minnesota power
AN ALLETE COMPANY

2023 Integrated Distribution Plan

Docket No. E015/M-23-258

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 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))

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

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

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

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

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

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TABLE OF 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

I. Introduction

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's 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:

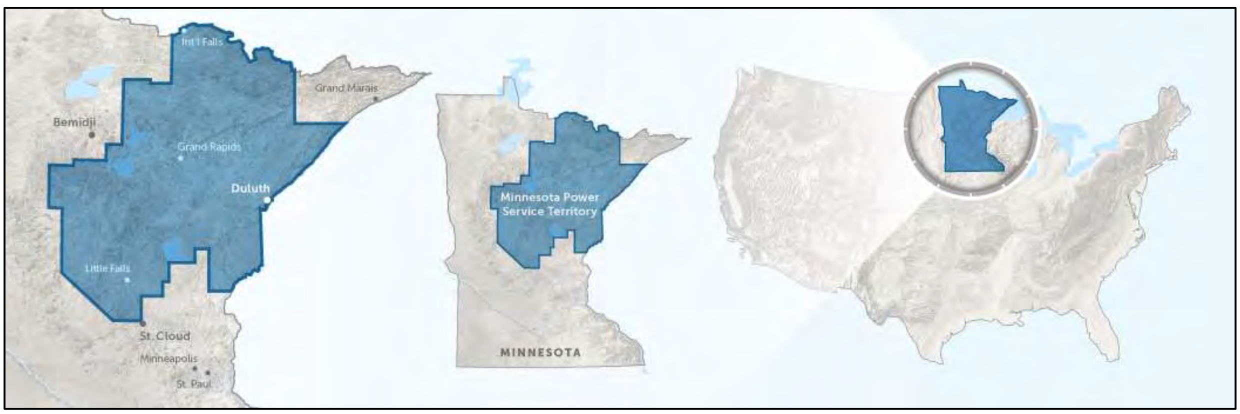
- Analysis of how the information in the IDP relates to each Planning Objective;
- The location in the IDP;
- Analysis of efforts taken by the Company to improve upon the fulfillment of the Planning Objectives; and
- Suggestions as to any refinements to the IDP filing requirements that would enhance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

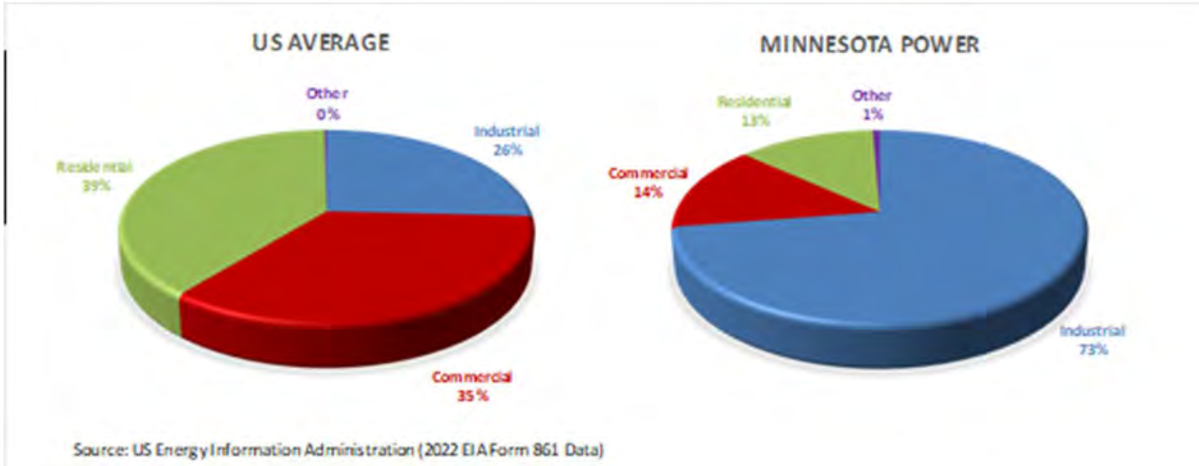
Minnesota Power is transforming the way it energizes communities and businesses through its *Energy**Forward*** resource strategy. First incorporated in 1906, Minnesota Power serves electricity to 150,000 customers, 14 municipal systems, and some of the nation's largest industrial customers across northeastern 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

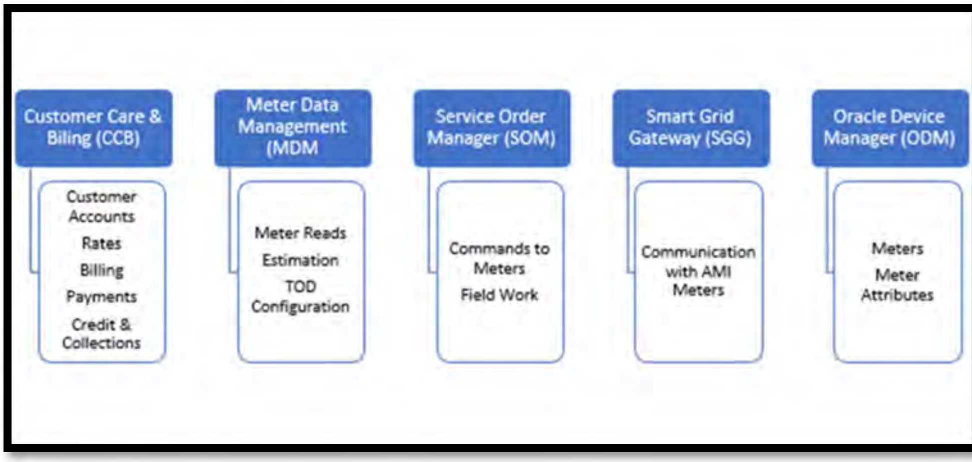
The following sections provide a brief overview of each system critical to the operation of the Company's distribution system. All existing and new systems are necessary for ensuring electric service regardless of this distribution plan, and the Company would not attribute the costs of obtaining data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

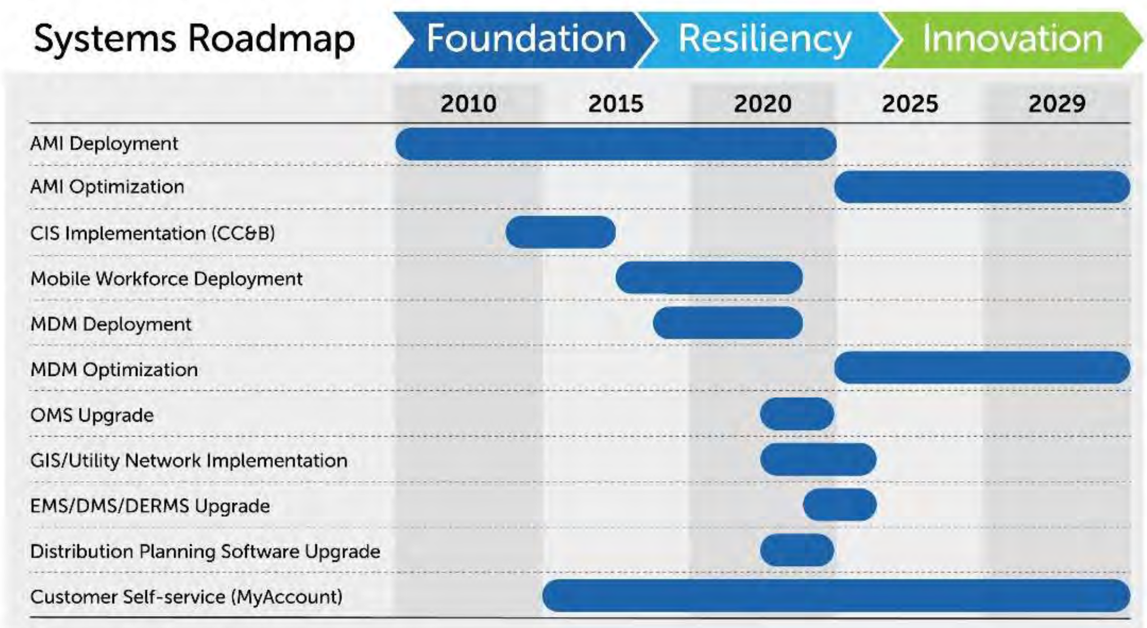
40 years old, asset management programs and investments have increasingly become an area of significant focus for Minnesota Power. Asset renewal programs have been bolstered in recent years in an effort to target areas known to impact customer reliability and system resiliency. Minnesota Power has taken 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



II. Current DER programming and 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.

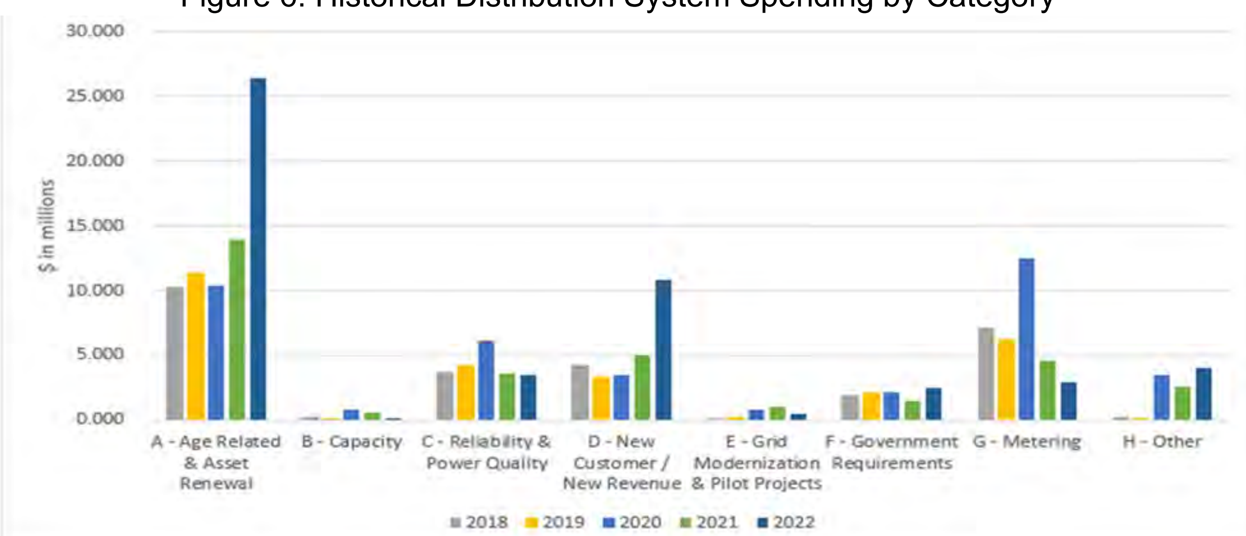
Minnesota Power has traditionally followed a depreciation level spending pattern for its distribution system. The historical annual expenditures depicted in Figure 6: Historical Distribution System Spending by Category reflect depreciation level spend until 2021. Budgets are adjusted annually to meet 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.

