# APPENDIX G: DISTRIBUTION PLANNING ACTIVITIES

Minnesota laws and reporting rules governing electric utilities require that electric utilities with a Minnesota service area submit to the Minnesota Public Utilities Commission ("Commission") a biennial report containing a five-year historical summary as well as a five-year investment plan and ten-year outlook for the distribution system. Minnesota Power's (or the "Company") Integrated Distribution Plan ("IDP") reporting requirements were established by the Commission in Docket No. E015/CI-18-254. The IDP is submitted biennially by November 1 of each odd year. Minnesota Power's 2023 IDP[1] contains all the information necessary to meet this biennial requirement and is attached as part of the Company's 2025-2039 Integrated Resource Plan ("2025 Plan") filing. The Commission accepted the Company's 2023 IDP on September 16, 2024. Some of the content from the 2023 IDP is highlighted below, including:

- a high-level overview;
- information on distribution and resource planning coordination; and
- information on the vetting of non-wires alternatives.

A brief update on distribution coordination related to the Company's proposed package of distribution-connected solar projects, designed to aid in the recovery from the economic impacts of the COVID-19 pandemic, is also provided.

## A. Integrated Distribution Plan Overview

To meet the needs of Minnesota Power's diverse customer base, the Company built its distribution strategy on the foundation of technology, innovation, and continuous improvement. Customers expect reliable, safe, and increasingly low-carbon electric service at a reasonable cost, all of which are encompassed in these core distribution values. Meeting these expectations requires deploying right time/right fit distribution technology that is flexible, adaptable, and upgradable. The Company contends that equity – in all of its forms – plays a critical role in ensuring security, comfort, and quality of life for customers. Therefore, the Company has strategically positioned its distribution system for the deployment of emerging distribution technologies through thoughtful planning in all areas of its business, while maintaining a focus on customers' needs, upholding its distribution planning principals, and aligning these investments with the Company's sustainability goals. Sustainable prosperity that balances economic, environmental, and social needs for both the Company and its customers over the long-term is Minnesota Power's goal. Safety, integrity, environmental stewardship, employee development, and community engagement are key considerations in distribution planning. As the energy transition continues and our communities adapt and change, Minnesota Power is committed to working with its customers to understand their expectations and needs so the Company can continue to deliver vital services in a meaningful and respectful way to meet the diverse needs of those we have the privilege to serve.

Minnesota Power's 2023 IDP demonstrated how the Company is proactively meeting the unique needs of a distribution system that is primarily located in rural areas and encountering the new challenges of increased distributed energy resource ("DER") and electric vehicle ("EV") penetration. The 2023 IDP emphasized the importance of asset renewal for aging infrastructure while also integrating increased system visibility tools via innovative pilot programs and proactive investment. To support Minnesota Power's distribution grid modernization efforts, the Company

[1] *In the Matter of Minnesota Power's 2023 Integrated Distribution Plan*, Docket No. E-015/M-23-258, 2023 Integrated Distribution Plan (Oct. 16, 2023).

submitted a grant application for $50 million in Department of Energy ("DOE") funding under the Federal Infrastructure Investment and Jobs Act ("IIJA") to support a distribution project called the Resilience and Preparedness ("RAP") Project. The funding, if awarded, would have allowed Minnesota Power to more quickly advance its asset renewal plans and would have allowed the Company to make technology upgrades faster and more quickly integrate DERs. Minnesota Power's RAP Project ultimately was not selected for the award, but the Company continues to make progress on the plans the award would have supported and look for additional federal funding opportunities to apply for.

## B. Integrated Distribution & Resource Planning

Minnesota Power's Distribution Planning and Resource Planning departments work in close collaboration with one another to ensure collaborative and robust integrated system planning. Coordinated discussions take place at regular intervals throughout the year to share information on potential supply side and demand side opportunities located at the distribution level, and the two groups coordinate in the development of the Distributed Energy Resource Scenario Analysis for the IDP. As the Company's Distribution Planning processes evolve, the primary areas of active coordination in the near-term between Distribution Planning and Resource Planning will be in load forecasting and vetting of non-wires alternatives.

## C. Non-Wires Alternatives

Generally, the types of projects that lend themselves to non-wires solutions are those designed to address reliability performance or load-serving issues. Specifically, non-wires solutions may be suitable for addressing reliability performance issues where there is limited or no backup capability following loss of the primary source to a feeder. In that case, a non-wires solution may be able to provide redundancy to the feeder, enhancing restoration times and ultimately improving reliability. A non-wires solution may also 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.

While non-wires solutions are suitable in specific circumstances, the majority of distribution spending reported in the 2023 IDP is focused on the renewal of aging infrastructure. These types of projects are not good candidate opportunities for non-wires solutions. However, Minnesota Power hired a consultant to review four locations for non-wires alternative projects and currently is out for bid on a Battery Energy Storage System ("BESS") project in the Kerrick, Minnesota area of its service territory. Non-wires solutions will continue to be evaluated in the next IDP, due to the Commission on November 1, 2025.

## D. Distribution-Connected Solar Projects

Minnesota Power installed roughly 22 MW of solar projects at three locations on the distribution system in northern Minnesota throughout 2022 and 2023. The Company's intent was to install these projects in 2022 and 2023 in order to aid in the local economic recovery from the COVID-19 pandemic. The three solar installations allow the Company to meet its obligations for the state's Solar Energy Standard mandate and were approved by the Commission on June 29, 2021.[2] All three projects are in service and the interconnection of these projects was coordinated with the Distribution Planning and Engineering departments to ensure that they were reliably

[2] *In the Matter of Minnesota Power's Petition for Approval of the Acquisition of Solar Power to Support Economic Relief and Recovery*, Docket No. E-015/M-20-828, Order Granting Petition and Requiring Compliance Filings at 3 (June 29, 2021).

interconnected to the Company's distribution system, and that the proper system upgrades were implemented to enable their interconnection.

As of December 31, 2023, Minnesota Power has interconnected 990 customer-sited distributed generation systems which total 16.2 MW.[3] Most distributed generation on the Company's system is residential solar, mostly concentrated in and around Duluth. Minnesota Power supports customer-sited solar through its SolarSense rebate and the interconnection process. The Company handles these interconnections through a robust process that follows the state of Minnesota's Distributed Energy Interconnection Process (or, "MNDIP") and Technical Interconnection and Interoperability Requirements (or, "TIIR"). The Company has developed its own Technical Service Manual to support this process as well. The Company is currently engaging in multiple Commission-led workgroups to improve both the interconnection process and distribution system planning to prepare for increased penetration of these resources.

In addition, in compliance with Minn. Stat. § 216B.1691, subd. 2h, the Commission, in Docket No. E002, E015, E017/CI-23-403, required that Minnesota Power obtain three percent of its total retail electric sales from distributed solar by 2030.[4] In order to meet this requirement, the Company expects to install 65 to 85 MW of distribution connected solar in the form of self-builds, build-own-transfers, or power purchase agreements ("PPAs") through multiple rounds of bidding, reviewing, and awarding the projects. The Company issued its first request for proposals ("RFP")[5] on January 30, 2025, with the intent of securing proposals for distributed solar resources with a commercial operation date ("COD") on or before December 31, 2028. The Company expects to issue its second RFP for distributed solar resources on or before July 30, 2026.

[3] *In the Matter of Minnesota Power's 2023 Distributed Energy Resources (DER) Interconnection Report*, Docket No. E-999/PR-24-10, Compliance Filing (March 6, 2024).
[4] *In the Matter of the Implementation of the New Distributed Solar Energy Standard Pursuant to 2023 Amendments to Minnesota Statutes, Section 216B.1691*, Docket No. E-002, E-015, E-017/CI-23-403, Order Clarifying Implementation of Distributed Solar Energy Standard (June 26, 2024).
[5] Minnesota Power is seeking proposals for distributed solar resources, available at https://www.mnpower.com/Environment/DSESRFP.

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

---

| | |
|---|---|
| In the Matter of Minnesota Power's<br>2023 Integrated Distribution Plan | Docket No. E015/M-23-258 |

---

## SUMMARY OF FILING

Minnesota Power (or "the Company") continues to advance the transformation of its power supply to a cleaner energy future through its *Energy**Forward*** strategy and, having become the first Minnesota utility to generate 50 percent of its electricity from renewable sources in 2020, the Company continues to invest in the grid of the future through new renewable generation assets and the infrastructure to support them. 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. Resiliency is a key component of Minnesota Power's *Energy**Forward*** strategy and the 2023 IDP details the Company's distribution planning processes and continuous foundational investments in areas such as increased asset renewal spending, Non-Wires Alternatives (or "NWA"), transportation electrification, and sophisticated load forecasting for a grid that will continue to provide the essential services customers rely on. Minnesota Power respectfully submits this third biennial Integrated Distribution Plan ("2023 IDP") to the Minnesota Public Utilities Commission ("Commission") in accordance with relevant Commission-issued orders, including the Commission's December 8, 2022 Order accepting the Company's 2021 IDP (Docket No. E-105/M-21-390) and its January 9, 2023 Order approving the Company's Integrated Resource Plan and setting additional requirements (Docket No. E-015/RP-21-33).

## 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.

Name, Address and Telephone Number of Utility (Minn. Rule 7829.1300, subp. 4(A))

Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 722–2641

Name, Address and Telephone Number of Utility Attorney (Minn. Rule 7829.1300, subp. 4(B))

Matt Brodin
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355–3152
mbrodin@allete.com

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))

Jess McCullough
Public Policy Advisor II
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3178
jmccullough@mnpower.com

Service List (Minn. Rule 7829.0700)

Matt Brodin
Senior Attorney
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3152
mbrodin@allete.com

Jess McCullough
Public Policy Advisor II
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3178
jmccullough@mnpower.com

Minnesota Power's Discovery Manager
discoverymanager@mnpower.com

**TABLE OF CONTENTS**

## TABLE OF FIGURES

## TABLE OF CHARTS



## TABLE OF ACRONYMS

| ACRONYM/DEFINED TERM | DEFINITION |
|---|---|
| ADMS | Advanced Distribution Management System |
| AMI | Advanced Metering Infrastructure |
| ANSI | American National Standards Institute |
| AFR | Annual Forecast Report |
| AMR | Automated Meter Reading |
| BESS | Battery Energy Storage System |
| CAGR | Compound Annual Growth Rate |
| CIP | Conservation Improvement Program |
| CVR | Conservation Voltage Reduction |
| CEUD | Customer Energy Use Data |
| CIS | Customer Information System |
| C2M | Customer to Meter |

| | |
|---|---|
| DR | Demand Response |
| DSM | Demand-Side Management |
| DCFC | Direct Current Fast Charging |
| DER | Distributed Energy Resource |
| DERMS | Distributed Energy Resources Management System |
| DG | Distributed Generation |
| DGWG | Distribution Generation Working Group |
| DMS | Distribution Management System |
| DRIVE | Distribution Resource Integration and Value Estimation |
| DE&I | Diversity, Equity, and Inclusion |
| E-ISAC | Electricity Information Sharing and Analysis Center |
| EPRI | Electric Power Research Institute |
| EV | Electric Vehicle |
| EVSE | Electric Vehicle Supply Equipment |
| ECO Act | Energy Conservation and Optimization Act of 2021 |
| EMS | Energy Management System |
| FLISR | Fault Location, Isolation, and System Restoration |
| FCI | Faulted Circuit Indicators |
| FERC | Federal Energy Regulatory Commission |
| GIS | Geographic Information Systems/Utility Network Model |
| GRPU | Grand Rapids Public Utilities |
| GWh | Gigawatt Hours |
| ISO | Independent System Operator |
| IT | Informational Technology |
| IEEE | Institute of Electrical and Electronic Engineers |
| IDP | Integrated Distribution Plan |
| IRP | Integrated Resource Plan |
| IBR | Inverted Block Rate |
| kVARh | KiloVAR-Hour |
| kW | Kilowatt |
| kWh | Kilowatt-Hour |

| | |
|---|---|
| LMR | Land Mobile Radio |
| LED | Light Emitting Diode |
| LI Solar | Low Income Solar |
| LIHEAP | Low Income Home Energy Assistance Program |
| MDM | Meter Data Management |
| MISO | Midcontinent Independent System Operator |
| MN-DIP | Minnesota Distributed Generation Interconnection Process |
| MW | Megawatt |
| MWh | Megawatt Hours |
| MVAR | MegaVAR |
| NERC | North American Electric Reliability Corporation |
| OT | Operational Technology |
| O&M | Operations and Maintenance |
| OMS | Outage Management System |
| PLMA | Peak Load Management Alliance |
| PV | Photovoltaic |
| RTO | Regional Transmission Organization |
| RTU | Remote Terminal Unit |
| RREAL | Rural Renewable Energy Alliance |
| SEPA | Smart Electric Power Alliance |
| SES | Minnesota Solar Energy Standard |
| STATCOM | Static Synchronous Compensator |
| SCADA | Supervisory Control and Data Acquisition |
| TIIR | Technical Interconnection and Interoperability Requirement |
| TSM | Technical Specification Manual |
| TOD | Time-of-Day |
| TOU | Time-of-Use |
| VVO | Volt-VAR Optimization |

# INTRODUCTION

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

| | |
|---|---|
| In the Matter of Minnesota Power's<br>2021 Integrated Distribution Plan | Docket No. E015/M-23-258 |

# I. INTRODUCTION

Minnesota Power's (or "the Company") 2023 Integrated Distribution Plan ("2023 IDP") provides information on each of the Minnesota Public Utilities Commission ("Commission") 2023 IDP objectives described below. In order to evaluate Minnesota Power's long term distribution planning efforts, it is important to understand the Company, its unique customer mix and service territory. Included in this section is an introduction to Minnesota Power, its *Energy**Forward*** strategy, and a brief overview of current systems relevant to a discussion on distribution planning efforts.

## A. Integrated Distribution Plan Procedural History

In its Order dated February 20, 2019,[1] 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 an Order dated December 8, 2022,[2] 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 currently attached as Appendix E in this filing. The Commission also required Minnesota Power to incorporate additional distribution and resource planning and non-wires alternative data in its Order accepting the Company's 2021 Integrated Resource Plan filing[3].

[1] Docket No. E-015/CI-18-254.
[2] Docket No. E-015/M-19-684.
[3] Docket No. E015/RP-21-33

As outlined in the May 27, 2020 Order, the Commission has identified the following objectives of 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 directed Minnesota Power to discuss the following points in addition to the original five objectives:

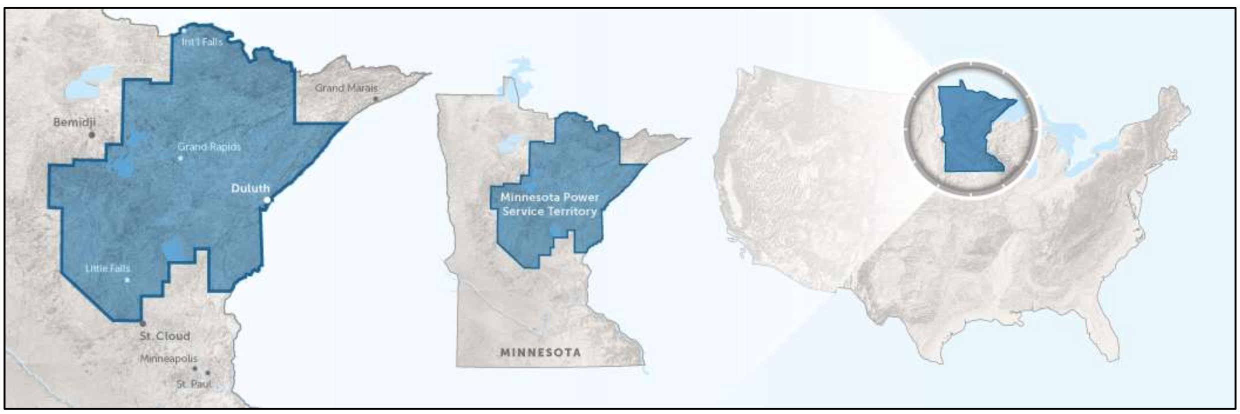
- Analysis of how the information in the IDP relates to each Planning Objective;
- The location in the IDP;
- Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives; and
- Suggestions as to any refinements to the IDP filing requirements that would enhance Minnesota Power's ability to meet the Planning Objectives.

Minnesota Power respectfully submits this 2023 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.

## B. Minnesota Power Overview

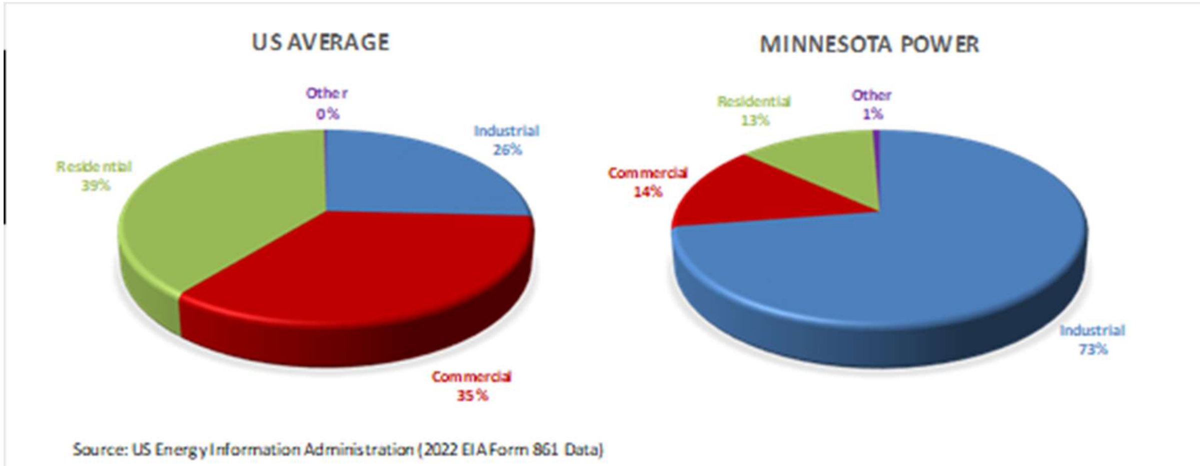
Minnesota Power is transforming the way it energizes communities and businesses through its *Energy**Forward*** resource strategy. First incorporated in 1906, Minnesota Power serves electricity to 150,000 customers, 14 municipal systems, and some of the nation's largest industrial customers across northeastern and central Minnesota. Minnesota Power's distribution system is comprised of 6,216 miles of distribution lines and 201 distribution substations ("distribution system"). The maintenance and renewal of assets on this system is the most critical aspect of the Company's distribution planning. Minnesota Power's service territory spans over 26,000 square miles from International Falls in the north to Royalton in the south, and from Duluth in the east to as far west as the Long Prairie and Park Rapids communities as shown in Figure 1.

Figure 1: Minnesota Power's Service Territory




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 on system planning, as described further below.

Figure 2: Minnesota Power's Customer Concentration is Unique




Minnesota Power's commercial customers account for approximately fourteen percent of 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.). Reliability is of the utmost priority to commercial customers and, for many of these customers, any interruption in electric service has the potential to stop business and immediately impact their bottom line. For example, customer businesses consisting of office workers may no longer have access to the internet or phones and productivity drops, retailers may lose the ability to conduct business resulting in lost revenue, and manufacturers may sacrifice product output from disrupted manufacturing processes. For those customers with sensitive loads and technology-related businesses, power quality and even momentary outages may be a significant issue.

Minnesota Power's residential customers represent approximately thirteen percent of the Company's annual retail electric sales that are served directly from 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 service, program, and rate questions. Since most of Minnesota Power's retail energy sales are served via transmission-level voltage, residential customers comprise a relatively large portion of the company's distribution system load. Additionally, much of Minnesota Power's service territory across northern and central Minnesota consists of rural communities. These rural communities and customers present 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.

