There are now only three populations of whooping cranes in North America. One, the Aransas/Wood Buffalo population, is a self-sustaining, wild population. This population embarks on a bi-annual migration through the interior United States from summer nesting and breeding grounds in Wood Buffalo National Park in northern Alberta to the barrier islands and coastal marshes of the Aransas National Wildlife Refuge on the Gulf Coast of Texas. The second population is a non-migratory, captive-raised population in central Florida. A third population consists of captive-raised birds that migrate between Wisconsin and Florida. This population is considered by the USFWS to be an experimental, non-essential population.[289] For the purposes of consultation, non-essential experimental populations are treated as threatened species on National Wildlife Refuge and National Park land (require consultation under 7(a)(2) of the ESA) and as a proposed species on private land (no section 7(a)(2) requirements, but Federal agencies must not jeopardize their existence (section 7(a)(4)). The species will be treated as proposed on private lands.

Suitable breeding, migrating, wintering, and foraging habitat for this species consists of coastal marshes and estuaries, inland marshes, lakes, open ponds, shallow bays, salt marshes, sand or tidal flats, wet meadows and rivers, pastures, and agricultural fields. Much of the Project Study Area consists of agricultural fields, which the whooping crane could use as stopover habitat for foraging waste grains; however, there is minimal amount of shoreline habitat for the species to roost. Despite the lack of habitat, there have been some limited reported sightings as recent as July 2024 within the Project Study Area.[290]

10.3.3.5 Topeka Shiner

The Topeka shiner is a small minnow that was ESA-listed as endangered in 1999. It is typically less than three inches in length, primarily found in small to mid-size prairie streams in the central United States (i.e., South Dakota, Minnesota, Kansas, Iowa, Missouri, and Nebraska).[291] Records of Topeka shiner occur in Lincoln, Murray, Pipestone, Nobles, and Rock counties, with some as recent as 2019. Impacts on Topeka shiner are possible if construction activities impact suitable stream habitat by increasing sediment load, altering the temperature, flow, or streambed composition of suitable streams. The species is particularly vulnerable to impacts

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289 USFWS. Whooping Crane. Available at: https://www.fws.gov/apps/species/whooping-crane-grus-americana.

290 eBird. Species results return for whooping crane. Available at: https://www.birds.cornell.edu/landtrust/how-to-ebird/

291 USFWS. Topeka Shiner. Available at: https://www.fws.gov/species/topeka-shiner-notropis-topeka.

which take place during the spawning season (generally, mid-May to early July, but is temperature-dependent).[292]

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 (PCEs), which are physiological or biological features of habitat that are considered essential for the conservation of the species.

The PCEs of Topeka shiner critical habitat include streams most often with permanent flow, but that can become intermittent during dry periods; side-channel pools and oxbows either seasonally connected to a stream or maintained by groundwater inputs; streams and side-channel pools with water quality necessary for unimpaired behavior, growth, and viability of all life stages; living and spawning areas for adults with water velocities less than 0.5 meters per second up to 2.0 meters in depth; living areas for juveniles with water velocities less than 0.5 meters per second up to 0.25 meters in depth with moderate amounts of cover; sand, gravel, cobble, and silt substrates with amounts of fine sediment and substrate to allow for nest building and maintenance of nests and eggs; adequate terrestrial, semiaquatic, and aquatic invertebrate food base; a hydrologic regime capable of forming, maintaining, or restoring the flow periodicity, channel morphology, fish community composition, off-channel habitats, and habitat components described in the other PCEs; and few or no non-native predatory or non-native competitive species present.[293]

In Minnesota, designated critical habitat includes the stream channels within the identified stream reaches and off-channel pools and oxbows. Designated critical habitat streams and reaches are present within Lincoln, Murray, Pipestone, Nobles, and Rock counties.

10.3.3.6 Higgins Eye (Pearlymussel)

The Higgins eye is an oval or elliptical, somewhat inflated freshwater mussel that was ESA-listed as endangered in 1972. The species was the first freshwater mussel to be listed under the federal ESA. It can grow up to 6 inches long and the shell is usually yellow, green, red, or brown with green rays with a white, iridescent inside.[294]

[292] MDNR. Topeka Shiner. Available at: https://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=AFCJB28960.

[293] Federal Register, USFWS, Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Topeka Shiner. Available at: https://www.federalregister.gov/documents/2002/08/21/02-20939/endangered-and-threatened-wildlife-and-plants-designation-of-critical-habitat-for-the-topeka-shiner.

[294] USFWS, Higgins' Eye. Available at: https://www.fws.gov/rivers/species/higgins-eye-lampsilis-higginsii.

The Higgins eye has been extirpated from most of its historical range and now only occurs in parts of the Mississippi River north of Lock and Dam 9 at Keokuk, Iowa and three tributaries to the Mississippi river: the St. Croix River between Minnesota and Wisconsin, the Wisconsin River in Wisconsin, and the lower Rock River between Illinois and Iowa. Impacts to this species due to the Project actions are unlikely as the Project does not intersect any of these waterbodies.

10.3.3.7 Salamander Mussel

Salamander mussels are within the pearlymussel family and are small, elliptical-shaped mussels, reaching only up to 2 inches in length. On August 22, 2023, USFWS published a proposed rule listing the salamander mussel as federally endangered under the ESA. Proposed species are not protected under the ESA; however, federal agencies are required to confer with the USFWS on agency actions that may be likely to jeopardize the continued existence of a proposed species.

Suitable habitat includes rivers, streams, and even lakes with suitable amounts of flow. Unique to salamander mussels is that the host species for larva is the mudpuppy (*Necturus maculosus),* a species of large salamander. Mudpuppies must be present during the salamander mussel breeding season for the mussels to propagate.[295] The salamander mussel ranges widely throughout the Mississippi and Ohio river drainages; however, it is rarely found. In Minnesota, the salamander mussel is restricted to the lower St. Croix River. Impacts to this species due to Project are unlikely as the Project does not intersect this waterbody.

10.3.3.8 Dakota Skipper

The Dakota skipper is a small-to-medium sized butterfly that was ESA-listed as threatened in 2014. It is characterized by a short, sturdy body and a quick, skipping flight. Adult males are tawny-orange to brown on dorsal surfaces with lighter, dusty yellow-orange ventral surfaces; forewings display conspicuous dark markings. Dakota skipper adults have a lifespan of only one to two weeks and can be seen during the breeding and egg-laying season between mid-June and mid-July. Adult skipper flight periods may be tied to the purple cornflower blooming period in prairie habitats where this species is present. The species is present in suitable habitat year-round as the larvae overwinter at the base of plants on which they forage in the spring.

The species is an obligate of untilled, high-quality native prairie containing a variety of wildflowers and grasses. Dakota skippers do not thrive in heavily grazed or cultivated areas but can be found in both wetlands and uplands. The preferred wetland habitat is associated with

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[295] USFWS. Salamander Mussel. Available at: https://www.fws.gov/species/salamander-mussel-simpsonaias-ambigua.

plant species consisting of little bluestem (*Schizachyrium scoparium* var. *scoparium*), wood lily (*Lilium philadelphicum*), and harebell (*Campanula rotundifolia*).[296] In Minnesota, the Dakota skipper may be found primarily in native dry-mesic to dry prairie where mid-height grasses such as little bluestem, prairie dropseed (*Sporobolus heterolepis*), and side-oats grama (*Bouteloua curtipendula* var. *curtipendula*) dominate.[297]

The status of the Dakota skipper in Minnesota is tenuous: intensive survey efforts since 2012 have found only one remaining Dakota skipper population in Minnesota.[298] Potentially suitable prairie habitat for Dakota skippers may be present within the Inner Coteau, Coteau Moraines, and Minnesota River Prairie subsections in the Project Study Area.

Critical habitat has been designated for the Dakota skipper, and is present in Lincoln, Murray, and Pipestone Counties. The PCEs of Dakota skipper critical habitat include wet-mesic tallgrass or mixed-grass remnant prairie occurring on or near glacial lake deposits or high-quality dry-mesic remnant prairie containing native forbs and grasses, glacial soils with micro-climate conditions suitable for larval survival and native prairie vegetation, less than 5 percent tree or shrub cover in dry prairies and less than 25 percent cover in wet mesic prairies, and less than 5 percent invasive or nonnative plant species. Undeveloped grassland habitat dominated by perennial grasses with no barriers must be present within 0.6 mile of native high quality remnant prairie that connects high-quality wet-mesic to dry tallgrass prairie or moist meadow habitats. Native grasses and native flowering forbs must be available for larval and adult food and shelter, specifically prairie dropseed or little bluestem. Additionally, one or more specific flowering forbs must be in bloom during the Dakota skipper flight period.[299]

10.3.3.9 Monarch Butterfly

The monarch butterfly is well-known for the species' long-distance migration throughout North America. On December 12, 2024, USFWS published a proposed rule listing the monarch butterfly as federally threatened with a 4(d) rule under the ESA. A final rule has yet to be published to the federal register. Proposed species are not protected under the ESA; however, federal

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[296] USFWS. Dakota Skipper. Available at: https://www.fws.gov/species/dakota-skipper-hesperia-dacotae.

[297] MDNR, Rare Species Guide: Dakota Skipper. Available at: https://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=IILEP65140.

[298] MDNR, Rare Species Guide: Dakota Skipper. Available at: https://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=IILEP65140.

[299] Federal Register, USFWS, Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Dakota Skipper and Poweshiek Skipperling. Available at: https://www.federalregister.gov/documents/2015/10/01/2015-24184/endangered-and-threatened-wildlife-and-plants-designation-of-critical-habitat-for-the-dakota-skipper.

agencies are required to confer with the USFWS on agency actions that may be likely to jeopardize the continued existence of a proposed species.

The species can be found in a wide variety of habitats including prairies, grasslands, urban gardens, road ditches, and agricultural fields, if there are a healthy and abundant milkweed supply and a diversity of nectar resources. Milkweed is the sole host plant for oviposition and for the larvae to feed on until the larvae pupates into a butterfly. Most adults only live approximately 2 to 5 weeks. However, some overwintering adults live 6 to 9 months as they undergo reproductive diapause.[300] There are two populations, located east and west of the Rocky Mountains. Primary drivers affecting the decrease in the monarch butterfly population include loss and degradation of habitat, exposure to insecticides, and climate change. Suitable habitat is present in the Project Study Area.

10.3.3.10 Rusty Patched Bumble Bee

The rusty patched bumble bee was ESA-listed as endangered in 2017. It is characterized by the rusty-colored patch located centrally on the second abdominal segment on the workers and males. Queens lack the species' eponymous rusty patch and can be further distinguished from workers and males by their large size. Historically, the species was distributed across much of the eastern United States and upper Midwest and into southern parts of Canada. The reasons for its decline include pathogens, pesticides, habitat loss, and climate change.[301]

Suitable habitat for the rusty patched bumble bee can be found in grasslands, prairies, marshes, agricultural areas, woodlands, and residential parks and gardens. The species is a generalist forager and utilizes both pollen and nectar from a wide variety of plants. It is thought that like other bumble bee species, rusty patched bumble bees typically forage within 0.6 mile from the nest site. Nests are commonly established underground in abandoned rodent burrows or other cavities, typically 1 to 4 feet beneath the surface; however, the species may also utilize clumps of grass above ground. Suitable habitat must also provide overwintering sites for hibernating queens. While little is known regarding the overwintering habits of rusty patched queens, it is thought they may behave similarly to other *Bombus* species, that is, queens hibernate in a chamber created in uncompacted soils. Rusty patched bumble bees may choose hibernation sites in sandy, moss-covered soil on northwest slopes, and may be found in interior forest areas. Areas with these characteristics near forested edges and open

[300] USFWS. Monarch (*Danaus plexippus*) Species Status Assessment Report, Version 2.1. Available at: https://www.fws.gov/sites/default/files/documents/Monarch-Butterfly-SSA-Report-September-2020.pdf.