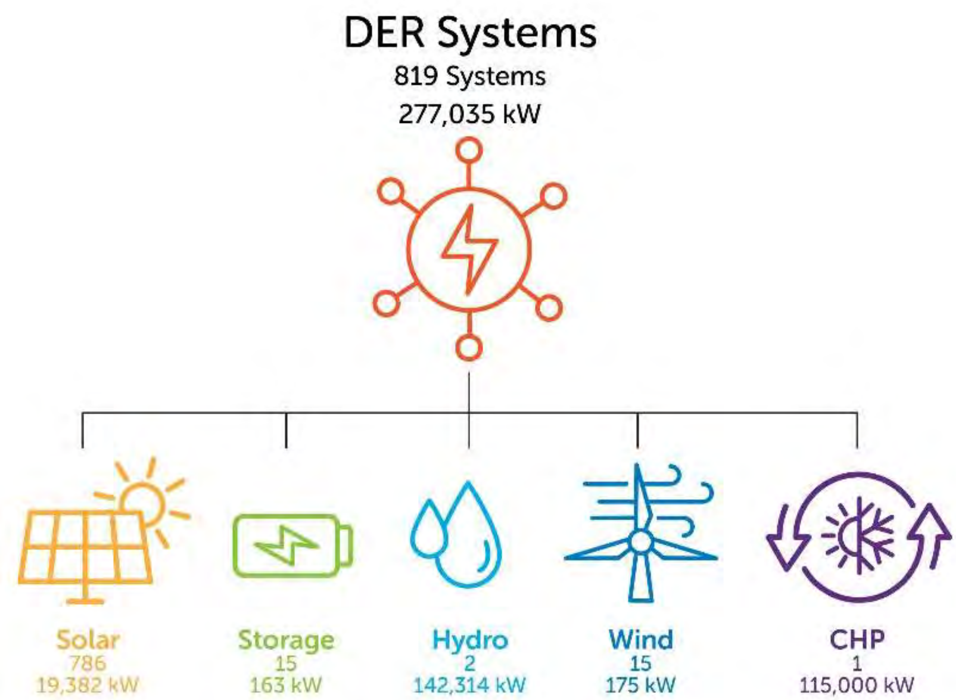
1. DER Systems

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

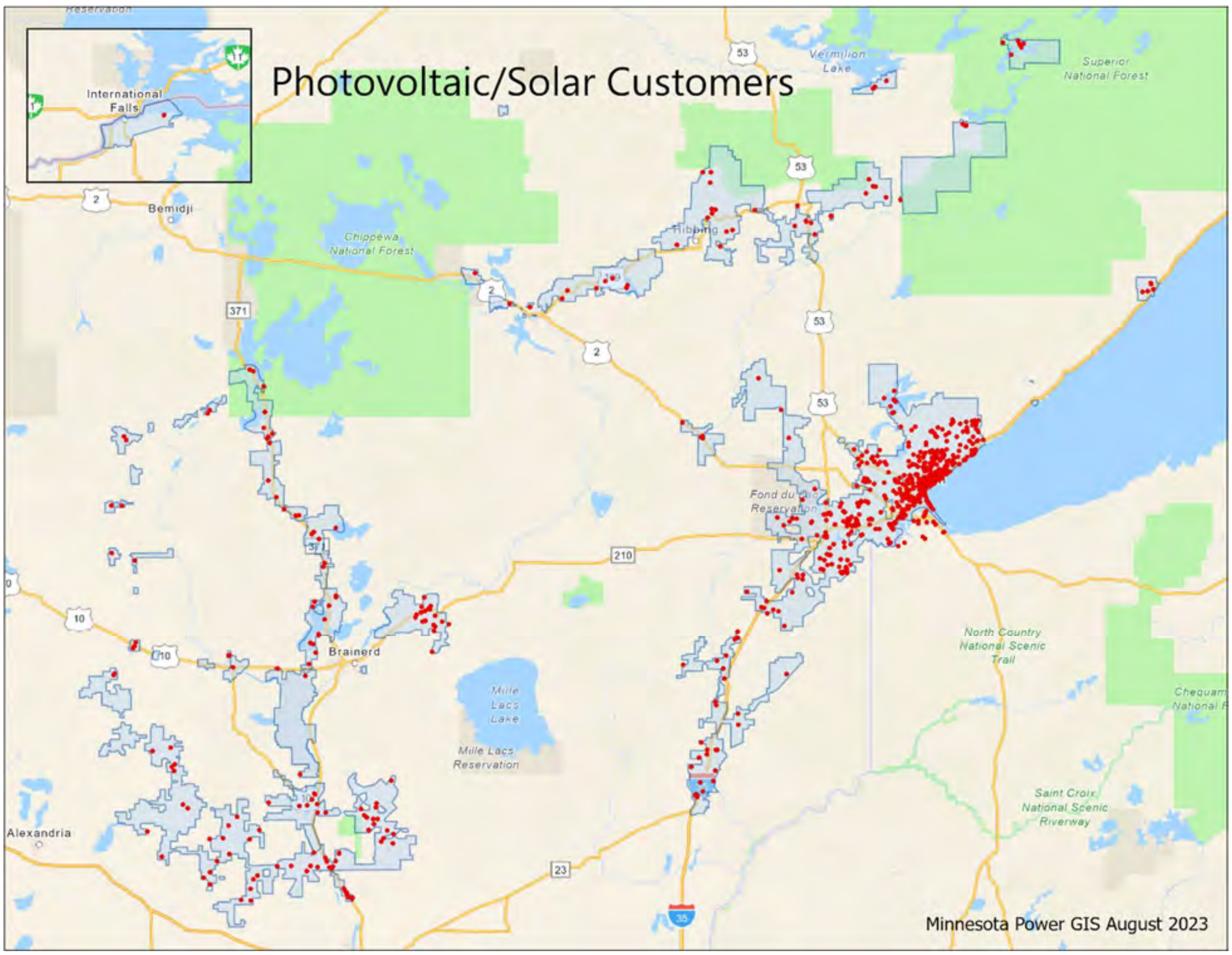
Following the passage of the Minnesota Solar Energy Standard ("SES"), Minnesota Power developed a thoughtful solar strategy that included activities balanced across three key pillars: Utility, Community, and Customer. Minnesota Power continues to see solar investments at the utility scale creating efficiencies 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.

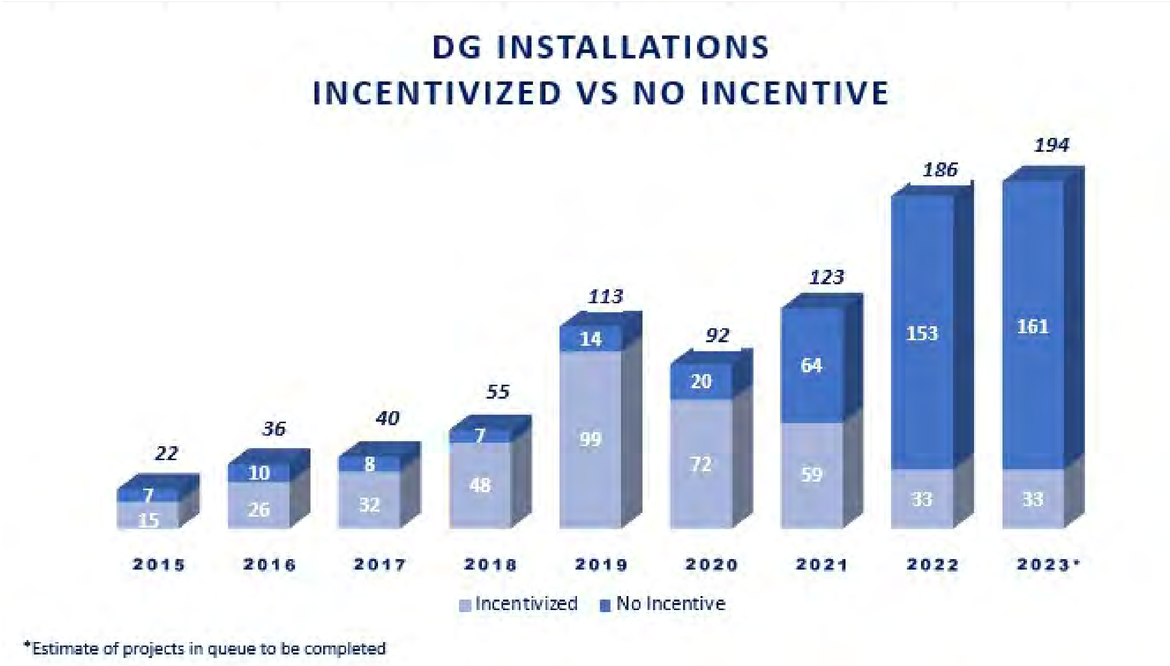
Until 2020, roughly 80 percent of all solar interconnections in Minnesota Power's service territory received a SolarSense rebate, demonstrating that rebates were critical to driving the solar market. Interconnection activity has grown significantly since the SolarSense program has been in place and continues 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

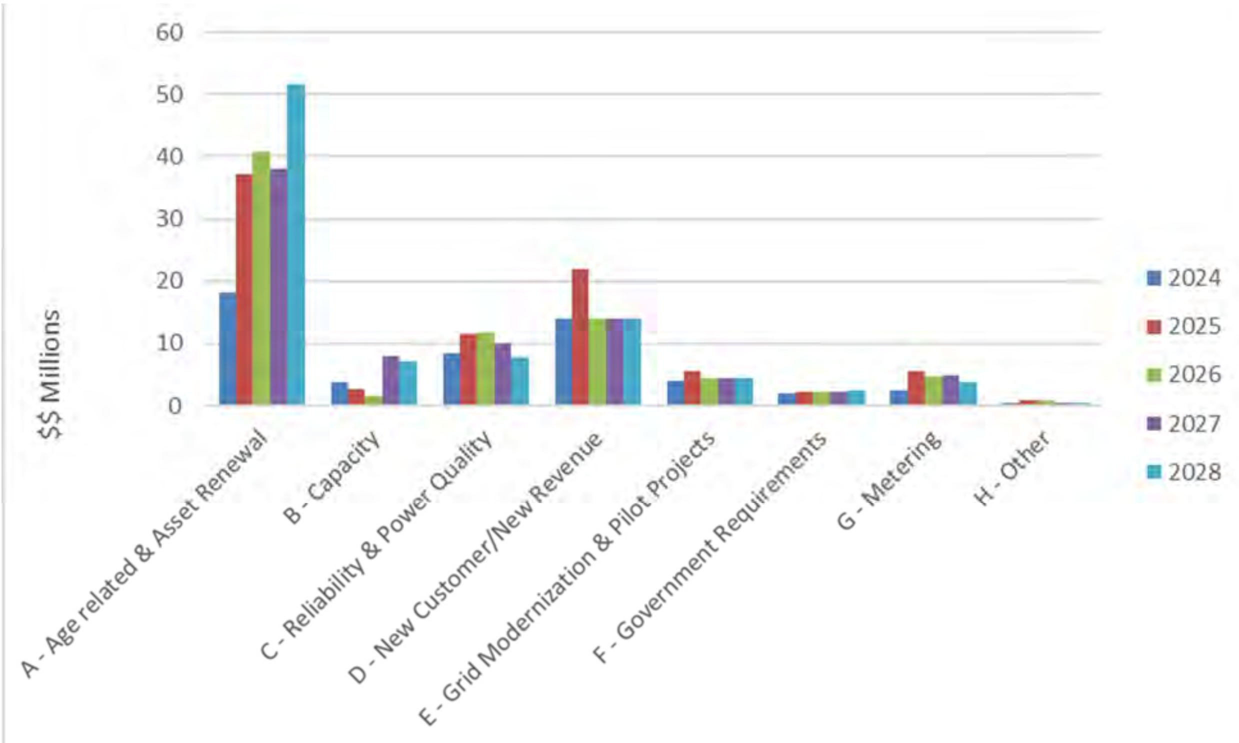


Table 3: Five Year Future Investments by Category

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 **(Asset Renewal)**	$8.0M $4.2M	2026 2028	*Anticipated Substations*:* Haines Road (Hermantown) Colbyville (Duluth) **subject to change based on asset renewal project prioritization*
Substation Modernization Program **(Asset Renewal)**	$10.4M $6.0M $7.4M $9.9M $8.8M $6.9M $6.7M $10.9M	2024 2025 2025 2026 2026 2027 2027 2027	*Anticipated Substations*:* Long Prairie, Winton, Maturi (Chisholm), Ridgeview (Duluth), Hibbing, Verndale, Cloquet, Little Falls **subject to change based on asset renewal project prioritization*
Cloquet Area 34 kV Expansion	$2.2M $6.6M	2023 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.

III. 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

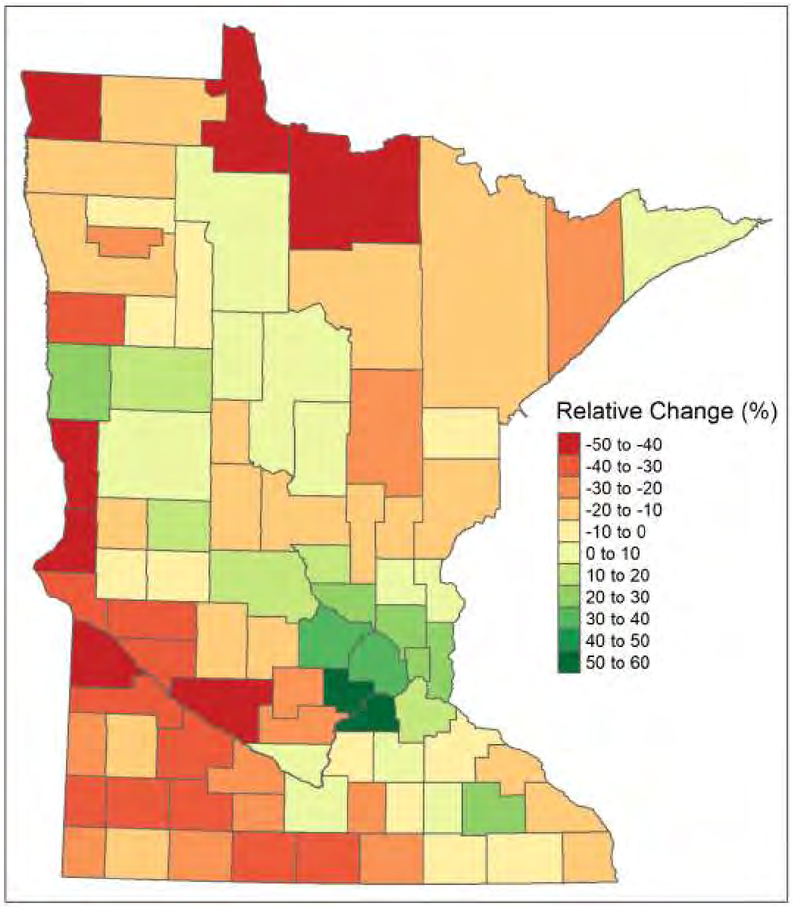
[23] For purposes of the discussion in this subsection of the 2021 IDP, non-wires solutions do not encompass demand response or energy efficiency initiatives. Those programs are addressed in other sections of this Plan.