The Company continues to be impacted by supply chain disruption in its day-to-day operations. An aspect of supply chain disruption is unexpected, significant increases in commodity prices and lengthy delays in material delivery times related to vendor workforce shortages, commodity shortages and capacity limitations. For example, meter pedestals, transformers, and cable lead-times are currently exceeding 52 weeks. The Company has been proactively finding creative ways to address these impacts, including working with neighboring utilities, communicating with customers, and working diligently with vendors and suppliers to identify new options and plan for longer lead times.

1. Minnesota Power's *Energy**Forward*** Strategy

Minnesota Power continues to advance the transformation of its power supply to a cleaner energy future through its *Energy**Forward*** 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. In early 2021, Minnesota Power filed its 2021 Integrated Resource Plan ("IRP"),[4] which outlined a path towards even further carbon reduction, including steps to reach an 80 percent reduction in carbon by 2035 and a vision of being completely carbon free by 2050. The Company has reduced carbon faster than any other utility in the state and executed this transformation of its power supply while continuing to provide safe, reliable, and affordable energy for its customers. On

[4] Docket No. E015/RP-21-33

November 10, 2022 the Commission unanimously approved Minnesota Power's Integrated Resource Plan, which included all elements of a joint agreement between Minnesota Power and stakeholders from clean energy organizations, labor groups, the city of Cohasset and Itasca County. The Commission stated the agreement was "a reasonable resolution of the issues and soundly supported by the record." Following Governor Walz's 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 and will provide its next refinement to its long-term energy plan in its 2025 Integrated Resource Plan. An important aspect of *Energy**Forward*** 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 programs, a Community Solar Garden Pilot Program, and its Renewable Source program. Renewable Source is an easy way for customers to influence how much renewable energy is delivered to the power grid. Customers pay a premium to add renewable energy to the power grid equal to a percentage of their monthly energy use. They can choose to add 25 percent, 50 percent, 75 percent, or 100 percent. At the same time, the Company is positioning itself to provide a streamlined and supportive process for customers interested in installing Distributed Energy Resources ("DER") through the systems upgrades and expansion of its own utilization of distribution-sited resources, as discussed later in this 2023 IDP. Minnesota Power serves a variety of customer needs while balancing integration of cleaner, more decentralized energy sources.

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. Sustainable prosperity that balances economic, environmental, and social needs for both the Company and its customers over the long-term is Minnesota Power's goal. Safety, integrity, environmental stewardship, employee development, and community engagement must be in the balance of every decision made and action taken.

The sustainable prosperity mentioned above includes the Company's commitment to strengthening its diversity, equity, and inclusion ("DE&I") efforts. Minnesota Power's framework to strengthen these efforts identified three key areas where the Company continues to take action, but in 2022 expanded those efforts to five:

- Workforce: Increasing employee diversity enriches the company culture. ALLETE employees, like the communities the Company serves, operate in an increasingly diverse society, and our workforce needs to reflect the diversity of the communities we serve, promote inclusivity and be equitable. ALLETE leverages diversity recruitment efforts to engage those underrepresented in the workforce, including those facing barriers to employment. The company notifies external partners about job openings, including tribal organizations, community colleges, universities, chambers of commerce, and community workforce organizations. Additionally, ALLETE posts open positions on the Company website, applicable state CareerForce websites, and a variety of other online job boards such as the Veterans Job Listings board.
- Supply chain: Minnesota Power supports DE&I by partnering with diverse suppliers including minority-owned, women-owned, veteran-owned, LGBT+-owned, small economically disadvantaged businesses, HUBZone businesses, and disability-owned businesses. Minnesota Power continues to build these partnerships to better reflect the diversity of the communities it serves. Minnesota Power provides and encourages equal access for all qualified businesses at the Tier 1 and Tier 2 levels. In addition to the new position added as described earlier in my Direct Testimony, budget dollars were added for funding of outreach efforts and membership in diverse community organizations to support supplier diversity efforts.

- Community citizen: As a leader and essential resource in our communities, the Company has a responsibility to be responsive to community needs through the thoughtful distribution of grants. We strive to strengthen our ability to recognize and respond to these diverse needs in order to maintain the highest quality of life in increasingly diverse communities.
- Customers: As a provider of essential services, Minnesota Power has continued to evolve and expand its programs and resources for customers, particularly for energy affordability, energy efficiency, and community engagement. As the energy transition continues and our communities adapt and change, Minnesota Power is committed to working with its customers to understand their expectations and needs so we can continue to deliver vital services in a meaningful and respectful way to meet the diverse needs of those we have the privilege to serve.
- Communications: Minnesota Power supports our efforts to foster a diverse, inclusive, and equitable society through internal and external communications to prompt engagement, raise awareness, and provide training and educational opportunities while demonstrating support for community organizations and groups that are working to build a more diverse, inclusive, and equitable world.

## C. Integrated Distribution Planning

Minnesota Power's Transmission & Distribution Planning and Resource Planning departments work in close collaboration with one another to ensure integrated system planning for the Company. Coordinated discussions take place at regular intervals continuously throughout the year to share information on potential supply and demand side opportunities located at the distribution level. Distribution Planning and Engineering also provides information needed for inclusion in the distribution appendix to the IRP, and the groups coordinate in the development of the Distributed Energy Resource Scenario Analysis for the Integrated Distribution Plan. For the foreseeable future, the primary areas of active coordination between Distribution Planning and Resource Planning will continue to be load forecasting and vetting of supply-side or demand-side non-wire alternatives.

With respect to load forecasting, Distribution Planning obtains historical loading information by feeder from Supervisory Control and Data Acquisition ("SCADA") and meter data for its entire system on an annual basis. Where necessary to support out-year distribution planning analysis of a particular area, this historical load data may then be provided to Load Forecasting. Load Forecasting develops projected annual growth rates by feeder based on the latest Annual Forecast Report[5] ("AFR") and supplies the growth rates to Distribution Planning to be used to develop an out-year peak load scenario for distribution planning analysis. This ensures that any issues identified in the evaluation of the out-year peak scenario are consistent with the latest load growth forecast from Resource Planning. Distribution System Losses are discussed in Appendix D. For this filing, the Company is operating on system loss data as of 2021. It is the Company's intention to refresh this information in the coming year and file it with the 2025 IDP.

For the Distributed Energy Resource Scenario Analysis Section IV.C, the Load Forecasting group provided the base-case scenario for DER deployment on the distribution system. The assumptions for DER deployment in the base-case were aligned with assumptions used in the latest AFR. Load Forecasting, Distribution Engineering, and Distribution Planning then worked together to develop the DER outlook for the medium and high scenarios. Please refer to the Section IV.C– Distributed Resource Scenario Analysis for more details on the approach and results.

With respect to supply-side or demand-side non-wire alternatives, Distribution Planning identifies candidate reliability or load-serving issues on the distribution system through regular planning assessments. (See Section III.B - Non-Wires (Non-Traditional) Solution for a discussion of how Minnesota Power determines if an issue is a good candidate for a potential non-wires solution.) If it is expected that the traditional solution to an issue will be a major project (greater than $2 million, as established in the IDP Requirements), a subsequent alternatives analysis will be conducted. Within this alternatives analysis, both traditional and non-wires solutions will be considered. For non-wires solutions, scoping-level information about the non-wires solutions (necessary size, location, and operational characteristics required to resolve the issue) may be developed by Distribution Planning

[5] Docket No. E-999/PR-21-11

and shared with Resource Planning to facilitate the identification of viable non-wires alternatives. This includes developing an anticipated cost, implementation timeline, power supply benefits, societal benefits, and other potential benefits specific to locating non-wires alternatives on the distribution system. Non-wires solutions considered for the purpose of resolving distribution reliability and load-serving issues will include supply side solutions (i.e. solar and batteries) or demand side solutions (residential/commercial demand response programs).

If any non-wires alternatives identified through this exercise show potential benefits for customers and the distribution system, these alternatives could be considered as resource options in the next IRP. However, the consideration in the IRP of non-wires alternatives for distribution system issues may be impacted by the required implementation timeline associated with the particular issues being addressed. In some cases, a solution may need to be implemented for the distribution system outside of the IRP process.

### D. Sustainability Holistically Considers the Customer, Community, Climate and Company

Minnesota Power's *Energy**Forward*** strategy outlines a vision for delivering value to customers, coworkers, communities, and investors through sustainable energy solutions with a focus on expanding renewables, reducing carbon, focusing on customers, enhancing resiliency, and driving innovation. *Energy**Forward*** is built around the "Four Cs": Customer, Community, Climate, and Company. The Company's 2023 IDP considers each of these important perspectives, as depicted in

Figure 3. Minnesota Power is planning for the future of an advanced grid while also enhancing the customer experience. The Company's 10-year, long-term plan focuses on continued investment in infrastructure with accelerated investments in the near-term in systems and data to optimize the 21st Century power grid. Investments in data and applications will provide a greatly enhanced customer experience while enabling key operational benefits for reliability and safety.

Figure 3: 2023 IDP Key Themes


1. Customer: *Enhancing the Customer Experience*

As Minnesota Power plans for a future grid the Company will remain customer-focused, continuously improving the 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's approach to customer service is to continue to provide the core services customers count on as effectively as possible, while leveraging technological advances where applicable and practical to meet the modern day needs of customers. The Company recognizes that, above all else, customers expect reliable, affordable, and safe electric service. Inherent to each of these expectations is convenience, transparency, and timeliness of service interruption updates, as well as clarity with respect to costs and program offerings. However, in order to meet these customer needs, the Company must ensure the right resources are working on the right priorities at the right time. Part of enhancing the customer experience will be making thoughtful decisions around investment priorities while attracting and aligning talent with the changing customer, technology, data, and analytics needs of the industry.

Today, Minnesota Power is continuously improving the customer experience through the Company's online tools, programs and services, and steady support from its Customer Care and Support team. Minnesota Power currently incorporates customer insights gained from customer interactions, satisfaction surveys, and benchmarking tools along with industry best practices to ensure energy solutions meet the needs and expectations of customers today and into the future. Customers will 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 for importance of demand response versus resource.

As a result of the Company's engagement in other industry forums, Minnesota Power is aware that customers place a high level of importance upon digital channels for billing, payment, energy usage, and outage communication. The Company has therefore taken steps to improve payment options and enhance digital platforms for customer interaction. Minnesota Power has made significant progress in digital platforms that support customers that prefer digital channels, whether through the MyAccount portal, mobile app, or launching of the no-fee credit or debit card bill pay option, as approved in the 2016 Rate Case.[6]

From July 20 to August 3, 2023 Rapp Strategies conducted a survey of Minnesota Power residential customers. The survey identified that 40 percent of the customers surveyed engage with the Minnesota Power website and approximately one third utilize the Minnesota Power app, a 10 percent increase from 2021 in both cases. Amongst the customers that use these communication and engagement channels, there was a very high level of satisfaction rating of 97 percent. These digital platforms are important for customers to access their bill, make payments, review energy use, and to report and monitor outage communications.

Finally, an overarching consideration for customers is maintaining affordability as the Company prepares the distribution system for the future. Each investment is carefully evaluated, and Minnesota Power prudently selects investments that provide an overall benefit for customers. Rising costs make this evaluation even more important for our customers during this inflationary period.

[6] Docket No. E015/GR-16-664

2. Community: *Enhancing Resiliency to Ensure Grid Reliability*

Planning for a reliable and resilient power supply to communities as they experience increased extreme weather events is a critical part of Minnesota Power's distribution planning process. This 2023 IDP outlines a number of 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, and more. Partnerships with the communities it serves will be a critical component as Minnesota Power continues its state-leading carbon reduction journey towards a 100 percent carbon free energy supply.

On September 13, 2023 Minnesota Power held a hybrid stakeholder meeting at BoomTown Woodfire Bar & Grill in Duluth. Attendees included representatives from the Minnesota Public Utilities Commission, City of Duluth, Northspan, IBEW 31, the Fond du Lac Band of Lake Superior Ojibwe, Ecolibrium3, and Clean Energy Economy Minnesota. The Company presented on the IDP topics established in the Commission's Order and solicited input from stakeholders on these topics. Stakeholders were engaged and curious about DER and Electric Vehicle related topics. Discussion during the stakeholder meeting was fruitful and emphasized the intersection of interests among stakeholders regarding distribution related grid planning and forecasting. For example, a representative from the City of Duluth emphasized a desire for closer collaboration and communication between the City and Minnesota Power as the City prepares its own plans for DER and storage deployment. The Company's key takeaway from this event was that the need for distribution level investment in Minnesota Power's service territory is understood and supported, with specific interests desiring increased collaboration with the Company. Appendix B contains additional information on the stakeholder meeting including the presentation.

3. Climate: *Optimizing the Grid for Demand Side Resources and Electrification*

As Minnesota Power advances towards its carbon-free vision and prepares to meet the State's energy policy objectives, the Company will focus on right time/right fit investments, operational efficiencies, and reliability/resiliency upgrades to ensure a modern grid can continue to support further transformation. The systems implementation timeline communicated through this 2023 IDP integrates current customer systems, asset management, and operational systems under one real-time Utility Network model. This secure end-to-end system model will integrate all of Minnesota Power's generation sources, transmission infrastructure, and distributed assets and resources. This model will enable Minnesota Power to continue movement from a reactive maintenance environment to a preventative maintenance environment, improving reliability and resiliency of the overall system. This model will reside within a flexible, adaptable, and upgradable platform which will aid the Company to grow and respond to utility system dynamics and meet public policy goals. It will allow for a streamlined data gathering process to provide meaningful and proper data sets for stakeholders and the Company which will be utilized to advance a customer-centric, modern grid. The Company continues to make energy conservation part of its climate action strategy. 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.[7] Implementation of Minnesota Power's ECO plan requires a direct relationship with distribution planning and related investments.

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. Customers are interested in products and services that increase accessibility to energy conservation programs, renewable energy, and electrification. While the Company's current 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's carefully considered investments in the distribution system not only allow for increased penetration of renewable distributed energy resources, but efforts toward electrifying fossil fuel-based distribution level

[7] Docket No. E015/CIP-23-93

emission sources such as building heat, vehicle fleets, and personal items impacts the climate by connecting these sources to the electrical grid, the fastest decarbonizing sector of the economy. Further to this point, the recently passed amendment to Minnesota Statute 216B.1691 Renewable Energy Objectives has mandated that at least 3 percent of Minnesota Power's retail electric sales must come from distributed 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 2023 IDP.

4. Company: *Securing the Grid of the Future*

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 described in the following section 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. For example, the Company is currently an active participant in the Department of Commerce workgroup ordered by the commission in its June 7, 2023 order in Docket E999/CI-20-800, In the Matter of a Commission Investigation on Grid and Customer Security Issues. A report on the Company's compliance with the policy set forth in said order is included as Appendix F in this IDP. 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.

As the grid evolves more management systems such as the Outage Management System ("OMS"), Emergency Management System ("EMS"), Meter Data Management ("MDM"), and Geographic Information Systems ("GIS") are necessary to track, monitor, and make changes to the system in real-time and to react to a dynamic changing environment. These systems are reviewed further in the System Overview and Foundational Investment sections.

## E. Overview of Minnesota Power's Current Systems

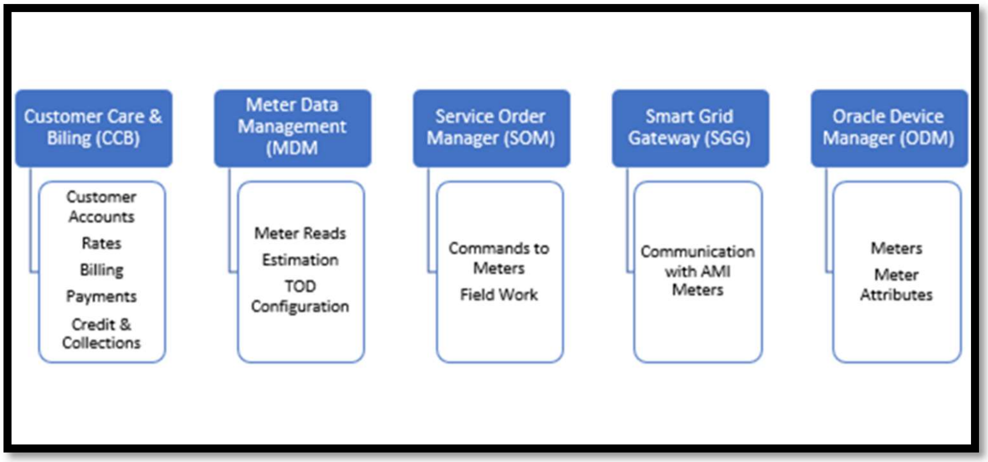
The following sections provide a brief overview of each system critical to the operation of the Company's distribution system. All existing and new systems are necessary for ensuring electric service regardless of this distribution plan, and the Company would not attribute the costs of obtaining data from these systems to this plan. However, the systems below provide a robust basis for developing the system data necessary for future distribution planning, such as Photovoltaic ("PV") output profiles, Demand Response ("DR") products and profiles, and Electric Vehicle ("EV") charging profiles.

### 1. 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 new technologies and customer-facing improvements.

*Customer to Meter ("C2M") Customer Information System* – The core customer information system is designed to securely store customer information and act as the primary billing and rate engine for Minnesota Power customers. This system was upgraded in 2021 as part of the C2M project, which has enabled additional functionality through the specialized modules that were deployed in the overall system.

Figure 4: 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. Metering systems include the Advanced Metering Infrastructure ("AMI") and interconnected industrial meters.

*MyAccount* – This online portal allows customers to view and pay bills, look at and track daily and hourly usage, request a stop, start, or transfer of service, and perform other account functions. This tool will continue to be enhanced through modest, meaningful investment annually over the next 10 years and will leverage customer data provided by the underlying customer systems. As well as maintaining its initial purpose of providing customers with consumption and usage data to make informed energy decisions and increase energy efficiency, additional functionality was deployed to provide customers with the ability to view their bills and make payments on-line. Customers can also access MyAccount through the Minnesota Power Outage information and reporting app.

*Automated Meter Reading* ("AMR") – AMR is the legacy metering system that was installed at Minnesota Power from 2002-2006 utilizing first generation power line carrier technology. This investment streamlined the meter reading system over the past 20 years by reducing the need for in person meter reading. The system was very effective at one-way acquisition of meter reads but had limited bandwidth for supporting complex rates or real-time data capabilities. Minnesota Power's AMR system was decommissioned in April of 2023 in favor of the Advanced Metering Infrastructure (see below).

*Advanced Metering Infrastructure* ("AMI") – Minnesota Power is the first investor-owned utility in Minnesota to fully implement Advanced Metering Infrastructure. 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. AMI has the ability to enable advanced Time-of-Use ("TOU") rates when combined with a MDM. The current AMI system is fully deployed and includes further integration with other operational software systems. See further info in Section II.F.2 – AMI.

*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, TOU 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. This system provides the appropriate level of information to automate some of the commands and AMI system features out of the billing system and allow for verification of meter configuration and readiness for specific rates within the MDM system.

*Outage Management System* – The current OMS system contains all reports of power outages and predicts the failed equipment and fault location related to outages reported on the system. It is the source for all customer-facing outage data and provides record of all outages and trouble orders for regulatory reporting. This system is slated for replacement in early 2024. Currently, customers are able to view and report outage information through the Minnesota Power mobile application and on the Company website (www.mnpower.com). More information on the OMS system can be found in Section II.E – Infrastructure 5-year Investment Plan.

*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.

2. Operational Systems Overview

*Geographic Information Systems/Utility Network Model* – Minnesota Power has utilized 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 will integrate asset models from Generation, Transmission, and Distribution systems to create a real-time Utility Network model. This Utility Network model will continue to be interconnected to Company systems and allow for secure and tailored access for customer, internal, and stakeholder applications. More information on the use of GIS can be found in the Section II.E – Infrastructure 5-year Investment Plan.