[301] USFWS. Rusty Patched Bumble Bee Conservation. Available at: https://www.fws.gov/project/rusty-patched-bumble-bee-conservation.

fields may be especially important. They may also use other areas, such as compost piles or mole hills.[302]

The USFWS has identified high potential zones around current records (i.e., 2007-present); these areas indicate a high probability of rusty patched bumble bee presence. Within these zones, both suitable and unsuitable habitat may be present. High potential zones exist within the Project Study Area in Cottonwood, Jackson, Freeborn, Mower, Dodge, Olmsted, Goodhue, and Dakota Counties. Suitable habitat is present in the Project Study Area.

10.3.3.11 Suckley's Cuckoo Bumble Bee

Suckley's cuckoo bumble bee is a rare parasitic bee species. On December 17, 2024, USFWS published a proposed rule listing the species as federally endangered under the ESA. A final rule has yet to be published to the federal register. Proposed species are not protected under the ESA; however, federal agencies are required to confer with the USFWS on agency actions that may be likely to jeopardize the continued existence of a proposed species.

Suckley's cuckoo bumble bee range spans from the Yukon south to Arizona and as far as Newfoundland in a widely distributed range of elevations. Suckley's cuckoo bumble bee are obligatory social parasites and cannot successfully reproduce without the availability of a suitable host colony of other *Bombus* species. Host bumble bee nests are often found in abandoned underground holes in a variety of habitat types including meadows, fallow fields, croplands, urban areas, and forests. When a female Suckley's cuckoo bumble bee emerges from hibernation, it takes over the nest of a suitable host colony (most notably, western bumble bees and Nevada bumble bees) and the host workers provide for the Suckley's young. Once developed, all Suckley's adults are reproductive and leave the nest to mate. The males die after mating, but the females continue to feed on nectar and pollen prior to overwintering in areas separate from nesting habitat, likely using loose substrates such as leaf litter, duff, or rotting logs.

A generalist, adult females, eggs, larvae, male drones, and new females all require a diversity of native floral resources for pollen and nectar. The species is found in a variety of habitats, including prairies, grasslands, farmsteads, woodlands, boreal forests, active and fallow agricultural fields, and urban areas.[303] Suitable habitat is present in the Project Study Area.

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[302] USFWS. Recovery Plan for Rusty Patched Bumble Bee (*Bombus affinis*). Available at: https://www.fws.gov/sites/default/files/documents/Final%20Recovery%20Plan%20_Rusty%20Patched%20Bumble%20Bee_2021.pdf.

[303] USFWS. Suckley's Cuckoo Bumble Bee (*Bombus suckleyi*) Species Status Assessment, Version 1.0. Available at: https://iris.fws.gov/APPS/ServCat/DownloadFile/263505.

10.3.3.12 Western Regal Fritillary

The western regal fritillary is a strong-flying, non-migratory butterfly. On August 6, 2024, the USFWS published a proposed rule listing the western regal fritillary as federally threatened under the ESA. Proposed species are not protected under the ESA. However, federal agencies are required to confer with the USFWS on agency actions that may be likely to jeopardize the continued existence of a proposed species.

The western regal fritillary has a wingspan up to 4 inches. The forewing is orange with black markings, while the hindwing is mostly black with a row of white spots across the middle. The spots on the outer margin of the hindwing are white in females and orange in males. The caterpillars are velvety black, yellow, or deep orange, with orange or red stripes, and yellow-white branching spines with black tips.[304]

The species is found in native tallgrass prairie habitats and was once commonly found in 32 states extending north in New England, south to Oklahoma, and west to Colorado. Today, the western subspecies is found in portions of Arkansas, Colorado, Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, Oklahoma, South Dakota, Wisconsin, and Wyoming. Regal fritillaries can range widely with females potentially traveling up to 100 miles searching for three main habitat components: violet hostplants for larvae, nectar plants for adults, and native grasses to provide protection throughout the life cycle. Adults can be found foraging in both upland and wet prairie habitats; however, habitat can only be considered suitable for all life stages if violet species are present to provide shelter and forage for larvae. The density of violets seems to correlate positively to the number of butterflies within a given area. Habitat alteration has reduced the species' range and abundance.[305]

Adults mate once annually in mid to late summer. However, females do not undergo reproductive diapause until fall. Eggs hatch in about 3 to 4 weeks and then larvae quickly seek duff material where they overwinter. When active in spring, larvae begin feeding on young violets. Mortality is high during the larvae stage. After a 2- to 4-week pupae stage in late spring, adults emerge in early summer. Dispersal of adults may be driven by localized threats or poor habitat conditions, and success is dependent upon connectivity of suitable habitat, availability

[304] USFWS. Species Status Assessment for Regal Fritillary (*Argynnis (Speyeria) idalia*): Eastern Subspecies (*Argynnis idalia idalia*) and Western Subspecies (*A. I. occidentalis*). Available at: https://iris.fws.gov/APPS/ServCat/DownloadFile/253168.

[305] USFWS. Species Status Assessment for Regal Fritillary (*Argynnis (Speyeria) idalia*): Eastern Subspecies (*Argynnis idalia idalia*) and Western Subspecies (*A. I. occidentalis*). Available at: https://iris.fws.gov/APPS/ServCat/DownloadFile/253168.

of nectar sources, and habitat patch sizes among other factors.[306] Suitable habitat is present in the Project Study Area.

10.3.3.13 Minnesota Dwarf Trout Lily

The Minnesota dwarf trout lily was ESA-listed as endangered in 1986. It is an endemic forest wildflower found only in Goodhue, Rice, and Steele counties. Minnesota dwarf trout lilies are found in river terraces, mesic oak-basswood forests, or mesic maple-basswood forests on north-facing slopes above or near a stream. The species completes its life cycle in early spring prior to tree leaf-out. Main threats to the species include loss of suitable prairie habitat from land conversion to agricultural uses and urban development. Competition from invasive species, climate change and large-scale precipitation events, and housing and agricultural developments are also threats which may contribute to population declines.[307]

There are populations of Minnesota dwarf trout lily that are present at the edge of the Project Study Area in northwestern Goodhue County.

10.3.3.14 Prairie Bush-clover

Prairie bush clover was ESA-listed as threatened in 1987. It is found only in the tallgrass prairie region of four Midwestern states. It is a member of the bean family and a midwestern endemic species known in the tallgrass prairie region of the upper Mississippi River Valley. Most known populations are found in north central Iowa and southern Minnesota. Main threats to the species include loss of suitable prairie habitat from land conversion to agricultural uses and urban development. Competition from invasive species, climate change, and increased herbicide use are also threats which may contribute to population decline.[308] The species is typically found in undisturbed prairie remnants but is also tolerant of disturbed sites. Tallgrass prairie habitats with a history of mowing, burning, cultivation, or grazing may provide suitable conditions as well.

The extent of extant populations of prairie bush clover is well-known in Minnesota; these are present in the Project Study Area within the Inner Coteau, Coteau Moraines, Minnesota River Prairie, Oak Savanna, and Rochester Plateau subsections.

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[306] USFWS. Species Status Assessment for Regal Fritillary (*Argynnis (Speyeria) idalia*): Eastern Subspecies (*Argynnis idalia idalia*) and Western Subspecies (*A. I. occidentalis*). Available at: Species status assessment report for the regal fritillary.

[307] USFWS. Minnesota Fawnlily. Available at: https://www.fws.gov/species/minnesota-fawnlily-erythronium-propullans

[308] USFWS. Prairie Lespedeza. Available at: https://www.fws.gov/species/prairie-lespedeza-lespedeza-leptostachya.

10.3.3.15 Western Prairie Fringed Orchid

Western Prairie Fringed Orchid was ESA-listed as threatened in 1989. A member of the orchid family, the western prairie fringed orchid is found in moist tallgrass prairies in Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and Manitoba, Canada. 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. In Minnesota, habitat characteristics vary with location; in southern Minnesota, most populations are found in southern mesic or southern wet prairies.[309] Potentially suitable habitat for the species is present in the Inner Couteau and Oak Savanna subsections of the Project Study Area.

10.3.3.16 Poweshiek Skipperling

The Poweshiek skipperling was ESA-listed as endangered in 2015 and critical habitat was designated in 2015. The Poweshiek skipperling is a small butterfly that was once found in native prairies in Manitoba, North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Illinois, Indiana, and Michigan. It is now known only from Michigan, Manitoba and perhaps one location in Wisconsin.[310] Although the Poweshiek skipperling is listed as endangered, IPaC did not indicate its presence in counties within the Project Study Area, despite the presence of Final Designated Critical Habitat.

Designated critical habitat is present in Cottonwood, Lincoln, Lyon, Murray, and Pipestone counties. The PCE of Poweshiek skipperling critical habitat include wet-mesic to dry tallgrass remnant prairies, prairie fen habitats, and/or remnant moist meadows containing predominantly native grasses and forbs for larval and adult food and shelter, undisturbed glacial soils for larval survival, low wet areas adjacent to prairies for shelter, less than 5 percent trees or shrubs in dry prairies, and less than 25 percent trees or shrubs in wet mesic prairies, and less than 5 percent nonnative invasive species. Dispersal grassland habitat that is within 1 kilometer (0.6 mile) of native high-quality remnant prairie that connects high quality wet-mesic to dry tallgrass prairies, moist meadows, or prairie fen habitats is also important. Dispersal grassland habitat consists of undeveloped open areas dominated by perennial grassland with limited or no barriers to dispersal including tree or shrub cover less than 25

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309 MDNR. Rare Species Guide: Western Prairie Fringed Orchid. Available at: https://www.dnr.state.mn.us/rsg/profile.html?action=elementDetail&selectedElement=PMORC1Y0S0.

310 USFWS. Poweshiek Skipperling. Available at: https://www.fws.gov/species/poweshiek-skipperling-oarisma-poweshiek

percent of the area and no row crops such as corn, beans, potatoes, or sunflowers.[311] Potentially suitable habitat for the species is present within the areas designated as critical habitat.

10.3.4 Bald and Golden Eagles

Bald eagles (*Haliaeetus leucocephalus*) and golden eagles (*Aquila chrysaetos)* are protected under the Bald and Golden Eagle Protection Act (BGEPA). BGEPA prohibits anyone without a permit issued by the Secretary of the Interior from taking bald or golden eagles, including their parts, nests, or eggs. BGEPA defines take as pursue, shoot, shoot at, poison, wound, kill, capture, trap, collect, molest, or disturb.

In Minnesota, the bald eagle nesting season is generally January 15 to August 15.[312] Bald eagles may be present in Minnesota year-round. Suitable nesting habitat for bald eagles is present in all ECS subsections where large bodies of water are found (i.e., rivers, lakes, marshes), a consistent food supply is available, and large trees for perching and nesting are nearby. Primarily, the species has been found overwintering near the Mississippi River in Wabasha and Red Wing. Breeding and nesting primarily occur in the northeast and north central regions of Minnesota.[313] Breeding and nesting areas are rare throughout some portions of the Project Study Area. However, there have been recorded sightings of such via the Minnesota Biological Survey.

If construction activities will 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., late March/early April) of the year of construction. If active nests are identified within the disturbance buffer, the Applicants will consult with the USFWS to determine next steps and develop appropriate avoidance and minimization measures.

10.3.5 State-listed Species

The Applicants reviewed the Minnesota Natural Heritage Inventory System database for state-listed threatened and endangered species that may have the potential to occur within the Project Study Area (under License Agreement No. 2023-052; see **Table 10.3-3**).

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311 Federal Register, USFWS, Endangered and Threatened Wildlife and Plants; Designation of Critical Habitat for the Dakota Skipper and Poweshiek Skipperling. Available at: https://www.federalregister.gov/documents/2015/10/01/2015-24184/endangered-and-threatened-wildlife-and-plants-designation-of-critical-habitat-for-the-dakota-skipper.

