



2025 Integrated Distribution Plan





November 3, 2025

VIA E-FILING

Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's 2025 Integrated Distribution Plan
Docket No. E015/M-25-140
COMPLIANCE FILING

Dear Ms. Bergman:

Minnesota Power (or "the Company") is pleased to present its 2025 Integrated Distribution Plan ("2025 IDP"), which details the Company's plans to ensure a reliable, resilient, and adaptable electric grid as it continues to renew its assets and integrate new distributed generation resources. Through Minnesota Power's *EnergyForward* strategy, it became the first Minnesota utility to deliver 50 percent renewable energy to its customers. The Company has supported the energy transition while continuing to ensure safe, reliable, and affordable energy to its customers. A resilient and secure grid becomes ever more important as technology evolves, customer expectations change, climate change results in increased extreme weather events, and the power supply becomes more renewable. Minnesota Power appreciates the opportunity to submit this 2025 IDP. If you have any questions regarding this filing, please contact me at (218) 355-3082 or cvatalaro@allete.com.

Respectfully,



Claire Vatalaro
Public Policy Advisor

CMRV:th
Attach.

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

In the Matter of Minnesota Power's
2025 Integrated Distribution Plan

Docket No. E015/M-25-140
BIENNIAL COMPLIANCE FILING

SUMMARY OF FILING

Minnesota Power (or “the Company”) respectfully submits this fourth biennial Integrated Distribution Plan (“2025 IDP”), filed under Docket No. E015/M-25-140, to the Minnesota Public Utilities Commission (“Commission”) in accordance with relevant Commission-issued orders, including the Commission’s June 3, 2025 Notice requiring discussion of the impacts of electrification where appropriate. The 2025 IDP outlines the Company's strategic approach to modernizing its distribution system to meet the evolving energy needs of its customers and support Minnesota’s clean energy goals. Minnesota Power continues to advance the transformation of its power supply through its *EnergyForward* strategy and, having become the first Minnesota utility to generate 50 percent of its electricity from renewable sources, the Company continues to support the energy transition and invest in the grid of the future through thoughtful, optimized asset renewal programs and holistic, integrated distribution system planning.

Minnesota Power’s distribution system is more than just a delivery mechanism for electricity. It is a resource that plays a critical role in ensuring that safe, reliable, and reasonably priced electricity is available for a diverse range of customers.

The Company’s approach to distribution planning is guided by four key themes:

- Meeting customer energy needs
- Optimized asset renewal
- Integrated distribution system planning, and
- Supporting the energy transition

These themes serve as the pillars of the 2025 IDP, shaping the Company's investment strategy and ensuring that the distribution system remains adaptable, efficient, and future-ready.

A resilient and secure grid becomes ever more important to meeting customer energy needs as technology and policy evolve, customer expectations change, and the region experiences increased severe weather events. The 2025 IDP details the Company's distribution planning processes and continuous foundational investments in areas such as increased asset renewal spending, distributed generation integration, system visibility, wildfire mitigation, transportation electrification, and sophisticated load forecasting for a grid that will continue to provide the essential services customers rely on. Through strategic investments, customer-focused programs, and integrated planning, Minnesota Power is building a resilient and flexible grid to meet the challenges and opportunities of the future.

PROCEDURAL MATTERS

Pursuant to Minn. Stat. § 216B.16, subd. 1 and Minn. Rule 7829.1300, Minnesota Power provides the following required filing information.

Summary of Filing (Minn. Rule 7829.1300, subp.1)

A one-paragraph summary accompanies this Petition.

Service on Other Parties (Minn. Rule 7829.1300, subp. 2)

Pursuant to Minn. Stat. § 216.17, subd. 3 and Minn. Rule 7829.1300, subp. 2, Minnesota Power eFiles the Petition on the Department of Commerce - Division of Energy Resources ("the Department") and the Minnesota Office of the Attorney General - Antitrust and Utilities Division. A summary of the filing prepared in accordance with Minn. Rule 7829.1300, subp. 1 is being served on Minnesota Power's general service list.

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Date of Filing and Date Proposed Rate Takes Effect (Minn. Rule 7829.1300, subp. 4(C))

This Petition is being filed on October 16, 2023. The effective date is the date of the Commission's Order or such other date as directed in the Commission's Order. The Petition will not result in any rate changes.

Statute Controlling Schedule for Processing the Filing (Minn. Rule 7829.1300, subp. 4(D))

There is no specific statutorily prescribed timeframe for processing this filing. Accordingly, this filing is controlled by the Commission's rules on Miscellaneous Filings, Minn. R. 7829.1300 and 7829.1400.

Utility Employee Responsible for Filing (Minn. Rule 7829.1300, subp. 4(E))

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Table of Acronyms

Acronym	Definition
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
ASHP	Air Source Heat Pump
BCA	Benefit Cost Analysis
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
C2M	Customer to Meter
CEUD	Customer Energy Use Data
CFS	Carbon-Free Standard
CIP	Conservation Improvement Program

CSG	Community Solar Garden
CVR	Conservation Voltage Reduction
DCFC	Direct Current Fast Charger
DER	Distributed Energy Resources
DG	Distributed Generation
DNP3	Distributed Network Protocol 3
DR	Demand Response
DSES	Distributed Solar Energy Standard
E-ISAC	Electricity Information Sharing and Analysis Center
ECO	Energy Conservation and Optimization
EFS	Efficient Fuel Switching
EMS	Energy Management System
EV	Electric Vehicle
FAN	Field Area Network
FLISR	Fault Location, Isolation and Service Restoration
FPI	Fire Potential Index
GIS	Geographic Information System
HVAC	Heating, Ventilation, and Air Conditioning
IBR	Inverted Block Rates
IDP	Integrated Distribution Plan
IEEE	Institute of Electrical and Electronic Engineers
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
MDM	Meter Data Management
MDU	Multi-Dwelling Units

NERC	North American Electric Reliability Corporation
NWA	Non-Wires Alternatives
OMS	Outage Management System
PHEV	Plug-in Hybrid Electric Vehicle
RES	Renewable Energy Standard
RTU	Remote Terminal Unit
SES	Solar Energy Standard
STATCOM	Static Synchronous Compensator
TOD	Time-of-Day
VPP	Virtual Power Plant
VVO	Volt-VAR Optimization
WMP	Wildfire Mitigation Plan

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I. INTRODUCTION

Minnesota Power's (or, "Company") 2025 Integrated Distribution Plan ("2025 IDP") reflects the Company's commitment to delivering safe, reliable, affordable, and sustainable energy while meeting the evolving needs of customers and communities. The Company views its distribution system¹ not only as a delivery system but as an asset critical to the future energy grid. As such, one of the key pillars of this plan is Optimized Asset Renewal, upgrading aging infrastructure as it is replaced and ensuring that these investments are both forward-looking and cost-effective. By modernizing aging assets and integrating advanced technologies, the Company continues to enhance system reliability and resilience, positioning the distribution system to support the growing and changing demands of Minnesota's energy future and customer expectations.

The 2025 IDP represents a comprehensive and forward-looking strategy to strengthen the Company's distribution system, ensuring it meets the evolving needs of customers while supporting Minnesota's clean energy transition. As the use of distributed generation continues to grow in number and importance, such as through the Distributed Solar Energy Standard ("DSES"), the Company is creating a more diverse and flexible energy system that uses the entire energy grid to provide reliable, resilient, electricity at a reasonable cost to Minnesota Power customers. This effort is complemented by the Company's integrated distribution system planning, which aligns distribution planning with the Company's 2025 Integrated Resource Plan ("IRP") and Energy Conservation and Optimization ("ECO") goals. The 2025 IDP also reflects Minnesota Power's role in supporting the energy transition. It emphasizes the importance of aligning distribution system investments with the state's energy goals, customer expectations, and the challenges of a rapidly changing energy landscape.

¹ Distribution systems at Minnesota Power consist of systems with voltages under 100 kilovolts ("kV") and the facilities that serve customers from the transmission-distribution substation to a customer meter.

II. INTEGRATED DISTRIBUTION PLAN BACKGROUND AND REQUIREMENTS

a. IDP Origin and Procedural History

The IDP's origins stem from a 2015 Commission Investigation into grid modernization. Following a series of workshops with utilities and other stakeholders, Commission staff issued a report in March 2016 recommending an integrated distribution planning process as integral to assisting the Commission and stakeholders to evaluate potential investments to modernize the grid.²

In its February 20, 2019 Order³, the Commission adopted IDP filing requirements and ordered Minnesota Power to file an IDP biennially beginning on November 1, 2019. Minnesota Power's first IDP filing in 2019 provided information about the Company's distribution system and highlighted continuous foundational investments related to serving customers, ensuring reliability, and preparing for a more resilient grid.

In its May 27, 2020 Order⁴, the Commission identified the following objectives for IDPs:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value.

In its December 8, 2022 Order, the Commission accepted Minnesota Power's 2021 IDP and modified future filing requirement 3.D.1(k) to include cost-benefit analysis for each grid modernization project in its 5-year action plan, as well as ordering the inclusion of the Transportation Electrification Plan in future IDP filings and required Minnesota Power to

² Docket No. E999/CI-15-556, March 24, 2016.

³ Docket No. E-015/CI-18-254.

⁴ Docket No. E-015/M-19-684.

incorporate additional distribution and resource planning and non-wires alternative data in its Order accepting the Company's 2021 Integrated Resource Plan filing.⁵

b. New IDP Filing Requirements

The 2025 IDP is subject to several new filing requirements as established after approval of the Company's 2023 IDP.

In its Order dated September 16, 2024, the Commission accepted Minnesota Power's 2023 IDP.⁶ Order Point 2 of the Commission's Order delegated authority to the Executive Secretary to develop a proposal for what distribution data is reported in the IDP and what data continues to be reported in other dockets. Any resulting changes from this workgroup and Commission decision will be reflected in the Company's 2027 IDP.

Order Point 3 delegated authority to the Executive Secretary "to work with Minnesota Power, the Department, and stakeholders to modify the IDP filing requirements to include discussions of the impacts of electrification where appropriate." These changes as approved by the Commission's Notice on June 3, 2025, have been incorporated into the 2025 IDP.⁷ These amendments were filed in both redline and clean versions as Attachment A to the Notice and have been incorporated into this IDP.

Order Point 5 of the same Order required Minnesota Power to consider demand response, energy efficiency, and renewable generation as part of its future Non-Wires Alternatives processes. The Company has adhered to all relevant compliance items, which may be reviewed in Appendix A.

Minnesota Power respectfully submits this 2025 IDP, which provides the information required in the Commission orders listed above, as well as information on how the Company is meeting the Commission's distribution planning objectives.

c. IDP Landscape

Distribution planning is a much more dynamic process than it was ten years ago, driven by evolving energy policy, advances in technology, and the integration of distributed energy resources. Traditional planning, which focused primarily on capacity planning and reliability

⁵ Docket No. E015/RP-21-33.

⁶ Docket No. E015/M-23-258, September 16, 2024.

⁷ Docket No. E015/M-25-140, June 3, 2025.

improvement, has expanded to include the two-way management of distributed energy resources such as distributed solar systems and battery storage.

On its own system, Minnesota Power has seen marked increases in the adoption of air and ground source heat pumps, electric vehicles, and distributed solar systems which have increased the amount of energy moving back and forth across the distribution system. The Company anticipates that these adoption rates will continue to climb. Additionally, large, electricity-intensive industries continue to express interest in the Minnesota Power service territory, which requires planning for additional generation and distribution infrastructure.

At the same time, Minnesota Power's distribution system—comprising over 6,200 miles of distribution lines and nearly 200 substations—includes many assets that are more than 40 years old, making asset renewal and age-related investments critical to maintaining reliability and resiliency. The Company has prudently maintained and operated its distribution assets to extend their operational life, in many cases well beyond their original design life, to maximize value for customers. However, aging infrastructure is increasingly prone to failures, which can disrupt service and escalate maintenance costs. These challenges are further compounded by rising material, labor, and equipment costs across the utility industry. In recent years, utilities nationwide have experienced significant increases in the cost of poles, wire, transformers, and substation components driven by global supply chain constraints, inflationary pressures, and heightened demand for grid modernization. As a result, the cost of rebuilding and maintaining distribution systems has grown substantially, increasing the importance of prioritizing strategic, data-driven reinvestment decisions.

To address these challenges, Minnesota Power has bolstered its asset renewal programs, prioritizing proactive replacements and substation modernization projects to efficiently address end-of-life infrastructure and improve system performance. These investments are essential to transitioning from reactive to preventative maintenance, ensuring a resilient grid capable of supporting customer needs, integrating distributed energy resources, and meeting Minnesota's clean energy goals. Distribution system policy has continued to evolve to address the rapidly changing nature of the distribution technology itself. Since the 2023 IDP, there have been several legislative and Commission-led policy changes that impact the overall distribution landscape, many of which pertain to accelerated development of distributed generation sources and streamlining the interconnection process for them. Perhaps the most significant policy change is the DSES, which requires three percent of Minnesota Power's total retail electric sales (not

including large power sales) in Minnesota to be generated from distribution-connected systems with a capacity of ten MW or less by the end of 2030.⁸

In November 2024, the Commission convened a workgroup to develop draft generic standards for the Distribution System Reactive Upgrades Process which would allow cost sharing among parties wishing to interconnect in congested or constrained portions of the distribution system.⁹ Interconnection streamlining continues in other avenues as well, such as the ongoing Distributed Generation Working Group, and the workgroup convened by the Commission on June 6, 2025 and facilitated by Converge Strategies to establish secure distribution grid data sharing policies between utilities and developers.¹⁰ The recommendations of this group will be presented to the Commission in 2026. These and other distribution-related policy efforts have informed the Company's planning process.

The Company continues to develop programming to facilitate EV adoption, including the installation of the first of its 16 public DCFC charging stations¹¹ and its make-ready charging infrastructure pilot program for customers living in Multi-Dwelling Units ("MDUs").¹² These programs prioritize customers in identified disadvantaged communities and environmental justice areas to promote equitable access to EV infrastructure throughout the Company's service territory.

Minnesota Power approaches distribution policy with a proactive and adaptive planning process that prioritizes reliability, customer benefits and regulatory compliance. The Company continuously monitors evolving policies and emerging technologies to ensure alignment with state and company goals, advance the energy transition, and provide equitable access to energy resources and programming for its customers. Policy changes are incorporated into distribution planning through data-driven analysis to assess impacts and identify opportunities for improvement. By integrating policy considerations into its long-term asset management, DER integration, and demand response programs, the company ensures that its distribution system remains resilient, reliable, and adaptable to future regulatory and market changes.

⁸ Docket No. E015/CI-23-403.

⁹ Docket No. E015/CI-24-288.

¹⁰ Docket No. E999/CI-20-800.

¹¹ <https://www.mnpower.com/ProgramsRebates/EVdcfcProgram>.

¹² Docket No. E015/M-23-258.

d. Customers, Communities, and Climate Action

Minnesota Power's *EnergyForward* strategy outlines a vision for delivering value to customers, coworkers, and communities through sustainable energy solutions with a focus on expanding renewables, reducing carbon, enhancing resiliency, and driving innovation. *EnergyForward* is built around Customers, Communities, and Climate Action.

As Minnesota Power plans the grid of the future, the Company will remain customer-focused, continuously improving customer experience, building relationships, improving reliability, and ensuring consumer benefits. To do so, the Company continually strives to maintain and build relationships with its various customer groups. Minnesota Power continues to provide the core services customers count on while leveraging technological advances where applicable and practical to meet the customer's current needs. Customers expect reliable, affordable, and safe electric service that is convenient, transparent, and they place a high level of importance upon digital channels for billing, payment, energy usage, and outage communication. The Company has therefore made significant progress with digital platforms that support customers, whether through the MyAccount portal, mobile app, or continuing the no-fee credit or debit card bill pay option, as approved in the 2016 Rate Case. A 2023 survey by Rapp Strategies showed a 97 percent satisfaction rate among customers using the Company's digital communication channels.

Customers serve an increasingly interactive role in helping to maintain reliability of the system, particularly during peak demand periods and as variable renewable energy sources become a growing part of the energy mix and flexible distribution loads become critical to managing the reliability of the grid. An overarching consideration for customers is keeping costs as low as possible as the Company plans distribution system investments. Each investment is carefully evaluated, and Minnesota Power prudently selects investments that provide the best overall benefit for customers. The combination of aging assets and rising costs during this inflationary period make this evaluation even more important.

As communities experience increasing extreme weather events as a result of climate change, planning for a reliable and resilient power supply is a critical part of Minnesota Power's distribution planning process. This 2025 IDP outlines efforts aimed at planning for a more resilient grid to ensure reliability for communities, including efforts like asset renewal investments, strategic undergrounding, grid modernization efforts, wildfire mitigation, and more.

Partnerships with the communities it serves are a critical component of Minnesota Power's state-leading carbon reduction journey. As a means of supporting these partnerships, Minnesota Power

hosted two engagement meetings in preparation for the 2025 IDP to provide participants with information on the Company's distribution system, its planning process, and forthcoming developments. The Company solicited feedback from participants at both meetings. The first of these meetings were held at Minnesota Power Headquarters in Duluth, Minnesota on July 18, 2025. A second, feedback-oriented meeting was held online on September 3, 2025. These meetings were attended in person and online by representatives from the Public Utilities Commission, the Minnesota Department of Commerce, the Fond du Lac Band of Lake Superior Chippewa, the cities of Duluth, Two Harbors, and Virginia, labor groups, the Center for Energy and the Environment Minnesota, Fresh Energy and clean energy organizations, and other utilities. Both meetings consisted of productive discussions, particularly about EV programming and planning, asset renewal, wildfire mitigation, and load shifting. The Company values these discussions and has used them to inform this filing. Information shared during these meetings may be found in Appendix B.

Minnesota Power is committed to climate action and working towards a sustainable future for both its customers and communities. The Company considers its distribution system to be a resource and valuable tool in meeting these goals. Customers are interested in programs and services that increase accessibility to energy conservation programs, renewable energy, and electrification. While the Company's current generation portfolio includes more than 50 percent renewable resources, some customers want even more of their energy supplied from renewable sources. As the Company plans for a distribution system of the future, accommodating customer desires on efficiency, renewable energy and electrification is critical. The Company continues to make energy conservation part of its climate action strategy. As technology continues to evolve, there is a growing desire on behalf of customers for more individualized services that include renewable or lower carbon options. The Energy Conservation and Optimization Act of 2021 ("ECO Act") provides a timely pathway for building on core conservation program offerings and expanding those to reach more customers while providing a broader suite of program and service offerings. Minnesota Power filed its 2024–2026 Triennial ECO Plan on June 30, 2023.¹³ Implementation of Minnesota Power's ECO plan requires a direct relationship with distribution planning and related investments.

The Company carefully considers investments in the distribution system which allow for increased penetration of renewable distributed generation, as well as efforts toward electrifying fossil fuel-

¹³ Docket No. E015/CIP-23-93.

based distribution level emission sources such as building heat and vehicle fleets, thereby connecting these sources to the electrical grid, the fastest decarbonizing sector of the economy. Further to this point, the amendment to Minnesota Statute 216B.1691 Renewable Energy Objectives has mandated that at least 3 percent of Minnesota Power's non-exempt retail electric sales must come from distributed solar generation sources by 2030. These new sources will be installed at the distribution level, further demonstrating the distribution system's vital role in decarbonizing the electric grid. The assumptions and programs discussed above are reflected in the 2025 IDP.

III. DISTRIBUTION SYSTEM STRATEGY

Minnesota Power's 2025 IDP is framed around four key themes which represent the Company's intentional and strategic approach to delivering safe and reliable distribution services while making necessary investments to advance the clean energy transition.

a. Meeting Customer Energy needs

Customer energy needs are evolving rapidly. The distribution system is no longer a one-way path for electricity delivery—it now accommodates a wide range of technologies, including distributed generation, battery storage, and electric vehicles. As these technologies become more concentrated in specific areas, they may necessitate system upgrades to ensure continued reliability and performance. Additionally, fuel switching and electrification of homes, vehicles and businesses require more energy to move through the system and to be discharged back onto it. As part of the Company's obligation and privilege to serve, the Company continues to proactively invest in hardware and software solutions and innovative pilots and programs to ensure that safe, reliable, reasonably priced electricity is available for a diverse range of customers. Minnesota Power recognizes its responsibility and the importance of serving new economic growth developing in the region, and the 2025 IDP addresses the Company's responsiveness to current and anticipated customer energy needs. Thoughtful distribution planning is not only critical to ensuring reliability and resiliency for customers at rates they can afford but is also key to ensuring the Company's commitment to the customers and regional partners it serves.

b. Investing in Optimized Asset Renewal

Optimized Asset Renewal is the process by which the Company replaces distribution assets like poles, transformers, and substations that have reached or are reaching the end of their useful life. Minnesota Power's asset renewal program does not replace like for like but rather upgrades and

improves the distribution system with newer, more innovative, future-ready technology as it is replaced. These investments improve and maintain the reliability, resiliency, and visibility of the distribution system through efficient, strategic, and cost-effective investments, maximizing the benefits and use of existing assets. Examples of this strategy include strategic undergrounding of overhead lines, Advanced Metering Infrastructure (“AMI”) integration, installation and implementation of Fault Location, Isolation and Service Restoration (“FLISR”) technology, mitigating wildfire risks, and more. Optimized Asset Renewal for the Company’s geographically large and dispersed distribution system remains the Company’s highest investment priority.

c. Integrated Distribution System Planning

Integrated Distribution System Planning is Minnesota Power’s approach to considering distribution holistically including Optimized Asset Renewal, the resource planning process for generation resources now participating on the distribution system, and the impact from the ECO program. Integrated Distribution System Planning is essential to building a sustainable and reliable energy future. The Company is integrating learnings from previous IDPs, initiatives, and pilots to support resource planning through efficient distribution and management of electricity on its system. As the Company continues to invest in systems that result in additional grid visibility data and insights, it continues to evaluate new opportunities to provide innovative system management, customer programs and services, and planning opportunities that support efficient generation, conservation and use of electricity.

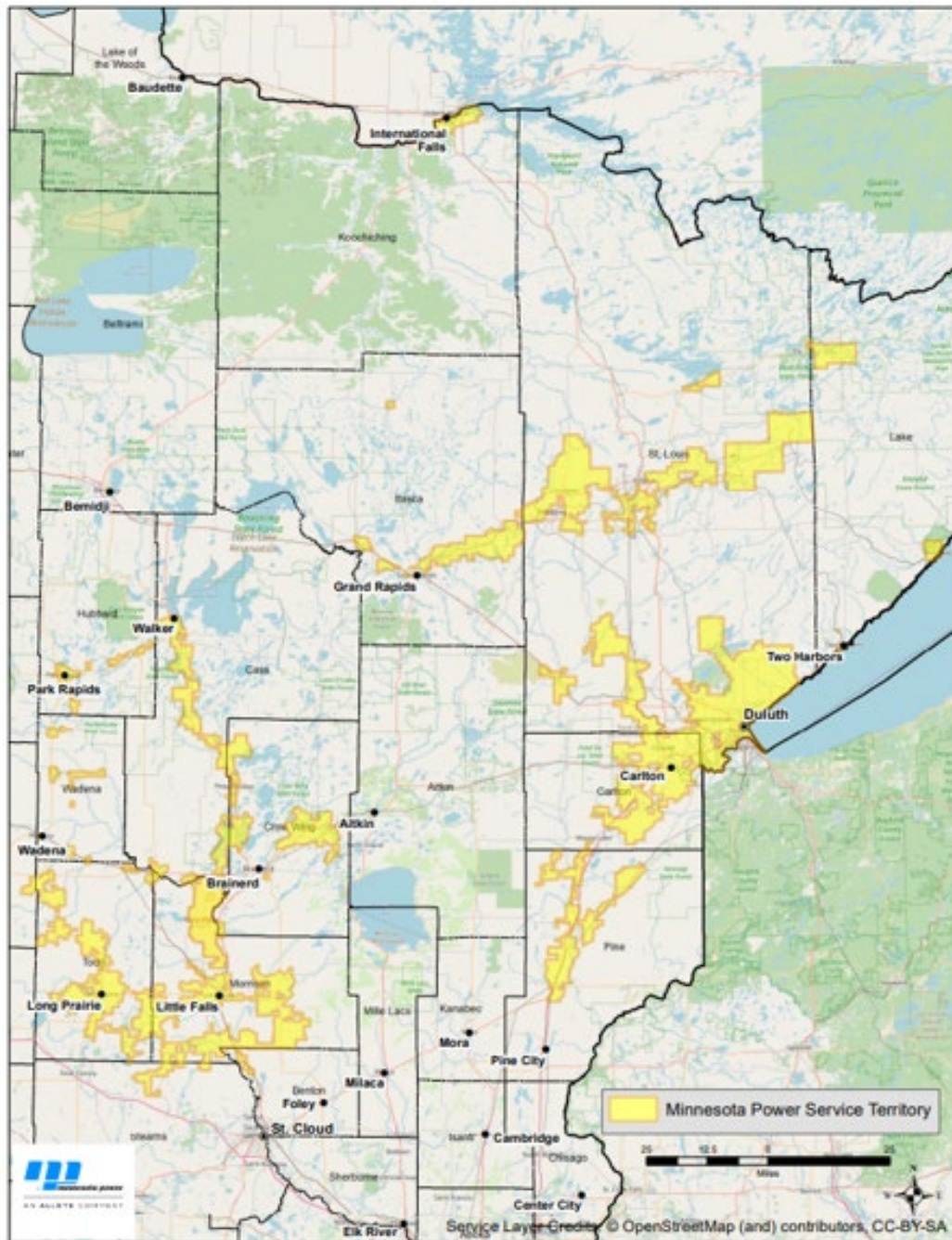
d. Supporting the Energy Transition

The 2025 IDP also addresses how Minnesota Power is using its distribution system to support the energy transition. The Company’s efforts in supporting DER deployment, energy conservation, and efficient fuel switching are detailed in this IDP. As the DSES is implemented and increasing adoption of smaller distributed generation resources increases, the distribution system’s value as an energy resource will increase. Furthermore, the distribution system will continue to transfer an evolving energy mix from the transmission system to distribution customers and enable the deployment of advanced technology that will further support meeting the Renewable Energy Standard (“RES”) and Carbon-Free Standard (“CFS”).

IV. OVERVIEW OF MINNESOTA POWER AND ITS DISTRIBUTION SYSTEM

a. Minnesota Power's *EnergyForward* Strategy

Figure 1: Minnesota Power's Service Territory

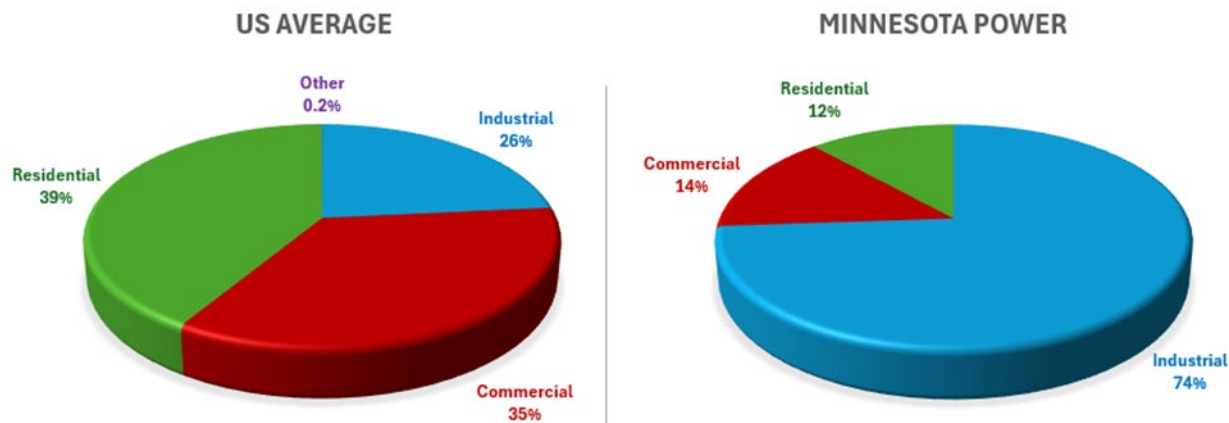


Minnesota Power, a division of ALLETE, Inc., is an investor-owned utility headquartered in Duluth, Minnesota. First incorporated in 1906, Minnesota Power serves electricity to approximately 150,000 retail electric customers, 14 non-affiliated municipal customers, and some of the nation's largest industrial customers in a 26,000-square-mile service area across northeastern and central Minnesota.

The Company's **EnergyForward** resource strategy continues to transform the way low-carbon energy fuels communities and businesses safely, reliably and at as reasonable a cost as possible – including by leveraging distribution assets to generate, transport, and store electricity.

Minnesota Power's customer mix is unique and distinct from most utilities in the United States as shown in Figure 2. This unique customer mix has implications for system planning, as described below.

Figure 2: Minnesota Power's Customer Concentration is Unique



Source: US Energy Information Administration (2024 EIA Form 861 Data)

Minnesota Power's commercial customers account for fourteen percent of the Company's annual regulated retail electric sales revenue and are served directly from the distribution system. A wide range of interactions occur with commercial customers including planning for new construction, service extensions, outage restoration, reliability and power quality concerns, system upgrades, and responding to a variety of other electric service and rate questions. These customers are a diverse group with varying needs and expectations depending on the business (i.e., electric costs as a percentage of total operating/production costs, power quality and reliability needs, etc.).

Minnesota Power's residential customers represent approximately twelve percent of the Company's annual retail electric sales and are served directly by the distribution system.

Interactions with these customers are similar to commercial customers but are higher in volume and include items such as planning for new construction, service extensions, outage restoration, system upgrades and responding to a wide variety of other electric services, customer programs, and rate or billing impact questions. Additionally, Minnesota Power's service territory is spread across primary areas in northern and central Minnesota and serves both urban and rural communities. This geographical dispersion of rural communities and customers presents unique issues when planning for investment in the distribution system. Customers located at the end of multiple miles of line on a single feeder will have different challenges and requirements than a customer located in a more populated area with feeder redundancy.

Minnesota Power continues to advance the transformation of its power supply to cleaner energy resources through its **EnergyForward** strategy. Since 2005, Minnesota Power has reduced carbon emissions by over 50 percent and retired, idled, or re-missioned 7 of its 9 coal-fired generation units, removing approximately 700 megawatts ("MW") of coal-fired generation from its 1600 MW system. The Company's last remaining coal generating facility, Boswell Energy Center in Cohasset, Minnesota, will cease coal operations for Minnesota Power customer by 2035.

Following the signing of the Minnesota Carbon-Free Electricity Standard into law on February 7, 2023, Minnesota Power continues to evaluate the Company's path to 100 percent carbon-free energy supply for its customers and provided its latest refinement to its long-term energy supply plan in its 2025 Integrated Resource Plan ("2025 IRP"), filed on March 3, 2025 in Docket No. E015/RP-25-127. The 2025 IRP lays out the Company's plan to provide 90 percent renewable generation by 2035 while providing reliable service and reasonably priced electricity to customers. The path forward proposed in the 2025 IRP not only prioritizes reliability and affordability while advancing toward a carbon-free grid, but positions for load readiness. The Company's distribution system will play an integral role in maximizing benefits for customers during this unique and exciting time of transition. An important aspect of **EnergyForward** is supporting customers in their pursuit of cleaner energy. For customers that desire higher levels of renewable energy (beyond the 50 percent provided in their current energy mix), Minnesota Power offers several different renewable options, including its SolarSense rebate program, a Community Solar Garden Pilot program, and its Renewable Source program. At the same time, the Company is preparing to add roughly 45-55 MW of additional distributed solar to its distribution system in compliance with the

DSES.¹⁴ The Company released its Request for Proposals (“RFP”) to solicit bids for this project on January 30, 2025. The DSES is discussed in detail in Section V.

To meet the needs of its unique customer base, Minnesota Power built its distribution strategy on the foundation of technology, innovation, and continuous learning. Customers expect reliable, affordable, safe, and increasingly low-carbon electric service, all of which are encompassed in the Company’s distribution planning strategy. Meeting these expectations requires deploying right time/right fit distribution technology that is flexible, adaptable, and upgradable. The Company has strategically positioned its distribution system for the deployment of emerging distribution technology through thoughtful planning in all areas of its business while maintaining a focus on customers’ needs, upholding distribution planning principles, and aligning these investments with the Company’s sustainability goals, which balance economic, environmental, and social needs for both the Company and its customers over the long-term.

b. Minnesota Power’s Distribution System

Minnesota Power’s distribution system is comprised of 6,253 miles of distribution lines and 193 distribution substations (“distribution system”). At the end of 2024 Minnesota Power had 1,657 MVA of transmission-to-distribution substation transformer capacity. There are currently 4,542 miles of above ground wire on the distribution system and a total of 1,711 miles of underground wire. In 2024, over 54 miles of underground cable was installed across the distribution system including the conversion of overhead facilities to underground facilities.

Minnesota Power currently has 329 distribution feeders throughout its service territory. Some of these are three phase feeders while others are single phase. Minnesota Power has visibility and control of primary and three-phase distribution. The Company currently has limited or no visibility or control of most single-phase feeders. Of the Company’s 329 distribution feeders, 162 feeders (49 percent) have supervisory control and data acquisition (“SCADA”) at the feeder breaker. This is 1,855 MVA of service transformer capacity interconnected to Minnesota Power’s 329 distribution feeders. These service transformers are that last step in voltage before serving approximately 150,000 customers. The maintenance and renewal of assets on this system is a critical aspect of the Company’s distribution planning.

¹⁴ Minn. Stat. § 216B.1691 Subd. 2h.

1. System Visibility and Control

Minnesota Power uses four different methods to monitor and control its distribution system: SCADA, smart sensors, automated/advanced metering data collection, and manual meter reading. Each of these monitoring and control methods is discussed briefly below.

The SCADA system oversees the state and health of the distribution system on roughly half of the Company's feeders. This system brings back measurement data in the form of analog (e.g., Amperes, MW, Megavolt-Ampere Reactive ("MVAR"), Megavolt-Ampere ("MVA"), and kilovolt ("kV")) and binary (e.g., statuses, alarms, and outages) values from these feeders. The SCADA system measures analog data in 4 second intervals and binary information in 60 second intervals as well as when there is a change of state. The information is recorded in a historical database that is accessible for engineering planning and analysis. In addition, the SCADA system enables Minnesota Power's system operators to remotely operate breakers and motor operated switches to isolate faulted equipment and feeder sections, greatly expediting the restoration process, enhancing reliability, and reducing customer impacts.

Smart sensors are installed on feeders that do not currently have SCADA installed. These feeders' substations are usually in remote rural areas where communication paths are limited. The smart sensors monitor voltage and current near the feeder breaker and store measured data offsite in a data historian. A secure account is used to review and download the information for engineering and event analysis as well as restoration efforts. Minnesota Power has installed these sensors at most substations that do not have SCADA to gather better data and eliminate manual reads. In 2017, Minnesota Power began implementing smart sensors on the remaining distribution feeders. At the end of 2024, 133 distribution feeders (40 percent of total feeders) had smart sensors installed near the feeder source. Eleven additional locations on seven feeders have smart sensors installed to assist in fault locating. Minnesota Power has finished the deployment of smart sensors on distribution feeders at the substation exits. Minnesota Power will continue installing smart sensors in multiple locations on feeders to assist in fault location, increasing real-time visibility on the distribution system and creating efficiencies.

Manual reads are occasionally collected by operations personnel during substation inspections. These reads collect peak amp data each month and are reset upon reading. This information is then housed in the Company's asset management system for analysis. There are a number of rural 4kV feeders on the distribution system that are not read or inspected because they are

remotely located and serve a very small number of customers. Most of these locations are part of the investment plan and will be upgraded or removed in future years.

Minnesota Power utilizes AMI technology for the vast majority of its meter collection systems. The AMI system records voltage, kW, kilowatt-hours (“kWh”), kilovar-Hour (“kVARh”), click counts and informs the OMS of customer outages and restorations. AMI collects 15-minute interval usage data, giving customers more granular data through the MyAccount tool and positioning Minnesota Power for future advanced time-based customer rate offerings. Customers are provided the option to opt out of AMI for a monthly fee. This is done by using non-standard metering and requires manual reads.

2. Advanced Metering Infrastructure (“AMI”)

Minnesota Power is the first investor-owned utility in Minnesota to fully implement Advanced Metering Infrastructure. Minnesota Power received a Smart Grid Investment Grant in 2009 that allowed the Company to deploy advanced metering infrastructure with a goal of modernizing the grid and improving customer service. AMI is an advanced, two-way metering system that provides metering, operational, and real-time notification of system conditions at customer premises for virtually all retail residential and commercial customers. The meters act as “smart nodes” at each customer’s premise, allowing multiple benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues (such as low/high voltage, over current, and tamper warnings); improved load control; more frequent customer usage data. AMI also enables advanced TOD rates when combined with a meter data management system (“MDM”). Further, replacement of the aging dual fuel and controlled access control systems has allowed for improvements to demand response offerings that support reliability with increased variable renewable energy on the system. The current AMI system was fully deployed as of 2023 and includes further integration with other operational software systems. A subset of these meters are remote-capable, allowing for remote disconnection and reconnection of service. The Company’s Reconnect Pilot Program¹⁵ has been in effect since 2021 and is in effect until July 2026. Under this pilot, reconnection fees are waived if a remote-capable meter is installed, allowing for nearly instantaneous reconnections once a customer has met reconnection requirements. In 2023, Minnesota Power, with Commission approval, transitioned to a formal AMI opt-out process for residential customers that includes a monthly fee to read and maintain the meter. The expansion of Minnesota Power’s AMI capabilities also lays the groundwork for further

¹⁵ Docket No. E015/M-19-766.

grid modernization initiatives, innovative customer programs, and improvement to the overall customer experience.

Table 1: AMI Meter Deployment

	AMI Meters Installed	Remaining AMR Meters
2016 Actual	11,092	92,084
2017 Actual	11,476	80,608
2018 Actual	13,155	67,453
2019 Actual	10,635	56,818
2020 Actual	35,437	21,381
2021 Actual	18,392	5656
2022 Actual	6109	203
2023 Actual	203	0

As of January 2025, there were 149,334 AMI meters deployed on Minnesota Power’s system (roughly 99.78 percent of deployed meters). With the aid of a Smart Grid Investment Grant, 8,030 meters were deployed. The Company’s automated meter reading (“AMR”) system was decommissioned in April of 2023.

3. System Interoperability and Communications Strategy

Minnesota Power owns and operates a communications transport system that consists of fiber optics, microwave radios, leased services, and other technologies. This system provides communications for all areas of Minnesota Power including transmission SCADA, transmission line protection, distribution SCADA, land mobile radio, business IT systems, voice, video, and others. The Company uses a variety of communications methods based on the cost and specific requirements of the application. To support the growing need to monitor and control distribution devices, Minnesota Power is expanding the transport system and exploring new cost-effective ways to leverage existing systems and infrastructure.

To ensure the maximal value of systems and data, the Company regularly evaluates system integrations to increase the interoperability of its tools. One example is the integration of AMI, the outage management system (“OMS”), and the geographic information system (“GIS”) systems to

enhance real-time data collection and analysis, enabling faster outage detection and resolution. AMI provides detailed consumption and status data, OMS streamlines outage response, and GIS visualizes infrastructure and affected areas. Together, these systems improve operational efficiency, reduce downtime, and enhance customer satisfaction by enabling proactive communication and precise service restoration. Additionally, this integration supports better planning and decision-making, optimizing resource allocation and improving overall grid reliability.

As the Company continues to invest in smart field devices, standardizing the architecture and hardware to ensure interoperability is increasingly important. For example, the Company has standardized a single remote terminal unit (“RTU”) manufacturer for polling, Distributed Network Protocol 3 (“DNP3”) as a communication protocol, and a single model of reclosure and relay in the field. This consistency ensures all the new investments function and work together to strengthen the system overall.

As the Company’s communication strategy continues to evolve, alternative communication options are monitored for effectiveness. For example, Minnesota Power plans to evaluate field area network (“FAN”) options in the future. This effort will include working with internal stakeholders to develop a list of use cases and the specific communication requirements of each use case. The Company will explore FAN options including private LTE, public cellular, FirstNet, multiple address (“MAS”) radio solutions and others to determine the best fit for its purposes. The Company will then develop a project plan to build out the chosen solution to support the growing need for communication to distribution field devices. The Company will provide updates on this project through future IDPs.

4. Cyber Security

The rapid advancement of data and system capabilities, coupled with the growing integration of DER into the utility system, make it critical for the Company to continuously evolve its cybersecurity program to safeguard the security and integrity of customer and utility systems and data. Minnesota Power has developed a robust, multi-layered cybersecurity program grounded in the internationally recognized Critical Security Controls for Effective Cyber Defense framework, established by the Center for Internet.

Minnesota Power’s cybersecurity program encompasses several key components, including dedicated leadership and oversight, external and internal threat sensing, intrusion prevention, and intrusion detection and mitigation. These measures are continually refined and adapted to

address the ever-changing cybersecurity threat landscape, ensuring the resilience of the Company's systems.

The Company's commitment to cyber security extends beyond internal measures. This November, Minnesota Power will participate in GridExVIII, a large-scale grid security exercise organized by the North American Electric Reliability Corporation ("NERC") and its Electricity Information Sharing and Analysis Center ("E-ISAC"). This exercise is designed to test and enhance the industry's readiness to respond to grid security threats.

Furthermore, Minnesota Power actively collaborates with neighboring utilities, industry-specific organizations, technology partners, and public officials to exchange best practices and strengthen both cyber and physical security measures. These partnerships are vital in fostering a collective defense against emerging threats.

The electric grid continues to evolve to meet increased demands from new technology, customers, and weather, and it is imperative that both the physical and cyber security of the system be maintained. Minnesota Power is investing in systems that not only meet the needs of customers but ensure the distribution system is able to operate efficiently and securely. Minnesota Power has been an active participant in industry associations, workgroups and Commission dockets that address grid security and data privacy issues. The security of grid and associated data is of critical importance to Minnesota Power, and as such the Company has been actively engaged in developing a standardized process for securely sharing grid data with potential developers as part of the workgroup established in the Commission's June 6, 2025 Notice of Workgroup.¹⁶ The Company has participated in three sessions coordinated by Converge Strategies between July 11 and October 6, 2025 to develop recommendations.

The Company has also been actively involved with the Commission process establishing Open Data Access Standards and privacy policies in Dockets Nos. E,G-999/M-19-505 and E,G-999/CI-12-1344. Because disclosing Customer Energy Use Data ("CEUD") to third parties has the potential to reveal confidential information about customers and the distribution system, the Company has worked with other utilities, customers, interested stakeholders, and the Commission to incrementally develop Standards that appropriately balance public interest in energy use data, customer privacy, and grid security.

¹⁶ Docket No. E-999/CI-20-800.

c. Overview of Current Systems

The following sections provide a brief overview of software systems critical to the operation of the Company's distribution system. All existing and new systems are necessary for ensuring electric service regardless of this distribution plan, and the Company would not attribute the costs of obtaining data from these systems to this plan. However, the systems below are critical to distribution planning, operation and general customer service.

i. Customer Focused Systems Overview

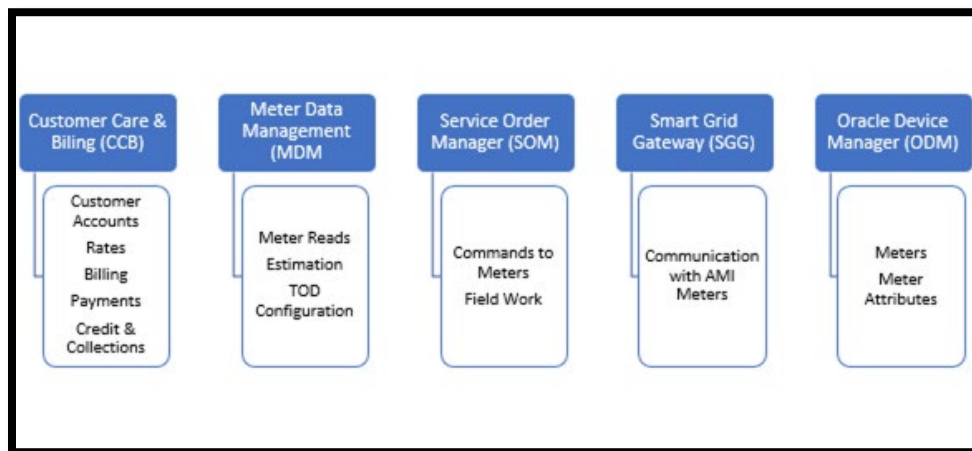
Investments in customer systems have been driven by customer desire for more convenient and diverse products and services, including self-service electronic communication options and services, and information about energy and product offerings, generally through efficiency and pricing or a combination of the two. Minnesota Power's approach is to continue to provide the core services customers count on as effectively as possible, leveraging advances in technology where applicable and practical. To meet customers' needs, the Company must continually invest in existing as well as new technologies to make customer-facing improvements.