*Energy Management System ("EMS")/ Distribution Management System ("DMS")/ Distributed Energy Resource Management System ("DERMS")* – Minnesota Power has been utilizing an EMS for nearly 40 years. Over that time, the capabilities and the system model of the EMS have been continually expanded and optimized to meet Minnesota Power's needs. Minnesota Power is currently upgrading the EMS with a tentative operational date in the fourth quarter of 2023. The upgraded product has enhancements to existing situational awareness tools that will improve the operators' visibility to real time and state estimator data with improved alarm and event filtering capabilities. Currently, DER is not actively managed through EMS, however, small distribution-connected solar is monitored with the AMI system while larger Minnesota Power owned solar (greater than 1MW) is centrally monitored and reported within EMS. Currently, the amount of solar connected to the Company's distribution system does not require a DERMS. Nonetheless, DER growth will be monitored and the system tailored as the need for control arises within different aspects of the Company's distribution system.

*Infrastructure/Distribution Asset Management* – Minnesota Power has developed a plan to modernize the system and ensure reliability of service. With many assets more than

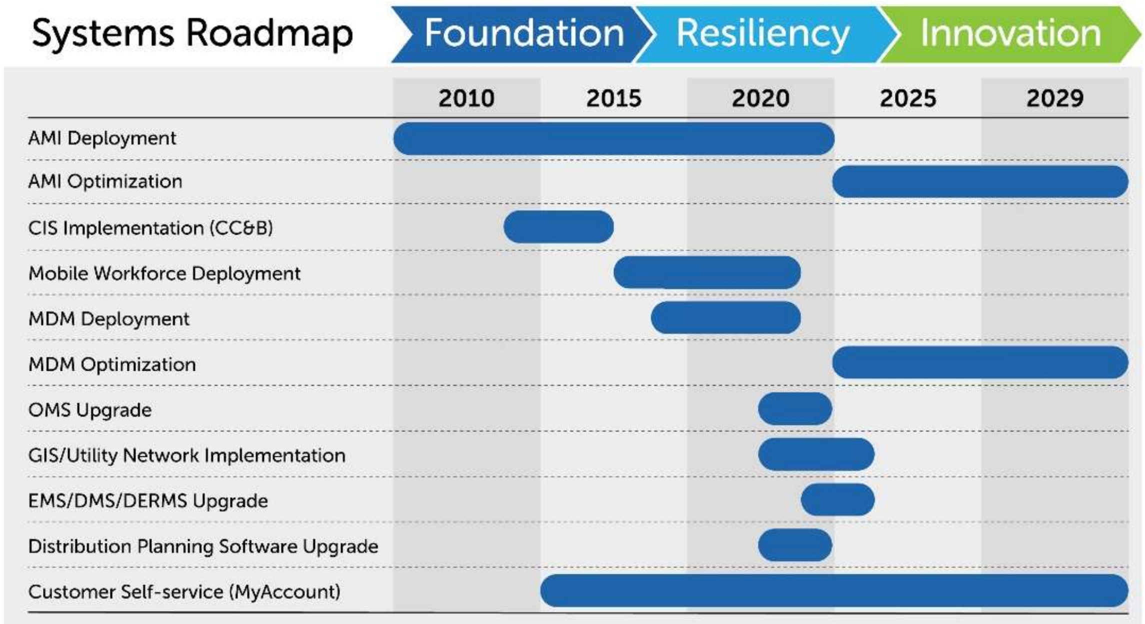
40 years old, asset management programs and investments have increasingly become an area of significant focus for Minnesota Power. Asset renewal programs have been bolstered in recent years in an effort to target areas known to impact customer reliability and system resiliency. Minnesota Power has taken a strategic approach 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 of the asset renewal needs at a site with one comprehensive project.

Along with these asset renewal strategies, Minnesota Power has been refining its preventative maintenance and emergency replacement programs to track and enhance the health and reliability of its distribution assets. These systems are in the process of being optimized to support Minnesota Power's long-term utility asset management needs. 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. Together, these systems allow the Company to more readily implement a future DERMS and/or an Advanced Distribution Management System ("ADMS") to control widespread use of solar and other distributed generation ("DG") sources as needed.

3. Systems Implementation Timeline

In order to facilitate advancement towards a modernized grid and customer experience, the Company is implementing a foundational systems strategy as communicated in Figure 4. 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. Each of these system upgrades are discussed in detail in Section II.E - Infrastructure 5-Year Investment Plan. Figure 5 provides a historical view of systems that are fully implemented as well as those still in progress.

Figure 5: Systems Implementation



# FOUNDATIONAL INVESTMENTS

## II. CURRENT DER PROGRAMMING AND FOUNDATIONAL INVESTMENTS

Minnesota Power has been operating and maintaining its distribution system for many decades to serve customers in Northeast Minnesota to ensure they have access to safe, reliable, and affordable service. As the Company continues to build a smarter, more resilient electrical grid, energy conservation continues to play a critical role in this process. Minnesota Power has over a decade of highly successful energy conservation program achievements, surpassing the state energy efficiency goals each year since the goal's inception in 2010. Between 2013 and 2022, 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 through its Conservation Improvement Program ("CIP"). The Company had a savings total of more than 76 GWh in 2022. That is enough energy to power roughly 8,400 homes and avoid about 45,000 tons of carbon emissions per year; the equivalent of taking almost 9,000 cars off the road. In 2021, the Energy Conservation and Optimization Act ("ECO") was passed, increasing the energy savings goal to 1.75 percent, beginning 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 peak, which typically occurs in the summer. The average peak demand savings reported for 2017 through 2022 was 8.0 MW.[8]

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

[8] The Company's Demand Side Management ("DSM") 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.

Table 1: 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% |

As referenced in Section I.D. and above, the ECO Act passed during the 2021 legislative session and allows for an expanded suite of customer offerings including efficient fuel switching and load management programs. Minnesota Power submitted its first ECO plan on June 30, 2023. The Company will continue to evaluate cost-effective opportunities to incorporate load management and fuel switching into its ECO plan as more information about the implementation and evaluation requirements are available and as details about overlapping programs (specifically those created through recent federal and state funding) are determined.

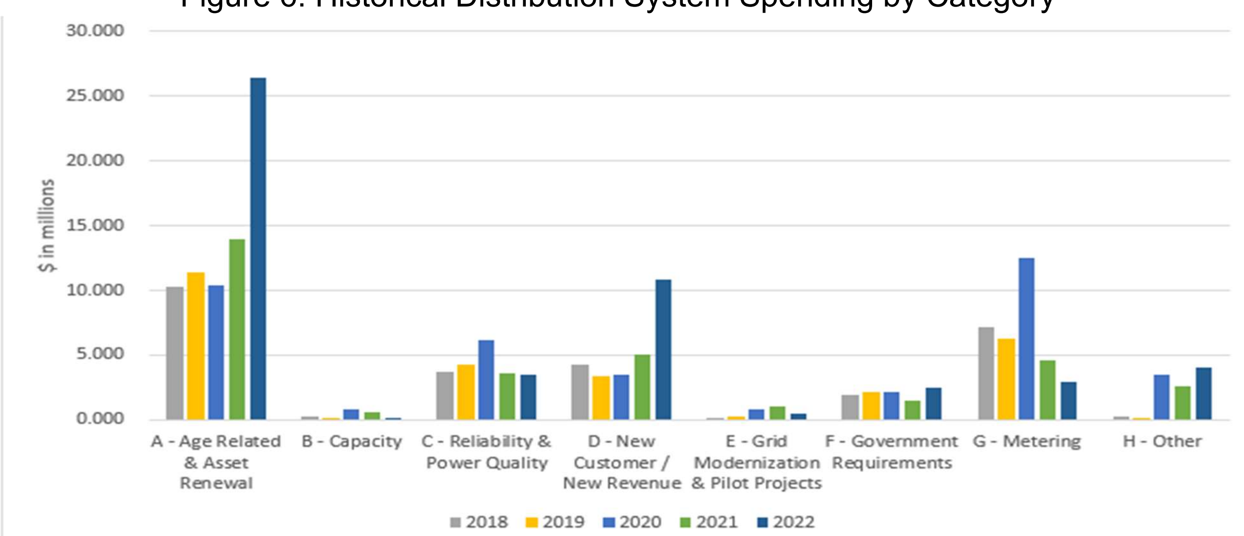
Minnesota Power has traditionally followed a depreciation level spending pattern for its distribution system. The historical annual expenditures depicted in Figure 6: Historical Distribution System Spending by Category reflect depreciation level spend until 2021. Budgets are adjusted annually to meet internal and external customer needs including government-mandated projects, regulatory requirements, age-related replacements, metering advancement, asset renewal programs, and inflation, among others. Foundational investments are focused on traditional system improvements and often result in upgrades made to underperforming areas. These investments are even more critical today during this high rate of change to maintain reliability and allow Minnesota Power to manage an increase of DER penetration within the distribution system.

The foundational investments outlined in this 2023 IDP are not only accommodating the current needs of the system but are also positioning the Company for a transition to an innovative future. Starting in 2021 and going forward, Minnesota Power increased its investments above depreciation level spend to accelerate asset renewal, modernization and reliability projects as communicated in Section IV – Planning for a Resilient Future. This section will include information on the Company's current DER programming, modernization investments, its five-year investment plan, current projects, an analysis of system data, communication strategy and cyber security efforts.

Table 2: Historical Distribution Spending

| Planned Distribution Capital Investments by Categroy | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| A - Age Related & Asset Renewal | 10.226 | 11.421 | 10.439 | 13.975 | 26.478 |
| B - Capacity | 0.267 | 0.124 | 0.805 | 0.565 | 0.114 |
| C - Reliability & Power Quality | 3.717 | 4.289 | 6.168 | 3.579 | 3.462 |
| D - New Customer / New Revenue | 4.242 | 3.322 | 3.484 | 5.079 | 10.883 |
| E - Grid Modernization & Pilot Projects | 0.152 | 0.237 | 0.815 | 0.999 | 0.504 |
| F - Government Requirements | 1.938 | 2.201 | 2.120 | 1.515 | 2.444 |
| G - Metering | 7.107 | 6.255 | 12.523 | 4.653 | 2.912 |
| H - Other | 0.207 | 0.151 | 3.480 | 2.618 | 3.993 |
| **Total ($ in Millions)** | **$27.856** | **$28.000** | **$39.834** | **$32.983** | **$50.790** |

Figure 6: Historical Distribution System Spending by Category



## A. Current DER Programming and Background

Minnesota Power has a longstanding history of working collaboratively with its customers as they implement DERs. The Company is continuously monitoring emerging DER technologies, both nationally and locally, and customer goals as they relate to onsite generation. By enhancing customer communication efforts, Minnesota Power is helping to align customer expectations with achieved results. These efforts will aid in ensuring that DERs continue to be installed in a safe, reliable, and effective manner in Minnesota Power's service territory.

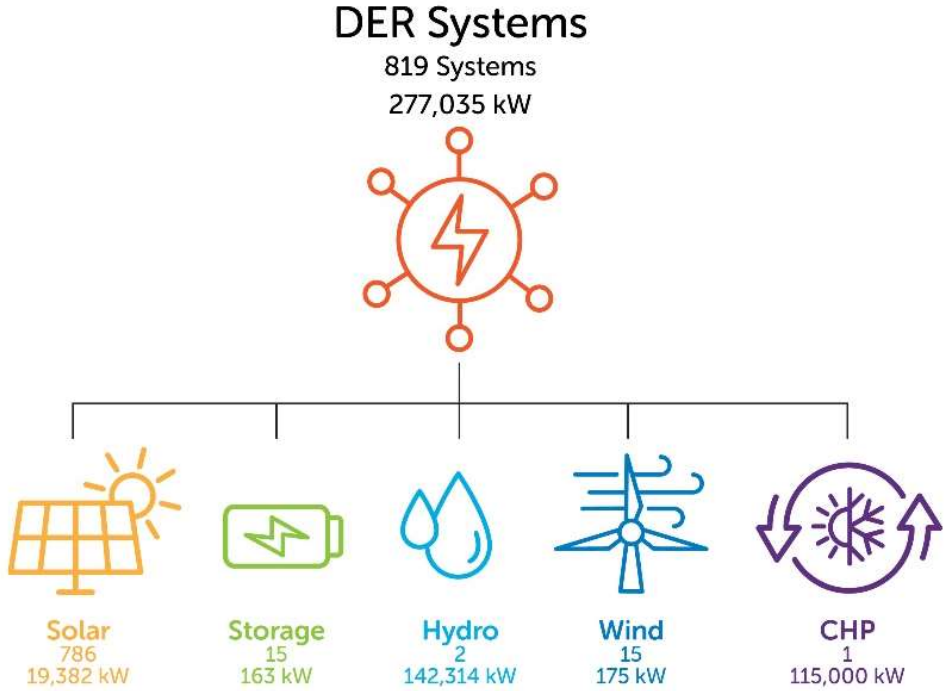
### 1. DER Systems

At the end of 2022, Minnesota Power had 819 registered DER systems[9] as depicted in

Figure 7. The majority of DER systems on Minnesota's Power's system are distributed solar. This represents a fairly diffuse penetration of DER on the system as a whole, but there are a few concentrated areas worth noting as outlined in Section IV.C.6 - IEEE Std. 1547-2018 Impacts. The Company's DER forecasting and analysis can be found in Section IV.C – Distribution Forecasting.

[9] Docket No. E999/PR-23-10

Figure 7: Current DER Systems




2. Demand Response

Minnesota Power leads the state in the amount of DR as a percentage of peak demand, with approximately 240 MW[10] of Midcontinent Independent System Operator ("MISO") accredited DR from the Company's large industrial customers[11] representing approximately 15 percent of peak demand.[12] In addition to DR programs for its largest customers, 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 a system emergency. Since this program deals almost exclusively with electric heat, there is minimal load to curtail in summer months - approximately 3MW, mostly from commercial/industrial loads. The

[10] Planning Year 2023-2024 is 244 MW of capability in the Summer. Actual Zonal Resource Credits received was 268 MWh, which is adjusted for transmission losses and MISO Planning Reserve Margin.

[11] These customers are transmission-connected, and not served by Minnesota Power's distribution system

[12] Minnesota Power's 2022 peak load was 1,556 MW

available curtailable load in winter months depends on temperature and heating loads, mostly of residential customers, but can deliver demand response of approximately 30 MW, or approximately 2 percent of the winter peak load. Minnesota Power is continually working to increase demand response beyond current levels. Order Point 1e of the Commission's order approving the Company's 2021 IRP sets the requirement to "pursue at least 50 MW of additional long-term demand response to address future resource adequacy changes by 2030." The Company continues to have discussions with its long-term industrial customers on demand response products.

3. Electric Vehicles/Beneficial Electrification

Minnesota Power monitors both publicly available data and participation in programs and tariffs to gauge customer adoption rates of EVs. The Company estimates there are about 500 light duty EVs (i.e. passenger vehicles) in Minnesota Power's retail service territory.[13] This equates to a 0.26 percent penetration rate, meaning approximately 0.46 percent of households own an EV (on average). According to the Minnesota Department of Transportation's Electric Vehicle Dashboard[14], there are 61 public EV charging stations in Minnesota Power's service territory, with 87 level 2 and 53 level 3 charging ports. Additionally, there are currently 27 residential customers enrolled in the Company's Off-Peak Residential Electric Vehicle rate and 15 customers enrolled in the Commercial Electric Vehicle Charging rate.

Barriers to adoption including range anxiety (especially in cold weather with heating systems), lack of public charging infrastructure, quality of heating systems in winter, and the upfront cost of the vehicle continue to prevent many consumers from purchasing an electric vehicle. Minnesota Power offers EV programs designed to address these barriers, including rebates for home charging equipment, residential and commercial EV charging rates, and an EV education and outreach program. These programs and offerings all include components intended to encourage efficient charging behaviors through time-based rate structures or promotion of enabling technology like smart chargers. Minnesota

[13] Estimate for October 2021
[14] MNDOT electric vehicle dashboard. < http://www.dot.state.mn.us/sustainability/electric-vehicle-dashboard.html>

Power also recognizes that access to reliable EV charging infrastructure is a major concern for EV drivers in northern Minnesota and as such, the Company plans to install 16 direct current fast charging ("DCFC") stations ranging from 50 kilwatts ("kW") to 350 kW through a proposal approved by the Commission.[15] The Company aims to advance an equitable distribution of these charging stations to provide access to EV users in rural population centers and travel corridors throughout the Minnesota Power service area. The chargers are expected to be operational in 2024.

While the Company has taken steps to address barriers to EV adoption, market conditions associated with this rapidly evolving industry continue to impact new programs and projects. Minnesota Power was forced to cancel its EV charging rewards pilot program after the delivery vendor was acquired and discontinued the offering. Additionally, Minnesota Power's DCFC project has been delayed because the selected installation partner is no longer operating in utility markets. Despite these challenges, Minnesota Power anticipates that EV adoption in northern Minnesota will continue to increase as upfront costs for EVs decline, the secondary market grows, and new models continue to emerge. Minnesota Power will continue to explore best practice options for alleviating customer barriers while navigating the rapidly evolving EV industry and broader supply chain challenges.

4. Small-Scale Solar

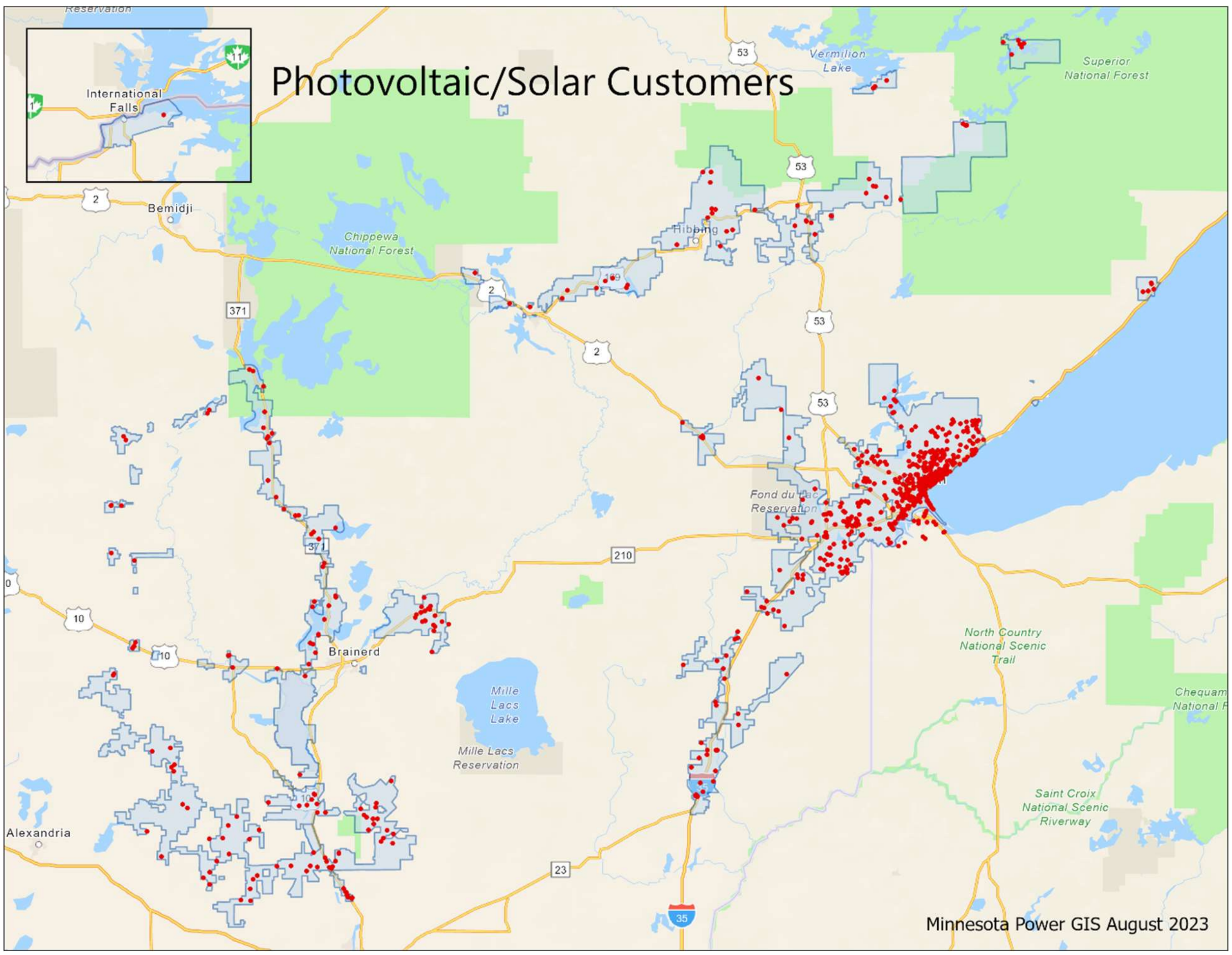
Following the passage of the Minnesota Solar Energy Standard ("SES"), Minnesota Power developed a thoughtful solar strategy that included activities balanced across three key pillars: Utility, Community, and Customer. Minnesota Power continues to see solar investments at the utility scale creating efficiencies and cost savings through economies of scale. However, the Company believes partnering with the community and providing individuals with options for customer-sited solar are equally important. With thorough planning and proactive action in each area of the Company's solar strategy, Minnesota Power has successfully met the requirements of the SES and is carefully considering the

[15] Docket No. E015/M-21-257

implications of the passage of Minnesota Statute 216B.1691, Subd.2h (Distributed solar energy standard).