312 USFWS, General Permit Condition – Bald Eagle Disturbance. Available at: https://www.fws.gov/sites/default/files/documents/2024-03/gp-standard-terms_disturbance_final_website_03.01.24.pdf.

313 MDNR. Bald Eagles. Available at: https://www.dnr.state.mn.us/birds/eagles/index.html.

Table 10.3-3 State Listed Species Potentially Present in the Project Study Area			
		Status [a]	
Common Name	**Scientific Name**	**State**	**Federal**
AMPHIBIANS			
Blanchard's Cricket Frog	*Acris blanchardi*	E	NL
REPTILES			
Blanding's Turtle	*Emydoidea blandingii*	T	NL
Timber Rattlesnake	*Crotalus horridus*	T	NL
Wood Turtle	*Glyptemys insculpta*	T	NL
BIRDS			
Burrowing Owl	*Athene cunicularia*	E	NL
Chestnut-collard Longspur	*Calcarius ornatus*	E	NL
Henslow's Sparrow	*Centronyx henslowii*	E	NL
King Rail	*Rallus elegans*	E	NL
Loggerhead Shrike	*Lanius ludovicianus*	E	NL
Wilson's Phalarope	*Phalaropus tricolor*	T	NL
MOLLUSKS			
Elktoe	*Alasmidonta marginata*	T	NL
Ellipse	*Venustaconcha ellipsiformis*	T	NL
Fluted-shell	*Lasmigona costata*	T	NL
Monkeyface	*Theliderma metanevra*	T	NL
Mucket	*Actinonaias ligamentina*	T	NL
Pondmussel	*Sagittunio subrostratus*	T	NL
Sheepnose	*Plethobasus cyphyus*	E	E
Spike	*Eurynia dilatata*	T	NL
FISH			
Gravel Chub	*Erimystax x-punctatus*	T	NL
Plains Topminnow	*Fundulus sciadicus*	T	NL
Paddlefish	*Polyodon spathula*	T	NL
Slender Madtom	*Noturus exilis*	E	NL
INSECTS			
Caddisfly	*Ironoquia punctatissima*	T	NL
Caddisfly	*Limnephilus secludens*	E	NL
Dakota Skipper	*Hesperia dacotae*	E	T
Ottoe Skipper	*Hesperia ottoe*	E	NL
Poweshiek Skipperling	*Oarisma poweshiek*	E	E
Uncas Skipper	*Hesperia uncas*	E	NL
PLANTS			

Table 10.3-3 State Listed Species Potentially Present in the Project Study Area			
		Status [a]	
Common Name	**Scientific Name**	**State**	**Federal**
Dwarf Trout Lily	*Erythronium propullans*	E	E
Edible Valerian	*Valeriana edulis var. ciliata*	T	NL
Butternut	*Juglans cinerea*	E	NL
Davis' Sedge	*Carex davisii*	T	NL
Eared False Foxglove	*Agalinis auriculata*	E	NL
Glade Mallow	*Napaea dioica*	T	NL
Goldenseal	*Hydrastis canadensis*	E	NL
Great Indian Plantain	*Arnoglossum reniforme*	T	NL
Hair-like Beak Rush	*Rhynchospora capillacea*	T	NL
Hairy Waterclover	*Marsilea vestita*	E	NL
Handsome Sedge	*Carex formosa*	E	NL
Hooded Arrowhead	*Sagittaria montevidensis ssp. calycina*	T	NL
James' Sedge	*Carex jamesii*	T	NL
Kitten-tails	*Synthyris bullii*	T	NL
Larger Water Starwort	*Callitriche heterophylla*	T	NL
Mud Plantain	*Heteranthera limosa*	T	NL
Prairie Bush-clover	*Lespedeza leptostachya*	T	T
Prairie Milkweed	*Asclepias hirtella*	T	NL
Prairie Quillwort	*Isoetes melanopoda*	E	NL
Short-beaked Arrowhead	*Sagittaria brevirostra*	E	NL
Short-pointed Umbrella Sedge	*Cyperus acuminatus*	T	NL
Sterile Sedge	*Carex sterilis*	T	NL
Stream Parsnip	*Berula erecta*	T	NL
Sulllivant's Milkweed	*Asclepias sullivantii*	T	NL
Sweet-smelling Indian Plantain	*Hasteola suaveolens*	E	NL
Three-leaved Coneflower	*Rudbeckia triloba var. triloba*	T	NL
Tubercled Rein Orchid	*Platanthera flava var. herbiola*	T	NL
Tuberous Indian Plantain	*Arnoglossum plantagineum*	T	NL
Water Pygmyweed	*Crassula aquatica*	T	NL
Waterhyssop	*Bacopa rotundifolia*	T	NL
Western Prairie Fringed Orchid	*Platanthera praeclara*	E	T
Whorled Nutrush	*Scleria verticillata*	T	NL
Wild Quinine	*Parthenium integrifolium*	E	NL
Wolf's Spikerush	*Eleocharis wolfii*	E	NL
[a] E = Endangered, T = Threatened, NL = Not Listed			

The Applicants will conduct a Natural Heritage Review utilizing the MDNR's Minnesota Conservation Explorer[314] online tool. Applicants will also consult with MDNR regarding potential impacts to state-listed species.

10.4 Land Use

Most of the Project Study Area is rural, with scattered small municipalities and farmsteads throughout. Based on review of the USGS National Land Cover Database (NLCD), the predominant land use category throughout the Project Study Area is cultivated crops, followed by developed land. **Table 10.4-1** presents the acres of each land use category within the Project Study Area organized by ECS subsection.[315]

Table 10.4-1
Land Use by ECS Subsections in the Project Study Area (acres)

Land Use Category	ECS SUBSECTION						Percentage of Project Study Area
	Inner Coteau	Coteau Moraines	Minnesota River Prairie	Oak Savanna	Rochester Plateau	The Blufflands	
Barren Land	987	1,195	224	624	613	17	0.1
Cultivated Crops	624,013	1,464,968	1,119,512	618,956	99,211	303	82.2
Deciduous Forest	2,661	18,468	7,341	14,114	20,993	1,306	1.4
Developed, High Intensity	254	375	342	212	36	52	<0.1
Developed, Low Intensity	9,502	24,792	19,299	19,710	6,428	373	1.7
Developed, Medium Intensity	2,537	4,889	4,369	3,330	838	181	0.3
Developed, Open Space	32,019	69,733	43,154	23,281	4,819	224	3.6
Emergent Herbaceous Wetlands	10,407	65,059	25,485	11,045	1,085	6	2.4
Evergreen Forest	2	26	3	24	74	20	0.0
Grassland/ Herbaceous	11,525	19,693	287	339	80	31	0.7
Mixed Forest	19	76	51	143	245	26	<0.1
Open Water	743	39,894	19,449	6,596	209	0	1.4
Pasture/Hay	72,111	123,272	22,705	34,808	19,913	608	5.7
Shrub/Scrub	<0.1	7	4	15	11	1	<0.1
Woody Wetlands	64	2,875	13,532	6,932	2,681	65	0.5

314 MDNR. Minnesota Conservation Explorer. Available at: https://mce.dnr.state.mn.us/.

315 USGS NLCD. 2019. Available at: https://www.sciencebase.gov/catalog/item/5f21cef582cef313ed940043.

Table 10.4-1 Land Use by ECS Subsections in the Project Study Area (acres)							
	ECS SUBSECTION						
Land Use Category	Inner Coteau	Coteau Moraines	Minnesota River Prairie	Oak Savanna	Rochester Plateau	The Blufflands	Percentage of Project Study Area
PROJECT TOTAL	**766,845**	**1,835,325**	**1,275,757**	**740,129**	**157,235**	**3,214**	**100.0**
Note: Some totals may not add due to rounding. Source: USGS NLCD, 2019. Available at: https://www.sciencebase.gov/catalog/item/5f21cef582cef313ed940043.							

The data in **Table 10.4-1** illustrates how land uses differ between the ECSs in the Project Study Area from west to east. While cultivated cropland is the predominant land-use type across the Project Study Area, the Inner Couteau, Coteau Moraines, Minnesota River Prairie, and Oak Savanna subsections contain a greater amount of cultivated cropland (81, 80, 87, and 83 percent, respectively). Moving east, the Rochester Prairie subsection is comprised of 63 percent cultivated crops, and The Blufflands subsection is comprised of 9 percent cultivated crops. On the east side of the Project Study Area, The Blufflands subsection has a higher percentage of deciduous and evergreen forest and open water than the western subsections. It also has the highest percentage of developed land use types.

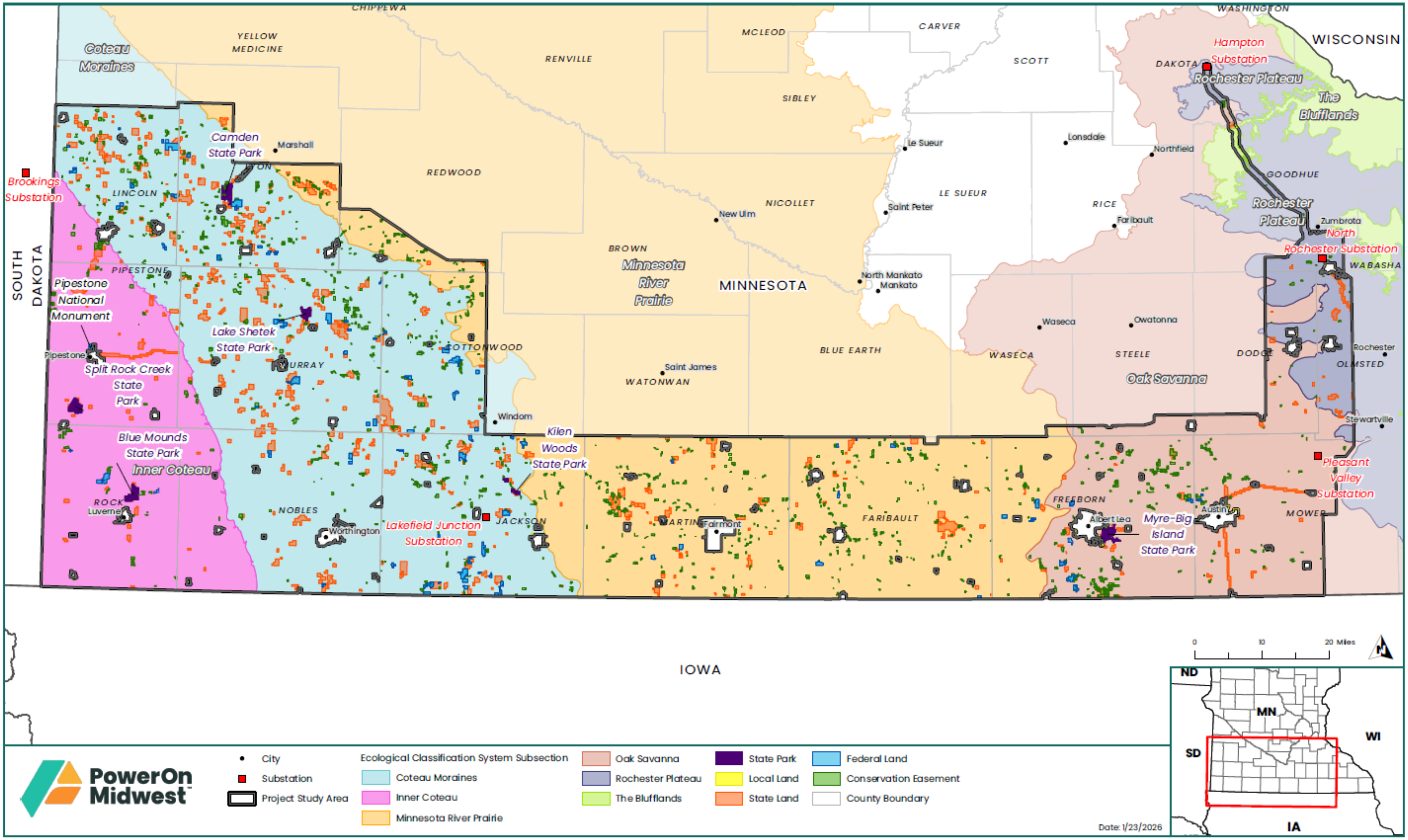
10.4.1 Recreation and Managed Lands

Recreational opportunities within the Project Study Area include, but are not limited to camping, hunting, fishing, hiking, skiing, boating, canoeing, kayaking, snowmobiling, and wildlife viewing. These occur on private lands as well as on public lands managed for habitat, conservation, or recreational purposes. Some features, such as game refuges used for small game, waterfowl, or deer hunting, can be private, public, or a combination, and are subject to restrictions of use based on the type of activity or the time of year.[316] The distribution of publicly-managed lands and recreation areas within the Project Study Area is depicted on **Figure 10.4-1**.