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>

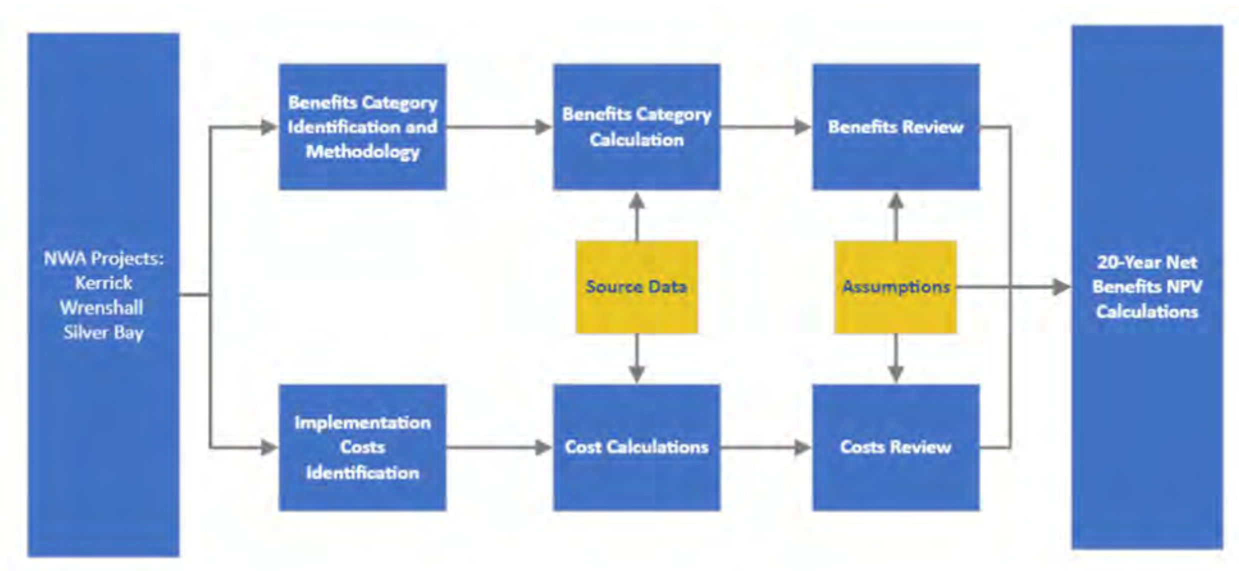
The BCA Framework Report summarizes Black & Veatch's efforts to develop a realistic business case for evaluation and justification of NWA projects in Minnesota Power's service territory. The process of developing this framework included the following steps:

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

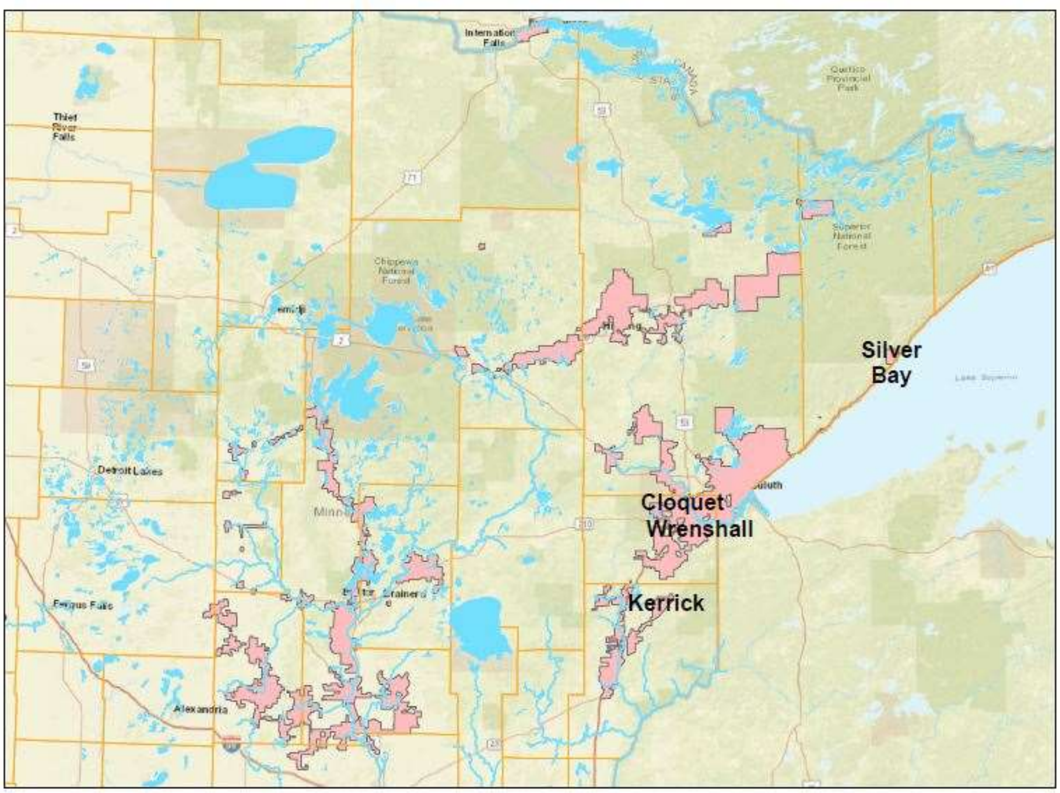
The Silver Bay NWA Solution Report describes the evaluation and recommendations from Black & Veatch and its subconsultant K&A Engineering for the Silver Bay Scenario. The City of Silver Bay was formerly served solely by the Silver Bay Hillside 115/13.8 kV Substation, including approximately 1,348 customers 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



IV. Planning for a resilient 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.

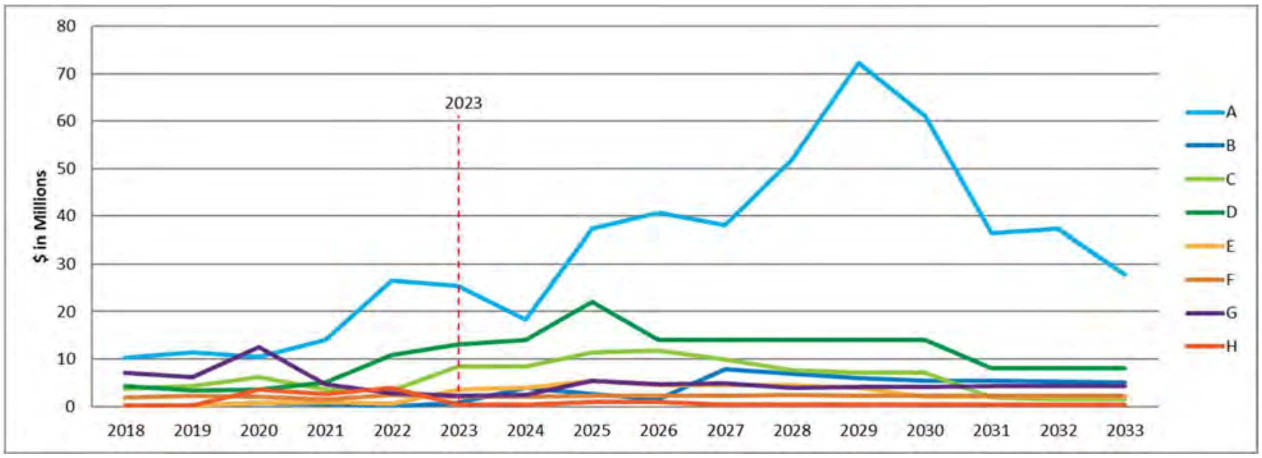
The numbers in the Company's forecasts below do not reflect the latest "3% by 2030" Distributed Generation requirements added to Minnesota Statute 216B.1691 Renewable Energy Objectives. Subd. 2h. The Company is aware of these requirements and will report on them in Docket No. E002,E015,E017/CI-23-403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

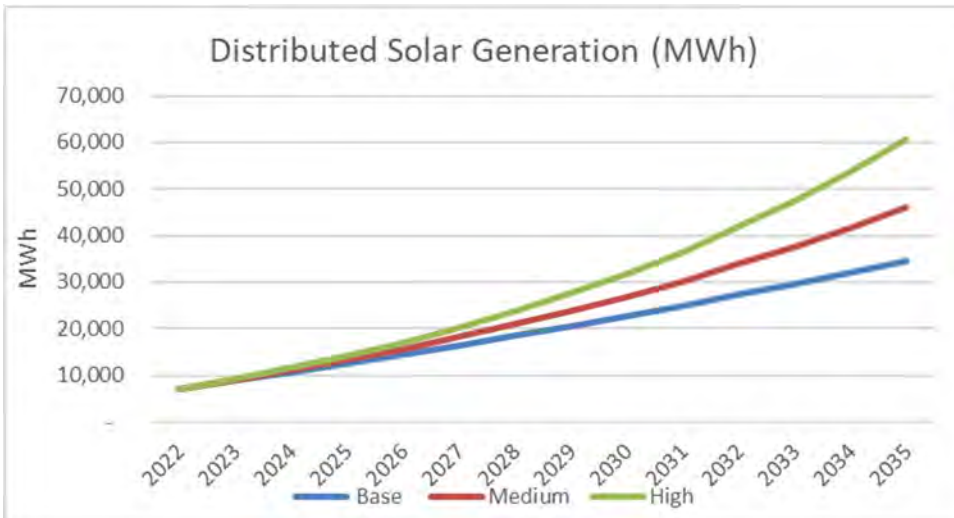


Figure 16: Distributed Solar Generation (Summer Peak)

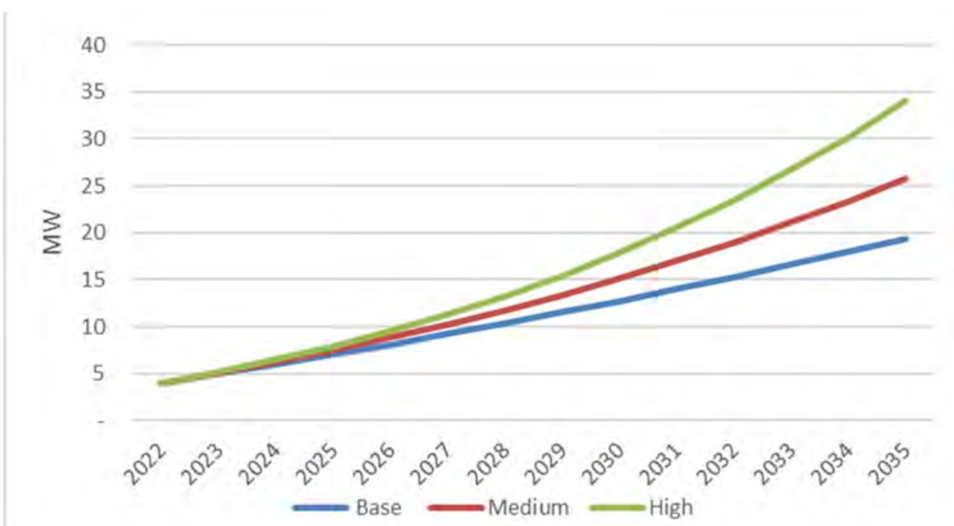


Table 7: Total Distributed Generation under three Forecast Scenarios

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.