In terms of the Customer pillar of Minnesota Power's solar strategy, the Company supports customer-sited solar systems through its SolarSense rebate program and the interconnection process. The majority of DER on Minnesota Power's system are distributed solar installations. As shown in Figure 8, these solar installations are highly concentrated in and around Duluth but are also scattered throughout Minnesota Power's system.

Figure 8: Customer Sited Solar



Minnesota Power's SolarSense rebate program has been in place since 2004, well before Minnesota's SES was enacted[16] and was expanded significantly in 2017 as a means of compliance with the SES. In an effort to align the program with industry trends and customer needs, the Commission approved a decreased program budget on December 17, 2020 in Docket No. E015/M-20-607 for program years 2021 through 2024. This included a gradual decrease to the rebate budget for customer-sited systems and a significant increase to the Low-Income Solar Grant Program budget in an effort to redistribute more of the program funds to income-qualified customers. The Low-Income Solar Grant Program is a first of its kind program in Minnesota, designed to increase accessibility of solar energy to low-income customers. More information on that program can be found in Section III.A.2 – SolarSense Low-Income Solar Grant Program. Since its inception, Minnesota Power's SolarSense program has supported nearly 450 solar installations totaling over $4.16 million in rebates.

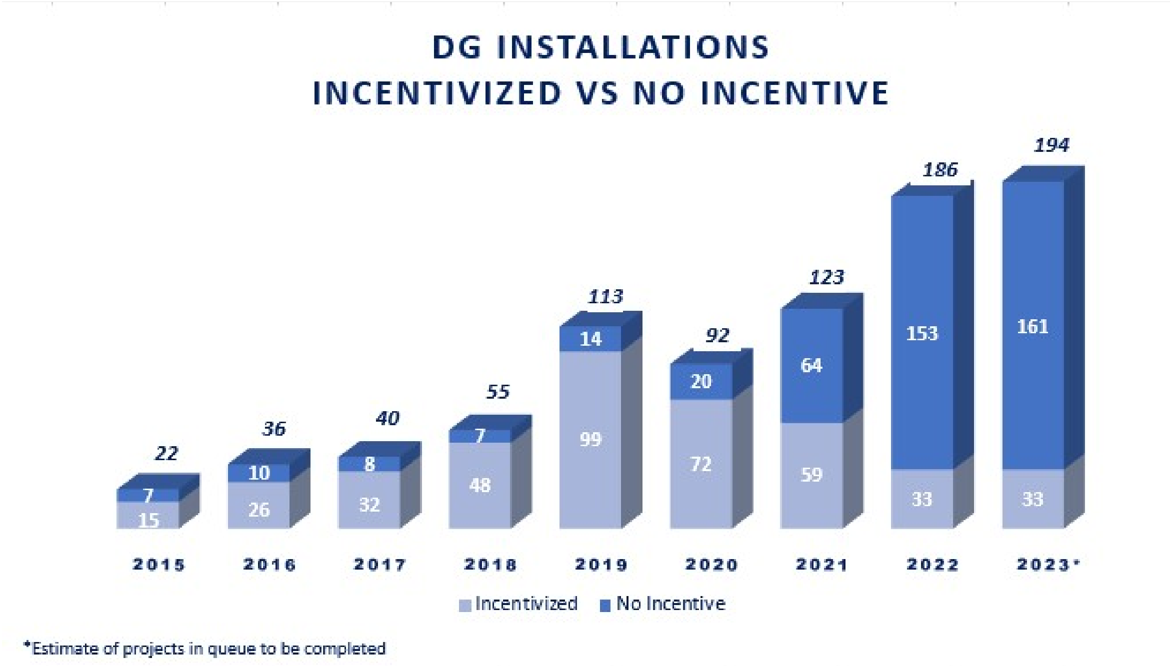
Until 2020, roughly 80 percent of all solar interconnections in Minnesota Power's service territory received a SolarSense rebate, demonstrating that rebates were critical to driving the solar market. Interconnection activity has grown significantly since the SolarSense program has been in place and continues to show increasing demand despite the decreasing budget for customer rebates. In 2022, the majority of interconnections installed did not receive a SolarSense rebate in comparison to those receiving the rebate as recognized in Figure 9. This trend is an indicator that the customer rebate program is no longer the driving force for the small-scale solar market in Minnesota Power's service territory. This is likely the result of a combination of factors including an increase in the cost of electricity, the declining cost of solar installations and availability of other funding sources such as federal tax credits.

As highlighted in Figure 9, the number of solar installations per year have varied greatly depending on available incentive funding. While rebated installations have varied year over year, an increasing number of solar projects are moving forward without an incentive

[16] Minn. Stat. § 216B.1691 Subd 2(f)

from the Company as solar costs continue to decline. For further information please see Appendix C.

Figure 9: Minnesota Power Incentivized DG Installations vs No Incentive




Per Minnesota Power's Distributed Generation Interconnection Report filed in Docket No. E999/PR-23-10 on March 01, 2023, 186 distributed generation systems were interconnected in 2022. Of those installations, 183 customers reported an installation cost before incentives amounting to a total of $6,732,783 including $6,612,370 for residential systems and $606,413 for commercial systems. During that same time period, non--Minnesota Power investments in distribution system upgrades required as a condition of customer-sited solar interconnections amounted to $22,345. Moving forward, Minnesota Power anticipates non-Minnesota Power investments to accommodate customer-sited systems to increase. Additionally, Minnesota Power began charging an application fee for all applicable solar installations on June 17, 2019 in accordance with the State of Minnesota Distributed Generation Interconnection Process ("MN-DIP").

B. <u>Distributed Generation Standard & Ongoing System Planning</u>

Effective May 2023, Sec. 16. Minnesota Statutes 2022, section 216B.1691 Renewable Energy Objectives, was amended by adding a subdivision requiring that for public utilities with at least 100,000 but fewer than 200,000 retail electric customers in Minnesota, at least 3 percent of retail electric sales must be generated from solar energy generating systems by the end of 2030 (the "Distributed Solar Energy Standard"). Sales to industrial customers in Minnesota must be subtracted from the utility's total retail electric sales for the purpose of calculating the retail electric sales in Minnesota subject to the Distributed Solar Energy Standard. Large industrial customers are exempt from this standard as they are more often connected to the transmission system than the distribution system. To be counted toward the Distributed Solar Energy Standard, a solar energy generating system must have a capacity of 10 megawatts or less, be connected to the public utility's distribution system, be located within the Minnesota service territory of the public utility system and be procured or constructed after August 1, 2023.

To satisfy the Distributed Solar Energy Standard, a public utility must select projects through a competitive bidding process approved by the Minnesota Public Utilities Commission. These proven procurement processes will be used on future solar projects to capture savings for customers wherever possible. Minnesota Power agrees that competitive bidding is a proven path towards getting the most cost effective and productive projects. The Distributed Solar Energy Standard also states that a solar energy generating system with a capacity of 100 kilowatts or more does not count toward compliance unless the public utility can verify that construction trades workers who constructed the solar energy generating system were all paid no less than the prevailing wage rate (as defined in section 117.42) and whose employer participated in an apprenticeship program registered under chapter 178 or Code of Federal Regulations, title 29, part 29. Minnesota Power has a strong working relationship with the trades, unions, and labor organizations, and wages for these types of projects are typically at or above prevailing wage.

In January 2023, the Minnesota Public Utilities Commission issued an Order approving Minnesota Power's 2021 Integrated Resources 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. Minnesota Power is exploring options to best integrate additional solar resources to the Company's distribution system. Minnesota

Power is beginning to experience a higher volume of interconnections and more interest in larger systems for net metering. The Company is constantly improving the system to accommodate increased amounts of DER.

As an example of the Company's commitment and leadership in this area, Minnesota Power recently completed three solar projects utilizing union labor and contractors for construction. The solar modules were procured from a company with manufacturing facilities in Minnesota Power's service territory. Bidder questionnaires were issued with many of the requests for bids to identify local and diverse suppliers. For all three projects combined, Minnesota Power executed 60 contracts with local suppliers and contractors totaling $29.6 million. The Company intends to utilize a similar approach for future solar projects to meet the Distributed Solar Energy Standard. The Company looks forward to engagement with developers, communities, and other stakeholders to develop a path forward to compliance with the new standard.

## C. Modernization Investments

The keys to successful modernization investments are detailed planning, project execution plans, project metrics, cost, and anticipated vs. actual benefits. Minnesota Power's approach to modernization has been to target pilot-scale projects that incorporate optionality and scalability. This approach has yielded benefits, including improved integration of DER, as a result of both Operational Technology ("OT") and Information Technology ("IT") investments that speed the process of interconnection to the distribution system.

Modernization investments are made with a continued focus on safety, reliability, and affordability. Most modernization improvements begin with data-based analysis that has been collected through the Company's information management systems. The capital utilized in modernization activities can generally be broken down into two specific categories:

- Operational Technology – Replacement of existing assets with modern asset designs that incorporate solid state components, sensors, and communication technology to provide visibility, connectivity, and data streams to system operations (i.e. AMI, voltage monitors, intelligent switches, or sensors) that are integrated with centralized software and control systems.

- Information Technology– Software and OT interface investments that allow for storage, reporting, control and utilization of data and information in operations.

These technology investments, combined with a customer-centric outlook, allow for prudent system evaluation based on an ever-expanding foundation of data and information. This data provides more confidence in load research, modeling, and forecasting. The data can be used in rate design, class cost of service studies, targeted conservation and demand response, new product offerings, etc.

### D. Interconnection Process Changes

Interconnections are one of the most complicated interactions a utility may face with customers and developers. The interconnection of distributed energy resources operating in parallel to the distribution system requires careful attention and cross functional coordination to ensure safe, reliable integration of those assets. A wide variety of customers, and increasing demand drive the need for constant process improvements. Minnesota Power has continually worked to meet customer and regulatory expectations for the interconnection process.

Over the past few years, Minnesota Power has worked with the Distribution Generation Working Group ("DGWG") to update the MN-DIP process and compile technical standards that apply to various types of interconnections. In general, the MN-DIP process has been a positive change for Minnesota Power and its customers. Over the past few years, the number of interconnection applications has increased, while the number of direct utility incentivized installations has decreased. In addition, a trend of installing larger systems is emerging. As a result of this rising demand, Minnesota Power continues to monitor and streamline internal processes and expects to implement an online application portal for installers and customers in 2024. This software application and database will increase communications automation, track applications, and generally streamline the interconnection process both internally and externally. In addition, cross functional teams that have roles in the interconnection process have taken part in process mapping exercises to improve upon internal communication and interconnection handling.

In July of 2020, the Minnesota Technical Interconnection and Interoperability Requirement ("TIIR") went into partial effect. 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. While the TSM formalized some previous standards that could not be easily found in one place, most of the requirements for DER already existed. The TSM has since been updated to include changing provisions in the TIIR. The emergence of smart inverters will be monitored to unlock potential customer and company benefits while integrating greater amounts of inverter based DERs.

The primary changes in Minnesota Power's standards were requiring a default 0.98 absorbing power factor for inverter-based generation and the updates surrounding remote monitoring and telemetry. Minnesota Power now requires all DER with a nameplate capacity of 250 kW or greater to be remotely monitored so that these systems can be incorporated into EMS (and eventually ADMS) models. Monitoring larger installations will be crucial as DER penetrations increase, and more visibility is required to safely operate the system. The move to a 0.98 absorbing power factor was common across all utilities and was made to increase potential penetration levels on the distribution system. So far the changes have been well-received, although Minnesota Power has had no external interconnections greater than 250 kW since July 2020.

## E. Infrastructure 5-Year Investment 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 10. These are identified as part of broader strategic Minnesota Power initiatives that most often directly benefit the Company's customers.

Figure 10: Five Year Future Investments by Category

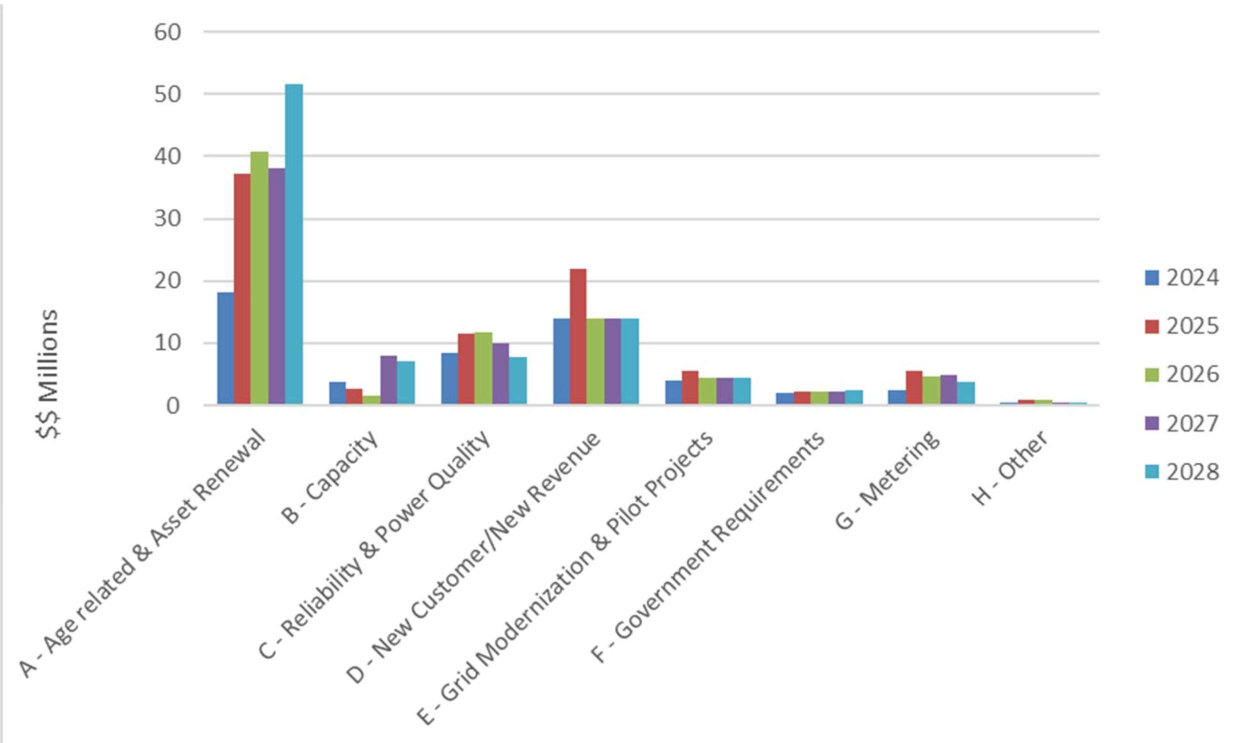



Table 3: Five Year Future Investments by Category

| Planned Distribution Capital Investments by Category | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|
| A - Age related & Asset Renewal | $18.3 | $37.3 | $40.7 | $38.2 | $51.7 |
| B - Capacity | $3.9 | $2.6 | $1.6 | $7.9 | $7.0 |
| C - Reliability & Power Quality | $8.4 | $11.5 | $11.8 | $9.9 | $7.7 |
| D - New Customer/New Revenue | $14.0 | $22.0 | $14.0 | $14.0 | $14.0 |
| E - Grid Modernization & Pilot Projects | $4.0 | $5.5 | $4.5 | $4.5 | $4.5 |
| F - Government Requirements | $2.0 | $2.2 | $2.2 | $2.2 | $2.5 |
| G - Metering | $2.4 | $5.5 | $4.6 | $4.9 | $3.9 |
| H - Other | $0.4 | $0.9 | $0.9 | $0.4 | $0.4 |
| **Total ($ in Millions)** | **$53.2** | **$87.4** | **$80.4** | **$81.9** | **$91.7** |

Age-Related Replacements and Asset Renewal Projects (Category A) 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. In some cases, the Company experiences a number of failures in a certain area of the system or with a particular type of asset and these 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 modernization projects have been identified and prioritized based on the age, past performance, and direct customer impact of major substation apparatus.

System Upgrades for Capacity (Category B) or Reliability & Power Quality (Category C) 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 in order 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.

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 for 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. 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.

New Customer Projects and New Revenue projects (Category D) include construction of distribution line extensions to serve new customer load. The Company has an obligation to serve new load 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 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 Projects (Category E) 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, automatic 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 the associated communications infrastructure improvements in strategic locations on the distribution system. Increased information from the distribution system helps improve customer communications and reliability of service.

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. One pilot Minnesota Power is evaluating is a Battery Energy Storage System ("BESS") project to improve reliability in a rural community.

The Company worked with a consultant to develop a cost-benefit analysis framework as part of its Distribution Non-Wire Alternatives Study, which is discussed further in Section III.C. Grid Modernization projects are either still in the pilot project phase or continue to build on previous pilots like those discussed in Section III.A. 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. The Company is also working to leverage the knowledge gained from its recent Distribution Non-Wire Alternative Study, discussed in Section III.B in this 2023 IDP filing, to evaluate and develop grid modernization solutions and additional pilot projects.

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

- Supply usage information to customers: Interval usage information is loaded into the MyAccount customer portal available on the Minnesota Power website and through the Minnesota Power app.
- Reduced billing estimations when compared with the legacy Automated Meter Reading “AMR” system.
- Integration of AMI, GIS, and 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.
- Replacement of the aging dual fuel and controlled access control systems: AMI meters replace legacy socket collars, and are controlled with the AMI system, which allows for future improvements that support reliability with increased variable renewable energy on the system.
- More timely and cost-effective restoration of service to customers who have been disconnected by using meters with remote disconnect/reconnect capability. This technology is being deployed on a limited basis through Minnesota Power’s Reconnect Pilot Program, described in Docket No. E015/M-19-766. The Company estimates up to ten percent or approximately 12,250 residential customers will have remote capable AMI meters and be eligible for this Pilot.
- Improving the coverage of the existing AMI communication infrastructure.

Projects included in the “Other” category (Category H) 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.

1. 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, SCADA 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.

The OMS uses information provided from the GIS for an accurate representation of the distribution system. GIS data must go through a complex mapping process before it can be utilized by the OMS. The current GIS technology is not fully compatible with the OMS, leading to lost hours of productivity, which has resulted in the OMS having inaccurate and/or incomplete representation of portions of the distribution system. This in turn has limited the OMS's ability to accurately predict outages in certain locations and, in some cases, for the OMS to predict outages where none were actually present. In addition, the OMS application and the servers and databases it runs on are all approaching end of support, increasing the potential for security, functionality, and performance issues to emerge for which no solution is available from the manufacturer.