In general, public recreation areas and managed lands are intended to be avoided through routing design. If these areas cannot be avoided, the Applicants will work with the federal, state, county, or local agency, as appropriate, to develop measures to minimize impacts on public recreational use of these areas (e.g., avoiding construction during the peak use season, signage, and ensuring public recreation access is not restricted).

[316] MDNR. State Game Refuges. Available at: https://www.dnr.state.mn.us/hunting/state-refuges.html.

Figure 10.4-1: Publicly-Managed Lands and Recreation Areas within the Project Study Area



10.4.1.1 Conservation Easements

Various types of conservation easements are present throughout the Project Study Area. A conservation easement is land where the landowner has established an agreement with a federal, state, or county agency, or non-profit organization, who in turn applied specific development or activity restrictions designed to protect and conserve natural resources. The Applicants reviewed publicly available information through the USGS' Protected Area Database of the United States (PAD-US) to identify existing conservation easements within the Project Study Area. **Table 10.4-2** presents an estimate of the number acres of land owned by private entities associated with federal, state, or other conservation easements in each of the ECSs in the Project Study Area. These lands are shown on **Figure 10.4-1**.

Table 10.4-2
Conservation Easements by ECS Subsection in the Project Study Area (acres)

Conservation Easement Management [a]	ECS SUBSECTION					
	Inner Coteau	Coteau Moraines	Minnesota River Prairie	Oak Savanna Subsection	Rochester Plateau Subsection	Blufflands Subsection
Federal	2,454	5,975	1,748	8,616	279	0
State	1,179	15,651	13,713	2,632	183	17
Non-Governmental Organization and County	1,111	129	158	347	24	0
PROJECT TOTAL	**4,744**	**21,756**	**15,619**	**11,595**	**487**	**17**

[a] PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download. Sorted by Owner Name = Private or Non-Governmental Organization.

Federal conservation easements on private land include those managed by the USWFS as part of Wetland Management Districts, Waterfowl Production Areas (WPAs), or as part of the National Wildlife Refuge (NWR) System. The U.S. Department of Agriculture (USDA) also holds easements thought the Farm Service Agency, and through the Natural Resources Conservation Service (NRCS) as part of the Wetland Reserve Program, Emergency Watershed Protection Floodplain Program, and Farm and Ranch Land Protection Program.

State conservation easements on private land are managed by BWSR. These include easements under the Conservation Reserve Enhancement Program (CREP), Reinvest in Minnesota Program, and easements for marginal cropland, permanent wetland preserves, riparian lands, road replacements, flowages, and sensitive groundwater.

Private, non-governmental organizations such as the Nature Conservancy own conservation land within the Project Study Area. Counties also manage conservation easements directly on private land or in partnership with the NRCS through the Farm and Ranch Land Protection Program.

Depending on the governing conservation program, specific restrictions may apply that limit or restrict development of a transmission line (e.g., prohibition of tree clearing or placement of permanent structures). The primary method of mitigation for impacts on conservation easements is avoidance. As routing of the Project proceeds, the Applicants will work with private landowners and managing agencies and organizations to identify conservation easements that may be affected by the Project. If a conservation easement cannot be avoided through modifications in Project design, the Applicants will work with the owner and managing agency to develop appropriate measures to minimize effects.

10.4.1.2 Federal Lands

The Applicants reviewed publicly available information through PAD-US to identify lands managed by a federal agency within the Project Study Area.[317] Federal lands within the Project Study Area listed in PAD-US include fee-title lands managed by the USFWS and the National Park Service (NPS). Federally-administered lands listed in the PAD-US dataset are shown on **Figure 10.4-1**. The USFWS also maintains a database of its national realty boundaries.[318] Federal funding has also historically been used to acquire state-administered lands (e.g., Land and Water Conservation Fund, or LAWCON).

There are approximately 5,100 acres within the Inner Coteau and Coteau Moraines subsections that are fee-owned by the USFWS and associated with the Northern Tallgrass Prairie NWR.[319] The Northern Tallgrass Prairie NWR encompasses all or part of 85 counties in western Minnesota and Northern Iowa. The refuge was created to work with individuals, groups, and government agencies to permanently preserve and restore some of the northern tallgrass prairie. Land within the refuge is purchased and held by the USFWS or under easement on private lands.

[317] USGS PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download. Sorted by Owner Name = Federal Agency (i.e., BLM, USFWS, NPS). This does not include 0.6 acre of land indicated as managed by the BLM along Lake Louisa and Lake Sarah within the Coteau Moraines subsection, which appear to be on private tracts or over open water.

[318] USFWS. National Realty Boundaries. Available online at: https://gis-fws.opendata.arcgis.com/datasets/fws::fws-national-realty-boundaries/about.

[319] USGS PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download.

Activities within open portions of the refuge include hunting, fishing, photography, wildlife and bird watching, and hiking. [320]

The USFWS also manages 37,500 acres of WPAs within the Coteau Moraines, Minnesota River Prairie, and Oak Savanna subsections; specifically, within Cottonwood, Jackson, Lincoln, Lyon, Murray, Martin, Nobles, Faribault, and Freeborn counties.[321] Ninety-five percent of the USFWS's WPAs are within the shallow lakes and depressions of the Prairie Pothole Region, the landscape of which makes them ideal nurseries for waterfowl. WPAs provide habitat for ducks, wetland birds, grassland birds, and shorebirds. Fee-title-owned WPAs are open to recreation activities unless public safety or other concerns dictate otherwise.[322]

The NPS manages approximately 300 acres of land associated with the Pipestone National Monument in Pipestone County, within the Inner Coteau subsection (see **Figure 10.4-1**).[323] American Indians have come to the site for over 3,000 years to obtain a soft, red claystone (or, "pipestone") for use in making pipes. The pipe is sacred and used for prayer, rites, and civil and religious ceremonies. The monument was established in 1937 to ensure access for American Indians to the pipestone quarries. Members of federally-recognized Tribes still actively quarry pipestone from the monument today.[324] The monument is also open for visitors for hiking and plant and wildlife viewing.

The Applicants will carefully consider the location of federal fee title lands, including other public lands purchased with federal funds, when routing the Project. The Project will not be sited on the Pipestone National Monument. The Applicants will engage with Tribes and federal land-managing agencies regarding routing in the vicinity of these resources.

10.4.1.3 State Administered Resources

The Applicants reviewed MDNR fee-surface administrative lands available through the Minnesota Geospatial Commons. There are approximately 140,000 acres of state-administered lands within the Project Study Area. **Table 10.4-3** presents a summary of the

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[320] USFWS. Northern Tallgrass Prairie NWR. Available at: https://www.fws.gov/refuge/northern-tallgrass-prairie/about-us.

[321] USGS PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download.

[322] USFWS. Wetland Management Districts and Waterfowl Production Areas. Available at: https://www.fws.gov/story/waterfowl-production-areas.

[323] USGS PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download.

[324] NPS. Pipestone National Monument Frequently Asked Questions. Available at: https://www.nps.gov/pipe/faqs.htm.

different types of MDNR-administered lands within the Project Study Area. State-administered lands are shown on **Figure 10.4-1**.

Table 10.4-3
State-Administered Lands by ECS Subsection in the Project Study Area (acres)

	ECS SUBSECTION					
Management Type	**Inner Coteau**	**Coteau Moraines**	**Minnesota River Prairie**	**Oak Savanna Subsection**	**Rochester Plateau Subsection**	**Blufflands Subsection**
Aquatic Management Area	9	927	1,394	670	-	-
Canoe and Boating Route	-	125	-	40	-	-
Fish Management Area	-	252	-		-	-
Scientific and Natural Area	375	1,027	40	2,504	-	-
State Park	3,040	3,539	-	2,024	-	-
State Trail	2,624	920	-	759	1,644	-
Water Access Site	-	1,384	995	238	-	-
Wildlife Management Area	7,013	73,857	18,883	7,623	2,205	-
Miscellaneous Land [a]	-	3,546	2,220	-	40	-
PROJECT TOTAL	**13,061**	**85,577**	**23,532**	**13,858**	**3,888**	**0**

[a] Includes lands within dataset not assigned with a Management Project Name or Management Program Code, or designated as "Wildlife Program Other"

Source: MDNR. State Surface Interests Administered by MDNR. Available at: https://gisdata.mn.gov/id/dataset/plan-stateland-dnr. Sorted where INT_TYPE = Fee Surface.

Of the 140,000 acres of MDNR administered land in the Project Study Area, 110,000 acres (or 77 percent) are managed as Wildlife Management Areas (WMAs). This land is spread across 310 unique WMAs, the majority of which are in the Coteau Moraines subsection. Land acquired for WMAs is often purchased with federal funds. WMAs provide opportunities for hunters and trappers, as well as wildlife watching and photography opportunities.[325]

Six State Parks comprise approximately 8,600 acres of land within the Project Study Area. These include Blue Mounds and Split Rock Creek in the Inner Couteau subsection; Camden, Kilen Woods, and Lake Shetek in the Coteau Moraines subsection; and Myre-Big Island in the Oak Savanna subsection. These State Parks range from 400 acres (Kilen Woods) to 2,100 acres (Camden). State Parks are shown on **Figure 10.4-1**.

325 MDNR. Wildlife Management Areas. Available at: https://www.dnr.state.mn.us/wmas/index.html.

Ten Scientific and Natural Areas (SNAs) are present in the Project Study Area. SNAs are overseen by the MDNR to safeguard native plant habitats, rare wildlife, and distinctive geological formations, including NPCs and SOBS (see **Section 10.3.1.1**). While their primary purpose is conservation, SNAs also offer limited recreational activities such as hiking, wildlife observation, nature photography, snowshoeing, and cross-country skiing.[326]

Other management areas under MDNR's jurisdiction include 14 Aquatic Management Areas, 2 Fish Management Areas, 5 State Trails (land and water trails), 51 Water Access Sites, properties along canoe and boating routes, and miscellaneous other state lands. These lands are managed for a variety of different purposes.

Some PWI watercourses within the Project Study Area are designated as state water trails: the Blue Earth River, Cannon River, Cedar River, Des Moines River, Redwood River, Shell Rock River, and Zumbro River.[327] The Cannon River in the Oak Savanna subsection is also a designated Minnesota Wild and Scenic River from Tetonka Lake west of Faribault, through Cannon Falls, and on to the Mississippi River. [328]

The Applicants will consider the location of state lands and other state recreational resources when routing the Project and will coordinate with applicable regulatory authorities, as appropriate.

10.4.1.4 Locally Managed Lands

The Applicants reviewed publicly available information through PAD-US to identify locally managed lands within the Project Study Area.[329] As described in **Section 1.8**, the Applicants removed municipalities with over 200 people from the Notice Area, and therefore the Project Study Area, because routing the Project within such municipalities is unlikely. Therefore, many locally managed lands are excluded from this summary because they occur within municipal boundaries and will not be affected by the Project. Locally managed lands are shown on **Figure 10.4-1**.