Customer to Meter ("C2M") System – C2M is the core customer information system that is designed to securely store customer information and act as the primary billing and rate engine for Minnesota Power customers. The C2M solution, implemented in 2021, serves as an Advanced Metering Billing System, incorporating modules for customer billing, meter data management, smart grid integration, meter asset management, and service order management (see Figure 3). Shared with Minnesota Power and Superior Water Light & Power, C2M serves as the Company's accounts receivable system, customer billing platform, and advanced rates engine. The Company has realized several operational benefits from the C2M system, including:

- Supporting the Time-of-Day ("TOD") pilot project
- Enabling additional data integration with the Company's customer portal, MyAccount, for enhanced customer access
- Improving billing processes through validation, enhancement, and editing of billing estimates
- Facilitating remote connect and disconnect capabilities
- Implementing new or enhanced rates and programs

A technical upgrade was implemented for this system in 2024. This project allowed the Company to maintain version compliance while enhancing the underlying technology platforms.

Figure 3: C2M Project Components



Meter Data Management (“MDM”) – The MDM was implemented as part of the C2M project and is the module that provides a data engine that performs validation, editing, estimating, and organized storage of both rate and operational information from metering systems. Future investment may be required to enhance the operational information capabilities of the MDM, ensuring it remains scalable, accurate, and aligned with evolving technological and business needs. Metering systems include the AMI and interconnected industrial meters.

MyAccount – The Company’s online customer portal, MyAccount, provides customers with the ability to view and pay bills, track daily and hourly energy usage, request service changes (start, stop, or transfer), and perform other account management functions. This tool will continue to be enhanced through modest, strategic investments, leveraging customer data from the Company’s underlying systems. In addition to its original purpose of providing customers with energy consumption and usage data to support informed energy decisions and promote energy efficiency, the portal now includes enhanced functionality for bill viewing and online payments. In 2025, the Company completed an integration with its payment vendor, enabling customers to make payments directly within the portal without being redirected to an external website. This improvement provides a more secure and seamless user experience. Customers can also access MyAccount through the Minnesota Power Outage Information and Reporting app.

Meter Asset Management – The Meter Asset Management module was implemented as part of the C2M project in April 2021. The purpose of this module is to enable the storage of specific attributes related to AMI meters. Due to the specific requirements related to AMI meters (firmware management, TOD schedules, load/voltage profile structure, etc.) and specific rate data

associated with managing AMI assets, Minnesota Power strategically included this additional functionality with the C2M implementation. The system is designed to deliver the necessary level of information to automate certain commands, including remote disconnect and reconnect functionality, as well as AMI system features integrated with the billing system. Additionally, it facilitates the verification of meter configuration and readiness for specific rate structures within the MDM system.

Outage Management System – The OMS manages the detection, location, isolation, repair, and restoration of faults which occur unexpectedly on the distribution system, in addition to managing planned distribution outages. It provides support to operators at all stages of the outage life cycle, starting from events--customer reports, AMI outage notifications, system status from EMS operations, and notification from the field crews--and concluding with the restoration of electric service. The OMS is the overall coordinator of all tasks, processes and record keeping associated with the resolution of distribution outages and is the single source for communicating outage information to internal and external stakeholders. Currently, Minnesota Power customers are able to view and report outage information through the Minnesota Power mobile application and through the Company website.

Minnesota Power implemented a new OMS application in December 2024. This project was a strategic approach to improve outage analysis, customer communication and crew response by leveraging a stronger connection with GIS and other support applications. These improved integrations generate more accurate outage predictions and foster a better user experience for the dispatchers using the system.

Website updates – Minnesota Power implemented several improvements to the website over the last year. Applications for new construction now have an online fillable form that makes it easier for customers to submit applications. The Company also made several customer service-focused improvements to the website for new customers, existing customers, and construction services.

ii. Operational Systems Overview

Geographic Information System/Utility Network Model – Minnesota Power has utilized a GIS for close to 30 years. Many operational systems at the Company reference or utilize the GIS system to provide geographical context to operational data. In 2020, Minnesota Power began to move to a next generation GIS system which integrates asset models from Generation,

Transmission, and Distribution systems to create a real-time Utility Network model. The new network will allow the Company to create a “digital twin” where the full electric system is modeled from generation to customer. As a result, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system. Moving to a more real-time GIS system will lower costs by removing some of the delays in current data integrations. This will allow staff to act on information faster and resolve issues in a more timely manner. The project to implement the new Utility Network will be completed at the end of 2025.

Energy Management System (“EMS”) – Minnesota Power has been utilizing an EMS for more than 45 years, with a full system replacement occurring in 1995 and periodic upgrades every few years since. The Company most recently upgraded the EMS as of February 2024. The upgraded product has enhancements to existing situational awareness tools that improve the operators’ visibility to real-time and state estimator data with improved alarm and event filtering capabilities. Currently, larger Minnesota Power-owned solar systems (greater than 1 MW) are centrally monitored and reported within EMS while smaller, distribution-connected solar is monitored with the AMI system. The backbone of a healthy distribution system is communication and system management. They work in conjunction with each other to improve how information is provided and gathered, resulting in more accurate restoration times, outage statistics, and improved usability. As the grid evolves and DER penetration increases, the Company will continue to monitor the effectiveness of its EMS and evaluate more sophisticated platforms including an advanced distribution management system and a distributed energy management system. These platforms are described in more detail in Section VII.

Work Management System – Minnesota Power uses Maximo for its work management system. This system is used for distribution work creation, tracking, and execution. There is also integration between Maximo and several other programs for inspections, audits, and entering service requests for issues identified in the field so they can be addressed in a timely manner. Preventative maintenance activities are also created in Maximo and asset history is tracked within the system hierarchy. All scheduling activities and tasks within a work order are also tracked with Maximo. Minnesota Power will continue to look for integration opportunities with other systems to provide additional value to customers.

DG Interconnection Portal – The Company implemented a new software solution in 2024 to help further streamline the DG interconnection process. Previously, interconnection applications

were submitted via email or mail and were manually tracked in excel spreadsheets by multiple departments within Minnesota Power. As the number of interconnection applications received per year increased, a more automated process was needed to reduce timelines, manage transitions between departments and provide transparency to customers and installers regarding the status of their application. The Company is currently deploying this tool to manage the workflow of other customer-facing interactions which will provide a more seamless process internally and externally.

V. DISTRIBUTED ENERGY RESOURCES

a. Programs and Background

Minnesota Power has a longstanding history of supporting customers with the adoption of distributed energy resources. Programs and rates encouraging energy efficiency, onsite renewables and demand response have been available to Minnesota Power customers for decades. These offerings have effectively supported early adopters and served a critical role in helping customers meet their energy goals. Distributed energy resources have also been viewed as a resource planning tool through the Company's IRP process. As participation in these programs has increased and the number of DERs on the system has grown, the role of DERs in distribution planning and operations is continuing to evolve.

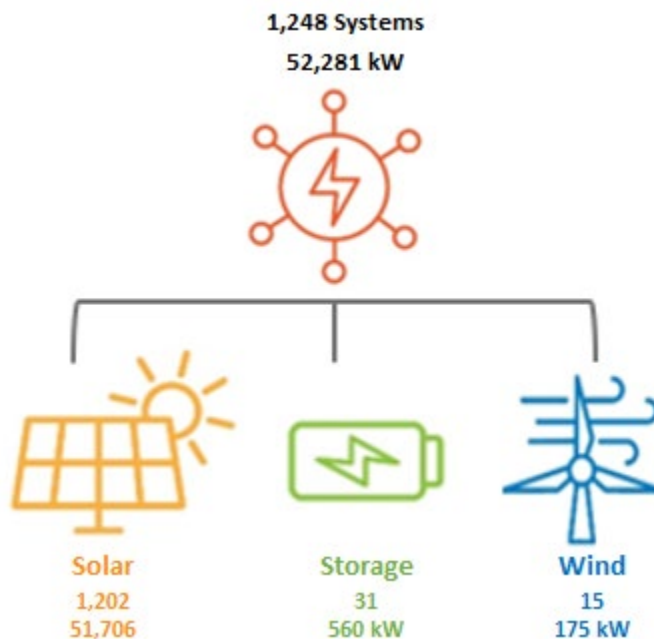
As outlined in the Commission's Notice Approving Updated Filing Requirements, the term distributed energy resource in this IDP refers to "supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers and can be installed on either the customer or utility side of the electric meter."¹⁷ For purposes of this filing, this may include distributed generation, energy storage, electrified end uses that can be used as a resource, demand side management, and energy efficiency. The sections below outline Minnesota Power's DER programs and initiatives.

1. Distributed Generation ("DG")

At the end of 2024, Minnesota Power had just under 1,250 DG systems connected to its distribution system, the majority of which were customer-sited solar as shown in Figure 4 below. This represents a relatively diffuse penetration of DG on the distribution system as a whole, but there are a few concentrated areas worth noting as outlined in Section V.B.

¹⁷ Docket No. E015/M-25-140, June 3, 2025.

Figure 4: Current DG Systems



Prior to 2013, the presence of distributed generation on Minnesota Power’s system was very limited with an average of 11 new interconnections per year. The passage of Minnesota’s Solar Energy Standard (“SES”)¹⁸ in 2013 spurred significant growth in the amount of solar on Minnesota Power’s system. The SES required 1.5 percent of a public utility’s retail sales, net of customer exclusions, to be served by solar energy resources by 2020. Of the 1.5 percent SES, at least 10 percent must be from solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kW or less (“Small Scale Carve-Out”). The SES statute was amended during the 2017 legislative session to increase the Small Scale Carve-Out of the SES from 20 kW or less to 40 kW or less for a public utility with between 50,000 and 200,000 retail electric customers which is applicable to Minnesota Power. Additionally, a provision was added to allow individual customer subscriptions of 40 kW or less to a community solar garden to count towards the utility’s Small Scale Carve-Out requirements.

In response to the SES, Minnesota Power developed a thoughtful solar strategy that included activities balanced across three key categories: Customer, Community and Utility. Minnesota Power continues to see larger, utility solar investments creating efficiencies and cost savings through economies of scale. However, programs that support customer and community adoption

¹⁸ Minn. Stat. § 216B.1691, Subd. 2f.

of small-scale solar were critical to compliance with the Small Scale Carve-Out of the SES and have served an important role in removing barriers to participation for early adopters.

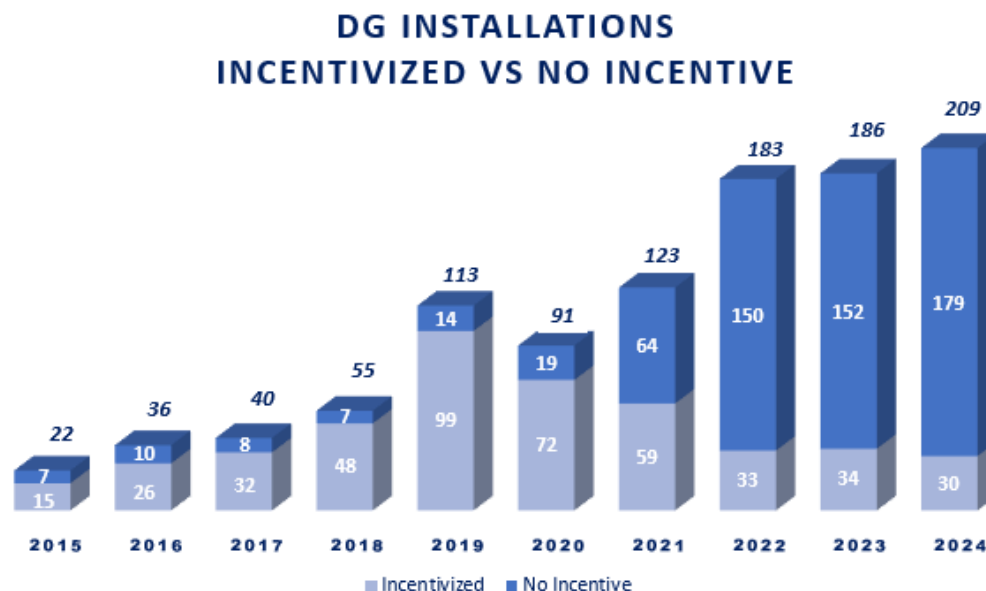
Customer Solar – Minnesota Power’s SolarSense program has been in place since 2004, well before Minnesota’s SES was enacted, and was expanded significantly in 2017 as a means of compliance with the Small Scale Carve-Out of the SES.¹⁹ The program expansion tripled the amount of funding available for customer-sited solar systems and established a solar program for income-qualified customers. The program played a critical role in driving early market adoption and supporting a budding solar installer market in northern Minnesota, with roughly 80 percent of all interconnections in Minnesota Power’s service territory receiving a utility rebate.

Through thoughtful and strategic planning, Minnesota Power successfully complied with the requirements of the SES Small Scale Carve-Out in 2020. In an effort to align the program with evolving industry trends including declining installation costs and a strong local solar installer network, the Commission approved SolarSense modifications for program years 2021 to 2024. These modifications included a reduced budget for customer-sited solar incentives and an increased budget for the Income-Qualified Solar Grant Program.²⁰ During that time, interconnection activity continued to grow, despite reduced rebate funding. Starting in 2021, roughly 52 percent of new solar interconnections were installed without a SolarSense rebate and that number continues to increase as illustrated in Figure 5. This shift suggests that rebates are no longer the primary driver of small-scale solar adoption in the region.

¹⁹ Docket No. E-015/M-16-485, February 10, 2017.

²⁰ Docket No. E015/M-20-607, December 17, 2020. This Order formally refers to this program as the Low-Income Solar Pilot Program.

Figure 5: Minnesota Power Incentivized DG Installations vs No Incentive



More recently, the Commission approved a three-year extension of the SolarSense program through 2027. The program extension modified the SolarSense program to have greater focus on increasing solar adoption among income-qualified customers by introducing an income cap of 150 percent of area median income and a preference for projects located in federally identified disadvantaged communities.²¹ The extension also applied to the Company's Income-Qualified Solar Grant Program budget. Since its inception, Minnesota Power's SolarSense program has supported 534 solar installations totaling nearly \$5.0 million in rebates.

Minnesota Power's most recent Distributed Generation Interconnection Report shows 209 new solar installations in 2024 compared to 186 systems in 2023 and 183 systems in 2022.²² Streamlining the interconnection process is essential to ensure timely, cost-effective integration of customer-sited generation while maintaining grid reliability and supporting broader clean energy goals. The interconnection process is described in more detail in Section V.B.

Community Solar – Many homes and businesses are not suitable to host a solar installation due to orientation, shading, structural issues or owner preferences. In those instances, a shared solar array positioned within a community may be a better alternative. The Company filed its voluntary Community Solar Garden Pilot Program ("CSG Pilot Program") with the Commission on

²¹ Docket No. E-015/M-20-607, January 8, 2025.

²² Docket No. E999/PR-25-10.

September 10, 2015, and received final approval of the program, tariff sheets and customer contracts on April 21, 2017.²³ The CSG Pilot Program was intentionally designed to provide flexibility and optionality for customers who wish to participate in solar programs but do not have a site that is well-suited for solar installation, or the upfront capital required to purchase solar panels for their homes.

The generation for Minnesota Power's CSG Pilot Program consists of a 1 MW solar array in Wrenshall, Minnesota and a 40 kW solar array on one of the most heavily trafficked thoroughfares in Duluth, Minnesota adjacent to Minnesota Power's Herbert Service Center. Construction of the 40kW array was completed in 2016 and the 1 MW array was completed in December 2017. Participating customers began receiving bill credits for the solar energy associated with their subscriptions in early 2018 and the program was fully subscribed by October of 2018.

Distributed Solar Energy Standard – As described above, the Company has met the requirements of the SES and is carefully considering the implications of the passage of the Distributed Solar Energy Standard.²⁴ The DSES represents the next phase of community-based solar policy in Minnesota, requiring that for a public utility with at least 100,000 but fewer than 200,000 retail electric customers in Minnesota, at least 3 percent of non-exempt retail electric sales must be generated from distributed solar systems by the end of 2030. Sales to industrial customers and large data centers in Minnesota must be subtracted from the utility's total retail electric sales for the purpose of calculating the DSES requirement. To be counted toward the DSES, a solar system must have a capacity of 10 MW or less, be connected to the public utility's distribution system, be interconnected within the Minnesota service territory of the public utility system and be procured or constructed after August 1, 2023.

The Commission issued an Order clarifying implementation of the Distributed Solar Energy Standard on June 26, 2024 ("DSES Order").²⁵ In the DSES Order, the Commission established that utilities shall file an RFP for DSES projects by November 1, 2024, subject to an affirmative checkoff by the Minnesota Department of Commerce ("Department"). Additionally, the Commission's DSES Order established that each utility shall convene a stakeholder workgroup to provide ongoing feedback to the utilities on a competitive bidding process used to solicit and evaluate DSES proposals. The Department filed a letter approving Minnesota Power's DSES RFP

²³ Docket No. E015/M-15-825.

²⁴ Minn. Stat. § 216B.1691, Subd.2h.

²⁵ Docket No. E-002,E-015,E-017/ CI-23-403.

on December 2, 2024, and the Company issued its first DSES request for proposals on January 30, 2025. Minnesota Power is currently evaluating proposals. The Company anticipates that 79,840 MWh, or roughly 45 to 55 MW, of additional distribution-connected solar energy will be needed by 2030 to satisfy the DSES.²⁶

Utility Solar - Minnesota Power continues to increase the amount of utility solar energy in its generation mix. The Company's first utility-scale solar project was a 10 MW distribution-connected solar array at Camp Ripley, the Minnesota National Guard base near Little Falls, Minnesota. At the time, this was the largest solar energy installation on military property in the state and the largest at any National Guard base in the country. The system was commissioned in 2016 and supplied roughly one third of the solar energy needed to comply with the state SES. The solar generation assets for the Camp Ripley Solar Project were originally financed through a lease agreement with a partner bank in order to fully utilize the Investment Tax Credits ("ITCs") to benefit ratepayers. The lease agreement includes an option for Minnesota Power to purchase the assets at the end of the initial ten-year lease term. The Company signaled its intention to eventually exercise this purchase option in the original petition and subsequent project and cost recovery filings, and on September 30, 2025, Minnesota Power filed a petition with the Commission seeking approval to exercise the purchase option at the end of the initial ten-year lease term. This Petition represents a cost-effective opportunity for the Company to take ownership of and continue to operate an important component of the Company's solar generation portfolio that continues to be in excellent operational condition. If approved, the Camp Ripley Solar Project will continue to contribute to compliance with the SES and future compliance with the CFS, while providing cost savings for solar-paying customers.

In 2020, the MPUC asked Minnesota utilities to expedite planned projects to help kick-start local economies affected by the COVID-19 pandemic.²⁷ As part of the Company's Economic Recovery filing the Commission approved the construction of three new solar projects in Minnesota Power's service territory: Laskin Solar, Sylvan Solar and the Jean Duluth Solar Project. The projects were energized in 2022 and 2023 and added 22.6 MW of solar energy to Minnesota Power's distribution system, satisfying the remainder of the Company's SES compliance obligations.

²⁶ The estimated DSES requirements stated in this IDP differs from the estimate of 50-70 MW as stated in the Company's February 8, 2024 filing in Docket No. E015/CI-23-403. The original estimate was based on customer exemptions for the SES, as DSES customer exemptions were not yet available. The DSES customer exemptions and an updated sales forecast provided a more refined outlook for 2030.

²⁷ Docket No. E,G 999/CI-20-492.

In January 2023, the Commission issued an Order approving Minnesota Power's 2021 Integrated Resource Plan, including order point 1b, which requires the Company to acquire at least 300 MW of regional/in-service territory or net-zero solar resources by 2026, as practicable. Solar projects selected through this RFP will be transmission-connected but will significantly increase the amount of large, utility-scale solar on Minnesota Power's system, bringing more renewable energy to Minnesota Power customers.²⁸

2. Load Management

Industrial Demand Response – Minnesota Power leads the state in the amount of Demand Response ("DR") as a percentage of peak demand, with approximately 230 MW of Midcontinent Independent System Operator ("MISO") accredited DR from the Company's large industrial customers. This represents approximately 15 percent of the winter peak demand. Minnesota Power is continually working to increase demand response beyond current levels. The Company continues to engage with its long-term industrial customers participating in demand response products.

Dual Fuel – In addition to DR programs for its largest customers that primarily impact the transmission system, Minnesota Power offers a Dual Fuel rate that allows the Company to curtail mainly heating load of approximately 8,000 residential, commercial, and small industrial customers during times of high market energy prices or to avoid a system peak. The Dual Fuel program was modified in Minnesota Power's 2021 general rate case to include two options: Dual Fuel Standard and Dual Fuel Plus.²⁹ Dual Fuel is an interruptible service rate initially designed primarily for electric heat that provides customers with a discount on their usage in exchange for occasional interruptions from Minnesota Power. Dual Fuel Standard offers a slightly lower discount for fewer interruptions while Dual Fuel Plus offers a deeper discount for customers who are able to accommodate more frequent and longer duration interruptions as shown in Figure 6.

²⁸ Docket No E-015/RP-21-33.

²⁹ Docket No: E015/GR-21-335, Peterson Direct and schedules.

Figure 6: Residential Dual Fuel Program Comparisons

COMPARE	DUAL FUEL STANDARD	DUAL FUEL PLUS
RATE	\$0.07989/kWh Service Charge: \$6.00/\$16.00	\$0.05584/kWh Service Charge: \$6.00/\$16.00
SAVINGS Compared to Standard Residential Rate \$0.10818/kWh	-\$0.02829/kWh	-\$0.05234/kWh
INTERRUPTIONS	• Can be interrupted two times per day up to four hours at a time. • Minimum two hours between any interruptions. • Maximum annual hours: 300	• Can be interrupted up to 20 hours per day. • Minimum two hours between any interruptions. • Maximum annual hours: 1,000
ONLY FOR ELECTRIC HEAT?	No	Yes
OVERVIEW	Flexible discounted rate that can be utilized for more than just electric heat.	Lowest cost way to electrically heat your home with appropriate heating and cooling system
BEST FIT FOR	Heating systems without automatic non-electric backup • Storage/Slab • Wood Heat • Fireplaces • Electric Vehicles • Water Heaters • Garages	Heating systems with automatic non-electric backup

Currently the Dual Fuel rate is applicable to many electric end-uses including electric heat, electric water heating, EV chargers, hydronic/resistive in-floor heat and more. Minnesota Power also offers a Dual Fuel Seasonal rate for customers with air source heat pumps (“ASHP”) used for heating and cooling. On this option, ASHP customers can forego interruptions in the summer months, so their air conditioning is not impacted.

Commercial customers are also eligible to participate in the Dual Fuel program. The participation details are shown in Figure 7 below.

Figure 7: Commercial Dual Fuel Program Rate Comparison

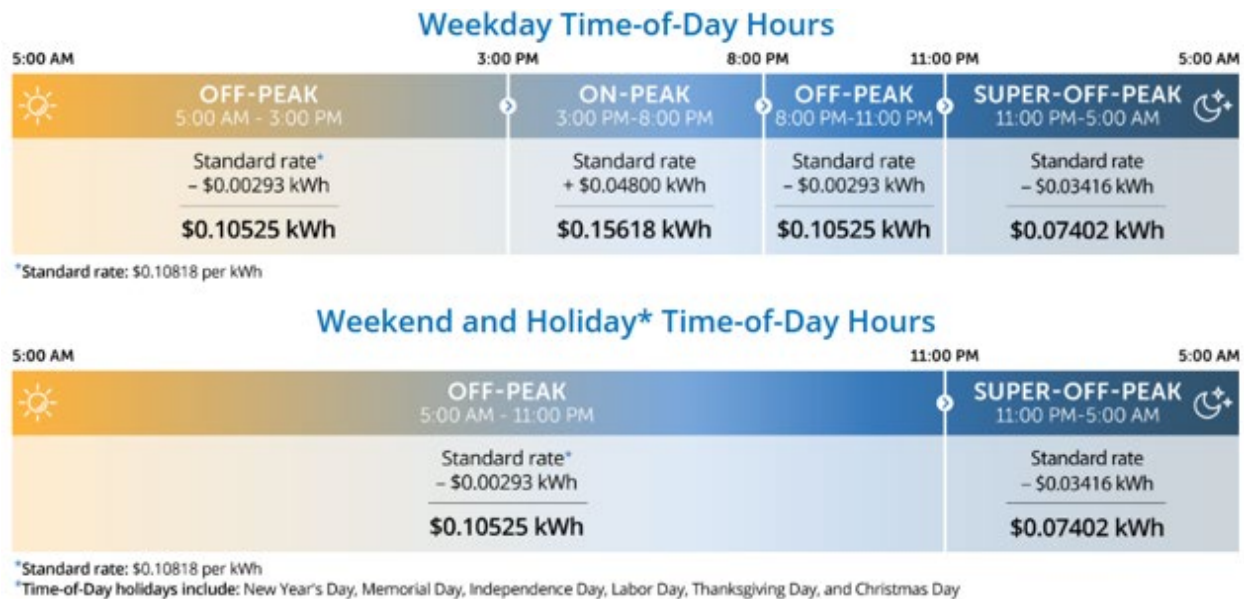
COMPARE	DUAL FUEL STANDARD	DUAL FUEL PLUS
SERVICE CHARGE Small	\$6	\$6
SERVICE CHARGE Large	\$16	\$16
RATE Small	\$0.07949	\$0.0551
RATE Large - Low Voltage	\$0.07949	\$0.0551
RATE Large - High Voltage	\$0.07812	\$0.0543
INTERRUPTIONS	• Can be interrupted two times per day up to four hours at a time • Minimum of two hours between interruptions • Maximum annual hours: 300	• Can be interrupted up to 20 hours per day • Minimum of two hours between interruptions • Maximum annual hours: 1,000
ONLY FOR ELECTRIC HEAT	NO	YES
OVERVIEW	Flexible discounted rate that can be utilized for more than just electric heat.	Lowest cost way to electrically heat your business with appropriate heating and cooling system

Since this program has historically focused on electric heat, there is minimal load to curtail in summer months – approximately 3 MW, mostly from commercial/industrial loads. The available curtailable load in winter months depends on temperature and heating loads, mostly from residential customers, but can deliver approximately 30 MW of DR, or roughly 2 percent of the winter peak load.

Time of Day Rates - Minnesota Power received approval to transition its residential customers from Inverted Block Rates (“IBR”) to TOD rates on August 27, 2021.³⁰ The final rate structure approved as part of this filing, which consisted of three TOD periods and an on-peak to super-off peak ratio of roughly 2:1, was the result of more than two years of collaboration with stakeholders and industry experts. The design took into account the Company’s unique electric system, industry best practices, and customer satisfaction and understanding. Figure 8 reflects the current residential TOD rates. While the rate itself has been updated since the original approval, the structure maintains its 2:1 price differential.

³⁰ Docket No. E015/M-20-850.

Figure 8: Time-of-Day Rates



After first transitioning customers to a flat rate, the Company began rolling out the approved TOD rate in phases. Customers that were selected as part of the treatment and control groups all had at least one year of usage data prior to being defaulted onto the rate to enable a more robust analysis and understanding of participant response rates to the price signals. Beginning in 2026, Minnesota Power plans to repeat this process with the rollout of phase three, where a new group of customers will be defaulted onto the rate and evaluated after twelve months. The results of the phase three evaluation will determine if the existing structure is achieving the intended results of shifting electricity usage or if additional adjustments are necessary.

The findings from the first two phases of the TOD rate transition can be found in the compliance filings submitted in the Company's residential rate design docket.³¹ The tables below reflect the average weekday impacts of the TOD rates by season and the system peak day impacts from phase two participants.

³¹ Docket No. E015/M-20-800.

Figure 9: Average Weekday Impacts Summarized by Season

Season	TOD Period	Observed kWh	Counterfactual kWh	Av. Impact	% Impact
Shoulder (Oct, Nov, Apr, May)	On-Peak	1.016	1.023	-0.007	-0.7%
	SOP	0.663	0.658	0.005	0.8%
Summer (June-Sept)	On-Peak	1.284	1.295	-0.011	-0.9%
	SOP	0.722	0.716	0.006	0.8%
Winter (Dec-Mar)	On-Peak	1.323	1.327	-0.003	-0.2%
	SOP	0.946	0.941	0.005	0.6%

These are preliminary results from a small group of participants. The impacts are currently nominal, and more evaluation is needed to determine the full potential of a default TOD rate and its associated value to the distribution system.

3. Energy Conservation

Energy Conservation is a critical component of Minnesota Power’s integrated planning strategy. The Company has a long history of highly successful energy conservation program achievements, meeting or exceeding the state energy savings goal each year since its inception in 2010. The Energy Conservation and Optimization Act (“ECO”), formerly referred to as the Conservation Improvement Program (“CIP”) was passed in 2021, increasing the energy savings goal from 1.5 percent to 1.75 percent and allowing for the inclusion of expanded customer offerings including efficient fuel switching and load management programs.³²

Between 2013 and 2024, Minnesota Power achieved an average of 74 gigawatt hours (“GWh”) in incremental (i.e. first year) annual energy savings, with achievements ranging from 64 GWh to 85 GWh. The Company achieved energy savings of more than 76 GWh in 2024.

Prior to 2017, Minnesota Power reported demand savings coincident with Minnesota Power’s system peak, which typically occurs in the winter. Between 2013 and 2016, peak demand savings resulting from the CIP programs ranged from 6 MW to 9 MW. Beginning in 2017, the Company was required to start reporting peak demand savings from CIP coincident with the MISO system

³² Minn. Stat. § 216B.241.

peak, which typically occurs in the summer. The average peak demand savings reported for 2017 through 2024 was 7.5 MW.³³

Both energy and demand savings are determined based on state-approved calculations and methodologies for pre-approved energy efficiency measures.

Table 2: Average Total Savings

	Reported MW Savings at Generator	Total MWh Savings	Percentage Savings
2013	5.72	77,631	2.5%
2014	9.22	76,338	2.5%
2015	7.23	85,611	2.8%
2016	9.49	64,034	2.1%
2017	8.59	72,372	2.6%
2018	8.10	72,480	2.6%
2019	8.34	67,669	2.5%
2020	6.81	70,774	2.6%
2021	6.83	74,539	2.8%
2022	8.20	76,400	2.9%
2023	7.07	73,589	2.8%
2024	5.94	76,583	3.0%

While the Company has a track record of exceeding the state's energy savings goal, the combination of unpredictable large business projects, changing baselines, economic uncertainty, and market saturation will make achieving higher levels of energy savings more challenging and costly in the future. At the same time, energy conservation remains a critical tool to help customers control costs considering rising energy rates. Minnesota Power remains committed to offering a robust and balanced ECO portfolio with programs designed to meet the needs of all customer segments.

Minnesota Power's next ECO triennial filing is expected to be submitted on June 1, 2026 and will outline the Company's ECO programs for the 2027-2029 program years. The Company is evaluating opportunities to expand on programs not historically offered or widely leveraged within

³³ The Company's Demand Side Management program provides end use load shapes. The load shapes developed through this program aid in determining the avoided marginal energy benefits of energy efficiency achievements.

its ECO portfolio like efficient fuel switching, load management and electric utility infrastructure. Additionally, Minnesota Power is exploring opportunities to build upon proven strategies and technologies like weatherization, heat pumps, trade ally engagement, and workforce development. The ECO program has long been an invaluable tool for helping customers manage their energy use and cost but with recent changes achieved through passage of the ECO Act, it has the potential to play a larger role in grid optimization going forward.

4. Electrification

For purposes of this filing, electrification refers to the conversion of an energy-consuming device, system, or sector from non-electric sources of energy to electricity. While the impacts of electrification have been minimal to date, the Company anticipates increasing customer energy tied to electrification and plans for the load accordingly. Until 2021, the state of Minnesota had a fuel switching prohibition within its conservation program, which prevented utilities from claiming savings for projects that encouraged customers to switch from one fuel type to another (e.g., propane to electricity). As described above, the passage of the ECO Act in 2021 made significant changes to the existing program, including the addition of a framework for utility efficient fuel switching (“EFS”) programs. The ECO Act was further refined in 2024 to ease the administrative requirements associated with EFS programs.

Despite historical fuel switching limitations, Minnesota Power has worked hard to increase the amount of heat pumps installed within its service territory for many years. A heat pump is a highly efficient system that transfers heat rather than generating it, allowing it to provide both heating and cooling for buildings. Heat pumps are a tool for electrifying heating and cooling loads, which account for roughly 45 percent of a home’s energy use.³⁴

The Minnesota Air Source Heat Pump Collaborative (“ASHP Collaborative”) was established in 2019 with a goal of promoting ASHP adoption across the state, especially in greater Minnesota where the technology can provide significant savings for homeowners with delivered fuel heating systems. The ASHP Collaborative is implemented by the Center for Energy and the Environment, administered by the Department of Commerce and funded by eight utilities, including Minnesota Power. The ASHP Collaborative focuses on promoting heat pumps through trade ally engagement, installation best practices, and consumer awareness and messaging. Minnesota

³⁴ Center for Sustainable Systems, University of Michigan. 2024. “Residential Buildings Factsheet.” Pub. No. CSS01-08.

Power leverages resources from the ASHP Collaborative to engage with manufacturers and distributors throughout northern Minnesota to ensure that heat pumps are readily available and contractors are trained in installation best practices. The Company also has a robust program for Heating, Ventilation, and Air Conditioning (“HVAC”) contractors to encourage installation of energy-efficient, electric heating sources with a primary focus on ASHPs. There are roughly 160 contractors currently enrolled in the program.

As shown in Table 3 below, Minnesota Power has provided rebates for nearly 2,800 ASHPs within the last five years. While many of these heat pumps were installed in homes with an existing electric heat source, some were installed in homes with other heating fuel types. In these scenarios, the rebate and related energy savings were specific to air conditioning provided by the ASHP. However, the Company assumes that in most instances, the ASHP is also being used for heating, meaning that the figures below represent a combination of energy efficiency and electrification.

Table 3: Air Source Heat Pumps Rebated 2020-2024

Measure	2024	2023	2022	2021	2020	Total
ASHP - Ducted	134	82	50	38	36	340
ASHP - Ductless	410	228	244	417	309	1,608
ASHP - Ductless - Cooling Only	6	127	152	152	0	437
Ground Source Heat Pump	24	22	17	15	7	85
Heat Pump - Cooling and Heating	97	36	72	63	55	323
Total	671	495	535	685	407	2,793

Minnesota Power plans to submit a modification to its current ECO portfolio to add an EFS program by the end of 2025. If approved, Minnesota Power customers without an electric baseline will be eligible for rebates on the following equipment:

- Air to Water Heat Pumps
- Air Source Heat Pumps
- Desuperheaters
- Electric Vehicles
- Electric Bicycles
- Ground Source Heat Pumps
- Heat Pump Water Heaters

- Outdoor Lawn Equipment

These will be the first EFS measures offered through Minnesota Power's ECO portfolio. The Company will include information about participation in the EFS program in future IDPs when the measures are available to customers.

5. *Electric Vehicles*

Adoption of electric vehicles is relatively minimal in northern Minnesota. Minnesota Power customers have indicated in surveys that range anxiety, lack of public charging infrastructure, and the upfront cost of the vehicle are of particular concern when considering EV adoption. These considerations are especially relevant in the Company's service territory, where lack of charging infrastructure could result in significant safety concerns for EV drivers, especially during the winter months when EV range is reduced by cold temperatures. The Company monitors both publicly available data and participation in its own programs and tariffs to gauge customer adoption rates of EVs. According to vehicle registration data published by the Minnesota Public Utilities Commission on July 7, 2025, there are 1,105 electric vehicle owners in Minnesota Power's service territory, 730 of which are battery electric vehicles ("BEV") and 375 are plug in hybrid electric vehicles ("PHEV").³⁵ Additionally, Minnesota Power estimates there are about 825 light-, 22 medium-, and 9 heavy-duty EVs in Minnesota Power's retail service territory, detailed more in Section V.C. According to a dashboard published by Atlas Public Policy, there are 74 public EV charging stations in Minnesota Power's service territory, with 134 level 2 and 88 level 3 charging ports.³⁶ Minnesota Power is currently working to expand the availability of public chargers in northern Minnesota through its direct current fast charger ("DCFC") project, which is described in Appendix E.

Minnesota Power currently offers three rates specific to EV charging. Participation in these programs is described in Table 4 below. The figures shown in this table are for the reporting period May 1, 2024 to April 30, 2025 and are included in Minnesota Power's June 2, 2025 compliance filing in Docket No. E015/M-15-120. Information about peak demand and the time of occurrence is also included in the compliance filing on a site-specific basis.

³⁵ <https://mn.gov/puc/activities/economic-analysis/electric-vehicles/>.

³⁶ <https://atlaspolicy.com/evaluatemn/>.

Table 4: Minnesota Power EV Rates

	Number of Participating Customers	Energy Consumed (kWh)
Residential EV Service Rate	64	277,460
Fleet EV Rate	1	34,327
Public EV Rate	21	1,655,966

As EV adoption in Minnesota Power’s service territory is still relatively minimal, there have not been significant distribution upgrade costs specific to accommodate EV charging. In 2024, Minnesota Power did not incur any system upgrade costs specific to EV charging outside of its DCFC project. The Company began tracking EV upgrade costs paid by customers separately in 2025. The Company will report on this information in future IDPs as more data is available. More information about the Company’s electric vehicle programs is included in Appendix E.

b. DER Interconnection Process

The interconnection of distributed energy resources operating in parallel to the distribution system requires careful consideration and cross functional coordination to ensure safe, reliable integration of those systems. Increasing customer demand and technological advancements drive the need for constant evaluation of technical requirements and delivery processes. Minnesota Power has continually worked to meet customer and regulatory expectations related to the interconnection process.

In recent years, Minnesota Power has worked with the Distribution Generation Working Group (“DGWG”) to update the Minnesota Distributed Energy Resources Interconnection Process (“MN-DIP”) to compile technical standards that apply to various types of interconnections. In general, the MN-DIP process has provided an updated and transparent set of guidelines and requirements for interconnection of DERs and has been well-received by customers and installers in Minnesota Power’s service territory. In recent years, the Company has seen an increase in the number of interconnection applications received and a trend of larger system sizes. As a result of this rising demand, Minnesota Power continues to monitor and streamline internal processes. In 2024 Minnesota Power implemented an online application portal for installers and customers to provide

increased communications automation, track applications, and generally streamline the interconnection process both internally and externally.

In January of 2024, the Minnesota Technical Interconnection and Interoperability Requirement (“TIIR”) went into full effect after the Commission gave notice that advanced inverters had become readily available. The TIIR outlines DER interconnection requirements that are common across all Minnesota utilities. In addition to the TIIR, each utility developed their own Technical Specification Manual (“TSM”) in which specific standards were outlined for new interconnection. The Company continues to evaluate the benefits of smart inverters, as described in the following section, to determine how they should be addressed in the TSM. Additionally, Minnesota Power now requires all DER with a nameplate capacity of 1,250 kW or greater to be remotely monitored so that these systems can be incorporated into the EMS (and eventually ADMS, if applicable) models. Monitoring larger installations will be crucial as DER penetrations increase, and more visibility is required to safely operate the distribution system.

Minnesota Power tracks system upgrade costs to gain an understanding of total DER installation cost. These costs are estimates of the actual time and material spent as there are many inputs that are not perfectly captured through current tracking methodology. Non-Minnesota Power investments in distribution upgrades total \$550,399.37 in the past five years. Additionally, Minnesota Power began charging an application fee for all applicable solar installations on June 17, 2019 in accordance with the MN-DIP. Tables 5 and 6 summarize cost data collected for 2024.

The upgrade fees received from customers in 2024 were \$69,048 compared to actual costs of reported projects of \$85,367. The difference of \$16,321 may be explained by sites that had a mixture of MP costs and customer costs associated with specific upgrades.

Table 5: Minnesota Power Costs (interconnection)

Minnesota Power Costs (interconnection)		
Area	2024	Cost descriptions
Metering	\$41,026	Application review, field work
Interconnection Coordination	\$116,653	Application processing, inquiry response, incentive admin
Distribution	\$5,124	Application review, field work

Table 6: Customer Costs (interconnection)

Customer Costs (interconnection)		
Area	2024	Cost descriptions
T&D- Asset	\$69,048	Upgrade work
Applications	\$26,322	Application fees

1. Institute of Electrical and Electronic Engineers (“IEEE”) Std. 1547-2018 Impacts

Minnesota Power closely monitors advances in inverter technology as governed by IEEE 1547 via participation in the Commission’s Distribution Generation Working Group, conversations with customers and installers, and various other industry groups. Since filing the 2023 IDP, Minnesota Power has not filed any updates to its Technical Specifications Manual. Minnesota Power currently requires inverters to be set at a fixed absorbing power factor of 0.98 and requires volt-watt activation to be disabled. This requirement was not changed with the arrival of advanced inverter technology, as the impact of such technology is not fully understood. To avoid impacts to customers, Minnesota Power has been studying inverter changes with caution. The Company anticipates that it will update its Technical Specification Manual to allow dynamic power factors—providing clearer sample configurations for interconnecting customers and define standards for connecting single-phase inverters to three-phase systems.

While Minnesota Power’s overall DER penetration level is still relatively low, there are a handful of feeders and substations on which the penetration is high relative to the load. Minnesota Power presently has a total of five feeders or substations—Blanchard Substation, Wrenshall Substation, Platte River 546 feeder, Laskin Substation, and Baxter Substation—which have DER installations with a generation nameplate capacity greater than or equal to the feeders’ or substations’ daytime minimum load. The Blanchard Substation, which includes the 10 MWac Camp Ripley solar facility and 18 MWac Blanchard Hydro Electric Station, has a 2024 daytime minimum load of 7.74 MW. The Wrenshall Substation, which includes the 1.00 MWac Wrenshall solar garden, has a 2024 daytime minimum load of 0.90 MW. The Platte River 546 feeder circuit includes three large customer-installed solar arrays with an aggregate nameplate output of 1.75 MW. This feeder has an estimated 2024 daytime minimum load of 0.1MW. The Laskin Substation, which includes the 5.6 MWac Laskin solar facility, has a 2024 daytime minimum load of 0.94 MW. The Baxter Substation, which includes the 15.2 MW Sylvan solar facility, has a 2024 daytime minimum load of 3.25 MW.

Over the years, Minnesota Power has experienced a number of relatively small issues related to customer solar installations. Recently, there have been more instances where upgrades to service transformers or secondary conductors were necessary. These upgrades are a result of customers adding larger systems or multiple customers served by the same service transformer adding DERs. These upgrades have been minor and are to ensure the local electric system could handle increased power flows or to ensure voltage levels were within American National Standards Institute (“ANSI”) standards at the point of common coupling. Since the 2023 IDP filing, there have not been any system upgrades necessary to solve harmonics or other non-conventional problems. Furthermore, to date, no known instances of an unintentional island caused by inverter-based resources involving more than one customer have occurred on Minnesota Power’s electric distribution system. The Company views these positive outcomes as an indication that utilizing a cautionary approach with inverter-based generation has allowed impacts from this new generation to remain positive for Minnesota Power’s customers.

As inverter-based DER penetration continues to increase, however, Minnesota Power anticipates seeing these types of issues (harmonics and/or unintentional islands), particularly on feeders with dense customer counts and dense small-scale inverter-based DER counts. Most of these issues should be solved with a transformer or service conductor upgrade for small-scale inverter systems. Larger installations, however, may require upgrades to mitigate these types of problems. Issues involving harmonics can be mitigated by lowering the system impedance at its connection point. Issues involving unintentional islands can be solved using transfer-trip schemes. If such problems arise, they will be solved by a thorough investigation as to how best mitigate or eliminate the problem with the least impact to customers.

Some of the larger installations already have additional isolation devices installed at the point of common coupling. A few of these installations (typically larger than 1,000 kW) are equipped with communications to the rest of Minnesota Power’s distribution network, to ensure that if there is a fault on a feeder with high DER penetration, the feeder will not island after the head of feeder protective device operates.

Processes and tools continue to evolve as the DER landscape changes. Over the past two years more exploratory pre-application report requests have been received than ever before and the Company anticipates that the demand for DER (especially large-scale solar) will increase, further impacting planning resources and the tools employed.

c. DER System Impacts and Benefits

Minnesota Power continues to investigate DER options as part of its broad utility planning process to consider non-wires alternatives. Applications such as solar and storage continue to be explored in this broad planning effort. The opportunities are considered in collaboration with the Company's resource, transmission, and distribution planning teams.

As these alternatives begin to demonstrate broader application for the system, it will be necessary to integrate and provide visibility through software, tools, and communication infrastructure. The Company will provide a general overview of current impacts and benefits in the sections below.

1. EV Impacts

Electric vehicles present vast potential benefits for most utilities. However, if the charging infrastructure is unmanaged, it has the potential to cause costly impacts to the distribution system. For example, customers installing Level 2 home charging equipment, with about 10 kW of load, can put stress on transformers or cause line voltage issues. This is particularly true if many homes begin installing chargers and then charge at the same time. However, if monitored through AMI and/or smart chargers, these loads could be managed effectively. With the current penetration level of EVs in Minnesota Power's service territory, the Company has not experienced any of these issues to date. The Company encourages and incentivizes customers to install smart chargers, which can be effectively utilized in conjunction with off-peak EV rate structures. In addition, utilities, in general, must continue to develop internal expertise, software systems, and protocols for engaging with these new DERs. As EV markets are still evolving, Minnesota Power continues to work closely with industry partners and service providers to propose and implement the most cost-effective, reliable, and affordable EV management and optimization tools possible. There are additional potential benefits related to EVs as they gain the ability not only to charge, but to discharge onto the system. This is an emerging area that will require significant investment in regulations, software platforms, charging equipment, and equitable rate structures. Minnesota Power, as highlighted in previous sections, is taking the first steps to provide a base for new rate structures and customer interactions through its internal EV efforts, system integrations and C2M implementation.