Given these issues, Minnesota Power is in the process of replacing the existing OMS with a modern, feature-rich OMS from another vendor. This new OMS is anticipated to be in-service in early 2024. The new OMS will improve integration with the GIS to eliminate or greatly reduce the mapping inconsistencies described above. This mapping improvement, combined with the Utility Network Model project described in Section I.E.2 - GIS, and AMI deployment, including the ability to detect electrical phase, will result in the OMS having a more accurate representation of the distribution system. This will reduce restoration times by locating isolated outages and improving prioritization of restoration work in multi-outage situations. Customers will be provided more accurate restoration times, potentially increasing customer satisfaction. A new OMS will also position Minnesota Power to more readily implement a DERMS and/or an ADMS to accommodate widespread use of solar and other distributed generation sources if and when the need arises. Another added feature includes improved automated prioritization and hazard recognition, allowing increased visibility leading to faster response on emergency jobs.

2. Geographic Information System

GIS is the suite of spatial technologies that Minnesota Power uses to store, analyze, and report on its electrical system. The purpose of the GIS at Minnesota Power is to store and analyze spatial information about the features that make up the electrical system and provide access to this information.

The GIS, as well as the staff that support and operate it, serve external customers in a variety of visible and unseen ways. As described above, data is translated out of the GIS and into the OMS which allows for rapid restoration of power during storms or other outages. Information from the OMS is then sent back to the GIS to support the customer outage map. This outage map was previously maintained by a third-party, but as of April 2019 it was re-designed and re-implemented as an in-house solution that has been seamlessly integrated with Minnesota Power's app where the MyAccount tool can also be accessed.

The current GIS is very stable, but challengeshave been identified with our current experiences in the shift toward real-time information and mobile technologies. Both internal and external drivers are pushing the GIS to provide more information to more people in more varied locations at increasingly faster speeds. This shift in expectations has amplified issues within the current GIS model both in terms of the information it can store as well as how that information is delivered.

The Company is transitioning to a cutting-edge GIS model (Utility Network) that will lower operating costs in a number of areas. 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.

As part of this real-time integration, the GIS is already being used to create work through the use of integrated apps. These apps feed into the asset management system and allow internal users to more quickly generate and complete work in mobile applications. These integrated apps also allow field users to more accurately mark the location of buried electric lines and communicate with the state one call system. This helps ensure the safety of our customers and utility workers.

3. Customer Information System

In 2021, the Company's Computer Information System ("CIS") was upgraded to a flexible, highly scalable solution with advanced meter data management capabilities, referenced also as Customer to Meter (C2M). This holistic solution involved upgrading the existing CIS system to an Advanced Meter Billing System that includes the following modules: Customer Information Billing and Rates, Meter Data Management, Smart Grid Gateway, Meter Asset Management, and Service Order Management. The CIS is a shared system with Minnesota Power and Superior Water Light & Power and is considered the Company's corporate accounts receivable system, customer billing system and advanced rates engine. The main drivers for upgrading our CIS to a state of the art Customer to Meter (C2M) system were to lay the foundation for future initiatives for one of the Company's core business systems, increase the efficiency of business operations, target automation and integration opportunities, and further promote data-driven decision making.

4. Customer to Meter

In April 2021, the Company deployed the Customer to Meter solution that included an upgrade to the existing customer information application and implementing the modules within the Advanced Meter Billing System. The system went through a stabilization phase and continues to include expansion of analytics, additional metering capabilities with other core systems, and exploring further complex and flexible billing functionality. The project objectives were to support key business drivers in regard to Distributed Generation, Grid Modernization, Customer Service, and Meter Asset Management.

The primary aim of C2M was to implement a single software solution to provide the functionality of an Advanced Meter Billing System. The Company expects many continued benefits, including cost and efficiency, and functionality within a robust multi-module platform that has streamlined installation and maintenance.

The C2M project will improve management of operational devices in the field such as meters and metering equipment. It allows the status of service orders more transparent and proactive identification and response to meter alarms and issues.

Benefits for customers include:

- Capability to automate billing for Time-of-Day and other time-varying rates.
- More comprehensive energy use data in MyAccount.
- Billing estimates will be more accurate.
- Remote service connections and disconnections will be simplified.
- New programs and rates for innovative technology such as electric vehicles will be more readily implemented.

This solution provides the foundation to respond more quickly to changing regulatory and marketing demands. It continues to improve the Company's understanding of its customers via data analytics, rate guidance and targeted program offerings to customers, as well as the efficiency and accuracy of the meter asset management process. Additionally, it has reduced risk through elimination of the internally developed system for distributing and analyzing meter data.

5. Groundline Inspection Accounting Shift

Minnesota Power has expanded the current groundline inspection program to provide better reliability to the distribution system. With the expanded inspections, poles experiencing deterioration below the surface will be more frequently identified for remediation, potentially giving the perception of an increased failure rate, but in actuality reflecting the more proactive approach. This improvement may require increased response when compared to the older program. This new program treats the poles with an Environmental Protection Agency-approved chemical that extends the life of the pole, identify areas to truss the pole to increase the life expectancy, or determine the pole is a candidate for replacement. These expanded inspections result in additional costs compared to the existing inspection program. However, the Company can capitalize the majority of these costs because of the life expectancy increase. Importantly, this new program will provide better reliability, resiliency, and a longer life expectancy of pole assets.

## F. Current Distribution Projects

The Company's five-year distribution capital plan includes three projects that are anticipated to have individual total costs of greater than two million dollars. The estimated cost and expected benefits of these projects are shown in Table 4.

Across Minnesota Power's system there are many transmission-to-distribution substations that require age-related upgrades. Much of the original equipment in these substations is nearing or beyond the end of its useful life. Minnesota Power's Switchgear Replacement and Substation Modernization (Asset Renewal) 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. These programs take a holistic, site-by-site approach to facilitating the coordinated and efficient modernization of aging substations with indoor switchgear throughout Minnesota Power's system, addressing the unique needs and constructability considerations of these sites.

The Canosia Road Substation 34 kV Expansion and Mahtowa Substation 34kV Expansion will be the first two projects in a multi-year plan to modernize and improve the Cloquet-area distribution system. There are several factors driving the need for improvements in the Cloquet area:

*Asset Renewal & Standardization*: Implementing a standard 34.5 kV backbone distribution network for the Cloquet area. There are presently three different backbone distribution voltages between Cloquet, and Hinckley. The Canosia Road and Mahtowa Substation Expansion projects will convert existing 24 kV and 46 kV systems to 34.5 kV while addressing asset renewal needs for existing feeders and stepdowns associated with these systems.

*System Capacity & Asset Renewal Project Constructability*: Enabling the Cloquet Substation Modernization (Asset Renewal) Project to take place. Cloquet Substation is one of highest-priority asset renewal sites on the Minnesota Power system. However, the surrounding distribution system lacks sufficient capacity to reliably support the Cloquet area during an extended outage which would be necessary to implement the asset renewal project. Aligning the three different voltages present and extending the 34.5 kV system around Cloquet will allow Minnesota Power to replace the Cloquet substation while improving reliability throughout the surrounding area.

*Reliability & Grid Modernization*: Improving reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34/14 kV stepdowns, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration

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 explained in Table 4 and discussed in Section III.C.

Table 4: Distribution Projects over $2 million

| Project Name | Preliminary Cost Est. | Anticipated ISD | Project Area |
|---|---|---|---|
| **Switchgear Replacement Program**<br><br>**(Asset Renewal)** | $8.0M<br>$4.2M | 2026<br>2028 | *Anticipated Substations*:*<br><br>Haines Road (Hermantown) Colbyville (Duluth)<br><br>**subject to change based on asset renewal project prioritization* |
| **Substation Modernization Program**<br><br>**(Asset Renewal)** | $10.4M<br>$6.0M<br>$7.4M<br>$9.9M<br>$8.8M<br>$6.9M<br>$6.7M<br>$10.9M | 2024<br>2025<br>2025<br>2026<br>2026<br>2027<br>2027<br>2027 | *Anticipated Substations*:*<br><br>Long Prairie, Winton, Maturi (Chisholm), Ridgeview (Duluth), Hibbing, Verndale, Cloquet, Little Falls<br><br>**subject to change based on asset renewal project prioritization* |
| **Cloquet Area 34 kV Expansion** | $2.2M<br>$6.6M | 2023<br>2025 | Canosia Road (Esko), Mahtowa |

G. Analysis and Visibility of System Data

1. Software

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 distributing 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.

In late 2018, Minnesota Power became part of the Electric Power Research Institute's ("EPRI") Distribution Resource Integration and Value Estimation ("DRIVE")[17] 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

[17] The EPRI DRIVE™ software determines the maximum amount of DER each distribution feeder can accommodate in its current state before unacceptable reliability, power quality, protection and thermal issues start to emerge.

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 WindMilmodels have curtailed progress and led, in part, to the aforementioned distribution planning software improvement initiative. Moving our 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 uses four different methods to monitor and control its distribution system: SCADA, smart sensors, automated/advanced meter 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., Amps, MW, MVAR, MVA, and 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 in order to gather better data and eliminate manual reads.

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 a 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. As part of the upgrade of the Company's C2M project and the addition of a Meter Data Management system, all meters were moved to collecting 15-minute interval usage data. This gives customers more granular data through the MyAccount tool, and positions 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. System Visibility

*SCADA & Smart Sensors*

Minnesota Power currently has 339 distribution feeders throughout its service territory. Some of these are three phase feeders while others are single phase. Minnesota Power has visibility into and control of primary and three-phase distribution. The Company currently has no visibility or control on most single-phase feeders. Of the Company's 339 distribution feeders, 170 feeders (50 percent) have SCADA at the feeder breaker. In 2017, Minnesota Power began implementing smart sensors on the remaining distribution feeders. Through 2022, 136 distribution feeders (40 percent of total feeders) have smart sensors installed near the feeder source. Nine additional locations on four 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. A few of the 4kV feeders that have very few customers will be converted to a higher voltage were not a part of the smart sensor program. 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.

*Faulted Circuit Indicators*

Minnesota Power is currently testing 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 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.

*AMI*

The AMI system allows for efficient metering access, improved data transmission and granularity, and enhanced situational awareness between Minnesota Power and its customers. The meters act as "smart nodes" at each customer's premises, allowing a number of 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; and the ability to more quickly reconnect customers who may have been involuntarily disconnected due to non-payment (where remote capability exists). The expansion of Minnesota Power's AMI capabilities also lays the groundwork for further grid modernization initiatives and improvements to the customer experience.

Table 5: Deployment Plan for AMI Meters

| | 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 Plan** | 203 | 0* |

**Likely will not be "0" in 2023 due to potential AMI opt-outs*

As of January 2023, there were 147,164 deployed AMI meters on Minnesota Power's system (roughly 99.7 percent of deployed meters). With the aid of a Smart Grid Investment Grant, 8,030 meters were deployed, as described in Section III.A.1 – Time-of-Day/Critical Peak Pricing of the Plan. There were 203 deployed meters remaining on the older AMR system as of January 2023, and most of those meters were replaced before the AMR system was decommissioned in April of 2023. Minnesota Power is actively working with property owners to gain access to the less than 20 AMR meters still installed.

3. 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 required reliability 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.

*Fault Location, Isolation, and Service Restoration System*

Minnesota Power's Fault Location, Isolation, and Service Restoration ("FLISR") system, which includes reclosers and smart switches, is connected via a fiber optic network switch system that is purpose-built and isolated from all other Minnesota Power communications systems. Extending the isolated fiber optic network switch system is the preferred solution for additional smart switch devices. This solution provides fast and reliable communications with strong network security. The Company will continue to evaluate alternative communication options for the FLISR system as it is expanded, but currently plans to extend fiber communications for this purpose.

*Other Distribution Devices*

Other Distribution devices such as reclosers, switches, regulators, capacitor banks, etc. that can be operated from the EMS are connected by several different methods:

- The fiber optic network switch system that was built for the FLISR system.
- Devices that can be economically connected to existing FLISR deployments are connected using that system.

*Land Mobile Radio Based SCADA Communications*

Minnesota Power's land mobile radio ("LMR") system supports a solution to provide a low-speed SCADA connection to a device within the radio coverage area. The LMR system has coverage in a large majority of Minnesota Power's service territory making it a wide scale and cost-effective communications solution. An upgrade of the LMR system is currently underway to enable this functionality system wide with a target completion by 2025. We currently have five distribution devices connected with this system and plan to expand as the capability becomes available in other areas of the system.

*Unlicensed 900 MHz radios, licensed 450 MHz radios or short fiber optic extensions that connect to a Remote Terminal Unit ("RTU")*

These solutions leverage an existing substation RTU that is located near the distribution device and is already connected to the EMS via the transport communications system. This allows for a low-cost communications channel when there is existing infrastructure in the area.

All of these solutions are in the Company's toolbox but require project-specific engineering to determine the most cost effective and economical solution for the specific need. Minnesota Power continues to evaluate these solutions and new technologies to ensure the best options are provided.

4. Cyber Security

With enhanced data and system capabilities, and increased DERs on the utility system, it is imperative that the Company continues to evolve its cyber security program to ensure the security and integrity of customer and utility systems and data. Minnesota Power has built a multi-layered cyber security program based on the Center for Internet Security's internationally accepted Critical Security Controls for Effective Cyber Defense framework to prevent, limit the impact of, and ultimately recover from impacts caused by cyber threats. In practice, Minnesota Power's cyber security program addresses: dedicated cyber security program and leadership, external sensing, internal sensing, intrusion prevention, and intrusion detection and mitigation. The program continues to be enhanced and adjusted to protect Minnesota Power's cyber systems from the evolving threat landscape. More information on the Company's cyber security program can be found in the Minnesota Power's most recent Safety, Reliability, and Service Quality Report.[18] This November the Company will be participating in GridExVII, a large scale grid security exercise organized by the North American Electric Reliability Corporation ("NERC")'s Electricity Information Sharing and Analysis Center ("E-ISAC"). Additionally,

[18] Docket No. E015/M-21-230

Minnesota Power collaborates with neighboring utilities, industry specific groups, industry partners, and public officials to share best practices for both cyber and physicalsecurity.

# DEMONSTRATING INNOVATION

## III. DEMONSTRATING INNOVATION

Minnesota Power has a long history of demonstrating innovation with new technologies and customer programming while being one of the most unique utilities in the country in terms of its customer mix and load profile. As the Company continues its Energy***Forward*** journey to a zero-carbon future, this value of innovation will be critical as the grid evolves to accommodate evolving customer expectations and power supply changes. This section will provide an overview of Minnesota Power's current and past pilot projects, the evolution of integrated distribution planning and the analysis of non-wires alternatives.

### A. Current and Past Pilots

Minnesota Power has routinely implemented technology solutions, where appropriate, to assist with outage detection, response time to outages, and to respond to customer expectations regarding more timely communication and transparency of operations. At the same time, the Company has piloted innovative technology in order to test the feasibility of certain applications for the distribution system, while utilizing resources wisely to gain benefits. The pilots outlined in this section are examples of how the Company continues to carefully leverage internal and external resources to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid.

#### 1. First Utility in the State to Implement Time-of-Day Rates for All Residential Customers

On December 1, 2020 the Company filed a petition to change the residential rate design.[19] At the time of submittal, Minnesota Power was the only utility in the state to have an inverted block rate ("IBR") structure in place. This filing originated in the Company's Time--of-Day ("TOD") Pilot filed in 2012[20] and represented a first-of-its-kind proposal in Minnesota to implement a default TOD rate for all residential customers. The petition supported goals collectively identified in the extensive stakeholder process, including:

[19] Docket No. E015/M-20-850
[20] E015/M-12-233

encouraging beneficial electrification, sending price signals to align customer behavior with system efficiency, providing customers with more control over their energy bills and protecting vulnerable customers currently benefitting from the affordability provisions inherent in an IBR structure.

On August 27, 2021, the Commission issued an Order approving Minnesota Power's proposal to begin the transition away from IBR and toward a default TOD rate for residential customers. This significant change in residential rate design will set a foundation for efficient use of renewable energy, empower customers with more control over their energy bills, and remove barriers to electrification while maintaining important affordability provisions. The approved proposal included multiple phases and gating points to slowly transition residential customers on to the rate over time, targeting 2027 for the rate to officially become the default standard residential rate. This transition was made possible by Minnesota Power's full deployment of AMI to all customers, the first investor-owned utility in the state to do so. The phased and thoughtful multi-year approach to arriving at the default rate is critical to making transition a success. Introducing customers to time-based rates now is an essential step to creating an educated and engaged customer base that will play a key role in supporting the grid of the future.

2. SolarSense Low-Income Solar Grant Program

Minnesota Power continued to discover opportunities to overcome the solar adoption challenges commonly faced by low-income customers through the Low-Income Solar ("LI Solar") Grant Program, the first of its kind in the State of Minnesota. On December 17, 2020, Minnesota Power's proposal to convert the Low-Income Solar Pilot Program into a LI Solar Grant Program was approved in Docket No. E015/M-20-607. The new program increased annual grant funding to $120,000 through 2024. Common challenges for low-income customers can include lack of upfront capital, home ownership status, physical condition of the home, low credit scores, limited access to information and more. This program was intentionally designed to be flexible to encourage a wide variety of project structures, partnerships, and creative solutions to address these barriers. The Company awarded $128,616 towards qualifying low-income solar projects in 2021 and 2022 and continues to explore innovative ways to establish a viable, long-term solar market for low-income customers. Examples of projects funded through the LI Solar Grant Program are outlined below:

*Green New Deal Housing ("GNDH")*

GNDH built an all-electric pilot home in Duluth's Central Hillside neighborhood for a low to moderate income family. The home is designed to be net zero energy with the addition of the solar PV array funded, in part, through the LI Solar Grant Program.

*Loaves and Fishes – Hannah House*

Loaves and Fishes serves people experiencing various stages of homelessness at four houses throughout Duluth. Hannah House is specifically dedicated to serving infants and youths. A grant from the LI Solar Grant Program allowed this customer to add an on-site solar array while upgrading the existing roof with a new metal roof. This will help to lower the long-term operating costs of this important community asset.

*Solar United Neighbors ("SUN")*

SUN is a national organization that gathers community members through education to bring collective buying power to local communities. They also find opportunities to assist those less able to fund a solar project. SUN received a grant for 50 percent of the cost of a system for a low-income family as a part of their overall group buy effort.

*One Roof – Plover Place*

One Roof, in coordination with community partners, is building a congregate living facility that will house up to 12 individuals experiencing homelessness. The facility is a module build design meant for reproduction in many areas. A 9-kW solar array is to be installed on the building to lower operating costs. The anticipated effect of the solar array is to make the building a net zero energy user.

*Habitat for Humanity Homes*

The Rural Renewable Energy Alliance ("RREAL") worked with Habitat for Humanity in Pequot Lakes and Calumet to install a solar array on Habitat for Humanity homes built for low-income Minnesota Power customers. The grant covered nearly all the added expense of the solar system.

*North Shore Area Partnership*

The North Shore Area Partnership (“NSAP”) serves the Silver Bay area senior population with many services both at their facility and in their homes. A solar PV array at their facility will lower operating costs, allowing NSAP to continue providing these vital services to low-income customers.

*One Roof Housing – Land Trust Homes*

One Roof Housing was awarded funding for two projects in 2022. Both projects were for the installation of solar arrays on houses participating in One Roof Housing’s land trust program. The land trust program ensures that these homes will remain in the low to moderate income market regardless of when they are sold in the future. The on-site solar arrays will help to reduce the energy costs of these homes, benefiting the homeowners.

3. Street Lighting – LED Replacement Project

In 2020, 2021 and 2022 Minnesota Power replaced 19,000 lights with energy efficient Light Emitting Diode (“LED”) lights. This eliminated all old, outdated fixtures and allowed for simpler application of the rates, as the number of choices of light fixtures was also reduced from 19 down to 7.