Parks throughout the Project Study Area provide important recreational opportunities for the communities they serve. Within the Coteau Moraines subsection, Jackson County manages

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326 MDNR. Minnesota Scientific and Natural Areas, Things to Do and Rules. Available at: https://www.dnr.state.mn.us/snas/rules.html.

327 MDNR. Water Trails. Available at: https://gisdata.mn.gov/dataset/trans-water-trails-minnesota.

328 MDNR. Cannon River State Water Trail. Available at: https://www.dnr.state.mn.us/watertrails/cannonriver/index.html.

329 USGS PAD-US. Available online at https://www.usgs.gov/programs/gap-analysis-project/science/pad-us-data-download. Sorted by Owner Name = City Land, County Land.

Fort Belmont Historic Park. Within the Oak Savanna subsection, the City of Cannon Falls manages the John Burch Park (a portion of which is also in The Blufflands subsection) and Freeborn County manages St. Nicholas Park. The City of Cannon Falls also manages South Pines Park in The Blufflands subsection.

The Applicants will consider the location of municipal recreation resources when routing the Project and will coordinate with applicable regulatory authorities, as appropriate.

10.4.2 Agricultural Production

Agricultural production plays a significant role in local economics throughout the State of Minnesota. Information from the USDA's 2022 Census of Agriculture for each of the counties in the Project Study Area is provided in **Table 10.4-4.** Cultivated cropland is the predominant land-use type across the Project Study Area, with the Inner Couteau, Coteau Moraines, Minnesota River Prairie, and Oak Savanna subsections containing the highest prevalence of cultivated cropland.

Table 10.4-4
Agricultural Statistics for Counties within the Project Study Area

County	Land in Farms (acres)	Top 3 Crops in Acreage	Top 3 Livestock Inventory
Cottonwood	392,494 (95% of county)	Corn, soybeans, forage	Hogs/pigs, turkeys, cattle/calves
Dakota	208,517 (56% of county)	Corn, soybeans, vegetables	Cattle/calves, layers, hogs/pigs
Dodge	280,440 (99% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, broilers
Faribault	383,231 (83% of county)	Corn, soybeans, vegetables	Hogs/pigs, cattle/calves, layers
Freeborn	351,174 (76% of county)	Corn, soybeans, vegetables	Hogs/pigs, turkeys, cattle/calves
Goodhue	421,698 (84% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, layers
Jackson	384,337 (84% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, sheep/lambs
Lincoln	212,420 (60% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, sheep/lambs
Lyon	424,591 (92% of county)	Corn, soybeans, forage	Turkeys, hogs/pigs, cattle/calves
Martin	454,025 (97% of county)	Corn, soybeans, vegetables	Hogs/pigs, cattle/calves, sheep/lambs
Mower	380,070 (84% of county)	Corn, soybeans, vegetables	Hogs/pigs, cattle/calves, layers
Murray	351,476 (76% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, sheep/lambs
Nobles	366,330 (79% of county)	Corn, soybean, corn silage	Hogs/pigs, cattle/calves, layers
Olmsted	308,004 (74% of county)	Corn, soybeans, forage	Cattle/calves, hogs/pigs, layers
Pipestone	227,976 (76% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, sheep/lambs
Redwood	560,222 (99% of county)	Corn, soybeans, sugar beets	Hogs/pigs, turkeys, cattle/calves

Table 10.4-4 Agricultural Statistics for Counties within the Project Study Area			
County	**Land in Farms (acres)**	**Top 3 Crops in Acreage**	**Top 3 Livestock Inventory**
Rock	261,220 (84% of county)	Corn, soybeans, forage	Hogs/pigs, cattle/calves, sheep/lambs
Steele	245,834 (89% of county)	Corn, soybeans, forage	Turkeys, hogs/pigs, cattle/calves
Waseca	266,866 (96% of county)	Corn, soybeans, vegetables	Hogs/pigs, turkeys, cattle/calves
Source: USDA. Census of Agriculture. Volume 1, Chapter 2: County Level Data, Table 1 County Summary Highlights: 2022. Available at: https://www.nass.usda.gov/Publications/AgCensus/2022/Full_Report/Volume_1,_Chapter_2_County_Level/Minnesota/.			

Corn and soybeans are the primary row crop by acreage in most of the counties in the Project Study Area. Hogs/pigs are the primary livestock by farms in most of the Project Study Area, followed by cattle/calves, sheep/lambs, and poultry.

The soil designation of prime farmland describes those soils which have "the best combination of physical and chemical characteristics for producing food, feed, forage, fiber and oilseed crops and is also available for these uses."[330] Designated prime farmland[331] or farmland of statewide importance accounts for about 4 million acres, or 84 percent of the Project Study Area.

The Applicants will maintain landowner access to agricultural fields, storage areas, structures, and other agricultural facilities and will work with landowners to address their concerns during construction to the extent practicable. The Applicants will work with landowners to address concerns with irrigation systems and drain tile. Crop production on some portions of agricultural lands may be temporarily interrupted while transmission line facilities are constructed, and there will be permanent loss of areas currently under agricultural production where transmission structures are placed. The Applicants will compensate landowners for impacts on crops resulting from the construction, operation, and maintenance of the Project.

10.4.3 Forestry Production

Commercial forestry operations are not common in the Project Study Area. Forested areas in the Project Study Area typically consist of narrow swaths of trees along the margins of

330 7 Code of Federal Regulations 657.5(a)(1).

331 Soil Survey Staff, NRCS. Soil Survey Geographic (SSURGO) Database. Available at: https://sdmdataaccess.sc.egov.usda.gov. Includes the following prime farmland categories: all areas are prime farmland, prime farmland if drained, prime farmland if irrigated, prime farmland if protected from flooding or not frequently flooded during the growing season, prime farmland if drained and either protected from flooding or not frequently flooded during the growing season.

waterbodies; shelterbelts surrounding farmsteads and agricultural fields; areas near towns and cities; in small woodlots; or in federal, state, or locally designated and managed lands (see **Section 10.4.1**). The Applicants did not identify any commercial forestry operations within the Project Study Area. Timber harvesting for personal use on private land may occur. Applicants will address any potential impacts through easement agreements with landowners.

10.4.4 Mineral Extraction

The Applicants reviewed publicly available information from the MDNR Aggregate Resource Mapping tools,[332] the Minnesota Department of Transportation (MnDOT) Aggregate Source Information System Map,[333] and the USGS Mineral Resources Data System[334] to identify mineral mining operations in the Project Study Area. There are various active and inactive mining operations spread throughout the Project Study Area including sand, gravel, and stone quarry operations. Sand and gravel are most often mined for local uses such as making concrete for roads and buildings. These operations are owned either by citizens, private companies, or MnDOT. There are no active mineral leases issued by the State of Minnesota in the Project Study Area.[335]

Mining operations can generally be avoided through route design. The Applicants will work with private owners and MnDOT to identify mining operations and design the Project to avoid these areas to the extent practicable.

10.5 Human Settlement

Human settlement within the Project Study Area includes municipalities, farmsteads, utility infrastructure, roadways, and commercial and industrial areas. Larger municipalities tend to be concentrated along roadways such as Interstates 35 and 90, U.S. Highways 14, 52, 59, and 75, or State Highways 15, 23, 30, 60, 91, and 109. Larger municipalities in the Project Study Area include Albert Lea, Austin, Blue Earth, Byron, Fairmont, Jackson, Kasson, Lake Benton, Luverne, Pipestone, and Worthington. Outside of these larger municipalities, communities are generally small and rural with farmsteads and residences located along roadways. Commercial and

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[332] MDNR. Online Aggregate Maps. Available at: https://www.dnr.state.mn.us/lands_minerals/aggregate_maps/online_maps/index.html.

[333] MnDOT. Aggregate Source Information System Map. Available at: https://www.dot.state.mn.us/materials/asis_GE.html.

[334] USGS. Mineral Resource Data System. Available at: https://mrdata.usgs.gov/mrds/.

[335] MDNR. State Mineral Leases. Available at: https://gisdata.mn.gov/dataset/plan-state-minleases.

industrial areas in the Project Study Area are generally located within or adjacent to larger municipalities.

Residential areas in the Project Study Area are located within large and small municipalities. Scattered farmsteads are located in more rural areas. NESC and Applicants' standards require minimum clearances between transmission line facilities and buildings to ensure safe operation of transmission line facilities.

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

10.5.1 Demographics and Socioeconomics

State- and county-level demographic information for the Project Study Area is based on the U.S. Census Bureau 2020: American Community Survey 5-year Estimates Data Profiles, available on Explore Census Data websites. **Table 10.5-1** presents demographic and socioeconomic information from the U.S. Census Bureau for the State of Minnesota and each county within the Project Study Area.

The Project Study Area encompasses all or portions of 13 counties with populations that vary from 439,882 persons in Dakota County to 5,640 persons in Lincoln County.[336] Population densities in counties near the Twin Cities and Rochester are often above 200 people per square mile, while population densities in rural portions of the Project Study Area are generally less than 50 people per square mile.

Table 10.5-2 presents information about the racial and ethnic groups in the counties within the Project Study Area. Percent total minority populations vary greatly with the largest percentage being 46.9 percent in Nobles County and the smallest percentage being 5.8 percent in Lincoln County. The average total minority percentage across the Project Study Area is approximately 16.4 percent.

[336] USCB. 2020 DEC Demographic and Housing Characteristics, Table P1 Total Population. Available at: https://www2.census.gov/programs-surveys/decennial/2020/data/. Accessed September 2025.

Table 10.5-1
Demographic Information for Counties within the Project Study Area

State/ County	Population [a]	Percent Population Change [a, b]	Population per Square Mile [a]	Per Capita Income in Last 12 Months (2020 $) [c]	Unemployment Rate (%) [c]	Persons in Poverty (%) [c]	Top 3 Industries [c]
MINNESOTA	**5,706,494**	**+ 7.1**	**67.2**	**46,957**	**2.7**	**9.2**	**1. E; 2. M; 3. R**
Cottonwood	11,517	- 1.5	17.7	34,105	2.5	14.2	1. E; 2. M; 3. Ag
Dakota	439,882	+ 9.4	749.4	50,901	2.6	5.6	1. E; 2. P; 3. R
Dodge	20,867	+ 3.7	47.4	43,903	2.2	5.4	1. E; 2. M; 3. C
Faribault	13,921	- 4.5	19.3	36,782	2.4	11.8	1. E; 2. M; 3. Ag
Freeborn	30,895	- 1.2	458.3	38,696	2.3	9.8	1. E; 2. M; 3. R
Goodhue	47,582	+ 2.9	62.9	42,254	2.3	9.3	1. E; 2. M; 3. R
Jackson	9,989	- 2.8	13.9	39,494	1.6	9.1	1. E; 2. M; 3. R
Lincoln	5,640	- 4.5	10.3	38,390	1.7	9.2	1. E; 2. Ag; 3. R
Lyon	25,269	- 2.3	35.0	37,201	2.3	12.5	1. E; 2. M; 3. R
Martin	20,025	- 4.1	27.4	37,466	2.8	11.1	1. E; 2. M; 3. R
Mower	40,029	+ 2.2	56.3	35,609	2.4	12.1	1. E; 2. M; 3. R
Murray	8,179	- 6.7	11.4	40,277	1.7	8.1	1. E; 2. Ag; 3. M
Nobles	22,290	+ 4.1	30.8	30,310	1.7	12.6	1. E; 2. M; 3. R
Olmsted	162,847	+ 11.4	248.6	52,059	2.5	7.9	1. E; 2. R; 3. M
Pipestone	9,424	- 1.8	20.2	36,551	2.0	11.4	1. E; 2. M; 3. Ag
Redwood	15,425	- 4.1	18.8	33,771	1.2	12.0	1. E; 2. M; 3. Ag
Rock	9,704	+ 0.2	20.1	38,201	1.8	9.5	1. E; 2. Ag; 3. M
Steele	37,406	+ 2.2	86.6	41,392	2.0	7.4	1. M; 2. E; 3. R
Waseca	18,968	- 0.9	43.8	37,199	2.6	7.2	1. E; 2. M; 3. R

[a] USCB. Decennial Census Data. Available at: https://www2.census.gov/programs-surveys/decennial/2020/data/.