2. Solar PV Impacts

Solar is being deployed on widely varying scales from streetlights to utility scale power plants. It offers many values to the distribution system while also presenting some challenges. The value

of small-scale solar is that it may offer resiliency to the system if deployed in a distributed manner. Geographically dispersed solar arrays avoid taking large amounts of generation offline during various meteorological events like cloud cover and storms. In addition, during outages, geographically dispersed and well-designed distribution systems may be able to isolate and repower sections not directly affected by system outages. For example, a solar powered retail center or housing development with battery storage may be designed to isolate itself during an outage event. The potential cost and benefits of these systems still require many resources and extensive research to determine the best path forward and socialized benefits have yet to be well defined.

The cost and benefits of any programmatic planned system wide deployment of solar will require ongoing analysis with input from many stakeholders. The cost of deploying small-scale solar arrays for specific segments of the distribution system versus larger centralized solar plants must be weighed against the benefits of having generation sources closer to load centers along with initial capital costs, ongoing fleet maintenance and operational costs. The benefits are not currently well understood on a case-by-case basis for most utilities. Ongoing investigations through stakeholder feedback and working groups such as the DGWG while reviewing benefits from a system and customer perspective pertaining to system upgrades, interconnection processes, and cost-sharing will help in clarifying these costs and benefits.

The primary technical concern with distributed solar PV is the potential for reverse power flow at the feeder-level. Historically, the distribution system has been designed for unidirectional power flow from the substation breaker to consumer loads. Bi-directional and reverse power flow conditions could negatively impact feeder voltage and system equipment that has been designed for, and is protected by schemes designed for, unidirectional flow. For individual DER installations, the potential impacts are examined during the interconnection process. The Company has already experienced some system impacts from small-scale solar installations, such as having to modify regulator settings on a feeder to account for a potential reverse power flow condition. Increasing penetration levels over the planning horizon will likely result in more feeders with reverse power flow conditions. Future mitigation options may include utilizing advanced inverter options.

3. Battery Storage: Number of Units and Ratings

There is currently one distribution level battery energy storage system (“BESS”) in development on the Company’s distribution system. The Company is implementing a 2.5 MW/5 MWH battery

energy storage system near Kerrick, MN as discussed in Section VII.B. Site development is ongoing and all major equipment should be installed in 2025.

While Minnesota Power customers install battery energy storage systems behind the meter, these BESS do not export energy to the utility grid. The Company tracks the installation of BESS through the interconnection process and records the kWh capacity of those systems. Thirty systems, ranging from 3.5 – 108 kWh, have been interconnected as of year-end 2024.

4. Barriers to DER Integration

At present there are few incentives for utilities and businesses to work together on a holistic system-wide approach to DER integration. While the cost of solar has decreased significantly in the last decade, policies to incentivize solar like net metering still make new DER developments cost effective for most customers. For example, one barrier to DER integration is the high cost of entry. Developers and customers who want to interconnect to the distribution system bear all costs for upgrades required to accommodate the proposed interconnection. Because of this, there may be some developers or customers who choose not to pursue interconnection. Conversely, policies designed to incentivize DERs, like net metering, shift system costs to non-participating customers including those that do not have the ability or interest to install DERs directly. Extended timeframes for program development and technology implementation are also barriers to deployment. An example is the Company's modernized metering infrastructure. Now that the AMI rollout is complete, the Company continues to evaluate the many potential benefits and programs enabled by advanced metering. Development costs tend to be high for these types of programs. Along with this, how various DER technologies like wind, solar, EVs, and storage will all work in tandem on the grid will require significant analysis, planning and stakeholder interaction.

Federal Energy Regulatory Commission Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) – Federal Energy Regulatory Commission ("FERC") Order No. 841 established reforms to remove barriers to the participation of electric storage resources in the Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") markets. FERC found that RTO/ISO market rules employed obstacles for electric storage resources to participate in the market. An excerpt from the Order follows:

“direct[s] regional grid operators to remove barriers to the participation of electric storage in wholesale markets. By directing the regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage,

the Order affirms that storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other energy resources. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs.”

Minnesota Power generally supports FERC Order 841 in regard to transmission level storage assets. However, the Company has reservations regarding the treatment of distribution-connected battery storage and DERs. The ability of electric storage resources to participate in the wholesale market at the distribution level and behind the meter will have implications for local distribution operators. In particular, the provision of Order 841 that encompasses DER resources, not just battery storage, is problematic. There are metering, operational, and wholesale market issues that arise due to the possible participation of DERs in wholesale RTO or ISO markets.

d. DER Forecasting and Scenario Analysis

Minnesota Power’s 2025 Annual Forecast Report (“AFR”) includes assumptions for residential and commercial adoption of distributed energy resources. The 2025 AFR’s forecast methodology for DERs and resulting decrease or increase in Minnesota Power sales are described below.

Distributed Generation Forecast – New DG Solar installations were projected using the U.S. Energy Information Administration’s forecast for distributed solar generation. This outlook for the number of new installations is combined with assumptions for the sizing (kW capacity) of those new installations, an expected capacity factor, and seasonal production characteristics to produce estimates of monthly energy production and peak reduction. The energy sales and peak demand forecasts are only adjusted for new installations (i.e. installations expected to come online in the forecast timeframe). The effects of currently installed DG systems are presumed to be embedded in the forecast.

- **Base Case** – The Company’s Base Case forecast assumes about 4,180 new small-scale DG Solar installations, adding almost 46,000 KW of nameplate capacity, which will be connected to Minnesota Power’s distribution system by 2039 (i.e. installed in years 2025-2039). These new installations would generate about 46,000 MWh per year and reduce sales to residential and commercial sectors by an equivalent amount. The Base Case forecast assumes cumulative capacity expands at a 21.6 percent compound annual growth rate (“CAGR”) from 2025 to 2039.

- Medium Case – The Medium DER scenario applies a ten percent growth rate to the Base Case’s cumulative capacity and results in an overall cumulative small-scale solar capacity CAGR of about 22.4 percent from present installed capacity to projected 2039 capacity.
- The High DER scenario applies a 25 percent growth rate to the Base Case, resulting in a CAGR of about 23.4 percent over the same period.

The outlooks for new DG Solar installations are shown in Figure 10 and Figure 11. Figure 10 shows the projected reduction in annual sales due to new distributed solar, and Figure 11 shows the predicted reduction in Minnesota Power’s summer peak resulting from coincident solar generation. Existing DER capacity located on Minnesota Power’s system is taken into consideration in both the state planning processes, such as IRPs, and the MISO’s resource adequacy module (Module E-1). Minnesota Power accounts for existing DERs at the system level by factoring them into the load forecast by reducing customer demand based on historical DER usage or product (such as distributed solar generation).

Figure 10: Distributed Solar Generation (MWh)

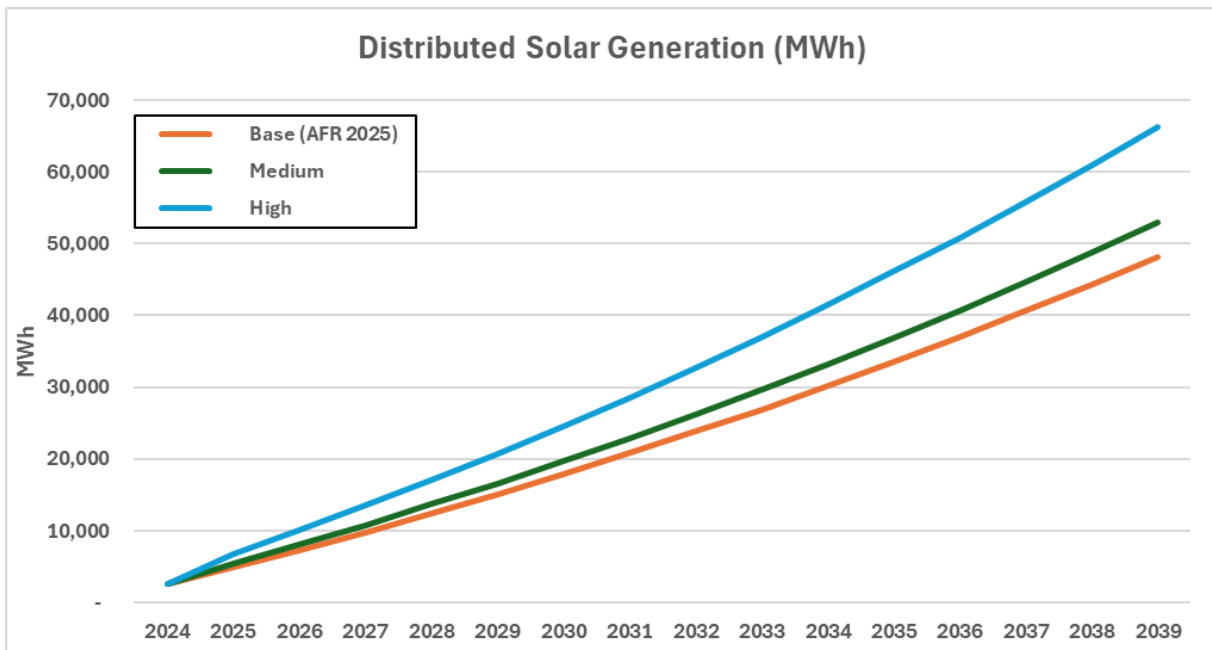


Figure 11: Distributed Solar Generation (Summer Peak)

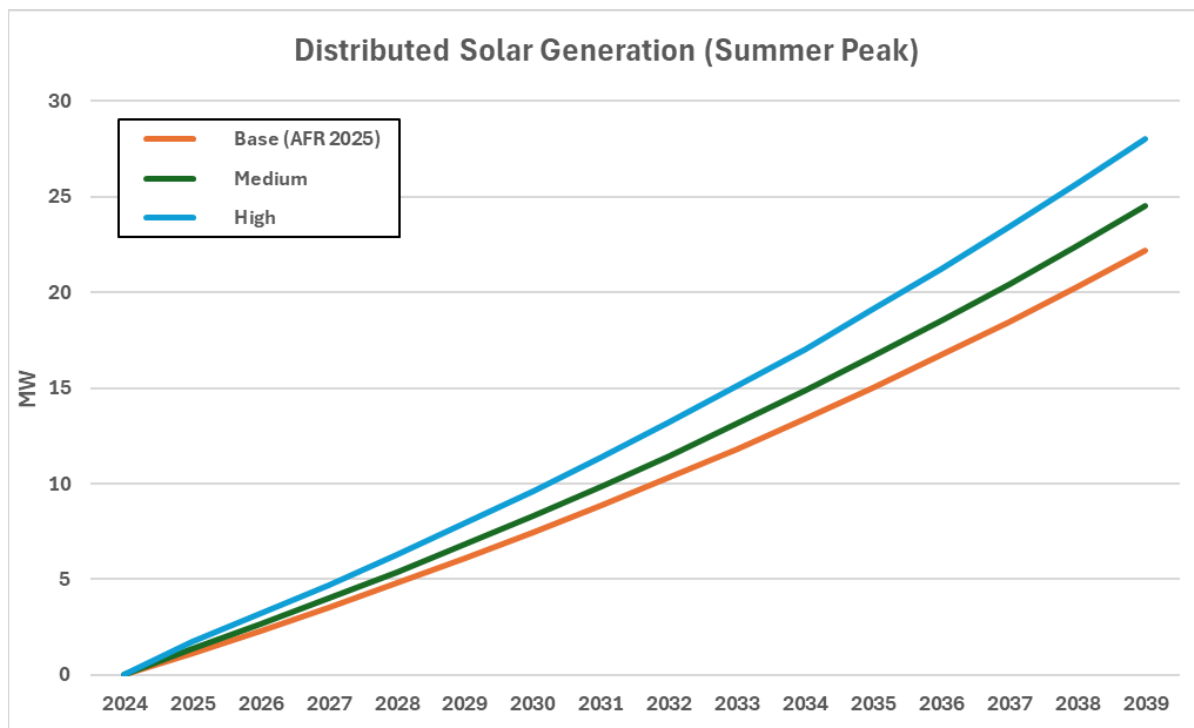


Table 7: DG Solar Capacity (MW)

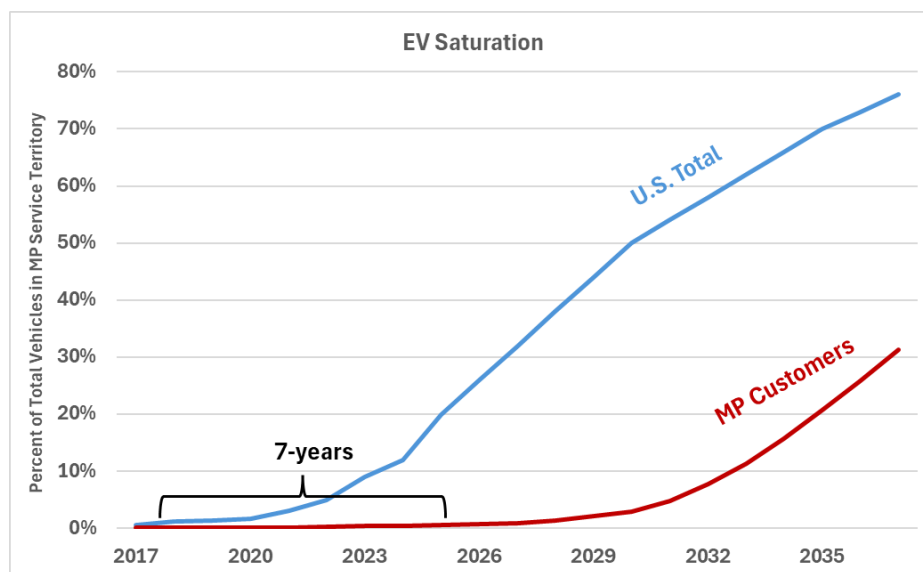
DG Solar Capacity (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base (AFR 2025)	2.6	4.9	7.4	9.9	12.5	15.2	18.1	21.0	24.0	27.2	30.4	33.8	37.3	41.0	44.7	48.6
Medium	2.6	5.4	8.1	10.9	13.8	16.8	19.9	23.1	26.4	29.9	33.5	37.2	41.1	45.1	49.2	53.5
High	2.6	6.2	9.2	12.4	15.7	19.1	22.6	26.2	30.0	34.0	38.0	42.3	46.7	51.2	55.9	60.8

Light-, Medium- and Heavy-Duty Electric Vehicle Forecast – Minnesota Power recognizes the load growth that could result from this electric end-use and has incorporated an outlook for Electric Vehicle adoption into the residential and commercial energy sales and peak demand forecasts. The Company projected residential passenger EV (light-duty vehicle) adoption based on a national-level outlook that has been scaled to the Minnesota Power region. The energy and demand requirements of EVs adopted in the forecast timeframe (2025-2039) are added to the energy sales and peak demand outlooks. The effects of currently owned EVs are presumed to be embedded in the econometric forecast. The Company also estimates there are about 825 light-, 22 medium-, and 9 heavy-duty EVs in Minnesota Power’s retail service territory. This equates to a 0.4 percent market share for all light-duty vehicles in MP service territory, 0.3 for medium-duty, and 0.4 percent market share for heavy-duty vehicles. This level of vehicle ownership translates

to an estimated 3,262 MWh of annualized energy consumption and represents 0.15 percent of all residential and commercial energy sales.

In its Base case, the Company projects that, by late 2039, EVs will consist of approximately 43 percent of regional vehicle ownership across all weight classes, and Minnesota Power will be the primary electric service provider to about 95,400 EVs. This equates to about 395,000 MWh in additional energy requirements from the residential and commercial sectors and an estimated increase of 44 MW and 131 MW in the summer and winter peaks (respectively).

Figure 12: Base Case EV Saturation



This outlook assumes Minnesota Power customers' EV penetration and adoption continues to lag the overall trend in the United States by about seven years, as shown in Figure 12. The Company attributes this lag in adoption to a variety of factors discussed in Section V.A. While Minnesota Power customers may "catch-up" to the rest of the country in EV adoption naturally, the Company has taken an active role in helping to support the adoption of the electric vehicle market. Refer to the Company's 2025 AFR for more detail on the base case scenario forecast or for a complete description of the methodology and data sources used to develop the outlook.³⁷ The Medium and High EV scenarios differ from the Base Case outlook. In the Medium and High EV scenarios, Minnesota Power's assumed light-, medium- and heavy-duty EV adoption grows at 10 percent and 25 percent over the Base Case's growth respectively.

³⁷ Docket No. e015/AA-24-64.

Table 8: Electric Vehicle Saturation

Base Case (000s)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	0.82	1.14	1.48	1.98	2.89	4.36	6.30	10.04	16.23	24.14	33.45	43.85	54.97	66.24	78.75	90.74
Medium Duty	0.02	0.03	0.04	0.06	0.07	0.11	0.16	0.24	0.38	0.61	0.90	1.25	1.64	2.04	2.48	2.95
Heavy Duty	0.01	0.01	0.02	0.02	0.03	0.05	0.07	0.10	0.17	0.25	0.35	0.45	0.57	0.68	0.81	0.94

Medium Case (000s)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	0.82	1.25	1.62	2.18	3.18	4.80	6.93	11.04	17.86	26.56	36.80	48.24	60.47	72.86	86.63	99.81
Medium Duty	0.02	0.03	0.05	0.06	0.08	0.12	0.18	0.26	0.41	0.67	1.00	1.38	1.81	2.25	2.73	3.24
Heavy Duty	0.01	0.01	0.02	0.02	0.03	0.05	0.07	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0

High Case (000s)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	0.8	1.4	1.8	2.5	3.6	5.5	7.9	12.5	20.3	30.2	41.8	54.8	68.7	82.8	98.4	113.4
Medium Duty	0.02	0.04	0.1	0.1	0.1	0.1	0.2	0.3	0.5	0.8	1.1	1.6	2.1	2.6	3.1	3.7
Heavy Duty	0.01	0.01	0.02	0.03	0.04	0.1	0.1	0.1	0.2	0.3	0.4	0.6	0.7	0.9	1.0	1.2

Figure 13: Electric Vehicles in MP Service Territory

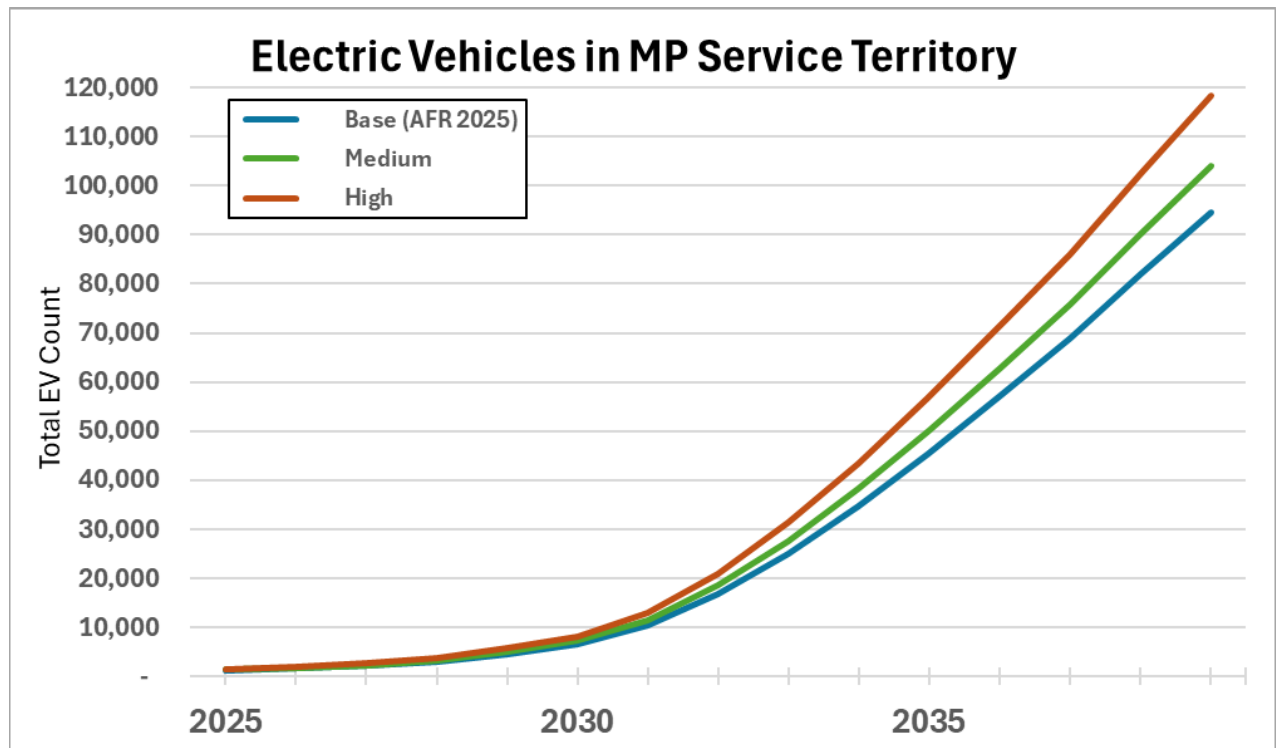


Table 9: Electric Vehicle Energy Consumption

Base Case (GWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	2.3	3.2	4.1	5.6	8.1	12.2	17.6	28.1	45.5	67.6	93.7	122.8	153.9	185.5	220.5	254.1
Medium Duty	0.1	0.2	0.3	0.3	0.4	0.7	1.0	1.4	2.3	3.7	5.4	7.5	9.9	12.3	14.9	17.7
Heavy Duty	0.8	1.1	1.5	2.0	2.9	4.4	6.3	10.0	16.2	24.1	33.4	43.8	54.9	66.2	78.7	90.6
Total	3.3	4.5	5.9	7.9	11.4	17.2	24.9	39.6	63.9	95.4	132.5	174.1	218.7	263.9	314.0	362.4

Medium Case (GWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	2.3	3.5	4.5	6.1	8.9	13.4	19.4	30.9	50.0	74.4	103.0	135.1	169.3	204.0	242.6	279.5
Medium Duty	0.1	0.2	0.3	0.4	0.5	0.7	1.1	1.6	2.5	4.0	6.0	8.3	10.8	13.5	16.4	19.5
Heavy Duty	0.8	1.2	1.6	2.2	3.2	4.8	6.9	11.0	17.8	26.5	36.8	48.2	60.4	72.8	86.5	99.7
Total	3.3	5.0	6.4	8.7	12.6	18.9	27.4	43.5	70.3	104.9	145.8	191.5	240.6	290.3	345.5	398.6

High Case (GWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Light Duty	2.3	4.0	5.2	6.9	10.1	15.3	22.1	35.1	56.8	84.5	117.1	153.5	192.4	231.8	275.6	317.6
Medium Duty	0.1	0.2	0.3	0.4	0.6	0.8	1.2	1.8	2.8	4.6	6.8	9.4	12.3	15.3	18.6	22.1
Heavy Duty	0.8	1.4	1.8	2.5	3.6	5.4	7.9	12.5	20.3	30.1	41.8	54.8	68.6	82.7	98.3	113.3
Total	3.3	5.6	7.3	9.8	14.3	21.5	31.2	49.4	79.9	119.2	165.6	217.6	273.4	329.9	392.6	453.0

Figure 14: Cumulative New EV Energy Consumption

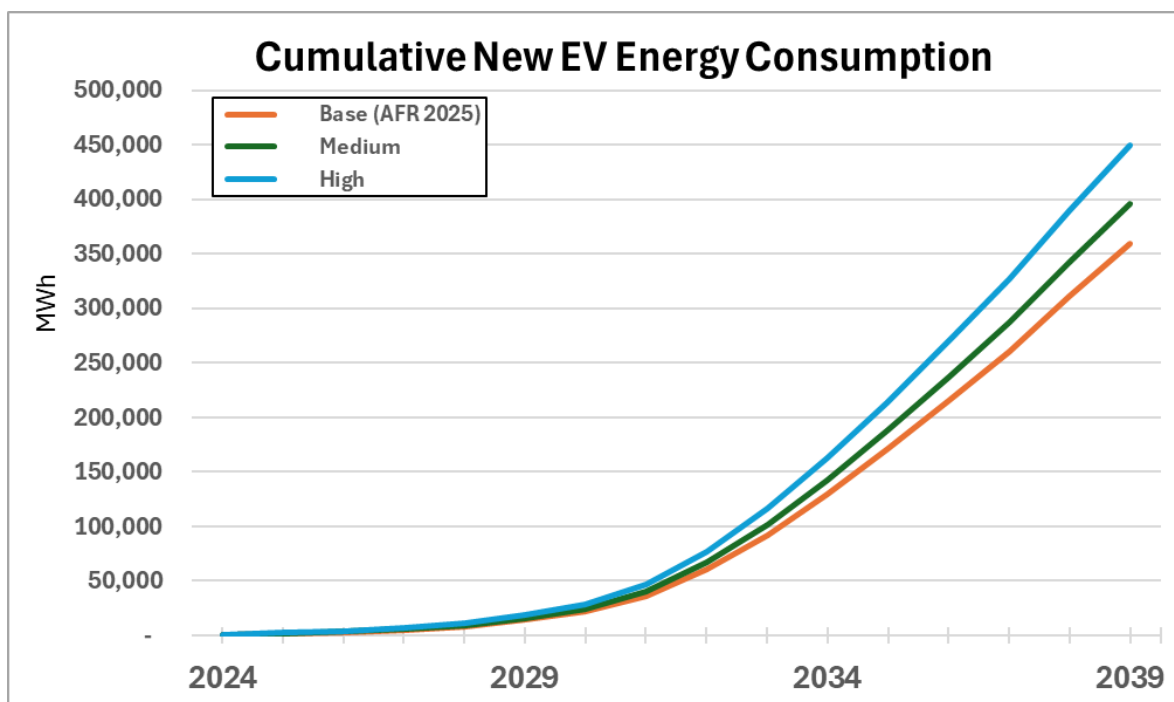


Table 10: Electric Vehicle Summer and Winter Peak Impact (MW)

EV Winter Peak Impact (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base (AFR 2025)	-	0.5	0.9	1.7	3.0	5.1	7.9	13.2	22.1	33.6	47.2	62.3	78.6	95.1	113.4	131.0
Medium	-	0.6	1.2	2.0	3.4	5.7	8.8	14.7	24.5	37.1	52.0	68.7	86.6	104.7	124.9	144.3
High	-	0.9	1.5	2.4	4.0	6.7	10.2	16.8	28.0	42.3	59.2	78.2	98.6	119.2	142.0	164.1

EV Summer Peak Impact (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base (AFR 2025)	-	0.2	0.3	0.6	1.0	1.7	2.7	4.5	7.6	11.5	16.1	21.3	26.8	32.5	38.7	44.7
Medium	-	0.2	0.4	0.7	1.2	2.0	3.0	5.0	8.4	12.7	17.8	23.5	29.6	35.8	42.6	49.3
High	-	0.3	0.5	0.8	1.4	2.3	3.5	5.8	9.5	14.4	20.2	26.7	33.6	40.7	48.5	56.0

Figure 15: EV Winter Peak Impact (MW)

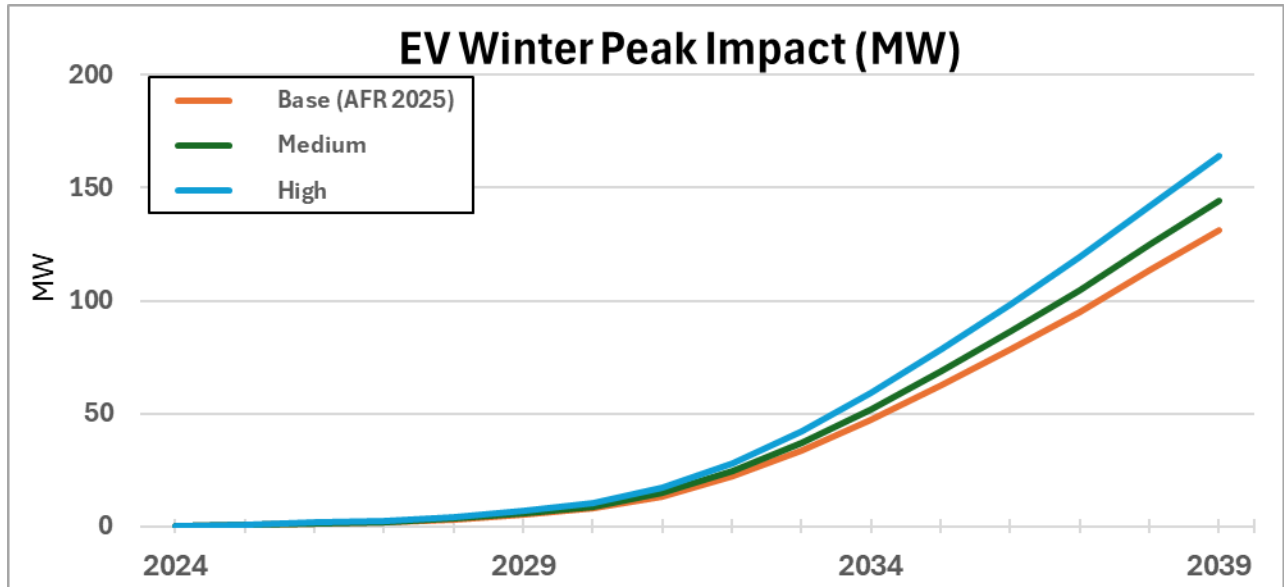


Figure 16: EV Summer Peak Impact (MW)

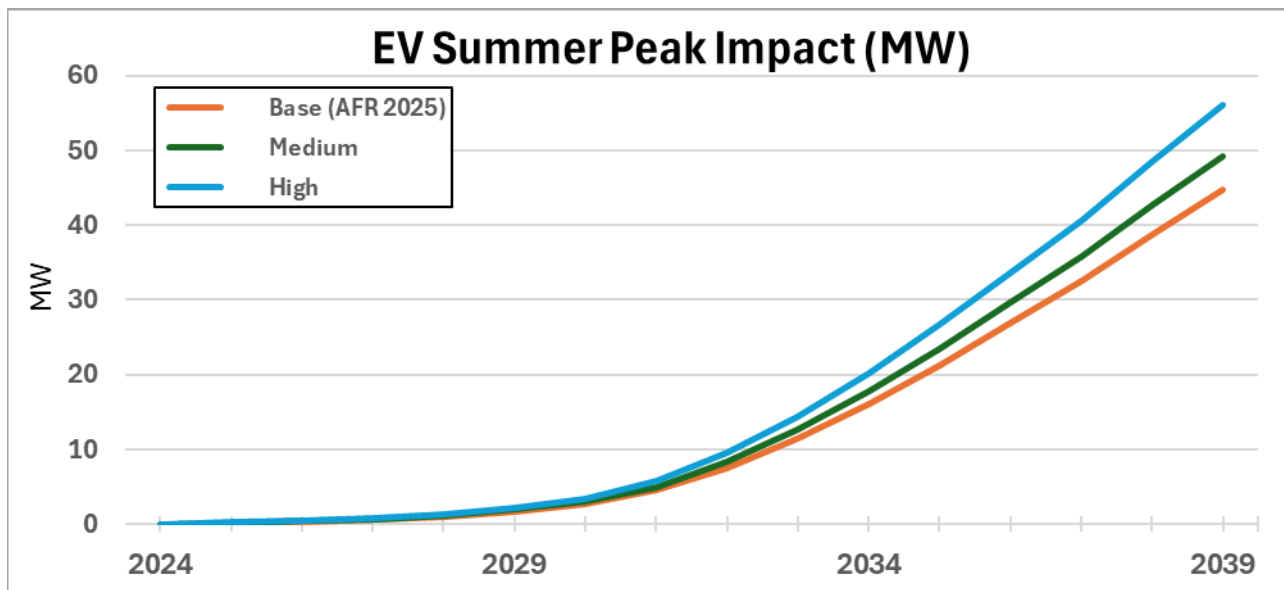


Table 11: Public Charger Energy Consumption and Summer Peak Impact

Energy Consumed (MWh)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Medium	-	338	876	1,178	1,719	2,590	3,743	5,962	9,641	14,338	19,868	26,043	32,649	39,340	46,771	53,890
High	-	388	1,008	1,355	1,977	2,978	4,304	6,856	11,087	16,488	22,848	29,949	37,546	45,241	53,786	61,973

Summer Peak Impact (MW)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Medium	-	0.1	0.1	0.2	0.3	0.4	0.6	0.9	1.4	2.2	3.0	3.9	4.9	5.9	7.0	8.1
High	-	0.1	0.2	0.2	0.3	0.4	0.6	1.0	1.7	2.5	3.4	4.5	5.6	6.8	8.1	9.3

Public EV charging was projected as part of the Company's analysis for its April 8, 2021 DCFC Infrastructure filing.³⁸ This forecast of public charging station demand was included in the two higher adoption 2025 IDP scenarios.

Minnesota Power's DCFC Infrastructure filing includes the construction of 16 DCFC stations within Minnesota Power's service territory ranging from 50 kW to 350 kW in capacity. The Company utilized existing public charger usage in similar regions within Minnesota Power service territory to estimate the energy and peak impact at each of the 16 DCFC stations.

The resulting estimates suggest the 16 DCFC stations will add about 3,500 MWh of energy use by 2030 and contribute about 0.6 MW to Minnesota Power's 2030 summer peak. By 2039, the 16 DCFC EV charging stations would add about 54,000 MWh of annual energy use and about 8 MW to summer peak demand. Table 11 shows the projected annual energy consumption by these 16 DCFC EV charging stations under each of the three forecast scenarios.

Residential Time-of-Day Rate - Time-of-Day residential rate impacts are also captured in the 2025 IDP scenario planning. The Company's approved Petition for Changes to Minnesota Power's Residential Rate Design included a roughly 2:1 on-peak to super off-peak price ratio, and an on-peak period lasting from 3 PM to 8 PM on weekdays, which encompasses the most common summer and winter peak times.³⁹ The associated rate specifications are shown in Table 12.

³⁸ Docket No. E015/M-21-257.

³⁹ Docket No. E-015/M-20-850.

Table 12: Current TOD Rates (\$/kWh) and Hours⁴⁰

Standard Rate	\$ 0.10818			
TOD Period	Adder	Standard Rate + Adder	Weekday Hours	Weekend Hours
On-Peak	\$ 0.04800	\$0.15618	3 pm to 8 pm	N/A
Off-Peak	\$ (0.00239)	\$0.10525	5 am to 3 pm; 8 pm to 11 pm	5 am to 11 pm
Super Off-Peak	\$ (0.03416)	\$0.07402	11 pm to 5 am	11 pm to 5 am

The Company hired a third-party consultant to conduct an elasticity analysis using peak period pricing and observed customer load behavior from its TOD Phase II Evaluation participants. A report discussing the results of this evaluation can be found in Minnesota Power's September Residential Rate Design compliance filing.⁴¹ Based on this data, a price elasticity of about -0.022, i.e. a 100 percent increase in the price of electricity led to a 2.2 percent decrease in quantity demanded. As more customers enroll in the new TOD rate, the Company will continue re-evaluating price elasticity with updated data.

This -0.022-elasticity estimate was applied to the on-peak price where the on-peak price (15.62 cents/kWh) reflects a roughly 44 percent increase over base residential rates (10.82cents/kWh). According to this analysis, it would result in an estimated one percent reduction in on-peak energy usage. This estimated percent reduction is applied to residential customer use profiles to approximate the overall demand reduction of about 0.01 kW per customer during an on-peak period. Overall system demand reduction is dependent on TOD participation rate; at 100 percent participation, the Company would expect a peak demand reduction of 1.3MW. Table 13 shows the summer peak demand reduction under each of the three scenarios.

Table 13: Summer Peak Demand Reduction

Summer Peak Impact (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base	(0.2)	(0.5)	(0.8)	(1.0)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Medium	(0.2)	(0.8)	(1.1)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
High	(0.2)	(1.0)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)

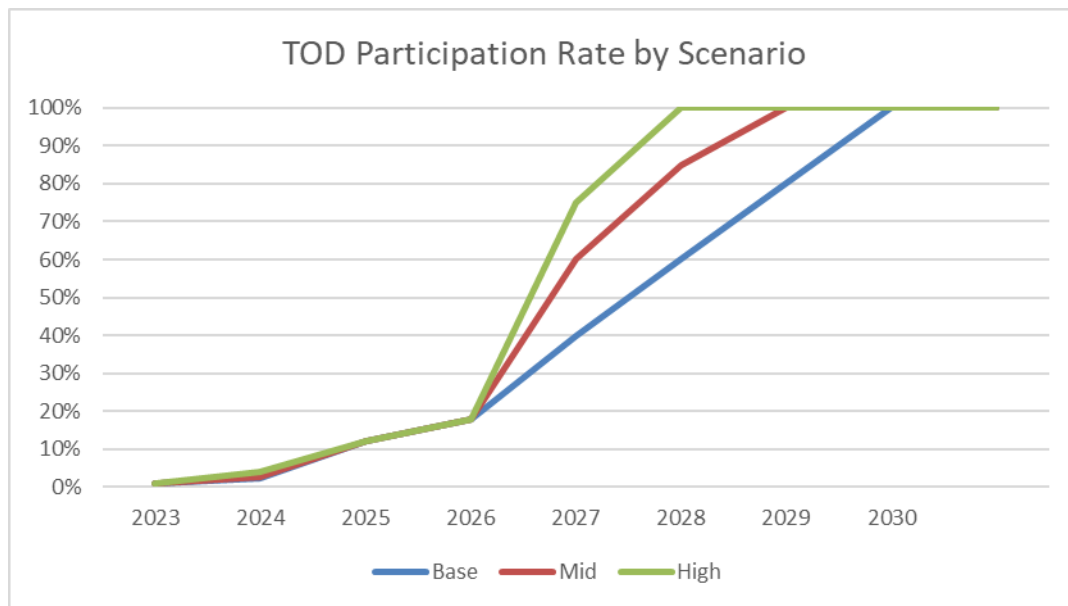
The 2025 IDP evaluated three scenarios for TOD that vary in their assumed rates of residential customer participation. The Company's Residential Rate Design filing proposed a schedule for transitioning all residential customers to TOD as a default rate by 2025-2027. Phase 1 of enrolling

⁴⁰ This rate is anticipated to change upon the completion of the ALLETE acquisition (Docket No. E015/PA-24-198).

⁴¹ Docket No. E-015/M-20-850, September 30, 2025.

customers in TOD began in October of 2022 with the intent of focusing on ensuring operational success and collecting customer feedback. During this phase operational adjustments were made, and the Company anticipates other adjustments to ensure operational efficiency and customer satisfaction. As a result, Figure 18 shows three scenarios that differ only in the pace of TOD adoption/participation by Minnesota Power’s residential customers: the base TOD scenario assumes 100 percent participation by 2029, the Medium case assumes full participation by 2028, and the high case assumes 100 percent participation by 2027.

Figure 18: TOD Participation by Scenario



Electrification – As Minnesota Power continues to develop and begins implementing efficient fuel switching programs as part of the ECO portfolio, the Company will begin to monitor electrification load adoption. Once Minnesota Power has more history and a better understanding of the future of these programs and their impacts on the Company’s system, the Company will explore how best to capture these impacts in load forecasts. The methodology will likely be similar to the manner in which energy efficiency programs are incorporated, where past program performance and the corresponding load impacts as well as future program plans and impacts are included as variables in the AFR. As EFS programs become a bigger part of the Company’s customer programs, other methods of electrification forecasting may become more apparent.

VI. DISTRIBUTION PLANNING

Minnesota Power's current processes and tools for distribution planning and interconnection analysis are tailored to current distribution planning needs. Regular distribution planning assessments focus on peak or minimum load model snapshots and reliability issues such as phase balancing, capacitor placement, capacity, voltage support, and contingency analysis. Distributed generation interconnection requests are screened per the MN-DIP requirements and in-depth studies are conducted as needed. Based on these evaluations and Minnesota Power's TSM, network upgrades and interconnection facilities are identified where needed for distribution generation interconnections on a case-by-case basis.

Increased adoption of distributed energy resources and electrification will impact these planning processes. Regular distribution planning assessments will become more complex, and identifying the location and characteristics of individual DERs or groups of DERs on a feeder will become necessary to adequately evaluate the system. Pockets of aggregated DERs will need to be evaluated as part of regular planning assessments to understand their impact on feeders and substations. Additional analysis will be required to identify load and generation conditions that may stress the system, and additional models will likely have to be evaluated beyond the traditional peak and minimum load models. Such analysis may require new modeling tools beyond the traditional snapshot-in-time models that Minnesota Power presently utilizes, perhaps to the point where models are needed to simulate hourly DER and load characteristics or transient switching impacts. For each additional system condition and each new type of analysis, the time and resources required to build the models and complete the analysis will increase.

As adoption of distributed generation and electrification grows, more direct impacts are expected on the processes and tools required to manage distributed generation interconnections. A substantial increase in the volume of interconnection requests would create additional administrative and technical work as the requests are processed and studied. More individual interconnection requests will likely fail the MN-DIP screens and require detailed technical analysis, due to the amount of DERs already connected to the feeder or the size of the individual DERs. Increasing complexity on the distribution system may lead to additional technical analysis that is not presently needed on a regular basis for distributed generation interconnection studies – such as electromagnetic transient studies and control system coordination studies – to ensure that DERs do not have a negative impact on end-use customers or other connected generators. Additional modeling programs or additional technical consultant studies may be required to

perform this work. Minnesota Power will have to expand its engineering resources, modeling and evaluation tools, and technical expertise as DER and electrification adoption grow significantly beyond recent adoption rates on the distribution system.

a. Distribution Planning Tools

Minnesota Power currently uses Milsoft's WindMil platform to perform basic distribution system analysis routines such as voltage drop, load balancing, fault current analysis, and switching studies for distribution planning. WindMil models are developed based on data exports from GIS and customer billing load data. In 2022 due to rising demand for analytical distribution system studies, Minnesota Power began an initiative targeted at exploring different distribution planning software options to improve efficiency and incorporate advanced functionality not available from its present software platform.

This review ultimately led to the selection of DNV's Synergi platform as the preferred long-term distribution planning software to meet the Company's needs. Synergi will provide Minnesota Power's distribution planning group with more analysis tools as well as increased efficiencies with model building compared to WindMil. Synergi will also be able to communicate directly with the Company's GIS Model (Utility Network) and billing data (C2M) to seamlessly provide the most accurate information for distribution planning studies. Synergi is able to perform the basic distribution analysis routines currently available to Minnesota Power's distribution planners as well as more advanced analysis routines for DER interconnections and planning. Synergi also has an integrated hosting capacity tool along with a more efficient integration with EPRI DRIVE. Minnesota Power is anticipating having working Synergi models by the end of 2025.

In late 2018, Minnesota Power became part of the Electric Power Research Institute's ("EPRI") Distribution Resource Integration and Value Estimation ("DRIVE") Tool User Group in order to gain understanding of hosting capacity analysis and the data and labor requirements for performing a comprehensive system-wide hosting capacity study. While Minnesota Power's experience with direct implementation of the EPRI DRIVE tool has been limited to date, the Company has worked with EPRI to understand how the DRIVE tool interfaces with Minnesota Power's existing WindMil models and how to produce hosting capacity heat maps from these models. As a result of that engagement, Minnesota Power has been able to produce hosting capacity results on a limited basis, but inefficiencies encountered in applying DRIVE with the Company's existing WindMil models have curtailed progress and led, in part, to the aforementioned distribution planning software improvement initiative. Moving the distribution

planning software to DNV Synergi will allow Minnesota Power to efficiently produce Hosting Capacity maps with the Synergi software or through a more efficient integration with EPRI Drive. Minnesota Power has included a hosting capacity table compiled from available data in Appendix F.

b. Preliminary Hosting Capacity Data

The Company currently does not perform hosting capacity analysis but is moving towards being able to do so on a targeted basis through its involvement in the EPRI DRIVE User Group and the new Synergi Distribution Planning software as discussed in Section VI.A. Peak load information is gathered annually to perform baseline planning studies on the distribution system. The Company's peak coincident load for the distribution system (as measured between the transmission and distribution system) was 582 MW on January 15, 2024 at 9:00 AM. This information is taken from hourly historical loading data collected between January 1, 2024 and December 31, 2024.

As historical peak load information was evaluated by feeder and substation for the 2023-2024 time period, daytime minimum load as well as average loading were evaluated where historical data was readily available. Where direct historical data points are not available, daytime minimum load is assumed to be 20 percent of the peak load for a feeder. Tables showing peak, daytime minimum, and average load by substation, parent feeder, and stepdown feeder for 2023 and 2024 are provided in Appendix G. In general, "Substations" are inclusive of all parent feeders connected to a substation. "Parent feeders" are inclusive of load directly connected to a feeder and any stepdown transformers connected to the feeder. "Stepdown feeders" are inclusive of load that is directly connected to a feeder that is served from a stepdown substation connected to a parent feeder, which is generally of a higher voltage class than the stepdown feeder.