This conversion to LED provided many benefits to customers. The LED fixture upgrades have no replacement cost to customers. Most customers no longer have to maintain their own lights, Minnesota Power will be responsible for maintenance of all lights under Option I. Also, customers experience fewer outages of lights, due to the longer operating life of LED fixtures. The number of calls for lights not working reduced from over 2000 in 2020 to around 250 so far in 2023. Customers may see reduced lighting rates or energy usage with the more efficient LED fixtures.

*Street Lighting – Option III*

Photoeye meter combination units, that are compatible with Minnesota Powers's AMI infrastructure, have been ordered for the remaining Option III lights. These meters will be installed in 2024 eliminating the need for Option III lighting rates.

4. Strategic Undergrounding

Strategic undergrounding was first initiated in 2020 and continues for some of the Company's worst performing overhead lines. The Company is targeting areas where customers do not allow access to vegetation management, such as tree trimming, and areas where overhead lines are installed cross-country in inaccessible areas with heavy vegetation. The main drivers for strategic undergrounding are reliability improvement, storm resiliency, aging asset replacement, 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 costs, accessibility for maintenance, and geology. The Company anticipates benefits could include fewer outages, cost savings, enhanced safety, and enhanced reliability. In 2022, over 37 miles of underground cable was installed across the distribution system including the conversion of overhead facilities to underground. There are currently 4473 miles of above ground wire on the distribution system and a total of 1650 miles of underground wire.

5. Municipal Solar Plus Storage System

*Grand Rapids Public Utilities*

Minnesota Power partnered with Grand Rapids Public Utilities ("GRPU"), one of the Company's wholesale municipal customers, to bring a new Solar Plus Energy Storage system to Grand Rapids, MN. The project includes a new 2 MW Solar PV array and a 1 MW/2.5-hour Li-Ion Energy Storage System. The project is located on a property near the Grand Rapids airport and features a pollinator garden. The PV array adds additional renewable energy to the GRPU portfolio, and both the solar and battery systems are being utilized to reduce monthly peak demand. Minnesota Power worked with GRPU to develop tools that forecast GRPU system demand and solar generation on a sub-hourly basis to then determine the optimal dispatch (charging and discharging) strategy for the energy storage system with the goal of monthly peak demand reduction. The project was commissioned August 2022 and the Company has been successful in reaching its goal by reducing Grand Rapids Peak Demand. Minnesota Power continues to learn and understand battery technology in this current application and is finding it helpful as the company investigates other opportunities for energy storage devices on its own distribution system.

6. Distribution Utility Scale Solar Installations

*Laskin Solar*

As part of the Company's Economic Recovery filing[21] 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. A brief overview of each project follows. The 5.6 MW Laskin solar array, located at the Laskin Energy Park in Hoyt Lakes, represents a continued investment in host communities that have experienced impacts from the Company's closure of coal plants, as coal operations ceased at Laskin Energy Center in 2015 and the facility transitioned to natural gas. The refueling and change in mission to a peaking capacity resource resulted in a significant reduction in the number of employees at the facility along with decreased economic activity in the community. Siting a new solar project at Laskin Energy Center is an intentional effort on behalf of the Company to reinvest in communities impacted by its transition to a cleaner energy future.

*Sylvan Solar*

The second economic recovery solar project is a 15.2 MW project sited near Minnesota Power's Sylvan Hydro Station west of Brainerd, Minnesota. The Company selected this site in an effort to spur economic recovery efforts within its service territory, because the land is already owned by the Company, and the location provides proximity to existing Company infrastructure, minimizing the expense and complexity of connecting into the

[21] Docket No. E,G999/CI-20-492 and Docket No. E015/M-20-828; Laskin, Sylvan, and Duluth solar make up this suite.

local distribution system. Investment at the Sylvan site reinforces the Company's commitment to economic development in the western part of its service territory.

*Jean Duluth Solar Project*

The final project in the suite of economic recovery solar projects approved in 2021 is the 1.6 MW Jean Duluth Solar project sited in Duluth, Minnesota – home of Minnesota Power's corporate headquarters and the Company's largest service center. Jean Duluth Solar is located in northeast Duluth, on approximately 9 acres of land owned by the City of Duluth. The Company selected this location because it is no longer used for City maintenance activities, it is located close to the Company's existing distribution infrastructure, will provide economic investment in the community that hosts the Company's corporate headquarters and aligns with the City of Duluth's sustainability goals. The City of Duluth has committed to reducing its greenhouse gas emissions 80 percent by 2050, intending to accomplish that goal through a combination of energy conservation, renewable energy projects, supporting multi-modal transportation and adapting infrastructure to the changing climate.[22] As such, the City is supportive of the Company siting new solar projects in Duluth.

7. Reconnect Pilot Program

Minnesota Power's Reconnect Pilot was approved by the Commission on December 9, 2020 under Docket No. E015/M-19-766. This is a voluntary three-year pilot program, under which residential electricity customers whose service has been disconnected due to non-payment would have the option to have their service reconnected remotely after meeting reconnection requirements. A participating customer with a remote-capable meter could have service reconnected within minutes after calling customer service, eliminating the need for Minnesota Power to send staff to the customer's location to reconnect service in person and allowing for a waived reconnection fee for the customer. The Company's target remote-capable meter deployment is 10 percent of residential meters, or about 12,250.

[22]https://duluthmn.gov/sustain/goalsmetrics/#:~:text=The%20City%20of%20Duluth%20works,emissions%20by%2080%25%20by%202050

Due to the COVID-19 pandemic and the related suspension of disconnections for residential customers facing financial hardship as a result of the coronavirus pandemic, the implementation of this Pilot was postponed. In its August 13, 2020 Order under Docket No. E,G999/CI-20-375, the Commission ordered suspension of disconnections for residential customers; suspension of negative reporting to credit agencies for residential customers; and waiving reconnection, service deposits, late fees, interest, and penalties for residential customers. In its May 26, 2021 Order in Docket No. E,G999/CI-20-375, the Commission adopted a modified Consumer Advocates' Transition Plan, and allowed for the resumption of disconnections on August 2, 2021. With the resumption of disconnections, Minnesota Power is in the process of deploying remote-capable meters, timed with reconnection of service to realize operational efficiency and maximize the potential savings to customers in terms of Company costs as well as direct costs such as future reconnection fees. As of December 31, 2022, there were approximately 4,437 remote-capable meters installed for residential accounts, as reported in the Company's SRSQ. The cumulative net cost changes for the pilot are $512,000, using 2021 and 2022 calendar year data. As of August 31, 2023, there were approximately 8,201 remote-capable meters in total installed for residential accounts, with 1,091 disconnections and 765 reconnections within 24 hours associated with these accounts in 2023.

On September 26, 2023, Minnesota Power requested a two-year extension of the pilot under Docket No. E015/M-19-766. This extension, if granted, will provide for a better evaluation period to further assess benefit and cost impacts and more definitively inform the business case for a broader offering going forward. The Company will continue to report on the Remote Reconnect Pilot Program status in its upcoming and future SRSQ report.

## B. Non-Wires Solutions

Generally speaking, the types of projects that lend themselves to non-wires solutions[23] are those designed to address reliability performance or load-serving issues. Specifically, non-wires solutions may be suitable for addressing reliability performance issues where

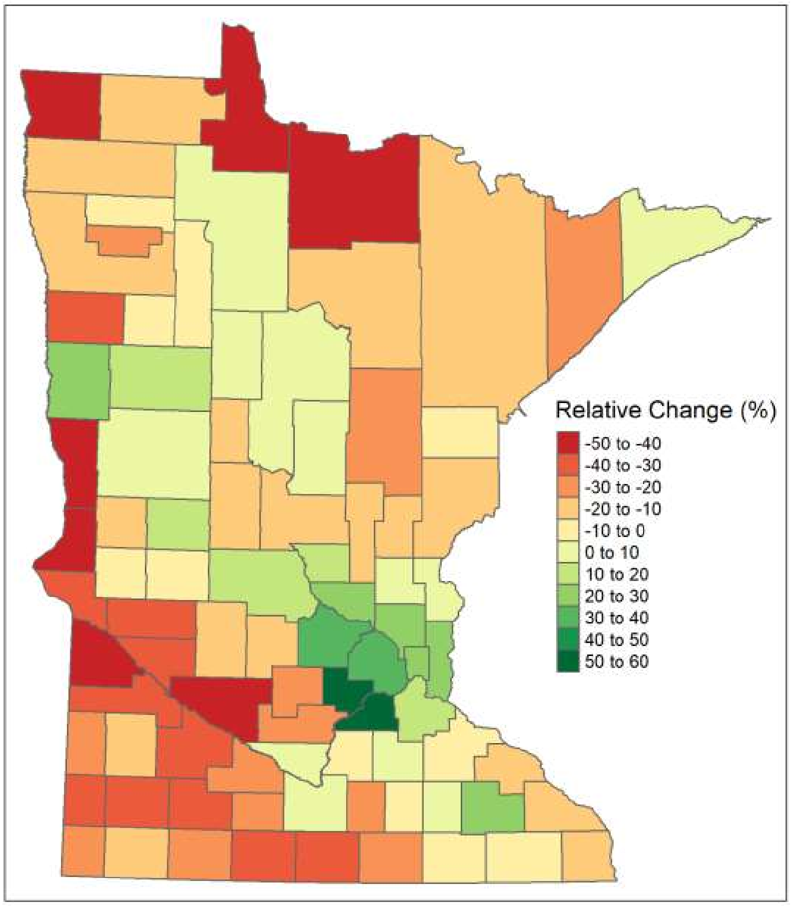
[23] For purposes of the discussion in this subsection of the 2021 IDP, non-wires solutions do not encompass demand response or energy efficiency initiatives. Those programs are addressed in other sections of this Plan.

there is limited or no backup capability following loss of the primary source to a feeder. In that case, a non-wires solution may be able to provide redundancy to the feeder, enhancing restoration times and ultimately improving reliability. 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. 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 enough 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 70-90 years are still in use. These substations should and are being addressed through Minnesota Power's Substation Modernization (Asset Renewal) Program.
- The 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.

Additionally, population growth is an important consideration when discussing non-wires alternatives. Minnesota Power's service territory is projected to continue a decline in population through 2053, as shown in figure 11.[24]

Figure 11: Relative Population Change by County, 2018-2053 in Minnesota




Smart Electric Power Alliance ("SEPA") and Peak Load Management Alliance's ("PLMA") November 2018 "Non-Wires Alternatives Case Studies from Leading U.S. Projects" report listed the majority of case studies as siting forecasts of high load growth as contributors to the identification of the need for infrastructure upgrades and non-wires solutions. Stagnant to declining population growth in a utility's service territory presents a unique challenge when evaluating non-wires options for distribution solutions.

[24]Minnesota State Demographic Center. (October 2020). Long-Term Population Projections for Minnesota: https://mn.gov/admin/assets/Long-Term-Population-Projections-for-Minnesota-dec2020_tcm36-457300.pdf

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. The components of 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 Study ("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.

### C. <u>Benefit Cost Analysis ("BCA") Framework Report</u>

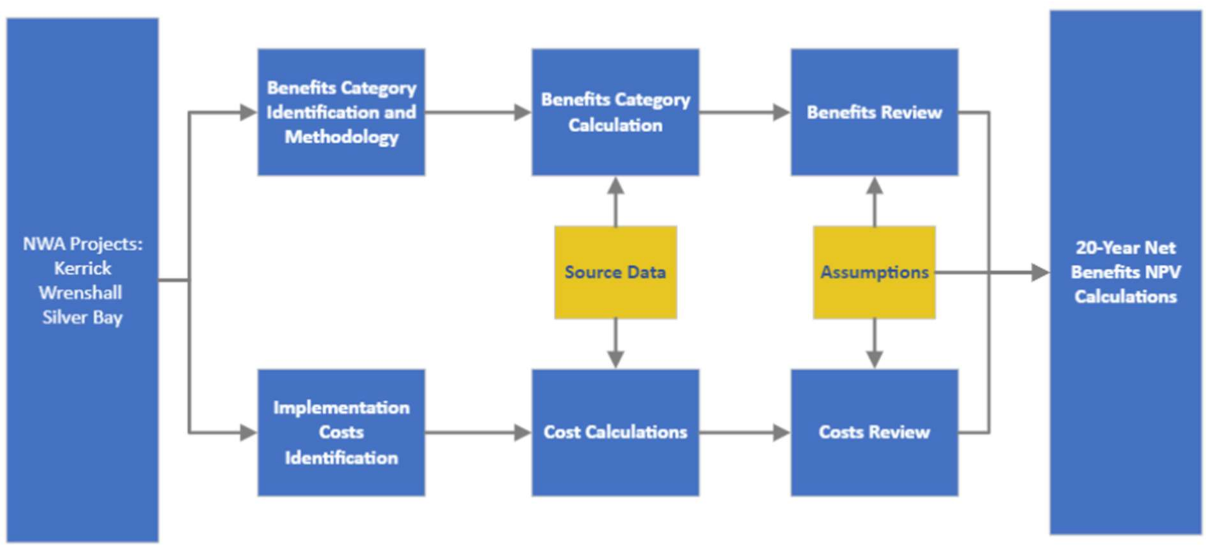
The BCA Framework Report summarizes Black & Veatch's efforts to develop a realistic business case for evaluation and justification of NWA projects in Minnesota Power's service territory. The process of developing this framework included the following steps:

1. Identify Benefits Framework – identify the benefit opportunities that are relevant to Minnesota Power and the NWA scenarios.

2. Compile Benefit Data – Gather Minnesota Power data to support calculation of benefits.
3. Quantify Benefits – Define calculation methodology for each type of benefit and test methodology on NWA scenarios.

Once Black & Veatch and Minnesota Power had finalized the BCA framework, it could be applied uniformly to the NWA scenarios according to the process shown in Figure 12 below in order to complete benefit-cost analysis for each specific scenario.

Figure 12: NWA Scenarios




For Minnesota Power's NWA Study scenarios, the BCA framework includes 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 is discussed in greater detail in the full report included in Appendix G.

Applying the BCA framework to the NWA Study scenarios produced benefit-cost ratios ("BCRs") ranging from 0.42 to 1.88. When the BCR exceeds 1.0, the calculated benefits exceed the estimated costs of the project and the NWA solution may be justified based on the business case assessment.

A brief overview of each NWA Study report is provided below, and the full NWA Study reports are included in Appendix G.

1. Kerrick Area Non-Wire Alternative Solution Report

The Kerrick Area NWA Solution Report describes the evaluation and recommendations from Black & Veatch and its subconsultant K&A Engineering for the Kerrick Area Scenario. The Bear Creek – Kerrick 46 kV Line ("23 Line") serves a relatively rural area along State Highway 23 south of Duluth. Stepdown substations connected to 23 Line serve just over 750 customers, with peak load of 1.80 MW. Formerly, the area was backed up by a 46 kV connection to the Thomson Substation. However, this connection is no longer a reliable backup source due to its age and condition as well as difficult access due to rough terrain that limits maintenance and restoration opportunities. Within the next 10 years, the Thomson 46 kV source will be decommissioned and 23 Line will be converted from 46 kV to 34.5 kV as part of Minnesota Power's asset renewal and standardization master plan for the area. At that point, 23 Line will become a fully radial line from Bear Creek with no backup options.

The Kerrick Area scenario evaluated non-wire alternatives involving battery energy storage system and automated FLISR as a reliability backup solution for 23 Line. Two alternative NWA solutions were analyzed involving Battery Energy Storage System "BESS" installations on the high or low side of the Kerrick and Askov stepdown transformers. The proposed BESS would provide a reliable backup for Kerrick-area customers in the event of an outage of 23 Line. The Kerrick Area NWA Solution had a BCR of 1.88, and consequently Minnesota Power has begun working to refine and develop this solution for implementation as a BESS reliability backup pilot project in the Kerrick Area (see Section IV.B.6).

### 2. Wrenshall Non-Wire Alternative Solution Final Report

The Wrenshall NWA Solution Report describes the evaluation and recommendations from Black & Veatch and its subconsultant K&A Engineering for the Wrenshall Scenario. The Wrenshall 115/13.8 kV Substation serves a small rural area south of Duluth, including just over 1,500 customers with peak load of 3.60 MW. While the majority of customers are rural residential and commercial, there are several aspects to the Wrenshall Substation that make the scenario unique:

- There is one backup source to the Wrenshall Substation, the Military Road 46/13.8 kV Substation. Military Road normally serves one customer, an industrial facility with demanding load requirements, with peak load of 2.81 MW.
- There is a 1.0 MW solar garden interconnected to the Wrenshall 13.8 kV feeder. Total daytime minimum loading for the feeder and substation is approximately 1.0 MW.
- Due to their age and condition, the Wrenshall and Military Road Substations are scheduled for a complete overhaul, modernization, and reconfiguration in the next 10 years.

The Wrenshall scenario evaluated long-term considerations for the configuration and operation of the Wrenshall area 13.8 kV system, given its varied characteristics and constraints. This scenario included assessment of non-wire alternatives such as volt-var optimization to manage voltage fluctuations from the solar garden and industrial facility, battery energy storage system to provide backup capability and potentially optimize solar garden operation, and automated FLISR. Two alternative NWA solutions were analyzed involving BESS and FLISR installations on the Wrenshall area 13.8 kV system. The proposed BESS solutions would back up the two existing Wrenshall feeders to support customers in the event of an outage of the source. The Wrenshall NWA Solution had a BCR of 0.85, and consequently Minnesota Power is continuing to look at traditional reliability backup solution options for the area in order to compare with or expand on the NWA Solutions developed by Black & Veatch.

### 3. Silver Bay Non-Wire Alternative Solution Final Report

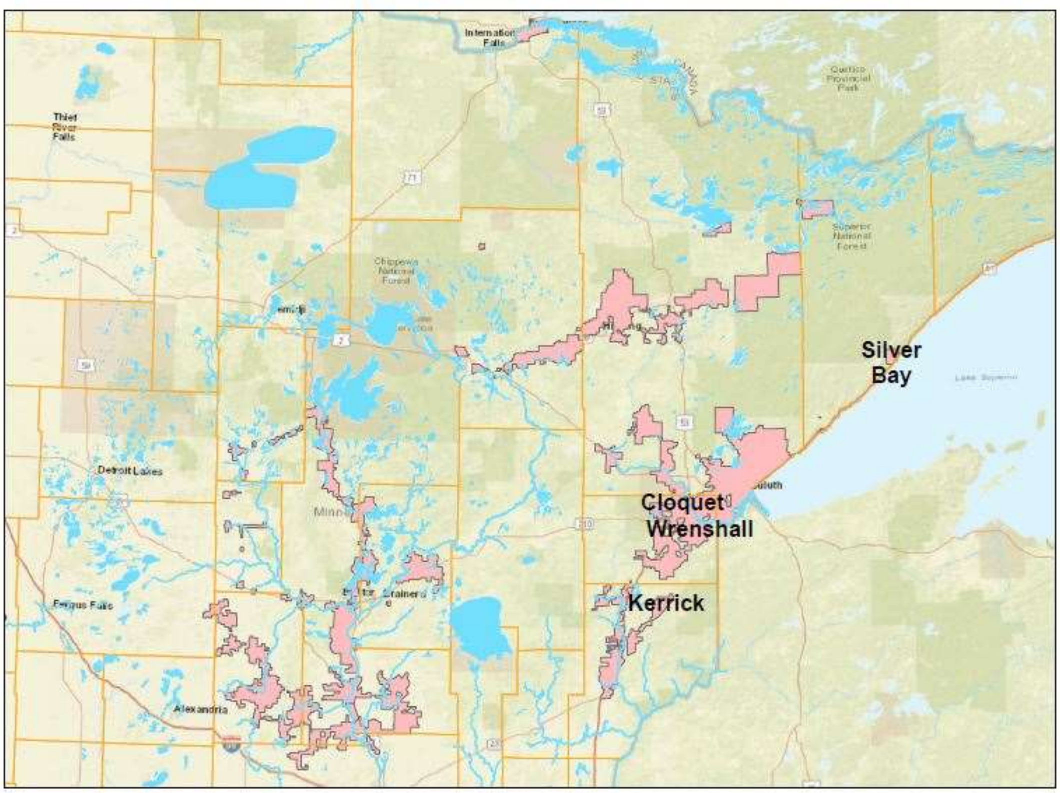
The Silver Bay NWA Solution Report describes the evaluation and recommendations from Black & Veatch and its subconsultant K&A Engineering for the Silver Bay Scenario. The City of Silver Bay was formerly served solely by the Silver Bay Hillside 115/13.8 kV Substation, including approximately 1,348 customers with an estimated peak load of 4.50 MW. Due to the age and condition of the Silver Bay Hillside Substation, Minnesota Power recently added a new 115/13.8 kV source at the North Shore Substation on the east side of Silver Bay, with the intention of ultimately decommissioning Silver Bay Hillside Substation and converting the site to a mobile substation hook-up location after all customers are transferred to the new source. Outside of this future mobile substation site, the only potential source of immediate backup capability for the City of Silver Bay following loss of the primary North Shore source is a tie into the switchgear of a nearby large industrial plant. Historically, this tie was used for backup from Minnesota Power into the plant, and its reliability for use by Minnesota Power to back up the City from the industrial plant is questionable.