[b] Percent population change is based on Population Census April 1, 2020, as compared to Population Census April 1, 2010.

[c] USCB. Selected Economic Characteristics. Industries defined under the 2012 North American Industry Classification System. Available at: https://data.census.gov/table/ACSDP5Y2023.DP03?q=DP03:+SELECTED+ECONOMIC+CHARACTERISTICS&g=040XX00US27.

Industries 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.

Table 10.5-2
Racial and Ethnic Group Information for Counties within the Project Study Area

County	White Alone, Not Hispanic or Latino (%)	Black or African American Alone (%)	American Indian or Alaska Native Alone (%)	Asian Alone (%)	Native Hawaiian/ Pacific Islander Alone (%)	Some other race alone (%)	Two or more races (%)	Hispanic or Latino (%)	Total Minority (%)[a]
MINNESOTA	**76.7**	**6.7**	**0.7**	**5.0**	**0.0**	**0.4**	**4.1**	**6.2**	**23.3**
Cottonwood	81.5	1.8	0.4	3.4	0.8	0.0	1.6	10.5	18.5
Dakota	73.8	7.2	0.2	5.1	0.0	0.6	4.6	8.4	26.2
Dodge	90.0	1.0	0.2	0.6	0.0	0.5	2.7	5.2	10.0
Faribault	88.6	0.6	0.2	0.6	0.0	0.4	1.7	7.8	11.4
Freeborn	82.2	1.2	0.1	3.1	0.2	0.2	2.5	10.6	17.8
Goodhue	89.6	1.6	0.9	0.8	0.0	0.7	2.5	3.9	10.4
Jackson	90.4	0.5	0.0	1.0	0.0	0.1	3.4	4.5	9.6
Lincoln	94.2	0.2	0.1	0.7	0.1	0.0	2.3	2.3	5.8
Lyon	82.0	2.5	0.3	4.7	0.0	0.3	2.8	7.4	18.0
Martin	88.7	0.8	0.2	0.6	0.0	1.2	1.8	6.8	11.3
Mower	74.0	3.5	0.0	5.7	0.4	0.6	2.6	13.0	26.0
Murray	89.6	0.6	0.2	1.1	0.0	1.1	2.5	4.9	10.4
Nobles	53.1	4.6	0.1	4.6	0.0	0.2	4.2	33.1	46.9
Olmsted	76.3	7.2	0.1	6.3	0.1	0.4	3.9	5.8	23.7
Pipestone	84.4	1.0	0.7	1.0	0.0	0.2	4.3	8.4	15.6
Redwood	85.5	0.6	3.6	2.6	0.1	0.3	3.5	4.0	14.5
Rock	92.0	0.2	0.5	0.6	0.0	0.0	3.0	3.8	8.0
Steele	84.3	3.4	0.1	0.7	0.0	0.2	2.7	8.6	15.7
Waseca	87.6	1.1	0.8	0.9	0.0	0.2	2.4	7.0	12.4

[a] Total minority percentage equals the total population minus the percentage of white alone, not Hispanic or Latino.

Source: USCB. American Community Survey 5-Year Estimates Detailed Tables - Hispanic or Latino Origin by Race. Available at: https://data.census.gov/table/ACSDT5Y2023.B03002?q=B03002:+Hispanic+or+Latino+Origin+by+Race&g=040XX00US27_050XX00US27033,27037,27039,27043,27047,27049,27063,27081,27083,27091,27099,27101,27105,27109,27117,27127,27133,27147,27161

Transmission line projects benefit the socioeconomic conditions of an area in the short term through an influx of non-local personnel, creation of construction jobs, purchases of construction material and other goods from local businesses, and expenditures on temporary housing for non-local personnel.

In the long term, transmission line projects beneficially impact the local tax base in the form of revenues generated from utility property taxes. Potential measures to enhance the socioeconomic benefits experienced by local communities include use of local personnel and construction material retailers during construction of the Project.

10.5.2 Environmental Justice

The Commission defines an environmental justice area – consistent with Minn. Stat. § 216B.1691, subd. 1(e) – as an area that meets one or more of the following criteria:

(1) 40 percent or more of the area's total population is nonwhite;

(2) 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;

(3) 40 percent or more of the area's residents over the age of five have limited English proficiency; or

(4) the area is located within Indian country, as defined in United State Code, title 18, section 1151.[337]

Although the statute quoted above applies to the establishment of Minnesota's renewable energy objectives, the Applicants apply this statutory definition because it is the only statutory definition of environmental justice applicable to any Commission proceedings.

The 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. MPCA has created an interactive map that shows identified areas of environmental justice concern throughout the state.[338]

[337] Minn. Stat. § 216B.1691, subd. 1(e).

[338] MPCA. n.d.(c) Understanding Environmental Justice in Minnesota, Environmental Justice – Overview of Areas of Concern. Available at: https://mpca.maps.arcgis.com/apps/MapSeries/index.html?appid=f5bf57c8dac24404b7f8ef1717f57d00.

The Project Study Area does not cross the boundaries of federally recognized Tribal Areas. The Applicants will review and analyze census tracts that intersect with proposed routes for environmental justice areas and will utilize MPCA's interactive map to supplement identification of environmental justice areas.

10.5.3 Public Services

Public services in the Project Study Area are similar to public services found elsewhere in Minnesota. Roads, railways, and airports are present throughout. Many residents outside cities and towns rely on private wells and septic systems. Churches and cemeteries exist throughout the Project Study Area.

10.5.3.1 Drinking Water

The portion of southern Minnesota within the Project Study Area is mostly rural. In rural areas, residents often rely on privately owned wells and septic systems, although some residents might have access to rural water distribution facilities. Larger population centers are often serviced by municipal public works for water and sewer.

Drinking Water Supply Management Areas (DWSMAs) define areas that are protected to prevent contamination of drinking water. Wellhead Protection Areas are established in and around DWSMAs to prevent contamination of public drinking water. Over 80 DWSMAs and Wellhead Protection Areas are present in the Project Study Area. [339] General construction BMPs to limit impacts to soils, surface water, and groundwater will mitigate impacts to drinking water.

10.5.3.2 Roads

Existing road infrastructure within the Project Study Area is a mix of federal, state, and county highways, and township and city roads. Interstate 90 runs from west to east across the Project Study Area from Rock County through Olmsted County, and Interstate 35 runs north to south, through Steele and Freeborn Counties. Major north-south roadways include U.S. Highways 52, 59, 71, 75, 169, and 218, and State Highways 4, 13, 15, 22, 23, 56, 86, and 91. Major east-west roadways include U.S. Highway 14 and State Highways 19, 30, 60, and 62. Roadway closures or diversions may be necessary to accommodate construction equipment or stringing conductors. The Applicants will work with the road authority to develop appropriate measures to minimize impacts on public services and transportation if road closures cannot be avoided. These measures may include avoiding construction during hours of peak use, detours, signage,

[339] MDH. Source Water Protection Web Map Viewer. Available at: https://www.health.state.mn.us/communities/environment/water/swp/mapviewer.html.

and ensuring access to public service infrastructure is not restricted, as well as placing temporary guard structures over roadways during conductor stringing activities.

10.5.3.3 Railroads

Railroads in the Project Study Area connect larger population centers throughout Minnesota; most travel between the larger Twin Cities metropolitan area and larger municipalities such as Worthington, Fairmont, Albert Lea, and Austin. An east-west railroad travels from the Wisconsin state line through Byron and Dodge Center to South Dakota near Brookings. The owners and operators of railroads within the Project Study Area are Burlington Northern Santa Fe Railway Company, Canadian Pacific Railway; Canadian National Railway; Dakota, Minnesota, and Eastern Railroad; Cedar River Railroad Company; Rapid City, Pierre and Eastern Railroad; Ellis and Eastern Railroad; and Union Pacific Railroad Company.[340]

The Applicants will coordinate with nearby railroads when designing the Project. The Applicants will complete induction studies where necessary when designing the Project near railroads and will use temporary guard structures over railroads during conductor stringing activities.

10.5.3.4 Airports

Four public airports are within the Project Study Area. Six public airports are outside the Project Study Area but still have zoning that overlaps the Project Study Area. **Table 10.5-3** lists the number of public airports with airport zoning crossed by the Project Study Area. In general, airports are more prevalent near larger municipalities. Private airports, which exist throughout the Project Study area, are more prevalent in the western portion of the state and are associated with medical center airstrips or landing pads and privately owned landing strips.

Table 10.5-3
Airport Zoning within Project Study Area by County [a]

County	Airport Within Notice Area (number)	Airport Outside Notice Area (number)
Cottonwood	1	0
Dodge	1	0
Faribault	1	0
Freeborn	0	1
Lincoln	0	1
Lyon	1	1
Martin	0	1
Mower	0	1

[340] MnDOT. Minnesota Rail Viewer Application (MnRail). Available at: https://www.dot.state.mn.us/ofrw/freight/data.html.

Table 10.5-3 Airport Zoning within Project Study Area by County [a]		
County	**Airport Within Notice Area (number)**	**Airport Outside Notice Area (number)**
Murray	0	1
TOTAL	**4**	**6**
[a] If an airport's zoning crosses into 2 or more counties, it is only counted for the county in which the airport is located. Source: Minnesota Department of Transportation. Available at: https://mndot.maps.arcgis.com/apps/webappviewer/index.html?id=c566f629e061483285d293a9904224eenDOT.		

Potential impacts to airports can be addressed through the route selection process (generally through avoidance) and structure design and/or marking and lighting (where an airport cannot be avoided). Detailed analysis will be conducted as part of the routing process.

10.5.3.5 Utilities & Generation

HVTLs exist throughout the Project Study Area, as depicted on **Figure 3.2-2.** Electrical substations supporting the transmission network are distributed across the Project Study Area.

The Applicants reviewed publicly available records of existing photovoltaic solar farms 1 MW or more to identify solar farms in the Project Study Area.[341] Review of the Commission's Energy Infrastructure Permitting webpage[342] also indicates that facilities greater than 50 MW are being proposed and permitted throughout the Project Study Area. Applicants will continue to work to identify existing and proposed solar facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

The Applicants reviewed the U.S. Wind Turbine Database Viewer to identify existing wind farms in the Project Study Area.[343] Review of the Commission's Energy Infrastructure Permitting webpage[344] also indicates that wind farms are being proposed and permitted throughout the Project Study Area. Applicants will continue to attempt to identify existing and proposed wind facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

341 USGS. U.S. Large-Scale Solar Photovoltaic Database. Available at: https://energy.usgs.gov/uspvdb/.

342 Commission. Energy Infrastructure Permitting. Available at: https://puc.eip.mn.gov/.

343 USGS. U.S. Wind Turbine Database Viewer. Available at: https://www.usgs.gov/tools/us-wind-turbine-database-uswtdb-viewer.

344 Commission. Energy Infrastructure Permitting. Available at: https://puc.eip.mn.gov.

The Applicants reviewed the Commission's Energy Infrastructure Permitting webpage for battery energy storage systems.[345] These systems are being proposed in the Project Study Area. The Applicants will continue to attempt to identify existing and proposed battery energy storage systems facilities as part of the routing process and will coordinate with owners/developers of those facilities, as needed.

Oil and gas transmission and distribution pipelines are present throughout the Project Study Area.[346] If the proposed transmission lines intersect or approach existing pipeline infrastructure, the Applicants will incorporate appropriate engineering standards into the Project design and secure all necessary crossing agreements and regulatory approvals.

Cellular and radio antenna structures are present throughout the Project Study Area. If the proposed transmission line intersects or approaches existing structures, the Applicants will incorporate appropriate engineering standards into the Project design and secure all necessary regulatory approvals.