VII. DISTRIBUTION SYSTEM MODERNIZATION AND INFRASTRUCTURE INVESTMENT PLANS

a. Historic Distribution Spending

Maintaining and strategically investing in aging distribution infrastructure is essential to upholding the safety, reliability, and resilience of the grid. Many assets across the distribution system are nearing or exceeding their design life, requiring replacement and modernization to avoid service disruptions and ensure continued performance. At the same time, increasing levels of distributed energy resources, risks associated with wildfires, extreme weather patterns and grid modernization efforts are introducing new operational complexities and accelerating the need for

infrastructure and software investments. Initiatives to support enhanced visibility, control capabilities, and system hardening within the distribution system will contribute to rising capital and operational costs. Optimized Asset Renewal prioritizing upgrades that deliver the greatest value is a cost-effective investment method of maintaining and improving system reliability, resilience, and customer affordability. Investments in areas like DG programming and planning, outage management systems, geographic information systems, and enhanced analysis and visibility capabilities are foundational to modernizing the electric distribution system. These efforts enable utilities to optimize asset renewal by targeting infrastructure and equipment upgrades based on real-time data and predictive analytics. They also support holistic distribution planning that integrates customer energy needs—such as reliability, affordability, and clean energy access—with broader state policy objectives like decarbonization and grid resilience.

For purposes for this IDP, distribution spending has been broken down into the following categories:

- a. Replacements and Asset Renewal
- b. System Expansion or Upgrades for Capacity
- c. System Expansion or Upgrades for Reliability and Power Quality
- d. New Customer Projects and New Revenue
- e. Grid Modernization and Pilot Projects
- f. Projects Related to Local (or Other) Government Requirements
- g. Metering
- h. Other

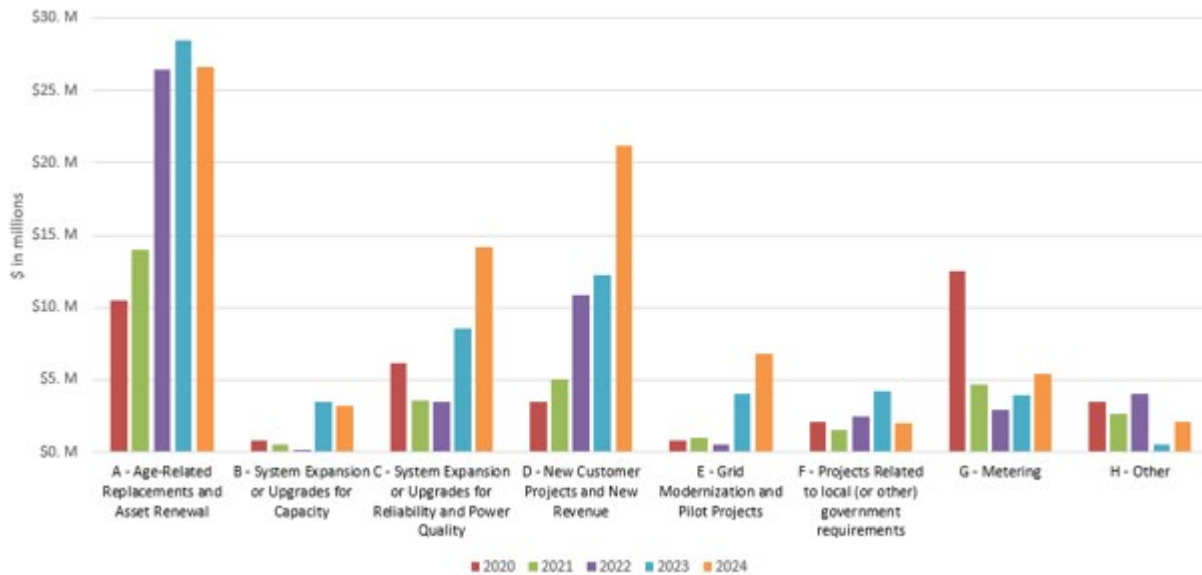
Costs related to the Company's EV programs are included in Appendix E: Transportation Electrification Plan.

Minnesota Power has traditionally followed a depreciation level spending pattern for its distribution system, as depicted in Table 14 and Figure 17. Starting in 2022, the Company increased its investments above depreciation level spend to accelerate asset renewal, modernization, and reliability projects.

Table 14: Historical Distribution Spending

IDP Category	2020	2021	2022	2023	2024
A - Age-Related Replacements and Asset Renewal	10.44	13.97	26.48	28.48	26.62
B - System Expansion or Upgrades for Capacity	0.80	0.56	0.11	3.48	3.15
C - System Expansion or Upgrades for Reliability and Power Quality	6.17	3.58	3.46	8.52	14.18
D - New Customer Projects and New Revenue	3.48	5.08	10.88	12.24	21.23
E - Grid Modernization and Pilot Projects	0.81	1.00	0.50	3.98	6.77
F - Projects Related to local (or other) government requirements	2.12	1.51	2.44	4.19	1.97
G - Metering	12.52	4.65	2.91	3.96	5.37
H - Other	3.48	2.62	3.99	0.49	2.12
Total	39.83	32.98	50.79	65.34	81.42

Figure 17: Historical Distribution Spending by Category



b. 5-year Action Plan

The 5-Year investment Plan includes a number of strategic projects in the Company's distribution capital budget and includes an increase in spending for key budget areas, as outlined in Figure 18 and Table 15. These projects are identified as part of broader strategic Minnesota Power initiatives that most often directly benefit the Company's customers.

Figure 18: Five Year Future Investments by Category

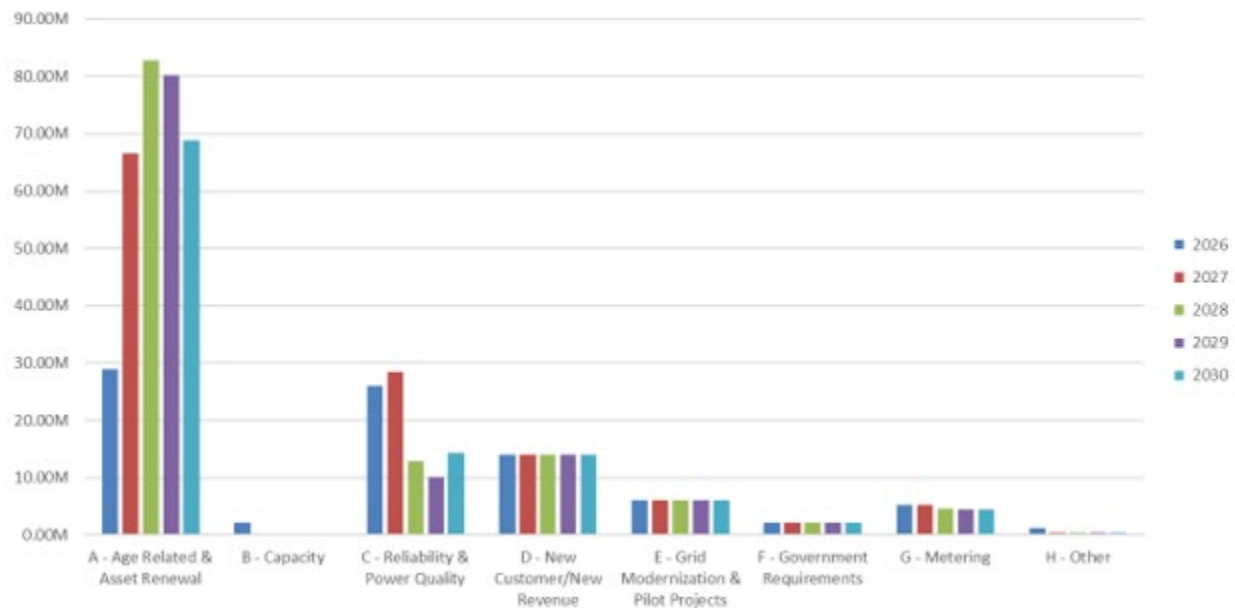


Table 15: Five Year Future Investments by Category

Planned Distribution Capital Investments by Category						
	2026	2027	2028	2029	2030	
A - Age Related & Asset Renewal	28.89M	66.56M	82.74M	80.25M	68.81M	
B - Capacity	2.10M	0.00M	0.00M	0.00M	0.00M	
C - Reliability & Power Quality	26.05M	28.36M	12.79M	10.08M	14.24M	
D - New Customer/New Revenue	14.00M	14.00M	14.00M	14.00M	14.00M	
E - Grid Modernization & Pilot Projects	6.00M	6.00M	6.00M	6.00M	6.00M	
F - Government Requirements	2.20M	2.20M	2.20M	2.20M	2.20M	
G - Metering	5.25M	5.25M	4.55M	4.35M	4.35M	
H - Other	1.23M	0.38M	0.38M	0.38M	0.38M	
Grand Total	85.72M	122.74M	122.65M	117.25M	109.98M	

The following sections describe the types of projects included in each of the budget categories.

Asset Renewal (Category A) – Age-Related Replacements and Asset Renewal Projects are used to replace failing and end of life infrastructure on the distribution system. Some age-related replacements and asset renewal projects are planned in advance and implemented proactively as engineers identify and prioritize age- and condition-based replacements or areas prone to failure based on reliability metrics and feedback from field crews. Other age-related replacements and asset renewal projects are implemented in response to unanticipated failures. Engineering

expertise helps prioritize proactive age-related and asset renewal efforts. With many assets more than 40 years old, Optimized Asset Renewal programs have been bolstered in recent years in an effort to target areas known to impact customer reliability and system resiliency. Minnesota Power has taken a strategic approach by targeting key feeder and substation connected assets. At the substation level, previously unconnected asset renewal programs have been integrated into a single substation modernization program designed to efficiently and holistically address all the asset renewal needs at a site with one comprehensive project. In some cases, the Company experiences multiple failures in a certain area of the system or with a particular type of asset. These types of failures inform where to direct capital spending. However, some age-related replacements naturally occur throughout the year due to unanticipated failures. At the transmission-to-distribution substation level, where failures can be more broadly impactful, costly, and have longer lead-times to fix, proactive asset renewal and modernization projects have been identified and prioritized based on the age, past performance, and direct customer impact of major substation apparatus. The Company's Optimized Asset Renewal approach leverages these considerations to cost-effectively maintain system reliability, resiliency, and future readiness to benefit customers.

Capacity and Reliability (Categories B & C) – System Upgrades for Capacity and Reliability & Power Quality are driven by improvement of load-serving capacity or customer reliability. If voltage or capacity issues are identified because of load growth on a circuit, the Company may need to reconductor a portion of a circuit to ensure continued reliable service. In the past, the Company has needed to build new distribution substations from time to time to increase load-serving capacity. If a certain area experiences exceptionally poor reliability over a short period of time, distribution engineers and planners may evaluate the local system and identify potential reliability improvements. Field crews are invaluable resources for feedback on areas of the system that could benefit from capacity or reliability improvements. With the prevalence of AMI on the system, the Company has been able to more frequently and preemptively identify areas of the system with power quality issues.

Strategic undergrounding is an important part of the Company's efforts to improve the reliability and resilience of the system. The Company targets areas where vegetation management, such as tree pruning, is difficult due to access, topography, or vegetative cover. The main drivers for strategic undergrounding are reliability improvement, storm resiliency, overhead conversion as part of evaluating aging assets, potential Operations and Maintenance ("O&M") vegetation reduction costs, reductions in trouble costs as reliability improves, and more pleasing aesthetics.

Locations are prioritized based on feeder reliability, vegetation management costs, accessibility for maintenance, and soil conditions and type in the area. The Company anticipates benefits will include fewer outages, cost savings, enhanced safety, and enhanced reliability.

In some cases, system upgrades for capacity or reliability and power quality will be integrated with Asset Renewal or Grid Modernization projects to more efficiently and holistically address the needs of the area. Many projects provide benefits in all four areas, and identifying the primary category for such projects is not a precise exercise. A project with a strong reliability component, such as reconductoring a section of feeder to a tie switch to ensure adequate backup capability for planned or unplanned outages, might also increase the capacity of the feeder. Although the main purpose of the project is to reliably serve load from another source during an outage, there is an inherent increase in capacity gained as well through this and similar processes. The very same project may also involve the replacement of end-of-life poles and conductor, thus achieving a strong asset renewal benefit at the same time. The minimal spend in Category B from 2027-2030 reflects this synergy between categories and may be adjusted as future planning continues to evolve.

New Customer Projects (Category D) – New Customer Projects and New Revenue projects include construction of distribution line extensions to meet anticipated customer energy needs. The Company has an obligation to meet new and existing needs within its service territory. Most new customer projects result in new (increased) revenue. The distance from existing facilities to the new service point is the most common condition that will determine the cost. Line extensions are made in accordance with the Company's Electric Service Regulations and commission-approved tariffs. The extension rules specify an allowance (credit) for each rate class. Extension costs that exceed the allowance are paid by the customer or may be covered by a guaranteed annual revenue agreement (excluding single-phase services) if the customer enters into a five-year electric service agreement.

Grid Modernization (Category E) – Grid Modernization Projects are efforts that go beyond the Company's baseline efforts to maintain safe, reliable, and affordable energy but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These projects are identified and selected through analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability on the system. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, smart switches, fault indicators, and trip savers. The Company is in the

process of rolling out a multi-year plan to install smart switches (“Intellirupters” and logic enhanced reclosers) and the associated communications infrastructure improvements in strategic locations on the distribution system. Increased information from the distribution system helps improve situational awareness to inform customer communications and condition of service.

Minnesota Power continues to test control capabilities on the distribution system. With the aid of smart sensors and faulted circuit indicators (“FCIs”), the Company plans to continue installing remotely controlled motor operated switches on the distribution system for voltages 46KV and higher in order to enhance fault isolation and system restoration capabilities. Motor operated switches enable Minnesota Power’s system operators to remotely control feeder switches. Smart sensors and FCIs give indication to the system operators about where the fault is located on the feeder. Combining motor operated switch installations with fault location information on a feeder enables Minnesota Power’s system operators to utilize the motor operated switches to rapidly isolate the faulted section of the feeder and restore service to customers on the sections of the feeder without electrical faults. All of this switching can be completed by the system operators in minutes, well before a trouble crew could reach the feeder to begin to identify the cause of the fault. With the faulted section of feeder identified and isolated by the system operators, the trouble crew can then focus its efforts on only the faulted feeder section to identify and fix the cause of the fault. The end result is a more rapid and efficient response to feeder-level fault events, which should greatly enhance reliability for the customers served from the feeders where this approach is implemented. FCIs are also being deployed as standalone devices to aid in normal fault location and restoration efforts by crews.

Pilot projects (also included in Category E) are the Company’s efforts to work with new and emerging applications on the distribution system. Pilots are most often projects that the Company has little experience with and are meant to facilitate learning and ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. The Company has pursued several pilot projects in the past that have resulted in tangible customer benefits, cost savings, and lessons learned. Moving forward, the primary goal of pilot projects is to find more cost savings and customer benefits with new and emerging technology and applications. More information about pilot projects currently being considered is provided in Section VII.b.3.

Grid Modernization projects are generally intended to achieve both quantifiable benefits, such as reduced customer outage time and reduced need for field deployments and restoration, as well

as non-quantifiable benefits, such as improved power quality, enhanced customer experience, and increased operational visibility and control of the distribution system.

Government Requirements (Category F) – The most common projects related to Government Requirements are relocation of lines located in public rights-of-way and relocation of distribution lines to avoid road construction conflicts. By the rules of the governing authority having jurisdiction, most projects are not reimbursable to the Company by local governments. Only relocation of existing lines outside road rights-of-way and protected by private property rights may be reimbursable. This category has tripled in spend over the last few years due to the addition of Americans with Disabilities Act (“ADA”) compliant sidewalks, bike and walking trails, and road moves increasing every year. The rural nature of Minnesota Power’s service territory is much more likely to have unplanned projects executed in short time frames to align with legislative schedules and the short construction season in northern Minnesota.

Metering (Category G) – Metering Projects are related to the procurement, installation, and communications of energy measurement technologies used for financial transactions. The main drivers for metering projects include:

- Replacement of aging meter equipment in the field.
- Provide more transparency and details about energy usage to customers through the MyAccount platform.
- More accurate usage data and reduced billing estimations when compared with the legacy AMR system.
- Support programs, demand response and rate options such as Dual Fuel and Time of Day rates.
- Improve load research and distribution planning functionality.
- Enhance outage detection and response capabilities.

Minnesota Power’s original AMI deployment occurred from 2009 through 2023. Since that deployment began, the Company has been working to improve coverage of the existing AMI communication infrastructure across its service territory to ensure consistent and timely receipt of interval data. Like most microprocessor-based technologies, the useful life of AMI meters is anticipated to be 15-20 years. Beginning in 2025, deployment of the next generation AMI technology began, as meters from the initial deployment come to end-of-life. This deployment is scheduled to occur over the next several years and will gradually replace end-of-life meters.

Remote-capable functionality will be included as the standard for AMI going forward, where available and applicable. This largely includes residential and small commercial service.

By integrating AMI, GIS, and the OMS, every AMI meter acts as an outage detection sensor and reports power restorations. The AMI system can also be used to detect what phase the meter is on. This data can be used to verify and update GIS data and improve outage predictions of the OMS.

Other (Category H) – Projects included in the “Other” category improve Distribution assets operations but do not meet the categories or drivers discussed above. Some examples include replacing assets due to damage incurred to the system by an unidentified third party for which there is no reimbursement or due to storms.

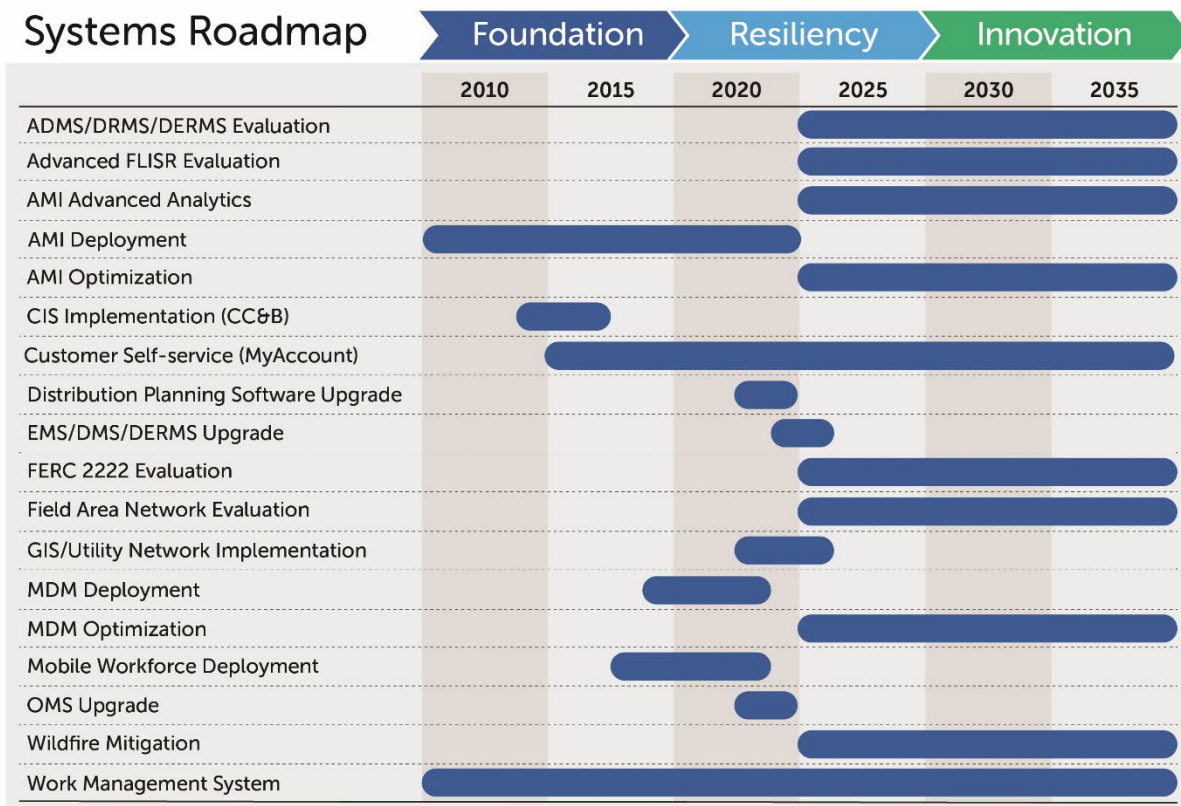
The following sections provide more information about Minnesota Power's 5-year action plan.

Software Solutions

As Minnesota Power continues to modernize the grid with smart technologies—including AMI, FLISR, DERs and more—advanced software solutions will be essential to fully realize the value of these assets. While software upgrades are not typically included in the Company's distribution budgets, they are critical to the operation of the distribution system. Software platforms enable real-time data integration, predictive analytics, and automated decision-making, which are critical for optimizing grid performance, enhancing reliability, and supporting future non-wires alternatives. By coordinating distributed energy resources, managing load flexibility, and streamlining outage response, software tools transform raw data into actionable insights. These capabilities not only improve operational efficiency but also support regulatory goals around decarbonization, resilience, and customer engagement.

The Company has identified several software solutions, including upgrades to existing platforms and new functionality, that will be critical to further leveraging its grid modernization investments going forward. A foundational systems strategy, as shown in Table 1, will help the Company implement the right tools at the right time, while balancing internal resource availability and investment. The system implementations are the building blocks for innovative programming, reliability-focused grid modernization improvements, and a smooth transition to a future with higher DER penetration. Figure 21 provides a historical view of systems that are fully implemented as well as those still in progress or under evaluation.

Figure 21: Systems Roadmap



The Company has identified several software solutions, in addition to the required upgrades to existing systems, that are currently being considered for implementation within the next five years. The timeline for implementing these solutions will depend on a variety of factors including resource availability, DER penetration, compliance with regulatory requirements and more.

Examples of tools currently being considered include:

- An AMI operational analytics tool to more efficiently use AMI data for load aggregation, voltage and power quality analysis, and system loss calculations. It could also help make AMI alarming data more actionable and help proactively identify distribution system problems.
- Several systems—including Advanced Distribution Management Systems, Demand Response Management Systems, and Distributed Energy Resource Management Systems—are continuously evaluated for operational benefits based on potential investment and implementation timing. These systems could be deployed individually or integrated into a unified platform to enhance operational efficiency. One or all of these

says will likely be needed as DER penetration increases and more dynamic, real-time coordination becomes critical. These systems may also be needed to facilitate compliance with FERC Order 2222 and other relevant policy objectives.

- Integrated Volt Var Control (“IVVC”) are advanced automation solutions used to optimize voltage levels and reactive power across the distribution grid. These systems coordinate the operation of voltage regulators, capacitor banks, and other grid devices to maintain voltage within acceptable limits, improve power quality, and reduce energy losses. IVVC plays a critical role in enabling a future Conservation Voltage Reduction (“CVR”) pilot.

The Company will continue to provide updates on its strategy to implement grid-enabling software solutions in future IDPs.

Wildfire Mitigation

Minnesota Power is committed to implementing a comprehensive wildfire mitigation plan that not only reduces the risk of catastrophic fire events but also enhances overall system reliability, resiliency, and safety. Recognizing the interconnected nature of these priorities, Minnesota Power's approach emphasizes multi-benefit planning—where wildfire risk reduction measures are evaluated alongside improvements to grid reliability, climate resilience, operational efficiencies, and customer service. Investments will be guided by data-driven risk assessments, community vulnerability analyses, and cost-effectiveness evaluations to ensure that mitigation efforts deliver the greatest value possible.

The Company's wildfire risk mitigation plan will be developed in four stages:

1. Wildfire Risk Map – The Company is working with industry leading consultants to develop fuel loading, vegetation information, wild-land urban interface areas and other risk factors to create a landscape/population wildfire risk map for Minnesota Power's service territory with hazardous fire areas ("HFA") identified. A schema for rating each HFA near Minnesota Power facilities and population areas will create a graphical representation of risk areas that can be used to drive decision-making on investments related to wildfire mitigation, such as hardening, undergrounding, and system operations.
2. Wildfire Risk Model – The model will build on the work done developing the wildfire risk map, integrating information about Minnesota Power's assets to the wildfire risk maps to help Minnesota Power effectively evaluate asset ignition and protection risk and more efficiently prioritize, operationalize, and implement wildfire mitigation initiatives.

Additionally, the work being done on the Company's wildfire risk model is intended to be used as a weighting factor into future capital investments and cost-benefit analysis.

3. Calibrate and Implement a Fire Potential Index ("FPI") – An FPI is an important situational awareness tool intended to inform and support field mitigation planning and operational decision-making, including proactive de-energization under fire danger conditions. Once complete, the FPI will help the Company to visualize and quantify current and forecasted fire danger conditions in designated areas and make operational decisions during fire season regarding hot-work, reclosing and inspections.
4. Wildfire Mitigation Plan ("WMP") – Evaluate Minnesota Power's current WMP based on resources developed in stages 1, 2 and 3. The WMP will document Minnesota Power's wildfire risk awareness and mitigation strategy and describe the wide array of mitigation programs, activities, technologies, tools, and business units contributing to wildfire risk reduction efforts. The plan will be informed by industry best practices and right-sized to Minnesota Power's risk profile and operations.

The Company has included a budget of roughly \$500,000 in this 5-year action plan, which is reflective of the currently known costs associated with developing a wildfire mitigation plan as described above. Once the HFAs have been identified and the wildfire risk model is completed, the Company will have a better sense of additional system investments and resources needed to properly mitigate wildfire risk in its service territory. This integrated framework enables Minnesota Power to deploy targeted solutions such as enhanced vegetation management, system hardening, and advanced monitoring technologies that simultaneously address wildfire threats and strengthen the distribution system's performance under both normal and extreme conditions.

Pilot Projects

As described above, the Company utilizes small-scale pilot programs to demonstrate new technologies or applications to identify grid modernization opportunities. The following pilot programs are currently being considered by the Company for potential implementation in the 5-year action plan:

Load Flexibility— Minnesota Power is actively exploring opportunities to increase the amount of flexible load programs available to customers through its ECO portfolio. Flexible load refers to initiatives that enable customers to adjust their electricity consumption in response to grid conditions, price signals, or system needs. These programs leverage smart technologies—such

as connected thermostats, water heaters, EV chargers, and commercial/industrial equipment—to shift or reduce energy use during peak demand periods or when renewable generation is abundant. The Company is also exploring opportunities to aggregate these load flexibility programs with other DERs including customer-sited storage, solar systems, or demand response, effectively creating a virtual power plant (“VPP”) on the distribution system. Efficiently delivering a VPP would require advanced software solutions to deploy, aggregate resources, and to dispatch resources to deliver increase benefits to customers, while also enhancing reliability and resiliency.

Advanced FLISR – The Company is exploring a Centralized Radio Recloser FLISR pilot which will expand upon the Radio Recloser FLISR pilot. A Centralized Radio Recloser FLISR pilot would entail implementing software in a centralized location which would utilize SCADA information to intelligently control the restoration of recloser FLISR. This software would consider system topology, loading limitations, and recloser status to issue restoration commands to participate in Radio Recloser FLISR devices following a recloser trip to lockout. Centralized Radio Recloser FLISR technology should allow FLISR to be deployed on more complex feeder topology scenarios, improve restoration performance, and move restoration logic from individual devices in the field to a central location to more efficiently manage changes on the distribution system. Centralized Radio Recloser FLISR has the potential to offer significant cost savings in suburban and rural areas by avoiding the fiber infrastructure expansion needed to accommodate more Intellirupter deployments. Additionally, this pilot should also allow a more rapid expansion of system visibility, improvement of reliability, and wildfire mitigation efforts.

Selective Customer Innovative Metering Applications - The Company is positioning itself to leverage measurement infrastructure beyond the utility metering point through investments in meter data management software, and increased energy data collection. These applications will enable informed program design and rate structures for specific electric end uses. This is becoming particularly valuable with the emergence of electric vehicles and charging infrastructure, as well as in the commercial building space. As part of the long-term evolution of data systems and customer programs, it is evident that piloting applications using innovative metering applications may be a critical part of future program designs.

Conservation Voltage Reduction - Minnesota Power is considering implementing a conservation voltage reduction (“CVR”)/Volt-VAR optimization (“VVO”) pilot in future years. CVR is the intentional operation of the distribution system in such a way that lowers the voltage profile along

a feeder to reduce demand and delivered energy. The system voltage would remain in the acceptable American National Standards Institute ANSI voltage range.

In order to implement a CVR/VVO pilot the Company would need to install additional voltage control and reactive power management equipment, such as regulators, tap changers, capacitor banks, or distribution-connected Static Synchronous Compensators (“STATCOM”), which would result in additional capital spend and long-term operation and maintenance costs. These costs could be offset by reducing demand and energy on the feeder.

Leveraging the AMI system is critical for a successful CVR/VVO pilot, as the Company can use customer voltage data to confidently push the voltage as low as possible while still maintaining acceptable service voltage within the range defined by ANSI. Additionally, the AMI system and the MDM will allow for greater data analysis which would aid in estimating the CVR potential benefits in terms of energy savings and demand reduction.

The Company evaluated a cost-benefit analysis framework in the Distribution Non-Wire Alternatives Study (discussed in Section VII.B) that may help create criteria and assess the benefits and potential payback period of a future CVR project. The installation and net-present value costs can be variable depending on which communication protocol is used to operate the devices, which head-end system is used to automate the system, and whether existing equipment in the substation and on the feeders can be retrofitted to participate in a CVR pilot. The costs and benefits of VVO also vary by the type of circuit (residential, commercial, or industrial load) that the system is installed on.

Non-Wires Alternative Discussion

Types of projects that lend themselves to non-wires solutions are those designed to address load-serving (capacity) or circuit backup (reliability) issues. A non-wires solution may be suitable for addressing a load-serving issue where the capacity of a feeder or associated substation equipment, including transformers, is less than the total peak load interconnected to the feeder or substation. In that case, a non-wires solution may be able to reduce the effective peak load seen by the feeder or substation to within the capacity of the existing assets, eliminating or deferring the need for infrastructure upgrades. A non-wires solution may also be suitable to improve reliability by enhancing circuit backup capability in situations where large capital costs projects are needed to create external backup sources. In that case a non-wires solution like a BESS can provide backup power during unplanned outages until crews restore service. However,

non-wires solutions are only viable for these types of issues where the following conditions are also met:

There is not a significant asset renewal need being addressed - Non-wires solutions cannot displace the need to modernize and replace aging equipment, even when the modernization project may result in increased reliability or load-serving capability. For example, if the issue is transformer capacity at a substation where the transformer is near or beyond end of life, a non-wires solution will not defer the need to replace the transformer for a significant period of time to be a cost-effective alternative. There are substations on the Minnesota Power system where transmission-to-distribution transformers as old as 81 years are still in use. These substations should and are being addressed through Minnesota Power's asset renewal efforts.

Operational characteristics of the non-wires solution adequately correspond to the need - Non-wires solutions, including both supply-side and demand-side alternatives, must be available at the necessary time, with the necessary response, and for the necessary duration to address a particular reliability or load-serving issue. For example, if the reliability issue to be resolved is loss of a feeder without adequate backup capability from another distribution feeder, a non-wires solution must be:

- available for dispatch or demand response
- able to ramp up quickly
- capable of following load, and sufficient for an appropriate duration based on the restoration time of the feeder.

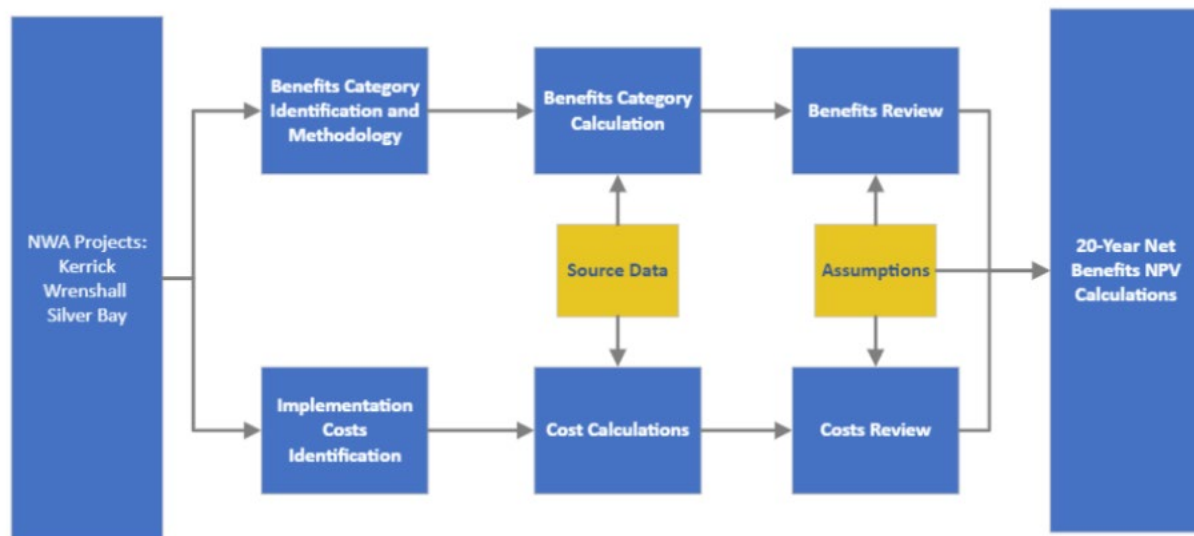
The amount of time necessary to identify, evaluate, justify, and implement a non-wires solution will vary depending on the scope and scale of the solution, whether that solution is related to demand response, energy efficiency, or renewable generation. The components of the implementation timeline include:

- Internal analysis, including distribution planning assessments, targeted alternatives analysis for non-wires solutions, and integrated resource planning analysis;
- Project development, including scoping and preliminary engineering for the non-wires solution;
- Project execution, including procurement, permitting, engineering and construction.

In mid-2021, Minnesota Power initiated a consultant-led Distribution Non-Wire Alternatives (“NWA”) Study to gain experience with the evaluation, development, and justification of non-wire solutions. The NWA Study focused on specific scenarios on Minnesota Power’s system where enhanced backup capability, feeder automation, or dynamic voltage control are or could become desirable. Black & Veatch was selected as the primary consultant to complete the NWA Study and tasked with developing one or more non-wire solutions for each scenario, assisting Minnesota Power in developing a benefit cost analysis (“BCA”) framework for determining where non-wire solutions provide sufficient value to recommend moving forward, and producing sufficient technical scoping information for Minnesota Power to separately develop and procure any or all of the non-wire solutions developed for the study. The NWA Study effort took place from 2021 through mid-2023 and resulted in five separate reports encompassing the four scenarios plus documentation of the BCA framework. The NWA reports and BCA framework documentation were provided in Minnesota Power’s 2023 IDP.

For the Company’s NWA Study scenarios, the BCA framework included assessment of benefits associated with Circuit Backup capability, FLISR capability, and Integrated Volt-VAR Control (“IVVC”). Benefits were applied to scenarios only as applicable based on the particular issues and solutions being evaluated. Within each of these categories, some or all of the following benefits were evaluated and quantified: Avoided Capital Costs, Avoided Generation Capacity, Generation Capacity Revenue, Avoided Energy Costs, Avoided Lost Sales Revenue, Reduced/Avoided Ancillary Services Costs, Reduced/Avoided T&D System Losses, Avoided Customer Fuel Cost, Avoided Restoration Costs, and Customer Outage Reduction Value. Additional risk-based benefits were also evaluated and quantified based on the probability and consequence of certain types of risks, including Compliance Risk, Power Quality Risk, and Customer Satisfaction Risk. The underlying rationale for each of these benefits was provided in the 2023 IDP and supplemental information requests. Minnesota Power continues to evaluate NWA opportunities.

Figure 19: NWA Scenarios



The Company's five-year distribution capital plan includes 18 projects that are anticipated to have individual total costs of greater than two million dollars. These 18 project investments are assigned to the IDP category that matches each project's main driver. In the Company's current five-year distribution capital plan, the 18 projects that have costs greater than two million dollars fall into two IDP investment categories (Category A – Age Related & Asset Renewal and Category C – Reliability & Power Quality). The estimated cost, expected In Service Date ("ISD") and IDP spend category of these projects are shown in Table 16.

Category A – Age Related & Asset Renewal: 12 of the 18 projects that have a cost greater than two million dollars fall into investment Category A. These projects are classified by Minnesota Power as Substation Modernization projects that require age-related upgrades to transmission to distribution substation. Minnesota Power's Substation Modernization Programs involve coordinated replacement of end-of-life assets and holistic modernization improvements designed to extend the lives of these substations for the next several decades. Planned age-related replacements include distribution-voltage outdoor circuit breakers, indoor switchgear, transformers, switches, and associated equipment. For the projects listed in Table 16 the age of the transformers is anywhere from 49 to 81 years old. These programs take a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of aging substations throughout Minnesota Power's system, addressing the unique needs and constructability considerations of these sites. As these projects are either asset renewal projects whose main driver is age-related replacement of end-of-life equipment or have a strong fundamental asset

renewal component to them (in addition to addressing other needs), they are not viable candidates for non-wire alternatives, as discussed in VII.B

Category C – Reliability & Power Quality: 6 of the 18 projects that have a cost greater than two million dollars fall into investment Reliability & Power Quality (Category C). These projects are driven by improvements to a transmission to distribution substation or distribution feeder that improves backup capability or customer reliability. These improvements involve either reconductoring existing feeders, adding additional feeders, or adding transformers. Almost all of the Reliability & Power Quality (Category C) projects increase the backup capability through external distribution feeder ties to accommodate Substation Modernization projects that fall into Age Related & Asset Renewal (Category A). For example, to accommodate the Virginia South Modernization project the Hat Trick Substation Expansion project is required first because the additional feeders from the Hat Trick Substation will create more backup capability for the Virginia Area. This will ensure reliability during the construction of the Virginia South Substation. As these projects are either improving backup capability or customer reliability, they are not viable candidates for non-wire alternatives as discussed in Section VII.B.

Table 16: Minnesota Power Distribution Projects greater than \$2M

Project	Preliminary Cost	Anticipated ISD	IDP Category
Cloquet 34 kV Expansion	\$3,100,000	2025-2028	C-Reliability & Power Quality
Mahtowa 34 kV Feeder Conversion	\$2,000,000	2025-2028	C-Reliability & Power Quality
Boswell 115/23 kV Transformer Addition	\$4,085,448	2026	C-Reliability & Power Quality
Winton Substation Modernization	\$8,552,612	2026	A-Age Related & Asset Renewal
Duluth 34 kV Expansion	\$3,200,000	2026-2032	C-Reliability & Power Quality
Ridgeview 115/34 kV Transformer Addition	\$8,128,256	2027	C-Reliability & Power Quality
Hat Trick Substation Expansion	\$4,761,152	2027	C-Reliability & Power Quality
LSPI 115/34 kV Transformer Replacement	\$4,000,000	2028	A-Age Related & Asset Renewal
Verndale Substation Modernization	\$20,086,862	2028	A-Age Related & Asset Renewal
Cloquet Substation Modernization	\$25,000,000	2028	A-Age Related & Asset Renewal
Mahtowa Substation Modernization	\$15,019,889	2028	A-Age Related & Asset Renewal
Wrenshall Substation Modernization	\$21,569,637	2029	A-Age Related & Asset Renewal
Haines Road Substation Modernization	\$23,344,200	2029	A-Age Related & Asset Renewal
Virginia South Substation Modernization	\$20,027,000	2029	A-Age Related & Asset Renewal
Babbitt-Winton “31 Line” Rebuild	\$15,500,000	2026-2029	A-Age Related & Asset Renewal
Little Falls Substation Modernization	\$22,000,000	2030	A-Age Related & Asset Renewal
Nashwauk Substation Modernization	\$5,000,000	2030	A-Age Related & Asset Renewal
Burnett Substation Modernization	\$5,000,000	2030	A-Age Related & Asset Renewal

c. Cost-Benefit Analysis

Order Point D.k of the Commission's September 16, 2024 Order in Docket No. E015/M-23-258 states "For each grid modernization project in its 5-year Action Plan, Minnesota Power should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Minnesota Power shall provide all information to support its analysis." As described in Section VII.B, the Company's five-year action plan includes a \$6 million annual budget for grid modernization projects. This budget includes two types of projects:

FLISR Implementation – FLISR automates the identification of fault locations, isolates affected segments and reroutes power to restore service to as many customers as possible. Successful implementation requires integration with SCADA systems, intelligent field devices such as reclosers and switches, and real-time communication infrastructure. The Company is currently in the process of deploying more intelligence on the distribution system such as line sensors, motor operated switches, smart switches ("Intellirupters" and logic enhanced reclosers), fault indicators, trip savers, and the associated communications infrastructure improvements in strategic locations on the distribution system. The Company performed a BCA analysis for the Cloquet area FLISR implementation that was evaluated in the Distribution Non-Wire Alternative Study and discussed in the 2023 Intergrated Distribution Plan.

The benefits of FLISR implementation include:

- Improved customer satisfaction through less outages and shorter duration events.
- Improved public safety through fast fault detection, crews can be dispatched more accurately to the location of the incident, which can reduce public interaction with downed conductors.
- Improved employee safety through automated reclosers which can be opened and closed remotely, limiting crews exposures to fault, busy intersections and dangerous right of ways.
- Greater grid visibility though additional data on circuit load and voltage that can inform operational and planning models.

There are several risks associated with not leveraging FLISR, particularly as expectations for grid reliability, resilience, and customer service continue to rise. Without FLISR, Minnesota Power must rely on manual fault detection and switching, which can lead to longer outage durations, slower restoration times, and higher operational costs due to increased truck rolls and field labor.

This can negatively impact the Company's reliability metrics and customer satisfaction. Additionally, the absence of FLISR limits Minnesota Power's ability to integrate and coordinate with DERs on the system.

Pilot projects – The Company regularly monitors and evaluates new and emerging technology applications for the distribution system. Pilots are most often small projects to demonstrate technologies that the Company has little experience with and are meant to facilitate learning. One such pilot was evaluated in the Company's 2023 IDP and is currently moving forward as a reliability project consistent with the 2023 IDP: implementing a 2.5 MW/5 MWH battery energy storage system near Kerrick, Minnesota, a small town on Highway 23 south of Duluth. Stepdown substations connected to the Bear Creek-Kerrick 46 kV Line serve just over 750 customers with a peak load of 1.80 MW. The proposed pilot energy storage system will support reliability of the distribution system by maintaining energy supply to the city of Kerrick and eliminate the need to rebuild almost 30 miles of aging 46kV infrastructure, thereby avoiding capital costs of around \$15.8 million. The Kerrick energy storage system is only available to operate as a distribution asset when needed to maintain or improve reliability of the distribution system. This asset is not available to operate to benefit all customers as an energy and capacity resource. The Kerrick energy storage system is a distribution asset, similar to other electric distribution infrastructure, where the need is driven by distribution system requirements and it is operated to directly serve the distribution system. The benefits and costs of the Kerrick BESS pilot were evaluated in the Distribution NWA Study and discussed in the 2023 IDP along with other applications for reliability-based energy storage systems. The Kerrick BESS pilot implementation is underway with delivery of the BESS anticipated in late 2025 and full implementation in 2026.

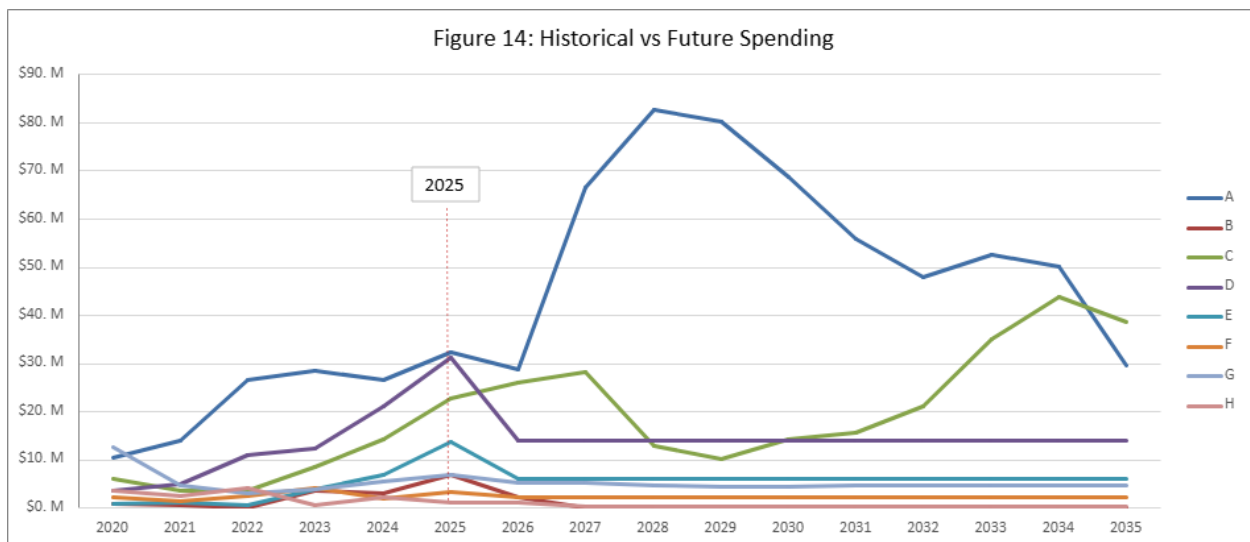
While benefit-cost analysis is a critical tool for evaluating the viability of distribution investments, applying it uniformly across all distribution projects is not cost-effective or practical. Site specific characteristics such as vegetation density, terrain, accessibility, climate or wildfire risks, available communications infrastructure and distance from Minnesota Power facilities will have significant impacts on the BCA of any distribution project. A case-by-case approach is needed to focus resources on projects with the highest potential for deferral or grid benefits such as reliability or resiliency, ensuring that BCA efforts are targeted, meaningful, and aligned with system planning priorities. Broad application of a detailed BCA across all projects would result in diminishing returns and unnecessary administrative burden.

d. Long-Term Investment Plan

The distribution long-range plan is reviewed comprehensively on an annual basis by Company experts. The Distribution Engineering and Distribution Planning departments coordinate the development of the plan, including projects affecting transmission-to-distribution substations as well as distribution feeders and distribution stepdown substations. The long-range plan incorporates localized distribution system reliability and asset renewal needs as identified by Distribution Engineering as well as larger-scale projects coordinated by Distribution Planning where transmission-to-distribution substation reliability, capacity, or asset renewal projects are necessary. Other projects and programs for asset renewal, grid modernization and pilot projects, required relocations, metering, and new customer interconnections are also included in the long-range plan, as identified by Distribution Engineering and Distribution Planning.