The Silver Bay NWA scenario evaluated non-wire alternatives involving BESS and automated FLISR as a reliability backup solution for the City of Silver Bay. Two alternative NWA solutions were analyzed involving BESS and FLISR installations on the Silver Bay area 13.8 kV system. The proposed BESS solutions would back up one or both of the existing Silver Bay feeders to support customers in the event of an outage of the source. The Silver Bay NWA Solution had a BCR of 0.75, and consequently Minnesota Power is continuing to look at traditional reliability backup solution options for the area in order to compare with or expand on the NWA Solutions developed by Black & Veatch.

### 4. Cloquet Non-Wire Alternative Solution Final Report

The Cloquet NWA Alternative Solution Final Report describes the evaluation and recommendations from Black & Veatch and its subconsultant K&A Engineering for the Cloquet Area Scenario. The Cloquet 115/13.8 kV Substation serves the City of Cloquet and the surrounding area with ties to feeders originating at the Canosia Road, Mahtowa and Thomson substations. The Cloquet Area scenario was added to the NWA Study scope of work specifically to evaluate the scope and benefits of implementing a FLISR project on the Cloquet area distribution system. Each Cloquet area feeder was evaluated under its system normal configuration and when being served by adjacent backup feeders through available tie switches. Where constraints inhibited the ability to fully back up one feeder from another, mitigation solutions were proposed. Finally, a FLISR analysis was performed to identify optimal locations for reclosers and sectionalizers to automate switching and limit customer exposure to feeder faults. The Cloquet area FLISR solution by itself had a BCR of 6.95, and consequently Minnesota Power will begin working to implement the solution in 2024 and subsequent years. If the regulators identified as part of the plan can be utilized for voltage correction and power quality improvements, the total BCR of the recommended Cloquet-area NWA solution increases to 9.39.

Figure 13: NWA Study Scenario Map



# PLANNING FOR A RESILLIENT FUTURE

# IV. PLANNING FOR A RESILIENT FUTURE

As the industry undergoes dramatic changes, technology advances, customer expectations change and climate change produces increased extreme weather events, utilities will have to plan not only for system reliability but to also ensure a more resilient future. This section of Minnesota Power's 2023 IDP will cover financial planning, potential pilots within the next decade, distribution forecasting, historical loading and preliminary hosting capacity data, and DER system impacts and benefits.

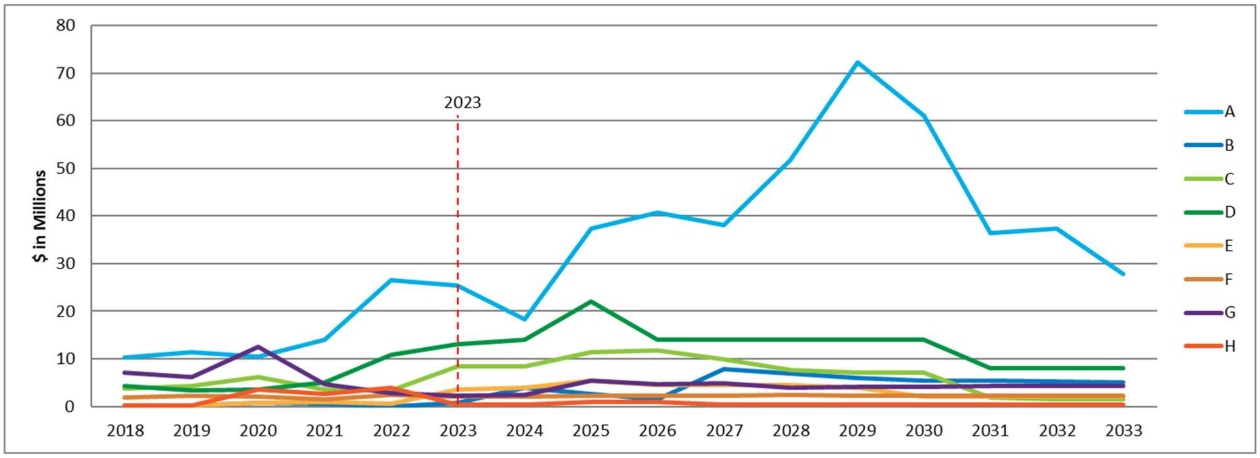
The numbers in the Company's forecasts below do not reflect the latest "3% by 2030" Distributed Generation requirements added to Minnesota Statute 216B.1691 Renewable Energy Objectives. Subd. 2h. The Company is aware of these requirements and will report on them in Docket No. E002,E015,E017/CI-23-403 as well as in subsequent Integrated Resource Plan filings.

## A. Financial Planning

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 fair amount of changes occur naturally in the long-range plan as the Company learns more information. That being said, the Company plans to dramatically increase its capital budget for grid modernization initiatives from 2023 through 2028.

Figure 14: 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*

## B. Potential Pilots and Ten-Year Plan

As communicated in Section IV.A – Financial Planning, the Company plans to dramatically increase its investment in grid modernization pilots starting in 2023. Below the Company highlights some areas of interest for potential pilots.

### 1. Residential, Commercial and Industrial Customer Demand Response

Minnesota Power continuously evaluates demand response programs and the role these programs play in a decarbonized grid. Demand response programs are considered within the long-term plan. In addition, Minn. Stat. § 216B.241, subd. 13 allows utilities to implement load management activities, or combinations of energy conservation improvements, fuel-switching improvements, and load management activities as part of their ECO plans. Through the ECO plan the Company will continue to evaluate opportunities to implement cost effective DR.

*Renewable Load Optimization Programs*

One of the known challenges of grid transformation is to identify and access the flexible customer loads to optimize the integration of variable renewable energy production. In addition to demand response, Minnesota Power sees the long-term need for customer facing programs to help optimize the use of renewable energy. While Minnesota Power's system is one of the most unique in the country, with large industrial customers creating a system with a uniquely high load factor, the Company is still committed to attempting to match generation to the load from residential and commercial customers on the distribution system. An example of this may be using peak renewable generation that is exceeding load for EV charging (i.e., work place charging programs). The Company will continue to evaluate the need and applicability of these types of programs as renewable generation increases. Another example is the Company's transition of residential rate design from an inverted block rate structure to a future TOD opt-out rate to align customer behavior with optimal use of generation to create system efficiencies.

2. Selective Customer Sub-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 trusted sub-metering applications may be a critical part of future program designs.

3. Solar/Storage Applications

Minnesota Power has been working diligently with all distribution customer classes in the implementation of solar arrays and battery storage. This resource combination has the capability to provide many reliability and power benefits to customers through Time-of-Day Rate and future system enhancements, such as an Advanced Distribution Management System. The Company continues to investigate opportunities and engage customer groups with opportunities to deploy this technology as it becomes more economical for customers. As an example and described previously in Section III, Minnesota Power worked with a wholesale customer, GRPU, on a solar project with a battery storage component which began operating in 2022.

4. 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 in order to reduce demand and delivered energy. The system voltage would still 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 the 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 III.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 or not 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.

5. Battery Energy Storage System ("BESS")

Minnesota Power is currently in the investigatory phase of a grid scale BESS pilot at Boswell Energy Center. The purpose of this potential pilot will primarily be to test and learn ideal arrangements to integrate battery storage onto MP's distribution system on a larger scale. Minnesota Power also intends to install approximately 1MW (3 MWH) of battery storage near Kerrick, MN. The Kerrick BESS pilot was evaluated in the Distribution Non-Wire Alternatives Study along with other applications for reliability-based battery energy storage systems (discussed in Section III.C).

## C. Distribution Forecasting

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[25] (Module E-1). Minnesota Power accounts for existing DERs at the system level via two methods, depending on the type of DER:

- The DER is accounted for in the load forecast by reducing customer demand based on historical DER usage or product (such as distributed solar generation), or
- The DER is accredited as a capacity resource and used to meet the Planning Reserve Margin Requirement in MISO Module E-1/IRP. To avoid double counting of capacity, DER resources receiving an accredited capacity value are not taken into consideration in the customer demand outlook by reducing demand (such as customer owned generation at a paper mill).

The method used to incorporate a specific DER into planning considerations is consistent between the IRP and MISO Module E-1, and the above listed methods should be

[25] MISO <https://www.misoenergy.org/planning/resource-adequacy/#t=10&p=0&s=FileName&sd=desc>

sufficient to capture DER impacts in resource planning and forecasting functions going forward. For its 2021 IRP, the Company developed three scenarios for technology adoption (EV and DG Solar) on the Minnesota Power system. The 2023 Distribution Plan leveraged these same scenarios, updated, and modified them slightly to include assumptions for Time-of-Day rate adoption and potential installation of 16 new Direct Current Fast Chargers:

1. Base Case – is consistent with the 2023 Annual Forecast Report[26] assumptions for light duty EV ownership and distributed solar generation. It excludes any assumptions for medium and heavy-duty vehicles. Additionally, the scenario assumes a transition of residential billing to a TOD rate consistent with the Company's December 1, 2020 Residential Rate Design proposal[27] where TOD becomes the default residential rate by 2027.

2. Medium DER – assumes slightly accelerated adoption of EVs and distributed solar generation, a transition to 100 percent residential TOD participation by 2026 (a year earlier than Base Case), and the installation of 16 new DCFC for EVs on the Minnesota Power system beginning in 2024. The medium and heavy-duty EV forecast ownership penetration rate is consistent with the light duty Base Case.

3. High DER – assumes an aggressively accelerated adoption of EVs and distributed solar generation, a transition to 100 percent residential TOD participation by 2025 (two years earlier than Base Case), and the installation of 16 new DCFC for EVs on the Minnesota Power system beginning in 2024. The medium and heavy duty forecast ownership penetration rate is accelerated versus Medium DER case.

Each DER component (EV, DG Solar, TOD, and DCFC stations) is detailed below. The resulting outlook for a DER component under each of the above-mentioned scenarios are described along with the method for forecasting each component. The Distributed Solar Energy Standard which requires 3 percent of retail electric sales to come from small solar

[26] Docket No.E-999/PR-23-11
[27] Docket No. E015/M-20-850

– and is discussed directly in section II.B. - is expected to impact distribution forecasting. This forecasting will be incorporated into subsequent Integrated Resource Plans filed by the Company.

1. Distributed Solar Generation

Minnesota Power's 2023 Annual Forecast Report includes assumptions for residential and commercial/industrial adoption of distributed solar generation. The 2023 AFR's forecast methodology for distributed solar adoption and resulting decrease in Minnesota Power sales are described below.

New DG Solar installations were projected[28] using the U.S. Energy Information Administration's forecast for distributed solar generation. This outlook for the number of new installs 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 installs (i.e. installations expected to come online in the forecast timeframe). The effects of currently installed arrays are presumed to be embedded in the forecast.

The Company's Base Case forecast assumes about 2,920 new small-scale DG Solar installations, adding almost 28,000 KW of nameplate capacity, will be connected to the Minnesota Power grid by 2035 (i.e. installed in years 2022-2035). These new installations would generate about 27,000 megawatt hours ("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 12.9 percent compound annual growth rate ("CAGR") from 2022 to 2035.

The Medium DER scenario applies a 2.5 percent adder to the annual growth rates and results in an overall cumulative small scale solar capacity CAGR of about 15.4 percent from present installed capacity to projected 2035 capacity. The High DER scenario

[28] Details of the methodology can be found in the Company's 2023 AFR (Docket No. E-999/PR-23-11), Section B iii Treatment of DSM, CIP, DG, and EV in the Forecast

applies a 5 percent adder, resulting in a CAGR of about 17.9 percent over the same period.

The outlooks for new DG Solar installations are shown on the next page in Figure 15 and Figure 16. Figure 15 shows the projected reduction in annual sales due to new distributed solar, and Figure 16 shows the predicted reduction in Minnesota Power's summer peak resulting from coincident solar generation.

Figure 15: Distributed Solar Generation (MWh)

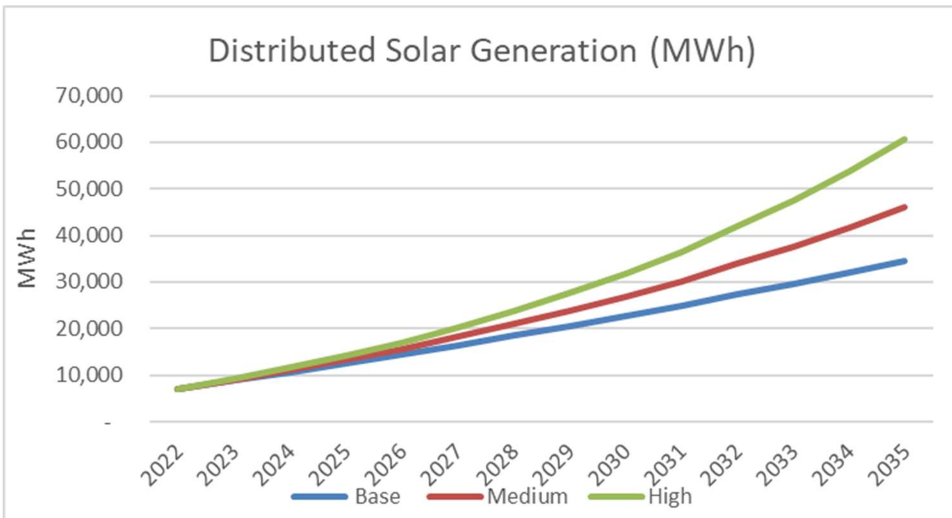



Figure 16: Distributed Solar Generation (Summer Peak)

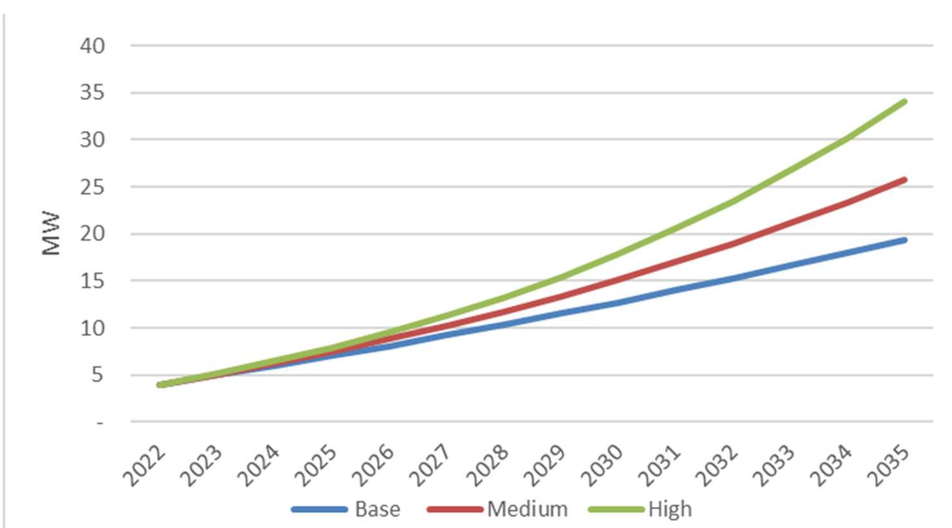


Table 7: Total Distributed Generation under three Forecast Scenarios

| DG Solar Capacity (MW) | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base | 7.2 | 8.9 | 10.7 | 12.6 | 14.5 | 16.5 | 18.6 | 20.7 | 22.9 | 25.1 | 27.5 | 29.9 | 32.3 | 34.9 |
| Medium | 7.2 | 9.1 | 11.2 | 13.4 | 15.8 | 18.4 | 21.1 | 24.0 | 27.2 | 30.5 | 34.1 | 37.9 | 42.0 | 46.4 |
| High | 7.2 | 9.3 | 11.6 | 14.2 | 17.1 | 20.3 | 23.9 | 27.8 | 32.1 | 36.9 | 42.1 | 47.9 | 54.3 | 61.3 |

2. Light-, Medium- and Heavy-Duty Electric Vehicles

Minnesota Power recognizes the potential load growth that could result from this new electric end-use and has incorporated an outlook for Electric Vehicle adoption into the residential energy sales and peak demand forecasts. The Company projected residential passenger EV (light-duty vehicle) adoption based on a national-level outlook[29] that has been scaled to the Minnesota Power region. The energy and demand requirements of EVs adopted in the forecast timeframe (2023-2035) 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.

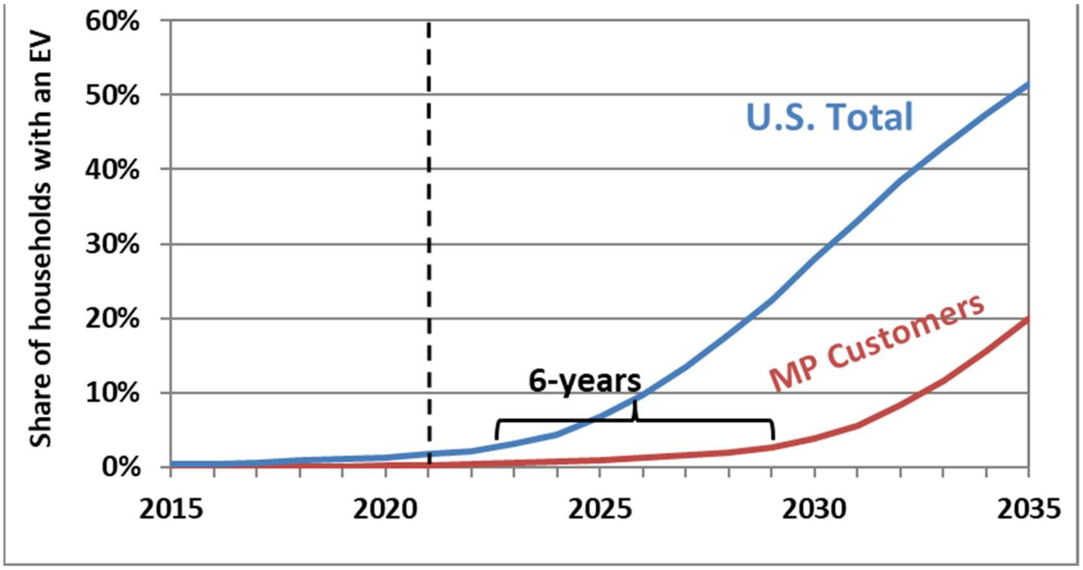
The Company estimates there are about 500 light duty EVs (i.e. passenger vehicles) in Minnesota Power's retail service territory.[30] This equates to a 0.26 percent penetration rate. This level of vehicle ownership translates to an estimated 1,262 MWh of annualized energy consumption and represents just 0.12 percent of all sales to residential customers. With limited data availability, Minnesota Power estimates there are 42 medium-duty EVs and 12 heavy-duty EVs owned in its service territory based upon the current light-duty vehicle penetration rate.

It its Base case, the Company projects that, by late 2035, approximately 11 percent of regional light vehicle ownership (or about 20 percent of households), and Minnesota Power will be the primary electric service provider to about 23,200 light-duty EVs. This equates to about 57,600 MWh in additional energy requirements from the residential sector and an estimated increase of 7 MW and 21MW in the 2035 summer and winter peaks (respectively).