10.6 Aesthetics

The visual character and setting of the majority of the Project Study Area includes largely flat agricultural fields broken up by areas with greater levels of topography. As discussed in **Section 10.5**, outside of municipalities, which range from small towns to large cities, farms and rural residences dot the landscape. Additional built infrastructure that is visible across the landscape includes roads, overhead distribution and transmission lines, substations, wind turbines, solar farms, railroads, and other infrastructure such as barns and grain silos.

Structures, conductors, insulators, aeronautical safety markings, avian diverters, substations, vegetation clearing, and access roads constructed as part of this Project will also be visible on the landscape. The Applicants will consider potential aesthetic impacts as part of the routing process, which will also include input from stakeholders regarding minimization of aesthetic impacts.

10.7 Archaeological and Historical Resources

Previously identified archaeological sites (e.g., pre-contact artifact assemblages, burial mounds, and earthworks) are present in the Project Study Area. Areas along rivers and other surface waters present a higher likelihood that these resources are present. As described in

345 Id.

346 National Pipeline Mapping System. Available at: https://www.npms.phmsa.dot.gov/GeneralPublic.aspx.

Section 10.4.1.2, the Pipestone National Monument in Pipestone County is of great significance to American Indians. The Project will not be routed through the Pipestone National Monument.

The Project Study Area also contains historic architectural resources most commonly associated within municipalities (e.g., churches, grain elevators, banks, railroads), though some rural farmsteads and bridges are also commonly considered historic architectural resources.

Some of the archaeological sites and historic architectural resources are listed or considered eligible for listing in the National Register of Historic Places (NRHP), while other sites have yet to be evaluated. The Applicants will complete Phase Ia literature reviews to characterize the prehistoric and historic context along identified route options and to identify previously recorded archaeological sites and historic architectural resources that need to be considered during routing due to their listing in or eligibility for listing in the NRHP.

Generally, effects on recorded historic properties can be avoided through routing and siting efforts. If impacts to any recorded site cannot be avoided by the Project, that recorded site will require a formal significance evaluation to determine if it meets the eligibility requirements of the NRHP. If found significant, mitigation strategies will be undertaken to reduce impacts. This could include identifying the site in detail prior to construction, limiting construction access and activities as much as possible, and having an archaeologist present during construction to monitor work and to gather any artifacts found. If properties 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 will work with the appropriate Tribes as well as federal and state agencies to identify resources and avoidance, minimization, and mitigation measures.

The Applicants sent initial outreach letters to Tribal government leaders, Natural Resource staff directors, and Tribal Historic Preservation Officers in October 2025 to learn how to best engage with individual Tribal Nations throughout the CN, route development, and Route Permit processes. The Applicants intend to engage early and often with Tribal leaders and staff to so that engagement efforts are useful and appropriate for the Tribes.

10.8 Other Permits and Approvals

In addition to the CN sought in this Application, the Project will require Route Permits from the Commission. Other permits and authorizations required to construct and operate the Project will depend on the final approved routes and the conditions encountered during construction. Once the Commission issues a Route Permit, local zoning, building, and land use regulations and rules are preempted per Minn. Stat. § 216I.18, subd. 1. A list of the permits and approvals that could potentially be required for the Project is provided in **Table 10.8-1**.

Table 10.8-1
Summary of Permits and Approvals Potentially Required for the Project

Permit	Jurisdiction
FEDERAL	
Section 404 Clean Water Act Permit	USACE
Section 10 Rivers and Harbors Act Permit	USACE
Section 408 Civil Works Permit	USACE
ESA / BGEPA /Migratory Bird Treaty Act Consultation	USFWS
Part 7460 Airport Obstruction Evaluation	FAA
SF-299 Application for Transportation, Utility Systems, Telecommunications and Facilities on Federal Lands and Property	Federal Land Managing Agency
STATE	
CN and Route Permit	Minnesota Public Utilities Commission
State Natural Heritage Consultation	MDNR
Endangered and Threatened Species Permit	MDNR
Utility Crossing License (Lands and Waters)	MDNR
Work in Public Waters Permit	MDNR
Water Appropriation Permit – Temporary Construction Dewatering	MDNR
Calcareous Fen Consultation / Calcareous Fen Concurrence or Management Plan	MDNR
National Historic Preservation Act Consultation Minnesota Field Archaeology Act Minnesota Historic Sites Act Minnesota Private Cemeteries Act	Minnesota State Historic Preservation Office Tribal Historic Preservation Officers
National Pollutant Discharge Elimination System Construction Stormwater Permit	MPCA
Section 401 Clean Water Act Water Quality Certification	MPCA
Driveway Access Permit	MnDOT
Miscellaneous Work Permit for Trunk Highways	MnDOT
Oversize and/or Overweight Permit	MnDOT
Utility Permit	MnDOT
LOCAL	
Watershed District Permit	Various Watershed Districts
Oversize/Overweight Moving Permit	Cities, Counties

Table 10.8-1
Summary of Permits and Approvals Potentially Required for the Project

Permit	Jurisdiction
Utility Permit	Cities, Counties
Driveway, Road, or Road Approach Permits	Cities, Counties
Right-of-Way Permit	Cities, Counties
OTHER	
Crossing Agreements	Utility or railroad owner

11 PUBLIC INPUT AND INVOLVEMENT

Recognizing the importance of early and meaningful outreach, the Applicants developed a comprehensive public engagement plan to proactively engage stakeholders, landowners, and the public to share information regarding the Midwest region's energy transition and the necessity of the Project. The Applicants created PowerOn Midwest communications platforms for landowners and community members within the exterior boundaries of the Project's Notice Area,[347] as well as other stakeholders. The coordinated approach taken to support this Application is described below. The Applicants conducted the outreach described in this section voluntarily and in addition to the Notice Plan. **Appendix H** contains the outreach materials prepared as part of these efforts.

11.1 Communication Channels

11.1.1 Website

The Applicants launched the PowerOn Midwest website at PowerOnMidwest.com on October 15, 2025. The website will be updated throughout the CN and Route Permit processes, as well as through construction of the Project. The website provides Project-specific information and resources for visitors. The Project website includes an interactive map where the public can leave comments pinned to a geographic marker. Screenshots of the website, along with usage analytics (more than 18,320 website views as of January 20, 2026), are included in **Appendix H**.

11.1.2 Project Email, Information Line, and Mailing Address

The Applicants established a dedicated Project information line at 888-283-4678, a Project email address at Connect@PowerOnMidwest.com, and a Project mailing address at 5115 Excelsior Blvd #113, St. Louis Park, MN 55416 to further facilitate public access to information and connection to the PowerOn Midwest team.

The Project information line was set up in October 2025, prior to the November 2025 open houses (discussed in more detail in **Section 11.4**). This allowed the public to contact the Project team and obtain information prior to these events. Callers were greeted with a short message and asked to provide their information and questions. PowerOn Midwest team members would then follow up with additional information as requested by the caller.

[347] As discussed in **Section 1.8**, the Project's Notice Area excluded areas within the boundaries of some municipalities. The Applicants conducted outreach to all municipalities despite their exclusion from the Notice Area to ensure that communities in the vicinity of the Project were included.

The Project email address was created for interested persons to send a message to the PowerOn Midwest team with a question or comment. A PowerOn Midwest team member would then respond with the requested information or let the person who emailed know that their comment is being reviewed and considered as part of the PowerOn Midwest development process.

11.2 Local, State, Federal, and Tribal Outreach

11.2.1 Local Government Units

PowerOn Midwest sent a letter to over 800 local government officials within the exterior boundaries of the Project's Notice Area, including township chairs and clerks, city mayors and the city clerk, and county board members and the county clerk in advance of the Application filing. The letter introduced the Project to these elected officials and provided information regarding the November 2025 open houses (discussed in more detail in **Section 11.4**). An example of the outreach letter is provided in **Appendix H**.

11.2.1.1 Counties

The PowerOn Midwest team reached out to each county within the exterior boundaries of the Project's Notice Area to provide an overview of the Project. The PowerOn Midwest team offered to present at each county board meeting. Based on county preferences, the PowerOn Midwest team presented to relevant county committees, the county board itself, or with county staff. **Table 11.2-1** outlines each county, presentation date, and audience description. This table is also included in **Appendix H.** An example of the outreach letter is provided in **Appendix H**.

Table 11.2-1
County Board Presentations

County	Date	Audience Description
Martin	Oct. 7, 2025	County Board
Faribault	Oct. 7, 2025	County Board
Lyon	Oct. 7, 2025	County Board
Martin	Oct. 7, 2025	County Board
Steele	Oct. 14, 2025	County Board
Mower	Oct. 14, 2025	County Board
Pipestone	Oct. 14, 2025	County Board
Goodhue	Oct. 27, 2025	County staff
Dodge	Oct. 28, 2025	County Board
Lincoln	Nov. 4, 2025	County Board
Jackson	Nov. 4, 2025	County Board

Table 11.2-1 County Board Presentations		
County	**Date**	**Audience Description**
Dakota	Nov. 6, 2025	Physical Development Committee
Olmsted	Nov. 18, 2025	Physical Development Committee
Nobles	Nov. 18, 2025	County Board
Cottonwood	Dec. 2, 2025	County Board
Murray	Dec. 2, 2025	County Board
Waseca	Dec. 2, 2025	County Board
Freeborn	Dec. 12, 2025	County Board
Redwood	Dec. 16, 2025	County Board
Rock	Jan. 20, 2026	County Board

The PowerOn Midwest overview PowerPoint was shared at each meeting to introduce the Project. The presentation varied slightly depending on the presenter or the location of the county. **Appendix H** contains a PowerPoint presentation that is inclusive of all slides presented to counties.

11.2.1.2 Cities

The Applicants sent city mayors and clerks located within the exterior boundaries of the Project's Notice Area an introduction letter in October 2025. This letter included an invitation to the November 2025 open houses (discussed in more detail in **Section 11.4**). An example of the outreach letter is included in **Appendix H**.

11.2.1.3 Townships

The Applicants sent township chairs and clerks located within the exterior boundaries of the Project's Notice Area a project introduction letter in October 2025. This letter included an invitation to the November 2025 open houses (discussed in more detail in **Section 11.4**). An example of the outreach letter is included in **Appendix H**.

11.2.1.4 Rural Minnesota Energy Board

The PowerOn Midwest team presented at the Rural Minnesota Energy Board meetings on September 22, 2025, and November 24, 2025. The first presentation was a project introduction, and the second presentation provided an update. The Rural Minnesota Energy Board is a joint powers board made up of 18 counties in southern Minnesota. An example presentation is included in **Appendix H.**

11.2.1.5 Watershed Districts

The Applicants sent Project introduction letters to representatives from Minnesota Watershed Districts (see **Section 10.2.2**) within the exterior boundaries of the Project's Notice Area in October 2025. This letter included an invitation to the November 2025 open houses as well as an offer to meet to present the Project. An example of the agency outreach letter is included in **Appendix H**.

11.2.1.6 Soil and Water Conservation Districts

The Applicants sent Project introduction letters to representatives of soil and water conservation districts and/or environmental departments from the cities and counties within the exterior boundaries of the Project's Notice Area in October 2025. The Applicants used the BWSR WCA local government unit directory to develop the list of recipients. This letter included an invitation to the November 2025 open houses as well as an offer to meet to present the Project. An example of the agency outreach letter is included in **Appendix H**.

11.2.2 State and Federal Agencies

The Applicants sent Project introduction letters to state and federal agencies with potential interest in the Project in October 2025. The Applicants ensured that contacts from the Commission's Tech Rep List (as of October 20, 2025) were included in this outreach. This letter included an invitation to the November 2025 open houses as well as an offer to meet to present the Project. An example of the agency outreach letter is included in **Appendix H**.