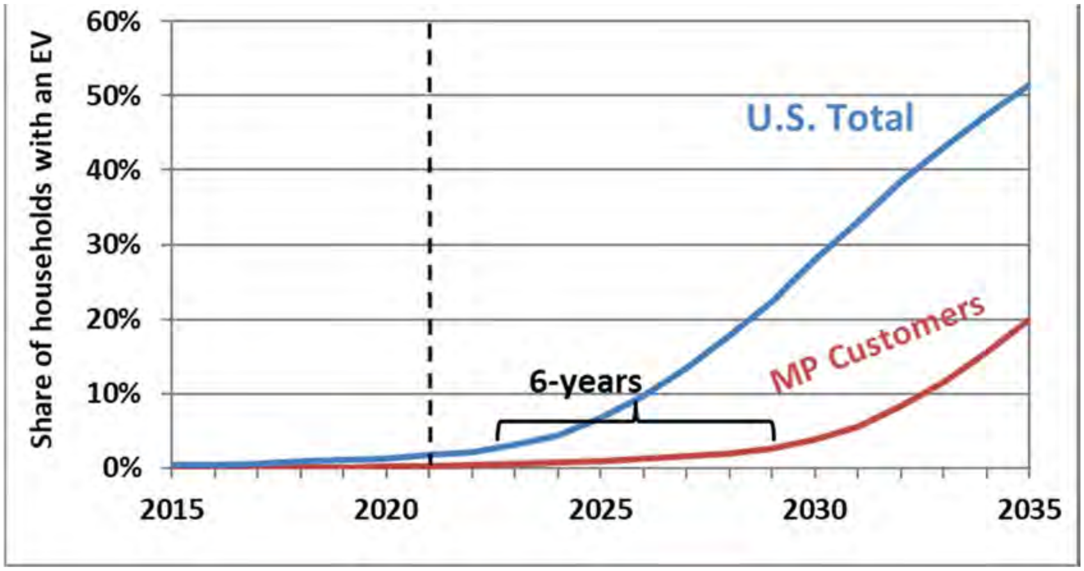
The Company estimates there are about 500 light duty EVs (i.e. passenger vehicles) in Minnesota Power's retail service territory.[30] This equates to a 0.26 percent penetration rate. This level of vehicle ownership translates to an estimated 1,262 MWh of annualized energy consumption and represents just 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

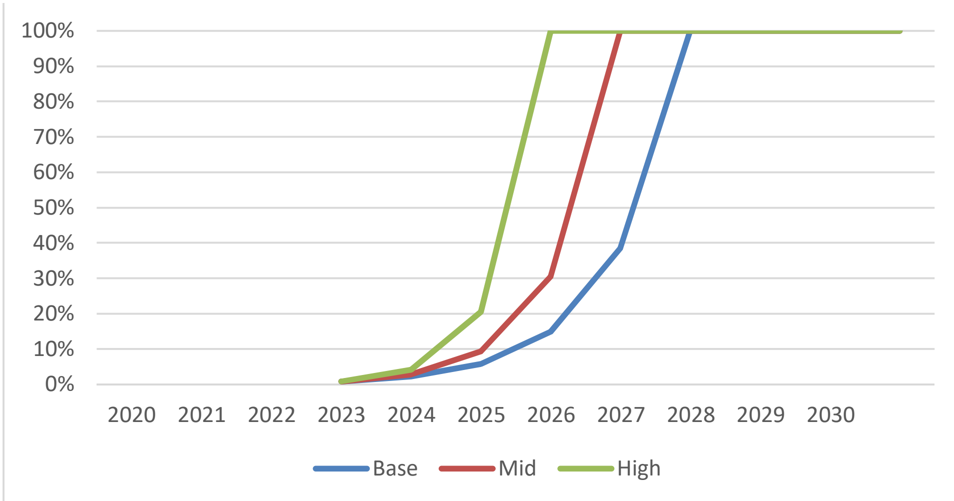
[35] Elasticity (price elasticity of demand) measures the percent change in electricity demand resulting from a percent change in price.

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.

V. 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,

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Appendices

Heading	PUC IDP Requirement	Location in Document
Baseline Distribution System and Financial Data (System Data)	Modeling software currently used and planned software deployments	1.E, 2.C, 2.H, 4.A
Baseline Distribution System and Financial Data (System Data)	Percentage of substations and feeders with monitoring and control capabilities, planned additions	2.H.1
Baseline Distribution System and Financial Data (System Data)	A summary of existing system visibility and measurement (feeder-level and time interval) and planned visibility improvements; include information on percentage of system with each level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)	2.H.2
Baseline Distribution System and Financial Data (System Data)	Number of customer meters with AMI/smart meters and those without, planned AMI investments, and overview of functionality available	2.H.2
Baseline Distribution System and Financial Data (System Data)	Discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans	1.B.1, 3.B, 4.C
Baseline Distribution System and Financial Data (System Data)	Discussion of how DER is considered in load forecasting and any expected changes in load forecasting methodology	4.C

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 **APPENDIX A**

Baseline Distribution System and Financial Data (System Data)	Discussion if and how IEEE Std. 1547-20185 impacts distribution system planning considerations (e.g. opportunities and constraints related to interoperability and advanced inverter functionality)	4.C.6
Baseline Distribution System and Financial Data (System Data)	Distribution system annual loss percentage for the prior year (average of 12 monthly loss percentages)	Appendix D, 1.C
Baseline Distribution System and Financial Data (System Data)	The maximum hourly coincident load (kW) for the distribution system as measured at the interface between the transmission and distribution system. This may be calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems	4.D
Baseline Distribution System and Financial Data (System Data)	Total distribution substation capacity in kVA	Appendix C
Baseline Distribution System and Financial Data (System Data)	Total distribution transformer capacity in kVA, if different from total distribution substation capacity and the reason for the difference.	Appendix C
Baseline Distribution System and Financial Data (System Data)	Total miles of overhead distribution wire	3.4
Baseline Distribution System and Financial Data (System Data)	Total miles of underground distribution wire	3.4

Baseline Distribution System and Financial Data (System Data)	Total number of distribution customers	1.B
Baseline Distribution System and Financial Data (System Data)	Total costs spent on DER generation installation in the prior year. These costs should be broken down by category (including application review, responding to inquiries, metering, testing, make ready, etc).	2.A.4
Baseline Distribution System and Financial Data (System Data)	Total charges to customers/member installers for DER generation installations, in the prior year. These costs should be broken down by category in which they were incurred (including application, fees, metering, make ready, etc.)	2.A.4
Baseline Distribution System and Financial Data (System Data)	Total nameplate kW of DER generation system which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	2.A.4
Baseline Distribution System and Financial Data (System Data)	Total number of DER generation systems which completed interconnection to the system in the prior year, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	2.A.4
Baseline Distribution System and Financial Data (System Data)	Total number and nameplate kW of existing DER systems interconnected to the distribution grid as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	2.A.1, Figure 7
Baseline Distribution System and Financial Data (System Data)	Total number and nameplate kW of queued DER systems as of time of filing, broken down by DER technology type (e.g. solar, combined solar/storage, storage, etc.)	Appendix C

Baseline Distribution System and Financial Data (System Data)	Total number of electric vehicles in service territory, by type where possible (e.g. light duty, transit, medium duty, heavy duty)	2.A.3, Appendix E
Baseline Distribution System and Financial Data (System Data)	Total number and capacity of public access electric vehicle charging stations, broken out by: a. Number and capacity of known public access Level 2 Charging Stations7 b. Number and capacity of Level 2 Charging Stations enrolled in a utility program, broken out by program8 c. Number and capacity of known public access direct current fast charging (DCFC) stations9 d. Number and capacity of DCFC installed through a utility EV program, broken out by program10 e. All other known EV charging stations (by type, ex DCFC, Level 2)	2.1.3, Appendix E
Baseline Distribution System and Financial Data (System Data)	Number of units and MW/MWh ratings of battery storage	2.A.1, Figure 7, 3.A.5, 4.B.5
Baseline Distribution System and Financial Data (System Data)	MWh saving and peak demand reductions from EE program spending in previous year	2, Table 1
Baseline Distribution System and Financial Data (System Data)	Amount of controllable demand (in both MW and as a percentage of system peak)	2.A.2

Baseline Distribution System and Financial Data (financial Data)	Historical distribution system spending for the past 5-years, in each category: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements (road-relocations, etc.) g. metering h. other i. electric vehicle programs 1) capital costs 2)O&M costs 3)marketing and communications 4) Other (provide explanation of what is in "other")	2, Table 2, Figure 6
Baseline Distribution System and Financial Data (financial Data)	All non-Minnesota Power investments in distribution system upgrades (e.g. those required as a condition of interconnection) by subset (e.g. CSG, customer-sited, PPA, and other) and location (i.e. feeder or substation).	2.A.4
Baseline Distribution System and Financial Data (financial Data)	Projected distribution system spending for 5-years into the future for the categories listed above, itemizing any non-traditional distribution projects	2.E, Figure 9, Table 5

Baseline Distribution System and Financial Data (financial Data)	Planned distribution capital projects, including drivers for the project, timeline for improvement, and summary of anticipated changes in historic spending. Driver categories should include: a. Age-Related Replacements and Asset Renewal b. System Expansion or Upgrades for Capacity c. System Expansion or Upgrades for Reliability and Power Quality d. New Customer Projects and New Revenue e. Grid Modernization and Pilot Projects f. Projects related to local (or other) government-requirements g. Metering h. Other i. Electric Vehicle Programs12 1) Capital Costs 2) O&M Costs 3) Marketing and Communications 4) Other (provide explanation of what is in "other")	2.G
Baseline Distribution System and Financial Data (financial Data)	Provide any available cost benefit analysis in which the company evaluated a nontraditional distribution system solution to either a capital or operating upgrade or replacement	3.C
Baseline Distribution System and Financial Data (DER Deployment)	Current DER deployment by type, size, and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.)	2.A.1, 4.C.6
Baseline Distribution System and Financial Data (DER Deployment)	Information on areas of existing or forecasted high DER penetration. Include definition and rationale for what the Company considers "high" DER penetration.	4.C

Baseline Distribution System and Financial Data (DER Deployment)	Information on areas with existing or forecasted abnormal voltage or frequency issues that may benefit from the utilization of advanced inverter technology; provide information describing experiences where DER installations have caused operational challenges: such as, power quality, voltage or system overload issues.	4.E.2
Baseline Distribution System and Financial Data (Electric Vehicles)	A summary table with the following information for each EV rate offering or program during the reporting period: a. Number of customers and/or vehicles enrolled at the end of the reporting period b. Energy consumed (MWh) during the reporting period c. Peak demand (MW) during the reporting period and the time at which it occurred.	Appendix E
Baseline Distribution System and Financial Data (Electric Vehicles)	Any system upgrades performed to accommodate EV charging, total costs paid by utility and by customer, and average cost per upgrade. Cost should be reported separately for the following customer groups: Residential, Government Fleet, Private Fleet, and Public Charging, Other (specify).	2.A.3, Appendix E
Preliminary Hosting Capacity Data	Provide an excel spreadsheet (or other equivalent format) by feeder of either daytime minimum load (daily, if available) or, if daytime minimum load is not available, peak load (time granularity should be specified)	4.D, Appendix H

Distributed Energy Resource Scenario Analysis	In order to understand the potential impacts of faster-than-anticipated DER adoption, define and develop conceptual base-case, medium, and high scenarios regarding increased DER deployment on the distribution system. Scenarios should reflect a reasonable mix of individual DER adoption and aggregated or bundled DER service types, dispersed geographically across the Minnesota Power distribution system in the locations Minnesota Power would reasonably anticipate seeing DER growth take place first. For electric vehicle forecasts scenarios, Minnesota Power shall provide base-case, medium, and high adoption, capacity, and energy forecasts by sector (light duty, medium duty, and heavy duty). medium duty, and heavy duty).	4.C
Distributed Enery Resource Scenario Analysis	Include information on methodologies used to develop the low, medium, and high scenarios, including the DER adoption rates (if different from the minimum 10% and 25% levels), geographic deployment assumptions, expected DER load profiles (for both individual and bundled installations), and any other relevant assumptions factored into the scenario discussion. Indicate whether or not these methodologies and inputs are consistent with Integrated Resource Plan inputs.	4.C

Distributed Enery Resource Scenario Analysis	Provide a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER integration, including whether existing processes and tools would be sufficient. Provide a discussion of the system impacts and benefits that may arise from increased DER adoption, potential barriers to DER integration, and the types of system upgrades that may be necessary to accommodate the DER at the listed penetration levels.	4.C.5
Distributed Enery Resource Scenario Analysis	Include information on anticipated impacts from FERC Order 84116 (Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators) and a discussion of potential impacts from the related FERC Docket RM18-9-000 (Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators)	4.E.4

Long-Term Distribution System Modernization and Infrastructure Investment Plan	Minnesota Power shall provide a 5-year Action Plan as part of a 10-year long-term plan for distribution system developments and investments in grid modernization based on internal business plans and considering the insights gained from the DER futures scenarios, hosting capacity/daytime minimum load data, and non-wires alternatives analysis. The 5-year Action Plan should include a detailed discussion of the underlying assumptions (including load growth assumptions) and the costs of distribution system investments planned for the next 5-years (topics and categories listed above). Minnesota Power should include specifics of the 5-year Action Plan investments. Topics that should be discussed, as appropriate, include at a minimum: a. Overview of investment plan: scope, timing, and cost recovery mechanism b. Grid Architecture: Description of steps planned to modernize the utility's grid and tools to help understand the complex interactions that exist in the present and possible future grid scenarios and what utility and customer benefits that could or will arise. Alternatives analysis of investment proposal: objectives intended with a project, general grid modernization investments considered, alternative cost and functionality analysis (both for the utility and the customer), implementation order options, and considerations made in pursuit of short term inestments. The analysis should be sufficient enough to justify and explain the investment. d. System interoperability and communications strategy e. Costs and plans associated with obtainint system data (EE load shapes, photovoltaic output profiles with and without battery storage, capacity impacts of demand response combined with EE, EV charging profiles, etc.) f. Interplay of investment with other utility programs (effects on existing utility programs such as demand response, efficiency projects, etc.) g. Customer anticipated benefit and cost h.Customer data and grid data management plan (how it is planned to be used and/or shared with customers and/or third parties) i. Plans to manage rate or bill impacts, if any j. IMpacts to net present value of system costs (in net present value revenue requirements/megawatt/hour or megawatt) k. for each grid modernization project in its f-year action plan, Minnesota Power should provide a cost-benefit analysis based on the best information it has at the time and include a discussion of nonquantifiable benefits. Minnesota power shall provide all information to support its analysis. l. Status of any existing pilots or potential for new opportunities for grid modernization pilots.	2.E