[29] Goldman Sachs 2023 Electric Vehicle Outlook <https://www.goldmansachs.com/intelligence/pages/electric-vehicles-are-forecast-to-be-half-of-global-car-sales-by-2035.html#:~>

[30] As of January 2023

Figure 17: 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 6 years, as shown in Figure 17. The Company attributes this lag in adoption to a variety of factors discussed in the Company's Electric Vehicle Supply Equipment ("EVSE") filing.[31] 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 2023 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. The Medium and High DER scenarios differ from the base case outlook. In the Medium DER scenario, Minnesota Power's assumed light-duty EV penetration levels are only three years behind the national average. In the high scenario, Minnesota Power's light-duty EV penetration level remains about three years behind the nation through 2027, about 2 years behind the national average through 2035.

Fleet vehicles and commercial charging are not addressed in AFR 2023 and therefore are not included in Minnesota Power's Base case scenario. The Medium and High DER cases both include assumptions for medium- and heavy-duty EV adoption. The Medium DER case forecast for medium- and heavy-duty vehicles matches the Base case light-

[31] Docket No. E015/M-21-257

duty penetration rate forecast. The High DER case forecast for medium- and heavy-duty vehicles matches the High DER case light duty penetration rate forecast.

The outlooks for number of light-, medium- and heavy-duty vehicles, energy consumption, and summer peak impacts under the three scenarios is shown in Table 6, Table 7, and Table 8.

Table 6: Electric Vehicle Adoption

| **Base Case (000s)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Light Duty** | 0.6 | 0.8 | 1.1 | 1.4 | 1.7 | 2.2 | 3.0 | 4.3 | 6.4 | 9.5 | 13.3 | 17.9 | 23.2 |
| **Medium Duty** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Heavy Duty** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | |
| **Medium Case (000s)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **Light Duty** | 1.4 | 1.7 | 2.2 | 3.0 | 4.3 | 6.4 | 9.4 | 13.2 | 17.8 | 23.0 | 28.9 | 35.1 | 41.2 |
| **Medium Duty** | 0.0 | 0.1 | 0.1 | 0.1 | 0.1 | 0.2 | 0.2 | 0.3 | 0.4 | 0.7 | 0.9 | 1.2 | 1.6 |
| **Heavy Duty** | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.4 |
| | | | | | | | | | | | | | |
| **High Case (000s)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| **Light Duty** | 1.4 | 1.7 | 2.2 | 3.0 | 4.3 | 9.4 | 13.2 | 17.7 | 23.0 | 28.9 | 35.0 | 41.2 | 47.0 |
| **Medium Duty** | 0.1 | 0.1 | 0.2 | 0.2 | 0.3 | 0.6 | 0.9 | 1.2 | 1.6 | 2.0 | 2.4 | 2.9 | 3.3 |
| **Heavy Duty** | 0.0 | 0.0 | 0.0 | 0.1 | 0.1 | 0.2 | 0.3 | 0.3 | 0.4 | 0.6 | 0.7 | 0.8 | 0.9 |

Table 7: Electric Vehicle Energy Consumption

| Base Case (GWh) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Light Duty | 1.5 | 2.1 | 2.8 | 3.4 | 4.3 | 5.5 | 7.5 | 10.8 | 16.1 | 23.8 | 33.5 | 45.1 | 58.4 |
| Medium Duty | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Heavy Duty | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | **1.5** | **2.1** | **2.8** | **3.4** | **4.3** | **5.5** | **7.5** | **10.8** | **16.1** | **23.8** | **33.5** | **45.1** | **58.4** |
| | | | | | | | | | | | | | |
| **Medium Case (GWh)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| Light Duty | 2.6 | 4.3 | 4.6 | 6.6 | 9.9 | 15.2 | 22.8 | 32.4 | 44.0 | 57.2 | 72.0 | 87.6 | 103.1 |
| Medium Duty | 0.5 | 0.7 | 1.0 | 1.2 | 1.5 | 1.9 | 2.6 | 3.7 | 5.5 | 8.2 | 11.5 | 15.4 | 20.0 |
| Heavy Duty | 1.1 | 1.6 | 2.1 | 2.6 | 3.2 | 4.1 | 5.6 | 8.1 | 12.0 | 17.7 | 24.9 | 33.6 | 43.5 |
| **Total** | **4.2** | **6.6** | **7.7** | **10.4** | **14.6** | **21.2** | **31.0** | **44.2** | **61.5** | **83.1** | **108.4** | **136.7** | **166.5** |
| | | | | | | | | | | | | | |
| **High Case (GWh)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| Light Duty | 3.4 | 4.3 | 5.5 | 7.5 | 10.8 | 23.6 | 33.2 | 44.7 | 57.9 | 72.7 | 88.3 | 103.8 | 118.4 |
| Medium Duty | 1.2 | 1.5 | 1.9 | 2.6 | 3.7 | 8.1 | 11.3 | 15.3 | 19.8 | 24.9 | 30.2 | 35.5 | 40.5 |
| Heavy Duty | 2.5 | 3.2 | 4.1 | 5.6 | 8.0 | 17.6 | 24.7 | 33.3 | 43.1 | 54.1 | 65.7 | 77.2 | 88.1 |
| **Total** | **7.1** | **9.0** | **11.5** | **15.6** | **22.4** | **49.2** | **69.2** | **93.3** | **120.8** | **151.7** | **184.2** | **216.4** | **246.9** |

Table 8: Electric Vehicle Summer and Winter Peak Impact (MW)

| Summer Peak Impact (MW) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base Case | 0.0 | 0.1 | 0.2 | 0.3 | 0.4 | 0.6 | 0.8 | 1.2 | 1.9 | 2.8 | 4.0 | 5.5 | 7.1 |
| Medium DER | 0.4 | 0.7 | 0.8 | 1.2 | 1.7 | 2.5 | 3.7 | 5.4 | 7.5 | 10.2 | 13.4 | 16.9 | 20.6 |
| High DER | 0.7 | 1.0 | 1.3 | 1.8 | 2.7 | 6.0 | 8.5 | 11.5 | 14.9 | 18.8 | 22.8 | 26.8 | 30.6 |
| | | | | | | | | | | | | | |
| **Winter Peak Impact (MW)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| Base Case | 0.1 | 0.4 | 0.6 | 0.8 | 1.2 | 1.6 | 2.3 | 3.5 | 5.5 | 8.3 | 11.8 | 16.1 | 20.9 |
| Medium DER | 1.1 | 2.0 | 2.4 | 3.4 | 4.9 | 7.3 | 10.9 | 15.7 | 22.0 | 29.9 | 39.2 | 49.5 | 60.4 |
| High DER | 2.2 | 2.9 | 3.8 | 5.3 | 7.8 | 17.6 | 24.9 | 33.6 | 43.7 | 55.0 | 66.8 | 78.6 | 89.7 |

### 3. Commercial (Public) EV Charging

Public EV charging was projected as part of the Company's analysis for its April 8, 2021 DCFC Infrastructure filing.[32] This forecast of public charging station demand were included in two higher adoption 2023 IDP scenarios, but pushed back one year due to DCFC installation delays explained in Section II.A.

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 number of charging sessions and overall usage on each proposed charger was estimated by Minnesota Power using regression analysis. The Company leveraged two years of usage data at 12 existing DCFC stations and analyzed how usage varied among these 12 stations according to three variables: proximate traffic, non-Tesla EV ownership (county), and employment (city). These three variables explain about 40

[32] Docket No. E015/M-21-257

percent of the variance among 12 distinct stations located in both urban and suburban areas.

The Company then gathered traffic, EV ownership, and employment information on each of its anticipated locations, and modeled the number of sessions and overall usage at each location as if they had been operating in 2019.[33] This estimate of 2019 charging sessions and usage was escalated per the Company's forecast of regional EV adoption as filed in its 2021 AFR.

The resulting estimates suggest the 16 DCFC stations will add about 1,000 MWh of energy use by 2030 and contribute about 0.2 MW to Minnesota Power's 2030 summer peak. By 2035, the 16 DCFC EV charging stations would add about 2,900 MWh of annual energy use and about 0.4 MW to summer peak demand. Table 9 below shows the projected annual energy consumption by these 16 DCFC EV charging stations under each of the three forecast scenarios.

Table 9: Projected Annual Energy Consumption

| Energy Consumed (MWh) | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Base | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Medium | - | 232 | 322 | 427 | 524 | 653 | 818 | 1,013 | 1,265 | 1,619 | 2,097 | 2,519 | 2,859 |
| High | - | 232 | 322 | 427 | 524 | 653 | 818 | 1,013 | 1,265 | 1,619 | 2,097 | 2,519 | 2,859 |
| | | | | | | | | | | | | | |
| **Summer Peak Impact (MW)** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** |
| Base | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Medium | - | 0.04 | 0.05 | 0.06 | 0.08 | 0.10 | 0.12 | 0.15 | 0.19 | 0.24 | 0.32 | 0.38 | 0.43 |
| High | - | 0.04 | 0.05 | 0.06 | 0.08 | 0.10 | 0.12 | 0.15 | 0.19 | 0.24 | 0.32 | 0.38 | 0.43 |

The forecast for load and energy added as a result of these public charging stations was excluded from the base 2023 IDP forecast, but is included under the medium and high 2023 IDP scenarios. Both the medium and high scenarios leverage the same outlook for public charging load.

### 4. Residential Time-of-Day Rate

Time-of-Day residential rate impacts are also captured in 2023 IDP scenario planning. The Company's approved Petition for Changes to Minnesota Power's Residential Rate

[33] The Company modeled only the 2019 usage data since 2020 travel was notably impacted by COVID-19.

Design[34] 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. The associated rate specifications are shown in Table 10.

Table 10: Current TOD Rates ($/kWh) and Hours

| | | | | |
|---|---|---|---|---|
| **Standard Rate** | $ 0.08384 | | | |
| | | | | |
| **TOD Period** | **Adder** | **Std Rate + Adder** | **Weekday Hours** | **Weekend Hours** |
| On-Peak | $ 0.03667 | $ 0.1205 | 3 pm to 8 pm | N/A |
| Off-Peak | $ (0.00239) | $ 0.0815 | 5 am to 3 pm; 8 pm to 11 pm | 5 am to 11 pm |
| Super Off-Peak | $ (0.02677) | $ 0.0571 | 11 pm to 5 am | 11 pm to 5 am |

The Company conducted an elasticity[35] analysis using peak period pricing and observed customer load behavior from its legacy TOD Pilot participants. Based on this data, the Company estimates a price elasticity of about -0.35, i.e. a 10 percent increase in the price of electricity led to a 3.5 percent decrease in quantity demanded. As more customers enroll in the new TOD rate, the Company will begin re-evaluating price elasticity with updated data.

This -0.35 elasticity estimate was applied to the on-peak price where the on-peak price (12.05 cents/kWh) reflects a roughly 44 percent increase over base residential rates (8.384cents/kWh). According to this analysis, it would result in an estimated 15 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 0.17 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 20-21MW. Table 11 shows the summer peak demand reduction under each of the three scenarios.

[34] Docket No. E015/M-20-850, Docket No. E015/M-12-233

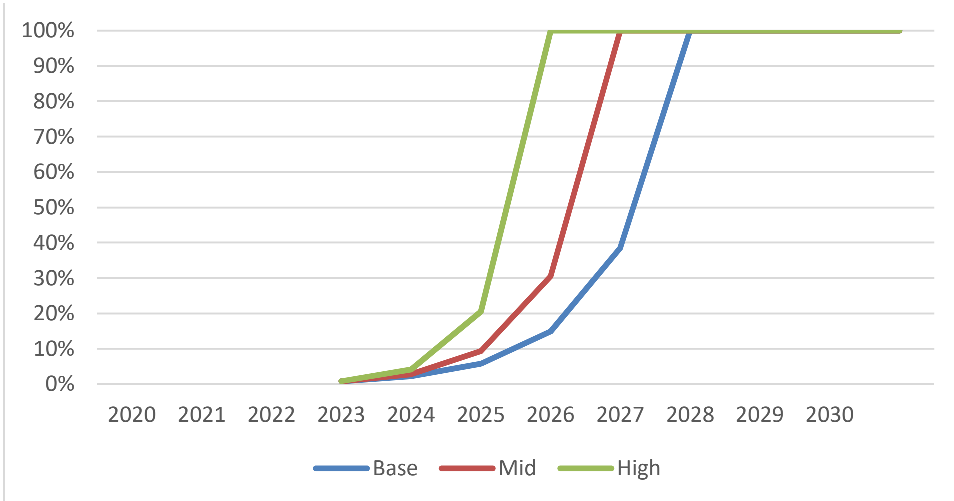
[35] Elasticity (price elasticity of demand) measures the percent change in electricity demand resulting from a percent change in price.

Table 11: Summer Peak Demand Reduction

| Summer Peak Impact (MW) | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Base** | (1.1) | (3.0) | (7.7) | (20.0) | (20.4) | (20.4) | (20.5) | (20.5) | (20.6) | (20.6) | (20.7) | (20.7) | (20.8) | (20.8) |
| **Medium** | (1.8) | (6.1) | (20.0) | (20.3) | (20.4) | (20.4) | (20.5) | (20.5) | (20.6) | (20.6) | (20.7) | (20.7) | (20.8) | (20.8) |
| **High** | (4.1) | (19.9) | (20.3) | (20.3) | (20.4) | (20.4) | (20.5) | (20.5) | (20.6) | (20.6) | (20.7) | (20.7) | (20.8) | (20.8) |

The 2023 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 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 it is currently more realistic to assume the earliest all residential customers would be transitioned to the new TOD rate is 2026. 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 2028, the "Mid" or Medium case assume full participation by 2027, and the high case assume 100 percent participation by 2026.

Figure 18: TOD Participation by Scenario




5. Impact of Increased DER Adoption Rates on Planning Processes and Tools

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. Distribution 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 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 impacts 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 DER adoption 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 distribution 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 adoption grows significantly beyond recent adoption rates on the distribution system.

6. Institute of Electrical and Electronic Engineers ("IEEE") Std. 1547-2018[36] Impacts

Minnesota Power closely monitors advances in inverter technology via participation in the Distribution Generation Working Group, conversations with customers and installers, and various other industry groups. 2021 IDP, Minnesota Power has filed and implemented an update to its first Technical Specifications Manual and the primary deviation from previous

[36] NERC.<https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/IEEE%20SCC21_1547_Overview_NERC_SPIDERWG_01072019.pdf>
NRECA.<https://www.cooperative.com/programs-services/bts/Documents/Reports/NRECA-Guide-to-IEEE-1547-2018-March-2019.pdf>

practices in terms of inverters setting were adding abnormal voltage ride-through and tripping settings as well as frequency ride-through and tripping settings.

While Minnesota Power's overall DER penetration level is low, there are a handful of feeders on which the penetration is high relative to the load. Minnesota Power presently has five feeders or substations, Blanchard 508 feeder, Wrenshall 411 feeder, Platte River 546 feeder, Laskin Substation, and Baxter Substation which have DER installations with a generation nameplate capacity greater than or equal to the feeder's daytime minimum load. The Blanchard 508 feeder circuit, which includes the 10 MWac Camp Ripley solar facility, has a 2022 daytime minimum load of 1.98 MW. On the Wrenshall 411 feeder circuit, which includes the 1.00 MWac Wrenshall solar garden, has a 2022 daytime minimum load of 0.77MW. The Platte River 546 feeder circuit includes three large customer-installed solar arrays with a cumulative nameplate output of 1.75 MW. This feeder has an estimated 2022 daytime minimum The Laskin Substation, which includes the 5.6 MWac Laskin solar facility, has a 2022 daytime minimum load of 0.94 MW. The Baxter Substation, which includes the 15.2 MW Sylvan solar facility, has a 2022 daytime minimum load of 2.36 MW.

Over the years, Minnesota Power has experienced a number of relatively small issues related to customer solar installations. As discussed in the 2021 IDP, Minnesota Power had to adjust the taps on a transformer for its own 40 kW solar garden. In the last two years, one customer experienced issues with their inverter tripping offline unexpectedly due to voltage rise. The Company was able to identify undersized secondary wire and upgraded accordingly.

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. Minnesota Power will be moving to a new modeling software in the next two years and reevaluating planning tools for increased DER penetration across the service territory.

## D. Historical Loading and 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. Peak load information is gathered annually in order 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 649 MW on January 25, 2022 at 8:00 AM. This information is taken from hourly historical loading data collected between January 1, 2022 and December 31, 2022.

As historical peak load information was evaluated by feeder and substation for the 2021-2022 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 2021 and 2022 are provided in Appendix H. 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.

## E. 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 advanced metering infrastructure 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. It is prudent to consider customer programming that 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 previously discussed, the EV and EV infrastructure service markets are young and still evolving. Minnesota Power continues to work closely with industry partners to secure the most cost-effective, reliable, and affordable EV infrastructure available.

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 Photovoltaic Impacts

Solar is being deployed on widely varying scale 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. An example may be a solar powered retail center or housing development 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. This will require clear policy frameworks for leveraging resources to investigate and plan for DER integration in a well-managed and advantageous manner.

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. 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 and tax credits are still needed to 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 current efforts to modernize its metering infrastructure. Now that the meter rollout is nearly complete, it will still take some time to fully realize the many potential benefits and programs enabled by advanced metering and the 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.

4. 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 in regard to 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 is metering, operational, and wholesale market issues that arise due to the possible participation of DERs in wholesale RTO or ISO markets.

As a result, Minnesota Power would most likely file a tariff with FERC to address DER participation in wholesale markets. At a high level these tariffs would address distribution system upgrade costs, metering capability, reliability assurance mechanisms, and cost recovery.

# CONCLUSION

## V. CONCLUSION

Minnesota Power's 2023 IDP provides an overview of the Company's current distribution planning processes and future investment plans. Historical spend and planning has positioned the Company for a seamless transition to an innovative future to meet customers' needs and expectations. The foundational investments are built upon the Company's Core Values and distribution strategy of technology, innovation, and continuous learning. The Company has demonstrated these values by focusing on right time, right fit investments and by thoughtfully leveraging internal and external resources in a cost-conscious manner to test the advanced technology required for innovative customer programming and a more technically advanced distribution grid. This IDP has expanded on the NWA and benefit-cost analysis as requested by stakeholders.

Throughout this IDP the Company has illustrated how it is maintaining and enhancing safety, security, reliability, and resilience of the grid through a thoughtful planning process and proactive engagement with the latest trends in grid security and customer privacy. Minnesota Power's culture of continuous improvement aligns with the Commission's planning objectives.

The results of this customer-focused, thoughtful planning process are evidenced by Minnesota Power's leadership in the state of Minnesota in AMI implementation, exceedance of the state's energy savings goals year-over-year, and piloting of innovative rate structures such as TOD. These initiatives compliment 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 more than 50 percent renewable to customers. Minnesota Power is thoughtfully transforming its energy supply while investing in the grid to ensure reliable, affordable and increasingly clean energy for customers.

Moving towards the future, Minnesota Power is executing its distribution plan, focusing ongoing efforts to support customers, communities, the climate, and the Company. Above all else, customers expect reliable, affordable, and safe electric service, all of which are encompassed in Minnesota Power's distribution values. The thoughtful system investments currently taking place provide a foundation for Minnesota Power to continue advancing innovative customer programming, along with additional investment in grid modernization pilots and initiatives. The investments and programs outlined in this 2023 IDP will create greater customer engagement, empowerment, and options for energy services; and this connective model will support the development and integration of DER technologies and enhance the value of their application as it relates to grid operations. Minnesota Power is proud to share its vision for a resilient future through this 2023 IDP.

Dated: October 16, 2023

Respectfully Submitted,

Jess McCullough
Public Policy Advisor II
Minnesota Power
30 West Superior Street
Duluth, MN 55802
(218) 355-3178
jmccullough@mnpower.com