The long-range plan generally utilizes historical spending to establish amounts for routine maintenance. Specific projects are slotted into the plan based on timing and need, as identified through asset renewal prioritization, system analysis or external constraints. Many of these specific projects require close coordination with customers, local government, or other business groups within the Company. Since many projects are dependent on timelines and needs outside of the Company's control, a significant amount of change occurs naturally in the long-range plan as the Company learns more information. That being said, the Company has increased its capital budget for grid modernization initiatives from 2025 through 2030 and beyond.

Figure 20: Historical Vs. Future Spending



- A - Age-Related Replacements and Asset Renewal;
- B - System Expansion or Upgrades for Capacity;
- C - System Expansion or Upgrades for Reliability and Power Quality;
- D - New Customer Projects and New Revenue;
- E - Grid Modernization and Pilot Projects;
- F - Projects Related to local (or other) government requirements;
- G - Metering;
- H - Other

VIII. CONCLUSION

Minnesota Power's 2025 IDP provides an overview of the Company's current distribution planning processes and future investment plans. These foundational investments are built upon the Company's Core Values and a distribution strategy focused on technology, innovation, and continuous learning. The Company has demonstrated these values by focusing on right time, right fit investments, leveraging grid data learnings, and by thoughtfully leveraging internal and external resources in a cost-conscious manner to maximize the value of existing distribution assets. The 2025 illustrates how Minnesota Power is readying its system to meet anticipated customer energy needs and integrate large, new distributed generation projects while meeting state policy objectives through a holistic integrated planning approach.

The results of this customer-focused, thoughtful planning process are evidenced by Minnesota Power's leadership in the state of Minnesota in AMI implementation and exceedance of the state's energy savings goals year-over-year. These initiatives complement the Company's steady progress towards carbon reduction and increased renewable generation. The Company has led the State of Minnesota in carbon reduction and is now delivering energy that is between 50 and 60 percent renewable to customers. Minnesota Power is thoughtfully transforming its energy supply while investing in the grid to ensure reliable, resilient, and increasingly carbon-free energy for customers while keeping costs affordable.

Moving towards the future, Minnesota Power is focusing ongoing efforts to support the customers, communities, and region it serves. Above all else, customers expect reliable and safe electric service at a reasonable cost, all of which are encompassed in Minnesota Power's distribution values. Past and present system planning and investments provide a foundation for Minnesota Power to continue advancing innovative distribution programs and technologies. The investments and programs outlined in this 2025 IDP will support Minnesota Power's continuing efforts to improve reliability and resiliency by reinvesting in its system, readying the system for the anticipated electricity and distributed generation needs of its customers, and maximizing

efficiencies and customer benefits while using the system as a resource to support the energy transition.

Date Submitted: November 3, 2025

Respectfully,

Claire Vatalaro

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Minnesota Power
30 W Superior Street
Duluth, MN 55802

Section	Number	Compliance Item	Section/Page Number
Section A: System Data	1	Modeling software currently used and planned software deployments	VI.a, p.56
Section A: System Data	2	Percentage of substations and feeders with monitoring and control capabilities, planned additions	IV.b., p.14
Section A: System Data	3	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	IV.b., p.14
Section A: System Data	4	Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available	IV.b., p.14
Section A: System Data	5	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans	I., p.1
Section A: System Data	6	Discussion of how DERs and electrification are considered in load forecasting and any expected changes in load forecasting methodology	V.b., p.38
Section A: System Data	7	Discussion if and how IEEE Std. 1547-2018 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)	V.b., p.40
Section A: System Data	8	Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)	Appendix D

Section A: System Data	9	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems	IV.b., p.13
Section A: System Data	10	Total distribution substation capacity in kVA	IV.b., p.14
Section A: System Data	11	Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference	IV.b., p.15
Section A: System Data	12	Total miles of overhead distribution wire	IV.b., p.13
Section A: System Data	13	Total miles of underground distribution wire	IV.b., p.13
Section A: System Data	14	Total number of distribution customers	IV.b., p.13
Section A: System Data	15	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc)	Table 5
Section A: System Data	16	Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	Table 6
Section A: System Data	17	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix C
Section A: System Data	18	Total number of DER generation systems which completed interconnection to the system in the	Appendix C

		prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	
Section A: System Data	19	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix C
Section A: System Data	20	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix C
Section A: System Data	22	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program c. Number and capacity of known public access direct current fast charging (DCFC) stations d. Number and capacity of DCFC installed through a utility EV program, broken out by program e. All other known EV charging stations (by type, ex DCFC, Level 2)	V., p.52
Section A: System Data	23	Number of units and MW/MWh ratings of battery storage	V., p.43
Section A: System Data	24	MWh saving and peak demand reductions from EE program spending in previous year	Table 13
Section A: System Data	25	Amount of controllable demand (in both MW and as a percentage of system peak)	V. p. 31

Section A: Financial Data	26	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements (road-relocations, etc.) g. Metering h. Other i. Electric Vehicle Programs	VII.a, p.59
Section A: Financial Data	27	All non-Minnesota Power investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation)	VII.a, p.57
Section A: Financial Data	28	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	VII.a, p.60
Section A: Financial Data	29	Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs	VII.a, p.60

Section A: Financial Data	30	Provide any available cost benefit analysis in which the company evaluated a non-traditional distribution system solution to either a capital or operating upgrade or replacement	VII.a, p.60
Section A: DER Deployment	31	Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	Appendix C
Section A: DER Deployment	32	Information on areas of existing or forecasted high and/or electrification penetration. Include definition and rationale for what the Association considers "high" DER and electrification penetration.	VII., p.65
Section A: DER Deployment	33	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues	V., p.38
Section A: DER Deployment	34	Information on distribution upgrades made to accommodate electrification, when known, including whether it was reactive to new load or based on a short-term forecast.	V., p.35
Section A: DER Deployment	35	Number of fuel-switching rebated granted through Minnesota Power's Energy Conservation Optimization (ECO) plan in the prior year, broken out by technology type (air/ground source heat pump, water heater, cooking, other industrial process heat, electric vehicles, etc.)	V., p.35
Section A: DER Deployment	36	Number of electric space or water heating devices enrolled in a time-of-	V., p.36

		use rate or demand response program, broken out by program type.	
Section A: Electric Vehicles	37	A summary table with the following information for each EV rate offering or program during the reporting period: a. Number of customers and/or vehicles enrolled at the end of the reporting period b. Energy consumed (MWh) during the reporting period c. Peak demand (MW) during the reporting period and the time at which it occurred	Table 4
Section A: Electric Vehicles	38	Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify)	V., p.38
Section B: Hosting Capacity Data	1	Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)	Appendix F
Section C: Distributed Energy Resource and Electrification Scenario Analysis	1	In order to understand the potential impacts of faster-than-anticipated DER and electrification adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER and electrification deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER and electrification adoption and aggregated or bundled DER/electrification service types, dispersed geographically across the Minnesota Power distribution system in the locations Minnesota Power would reasonably anticipate seeing	V., p.45

		DER and electrification growth take place first and how the [utility] would anticipate the combined impacts of simultaneous DER and electrification growth. For electric vehicle forecasts scenarios, Minnesota Power shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty	
Section C: Distributed Energy Resource and Electrification Scenario Analysis	2	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER and electrification adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER and electrification load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	V., p.45
Section C: Distributed Energy Resource and Electrification Scenario Analysis	3	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER and electrification integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER and electrification adoption, potential barriers to DER and electrification integration, and the types of system upgrades that may be necessary to accommodate the DER and electrification at the listed penetration levels.	V., p.45

Section C: Distributed Energy Resource and Electrification Scenario Analysis	4	Include information on anticipated impacts from FERC Order 841 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	V., p.45
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1a	Overview of investment plan: scope, timing, and cost recovery mechanism	VII. p.73
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1b	Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise.	VII. p.73
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1c	Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short-term investments. The analysis should be sufficient enough to justify and explain the investment.	VII. p.70
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1d	System interoperability and communications strategy	IV. p.16

Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1e	Costs and plans associated with obtaining system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, load profiles of electrification, etc.)	V., p.24
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1f	Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.)	V., p.24
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1g	Customer anticipated benefit and cost	V., p.24
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1h	Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties)	VIII., p.79
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1i	Plans to manage rate or bill impacts, if any	VI., p.56
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1j	Impacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt)	VII. p.70
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1k	For each grid modernization project in its 5-year Action Plan, Minnesota Power should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of non-quantifiable benefits. Minnesota Power shall provide all information to support its analysis.	VII. p.72

Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	1l	Status of any existing pilots or potential for new opportunities for grid modernization pilots	VII. p.77
Section D: Long-Term Distribution System Modernization and Infrastructure Investment Plan	2	In addition to the 5-year Action Plan, Minnesota Power shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER and electrification into future planning processes based on the DER and electrification futures analysis, and any other types of changes that may need to take place in the tools and processes Minnesota Power is currently using.	VII. p.78
December 8, 2022 Order (E015/M-21-390 and E999/CI-17-879)	3	Allowed utilities to file electric vehicle data in future Integrated Distribution System Plans that aligns with the data filed in their Annual Program Electric Vehicle reports, currently due June 1 of each year.	V., p.48
January 9, 2023 Order (E015/RP-21-33)	9a	Set the forecasts for distributed energy resources consistently in its resource plan and its IDP.	V., p.45
January 9, 2023 Order (E015/RP-21-33)	9b	Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level.	V., p.45
January 9, 2023 Order (E015/RP-21-33)	9c	Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the	V., p.45

		forecast for distributed energy resources.	
January 9, 2023 Order (E015/RP-21-33)	9d	Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs.	VII., p.70
January 9, 2023 Order (E015/RP-21-33)	9e	Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	VII., p.69
September 16, 2024 Order (E015/M-23-258)	5	In its next IDP, Minnesota Power shall consider demand response, energy efficiency, and renewable generation as part of its future Non-Wires Alternatives process.	VII., p.65

MINNESOTA POWER'S 2025 INTEGRATED DISTRIBUTION PLAN

Engagement Meeting – July 18, 2025



I AM
ZERO INJURY.

TOGETHER

we choose to work safely
for our

FAMILIES,

— each other, and the public. —

We **COMMIT** to be injury-free
through continuous
learning and improvement.

In the event of an emergency....

911 Contact – Jess McCullough

First Aid/CPR – Eric Clement

AED – Cory Erickson

Fire Extinguisher – Katie Frye



OVERVIEW

- ❖ Minnesota Power & IDP overview
 - ❖ Distribution System, Investments, Capabilities & Customer Benefits
 - ❖ Modernizing the Grid to Maximize Benefits
 - ❖ Load & DER Forecasts
 - ❖ Transportation Electrification Plan
 - ❖ Questions
- ❖ *We will pause at noon to grab some lunch and then continue the presentation*

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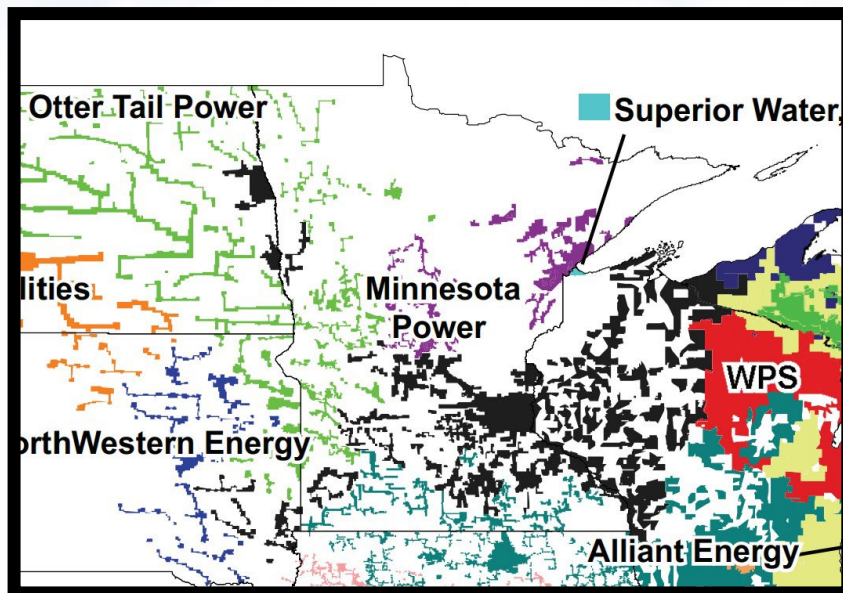
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MINNESOTA POWER & THE IDP OVERVIEW

JESS MCCULLOUGH – PUBLIC POLICY ADVISOR, REGULATORY STRATEGY & POLICY

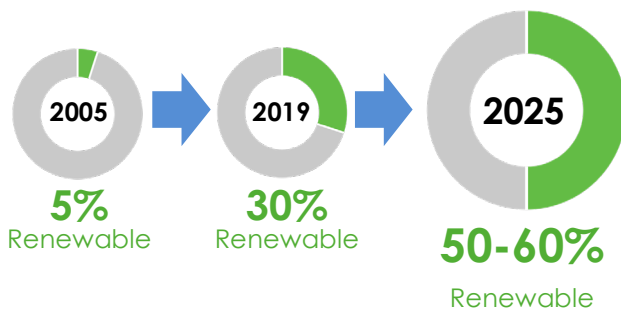


MINNESOTA POWER'S SERVICE TERRITORY



MINNESOTA POWER IS UNIQUE

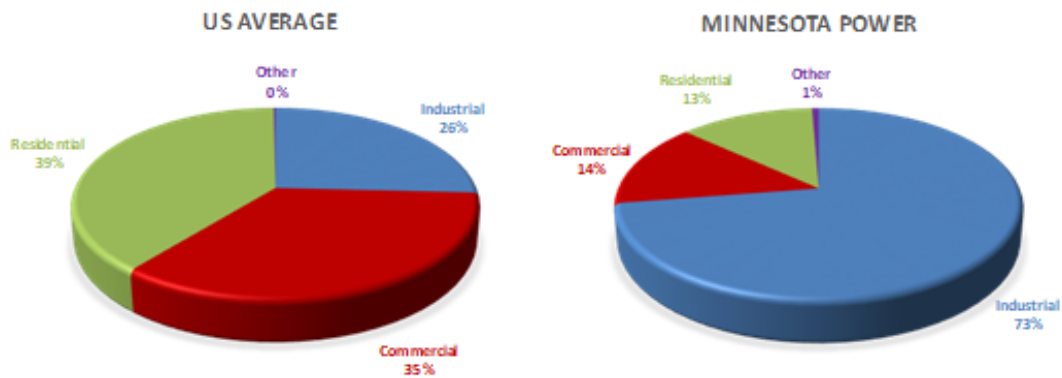
Leading MN in Renewables



Duluth, MN Headquarters
26,000 Square-miles
150,000 Customers
13% Residential sales
73% Industrial sales
14 Municipalities



MINNESOTA POWER IS UNIQUE CONT'D



Source: US Energy Information Administration (2022 EIA Form 861 Data)



PURPOSE OF IDP:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs; and
- Provide the Commission with the information necessary to understand the utility's short-term and long-term distribution-system plans, the costs and benefits of specific investments, and a comprehensive analysis of ratepayer cost and value

KEY THEMES

❖ Integration

- ❖ MP approaches distribution planning holistically and in the context of resource planning (IRP) and energy conservation (ECO)

❖ Optimization

- ❖ The distribution grid isn't just a delivery mechanism, it is a tool in the drive to a carbon-free system

❖ Innovation

- ❖ Using the distribution system to explore new programs and projects that benefit customers and the grid.



ELEMENTS:

❖ Baseline Data For

- ❖ The distribution system – current status, operations, condition
- ❖ Finances – what investments are being made, how and when?
- ❖ Distributed Energy Resources (DER) Data – how much and what kind of generation is on the system? How is it performing?

❖ DER Scenario Analysis

❖ Non-Wire or Non-Traditional Alternatives

❖ Benefit Cost Analysis

❖ 5-10 Year System Modernization and Infrastructure Plan

❖ NEW – Increased reporting on Electrification

❖ Transportation Electrification Plan

INTEGRATION

❖ Holistic System Planning

- ❖ Integrated Resource Plan (IRP) – A long term plan for generation resources to meet forecasted demand and policy goals
- ❖ Integrated Distribution Plan (IDP) – Reporting and planning for a rapidly evolving energy paradigm – the distribution system now hosts generation of its own as well as moves energy in multiple directions; Electric vehicles, small solar, and storage systems now in the mix
- ❖ Energy Conservation and Optimization (ECO) – Planning and programming aiming to make the most efficient use of electricity on the system.

❖ Optimizing the Grid

- ❖ As electricity demand increases and generation technologies change, the distribution system plays a vital role in getting the most out of the electrical system that we have. Generation and Conservation both rely on a dependable and up to date distribution system.

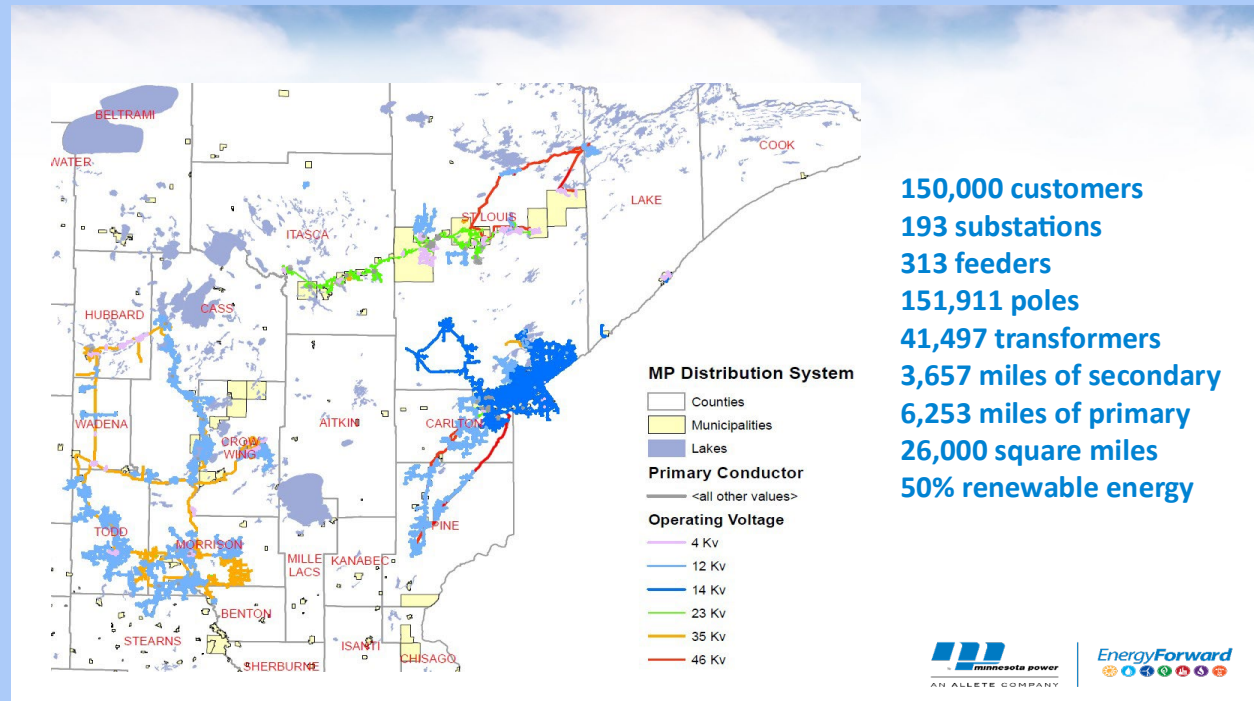
❖ Ready for the Future

- ❖ What does MP's distribution grid need to meet the demands of the next 5-10 years?

OPTIMIZATION - DISTRIBUTION SYSTEM OVERVIEW

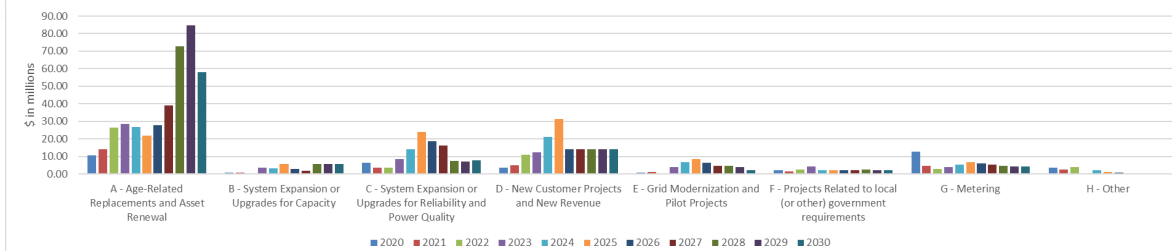
ERIC CLEMENT – MANAGER T&D GRID MODERNIZATION





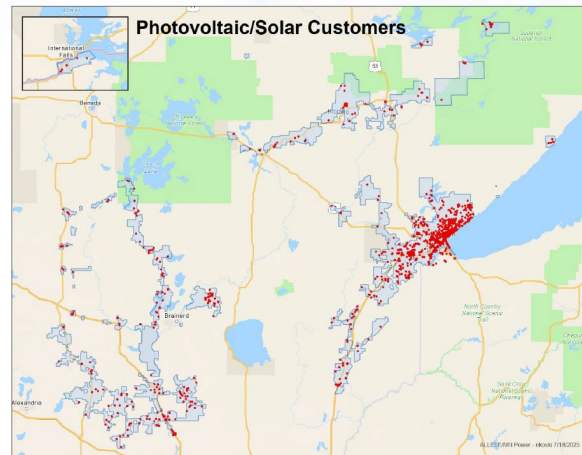
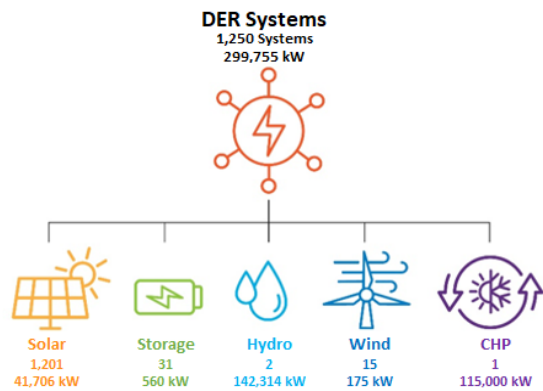
HISTORICAL & 5 YEAR INVESTMENT PLAN

Figure 5: Historical Distribution System Spending, by category



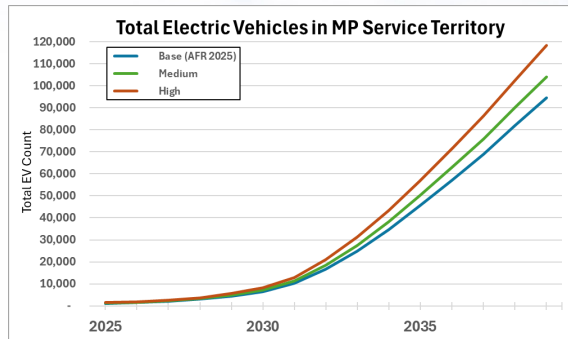
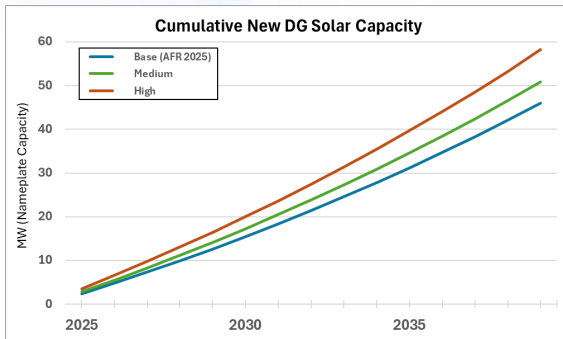
IDP Category	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
A - Age-Related Replacements and Asset Renewal	10.44	13.97	26.48	28.48	26.62	21.68	27.62	39.17	72.85	84.69	58.11
B - System Expansion or Upgrades for Capacity	0.80	0.56	0.11	3.48	3.15	5.52	2.80	1.90	5.50	5.50	5.50
C - System Expansion or Upgrades for Reliability and Power Quality	6.17	3.58	3.46	8.52	14.18	24.03	18.78	16.03	7.55	6.95	7.70
D - New Customer Projects and New Revenue	3.48	5.08	10.88	12.24	21.23	31.37	14.00	14.00	14.00	14.00	14.00
E - Grid Modernization and Pilot Projects	0.81	1.00	0.50	3.98	6.77	8.45	6.21	4.52	4.52	4.02	2.02
F - Projects Related to local (or other) government requirements	2.12	1.51	2.44	4.19	1.97	2.20	2.18	2.20	2.53	2.20	2.20
G - Metering	12.52	4.65	2.91	3.96	5.37	6.79	5.80	5.28	4.55	4.35	4.35
H - Other	3.48	2.62	3.99	0.49	2.12	1.08	0.88	0.38	0.38	0.38	0.38

DER Systems



LOAD AND DER SCENARIO ANALYSIS CORY ERICKSON - CUSTOMER INSIGHTS AND FORECASTING ANALYST

DER SCENARIO ANALYSIS – DG SOLAR & EV FORECASTS



Cumulative New DG Solar Capacity (MW)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base (AFR 2025)	2.4	4.8	7.3	9.9	12.7	15.5	18.4	21.4	24.6	27.8	31.2	34.7	38.4	42.1	46.1
Medium	2.8	5.5	8.3	11.2	14.2	17.3	20.5	23.8	27.3	30.9	34.6	38.5	42.5	46.6	50.9
High	3.6	6.6	9.8	13.1	16.5	20.0	23.7	27.4	31.4	35.5	39.7	44.1	48.6	53.3	58.2

Total EV Count	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Base (AFR 2025)	1,180	1,533	2,059	2,999	4,514	6,531	10,378	16,777	25,000	34,704	45,558	57,184	68,969	82,045	94,624
Medium	1,298	1,687	2,265	3,299	4,965	7,184	11,416	18,455	27,500	38,174	50,113	62,903	75,866	90,250	104,086
High	1,475	1,917	2,574	3,749	5,642	8,163	12,973	20,971	31,250	43,379	56,947	71,480	86,212	102,556	118,280



RELIABILITY/RESILIENCY TARGET AREAS

- ❖ Leveraging/Integrating Systems – C2M/AMI, EMS, GIS, OMS, Designer XI, Synergi Modeling software
- ❖ Vegetation Management – increased spend
- ❖ AMI integration – OMS, voltage monitoring, phase detection
- ❖ Maintenance – increased programming, low or no maintenance equipment
- ❖ Groundline – expanded programs
- ❖ Equipment – Underground first, Trip Savers rollout
- ❖ Automation – FLISR, Sensors, Motor Operators, Remote Recloser FLISR program
- ❖ Risk Mitigation – Wildfire, Resiliency

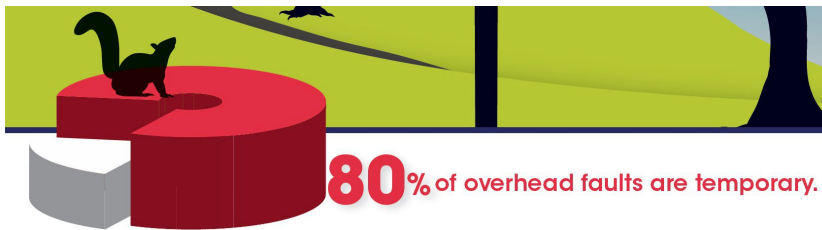
STRATEGIC UNDERGROUNDING

- 2020 and forward initiative
- Target heavy tree areas
- Improve reliability



TRIP SAVERS

- Recloser in a cutout body.
 - Over 350 installed on our system since 2017.
 - Proven technology to clear temporary faults without rolling a truck

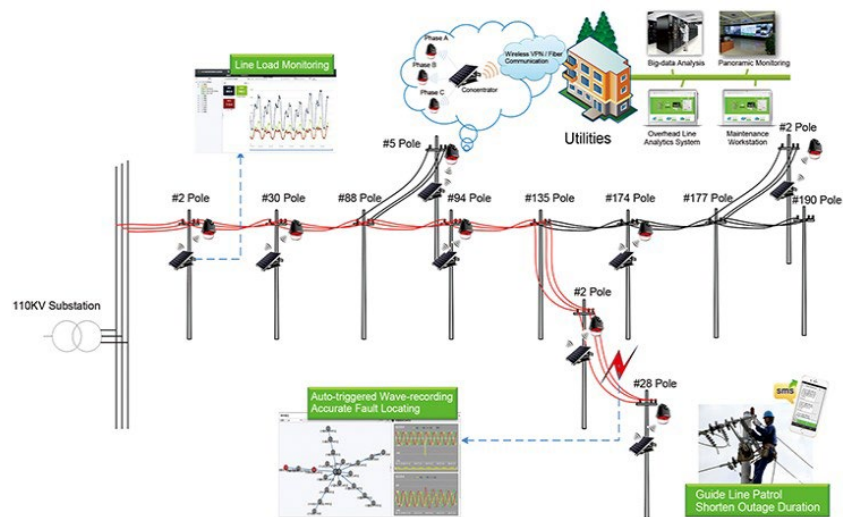


INTELLIRUPTERS

- FLISR technology
- Auto-restore customers
- Continue to rollout IntelliRupters.
- Targeting areas for increased reliability.
- Expanding recloser rollout



SMART SENSORS



MOTOR OPERATED SWITCHES

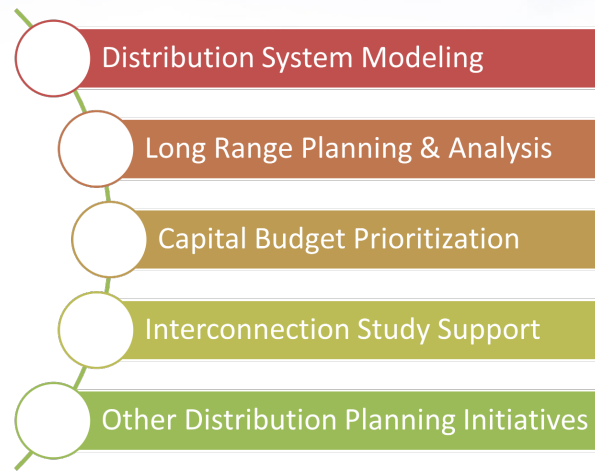
- Using existing communications systems
- Reduces response time
- Integrate with smart sensors



INNOVATION – PLANNING FOR NEW APPROACHES



DISTRIBUTION PLANNING



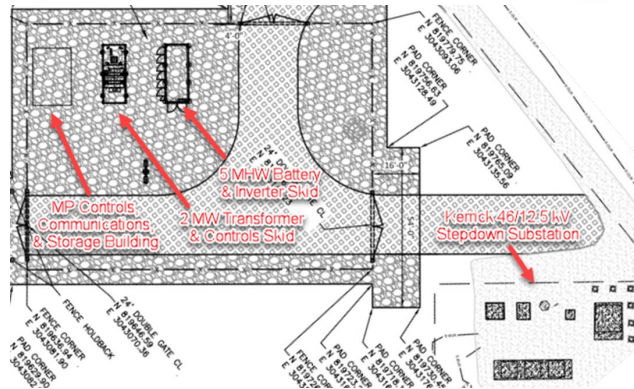
OTHER DISTRIBUTION PLANNING INITIATIVES

- Coordination – Strategy & Planning, Regulatory Affairs, Customer Programs and Service Representatives, Distribution Engineering, Distribution Service Representatives, System Operators, Other Utilities, etc...
- Participation – Distribution Planning-Focused Regulatory Initiatives, Grid Modernization, Key Customer Technical Support, Integrated Resource Plan Distribution Section, Solar Interconnection Process, etc...
- Technical Analysis – Any other regulatory or miscellaneous need for technical studies with a primary distribution focus



KERRICK BATTERY PROJECT UPDATE

- 2023 pilot from NWA analysis
 - Rebuild over 25 miles of 46kV over head
 - BCA above 1 – saves over \$10 million of asset renewal costs
- 2MW/5MWH battery
- 4 hours of back-up power for existing load
- ISD of Q1 2026
- Potential for future solar tie



TRANSPORTATION ELECTRIFICATION AND BEYOND

KATIE FRYE – MANAGER CUSTOMER PROGRAMS AND SERVICES



ELECTRIFICATION

- ❖ Electrification is the process of converting an energy-consuming device, system, or sector from non-electric sources of energy to electricity.
 - ❖ Carbon Reduction
 - ❖ Customer Cost Savings
 - ❖ Demand Flexibility
- ❖ Energy Conservation and Optimization (ECO) statute updated in 2021 and 2024 to allow for additional programs:
 - ❖ Energy efficiency
 - ❖ Efficient fuel switching/electrification
 - ❖ Load management
- ❖ MP will be adding electrification and load management in our next program triennial (2027-2029).



Electric Vehicle Programs & Initiatives

Rates	Rebates	Infrastructure	Education
Residential EV Charging	\$500 Level 2 Charger	20 L2 Chargers	First Responder Training
Residential Time of Day	\$500 Second Service	16 DCFC Stations	Community Events
Public EV Charging	ECO Rebates	Make Ready Pilot	Electrician Network
Fleet EV Charging			



QUESTIONS?



THANK YOU!

NOTE:

THE NEXT IDP ENGAGEMENT MEETING IS SCHEDULED FOR WEDNESDAY, SEPTEMBER 3



MINNESOTA POWER'S 2025 INTEGRATED DISTRIBUTION PLAN

September 3, 2025



OVERVIEW

- ❖ Overview of 2025 Integrated Distribution Plan
- ❖ Recap of July 18 Engagement Meeting
- ❖ Q & A and Discussion

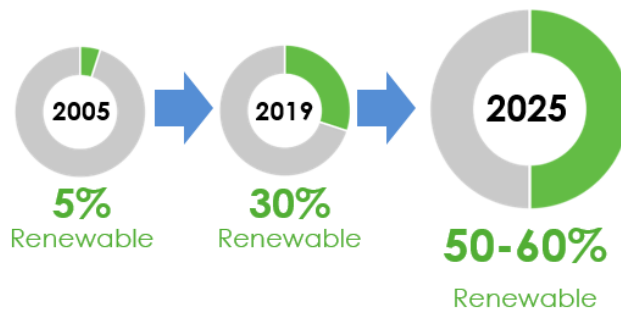
2025 INTEGRATED DISTRIBUTION PLAN OVERVIEW

JESS MCCULLOUGH – PUBLIC POLICY ADVISORS



MINNESOTA POWER IS UNIQUE

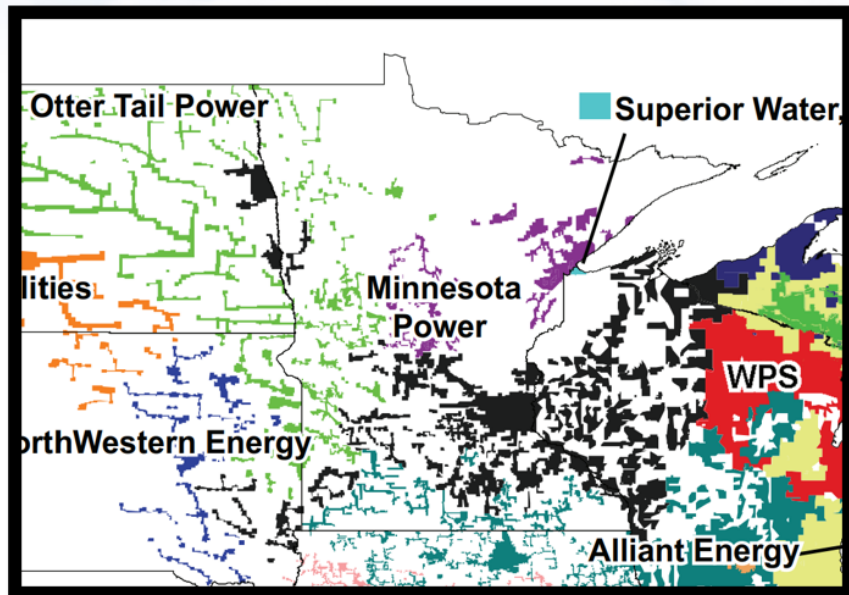
Leading MN in Renewables



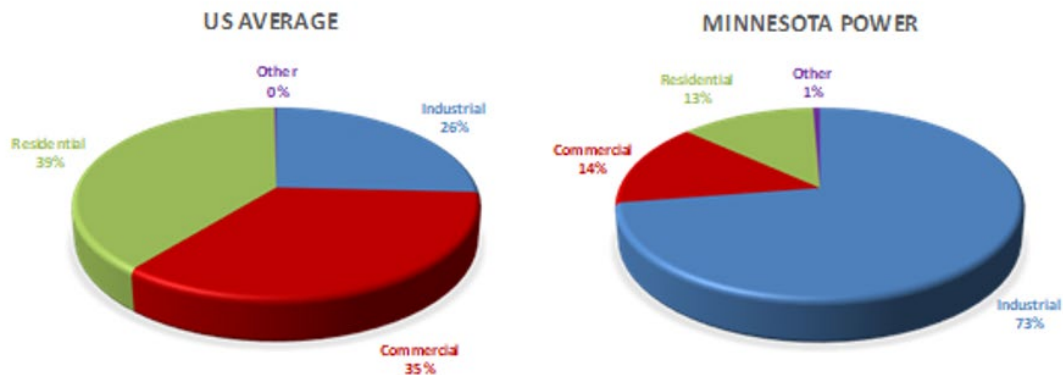
Duluth, MN Headquarters
26,000 Square-miles
150,000 Customers
13% Residential sales
73% Industrial sales
14 Municipalities



MINNESOTA POWER'S SERVICE TERRITORY



MINNESOTA POWER IS UNIQUE CONT'D



Source: US Energy Information Administration (2022 EIA Form 861 Data)

THEMES

❖ Investing in Optimized Asset Renewal

- ❖ Upgrading & Improving as we replace
- ❖ Efficient investment in and use of existing assets
- ❖ Improving resiliency & reliability

❖ Preparing for Anticipated Customer Energy Needs

- ❖ Electrification, EVs, DG

❖ Integrated Distribution System Planning

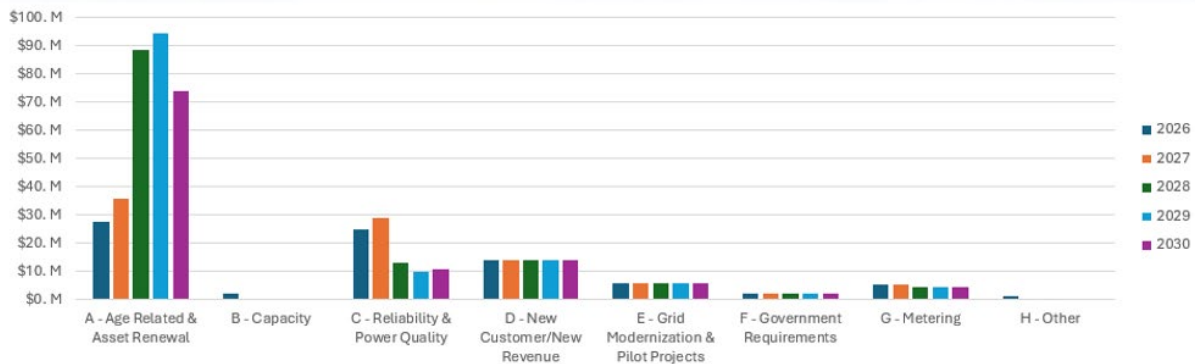
- ❖ MP approaches distribution planning holistically and in the context of resource planning (IRP) and energy conservation & optimization (ECO)
- ❖ Implementing previous IDP learnings and initiatives with an eye toward the future

❖ Meeting state policy objectives

- ❖ The distribution grid isn't just a delivery mechanism, it is a resource in the drive to a carbon-free system
- ❖ DSES, DG, CFS
- ❖ Meeting state policy



5-YEAR BUDGET



- ❖ Optimized Asset Renewal will continue to be of primary importance between 2025 and 2030
- ❖ "Renewal", not "Replacement"
- ❖ Continuing investment in grid visibility



JUNE 18 RECAP



JULY 18, 2025

- ❖ Held on site at Minnesota Power HQ in Duluth
- ❖ Attended virtually and in person
 - ❖ Agencies, Municipalities, Clean Energy Organizations represented
- ❖ Key Questions:
 - ❖ EV Fleet Programming
 - ❖ EV Forecasting Methods



Q&A: BENEFIT COST ANALYSIS



Q&A: DER



Q&A: BUDGETS



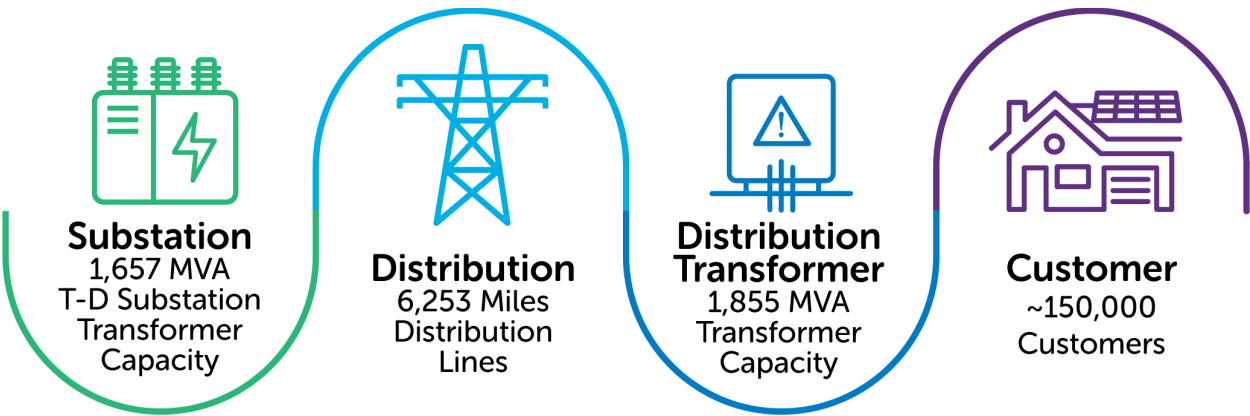
Q&A: TRANSPORTATION ELECTRIFICATION



Q&A: GENERAL

Current DER and System Summary

Figure 1: Minnesota Power System Summary 2025



Substation MVA is the firm capacity of all transmission to distribution substations that deliver power from the transmission system to Minnesota Power’s distribution system.

Distribution MVA is the total capacity of all stepdown transformers connected to the distribution system to serve customers.

Table 1: Minnesota Power Distributed Energy Resource Status

Minnesota Power Distributed Energy Resources Completed Interconnections in 2025		
DER Technology Type	Nameplate Rating	Interconnections
Solar	2,150.82	101
Combined Solar/Storage	37.34	3
Battery Storage		

Table 2: Minnesota Power Distributed Energy Resource Interconnection Queue

Minnesota Power Distributed Energy Resources Queued Interconnections in 2025		
Proposed DER Capacity (kW)	DER Type	Application Status
16.5	Solar	Construction
16.2	Solar	Construction
14.59	Solar	Construction
3.8	Solar	Construction
500	Solar	Construction
17.66	Solar	Construction
39.74	Solar	Construction

11.4	Solar	Construction
38	Solar	Construction
13.06	Solar	Construction
13.06	Solar	Construction
38.4	Solar	Construction
38.4	Solar	Construction
38	Solar	Construction
8.37	Solar	Construction
4.06	Solar	Construction
3.8	Solar	Construction
2.5	Solar	Construction
11.16	Solar	Construction
30	Solar	Construction
3.42	Solar	Construction
14.49	Solar	Construction
3.77	Solar	Construction
3.84	Solar	Construction
11.4	Solar	Construction
300	Solar	Construction
35.32	Solar	Construction
4.88	Solar	Construction
7.6	Solar	Construction
35	Solar	Construction
4.18	Solar	Construction
12.6	Solar	Construction
32	Solar	Construction
250	Solar	Construction
15.2	Solar	Construction
15.2	Solar	Construction
249.5	Solar	Construction
7.56	Solar	Construction
8.02	Solar	Construction
13.3	Solar	Construction
10	Solar	Construction
11.86	Solar	Construction
7.87	Solar	Construction
2.84	Solar	Construction
7.24	Solar	Construction
12	Energy Storage	Construction
4.19	Solar	Construction
3.77	Solar	Construction
10.02	Solar	Construction
3.6	Solar	Construction

5.85	Solar	Construction
4.53	Solar	Construction
7.6	Solar	Construction
9.21	Solar	Construction
4.19	Solar	Construction
10	Solar	Construction
15000	Energy Storage	Construction
4.88	Solar	Construction
7.98	Solar	Construction
13.82	Solar	Construction
11.4	Solar	Construction
6.3	Solar	Construction
30.4	Solar	Construction
120	Solar	Construction
2.9	Solar	Construction
7.6	Solar	Construction
18.15	Solar	Construction
6.63	Solar	Construction
400	Solar	Construction
5.03	Solar	Construction
5	Energy Storage	Construction
4.61	Solar	Construction

Minnesota Power

2024 Distribution Loss Study

Study Report



Distribution Planning
September 2025

Revision History

Date	Rev	Description
09/5/2025	0.0	Final Study Scope

Contributors

This study report borrows from the 2016 Distribution Loss Study and 2021 Distribution Loss Study with updated 2024 load data. The report was developed by the Distribution Planning Department, with significant contributions from Nick Boldt, Christian Winter, Garett Henriksen, Kai Syck, and Brad Bergslien.