Long-Term Distribution System Modernization and Infrastructure Investment Plan	In addition to the 5-year Action Plan, Minnesota Power shall provide a discussion of its vision for the planning, development, and use of the distribution system over the next 10 years. The 10-year Long-Term Plan discussion should address long-term assumptions (including load growth assumptions), the long-term impact of the 5-year Action Plan investments, what changes are necessary to incorporate DER into future planning processes based on the DER futures analysis, and any other types of changes that may need to take place in the tools and processes Minnesota Power is currently using	1.1.A-D
Non-Wires (Non-Traditional) Alternatives Analysis	Minnesota Power shall provide a detailed discussion of all distribution system projects in the filing year and the subsequent five years that are anticipated to have a total cost of greater than two million dollars. For any forthcoming project or project in the filing year, which cost two million dollars or more, provide an analysis on how non-wires alternatives compare in terms of viability, price, and long-term value.	2.F, Table 4

Non-Wires (Non-Traditional) Alternatives Analysis	Minnesota Power shall provide information on the following: a. Project types that would lend themselves to non-traditional solutions (i.e. load relief or reliability) b. A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation) c. Cost threshold of any project type that would need to be met to have a nontraditional solution reviewed d. A discussion of a proposed screening process to be used internally to determine that non-traditional alternatives are considered prior to distribution system investments are made.	3.B-C
Transportation Electrification Plan	Minnesota Power shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide a discussion of how it plans to facilitate: 20 a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory; b. availability of residential charging options for both single family and multiple unit dwellings; c. programs or tariffs in development to address flexible load or reduce metering and data costs; and d. fleet electrification.	Appendix E

Transportation Electrification Plan	Minnesota Power shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.	Appendix E
Transportation Electrification Plan	Minnesota Power shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 21- 257 at the conclusion of the pilot program	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).26	Appendix E
Transportation Electrification Plan	Minnesota Power shall provide attachments or links to the most recent reports for any ongoing EV pilots or programs.	Appendix E

Transportation Electrification Plan	Minnesota Power shall provide historical spending for the past 5-years on all transportation electrification initiatives, broken down across the sections of its budget Budget Category (ex, distribution, IT, transmission, etc.) Capital O&M Marketing and Communications Other (provide explanation of what is in "other)	Appendix E
IDP Points from IRP (no. 21-33)	In its next Integrated Distribution Plan (IDP), Minnesota Power must provide information on how it could implement the following steps to better align distribution and resource planning: -Set the forecasts for distributed energy resources consistently in its resource plan and its IDP. Conduct advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level. -Proactively plan investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources. -Improve non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Minnesota Power can take advantage of distributed energy resources to address discrete distribution system costs. -Plan for aggregated distributed energy resources to provide system value including energy/capacity during peak hours.	1.C, 3.B, 3.C

IDP Points from IRP (no. 21-33)	Minnesota Power must file the results from its consultant led non-wires alternative study in the next IDP docket. In next IDP, Minnesota Power will begin a discussion on how to integrate NWS into all the company's planning practices, including its next IRP and IDP.	3.C

MINNESOTA POWER'S 2023 INTEGRATED DISTRIBUTION PLAN

Stakeholder Meeting– September 13, 2023

minnesota power
AN ALLETE COMPANY
EnergyForward

I AM ZERO INJURY.

TOGETHER we choose to work safely for our FAMILIES, each other, and the public. We COMMIT to be injury-free through continuous learning and improvement.

In the event of an emergency....

911 Contact – Jess McCullough

First Aid/CPR – Eric Clement

AED – Beau Pocquette

Fire Extinguisher – Nick Boldt

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MINNESOTA POWER & THE IDP OVERVIEW
JESS MCCULLOUGH – PUBLIC POLICY ADVISOR, REGULATORY & LEGISLATIVE AFFAIRS
EnergyForward


MINNESOTA POWER & THE IDP OVERVIEW
JESS MCCULLOUGH – PUBLIC POLICY ADVISOR, REGULATORY & LEGISLATIVE AFFAIRS
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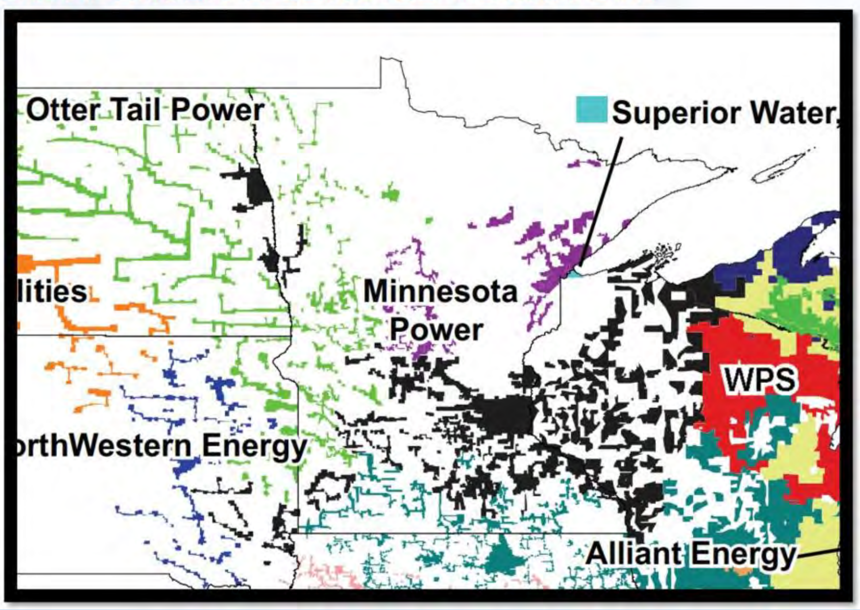
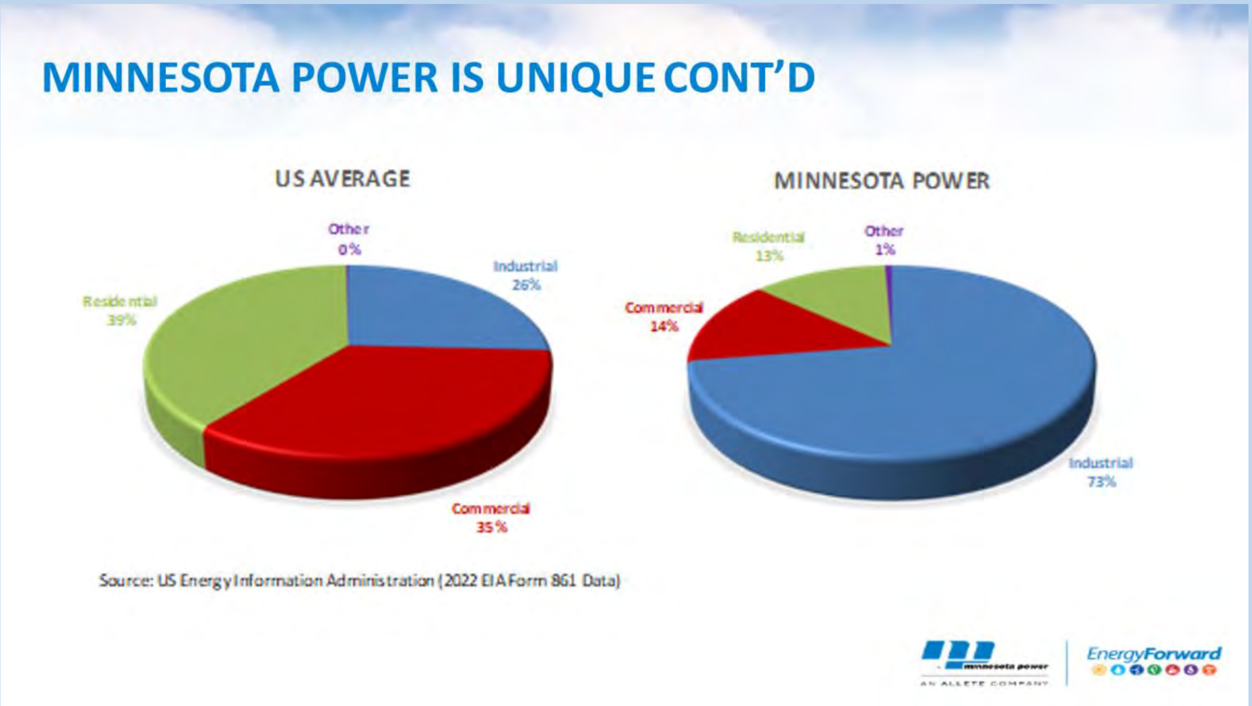
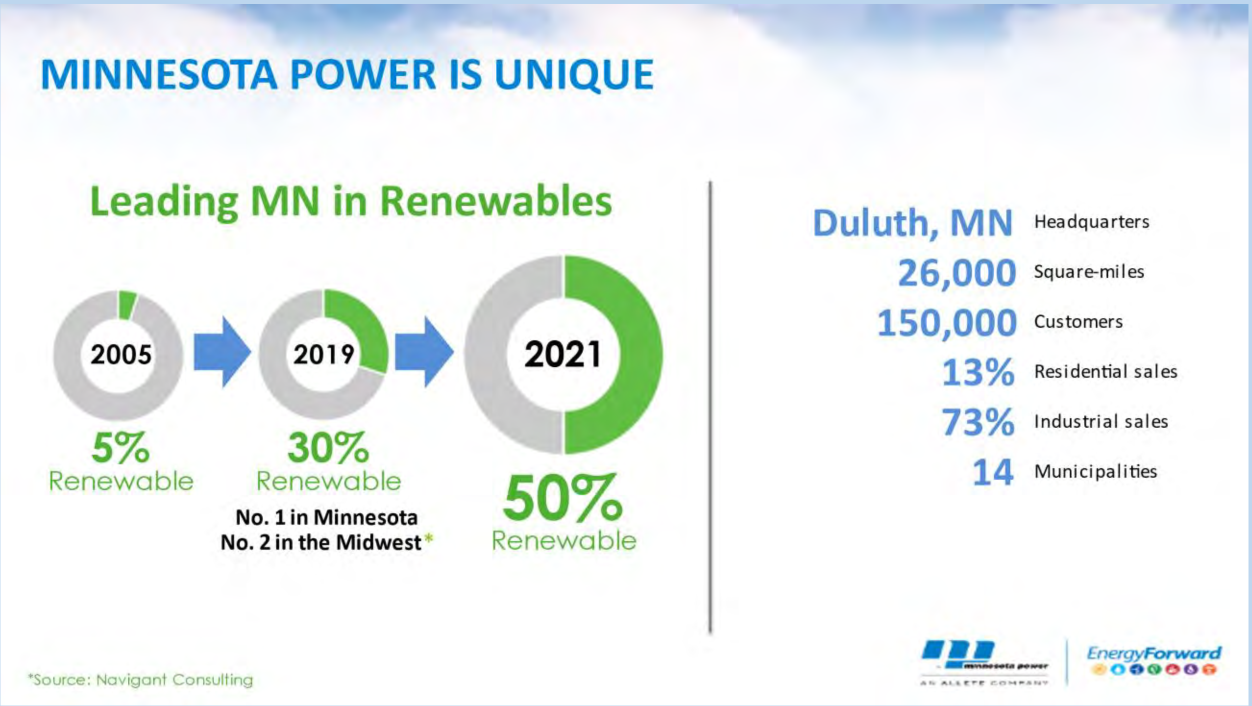
OVERVIEW

- Minnesota Power & IDP overview
- Distribution System, Investments, Capabilities & Customer Benefits
- Planning, NWA, and Benefit/Cost analysis
- Load & DER Forecasts
- Transportation Electrification Plan
- Questions
- Jean Duluth Solar tour