Recipients of the letter included representatives from the following state and federal agencies:

- USACE;
- USFWS;
- BWSR;
- MDA;
- MDH;
- MDNR;
- MnDOT;
- MPCA;
- Minnesota Department of Commerce;

- Minnesota Department of Labor and Industry;
- Minnesota Department of Revenue;
- Minnesota Indian Affairs Council;
- Minnesota Office of the State Archaeologist;
- Minnesota Office of Pipeline Safety; and
- Minnesota State Historic Preservation Office.

The Applicants received a variety of responses, most related to establishing main points of contact and interest in ongoing communication as the Project moves forward. The USFWS provided early coordination comments in December 2025. The Applicants also met with the MDNR on December 2, 2025, and with MnDOT on January 22, 2026, to provide a Project overview.

11.2.3 Tribes

The Applicants developed a Tribal outreach approach to seek input from Minnesota Tribal Nations and organizations as well as Tribal Nations outside of Minnesota with interest in the Project area. Tribal Nations and organizations within Minnesota include:

- 1854 Treaty Authority;
- Bois Forte Band of Chippewa;
- Fond du Lac Band of Lake Superior Chippewa;
- Grand Portage Band of Ojibwe;
- Leech Lake Band of Ojibwe;
- Lower Sioux Indian Community;
- Mille Lacs Band of Ojibwe;
- Minnesota Chippewa Tribe;
- Prairie Island Indian Community;
- Red Lake Nation;
- Shakopee Mdewakanton Sioux Community;
- Upper Sioux Community; and

- White Earth Nation.

Based on the U.S. Department of Housing and Urban Development's Tribal Directory Assessment Tool,[348] Tribal Nations outside of Minnesota with interest in the Project area include:

- Apache Tribe of Oklahoma;
- Cheyenne and Arapaho Tribes, Oklahoma;
- Flandreau Santee Sioux Tribe of South Dakota;
- Fort Belknap Indian Community of the Fort Belknap Reservation of Montana;
- Iowa Tribe of Kansas and Nebraska;
- Menominee Indian Tribe of Wisconsin;
- Santee Sioux Nation, Nebraska;
- Sisseton-Wahpeton Oyate of the Lake Traverse Reservation, South Dakota; and
- Spirit Lake Tribe, North Dakota.

The Applicants first introduced the Project to Minnesota Tribal Nations and organizations at Native Sun Community Power Development's Tribal Energy Forum on September 18, 2025, at Grand Casino in Mille Lacs. During an open session, Project representatives presented an overview of the Project and took questions. The Applicants also hosted a table in the main conference area to engage with interested parties, develop relationships, and answer questions. Images of the boards used at this event to depict the Project and describe the Project purpose and need are included in **Appendix H**.

In October 2025, the Applicants sent a letter to Tribal Nations and organizations to introduce the Project and answer questions. In Minnesota, this letter was addressed to the Tribal executive/chair, natural resource director, and Tribal Historic Preservation Officer from each Tribal Nation or organization. Tribes outside of Minnesota were contacted based on information listed in the Tribal Directory Assessment Tool. An example of this initial outreach letter is included in **Appendix H**.

The Applicants sent a second letter later in October 2025 to invite Tribal Nations and organizations to the November 2025 open houses and to offer to meet to present the Project.

[348] U.S. Department of Housing and Urban Development. Tribal Directory Assessment Tool. Available at: https://egis.hud.gov/tdat/.

These letters were addressed to the recipients of the first October 2025 letter as well as additional contacts from the Commission's Tribal Government List. An example of this second outreach letter is included in **Appendix H**. As a result of this invitation, staff from the Prairie Island Indian Community attended the November 2025 open house in Cannon Falls, Minnesota.

The Applicants presented at the Minnesota Tribal Environmental Committee meeting on October 28, 2025. The committee is comprised of environmental staff from Minnesota's Tribal Nations and Treaty Authorities. The Applicants gave an overview presentation about the Project and answered questions. The presentation is included in **Appendix H**.

In addition, the Applicants have reached out to the Minnesota Tribal Advocacy Council on Energy with an offer to make a similar presentation. The mission of Tribal Advocacy Council is to make recommendations for improving Tribal energy on Reservations, adjacent territories, and ceded territories.

11.3 Engagement Outreach

The Applicants hosted an initial phase of engagement between November 3 and 21, 2025. The goal of the engagement, including a series of in-person open houses and an associated virtual open house (discussed in more detail in **Section 11.4**) was to introduce PowerOn Midwest, share the need for the Project, answer questions, gather comments, and connect with potentially impacted stakeholders to talk about the Project. These efforts are detailed in the following sections.

11.3.1 Stakeholder Letter

The Applicants sent approximately 1,100 letters to specific stakeholders within the exterior boundaries of the Project's Notice Area in advance of the open houses (discussed in more detail in **Section 11.4**). Letters were put in the mail on October 17, 2025. The letter introduced PowerOn Midwest and detailed upcoming engagement opportunities. These letters went out to local government leaders (as detailed in **Sections 11.2.1**), the Region 9 Development Commission, the Southwest Regional Development Commission, the Mid-Minnesota Development Commission, the Minnesota Association of Townships, the League of Minnesota Cities, state senators and representatives in the Project area, United States senators and representatives, and key community groups. An example of the letter is shown in **Appendix H**.

11.3.2 Landowner Postcard

The Applicants used available parcel data to generate a postcard mailing to approximately 47,400 landowners in the Project Notice Area. The postcards were mailed between October 22 and 27, 2025, with the first mailings being delivered to those landowners located in the area of the first week of open houses. The postcard included information about the Project, engagement opportunities, a Project map, directions on how to provide a comment, availability of the virtual open house, and contact information. An example of the postcard is shown in **Appendix H**.

11.3.3 Social Media

The Applicants used Facebook, X, LinkedIn, and Instagram through its' existing communication channels to promote the PowerOn Midwest in-person public open houses and virtual engagement opportunities in November 2025. Examples of social media posts and analytics are shown in **Appendix H**.

11.3.4 Paid Advertisements

The Applicants placed paid advertisements in 44 local newspapers with distribution within the exterior boundaries of the Project's Notice Area announcing the public open houses and virtual open house. Examples of the paid advertisements are included in **Appendix H**, along with the name of the newspaper the advertisements were published and the run dates**.**

11.3.5 Media Advisory

The Applicants issued a media advisory on October 27, 2025, inviting the public to attend the open houses. The media advisory is included in **Appendix H**. In response to the media alert, paid advertisements, and other outreach efforts, at least five reporters came to the open houses. At least 10 news stories about the open houses ran on news outlets.

11.4 Engagement Events

11.4.1 Virtual Open House

The Applicants hosted a virtual open house on the Project website between November 3 and 21, 2025. The virtual open house included the same content presented during the in-person open houses in a website-type format. It provided an opportunity for viewers to view the materials at their convenience to learn more about the Project, the future routing processes, provide input and leave comments. As of January 20, 2026, there have been 341 views of the virtual open house. Screen shots of the virtual open house and analytics are available in **Appendix H**.

11.4.2 In-Person Public Open Houses

The Applicants hosted a series of in-person public open houses between November 3 and 14, 2025. Over this time, the Applicants hosted 17 open houses at 15 venues in 14 counties across southern Minnesota within the exterior boundaries of the Project's Notice Area. The locations of the open houses are presented in **Table 11.2-2**.

<table>
<tr><th colspan="4">Table 11.2-2
In-Person Open Houses</th></tr>
<tr><th>Date/Time</th><th>County</th><th>Location</th><th>Attendance</th></tr>
<tr><td colspan="4">Week 1: November 3 to November 6, 2025</td></tr>
<tr><td>Monday, Nov. 3
10 am – noon</td><td>Lincoln</td><td>Lake Benton Area Community & Event Center
114 Center Street S
Lake Benton, Minnesota 56149</td><td>19</td></tr>
<tr><td>Monday, Nov. 3
4 pm – 6 pm</td><td>Lyon</td><td>Five Family Ranch
2717 County Road 6
Marshall, Minnesota 56258</td><td>58</td></tr>
<tr><td>Tuesday, Nov. 4
10 am – noon</td><td>Pipestone</td><td>Hiawatha Lodge
201 4th Street NW
Pipestone, Minnesota 56164</td><td>23</td></tr>
<tr><td>Tuesday, Nov. 4
4 pm – 6 pm</td><td>Murray</td><td>American Legion
106 W Front Street
Fulda, Minnesota 56131</td><td>28</td></tr>
<tr><td>Wednesday, Nov. 5
10 am – noon</td><td>Nobles</td><td>Worthington Event Center
1447 Prairie Drive
Worthington, Minnesota 56187</td><td>29</td></tr>
<tr><td>Wednesday, Nov. 5
4 pm – 6 pm</td><td>Rock</td><td>Generations Events Center
105 S. Estey Street
Luverne, Minnesota 56156</td><td>26</td></tr>
<tr><td rowspan="2">Thursday, Nov. 6
10 am – noon
4 pm – 6 pm</td><td rowspan="2">Jackson</td><td rowspan="2">Heron Lake Community Center
312 10th Street
Heron Lake, Minnesota 56137</td><td>20 (AM)</td></tr>
<tr><td>8 (PM)</td></tr>
<tr><td colspan="3">Week 1 Subtotal</td><td>211</td></tr>
<tr><td colspan="4">Week 2: November 10 to November 14, 2025</td></tr>
<tr><td>Monday, Nov. 10
10 am - noon</td><td>Cottonwood</td><td>Windom Community Center
1750 Cottonwood Lake Drive
Windom, Minnesota 56101-1251</td><td>58</td></tr>
<tr><td>Monday, Nov. 10
4 pm – 6 pm</td><td>Martin</td><td>Knights of Columbus
920 East 10th Street
Fairmont, Minnesota 56031</td><td>58</td></tr>
<tr><td>Tuesday, Nov. 11
10 am - noon</td><td>Faribault</td><td>Naseic Event Center
789 Business Park Drive
Wells, Minnesota 56097</td><td>45</td></tr>
</table>

Table 11.2-2 In-Person Open Houses			
Date/Time	**County**	**Location**	**Attendance**
Tuesday, Nov. 11 4 pm – 6 pm	Freeborn	Wedgewood Cove 2200 W 9th Street Albert Lea, Minnesota 56007	52
Wednesday, Nov. 12 10 am – noon 4 pm- 6 pm	Dodge	Events by Saker 401 8th Street SE Kasson, Minnesota 55944	29 (AM) 35 (PM)
Thursday, Nov. 13 10 am – noon	Mower	Hormel Nature Center 1304 21st Street NE Austin, Minnesota 55912	30
Thursday, Nov. 13 4 pm – 6 pm	Goodhue	Zumbrota VFW 21 E 1st Street Zumbrota, Minnesota 55992	37
Friday, Nov. 14 9 am – 11 am	Goodhue	Grand 02 Event Center 32057 64th Avenue Cannon Falls, Minnesota 55009	22
Week 2 Subtotal			**366**
TOTAL			**577**

As shown in **Table 11.2-2,** approximately 600 people attended the open houses. Attendees were not required to sign-in at the open houses; rather attendance numbers were developed by taking a headcount as people arrived at each event.

11.4.2.1 Open House Materials

Each open house provided the same information for attendees to review. The open houses included Project displays, detailed Project Notice Area maps, and GIS mapping stations for the attendees to review and provide input. Attendees were greeted and connected with a Project staff member who provided a guided tour through the displays. This involved guiding the attendee(s) through the displays and maps and answering their questions along the way. Attendees also had the opportunity to sit with a GIS/mapping specialist to view their specific locations of concern, discuss potential constraints or opportunities for their parcel(s) or community, and have a PDF map of their area of interest printed at that time or emailed to them. The feedback received through in-person and virtual open houses will be reviewed and considered by the Applicants during the route development processes. A complete set of the engagement materials from the public open houses is available in **Appendix H.**

Additionally, the Applicants provided comment forms for open house attendees to provide written comments, vendor forms for local businesses to get involved with the Project, and

Project contact cards to provide attendees with information on how to contact PowerOn Midwest for further information. Examples of these materials are available in **Appendix H**.