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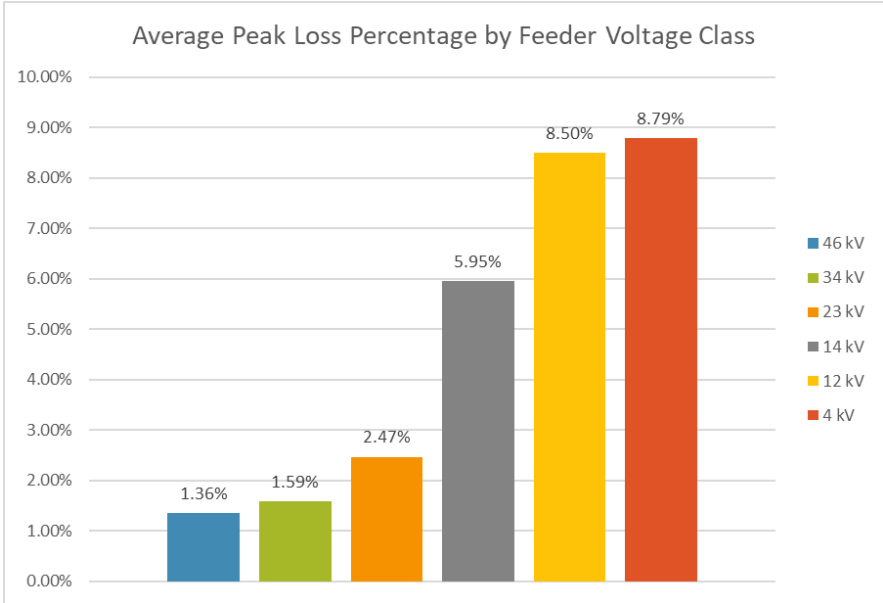
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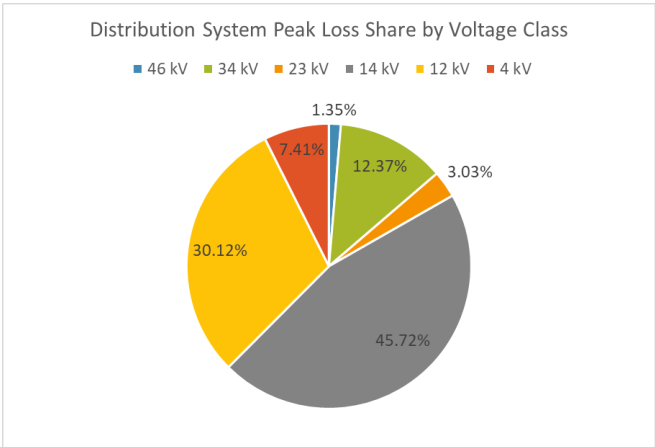
Executive Summary

Peak and energy loss percentages were calculated for Minnesota Power’s distribution system and delineated by voltage class. The study results include losses from the distribution substation bus to the customer meter.

Peak losses are the instantaneous power system losses at the time of greatest distribution system demand. Hourly distribution system loading data from 2024 was evaluated to identify coincident peak distribution system demand. Power system models were evaluated to determine average peak loss percentages by voltage class, as shown the figure below. The average peak loss percentages were then applied to the historical peak-hour demand to estimate total distribution system peak losses, the contribution of each voltage class to system peak losses, and the aggregate Minnesota Power distribution system peak loss percentage. All of these values are provided in the table and chart below. **The peak loss percentage for Minnesota Power’s distribution system is 5.83 percent.**



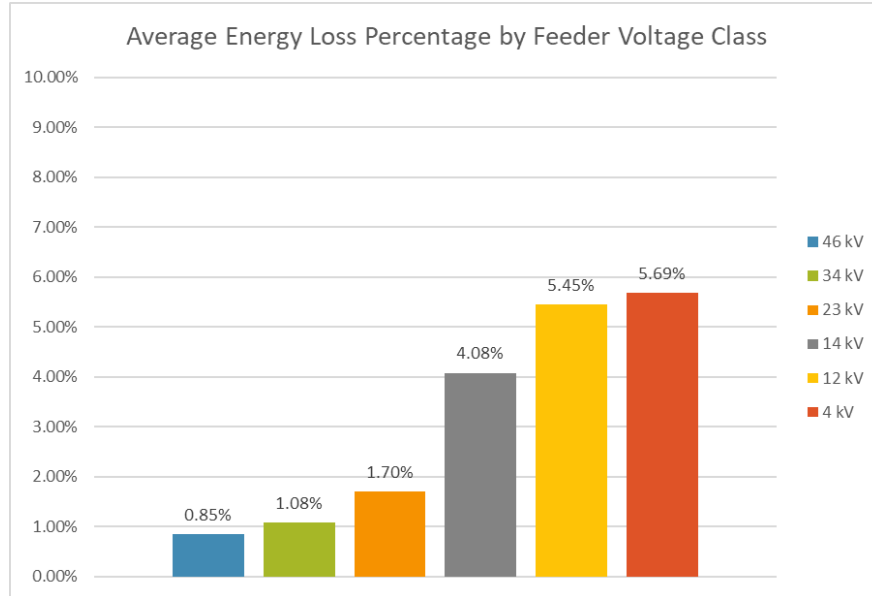
Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	2.33 MW	0.43 %
12 kV	9.47 MW	1.76 %
14 kV	14.37 MW	2.66 %
23 kV	0.95 MW	0.18 %
34 kV	3.89 MW	0.72 %
46 kV	0.42 MW	0.43 %
TOTAL	31.43 MW	5.83 %



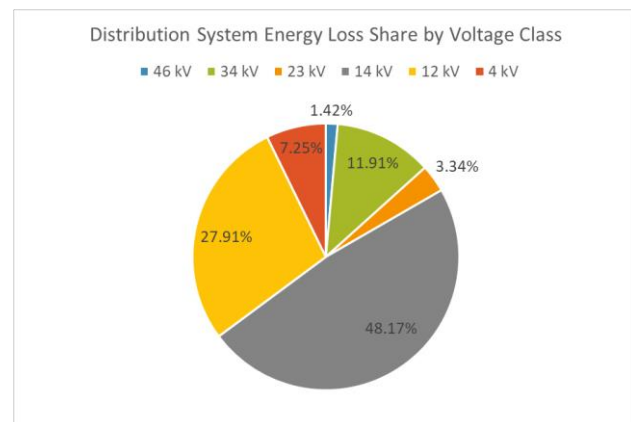
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September 2025

Energy losses are power system losses accumulated over time, in this case annually. Hourly distribution system loading data from 2024 was evaluated to identify total annual energy served from the distribution system. The average peak loss percentages by voltage class originally derived from power flow models were used along with historical loading information to calculate average energy loss percentages by voltage class, which are shown in the figure below. The average energy loss percentages were then applied to the historical annual energy for the distribution system to estimate annual distribution system energy losses, the contribution of each voltage class to annual energy losses, and the aggregate Minnesota Power distribution system annual energy loss percentage. All of these values are provided in the table and chart below. **The energy loss percentage for Minnesota Power's distribution system is 3.89 percent**



Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	8,805 MWh	0.28 %
12 kV	33,912 MWh	1.08 %
14 kV	58,517.8 MWh	1.87 %
23 kV	4,059 MWh	0.13 %
34 kV	14,463 MWh	0.46 %
46 kV	1,729 MWh	0.06 %
TOTAL	121,486 MWh	3.89 %



Section 1: Background

Losses are a measure of the energy flow across the system that is converted into heat due to impedance within the elements of the power system. It is necessary for utilities to provide enough generation to serve their respective system demands (plus reserves), taking into account the loss of energy before it can be usefully consumed. Unlike the networked transmission system, the distribution system is normally operated in a radial, source-to-load configuration. As a result of the radial configuration of the distribution system, the power flow on a typical radial distribution feeder corresponds directly to the load that is served by the feeder. This makes it possible to determine the losses specifically attributable to each particular feeder and its connected load. The purpose of this study report is to calculate the losses for Minnesota Power's distribution system based on evaluation of a representative subset of particular distribution feeders from the substation source to the customer meter.

Section 2: Model Development

Loss evaluation was completed in MilSoft WindMil software package using GIS-based feeder models. Historical evaluated load data was utilized as available from SCADA or line sensors to set peak load levels in the models. The loss study used only WindMil models that had previously been developed for other distribution planning studies. No new WindMil models were developed for the loss study.

Section 3: Study Methodology

The loss study utilized historical data and GIS-based feeder models to calculate the losses on a representative subset of Minnesota Power distribution feeders. The study pertains only to Minnesota Power distribution feeders. Losses on distribution systems owned by external entities are not included. The results of loss analysis for the subset of feeders included in the study were used to estimate peak and energy loss percentages by voltage class for Minnesota Power's entire distribution system. The study methodology is described in detail below.

3.1 Historical Data Analysis

For each of the feeders in the study, 2020 or 2024 historical data was evaluated to identify the feeder's annual peak demand when operating in its normal configuration, as well as average demand and annual energy consumption. Where available, SCADA-based historical data was utilized. Where feeders or stepdowns did not have SCADA, line sensor or billing load data was utilized to estimate the peak demand on the feeder. Where feeders serve both Minnesota Power and non-Minnesota Power loads, the impact of the non-Minnesota Power load on Minnesota Power distribution system losses is included in the analysis.

3.2 WindMil Model Simulation

The peak demand data was incorporated into the previously-built WindMil model. The WindMil model includes all data pertaining to the configuration of the feeder, including but not limited to line length, phasing and branch orientation, conductor and impedance assumptions, stepdown transformers and other connected devices, and how customer delivery points are dispersed along the feeder. The majority of this data is imported to WindMil from Minnesota Power's GIS database. Utilizing the WindMil model, the loss calculation was completed in one of three ways, depending on the configuration of the feeder:

- A. The following process was applied to calculate feeder peak losses for feeders consisting entirely of a single voltage class ("simple" feeders):
 - a. Set source voltage to 1.0 per unit (nominal), turn off all cap banks, and leave all voltage regulators in service and regulating

Study Report: 2024 Distribution Loss Study

September 2025

- b. Allocate historical feeder peak load, including real and reactive power, to all consumers on the feeder with ratios based on historical billing load data
 - c. Record total feeder losses reported by WindMil load allocation tool
 - B. The following process was applied to calculate feeder peak losses for the higher-voltage feeder in a feeder system consisting of multiple voltage classes ("parent" feeders):
 - a. Begin with a model of the entire multi-voltage feeder system, including the parent feeder, all stepdown transformers, and all stepdown feeders
 - b. Set source voltage to 1.0 per unit (nominal), turn off all cap banks, and leave all voltage regulators in service and regulating
 - c. Allocate historical feeder peak load, including real and reactive power, to all consumers on parent and stepdown feeders with ratios based on historical billing load data
 - d. For each stepdown transformer, add an equivalent consumer load at the high side of the transformer equal to the real and reactive power flow through the transformer, then disconnect the stepdown transformer and stepdown feeders
 - e. Run WindMil voltage drop function and record feeder losses for parent feeder only, including both "kW losses" (conductor losses) and "no load losses" (transformer losses)
 - C. The following process was applied to calculate feeder peak losses for the lower-voltage feeder in a feeder system consisting of multiple voltage classes ("stepdown" feeders) after previously completing the steps in Part B:
 - a. Place an equivalent source at the high side of the stepdown transformer and reconnect stepdown transformer and feeder to new equivalent source (keeping it disconnected from the parent feeder)
 - b. Allocate historical stepdown feeder load, if different from previous load allocation, to all consumers on stepdown feeder with ratios based on historical billing load data
 - c. Record stepdown feeder and transformer losses reported by WindMil load allocation tool

3.3 Calculation of Peak and Energy Loss Percentages

The processes described in Sections 3.1 and 3.2 provide the modeled peak losses for each feeder in the study. The feeder peak loss percentage may then be calculated according to the following formula:

$$(1) \quad \text{Feeder Peak Loss Percentage} = \text{Feeder Losses at Peak Demand} / \text{Feeder Peak Demand}$$

Feeder energy losses were also calculated. The peak loss percentage represents only the instantaneous losses on the feeder at the moment of peak load. In reality, demand for electric power is not constant and power flow on a given distribution feeder varies over time, increasing as demand increases and decreasing as demand decreases. Since feeder losses are proportional to the current flowing on the line, the losses on the feeder will also vary over time. Feeder energy losses represent the average annual energy losses accumulated on the feeder as the loading varies over time. The annual energy consumption for a feeder can be calculated by adding demand (kW) from all hours in a given year to get total energy in kilowatt-hours (kWh). There is no precise way to calculate average annual energy losses, but one common method¹ uses the peak and average feeder demand and the losses at peak demand to estimate average annual energy losses according to the following formulas:

$$(2) \quad \text{Load Factor} = \text{Average Demand} / \text{Peak Demand}$$

$$(3) \quad \text{Loss Factor} = (0.3 \times \text{Load Factor}) + (0.7 \times \text{Load Factor}^2)$$

$$(4) \quad \text{Annual Energy Losses (MWh)} = (\text{Loss Factor} \times \text{Losses at Peak Demand}) \times \text{Hours}$$

¹ Gönen, Turan. *Electric Power Distribution System Engineering*. McGraw Hill, 1986. 55, 58-59

Study Report: 2024 Distribution Loss Study

September 2025

The average demand and peak demand values in equation (2) are derived from historical data as described in Section 3.1. The losses at peak demand in equation (4) are derived from the WindMil model as described in Section 3.2. Normally the “Hours” in equation (4) would be 8,760, which is the total number of hours in a typical year. However, since this study used historical data from 2024, which was a leap year, the total number of hours used in equation (4) for this study was 8,784. The feeder energy loss percentage may then be calculated according to the following formula:

(5) $\text{Energy Loss Percentage} = \text{Annual Energy Losses} / \text{Annual Energy Consumption}$

3.4 Calculation of System Loss Percentages

System loss percentages were calculated based on the representative set of feeders included in the study. Table 1 at the end of this section lists the feeders that were included in the study along with the feeder voltage class and feeder type (simple, parent, or stepdown). For each of the voltage classes, the contribution of that voltage class to total distribution system losses and the total distribution system loss percentage was determined for peak losses and for energy losses, as described below.

System Peak Loss Percentages

- a) For each voltage class, calculate the peak loss percentage for that voltage class based on the average of peak loss percentages for all feeders of that voltage class included in the study
- b) From historical data, calculate the coincident peak load served by Minnesota Power’s distribution system at the transmission-to-distribution substation interface for calendar year 2024, excluding an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)
- c) For each substation, determine the share of the coincident peak load associated with each voltage class present at the substation
 - a. For substations with multi-voltage (parent/stepdown) feeder systems, develop an allocation factor for the substation to split the total substation load between the voltage classes that are present on the feeders. In general, the parent voltage class will carry the full load of the feeder while the stepdown voltage classes will only carry what is attributable to the stepdowns based on historical data or engineering estimates
- d) For each substation, calculate peak distribution system losses by voltage class according to the following formula:

$$\text{Peak Loss}_{VC} = \text{Peak Load}_{VC} \times \text{Peak Loss Percentage}_{VC}$$

Where Peak Load_{VC} is the share of that voltage class in the coincident peak load by substation from (c) and $\text{Peak Loss Percentage}_{VC}$ is the voltage class peak loss percentage from (a)

- e) Add up the peak losses calculated for each substation in (d) to obtain system peak losses by voltage class. Add up the peak losses for all voltage classes to obtain total system peak losses.
- f) The contribution of each voltage class to total system peak losses may then be represented both in terms of physical units (kW or MW) as well as a percentage of the total system peak losses

Energy Loss Percentages

- a) For each voltage class, calculate the energy loss percentage for that voltage class based on the average of energy loss percentages for all feeders of that voltage class included in the study
- b) From historical data, calculate the total annual energy served by Minnesota Power’s distribution system at the transmission-to-distribution substation interface for calendar year 2024, excluding an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)

Study Report: 2024 Distribution Loss Study

September 2025

- c) For each substation, determine the share of the total annual energy associated with each voltage class present at the substation
 - a. For substations with multi-voltage (parent/stepdown) feeder systems, develop an allocation factor for the substation to split the total annual energy between the voltage classes that are present on the feeders. In general, the parent voltage class will carry the full load of the feeder while the stepdown voltage classes will only carry what is attributable to the stepdowns based on historical data or engineering estimates
- d) For each substation, calculate distribution system energy losses by voltage class according to the following formula:

$$Energy\ Loss_{VC} = Annual\ Energy_{VC} \times Energy\ Loss\ Percentage_{VC}$$

Where *Annual Energy_{VC}* is the share of that voltage class in the total annual energy by substation from (c) and *Energy Loss Percentage_{VC}* is the voltage class energy loss percentage from (a)

- e) Add up the energy losses calculated for each substation in (d) to obtain system energy losses by voltage class. Add up the energy losses for all voltage classes to obtain total annual energy losses.
- f) The contribution of each voltage class to total annual energy losses may then be represented both in terms of physical units (kWh or MWh) as well as a percentage of the total annual energy losses

Study Report: 2024 Distribution Loss Study

September 2025

Feeder	kV	Area	Type	Feeder	kV	Area	Type
23 LINE	46	Central	Parent	HIB-312	23	Northern	Simple
ASK-6521	12	Central	Stepdown	HIB-315	23	Northern	Parent
CLQ-406	14	Central	Simple	INF-1	12	Northern	Simple
CLQ-409	14	Central	Parent	INF-2	12	Northern	Simple
CLQ-410	14	Central	Simple	INF-3	12	Northern	Simple
COL-240	14	Central	Simple	INF-4	12	Northern	Simple
COL-241	14	Central	Simple	KLY-1	4	Northern	Stepdown
COL-242	14	Central	Simple	MTU-330	23	Northern	Parent
COL-244	14	Central	Simple	STZ-1	4	Northern	Stepdown
COL-245	14	Central	Simple	STZ-2	4	Northern	Stepdown
CQB-6301	12	Central	Stepdown	SVE-1	4	Northern	Stepdown
FOR-262	14	Central	Stepdown	SVW-2	4	Northern	Stepdown
FOR-262	14	Central	Stepdown	SWB-1	4	Northern	Stepdown
FRR-275	14	Central	Simple	VRG-302	23	Northern	Simple
GRY-200	14	Central	Simple	BAX-534	34	Western	Parent
GRY-201	14	Central	Simple	BBR-1	12	Western	Stepdown
KER-6501	12	Central	Stepdown	BRW-1	12	Western	Stepdown
LSP-208	34	Central	Parent	BRW-2	12	Western	Stepdown
LSP-280	14	Central	Parent	CLR-1	12	Western	Stepdown
LSP-282	14	Central	Parent	CLR-2	12	Western	Stepdown
NIN-246	14	Central	Stepdown	EGV-517	34	Western	Parent
NIN-248	14	Central	Stepdown	FLN-1	12	Western	Stepdown
RGV-253	14	Central	Simple	FLN-2	12	Western	Stepdown
SLA-203	34	Central	Parent	GGR-1	12	Western	Stepdown
SND-217	14	Central	Stepdown	HPS-1	12	Western	Stepdown
SND-218	14	Central	Stepdown	LCH-1	12	Western	Stepdown
TFW-243	14	Central	Stepdown	LGP-1	12	Western	Stepdown
WRN-411	14	Central	Parent	LLK-1	12	Western	Stepdown
WRR-6321	12	Central	Stepdown	LNL-1	12	Western	Stepdown
31 LINE	46	Northern	Parent	LPD-2	4	Western	Stepdown
32 LINE	46	Northern	Parent	LPN-1	12	Western	Stepdown
33 LINE	46	Northern	Parent	LPR-501	34	Western	Parent
HYN-1	4	Northern	Stepdown	LPR-527	34	Western	Parent
HYN-2	4	Northern	Stepdown	LPR-535	34	Western	Parent
BAL-1	12	Northern	Stepdown	PIL-1	12	Western	Stepdown
BAL-2	12	Northern	Stepdown	PNB-1	12	Western	Stepdown
CHL-1	4	Northern	Stepdown	PNB-2	12	Western	Stepdown
CHL-2	4	Northern	Stepdown	PPL-514	34	Western	Parent
CHL-3	4	Northern	Stepdown	RVT-532	34	Western	Parent
AUR-313	23	Northern	Parent	RVD-1	12	Western	Stepdown
HIB-308	23	Northern	Parent	SWN-1	12	Western	Stepdown
HIB-310	23	Northern	Parent				

Table 1: Feeders Included in the Study

Section 4: Loss Analysis Results

4.1 Historical Data Analysis

For each of the feeders listed in Table 1, the values derived from historical data analysis are provided in the table in Appendix A: Feeder Loss Calculations. As shown in the appendix and described in Section 3, the feeder peak, average, and annual energy data were used to calculate loss percentages by feeder.

4.2 WindMil Model Simulation

For each of the feeders listed in Table 1, the losses derived from the WindMil model analysis are provided in the table in Appendix A: Feeder Loss Calculations. As shown in the appendix and described in Section 3, the modeled feeder losses were used along with historical data to calculate loss percentages by feeder.

4.3 Calculation of Peak and Energy Loss Percentages

For each of the feeders listed in Table 1, the individual feeder peak and energy loss percentages calculated from the combination of historical data and WindMil model analysis are also provided in the table in Appendix A: Feeder Loss Calculations. Individual feeder loss percentages vary from 0.1 percent to over 16 percent and, as expected, are inversely proportional to voltage (e.g. lower for higher voltage classes and higher for lower voltage classes). Energy loss percentages are generally lower than peak loss percentages, which is also an expected outcome since the feeders spend most of the year well below the peak condition and losses vary by the square of the current, meaning that the impacts of lower average loading are amplified exponentially in the energy losses. As discussed below and described in Section 3, the individual feeder loss percentages were used to estimate systemwide loss percentages by voltage class.

Table 2 below shows an example of feeder loss analysis for LSP-280, a 14 kV feeder originating at the LSPI Substation in West Duluth, using historical data and WindMil model values to calculate individual peak and energy loss percentages for the feeder.

Feeder Loss Evaluation

Line	Description	Value	Units	Source
0	Feeder	LSP-280		
1	Feeder Peak Date	12/12/2024 17:00		2024 Historical eDNA Data
2	Peak Loading @ Source	5.70	MW	2024 Historical eDNA Data
3	Peak Loading @ Source	5.70	MW	WindMil Model following Load Allocation
4	Peak Losses	273.30	kW	WindMil Model following Load Allocation
5	Peak Loss Percentage	4.79%		[Line 4] / [Line 3]
6	Avg Loading @ Source	3.18	MW	2024 Historical eDNA Data
7	Load Factor	55.75%		[Line 6] / [Line 2]
8	Loss Factor	38.48%		$(0.3 \times [\text{Line 7}]) + (0.7 \times [\text{Line 7}]^2)$
9	Average Losses	105.18	kW	[Line 8] x [Line 4]
10	Annual Energy Losses	924	MWh	[Line 9] / 1000 x 8784
11	Annual Energy	27,926	MWh	2024 Historical eDNA Data
12	Energy Loss Percentage	3.31%		[Line 10] / [Line 11]

Table 2: LSPI 280 Feeder Loss Evaluation Table

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4.4 Calculation of System Loss Percentages

As described in Section 3.4, the peak and energy loss percentages for each voltage class were calculated based on the average of all individual feeder peak and energy loss percentages for that voltage class. The calculated individual feeder peak and energy loss percentages are shown in Table 3 and illustrated in Figure 1 and Figure 2 below.

Voltage Class	Peak Loss Percentage	Energy Loss Percentage
4 kV	8.79 %	5.69 %
12 kV	8.50 %	5.45 %
14 kV	5.95 %	4.08 %
23 kV	2.47 %	1.70 %
34 kV	1.59 %	1.08 %
46 kV	1.36 %	0.85 %

Table 3: Peak & Energy Loss Percentages by Voltage Class

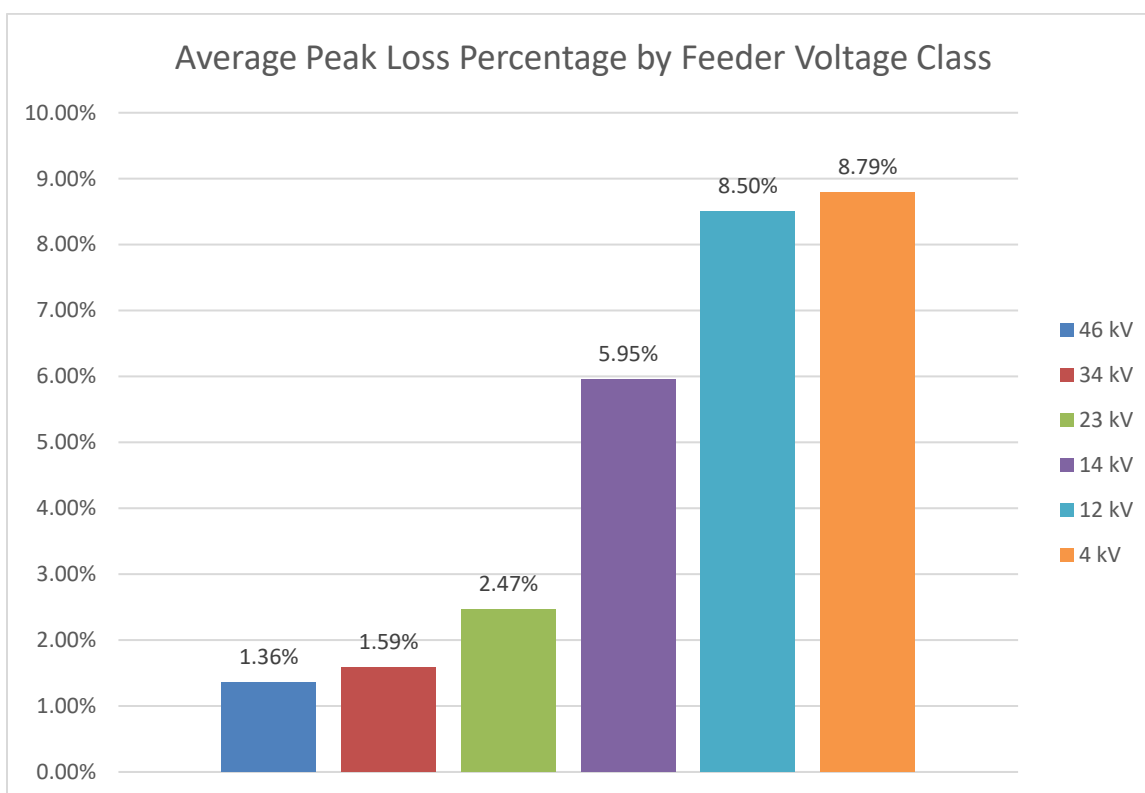


Figure 1: Average Peak Loss Percentage by Feeder Voltage Class

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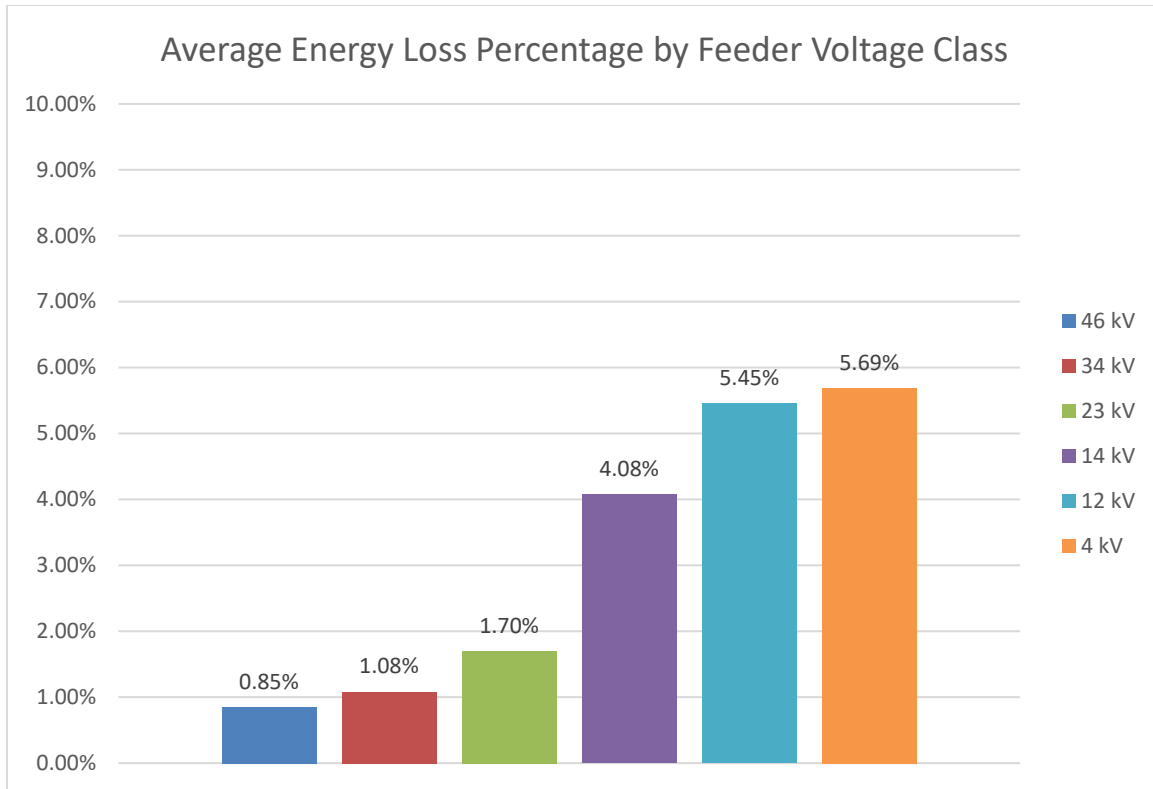


Figure 2: Average Energy Loss Percentage by Feeder Voltage Class

This methodology assumes that the sample set of feeders for each voltage class is sufficiently representative of the entire voltage class and that the inclusion of more feeders would not significantly change the average loss percentages.

4.5 Distribution System Loss Analysis

As described in Section 3.4, the calculated loss percentages by voltage class shown in Table 3 were utilized to estimate total Minnesota Power distribution system peak and energy losses and to identify the contribution of each voltage class to the totals. Calculated demand and energy losses are provided in Table 4 & Table 5, while the contribution of each voltage class to the total system losses is provided in Figure 4 and Figure 3. Details of the analysis are discussed below.

Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	2.33 MW	0.43 %
12 kV	9.47 MW	1.76 %
14 kV	14.37 MW	2.66 %
23 kV	0.95 MW	0.18 %
34 kV	3.89 MW	0.72 %
46 kV	0.42 MW	0.43 %
TOTAL	31.43 MW	5.83 %

Table 4: Distribution System Peak Losses

Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	8,805 MWh	0.28 %
12 kV	33,912 MWh	1.08 %
14 kV	58,517.8 MWh	1.87 %
23 kV	4,059 MWh	0.13 %
34 kV	14,463 MWh	0.46 %
46 kV	1,729 MWh	0.06 %
TOTAL	121,486 MWh	3.89 %

Table 5: Distribution System Energy Losses

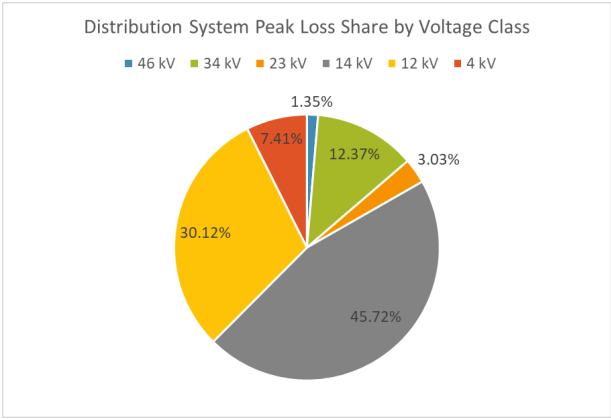


Figure 4: Peak Loss Share by Voltage Class

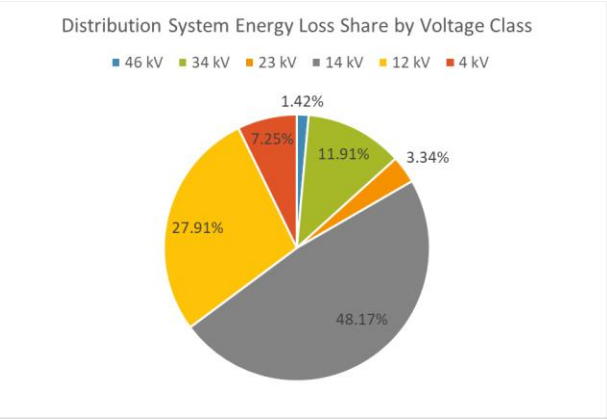


Figure 3: Energy Loss Share by Voltage Class

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Identification of Peak Loss Percentage

To determine total peak distribution system losses, historical load data from all Minnesota Power distribution feeders was grouped by substation and then evaluated to find the coincidence historical peak hour for Minnesota Power distribution system loading from calendar year 2024. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. As shown in Figure 5 below, the peak distribution system load from 2024 that was used for this loss analysis was 539 MW on July,31st 2024 at 2:00 PM.

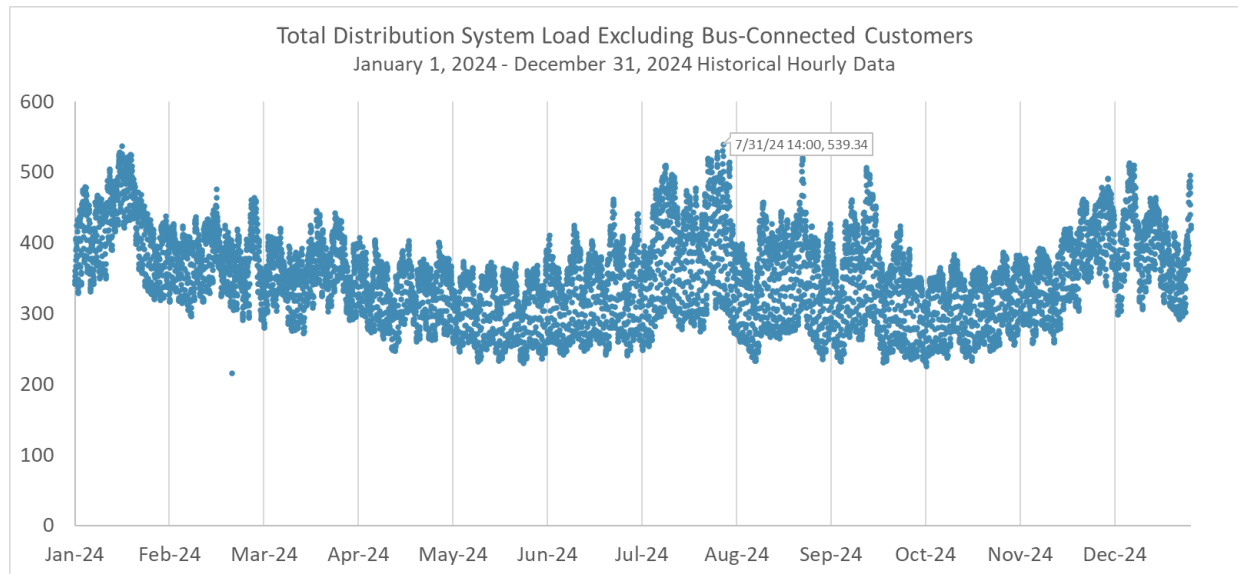


Figure 5: Minnesota Power 2024 Distribution System Coincident Loading

The contribution of each substation to peak-hour loading was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average peak loss factors from Table 3 to estimate the actual losses incurred on each voltage class at each substation during the 2024 peak load hour. The results from the individual substations were added up to determine the estimated peak losses by voltage class, the total system peak loss percentage, and the contribution of each voltage class to the total peak losses, as shown in Table 4 and Figure 4 above.

Identification of Energy Loss Percentage

To determine distribution system annual energy losses, hourly historical load data from all Minnesota Power distribution feeders was grouped by substation and then all 8,784 hours were added up to obtain total annual energy for calendar year 2024. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. The total annual energy for the Minnesota Power distribution system in 2024 that was used for this loss analysis was 3,126,717 MWh.

The contribution of each substation to annual energy consumption was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average energy loss factors from Table 3 to estimate the actual energy losses incurred on each voltage class at each substation during 2024. The results from the individual substations were added up to determine the estimated annual energy losses by voltage class, the total system energy loss percentage, and the contribution of each voltage class to the total energy losses, as shown in Table 5 and Figure 3 above.

Appendix A: Feeder Loss Calculations

The table on the following page provides detailed feeder loss calculation data for all feeders included in the study

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Feeder	Voltage Class (kV)	Area	Peak Loading @ Source (MW)	Peak Losses (kW)	Peak Loss Percentage	Avg Loading @ Source (MW)	Load Factor	Loss Factor	Average Losses (kW)	Energy Losses (MWh)	Annual Energy (MWh)	Energy Loss Percentage
31 Line	46	N	4.60	5.00	0.11%	2.55	55.51%	38.23%	1.91	16.79	22,431.40	0.07%
32 Line	46	N	8.40	136.00	1.62%	4.37	52.06%	34.59%	47.04	413.22	38,413.00	1.08%
33 Line	46	N	12.50	429.00	3.43%	5.32	42.59%	25.48%	109.30	960.13	46,769.30	2.05%
BCR-23	46	C	1.80	5.00	0.28%	0.95	52.96%	35.52%	1.78	15.60	8,373.00	0.19%
BAX-534	34	W	6.15	155.00	2.52%	2.71	44.01%	26.76%	41.48	364.36	23,767.18	1.53%
RVT-532	34	W	2.08	44.83	2.16%	0.52	25.08%	11.93%	5.35	46.97	4,572.72	1.03%
LSPI-208	34	C	8.10	50.00	0.62%	4.81	59.36%	42.48%	21.24	186.56	42,237.20	0.44%
SLA-203	34	C	13.60	362.11	2.66%	9.47	69.66%	54.86%	198.66	1,745.04	83,214.10	2.10%
LPR-501	34	W	6.70	57.00	0.85%	4.22	62.97%	46.65%	26.59	233.57	37,087.46	0.63%
LPR-527	34	W	7.48	10.80	0.14%	4.70	62.79%	46.44%	5.02	44.05	41,242.15	0.11%
LPR-535	34	W	11.84	244.00	2.06%	7.44	62.89%	46.55%	113.59	997.73	65,388.85	1.53%
EGV-517	34	W	7.90	102.00	1.29%	4.52	57.21%	40.08%	40.88	359.08	39,701.90	0.90%
PPL-514	34	W	8.40	167.97	2.00%	5.09	60.65%	43.94%	73.81	648.34	44,749.80	1.45%
AUR-313	23	N	4.26	79.02	1.85%	1.65	38.59%	22.00%	17.38	152.70	14,450.31	1.06%
HIB-308	23	N	4.55	128.00	2.82%	3.34	73.48%	59.83%	76.59	672.74	29,356.44	2.29%
HIB-310	23	N	6.69	462.00	6.91%	4.02	60.03%	43.24%	199.75	1,754.63	35,270.81	4.97%
HIB-315	23	N	1.19	17.00	1.43%	0.69	57.93%	40.87%	6.95	61.03	6,275.38	0.97%
MTU-330	23	N	2.80	53.00	1.89%	0.87	31.15%	16.14%	8.55	75.12	7,661.00	0.98%
HIB-312	23	N	7.38	47.00	0.64%	2.41	32.70%	17.30%	8.13	71.41	21,188.07	0.34%
VRG-302	23	N	4.77	83.00	1.74%	2.90	60.90%	44.23%	36.71	322.47	25,500.11	1.26%
GRY-200	14	C	3.22	171.30	5.32%	1.69	52.42%	34.96%	59.89	526.05	14,847.00	3.54%
GRY-201	14	C	4.69	346.10	7.38%	2.24	47.84%	30.37%	105.10	923.24	19,703.00	4.69%
LSP-280	14	C	5.70	273.30	4.79%	3.18	55.75%	38.48%	105.18	923.87	27,926.00	3.31%
LSP-282	14	C	0.79	43.20	5.45%	0.39	49.49%	32.00%	13.82	121.42	3,444.00	3.53%
FRR-275	14	C	3.10	272.30	8.78%	1.43	46.20%	28.80%	78.42	688.81	12,579.50	5.48%
RGV-253	14	C	4.50	336.60	7.48%	2.39	53.03%	35.60%	119.82	1,052.54	20,963.30	5.02%
CLQ-406	14	C	10.32	509.00	4.93%	5.97	57.90%	40.83%	207.83	1,825.60	52,482.55	3.48%
CLQ-409	14	C	7.32	394.78	5.37%	4.38	59.77%	42.94%	169.53	1,489.12	38,433.55	3.87%
CLQ-410	14	C	4.13	196.00	4.75%	2.48	60.11%	43.33%	84.92	745.95	21,780.82	3.42%
WRN-411	14	C	3.67	290.59	7.92%	1.91	52.15%	34.68%	100.78	885.25	16,796.74	5.27%
COL-240	14	C	7.53	495.90	6.58%	4.17	55.31%	38.01%	188.48	1,655.65	36,604.66	4.52%
COL-241	14	C	4.16	230.90	5.55%	2.17	52.21%	34.74%	80.22	704.62	19,091.83	3.69%
COL-242	14	C	6.27	358.60	5.71%	3.83	60.97%	44.32%	158.92	1,395.93	33,601.07	4.15%
COL-244	14	C	4.78	255.80	5.35%	2.76	57.73%	40.64%	103.97	913.26	24,231.71	3.77%
COL-245	14	C	1.67	203.20	12.15%	1.19	71.36%	57.05%	115.92	1,018.27	10,478.11	9.72%
TFW-243	14	C	3.20	157.30	4.92%	1.47	45.79%	28.41%	44.70	392.61	12,871.10	3.05%
FOR-263	14	C	2.90	107.80	3.72%	1.64	56.59%	39.40%	42.47	373.06	14,416.40	2.59%
FOR-262	14	C	2.60	93.80	3.61%	1.14	43.69%	26.47%	24.83	218.07	9,977.70	2.19%
SND-217	14	C	3.70	143.70	3.88%	1.97	53.32%	35.89%	51.58	453.07	17,328.40	2.61%
SND-218	14	C	2.40	127.00	5.29%	1.07	44.43%	27.15%	34.48	302.86	9,366.90	3.23%
NIN-248	14	C	3.80	235.00	6.18%	2.17	57.03%	39.88%	93.71	823.12	19,035.90	4.32%
NIN-246	14	C	2.60	149.10	5.73%	1.63	62.75%	46.39%	69.16	607.53	14,330.90	4.24%
INF-1	12	N	2.26	306.80	13.56%	1.29	57.10%	39.95%	122.57	1,076.64	11,345.69	9.49%
INF-2	12	N	3.54	193.80	5.48%	2.11	59.59%	42.74%	82.82	727.51	18,527.68	3.93%
INF-3	12	N	4.51	401.90	8.91%	2.64	58.48%	41.48%	166.70	1,464.33	23,177.16	6.32%
INF-4	12	N	2.85	148.90	5.23%	1.59	55.68%	38.41%	57.19	502.32	13,929.73	3.61%
WRR-6321	12	C	0.68	79.60	11.71%		52.15%	34.68%	27.61	242.49	2,924.13	8.29%
PIL-1	12	W	0.30	46.50	15.50%		44.01%	26.76%	12.44	109.31	2,078.75	5.26%
LNL-1	12	W	0.20	19.30	9.65%		44.01%	26.76%	5.16	45.37	1,385.83	3.27%
PNB-1/PNB-2	12	W	2.93	240.50	8.21%		44.01%	26.76%	64.36	565.34	20,302.42	2.78%
CQB-6301	12	C	1.20	108.80	9.07%		59.77%	42.94%	46.72	410.40	6,300.66	6.51%
RVD-1	12	W	0.47	35.10	7.47%		25.08%	11.93%	4.19	36.78	1,033.32	3.56%
LGP-1	12	W	0.81	93.80	11.58%		62.97%	46.65%	43.76	384.37	4,483.65	8.57%
GGR-1	12	W	2.69	152.00	5.65%		62.79%	46.44%	70.58	619.99	14,831.00	4.18%
BBR-1	12	W	1.20	31.50	2.63%		62.89%	46.55%	14.66	128.81	6,650.00	1.94%
HPS-1	12	W	0.51	22.50	4.41%		62.89%	46.55%	10.47	92.00	2,826.00	3.26%
LCH-1	12	W	0.65	60.20	9.26%		62.89%	46.55%	28.02	246.16	3,589.00	6.86%
LPN-1	12	W	0.05	3.90	7.80%		62.89%	46.55%	1.82	15.95	276.00	5.78%
CLR-1	12	W	2.20	160.00	7.27%		57.21%	40.08%	64.12	563.26	11,056.00	5.09%
CLR-2	12	W	0.20	16.50	8.25%		57.21%	40.08%	6.61	58.09	1,005.00	5.78%
BRW-1	12	W	3.03	236.00	7.79%		57.21%	40.08%	94.58	830.80	15,227.00	5.46%
BRW-2	12	W	3.45	451.00	13.07%		57.21%	40.08%	180.75	1,587.68	17,338.00	9.16%
FLN-1	12	W	0.15	6.80	4.53%		60.65%	43.94%	2.99	26.25	799.00	3.29%
FLN-2	12	W	0.65	52.00	8.00%		60.65%	43.94%	22.85	200.71	3,462.00	5.80%
LLK-1	12	W	0.72	67.80	9.42%		60.65%	43.94%	29.79	261.70	3,835.00	6.82%
SWN-1	12	W	2.27	133.00	5.86%		60.65%	43.94%	58.44	513.36	12,093.00	4.25%
BAL	12	N	1.41	23.80	1.69%		60.03%	43.24%	10.29	90.39	7,433.80	1.22%
KER-6501	12	C	0.50	80.90	16.18%		52.96%	35.52%	28.73	252.39	3,516.00	7.18%
ASK-6521	12	C	1.29	147.50	11.39%		52.96%	35.52%	52.39	460.17	4,856.00	9.48%
HYN-1	4	N	0.56	25.30	4.52%		38.59%	22.00%	5.57	48.89	1,899.57	2.57%
HYN-2	4	N	1.89	146.30	7.74%		38.59%	22.00%	32.19	282.72	6,411.05	4.41%

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LPD-2	4	W	0.58	24.20	4.17%		62.79%	46.44%	11.24	98.71	3,197.90	3.09%
SWB-1	4	N	0.20	32.80	16.40%		73.48%	59.84%	19.63	172.41	1,290.40	13.36%
CHL-1	4	N	2.30	184.00	8.00%		60.03%	43.24%	79.56	698.81	12,126.00	5.76%
CHL-2	4	N	1.15	80.70	7.02%		60.03%	43.24%	34.89	306.49	6,063.00	5.06%
CHL-3	4	N	1.87	146.40	7.83%		60.03%	43.24%	63.30	556.01	9,859.00	5.64%
KYL-1	4	N	0.56	49.00	8.75%		57.93%	40.87%	20.03	175.91	2,952.00	5.96%
SVE-1	4	N	0.09	12.00	13.33%		31.15%	16.14%	1.94	17.01	245.20	6.94%
SVW-1	4	N	0.26	24.50	9.42%		31.15%	16.14%	3.95	34.73	711.40	4.88%
STZ-1	4	N	0.22	21.00	9.55%		31.15%	16.14%	3.39	29.77	601.90	4.95%

Averages by Voltage Class	Peak Loss %	Energy Loss %
4	8.79%	5.69%
12	8.50%	5.45%
14	5.95%	4.08%
23	2.47%	1.70%
34	1.59%	1.08%
46	1.36%	0.85%

**STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION**

In the Matter of a Commission Inquiry into
Electric Vehicle Charging and Infrastructure

Docket No. E015/M-25-140
2025 Transportation Electrification Plan

I. Introduction

In its February 1, 2019 Order in Docket No. E-999/CI-17-879, Making Findings and Requiring Filings (the “Order”), the Minnesota Public Utilities Commission (or “Commission”) established general and specific findings for Minnesota’s utilities related to the advancement and adoption of electric vehicle (“EV”) integration. They are as follows:

General Findings:

- Electrification is in the public interest.
- Barriers to increased EV adoption in Minnesota include but are not limited to: (a) inadequate supply of and access to charging infrastructure, and (b) lack of consumer awareness of EV benefits and charging options.
- How EVs are integrated with the electric system will be critical to ensuring that transportation electrification advances the public interest.
- Minnesota’s electric utilities have an important role in facilitating the electrification of Minnesota’s transportation sector and optimizing the cost-effective integration of EVs.