MINNESOTA POWER'S SERVICE TERRITORY




MINNESOTA POWER IS UNIQUE CONT'D
US AVERAGE
Other 0%
Industrial 26%
Residential 39%
Commercial 35%
MINNESOTA POWER
Residential 13%
Other 1%
Commercial 14%
Industrial 73%
Source: US Energy Information Administration (2022 EIA Form 861 Data)
EnergyForward


MINNESOTA POWER IS UNIQUE
Leading MN in Renewables
2005
5% Renewable
2019
30% Renewable
No. 1 in Minnesota
No. 2 in the Midwest*
2021
50% Renewable
Duluth, MN Headquarters
26,000 Square-miles
150,000 Customers
13% Residential sales
73% Industrial sales
14 Municipalities
*Source: Navigant Consulting
EnergyForward

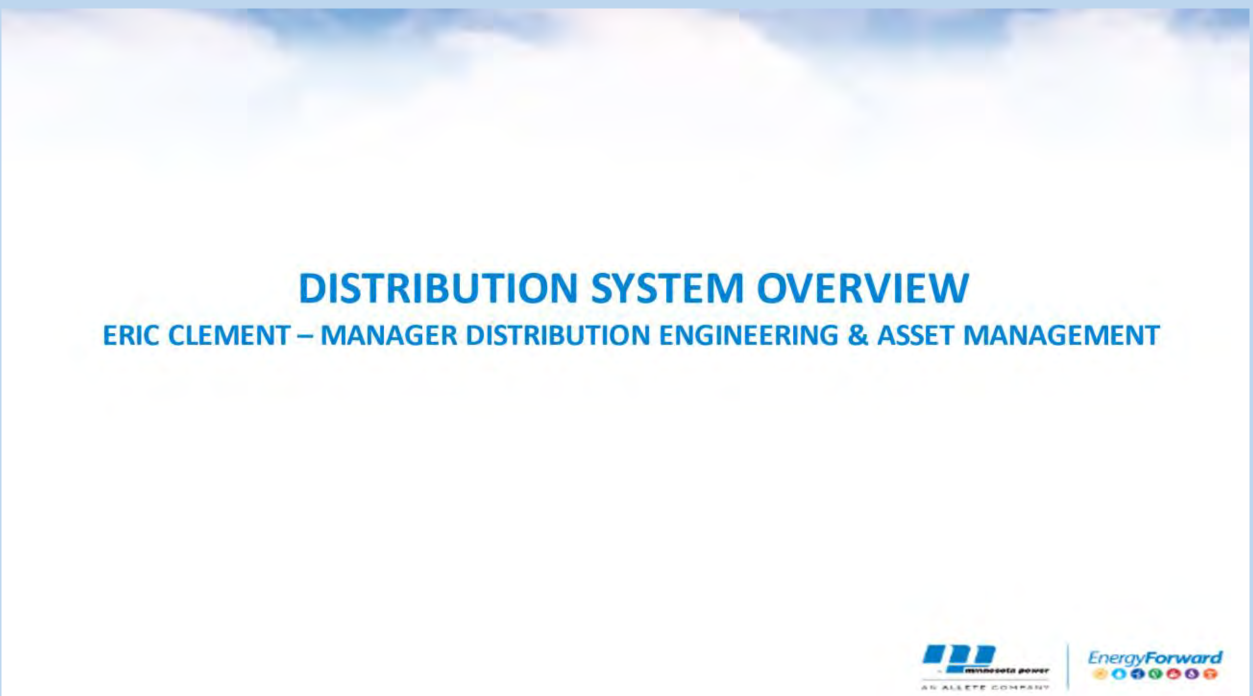
PURPOSE OF IDP:

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

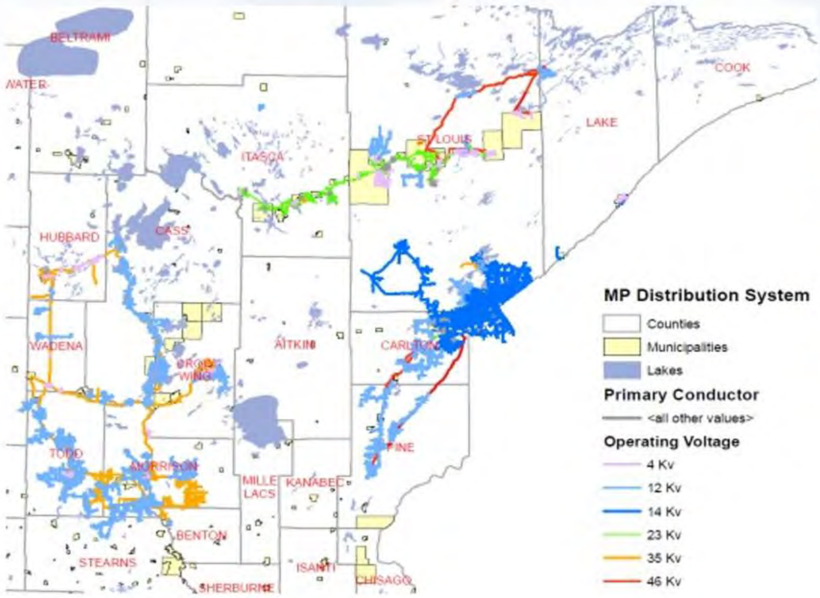
ELEMENTS:

- Baseline Distribution System Data
- Baseline Financial Data
- Baseline DER Data
- DER Scenario Analysis
- Non-Wire or Non-Traditional Alternatives
- Benefit Cost Analysis
- 5-10 Year System Modernization and Infrastructure Plan
- NEW – Transportation Electrification Plan


KEY THEMES
Customer
• Reliability; Strategic Undergrounding
• Thoughtful Decisions (Right Size/Time); Affordability
• Customer to Meter/ Customer Information System/MyAccount
• Advanced Metering Infrastructure/Advanced Rate Design
• Customer Programs
Communities
• Resiliency Against Extreme Weather
• Geographic Information Systems Benefits
• Distribution Asset Renewal for Reliability
Climate
• Electric Vehicles
– Public Charging Infrastructure
– Commercial Rates
– Residential Rebate Programs
• Distributed Energy Resources
• Energy Conservation
Company
• Grid Security (Cyber/Physical)
• Energy Management System/Demand-Side Management/Distributed Energy Resources Management System
• Supervisory Control and Data Acquisition
• Smart Sensors
• Distribution Forecasting
EnergyForward

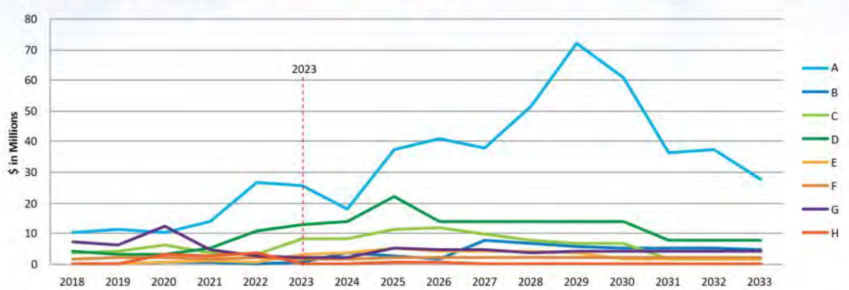

DISTRIBUTION SYSTEM OVERVIEW
ERIC CLEMENT – MANAGER DISTRIBUTION ENGINEERING & ASSET MANAGEMENT
EnergyForward

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 **APPENDIX B**



150,000 customers
201 substation
339 feeders
151,911 poles
41,497 transformers
3,657 miles of secondary
6,216 miles of primary
26,000 square miles
50% renewable energy

LONG-TERM INVESTMENT PLAN

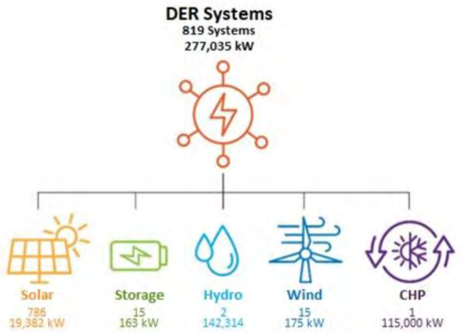


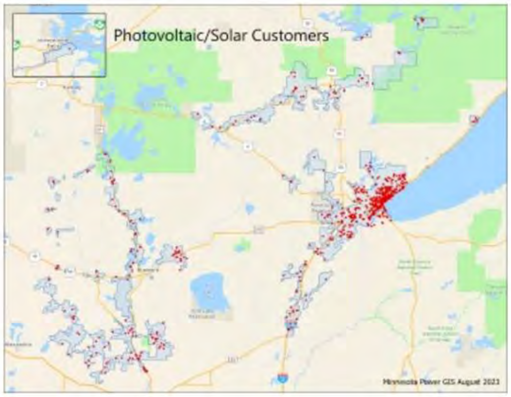
IDP Category		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
A - Age-Related Replacements and Asset Renewal	A	10.226	11.421	10.439	13.975	26.478	25.478	18.264	37.268	40.748	38.158	51.713	72.227	61.113	36.508	37.363	27.863
B - System Expansion or Upgrades for Capacity	B	0.267	0.124	0.805	0.565	0.114	0.699	3.850	2.600	1.600	7.900	7.000	6.000	5.500	5.500	5.200	5.000
C - System Expansion or Upgrades for Reliability and Power Quality	C	3.717	4.289	6.168	3.579	3.462	8.450	8.350	11.500	11.800	9.900	7.700	7.100	7.050	1.850	1.550	1.550
D - New Customer Projects and New Revenue	D	4.242	3.322	3.484	5.079	10.883	13.163	14.000	22.000	14.000	14.000	14.000	14.000	14.000	8.000	8.000	8.000
E - Grid Modernization and Pilot Projects	E	0.152	0.237	0.815	0.999	0.504	3.500	4.000	5.500	4.500	4.500	4.500	4.000	2.000	2.000	2.000	2.000
F - Projects Related to local (or other) government requirements	F	1.938	2.201	2.120	1.515	2.444	2.000	2.000	2.200	2.200	2.200	2.500	2.200	2.200	2.200	2.200	2.200
G - Metering	G	7.107	6.255	12.523	4.653	2.912	2.295	2.400	5.500	4.600	4.900	3.900	4.100	4.100	4.350	4.350	4.350
H - Other	H	0.207	0.151	3.480	2.618	3.993	0.425	0.375	0.900	0.900	0.400	0.400	0.400	0.400	0.400	0.400	0.400
Totals		27.856	28.000	39.834	32.983	50.790	56.010	53.239	87.468	80.348	81.958	91.713	110.027	96.363	60.808	61.063	51.363

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 APPENDIX B

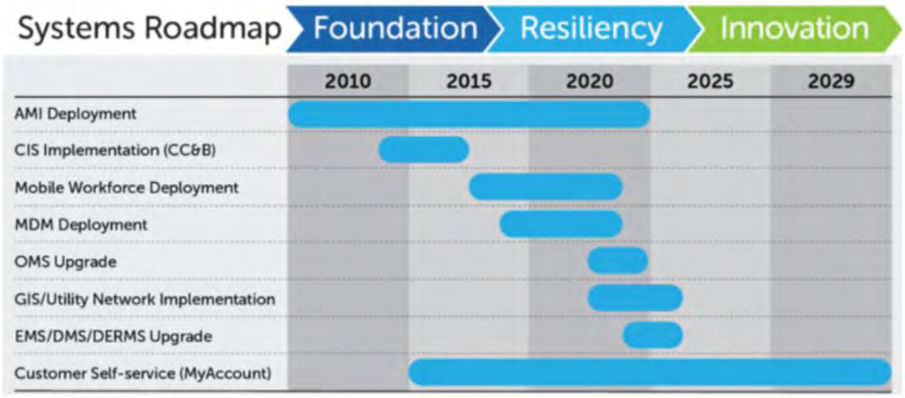
INNOVATION – PILOTS & PROGRAMMING

DER Systems





SYSTEMS FUTURE STATE & INNOVATION



STRATEGIC UNDERGROUNDING

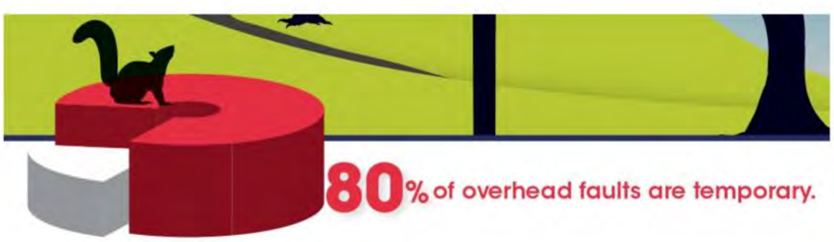
- 2020 and forward initiative
- Target heavy tree areas
- Improve reliability