Specific Findings:

- Minnesota’s investor-owned utilities should take steps to encourage the cost-effective adoption and integration of EVs.
- The following should be included at a minimum in any EV-related utility proposals:
 - Any EV-related proposals that involve significant investments for which the utility is seeking or will seek cost recovery should include a cost-benefit analysis that shows the expected costs along with the expected ratepayer, system and societal benefits associated with the proposal.

- In the case of a proposed pilot, the utility filing should include specific evaluation metrics for the pilot and identify what the utility expects to learn from the pilot.
- Utilities should use the Commission's current environmental externality values for carbon and criteria pollutants in analyzing the societal costs and benefits associated with EV-related proposals. Cost-benefit analyses should consider potential long-term ratepayer and societal benefits, including better grid management, public health, and other social benefits. These analyses should also consider potential long-term costs, including the risk of stranded investment.
- The Office of the Attorney General ("OAG") suggested a three-step process for evaluating utility investments in public charging infrastructure is reasonable.
- Utility investments and arrangements related to charging infrastructure should be designed to ensure interoperability, using standards such as Open Charge Point Protocol and Open Automated Demand Response.
- No single method of cost recovery should be generally precluded at this time for any EV-related investments.
- Minn. Stat. § 216B.1614, subd. 2(c)(2), allows utilities the opportunity to recover costs related to educating customers on the benefits of EVs beyond those costs related specifically to the utility's EV tariffs.

Following the Commission's order accepting Minnesota Power's second IDP on May 17, 2022, the Commission issued a Notice of Comment Period on August 1, 2022 asking "Should the Commission combine Minnesota Power, Otter Tail Power, and Xcel Energy's Transportation Electrification Plans with their Integrated Distribution Plans?" Following consultation with the Utilities, the Commission's order of December 8, 2022 made the TEP part of the Company's triennial Integrated Distribution Plan ("IDP") filing, and issued ten reporting requirements which superseded previous IDP requirements. These requirements are listed below:

1. Minnesota Power shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.
2. Minnesota Power shall provide a discussion of how it plans to facilitate:
 - a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory;

- b. availability of residential charging options for both single family and multiple unit dwellings;
 - c. programs or tariffs in development to address flexible load or reduce metering and data costs; and
 - d. fleet electrification.
3. Minnesota Power shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.
4. Minnesota Power shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.
5. Minnesota Power shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 21- 257 at the conclusion of the pilot program.
6. Minnesota Power shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.
7. Minnesota Power shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.
8. Minnesota Power shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).
9. Minnesota Power shall provide attachments or links to the most recent reports for any ongoing EV pilots or programs.
10. Minnesota Power shall provide historical spending for the past 5-years on all transportation electrification initiatives, broken down across the sections of its budget.

In its September 16, 2024 Order in Docket No. E015/M-23-258, the Commission added the following requirements to future Transportation Electrification Plans:

1. Minnesota Power shall include a discussion of how the Company is preparing and supporting adoption of medium- and heavy-duty electric vehicles, specifically transit buses, school buses, and truck fleets in future TEPs, and a count of each named category domiciling in the Company's service territory (e.g. number of electric transit buses, number of electric school buses, and number of electrified truck fleets).

2. Minnesota Power shall include a discussion of equity and an analysis of how the Company's EV programs are serving communities disproportionately impacted by transportation pollution including renters, multifamily housing residents, communities of color, low- to moderate-income customers, and rural communities in future TEPs. Minnesota Power shall also include a discussion on what gaps may remain.
3. Minnesota Power shall include a discussion of its coordination between EVs, energy efficiency, and building electrification planning, including its Energy Conservation and Optimization programs in future TEPs.

This 2025 Transportation Electrification Plan ("TEP") is submitted on behalf of Minnesota Power (or, "the Company") in response to the Commission's findings and actions.

II. Background

Minnesota Power's Electrification Guiding Principles

Minnesota Power works directly with customers, stakeholders, and trade allies to understand the barriers to EV adoption in northern Minnesota and has actively worked to address them through EV programs, educational initiatives and customer support. The following guiding principles serve as a tool in developing EV programming and will continue to be utilized in the Company's forthcoming offerings and strategies related to transportation electrification. They are described in more detail below.

Education

Provide tools and resources designed to increase awareness of electric transportation, provide information about transportation electrification programs and evolving technology, and empower customers to make informed decisions about electric transportation adoption.

Accessibility

Ensure equitable access to infrastructure for all customers, including in lower income, rural and underserved areas, in locations and applications that fit their everyday lives and communities.

Optimization

Design electric transportation programs that promote strategic and efficient use of the electric grid and grid resources and provide benefits to all customers.

Environment

Create electric transportation programs that promote renewable energy, decrease carbon emissions and improve air quality.

Simplicity

Deliver transparent and straightforward customer-focused offerings, creating a simple and convenient way for customers to adopt electric transportation while ensuring a positive customer experience.

Security

Ensure a sense of security for customers who have adopted or are considering adopting electric transportation through availability, reliability, interoperability and safety of charging equipment.

III. Response to Order Points

Electric vehicle adoption in Minnesota continues to rise, with over 67,000 EVs registered statewide as of November 2024.¹ However, over 80 percent of the registered EVs in Minnesota are located within the seven-county metro. This disparity highlights the need for programs aimed at reducing the main barriers to adoption in more rural parts of the state including access to charging infrastructure, high upfront cost, and general awareness among customers and trade allies.

Recent federal policy changes have introduced new challenges for EV adoption. The One Big Beautiful Bill Act, signed in July 2025, accelerates the phase-out of key federal EV tax credits that were originally set to run through 2032.² These credits have played a critical role in making EVs more affordable and accessible. Their abrupt end on September 30, 2025 is expected to disproportionately affect rural areas like northern Minnesota, where upfront costs remain a major barrier to adoption.

In the following sections the Company responds to the Commission's transportation electrification plan order points and outlines how its current and planned EV-related initiatives address the unique needs of northern Minnesota communities.

¹ [Electric Vehicles / Public Utilities Commission](#)

² [Trump's 'big beautiful bill' ends \\$7,500 EV tax credit](#)

1. Summary of Minnesota Power's Ongoing Transportation Electrification Efforts

Minnesota Power continues to deliver and enhance existing EV programs while also identifying opportunities to support the expanded adoption of EVs in northern Minnesota. Figure 1 below provides an overview and timeline of current and planned EV initiatives. The Company prioritizes programs that provide foundational support for transportation electrification including education and awareness, access to charging infrastructure, rebates to reduce the upfront purchase cost, and rates that encourage charging at optimal times. Minnesota Power's EV initiatives are strategically planned to provide support to encourage EV adoption while balancing the cost of additional EV programs or services, the rapid evolution of technology and service providers in this space, and reliability of equipment.

Figure 1: EV Initiatives Implementation Timeline



Minnesota Power's current and ongoing EV initiatives can be categorized into four main focus areas including infrastructure, rates, rebates, and awareness.

EV Charging Infrastructure

Minnesota Power has proposed and received approval for several initiatives aimed at increasing access to EV charging infrastructure for customers and EV drivers in northern Minnesota. In 2019, Minnesota Power worked with customers to donate 20 Level 2 chargers to site hosts throughout the Company's service territory. The chargers provided early access to public charging and an

opportunity for Minnesota Power and site hosts to learn about the process of installing and maintaining public chargers.

To build on that project and further expand access to public charging, the Company submitted a proposal to install, own and maintain 16 direct current fast charging ("DCFC") stations throughout its service territory.³ When completed, the DCFC stations will provide fast charging options both to Minnesota Power customers and EV owners traveling throughout northern Minnesota. Charging stations were strategically located along major travel corridors, near population clusters and in areas where public fast chargers are not currently available. The Company also selected locations that have been identified as a concern for environmental justice when possible.

Further, Minnesota Power received Commission approval to implement a three-year Make-Ready Pilot Program beginning in 2026.⁴ The program is designed to reduce the upfront costs needed to install EV charging infrastructure on both the utility- and customer-side of the meter. The program focuses on multifamily buildings but is also available for public and workplace charging, recognizing that an all-the-above approach is needed to truly reduce range anxiety and encourage EV adoption among renters in both multifamily and single-family homes. The Company intends to make the program available to customers in 2026 and is currently working through compliance requirements and implementation details.

Rates

Utilities play a critical role in ensuring that electric vehicles are added in a manner that doesn't negatively impact the system. By incentivizing customers to charge during off-peak periods, utilities can reduce peak load pressures, optimize system capacity, and support broader electrification goals in a cost-effective and sustainable manner. Minnesota Power currently offers three time-based rate options for residential customers and two rate options for commercial customers including:

- Residential EV Service Rate
- Residential Time-of-Day Rate
- Residential Dual Fuel Rate
- Commercial Fleet EV Charging Rate

³ Docket No. E015/M-21-257.

⁴ Docket No. E-015/M-23-258.

- Commercial Public EV Charging Rate

The Company is currently aware of 65 customers on the Residential EV Service Rate, 99 EV customers on the Residential Time-of-Day Rate, and 28 EV customers on the Residential Dual Fuel rate⁵. There are 22 commercial customer sites participating in EV charging rates including one fleet site and 21 public sites. It is important to note that customers are not required to notify Minnesota Power that they have an electric vehicle to participate in the non-EV specific rates including the residential time-of-day rate and the dual fuel rate. For that reason, there may be more EV owners enrolled in a time-based rate than reflected here.

Rebates

Minnesota Power began offering rebates for the purchase and installation of level 2 chargers in customer homes in 2021.⁶ There are currently two rebate options available to Minnesota Power customers: a \$500 rebate for the installation of a second service and a \$500 rebate for the purchase of a level 2 smart charger. The Company provided rebates for 55 level 2 smart chargers and 7 second service installations from April 1, 2024 to March 31, 2025.⁷ The goal of these rebates is to reduce the upfront cost of installing a smart EV charger and to encourage optimized EV charging.

The Company also submitted a modification to its Energy Conservation and Optimization program on October 28, 2025.⁸ If approved, the modification will allow the Company to provide rebates for the purchase of an electric vehicle and an e-bike for residential customers, helping to reduce the upfront cost of ownership.

Awareness

Based on conversations Minnesota Power staff have with customers, lack of general awareness about EVs continues to be a large barrier to adoption. Misconceptions about range, reliability, and charging access exist due to a lack of widespread education and outreach. The Company regularly engages with customers in several venues to address these barriers including presentations to interested customers, participation in community events, social media posts and promotional campaigns. In addition to general awareness initiatives, the Company conducts

⁵ This number includes EV drivers on Minnesota Power's Dual Fuel rate. The Company cannot verify that all EV charging is occurring on the customers Dual Fuel service.

⁶ Docket No. E015/M-20-638.

⁷ Docket No. E015/M-15-120.

⁸ Docket No. E015/CIP-23-93.

targeted outreach to trade allies that play a significant role in encouraging EV adoption including auto dealerships, electricians and first responders.

Auto dealerships are often the first place a consumer goes when looking to purchase a new vehicle. Dealerships that stock electric vehicles, have sales associates that are knowledgeable about the technology, and have qualified technicians to service them are an important part of the decision-making process. Minnesota Power regularly engages with dealerships throughout its service territory to answer questions about electric vehicles and share information about Minnesota Power's programs. The Company offers grants to interested dealerships for training, service equipment, advertising to promote electric vehicles, or EV chargers to be installed in the showroom, service center or for patron use.

Electricians also play a critical role in transportation electrification. Ensuring that they are familiar with Minnesota Power's processes, requirements and programs helps to create a seamless experience for EV drivers looking to install chargers at their home or business. They often serve as a trusted resource for customers on the efficacy of electric vehicles and the infrastructure needed to support them. Minnesota Power is in the process of establishing a participating electrician network to provide training opportunities, promote programs, and share information.

In 2024 Minnesota Power began hosting training sessions for first responders to provide information about passenger extractions and firefighting when EVs are involved. To date, the Company has provided training to over 115 first responders throughout northern Minnesota.

More details about the Company's current and planned EV initiatives are provided in the sections below in response to the Commission's order points.

2a. Availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace in Minnesota Power's service territory

The Company has undertaken significant work in recent years to better understand the availability and awareness of public EV charging infrastructure in its service territory. In addition to tracking public funding opportunities like the Minnesota Pollution Control Agency's ("MPCA") distribution of the Volkswagen settlement funds and the National Electric Vehicle Infrastructure ("NEVI") Formula Program, the Company has also made efforts to install public chargers in its service territory.

As described above, Minnesota Power worked with customers to donate 20 Level 2 EV chargers to businesses in strategic locations across the Company's service territory in 2019, expanding the availability of public Level 2 chargers. Minnesota Power also received approval by the Commission on October 22, 2021 to expand access to fast charging via the installation of 16 DCFC stations throughout Minnesota Power's service territory.⁹ The target locations were identified based on three criteria: gaps in existing public fast chargers, population clusters and proximity to major travel corridors. Where possible, the Company has ensured that chargers are located within areas identified as a concern for environmental justice.

Minnesota Power first issued a request for proposals ("RFP") for a turnkey vendor to provide procurement, installation and maintenance of the DCFC charging stations and selected a vendor in 2022. Contract negotiations continued for several months before the vendor informed Minnesota Power of a business model change that prevented them from moving forward with the project. As a result, the Company restructured its RFP to safeguard against future unexpected vendor changes and reissued the RFP in 2023. This change resulted in a delay to the project timeline but also led to contractual changes that the Company hopes will provide benefits in the long-term.

Chargers will range in size from 50 kW to 350 kW and will be located in areas with amenities available, including grocery stores, convenience stores, restaurants and more. The cost of charging will be based on a benchmark of other publicly available chargers in the region to ensure Minnesota Power's DCFC stations do not deter future private development of fast chargers. To date, 3 of the DCFC stations have been commissioned and are available to the public. The remaining 13 stations are scheduled to be completed in the coming months. Building a network of EV fast chargers will help to ensure that EV drivers are able to conveniently travel throughout the state, reducing range anxiety, particularly for drivers traveling outside the metro area.

In addition to company-owned fast chargers, Minnesota Power is working to implement a make ready pilot program to support privately-owned charging infrastructure. The pilot program, approved in the Commission's July 29, 2025 Order, is designed to address the high upfront cost of installing EV charging infrastructure with a focus on the unique challenges experienced in multi-dwelling unit ("MDU") buildings.¹⁰ While equitable access to charging for residents of MDUs is important, the Company recognizes that many customers of single family homes are also unable

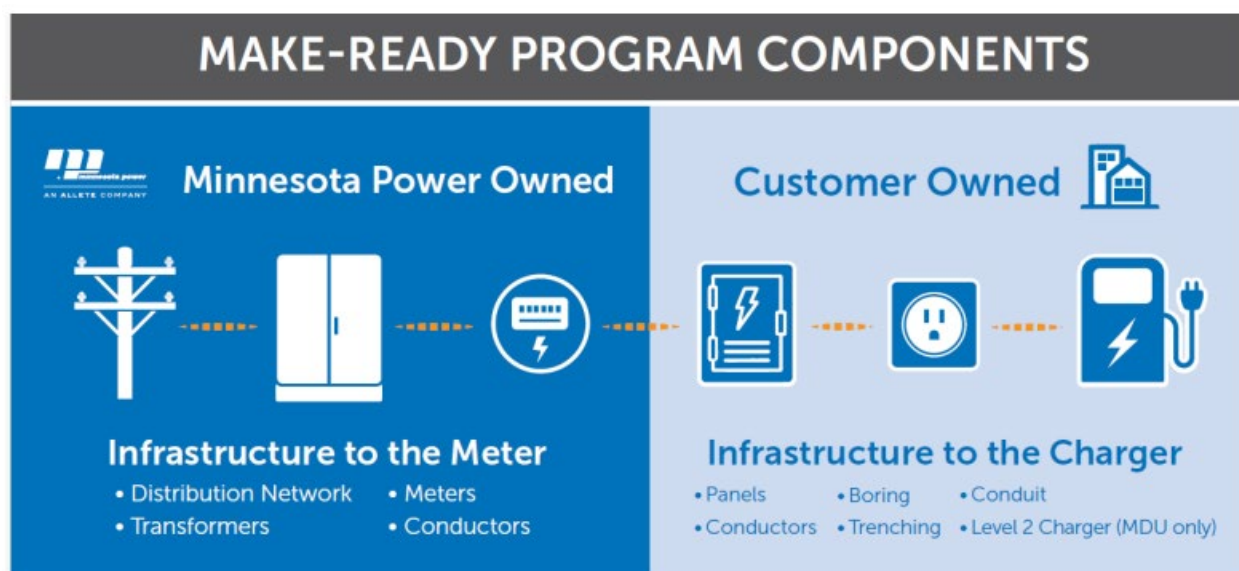
⁹ Docket No. E015/M-21-257

¹⁰ Docket No. E-015/M-23-258.

to install home charging due to lack of off-street parking or rental agreement limitations. Widespread availability of public EV charging is imperative to EV adoption, particularly for individuals without access to reliable home charging. To address this need, the Company has included public and workplace charging applications in this pilot program with a goal of increasing access to EV chargers more broadly throughout Minnesota Power's service territory while also evaluating what level of funding is needed to spur activity in these various sectors.

As shown in Figure 2, Minnesota Power will install, own, and maintain a dedicated service for EV charging including all infrastructure on the utility side of the meter. The customer will install, own, and maintain all equipment beyond the meter including a new service panel, conduit, and wiring up to the EV charger. Depending on charging application and income eligibility, participating customers will be eligible to receive a rebate to cover anywhere from zero to 100 percent of the costs of infrastructure on the customer side of the meter. Participating locations will be selected through a weighted application process that prioritizes facilities that are income-qualified or located within a recognized disadvantaged community, among other factors. The full evaluation matrix is included in the Company's September 29, 2025 compliance filing in Docket No. E-015/M-23-258.

Figure 2: Make Ready Pilot Program



According to a dashboard published by Atlas Public Policy, there are 74 public EV charging stations in Minnesota Power's service territory, with 134 level 2 and 88 level 3 charging ports.¹¹

¹¹ <https://atlaspolicy.com/evaluatemn/>

The number of public charging stations participating in Minnesota Power's Commercial Public EV Charging Rate has increased from 13 to 17 since the last TEP was submitted in November 2023. The Company will continue to monitor charging infrastructure within its territory and evaluate if more EV infrastructure programs and offerings are needed to support current and future EV adoption.

2b. Availability of residential charging options for both single family and multiple unit dwellings

Minnesota Power currently offers three rate options to residential customers that can be used for EV charging:

Residential EV Service Rate

Minnesota Power has offered a Residential Off-Peak Electric Vehicle Service rate¹² since 2015, with 64 customers currently enrolled. Customers are required to install a separate metered service to participate. The details of the rate are as follows:

Residential EV Service Rate	
Service Charge	\$6.00
Off-Peak Energy Charge (per kWh)	\$0.03231
On-Peak Energy Charge (per kWh)	\$0.11540
The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.	

The Residential EV Service rate has historically been available to residential customers for the sole purpose of charging an electric vehicle or battery powered equipment. Minnesota Power requested approval to modify the rate in accordance with the make-ready pilot program to allow multifamily buildings to participate. The Company also committed to updating the rate in its next general rate case to add a super off-peak time period and associated rate.¹³

¹² Docket No. E-015/M-15-120

¹³ Docket No. E-015/M-23-258.

Residential Time-of-Day Rate

The Company implemented a Residential Time-of-Day rate¹⁴ in October of 2022. This rate option provides discounted Off-Peak rates without a second metered service requirement. The details of the rate are as follows:

Residential Time-of-Day Tariff	
Service Charge	\$9.00
Super Off-Peak Energy Charge (per kWh)	\$0.07402
Off-Peak Energy Charge (per kWh)	\$0.10525
On-Peak Energy Charge (per kWh)	\$0.15618
The On-Peak Periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. The Super Off-Peak Period shall be defined as 11:00 p.m. to 5 a.m. Central Prevailing Time (CPT), inclusive. The Off-Peak Periods shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.	

Minnesota Power is in the process of transitioning all residential customers to the Residential Time-of-Day rate with a goal of completing the roll out by 2029. Customers are not required to inform Minnesota Power when they purchase an electric vehicle and while the Company does request this information, it is important to note that the number of EV drivers on this rate is likely understated in this TEP.

Residential Dual Fuel Rate

The Dual Fuel rate is an interruptible service rate designed primarily for electric heat that provides customers with a discount in exchange for occasional interruptions from Minnesota Power. There are two options under the rate: Dual Fuel Standard and Dual Fuel Plus. Dual Fuel Standard customers experience fewer interruptions than those participating in Dual Fuel Plus. Customers are allowed to connect their EV chargers to their Dual Fuel Standard service to receive discounted charging. The details of the rate are as follows:

¹⁴ Docket No. E-015/M-20-850.

Residential Dual Fuel Rate	
Service Charge	\$6.00
Energy Charge (per kWh)	\$0.07989
Customer must be prepared to have load interrupted for up to 300 hours of customer's Dual Fuel requirements during any annual period. Dual Fuel load can be interrupted two times per day up to four-hours at a time. There will also be at least two hours between any interruptions.	

Minnesota Power will continue to work with customers and stakeholders to understand how well these programs meet customer needs and address barriers to entry.

2c. Programs or tariffs in development to address flexible load or reduce metering and data costs

Minnesota Power currently provides several programs and tariffs designed to address flexible load and/or reduce metering costs. Specifically, the Company currently offers two EV charging rates designed to encourage charging during off-peak times and two off-peak charging rates for commercial customers (Commercial Fleet EV Charging Rate and Commercial Public EV Charging Rate).

The Company's Residential EV Service rate provides the greatest discount for residential off-peak charging but does require the installation of a second service. Minnesota Power is aware that this requirement is a barrier to participating in this rate. To overcome this barrier, the Company offers two rebates totaling up to \$1,000 per customer to reduce the upfront costs associated with installing a second service; 1) a \$500 rebate towards the cost of installing a second service and 2) a \$500 rebate for a smart charger (must be Wi-Fi or internet enabled and OCPP-compliant). For customers that don't want to or are not able to install a second service, the Company's Residential Time-of-Day rate provides an option for discounted off-peak charging.

2d. Fleet Electrification

Minnesota Power is actively engaging fleet operators throughout its service territory to better understand customer interest in fleet electrification. While some customers have expressed specific goals and interest in converting their fleets to electric vehicles, others are working to understand the impact of fleet electrification to their operations and expenses. As each customer

has unique considerations, Minnesota Power is actively exploring options to assist fleet managers in analyzing fleet conversion for their specific businesses in a cost-effective manner.

The Company received Commission approval in Docket No. E015/M-20-638 for an EV outreach budget, which included funding for online tools and fleet analytics. As a result, Minnesota Power worked with two fleet operators to explore fleet electrification assessments. These initiatives provided valuable information about what level of support is useful to fleet operators and strategies for Minnesota Power to provide impactful tools to encourage fleet conversion. The Company is currently evaluating opportunities to provide ongoing fleet conversion analysis or support within its Energy Conservation and Optimization portfolio.

Minnesota Power also provides discounted charging rates designed to encourage charging at optimal times. One rate is designed specifically for fleets that can charge during off-peak periods, while the other is intended for public charging applications where shifting the time of charging may not be possible. The details of the rates are as follows:

Commercial Fleet EV Charging Rate	
Service Charge	\$15.00
On-Peak Demand Charge (per kW)	\$6.50
On-Peak Transmission Demand Charge (per kW)	\$4.03
Energy Charge (per kWh)	\$0.06931
On-Peak periods shall be defined as 3:00 p.m. to 8:00 p.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas. Super Off-Peak shall be defined as 11:00 p.m. to 5:00 a.m. Central Prevailing Time (CPT), Monday through Friday, inclusive, excluding holidays. Off-Peak shall be all other hours other than On-Peak or Super Off-Peak. There shall be no Demand Charge applied during Off-Peak or Super Off-Peak hours.	

Commercial Public EV Charging Rate	
Service Charge	\$ 15.00
Demand Charge (per kW)	\$ 6.50
Transmission Demand Charge (per kW)	\$ 4.03
Energy Charge (per kWh)	\$ 0.06931
In no month shall the total demand charges, including Transmission Demand Charge, exceed 30% of customer's total bill excluding any applicable taxes and fees. If the Demand Charge is greater than 30% of the subtotal of the Service Charge, the Demand Charge, the Transmission Demand Charge, the Energy Charge, and all adjustments listed above, the customer shall receive an EV Demand Credit which will be applied against the demand charges, capping it at 30% of the pre-tax bill.	

In addition to the programs described in this section, the Company also sees value in applying the make ready program model to support infrastructure for fleet electrification. Minnesota Power proposed a budget in its recently approved make ready pilot program to offset a portion of the utility-side infrastructure costs for one fleet customer to test the effectiveness of the program model.¹⁵ The objectives and considerations for fleet electrification are significantly different from MDU, workplace, and public charging and the Company saw an opportunity to consolidate proposals by testing one program model for all charging applications. However, the fleet portion of the make ready pilot was ultimately removed from the proposal due to lack of stakeholder support. The Company looks forward to the implementation of the pilot program and will continue to evaluate internal resources and customer demand to expand the make ready program model, or an alternative offering, to fleets in the future.

3. Plans to optimize EV benefits, including alignment of charging during periods of lower customer demand and higher renewable energy production; improving grid management and overall system utilization/efficiency

The Company continuously explores ways in which it can align charging periods for EV rates with periods of lower electric system demand and higher renewable energy production. Minnesota Power's Residential EV Service Rate, Residential Time-of-Day Rate, and Commercial Fleet EV Charging Rate utilize time of use periods. These programs will prepare customers for anticipated time varying and dynamic pricing-based rates and will allow the Company to collect data around EV charging behavior and patterns, demand and other system impacts, and price

¹⁵ Docket No. E-015/M-23-258.

responsiveness. These insights will improve Minnesota Power's ability to perform the necessary forecasting and analytics to create effective programming in the future.

4. Encouraging more customers with electric vehicles to participate in managed charging

Minnesota Power works directly with customers to promote its time-based programs and rate offerings. Additionally, EV customers must be on a time-based rate in order to be eligible for the Company's residential EV charger rebates. Minnesota Power has developed dedicated webpages and marketing materials that explain the benefits of these programs and has focused on educating regional EV stakeholders including car dealerships, electricians, equipment distributors and regional/national EV advocacy groups on the availability of these programs. Most of the Company's public EV outreach and education efforts are centered around promoting time-based rates and programs. The Company will continue to explore effective ways to promote and encourage customers to participate in managed charging programs.

5. Possible divestment strategies for Minnesota Power's DCFC Network approved in Docket 21-257 at the conclusion of pilot program

In its October 22, 2021 Order, the Commission required Minnesota Power to include a discussion in future TEPs that addresses divestment issues and identifies possible divestment strategies for its DCFC stations. Minnesota Power's stated goal in Docket 21-257 is to stimulate the EV charging market and alleviate range anxiety for EV drivers in the Company's service territory, not to discourage private sector charging networks. The Company will investigate any and all possible divestment strategies at the conclusion of this pilot, including the sale of EV charging infrastructure to site hosts or third-party charging companies. As Minnesota Power is still in the process installing chargers, no divestment plan has been developed yet.

6. Evaluation of non-pilot EV programs, their cost-effectiveness, and possible improvements thereto.

Minnesota Power currently offers rates for residential, fleet and public EV charging. These rates are evaluated on an on-going basis through annual EV rate compliance filings and rate case efforts. Through these filings, Minnesota Power evaluates participants usage patterns as well as the on- to off-peak price differential to ensure it is meaningful enough to encourage beneficial charging behavior – one of the main objectives of the rate, reviews the peak period hours from

both the participants perspective and to understand impacts on the system, considers whether the benefits are high enough to off-set the costs to the participant of the program, and ensures that the rate is well aligned relative to other residential rates. The Company uses this information to inform any proposed changes to the rate through its rate case proceedings.

Additionally, the Company will use the Energy Conservation and Optimization ("ECO") cost-effectiveness framework to evaluate any EV rebates or programs offered through its ECO portfolio. This framework includes multiple tests—Utility, Minnesota, Participant, Ratepayer and Societal—that evaluate the benefits and costs of a program from multiple perspectives. These tests consider factors such as avoided energy and capacity costs, program administration, environmental benefits and participant incentives to ensure that the program delivers a net benefit impact. The ECO cost-effectiveness framework helps ensure that resources are allocated efficiently and that programs contribute to broader policy goals such as reducing greenhouse gas emissions and lowering energy bills for participants. Through these evaluations, the Company will determine the net benefits of an EV relative to a gasoline-powered vehicle.

7. Summary of Customer EV education initiatives.

General education and awareness about EVs continue to be a main priority for Minnesota Power. The Company has resources focused on promoting electric vehicle technology and available programs, designing and evaluating new EV proposals, and delivering programs and services to customers. Direct communication, including participation in community events, has been a successful strategy for promoting EVs. In its 2024/2025 Annual EV Report in Docket No. E-015/M-15-120, Minnesota Power tracked direct costs related to promotional activities at \$13,050 (this does not include labor, materials or advertisements that the Company designed and printed in-house).

Table 1: Outreach and Education Expenditures

Date	Event	Description	Estimated Attendance	Cost
4/4/2024	Duluth Arrowhead Home & Builders Show	MP hosted booth to promote electric vehicles and programs to Arrowhead Home & Builders Show attendees.	5,000	\$1,800
4/20/2024	Virginia Earth Fest	MP hosted booth to promote electric vehicles and programs to Earth Fest attendees.	1,300	\$0
4/20/2024	Duluth Eco Fest	MP hosted booth to promote electric vehicles and programs to Eco Fest attendees.	300	\$0
7/12/2024	Duluth Side Walk Days	MP hosted booth to promote electric vehicles and programs to Duluth Sidewalk Days attendees.	2,000	\$0
7/12/2024	Duluth Kolar Autoshow	MP hosted booth with five local EV owners to promote electric vehicles and programs to local car dealer show attendees.	500	\$0
7/26/2024	Park Rapids Powered Up! Energy Forum	MP cohosted event promoting electric vehicles. Event included EV showcase, regional vendors and presentations.	500	\$0
9/6/2024	Duluth Harvest Fest	MP hosted booth to promote electric vehicles and programs to festival attendees. Local EV drivers volunteer their time, vehicles and expertise.	6,000	\$1,250
10/8/2024	Aurora First Responder Training	MP hosted free training for regional first responders on how to safely respond to accidents involving electric vehicles.	23	\$2,500
10/9/2024	Little Falls First Responder Training	MP hosted free training for regional first responders on how to safely respond to accidents involving electric vehicles.	17	\$2,500
10/10/2024	Hermantown First Responder Training	MP hosted free training for regional first responders on how to safely respond to accidents involving electric vehicles.	59	\$2,500
Various	Customer Presentations	MP has made a number of direct presentations to customers and customer groups who have expressed interest in transportation electrification.	50	\$0
Various	Drive Electric Minnesota	Sponsorship for Drive Electric Minnesota		\$2,500

Additionally, Minnesota Power received approval for a dedicated EV Education and Outreach budget in the Commission's July 29, 2025 Order in Docket No. E-015/M-23-25. As the Company

implements its Make Ready Pilot Program in 2026, it will be focused on educational initiatives needed to support that program, in addition to the general EV awareness efforts described above.

Consistent with lessons learned through its ECO portfolio, the Company has found that trade allies play a critical role in promoting and supporting EV adoption. Electricians and auto dealers serve as a trusted resource to customers looking to purchase an electric vehicle or install charging equipment at their home or business. Strong communication with trade ensures that they are familiar with Minnesota Power's programs and can adequately demonstrate and promote the technology. The Company is currently designing an electrician network, modeled after its highly successful program for participating heating, ventilation, and air conditioning ("HVAC") contractors. The objectives of the program are to:

- Provide training opportunities for regional electricians on EV charging installation best practices.
- Promote the Make Ready Pilot Program and other EV program offerings to participating electricians, allowing them to share the information with their customers.
- Maintain a list of electricians that are informed about EV charging technologies and Minnesota Power's EV programs that customers can access.

The Company also provides grants to interested dealerships for training, service equipment, advertising to promote electric vehicles, or EV chargers to be installed in the showroom, service center or for patron use.

8. Summaries of proposals or pilots submitted to other regulatory agencies or jurisdictions (ex. CIP or other states)

On October 28, 2025 Minnesota Power submitted a modification to its current ECO portfolio to add an efficient fuel switching program. If approved, Minnesota Power customers without an electric baseline will be eligible for rebates for electrical equipment. The Company proposed rebates for the purchase of electric vehicles and electric bicycles and looks forward to getting experience delivering efficient fuel switching programs through its ECO portfolio.

As described above, Minnesota Power's next ECO triennial filing, outlining programs and services to be offered from 2027-2029, will be submitted on June 1, 2026. The Company continues to evaluate opportunities for additional transportation electrification offerings for inclusion in that filing.

9. Attachments or links to the other most recent reports for any ongoing EV pilots or programs

Information regarding evaluation of Minnesota Power's ongoing EV pilots can be found in the following dockets:

- Annual Electric Vehicle Report: Docket No. E015/M-15-120
- Commercial EV Charging Rate Pilot: Docket No. E015/M-19-337
- Portfolio of Electric Vehicle Programs: Docket No E015/M-20-638
- EV Charging Infrastructure Investment: Docket No. E015/M-21-257
- Make Ready Pilot Program: Docket No. E-015/M-23-258
- Energy Conservation and Optimization: Docket No. E015/CIP-23-93

10. Historical Spending for the past 5 years on all transportation electrification initiatives, broken down across the sections of its budget (See table example in PUC filing)

The majority of Minnesota Power's spending on transportation electrification in the last 5 years is related to the suite of offerings approved in the Company's EV Portfolio filing in Docket No. E015/M-20-638 and the DCFC project approved in Docket No. E015/M-21-257. Below is an overview of spending in relation to these programs.

Table 2: Historical Spending

Budget Category	Capital	O&M	Marketing & Communications	Other*
Distribution	\$3,189,615	\$313,367		
Customer Programs			\$	\$239,687

*Other expenses include rebate incentives and labor

11. Future spending for the next 5 years on all transportation electrification initiatives, broken down across the sections of its budget

Minnesota Power received Commission approval to implement a make ready pilot program in Docket No. E-015/M-23-258. The Company also continues to make progress on the installation of 16 DCFC stations approved by the Commission in Docket No. E015/M-21-257. The Company is nearing completion of that project and while there will likely be some ongoing costs associated with the installation and operation of the chargers, it is expected to be minimal and is not reflected in the figures below. The figures below represent the costs associated with the make ready pilot program, as well as delivery of the Company's rebate and educational programs over the next 5 years. Costs associated with transportation electrification initiatives included in the upcoming ECO triennial are unknown and are therefore not included.

Budget Category	Capital	O&M	Marketing & Communications	Other ²
Distribution	\$890,000 ¹			
Customer Programs			\$75,000	\$1,051,000

1. These costs are related to utility-side investment budgeted through the Company's recently approved Make Ready Pilot Program.
2. Other expenses include rebates and labor.

12. Support for adoption of medium- and heavy-duty electric vehicles

The Duluth Transit Authority ("DTA") was an early adopter of electric transit buses, purchasing seven buses in late 2018.¹⁶ The Company has worked closely with the DTA to understand the user experience and has proposed programs designed to address barriers to participation and operation. Specifically, the Company's Commercial EV Charging Rate was designed in close collaboration with the DTA and other interested customers to address high demand charges associated with charging large electric vehicles.¹⁷ Findings from that pilot rate were used to propose two standard rate offerings for commercial EV charging: the Commercial Fleet EV Charging Rate and the Commercial Public EV Charging Rate. The seven DTA buses are the only known medium- and heavy-duty electric vehicles in the Company's service territory currently.

¹⁶ [Duluth Transit Authority Battery-Electric Bus Evaluation](#)

¹⁷ Docket No. E015/M-19-337

Minnesota Power continues to promote the benefits of electric vehicles to large fleet operators, including schools with electric buses. The Company is currently evaluating two programs for possible inclusion in the upcoming ECO Triennial plan that would be designed to target medium- and heavy-duty fleet electrification. The first program is fleet conversion analytics to help fleet operators and managers determine which vehicles in their fleet would be the most appropriate to convert to an electric fuel source based on a variety of factors including utilization rates, cost and sustainability objectives. The second offering is a rebate for electric school buses specifically. Electrifying school buses not only improves air quality and reduces greenhouse gas emissions, but it also offers potential benefits to the electric grid. The Company recently launched a School Hub to provide a one-stop shop of resources for schools with information about clean technologies, including electrification, and available funding resources to support their objectives.

13. Equity within EV programs

Accessibility has long been one of Minnesota Power's guiding principles for design and delivery of electric vehicle programs. While the upfront purchase price of an electric vehicle is generally higher than that of a gas-powered vehicle, the ongoing fueling and maintenance costs are lower making them a good option for lower-income drivers. Having access to home and public charging infrastructure, rebates for electric vehicles and chargers, and discounted rates for off-peak charging are critical to ensuring adoption among income-qualified customers. Minnesota Power has thoughtfully planned its EV program proposals to address these concerns and provide equitable access to all customers including those disproportionately impacted by transportation pollution.

When choosing locations for its DCFC stations, the Company committed to locating them in areas identified as a concern for environmental justice to the extent possible.¹⁸ Of the 16 sites with executed site host agreements in place, all of them are located within disadvantaged communities.¹⁹ Minnesota Power also partnered with the Electric Nation to support their Upper Midwest Inter-Tribal EV Charging Community Network.²⁰ Through this project, Electric Nation will

¹⁸ Disadvantaged communities are determined using the Climate and Economic Justice Screening Tool published by the Council on Environmental Quality, environmental justice areas as determined by the Minnesota Pollution Control Agency or as defined under Minn. Statute 216B.1691 Subdivision 1(e), and Tribal lands located within Minnesota Power service territory.

¹⁹ DCFC sites qualified as disadvantaged communities based on federal census tract requirements and/or the Minnesota Pollution Control Agency's Environmental Justice map.

²⁰ [Electric Nation | Native Sun Community Power Development](#)

install DC fast charging units on Reservations and their vital travel routes, as well as level 2 EV chargers at community gathering spots, multi-dwelling units, Tribal colleges, and other destinations. Minnesota Power's DCFC stations are being used to support that initiative, helping to secure public funding for a project designed to support EV adoption for Tribal Nations in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan.

The make ready pilot program described above will also provide support for MDU owners to install EV charging infrastructure within their buildings, providing home charging to tenants. The program prioritizes income-qualified buildings, with a requirement to fund at least one project at an income-qualified building each year. The program also provides increased funding levels for income-qualified MDU buildings and public chargers located in disadvantaged communities.

Minnesota Power also recognizes that rebates to bring down the upfront cost of an electric vehicle or electric vehicle charger are critical to adoption among income-qualified customers, particularly in light of recent elimination of critical tax credits for new and used EVs. Minnesota Power currently offers a rebate for the purchase of a level 2 charger and recently proposed a new rebate for the purchase of an electric vehicle. Minnesota Power also proposed a rebate for the purchase of an electric bike. Compared to car ownership, electric bikes have significantly lower upfront and maintenance costs, making them a powerful tool for income-qualified customers living in more urban parts of the Company's service territory.

The Company will continue to evaluate equity and accessibility gaps within its programs and identify opportunities to address them through new program offerings. One area the Company continues to evaluate is electric ride sharing programs. Minnesota Power, in partnership with a municipality in its service territory, explored electric ride sharing services in 2024. At the time, it was determined that a feasibility study would be required to assess the demand for ride sharing services and evaluate feasibility. The Company will continue to explore these, and other, programs and services related to electric ride sharing.

14. Coordination between EV, energy efficiency and building electrification programs

Minnesota Power has taken a holistic approach to planning, designing and delivering customer programs and services including energy efficiency, electrification and demand response. Programs are designed such that customers participating in an electrification program are also encouraged, or in some instances required to also participate in demand response or load management programs to ensure that grid benefits are maximized. These offerings are also

delivered seamlessly through one department to ensure that customers are provided with information about all available programs to make informed decisions about how to achieve cost savings and meet their energy needs. As described in this IDP and TEP, the Company is evaluating opportunities to expand its ECO portfolio to include more electrification and load management programs in the future. The combination of these offerings with the existing energy efficiency programs will provide more opportunity for customers.

IV. Conclusion

As an important part of Minnesota Power's *EnergyForward* strategy to a carbon-free future, the Company is pleased to continue to share its plans and implementation timeframe for its transportation electrification initiatives. The programs outlined in this plan will encourage electrification by reducing barriers to adoption and helping to alleviate range anxiety for customers and visitors to Minnesota Power's service territory. With its current and proposed programs and pilots, Minnesota Power is making intentional and thoughtful efforts to collect data and identify additional barriers and opportunities that meet customer needs and optimize the system benefits associated with transportation electrification. This TEP outlines the Company's efforts towards the design and implementation of these appropriate programs and services.