RELIABILITY/RESILIENCY TARGET AREAS

- ❖ Leveraging Systems – C2M, EMS, GIS, OMS, Designer XI, Modeling software
- ❖ Vegetation Management – increased spend
- ❖ AMI integration – OMS, voltage monitoring, phase detection
- ❖ Maintenance – increased programming
- ❖ Groundline – expanded programs
- ❖ Equipment – Underground first, Trip Savers, no maintenance
- ❖ Automation – FLISR, Sensors, Motor Operators

TRIP SAVERS

- Recloser in a cutout body.
  - Over 300 installed on our system since 2017.
  - Proven technology to clear temporary faults without rolling a truck

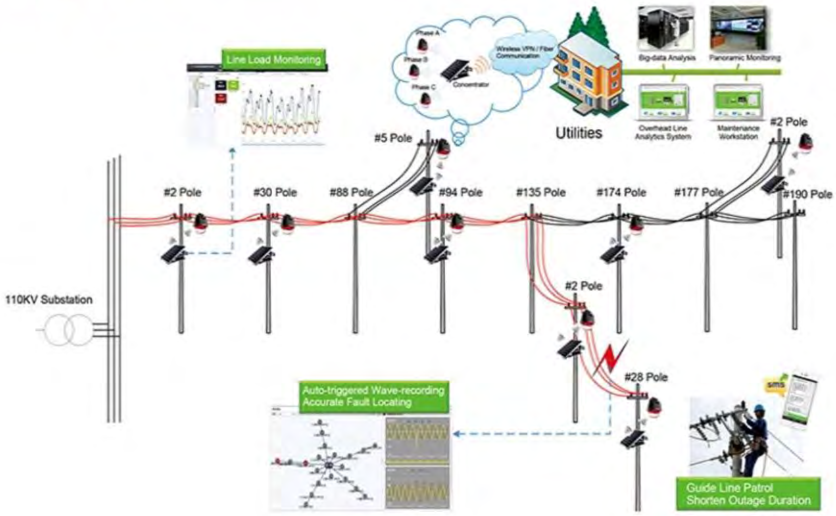


minnesota power
AN ALLETE COMPANY
EnergyForward

INTELLIRUPTERS

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

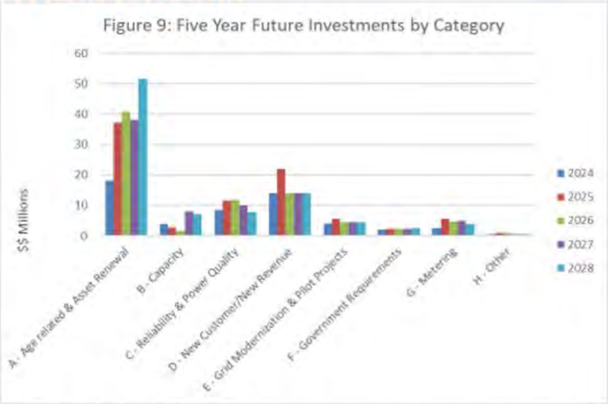
SMART SENSORS



MOTOR OPERATED SWITCHES

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

5 YEAR INVESTMENT PLAN



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**

PLANNING & DEMONSTRATING INNOVATION: NON-WIRES (NON-TRADITIONAL) SOLUTIONS

NICK BOLDT – T&D PLANNING SENIOR ENGINEER

DISTRIBUTION PLANNING

- Distribution System Modeling
- Long Range Planning & Analysis
- Capital Budget Prioritization
- Interconnection Study Support
- Other Distribution Planning Initiatives

OTHER DISTRIBUTION PLANNING INITIATIVES

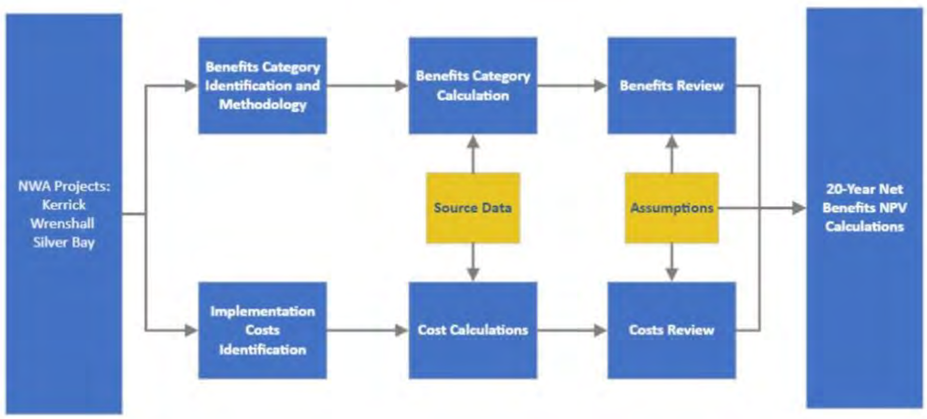
- Coordination – Strategy & Planning, Regulatory Affairs, Customer Programs and Service Representatives, Distribution Engineering, Distribution Service Representatives, System Operators, Other Utilities, etc…
- Participation – Distribution Planning -Focused Regulatory Initiatives, Grid Modernization,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

NON-WIRES ALTERNATIVES (NWA) STUDY

- Focused on 4 locations in MP Territory.
  - Backup Capability
    - Battery Energy Storage System (Kerrick, Wrenshall, & Silver Bay)
  - Feeder Automation
    - Fault Location Isolation and Service Restoration (FLISR) (Kerrick, Wrenshall, & Cloquet)
  - Integrated Volt-Var Control
    - Voltage Corrections (Kerrick, Wrenshall, Silver Bay, & Cloquet)
- Black & Veatch was selected as primary consultant.
  - Started in 2021 and wrapped up in mid-2023.
  - Assisted Minnesota Power in Developing Benefit Cost Analysis framework.
  - Produced reports on 4 different scenarios.

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 **APPENDIX B**

BENEFIT COST ANALYSIS (BCA) FRAMEWORK



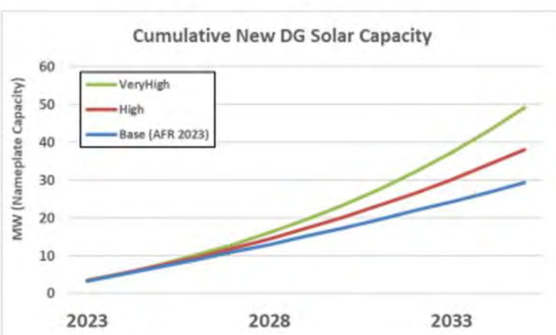
BENEFIT COST ANALYSIS RESULTS

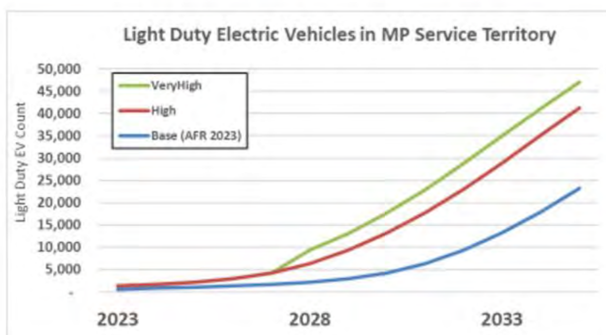
- The BCA developed benefit cost ratios ranging from 0.42 to 1.88.
  - Benefit cost ratios that exceed 1.0 means the calculated benefits exceed the estimated cost of the project and the NWA solution may be justified.
- The Kerrick area was the only scenario with a BCR above 1.0 after factoring in all three NWA solutions.
- Minnesota Power started working to refine and develop a BESS pilot Project for the Kerrick area.
- The framework developed by B&V will allow Minnesota Power to update assumptions and benefit categories to apply to future Non-wire solutions.

LOAD AND DER SCENARIO ANALYSIS

TIM BEDDOW - CUSTOMER INSIGHTS AND FORECASTING ANALYST SENIOR

DER SCENARIO ANALYSIS – DG SOLAR AND EV FORECASTS





TRANSPORTATION ELECTRIFICATION PLAN

KATIE FRYE – MANAGER CUSTOMER PROGRAMS AND SERVICES

Existing EV Programs

RATES
Residential EV Rate
Residential Time-of-Day Rate
Commercial EV Pilot Rate
REBATES
$500 Rebate for EV Second Service
$500 Rebate for L2 Smart Charger
EV INFRASTRUCTURE
20 L2 Chargers
16 DC Fast Charging Stations (In Progress)

Upcoming EV Initiatives

2023

Delivery of EV Rebate and Off-peak EV Charging Rate Programs

EV Outreach

2024

Commercial EV Rate Proposal

Installation of 16 DCFC Stations Completed

MDU EV charging Proposal

2025

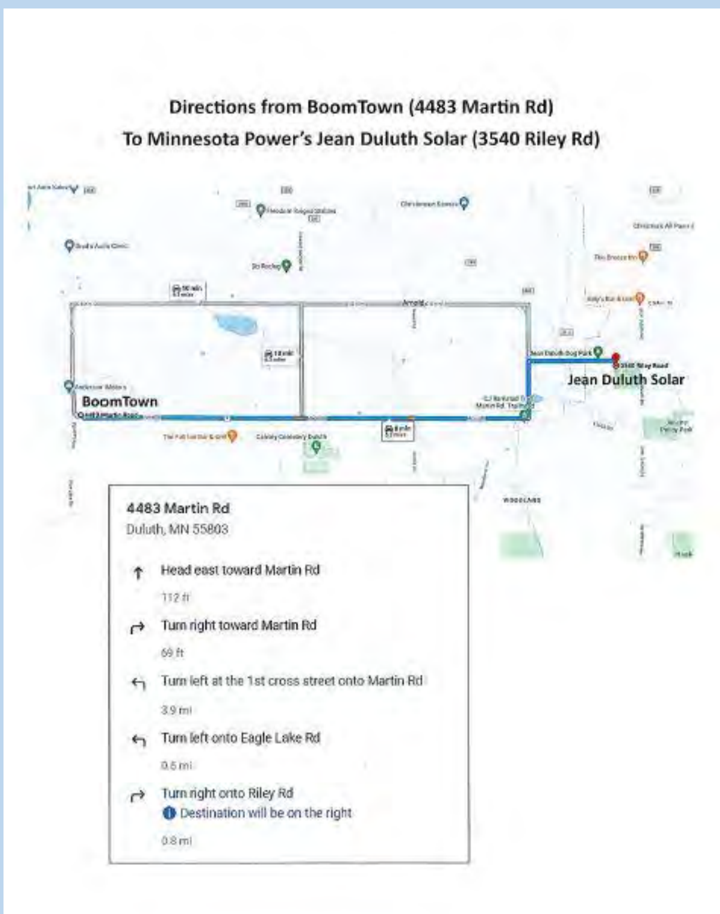
MDU EV Program Implementation

Evaluate Programs for EV Infrastructure

Continued Evaluation of EV Market Needs (Including Fleet Electrification)

QUESTIONS?

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 **APPENDIX B**



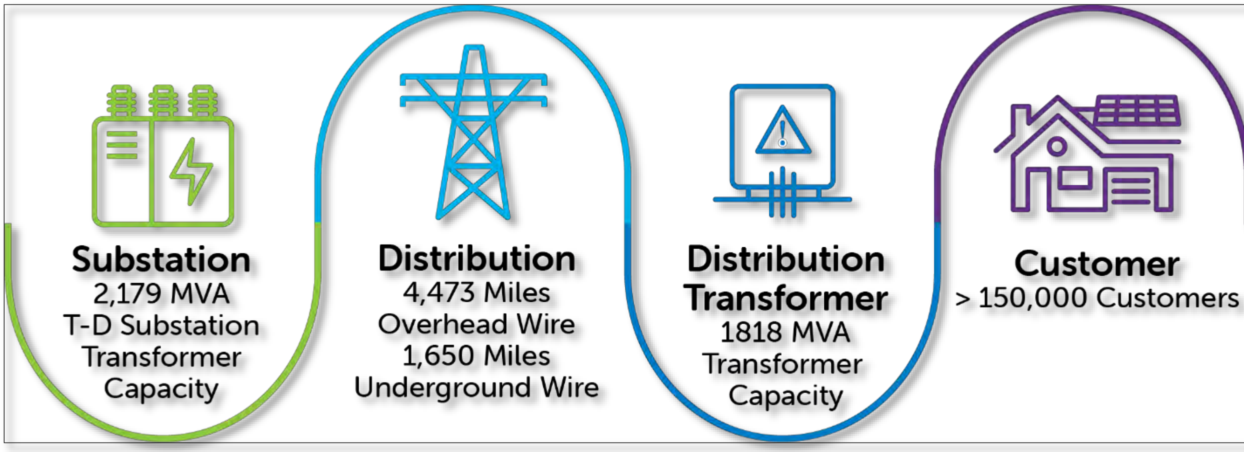
Directions from BoomTown (4483 Martin Rd)
To Minnesota Power's Jean Duluth Solar (3540 Riley Rd)