Dated: November 3, 2025

Respectfully submitted,



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2024 Transmission-Distribution Substation Loading Summary^{NOTE1,NOTE2}

Area	Substation	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
C	15th Ave West	115/14 kV	39.50	17.30	25.32	eDNA Historical Data
C	Bear Creek	69/46 kV	9.80	1.90	1.20	eDNA Historical Data Operated Networked
C	Big Rock	115/14 kV	5.90	2.60	3.22	eDNA Historical Data
C	Burnett	115/14 kV	1.44	0.19	0.72	Aclara Historical Data
C	Canosia Road	115/14 kV	9.90	2.90	4.83	eDNA Historical Data
C	Canosia Road	115/34 kV	2.26	0.10	0.22	eDNA Historical Data
C	Cloquet	115/14 kV	28.84	13.38	19.44	eDNA Historical Data
C	Colbyville	115/14 kV	22.05	8.90	12.36	eDNA Historical Data
C	Four Corners	115/14 kV	12.60	4.58	7.14	eDNA Historical Data
C	French River	115/14 kV	5.00	0.90	2.13	eDNA Historical Data
C	Gary	115/14 kV	10.98	2.93	6.86	eDNA Historical Data
C	Haines Road	115/14 kV	23.54	10.04	13.60	eDNA Historical Data
C	Hibbard	115/14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Hinckley East	69/46 kV	2.25	0.76	1.08	Aclara Historical Data
C	LSPI	115/14 kV	23.19	8.84	14.03	eDNA Historical Data
C	LSPI	115/34 kV	8.10	3.60	4.25	eDNA Historical Data
C	Mahtowa	115/23 kV	4.73	0.82	2.57	eDNA Historical Data
C	Mahtowa	115/46 kV	5.70	1.14	1.87	eDNA Historical Data (calc)
C	Meadowlands	115/14 kV	0.80	0.08	0.24	eDNA Historical Data
C	North Shore	115/14 kV	2.60	1.00	1.51	eDNA Historical Data
C	Ridgeview	115/14 kV	27.90	12.80	16.99	eDNA Historical Data
C	Savanna	115/14 kV	1.78	0.48	0.82	eDNA Historical Data
C	Silver Bay Hillside	115/14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Swan Lake Road	115/14 kV	20.90	9.40	11.43	eDNA Historical Data
C	Swan Lake Road	115/34 kV	10.20	5.00	7.45	eDNA Historical Data
C	Taft	115/34 kV	5.64	2.15	3.00	eDNA Historical Data
C	Thomson	115/14 kV	3.35	0.99	2.01	eDNA Historical Data
C	Thomson	115/46 kV	1.38	0.06	1.25	eDNA Historical Data
C	Two Harbors	115/14 kV	5.87	0.07	2.29	eDNA Historical Data
C	Wrenshall	115/14 kV	3.80	0.90	1.84	eDNA Historical Data
N	Babbitt	115/46 kV	32.08	12.38	17.15	eDNA Historical Data (calc) Operated Network
N	Big Fork Village	69/12 kV	1.60	0.60	0.85	eDNA Historical Data
N	Canisteo	115/14 kV	0.00	0.00	0.00	eDNA Historical Data
N	Diamond Lake	115/34 kV	0.00	0.00	0.00	eDNA Historical Data
N	Embarrass	115/23 kV	5.25	1.94	3.33	eDNA Historical Data
N	Hat Trick	115/23 kV	11.20	3.70	6.56	eDNA Historical Data
N	Hibbing	115/23 kV	30.59	10.52	19.72	eDNA Historical Data
N	International Falls	115/14 kV	6.14	2.66	3.51	eDNA Historical Data
N	Laskin	115/23 kV	2.68	0.94	1.31	eDNA Historical Data
N	Laskin	115/46 kV	0.00	0.00	0.00	eDNA Historical Data (calc)
N	Lind-Greenway	115/23 kV	2.20	0.40	1.67	eDNA Historical Data (calc)
N	Maturi	115/34 kV	0.00	0.00	0.00	eDNA Historical Data
N	Maturi	115/23 kV	1.90	0.40	0.53	eDNA Historical Data
N	Nashwauk	115/23 kV	5.97	2.30	3.26	eDNA Historical Data
N	Tower	115/46 kV	32.08	12.38	17.15	eDNA Historical Data (calc) Operated Network
N	Virginia	115/23 kV	20.87	8.82	13.01	eDNA Historical Data
N	Virginia	115/46 kV	11.38	4.27	6.49	eDNA Historical Data (calc) Operated Network
N	Zemple	115/23 kV	2.50	0.90	1.30	eDNA Historical Data
W	Akeley	115/34 kV	16.30	5.50	8.15	eDNA Historical Data
W	Baxter	115/34 kV	13.56	3.25	5.86	eDNA Historical Data
W	Blanchard	115/34 kV	32.39	7.74	18.70	eDNA Historical Data
W	Dog Lake	115/34 kV	9.10	2.40	4.61	eDNA Historical Data
W	Eagle Valley	115/34 kV	12.70	4.80	6.98	eDNA Historical Data
W	Little Falls	115/34 kV	34.17	12.35	18.34	eDNA Historical Data
W	Long Prairie	115/34 kV	24.87	9.87	16.06	eDNA Historical Data
W	Pepin Lake	115/34 kV	12.70	3.80	6.65	eDNA Historical Data
W	Pequot Lakes	115/34 kV	12.20	3.50	5.57	eDNA Historical Data

2024 Transmission-Distribution Substation Loading Summary^{NOTE1,NOTE2}

Area	Substation	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
W	Pine River	115/34 kV	5.40	1.90	3.27	eDNA Historical Data
W	Platte River	115/34 kV	6.10	0.60	3.65	eDNA Historical Data
W	Riverton	115/34 kV	19.84	3.61	8.21	eDNA Historical Data
W	Straight River	115/34 kV	1.80	0.40	1.10	eDNA Historical Data
W	Verndale	115/34 kV	31.39	11.67	17.87	eDNA Historical Data

NOTES

1. Values in table are non-coincident and shouldn't be added together
2. Values represent real power loading (MW) only; apparent power loading (MVA) will generally be slightly higher
3. Daytime Minimum corresponds to minimum hourly load between 0800-1800 where available or 20% of peak load where direct data is not available
4. Except as noted, values are based on hourly load data from the MP eDNA Data Historian at the distribution bus
5. Where possible, the effective load reduction from large-scale distribution-connected generation has been excluded

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
C	15th Ave West	FIF-219	14 kV	7.30	0.00	3.22	eDNA Historical Data
C	15th Ave West	FIF-220	14 kV	2.10	0.90	1.48	eDNA Historical Data
C	15th Ave West	FIF-221	14 kV	3.20	0.00	0.63	eDNA Historical Data
C	15th Ave West	FIF-222	14 kV	8.40	3.90	5.19	eDNA Historical Data
C	15th Ave West	FIF-226	14 kV	3.20	1.00	1.65	eDNA Historical Data
C	15th Ave West	FIF-228	14 kV	3.20	1.30	1.94	eDNA Historical Data
C	15th Ave West	FIF-230	14 kV	1.50	0.50	1.15	eDNA Historical Data
C	15th Ave West	FIF-231	14 kV	2.50	0.20	0.91	eDNA Historical Data
C	15th Ave West	FIF-232	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	15th Ave West	FIF-233	14 kV	2.80	1.10	1.54	eDNA Historical Data
C	15th Ave West	FIF-234	14 kV	0.50	0.10	0.24	eDNA Historical Data
C	15th Ave West	FIF-260	14 kV	6.30	2.10	3.51	eDNA Historical Data
C	15th Ave West	FIF-261	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	15th Ave West	FIF-264	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	15th Ave West	FIF-265	14 kV	2.20	0.50	1.46	eDNA Historical Data
C	15th Ave West	FIF-266	14 kV	3.30	1.30	2.39	eDNA Historical Data
C	Bear Creek	BCR-23	46 kV	1.80	0.40	0.95	eDNA Historical Data
C	Bear Creek	MAT-59	46 kV	5.70	1.14	1.87	eDNA Historical Data (calc)
C	Bear Creek - Hinckley	BCR-198	46 kV	5.30	1.06	2.23	eDNA Historical Data Operated Network
C	Big Rock	BGR-272	14 kV	5.90	2.60	3.21	eDNA Historical Data (Calc)
C	Big Rock	BGR-274	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Burnett	BUR-407	14 kV	0.00	0.00	0.00	Aclara Historical Data
C	Burnett	BUR-408	14 kV	1.44	0.19	0.72	Aclara Historical Data
C	Canosia Road	CNA-421	34 kV	2.26	0.10	0.22	eDNA Historical Data
C	Canosia Road	CNA-403	14 kV	1.60	0.30	0.69	eDNA Historical Data
C	Canosia Road	CNA-405	14 kV	4.60	1.50	2.35	eDNA Historical Data
C	Canosia Road	CNA-413	14 kV	4.50	1.00	1.80	eDNA Historical Data
C	Cloquet	CLQ-404	14 kV	9.50	3.29	6.83	eDNA Historical Data
C	Cloquet	CLQ-406	14 kV	10.29	4.55	5.92	eDNA Historical Data
C	Cloquet	CLQ-409	14 kV	6.95	3.05	4.22	eDNA Historical Data

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
C	Cloquet	CLQ-410	14 kV	3.99	1.17	2.30	eDNA Historical Data
C	Cloquet	CLQ-412	14 kV	0.35	0.02	0.17	eDNA Historical Data
C	Colbyville	COL-240	14 kV	5.16	1.27	2.66	eDNA Historical Data
C	Colbyville	COL-241	14 kV	3.93	1.35	2.08	eDNA Historical Data
C	Colbyville	COL-242	14 kV	7.09	2.90	3.88	eDNA Historical Data
C	Colbyville	COL-244	14 kV	4.98	1.97	2.65	eDNA Historical Data
C	Colbyville	COL-245	14 kV	1.70	0.21	1.10	eDNA Historical Data
C	Four Corners	FCS-214	14 kV	7.16	2.74	4.56	eDNA Historical Data
C	Four Corners	FCS-215	14 kV	5.47	1.52	2.58	eDNA Historical Data
C	French River	FRR-275	14 kV	3.00	0.50	1.31	eDNA Historical Data
C	French River	FRR-276	14 kV	2.00	0.40	0.81	eDNA Historical Data
C	Gary	GRY-200	14 kV	3.22	1.20	1.69	eDNA Historical Data
C	Gary	GRY-201	14 kV	4.69	1.50	2.24	eDNA Historical Data
C	Gary	GRY-210	14 kV	4.47	0.28	2.93	eDNA Historical Data
C	Haines Road	HNS-229	14 kV	8.07	3.72	4.85	eDNA Historical Data
C	Haines Road	HNS-235	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Haines Road	HNS-236	14 kV	8.53	2.46	3.59	eDNA Historical Data
C	Haines Road	HNS-237	14 kV	3.77	1.47	1.94	eDNA Historical Data
C	Haines Road	HNS-238	14 kV	2.46	0.72	0.98	eDNA Historical Data
C	Haines Road	HNS-239	14 kV	1.19	0.26	0.79	eDNA Historical Data
C	Haines Road	HNS-247	14 kV	2.68	1.13	1.43	eDNA Historical Data
C	Hibbard	MLH-267	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Hibbard	MLH-268	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Hibbard	MLH-279	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Hinckley East	HKZ-463	14 kV	2.25	0.76	1.08	Aclara Historical Data
C	LSPI	LSP-208	34 kV	8.10	3.60	4.25	eDNA Historical Data
C	LSPI	LSP-223	14 kV	7.92	3.21	3.81	eDNA Historical Data
C	LSPI	LSP-224	14 kV	3.28	0.21	1.62	eDNA Historical Data
C	LSPI	LSP-225	14 kV	5.76	2.51	2.90	eDNA Historical Data
C	LSPI	LSP-280	14 kV	5.70	1.53	3.18	eDNA Historical Data
C	LSPI	LSP-281	14 kV	3.37	1.28	1.96	eDNA Historical Data

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
C	LSPI	LSP-282	14 kV	0.79	0.25	0.39	eDNA Historical Data
C	Mahtowa	MAT-420	23 kV	4.73	0.82	2.57	eDNA Historical Data
C	Meadowlands	MDL-401	14 kV	0.80	0.08	0.24	eDNA Historical Data
C	North Shore	NSS-271	14 kV	2.60	1.00	1.51	eDNA Historical Data
C	North Shore	NSS-277	14 kV	0.00	0.00	0.00	eDNA Historical Data
C	Ridgeview	RGV-251	14 kV	2.30	0.70	1.15	eDNA Historical Data
C	Ridgeview	RGV-252	14 kV	6.70	3.10	4.03	eDNA Historical Data
C	Ridgeview	RGV-253	14 kV	7.50	2.40	3.76	eDNA Historical Data
C	Ridgeview	RGV-254	14 kV	4.80	2.00	2.90	eDNA Historical Data
C	Ridgeview	RGV-255	14 kV	7.70	3.20	4.28	eDNA Historical Data
C	Ridgeview	RGV-256	14 kV	1.90	0.60	0.87	eDNA Historical Data
C	Savanna	SAV-402	14 kV	1.78	0.48	0.82	eDNA Historical Data
C	Silver Bay Hillside	SBH-271	14 kV	0.00	0.00	0.00	eDNA Historical Data (calc)
C	Swan Lake	SLA-250	14 kV	8.70	3.50	4.98	eDNA Historical Data
C	Swan Lake	SLA-257	14 kV	5.90	2.40	3.14	eDNA Historical Data
C	Swan Lake	SLA-258	14 kV	6.70	2.60	3.31	eDNA Historical Data
C	Swan Lake	SLA-203	34 kV	10.20	5.00	7.45	eDNA Historical Data
C	Taft	TFT-202	34 kV	5.64	2.15	3.00	eDNA Historical Data
C	Thomson	TMS-412	14 kV	3.35	0.99	2.01	eDNA Historical Data (calc)
C	Thomson	TMS-23	46 kV	1.38	0.06	1.25	eDNA Historical Data
C	Two Harbors	TWH-273	14 kV	5.87	0.07	2.29	eDNA Historical Data (calc)
C	Wrenshall	WRN-411	14 kV	3.80	0.90	1.84	eDNA Historical Data
C	Wrenshall	WRN-415	14 kV	0.00	0.00	0.00	eDNA Historical Data
N	Babbitt-Winton	31 LINE	46 kV	5.00	1.70	2.51	eDNA Historical Data (calc)
N	Big Fork	BFV-1	12 kV	1.60	0.60	0.85	eDNA Historical Data
N	Canisteo	CNS-382	14 kV	0.00	0.00	0.00	eDNA Historical Data
N	Diamond Lake	DML-380	34 kV	0.00	0.00	0.00	eDNA Historical Data
N	Embarrass	EMB-317	23 kV	5.25	1.94	3.33	eDNA Historical Data
N	Grand Rapids	GRR-325	23 kV	0.30	0.00	1.04	eDNA Historical Data
N	Hat Trick	HAT-321	23 kV	7.10	2.70	3.86	eDNA Historical Data
N	Hat Trick	HAT-332	23 kV	4.30	1.80	2.70	eDNA Historical Data

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
N	Hibbing	HIB-307	23 kV	13.55	3.94	6.51	eDNA Historical Data
N	Hibbing	HIB-308	23 kV	5.30	1.83	4.08	eDNA Historical Data
N	Hibbing	HIB-310	23 kV	7.97	2.09	3.89	eDNA Historical Data
N	Hibbing	HIB-312	23 kV	0.00	0.00	0.00	eDNA Historical Data
N	Hibbing	HIB-315	23 kV	1.16	0.09	0.75	eDNA Historical Data
N	International Falls	INF-1	12 kV	2.05	0.83	1.19	eDNA Historical Data
N	International Falls	INF-2	12 kV	4.43	1.41	1.99	eDNA Historical Data
N	International Falls	INF-3	12 kV	0.46	0.04	0.16	eDNA Historical Data
N	International Falls	INF-4	12 kV	0.32	0.01	0.09	eDNA Historical Data
N	International Falls	INF-5	12 kV	0.15	0.05	0.08	eDNA Historical Data
N	Laskin	AUR-313	23 kV	2.68	0.94	1.31	eDNA Historical Data
N	Laskin	30 LINE	46 kV	0.00	0.00	0.00	eDNA Historical Data
N	Lind-Greenway	LGW-334	23 kV	0.83	0.17	0.63	eDNA Historical Data (calc)
N	Lind-Greenway	LGW-335	23 kV	1.37	0.27	1.04	eDNA Historical Data (calc)
N	Maturi	MTU-330	23 kV	1.90	0.40	0.53	eDNA Historical Data
N	Maturi	MTU-381	34 kV	0.00	0.00	0.00	eDNA Historical Data
N	Nashwauk	NAS-314	23 kV	3.00	1.03	1.46	eDNA Historical Data
N	Nashwauk	NAS-318	23 kV	0.00	0.00	0.00	eDNA Historical Data
N	Nashwauk	NAS-319	23 kV	3.33	1.27	1.80	eDNA Historical Data
N	Tower-Winton	TOW-32	46 kV	8.30	2.80	4.24	eDNA Historical Data (calc)
N	Virginia	VRG-301	23 kV	3.69	1.44	2.07	eDNA Historical Data
N	Virginia	VRG-302	23 kV	7.15	3.13	4.57	eDNA Historical Data
N	Virginia	VRG-303	23 kV	1.63	0.88	1.07	eDNA Historical Data
N	Virginia	VRG-304	23 kV	0.80	0.21	0.45	eDNA Historical Data
N	Virginia	VRG-305	23 kV	6.38	2.28	3.53	eDNA Historical Data
N	Virginia	VRG-306	23 kV	0.00	0.00	0.00	eDNA Historical Data
N	Virginia	VRG-311	23 kV	2.59	0.81	1.32	eDNA Historical Data
N	Virginia	30 LINE	46 kV	3.59	0.38	2.02	eDNA Historical Data
N	Virginia-Tower	199 LINE	46 kV	5.70	2.30	3.35	eDNA Historical Data (calc)
N	Winton	33 LINE	46 kV	12.50	3.20	5.03	eDNA Historical Data
N	Zemple	ZMP-335	23 kV	0.00	0.00	0.00	eDNA Historical Data

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
N	Zemple	ZMP-337	23 kV	2.50	0.90	1.30	eDNA Historical Data
W	Akeley	AKY-543	34 kV	8.00	3.30	4.68	eDNA Historical Data
W	Akeley	AKY-544	34 kV	9.40	1.30	3.36	eDNA Historical Data
W	Baxter	BAX-531	34 kV	5.65	1.55	2.50	eDNA Historical Data
W	Baxter	BAX-534	34 kV	7.64	1.97	3.36	eDNA Historical Data
W	Birch Lake	BLS-509	34 kV	7.90	2.10	3.66	eDNA Historical Data
W	Birch Lake	BLS-516	34 kV	2.10	0.50	0.94	eDNA Historical Data
W	Blanchard	BLD-508	34 kV	5.71	1.71	3.20	eDNA Historical Data
W	Blanchard	BLD-511	34 kV	6.21	2.00	1.94	eDNA Historical Data
W	Blanchard	BLD-521	34 kV	1.80	0.70	0.82	eDNA Historical Data
W	Blanchard	BLD-524	34 kV	6.64	1.95	3.45	eDNA Historical Data
W	Blueberry	BLU-552	34 kV	8.20	2.90	4.37	eDNA Historical Data
W	Dog Lake	DOG-503	34 kV	9.10	2.40	4.61	eDNA Historical Data
W	Eagle Valley	EGV-513	34 kV	4.30	1.80	2.36	eDNA Historical Data
W	Eagle Valley	EGV-517	34 kV	9.20	3.00	4.61	eDNA Historical Data
W	Little Falls	LFL-525	34 kV	8.62	2.64	4.32	eDNA Historical Data
W	Little Falls	LFL-526	34 kV	9.99	3.00	5.32	eDNA Historical Data
W	Little Falls	LFL-529	34 kV	11.72	4.31	5.73	eDNA Historical Data
W	Little Falls	LFL-536	34 kV	6.80	1.31	2.97	eDNA Historical Data
W	Long Lake	LNG-540	34 kV	0.20	0.10	0.11	eDNA Historical Data
W	Long Lake	LNG-541	34 kV	8.40	3.60	4.41	eDNA Historical Data
W	Long Lake	LNG-542	34 kV	7.20	2.20	3.88	eDNA Historical Data
W	Long Lake	LNG-545	34 kV	4.00	0.60	2.23	eDNA Historical Data
W	Long Prairie	LPR-501	34 kV	7.14	1.66	4.25	eDNA Historical Data
W	Long Prairie	LPR-527	34 kV	2.40	0.74	1.26	eDNA Historical Data
W	Long Prairie	LPR-535	34 kV	13.87	5.24	8.31	eDNA Historical Data
W	Long Prairie	LPR-537	34 kV	3.77	1.64	2.24	eDNA Historical Data
W	Pepin Lake	PPL-514	34 kV	8.90	2.60	4.81	eDNA Historical Data
W	Pepin Lake	PPL-539	34 kV	3.80	0.90	1.84	eDNA Historical Data
W	Pequot Lakes	PQT-507	34 kV	3.70	1.30	1.95	eDNA Historical Data
W	Pequot Lakes	PQT-531	34 kV	8.70	2.80	3.62	eDNA Historical Data

2024 Parent Feeder Loading Summary^{NOTE1,NOTE2}

Area	Substation	Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
W	Pine River	PNV-549	34 kV	4.10	1.70	2.40	eDNA Historical Data
W	Pine River	PNV-550	34 kV	1.80	0.10	0.81	eDNA Historical Data
W	Platte River	PLA-546	34 kV	2.70	0.10	2.09	eDNA Historical Data
W	Platte River	PLA-547	34 kV	3.70	0.70	1.56	eDNA Historical Data
W	Riverton	RVT-505	34 kV	5.13	1.79	2.54	eDNA Historical Data
W	Riverton	RVT-506	34 kV	7.53	2.95	3.89	eDNA Historical Data
W	Riverton	RVT-530	34 kV	0.67	0.06	0.66	eDNA Historical Data
W	Riverton	RVT-532	34 kV	10.72	0.21	1.12	eDNA Historical Data
W	Straight River	STG-551	34 kV	1.80	0.40	1.10	eDNA Historical Data
W	Sylvan	SYL-502	34 kV	0.30	0.05	0.20	eDNA Historical Data
W	Verndale	VRD-503	34 kV	8.91	3.28	5.03	eDNA Historical Data
W	Verndale	VRD-510	34 kV	4.74	3.75	2.60	eDNA Historical Data
W	Verndale	VRD-519	34 kV	3.30	0.10	1.01	eDNA Historical Data
W	Verndale	VRD-533	34 kV	15.94	6.00	9.15	eDNA Historical Data

NOTES

1. Values in table are non-coincident and shouldn't be added together
2. Values represent real power loading (MW) only; apparent power loading (MVA) will generally be slightly higher
3. Daytime Minimum corresponds to minimum hourly load between 0800-1800 where available or 20% of peak load where direct data is not available
4. Except as noted, values are based on hourly load data from the MP eDNA Data Historian
5. Where possible, the effective load reduction from large-scale distribution-connected generation has been excluded

2024 Stepdown Feeder Loading Summary^{NOTE1,NOTE2}

Area		Parent Feeder	Stepdown	Stepdown Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
C	Bear Creek	BCR 23 LINE	Askov	ASK-6521	12 kV	1.31	0.26	0.76	Aclara Historical Data
C	Bear Creek	BCR 23 LINE	Kerrick	KER-6501	12 kV	0.50	0.10	0.27	Aclara Historical Data
C	Bear Creek	59 LINE	Anderson Corner	FIN-6511	12 kV	0.80	0.16	0.46	Aclara Historical Data
C	Bear Creek - Hinckley	198 LINE	Sandstone	SAN-452	12 kV	1.38	0.28	N/A	Engineering Estimate
C	Bear Creek - Hinckley	198 LINE	Hinckley West	HKZ-461	12 kV	1.13	0.23	N/A	Engineering Estimate
C	Bear Creek - Hinckley	198 LINE	Hinckley West	HKZ-462	12 kV	4.09	0.82	N/A	Engineering Estimate
C	Canosia Road	CNA-421	Cloquet East	CES-417	14 kV	2.20	0.70	0.96	eDNA Historical Data
C	Cloquet	CLQ-409	Big Lake	CQB-6301	12 kV	0.91	0.18	0.44	Aclara Historical Data
C	Four Corners	FCS-214	Caribou Lake	CBL-214	12 kV	1.26	0.25	N/A	Engineering Estimate
C	Four Corners	FCS-214	Pike Lake	PLR-214	12 kV	0.50	0.10	N/A	Engineering Estimate
C	Four Corners	FCS-215	Seville Rd	SVR-215	12 kV	2.25	0.45	N/A	Engineering Estimate
C	LSPI	LSP-208	25th Ave West	TFW-243	14 kV	3.30	0.66	1.63	eDNA Historical Data
C	LSPI	LSP-208	4th Ave West	FOR-262	14 kV	1.90	0.38	1.07	eDNA Historical Data
C	LSPI	LSP-208	4th Ave West	FOR-263	14 kV	2.80	0.56	1.60	eDNA Historical Data
C	Mahtowa	59 LINE	Barnum	BAR-6421	12 kV	2.04	0.41	1.26	Aclara Historical Data
C	Mahtowa	59 LINE	Denham	DEN-6431	12 kV	6.18	1.24	N/A	Engineering Estimate
C	Mahtowa	MAT-420	Mahtowa	MAH-6411	12 kV	1.30	0.26	0.66	Aclara Historical Data
C	Mahtowa	MAT-420	Olsonville West	OLW-4471	4 kV	0.36	0.07	N/A	Engineering Estimate
C	Silver Bay Hillside	SBH-271	Silver Bay Townsite	SBT-4301	4 kV	1.14	0.23	0.63	Aclara Historical Data
C	Silver Bay Hillside	SBH-271	Silver Bay Townsite	SBT-4302	4 kV	1.00	0.20	0.58	Aclara Historical Data
C	Swan Lake	SLA-203	2nd Ave East	SND-217	14 kV	1.80	0.36	0.98	eDNA Historical Data
C	Swan Lake	SLA-203	2nd Ave East	SND-218	14 kV	2.40	0.48	1.27	eDNA Historical Data
C	Swan Lake	SLA-203	9th Ave East	NIN-246	14 kV	2.20	0.44	1.32	eDNA Historical Data
C	Swan Lake	SLA-203	9th Ave East	NIN-248	14 kV	3.20	0.64	1.71	eDNA Historical Data
C	Taft	TFT-202	Fredenburg	FBG-269	14 kV	3.32	0.66	N/A	Engineering Estimate
C	Taft	TFT-202	Pioneer Rd	PIO-270	14 kV	3.88	0.78	N/A	Engineering Estimate
C	Thomson	TMS 23 LINE	Military Rd	MLT-414	14 kV	1.38	0.06	1.25	eDNA Historical Data
C	Wrenshall	WRN-411	Wrenshall Riverside	WRR-6321	12 kV	0.61	0.12	0.27	Aclara Historical Data
N	Babbitt	31 LINE	Babbitt Townsite	BAB-1	4 kV	1.72	0.34	0.97	Aclara Historical Data
N	Babbitt	31 LINE	Babbitt Townsite	BAB-2	4 kV	0.27	0.05	0.16	Aclara Historical Data
N	Babbitt	31 LINE	Dunka River	DUN-1	4 kV	0.57	0.11	0.13	Aclara Historical Data
N	Embarrass	EMB-317	Aurora	AUN-1	4 kV	1.65	0.33	1.02	Aclara Historical Data
N	Embarrass	EMB-317	Aurora	AUN-2	4 kV	3.69	0.74	N/A	Engineering Estimate
N	Embarrass	EMB-317	Biwabik	BIW-1	12 kV	3.69	0.74	0.75	Aclara Historical Data
N	Embarrass	EMB-317	Biwabik	BIW-2	12 kV	1.46	0.29	N/A	Aclara Historical Data
N	Hat Trick	HAT-321	Eveleth	ESS-1	4 kV	1.55	0.31	0.89	Aclara Historical Data
N	Hat Trick	HAT-321	Half Moon Lake	HML-1	4 kV	0.14	0.03	N/A	Engineering Estimate
N	Hat Trick	HAT-332	Eveleth OHV	OHV-1	4 kV	0.02	0.00	N/A	Engineering Estimate
N	Hibbing	HIB-310	Balkan	BAL-1	12 kV	0.95	0.19	0.41	Aclara Historical Data
N	Hibbing	HIB-310	Balkan	BAL-2	12 kV	0.34	0.07	0.15	Aclara Historical Data
N	Hibbing	HIB-310	Chisholm	CHL-1	4 kV	2.16	0.43	1.80	Aclara Historical Data
N	Hibbing	HIB-310	Chisholm	CHL-2	4 kV	1.05	0.21	0.61	Aclara Historical Data
N	Hibbing	HIB-310	Chisholm	CHL-3	4 kV	1.81	0.36	1.09	Aclara Historical Data

2024 Stepdown Feeder Loading Summary^{NOTE1,NOTE2}

Area		Parent Feeder	Stepdown	Stepdown Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
N	Hibbing	HIB-315	Kelly Lake	KLY-1	4 kV	0.55	0.11	0.25	Aclara Historical Data
N	Hibbing	HIB-308	Stuntz Wilpen Bridge	SWB-1	4 kV	0.20	0.04	N/A	Engineering Estimate
N	Laskin	AUR-313	Hoyt Lakes	HYN-1	4 kV	0.61	0.12	0.40	Aclara Historical Data
N	Laskin	AUR-313	Hoyt Lakes	HYN-2	4 kV	1.84	0.37	0.90	Aclara Historical Data
N	Lind-Greenway	LGW-335	Cohasset	COA-1	4 kV	0.15	0.03	N/A	Engineering Estimate
N	Lind-Greenway	LGW-334	Coleraine COE	COE-1	4 kV	0.08	0.02	N/A	Engineering Estimate
N	Lind-Greenway	LGW-334	Coleraine COF	COF-1	4 kV	0.16	0.03	N/A	Engineering Estimate
N	Maturi	MTU-330	Stuntz	STZ-1	4 kV	0.39	0.08	N/A	Engineering Estimate
N	Maturi	MTU-330	Stuntz	STZ-2	4 kV	0.64	0.13	0.28	Aclara Historical Data
N	Maturi	MTU-330	Spudville East	SVE-1	4 kV	0.18	0.04	0.07	Aclara Historical Data
N	Maturi	MTU-330	Spudville West	SVW-1	4 kV	0.39	0.08	0.18	Aclara Historical Data
N	Nashwauk	NAS-319	Marble	MAR-1	4 kV	0.69	0.14	N/A	Engineering Estimate
N	Nashwauk	NAS-319	Pengilly North	PNN-1	4 kV	0.16	0.03	N/A	Engineering Estimate
N	Nashwauk	NAS-319	Pengilly South	PNS-1	4 kV	0.16	0.03	N/A	Engineering Estimate
N	Nashwauk	NAS-319	Taconite Village	TAC-1	4 kV	0.30	0.06	N/A	Engineering Estimate
N	Tower	32 LINE	Tower Soudan	TWN-1	12 kV	0.35	0.07	0.24	Aclara Historical Data
N	Tower	32 LINE	Tower Soudan	TWN-2	12 kV	1.51	0.30	0.72	Aclara Historical Data
N	Virginia	VRG-311	Iron	INJ-1	12 kV	0.98	0.20	0.51	Aclara Historical Data
N	Winton	33 LINE	St. Croix	STC-1	12 kV	0.33	0.07	0.13	Aclara Historical Data
N	Winton	33 LINE	St. Croix	STC-2	12 kV	1.56	0.31	N/A	Engineering Estimate
N	Zemple	ZMP-337	Deer River DRR	DRR-2	4 kV	1.50	0.30	0.82	Aclara Historical Data
W	Akeley	AKY-543	Akeley Dist	AKE-1	4 kV	1.03	0.21	0.55	Aclara Historical Data
W	Akeley	AKY-544	Nevis	NEV-1	4 kV	1.33	0.27	0.72	Aclara Historical Data
W	Akeley	AKY-543	Walker #1	WAK-1	12 kV	2.57	0.51	1.51	Aclara Historical Data
W	Akeley	AKY-543	Walker #2	WBK-1	12 kV	3.03	0.61	N/A	Engineering Estimate
W	Akeley	AKY-543	Walker Wye	WYE-1	12 kV	0.69	0.14	N/A	Engineering Estimate
W	Baxter	BAX-531	Gull Lake	GLL-1	12 kV	3.55	0.71	1.33	Aclara Historical Data
W	Baxter	BAX-531	Gull Lake	GLL-2	12 kV	1.57	0.31	N/A	Engineering Estimate
W	Baxter	BAX-531	Hole in the Day	HID-1	12 kV	1.59	0.32	0.55	Aclara Historical Data
W	Baxter	BAX-534	Lynch Lake	LNL-1	12 kV	0.20	0.04	N/A	Engineering Estimate
W	Baxter	BAX-534	Pillager Dist	PIL-1	12 kV	1.68	0.34	N/A	Engineering Estimate
W	Baxter	BAX-534	Pine Beach	PNB-1	12 kV	1.34	0.27	0.57	Aclara Historical Data
W	Baxter	BAX-534	Pine Beach	PNB-2	12 kV	2.02	0.40	0.81	Aclara Historical Data
W	Birch Lake	BLS-516	Backus	BAC-1	12 kV	1.81	0.36	0.88	Aclara Historical Data
W	Birch Lake	BLS-509	Hackensack	HCS-1	12 kV	1.81	0.36	0.96	Aclara Historical Data
W	Birch Lake	BLS-509	Tenmile Lake	TML-1	12 kV	0.43	0.09	0.19	Aclara Historical Data
W	Blanchard	BLD-524	Bowlus	BSD-1	12 kV	0.28	0.06	N/A	Engineering Estimate
W	Blanchard	BLD-524	Bowlus	BSD-2	12 kV	1.15	0.23	0.62	Aclara Historical Data
W	Blanchard	BLD-508	Camp Ripley Rural	CRS-1	12 kV	0.66	0.13	0.26	Aclara Historical Data
W	Blanchard	BLD-508	Ginger Rd	GIN-1	12 kV	1.21	0.24	0.63	Aclara Historical Data
W	Blanchard	BLD-511	Royalton	ROY-1	12 kV	2.01	0.40	N/A	Engineering Estimate
W	Blanchard	BLD-511	Royalton	ROY-2	12 kV	2.02	0.40	N/A	Engineering Estimate
W	Blanchard	BLD-524	Upsala	UPS-1	12 kV	1.82	0.36	1.01	Aclara Historical Data

2024 Stepdown Feeder Loading Summary^{NOTE1,NOTE2}

Area		Parent Feeder	Stepdown	Stepdown Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
W	Blanchard	BLD-524	Upsala	UPS-2	12 kV	0.98	0.20	0.54	Aclara Historical Data
W	Blueberry	BLU-552	Sebeka Nimrod	SEB-1	12 kV	1.45	0.29	0.84	Aclara Historical Data
W	Blueberry	BLU-552	Spirit Lake	SLS-1	12 kV	2.41	0.48	1.30	Aclara Historical Data
W	Dog Lake	DOG-503	Motley	MOT-1	12 kV	1.34	0.27	0.77	Aclara Historical Data
W	Dog Lake	DOG-503	Motley	MOT-2	12 kV	0.86	0.17	0.55	Aclara Historical Data
W	Dog Lake	DOG-503	Staples Rural	STR-1	12 kV	0.28	0.06	N/A	Engineering Estimate
W	Eagle Valley	EGV-513	Bertha	BER-1	12 kV	0.88	0.18	N/A	Engineering Estimate
W	Eagle Valley	EGV-517	Browerville	BRW-1	12 kV	0.82	0.16	0.49	Aclara Historical Data
W	Eagle Valley	EGV-517	Browerville	BRW-2	12 kV	0.91	0.18	0.47	Aclara Historical Data
W	Eagle Valley	EGV-517	Clarissa	CLR-1	12 kV	1.25	0.25	0.73	Aclara Historical Data
W	Eagle Valley	EGV-517	Clarissa	CLR-2	12 kV	0.20	0.04	0.09	Aclara Historical Data
W	Eagle Valley	EGV-513	Eagle Bend	EGB-1	12 kV	1.39	0.28	0.76	Aclara Historical Data
W	Hubbard	HBB-523	Hubbard Dist	HUB-1	12 kV	0.33	0.07	N/A	Engineering Estimate
W	Little Falls	LFL-529	Little Falls East Side	LFE-1	12 kV	2.04	0.41	0.87	Aclara Historical Data
W	Little Falls	LFL-529	Little Falls Hospital	LFG-1	12 kV	1.57	0.31	N/A	Engineering Estimate
W	Little Falls	LFL-529	Little Falls South Side	LFS-1	12 kV	2.25	0.45	1.14	Aclara Historical Data
W	Little Falls	LFL-525	Little Falls West Side	LFW-1	12 kV	1.82	0.36	0.86	Aclara Historical Data
W	Little Falls	LFL-525	Little Falls West Side	LFW-2	12 kV	2.15	0.43	1.13	Aclara Historical Data
W	Little Falls	LFL-525	Little Falls North Side	NTH-1	12 kV	0.85	0.17	N/A	Engineering Estimate
W	Little Falls	LFL-525	Little Falls North Side	NTH-2	12 kV	0.15	0.03	N/A	Engineering Estimate
W	Little Falls	LFL-526	Pierz-Genola	PZG-1	12 kV	3.11	0.62	1.43	Aclara Historical Data
W	Little Falls	LFL-526	Pierz-Genola	PZG-2	12 kV	1.74	0.35	0.75	Aclara Historical Data
W	Little Falls	LFL-526	Rich Prairie	RPR-1	12 kV	1.27	0.25	0.76	Aclara Historical Data
W	Long Lake	LNG-540	Dorset	DOR-1	4 kV	0.32	0.06	N/A	Engineering Estimate
W	Long Lake	LNG-541	Explorer Circle	ECS-1	4 kV	0.15	0.03	N/A	Engineering Estimate
W	Long Lake	LNG-541	Long Lake Park Rapids	LGL-1	4 kV	0.75	0.15	N/A	Engineering Estimate
W	Long Lake	LNG-541	Mud Lake Stepdown	MSD-1	4 kV	0.07	0.01	N/A	Engineering Estimate
W	Long Lake	LNG-542	Park Rapids Dist #2	PKD-1	4 kV	2.32	0.46	1.39	Aclara Historical Data
W	Long Lake	LNG-542	Park Rapids Dist #1	PKR-1	4 kV	1.26	0.25	0.67	Aclara Historical Data
W	Long Lake	LNG-541	Park Rapids Hospital	PRH-1	4 kV	0.50	0.10	0.24	Aclara Historical Data
W	Long Prairie	LPR-535	Big Bear	BBR-1	12 kV	1.20	0.24	N/A	Engineering Estimate
W	Long Prairie	LPR-537	Gutches Grove	GGR-1	12 kV	1.74	0.35	1.05	Aclara Historical Data
W	Long Prairie	LPR-535	Harts Press	HPS-1	12 kV	0.51	0.10	N/A	Engineering Estimate
W	Long Prairie	LPR-535	Lake Charlotte	LCH-1	12 kV	0.81	0.16	0.38	Aclara Historical Data
W	Long Prairie	LPR-537	Long Prairie Dist	LPD-1	4 kV	0.85	0.17	0.45	Aclara Historical Data
W	Long Prairie	LPR-537	Long Prairie Dist	LPD-2	4 kV	1.52	0.30	0.88	Aclara Historical Data
W	Long Prairie	LPR-535	Long Prairie North	LPN-1	12 kV	0.05	0.01	N/A	Engineering Estimate
W	Pepin Lake	PPL-514	Flensburg	FLN-1	12 kV	0.18	0.04	0.14	Aclara Historical Data
W	Pepin Lake	PPL-514	Flensburg	FLN-2	12 kV	0.76	0.15	0.38	Aclara Historical Data
W	Pepin Lake	PPL-539	Grey Eagle	GES-1	12 kV	1.38	0.28	0.71	Aclara Historical Data
W	Pepin Lake	PPL-514	Long Lake Stepdown	LLK-1	12 kV	0.72	0.14	N/A	Engineering Estimate
W	Pepin Lake	PPL-514	Swanville	SWN-1	12 kV	1.74	0.35	1.03	Aclara Historical Data
W	Pequot Lakes	PQT-531	Nisswa Pumping Station	NPS-1	12 kV	1.53	0.31	0.68	Aclara Historical Data

2024 Stepdown Feeder Loading Summary^{NOTE1,NOTE2}

Area		Parent Feeder	Stepdown	Stepdown Feeder	Voltage Class	Peak Load (MW)	Daytime Min (MW) ^{NOTE3}	Avg Load (MW)	Data Source ^{NOTE4}
W	Pequot Lakes	PQT-531	Nisswa	NSW-1	12 kV	1.66	0.33	0.76	Aclara Historical Data
W	Pequot Lakes	PQT-531	Nisswa	NSW-2	12 kV	2.46	0.49	1.13	Aclara Historical Data
W	Pequot Lakes	PQT-531	Northwest Gull Lake	NWG-1	12 kV	0.66	0.13	0.24	Aclara Historical Data
W	Pequot Lakes	PQT-531	Northwest Gull Lake	NWG-2	12 kV	1.20	0.24	0.47	Aclara Historical Data
W	Pequot Lakes	PQT-507	Pequot Lakes Dist	PQL-1	12 kV	0.37	0.07	0.16	Aclara Historical Data
W	Pequot Lakes	PQT-507	Pequot Lakes Dist	PQL-2	12 kV	3.41	0.68	1.87	Aclara Historical Data
W	Pequot Lakes	PQT-531	Round Lake	RDL-1	12 kV	0.80	0.16	N/A	Engineering Estimate
W	Pequot Lakes	PQT-531	Round Lake	RDL-2	12 kV	0.94	0.19	0.68	Aclara Historical Data
W	Pine River	PNV-549	Jenkins	JKS-1	12 kV	1.59	0.32	N/A	Engineering Estimate
W	Pine River	PNV-550	Pine River Dist	PNR-1	12 kV	0.95	0.19	0.49	Aclara Historical Data
W	Pine River	PNV-550	Pine River Dist	PNR-2	12 kV	0.93	0.19	0.47	Aclara Historical Data
W	Pine River	PNV-549	South Pine River	SPR-1	12 kV	1.77	0.35	1.21	Aclara Historical Data
W	Platte River	PLA-547	Rice	RIC-1	12 kV	2.38	0.48	1.09	Aclara Historical Data
W	Riverton	RVT-505	Crosby	CSB-1	4 kV	3.20	0.64	N/A	Engineering Estimate
W	Riverton	RVT-505	Crosby	CSB-2	4 kV	2.40	0.48	N/A	Engineering Estimate
W	Riverton	RVT-506	Cotton Tail Drive	CTD-1	12 kV	0.15	0.03	N/A	Engineering Estimate
W	Riverton	RVT-506	Cuyuna	CUY-1	4 kV	0.23	0.05	N/A	Engineering Estimate
W	Riverton	RVT-506	Deerwood	DER-1	12 kV	1.60	0.32	N/A	Engineering Estimate
W	Riverton	RVT-506	Deerwood	DER-2	12 kV	2.19	0.44	1.20	Aclara Historical Data
W	Riverton	RVT-506	Deerwood Highway	DHY-1	12 kV	1.45	0.29	0.73	Aclara Historical Data
W	Riverton	RVT-505	Ironton	IRN-1	4 kV	0.96	0.19	0.52	Aclara Historical Data
W	Riverton	RVT-532	Riverton Dist	RVD-1	12 kV	0.39	0.08	0.22	Aclara Historical Data
W	Riverton	RVT-530	Sylvan Dist	SYN-1	12 kV	1.07	0.21	0.60	Aclara Historical Data
W	Riverton	RVT-506	Trommald	TRM-1	4 kV	0.14	0.03	N/A	Engineering Estimate
W	Sylvan	SYL-502	Fort Ripley	FTR-1	14 kV	0.25	0.05	N/A	Engineering Estimate
W	Verndale	VRD-503	Aldrich	ALD-1	4 kV	0.14	0.03	0.06	Aclara Historical Data
W	Verndale	VRD-510	Blue Grass	BLG-1	4 kV	0.08	0.02	N/A	Aclara Historical Data
W	Verndale	VRD-519	Hewitt	HEW-1	12 kV	0.36	0.07	0.16	Aclara Historical Data
W	Verndale	VRD-510	Verndale Dist	VND-1	4 kV	1.38	0.28	0.68	Aclara Historical Data

NOTES

1. Values in table are non-coincident and shouldn't be added together
2. Values represent real power loading (MW) only; apparent power loading (MVA) will generally be slightly higher
3. Daytime Minimum corresponds to minimum hourly load between 0800-1800 where available or 20% of peak load where direct data is not available
4. Except as noted, values are based on hourly load data from the MP eDNA Data Historian

STATE OF MINNESOTA)
)ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING

I, Tiana C. Heger of the City of Duluth, County of St. Louis, State of Minnesota, hereby certify that on the 3rd day of November, 2025, I electronically filed a true and correct copy of Minnesota Power's Compliance Filing of its 2025 Integrated Distribution Plan in **Docket No. E015/M-25-140** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on eDocket's Official Service List for this Docket were served as requested.



Tiana Heger