4483 Martin Rd
Duluth, MN 55803

- Head east toward Martin Rd
  112 ft
- Turn right toward Martin Rd
  59 ft
- Turn left at the 1st cross street onto Martin Rd
  3.9 mi
- Turn left onto Eagle Lake Rd
  0.5 mi
- Turn right onto Riley Rd
  Destination will be on the right
  0.8 mi

Current DER and System Summary

Figure 1: Minnesota Power System Summary 2023



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

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

Table 1: Minnesota Power Distributed Energy Resource Status

Minnesota Power Distributed Energy Resources Completed Interconnections in 2023		
DER Technology Type	**Nameplate Rating**	**Interconnections**
Solar	17,108.12	137
Combined Solar/Storage	87.70	5
Battery Storage		

Table 2: Minnesota Power Distributed Energy Resource Interconnection Queue

Minnesota Power Distributed Energy Resources Completed Interconnections in 2023			
Application Completion Date	**Proposed DER Capacity (kW)**	**DER Type**	**Application Status**
4/20/21	24	Solar	Construction
3/7/22	11.4	Solar	Construction
4/18/22	7.6	Solar	Construction
4/27/22	10.15	Solar	Construction
5/6/22	4	Solar	Construction
6/24/22	13.7	Solar	Construction
7/22/22	1.63	Solar	Construction
8/11/22	25	Solar	Construction
9/13/22	39.9	Solar	Construction
9/23/22	3	Solar	Construction
10/17/22	875	Solar	Construction
10/17/22	4.06	Solar	Construction
10/22/22	30	Solar	Construction

MP's 2023 Integrated Distribution Plan
Docket No. E015/M-23-258 **APPENDIX C**

Application Completion Date	Proposed DER Capacity (kW)	DER Type	Application Status
10/28/22	4.35	Solar	Construction
11/15/22	39.9	Solar	Construction
11/28/22	2.5	Solar	Construction
12/10/22	40	Solar	Construction
1/16/23	39.9	Solar	Construction
2/16/23	8.19	Solar	Construction
3/10/23	7.46	Solar	Construction
3/10/23	17.6	Solar	Construction
3/17/23	20	Solar	Construction
3/24/23	2.56	Energy Storage	Construction
3/30/23	4.67	Solar	Construction
4/5/23	11.4	Solar	Construction
5/1/23	39	Solar	Construction
5/20/23	15.36	Solar	Construction
5/22/23	9.5	Solar	Construction
6/2/23	7.25	Solar	Construction
6/2/23	40	Solar	Construction
6/9/23	16.4	Solar	Construction
6/9/23	7.8	Solar	Construction
6/15/23	12.92	Solar	Construction
6/15/23	18.67	Solar	Construction
6/15/23	6.9	Solar	Construction
6/22/23	7.75	Solar	Construction
7/6/23	7.68	Solar	Construction
7/10/23	38.4	Solar	Construction
7/11/23	39	Solar	Construction
7/14/23	6.6	Solar	Construction
7/14/23	38.4	Solar	Construction
7/17/23	10.61	Solar	Construction
7/17/23	38.5	Solar	Construction
7/20/23	10.75	Solar	Construction
7/27/23	20.88	Solar	Construction
8/1/23	11.02	Solar	Construction
8/3/23	12.8	Solar	Construction
8/3/23	5.12	Solar	Construction
8/7/23	19.53	Solar	Construction
8/7/23	28.03	Solar	Construction
8/7/23	38.75	Solar	Construction
8/8/23	12	Solar	Construction
8/11/23	2.45	Solar and Energy Storage	Construction
8/17/23	66.6	Solar	Construction
8/18/23	7.56	Solar	Construction
8/18/23	4.6	Solar	Construction
8/18/23	8.56	Solar	Construction
8/18/23	6.58	Solar	Construction
8/22/23	6.96	Solar	Construction
8/22/23	17.4	Solar	Construction
8/22/23	38.5	Solar	Construction
8/24/23	15.36	Solar	Construction
8/24/23	39	Solar	Construction
8/28/23	6.9	Solar	Construction
9/4/23	10	Solar	Construction

Application Completion Date	Proposed DER Capacity (kW)	DER Type	Application Status
9/5/23	5.04	Solar	Construction
9/12/23	5.04	Solar	Construction
9/12/23	24	Solar and Energy Storage	Construction
9/15/23	3.84	Energy Storage	Construction

Minnesota Power

2021 Distribution Loss Study

Study Report

Distribution Planning
September 2021

Revision History

Date	Rev	Description
08/19/2021	0.0	Draft Study Scope
09/10/2021	1.0	Final Study Report

Contributors

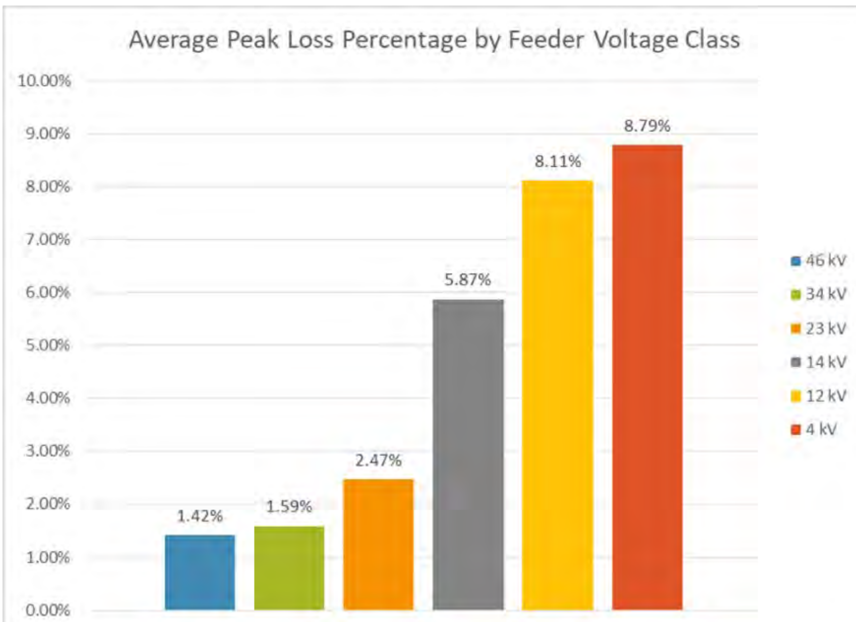
This study report borrows from the 2016 Distribution Loss Study while providing an updated methodology. The report was developed by the Transmission & Distribution Planning Department, with significant contributions from Nick Boldt, Garett Henriksen, and Christian Winter.

Table of Contents

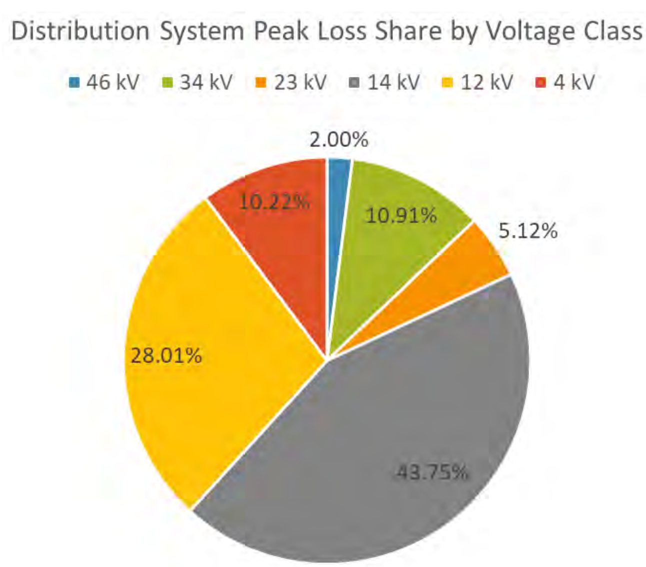
Executive Summary

Peak and energy loss percentages were calculated for Minnesota Power's distribution system and delineated by voltage class. The study results include losses from the distribution substation bus to the customer meter. This loss study replaces the previous (2016) loss study, and also applies and updated and more direct methodology based on GIS data, power flower modeling, and historical data.

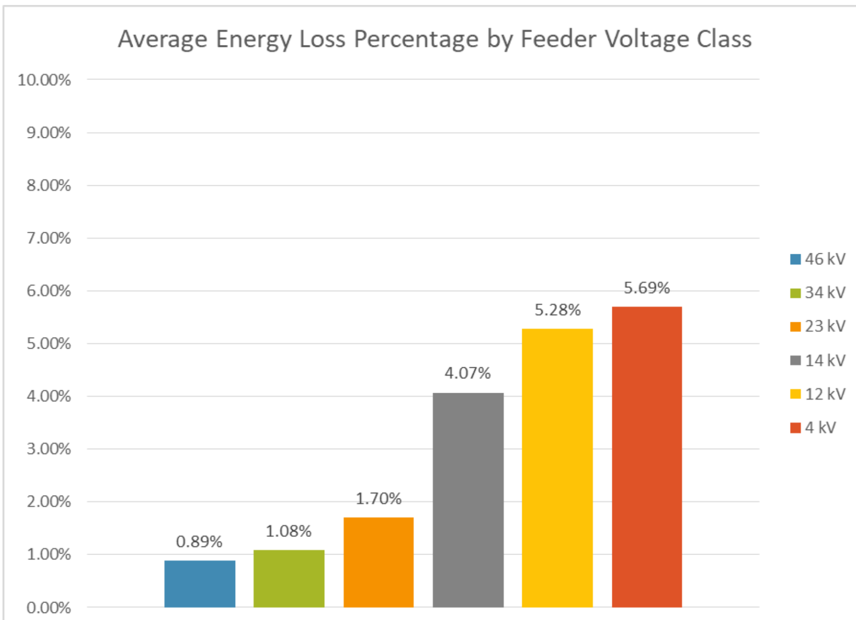
Peak losses are the instantaneous power system losses at the time of greatest distribution system demand. Hourly distribution system loading data from 2020 was evaluated to identify coincident peak distribution system demand. Power system models were evaluated to determine average peak loss percentages by voltage class, as shown the figure below. The average peak loss percentages were then applied to the historical peak-hour demand to estimate total distribution system peak losses, the contribution of each voltage class to system peak losses, and the aggregate Minnesota Power distribution system peak loss percentage. All of these values are provided in the table and chart below. **The peak loss percentage for Minnesota Power's distribution system is 5.75 percent.**



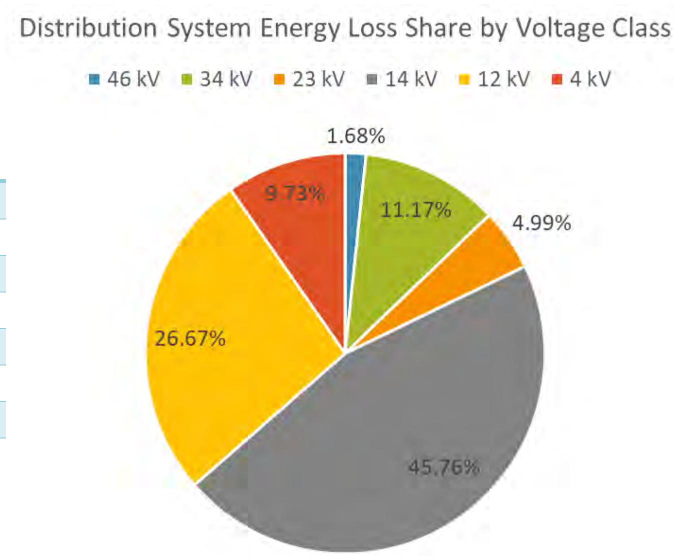
Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	3.37 MW	0.59 %
12 kV	9.24 MW	1.61 %
14 kV	14.43 MW	2.51 %
23 kV	1.69 MW	0.29 %
34 kV	3.60 MW	0.63 %
46 kV	0.66 MW	0.12 %
TOTAL	**33.00 MW**	**5.75 %**



Energy losses are power system losses accumulated over time, in this case annually. Hourly distribution system loading data from 2020 was evaluated to identify total annual energy served from the distribution system. The average peak loss percentages by voltage class originally derived from power flow models were used along with historical loading information to calculate average energy loss percentages by voltage class, which are shown in the figure below. The average energy loss percentages were then applied to the historical annual energy for the distribution system to estimate annual distribution system energy losses, the contribution of each voltage class to annual energy losses, and the aggregate Minnesota Power distribution system annual energy loss percentage. All of these values are provided in the table and chart below. **The energy loss percentage for Minnesota Power's distribution system is 3.88 percent**



Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	12,588 MWh	0.38 %
12 kV	34,492 MWh	1.04 %
14 kV	59,173 MWh	1.78 %
23 kV	6,457 MWh	0.19 %
34 kV	14,439 MWh	0.43 %
46 kV	2,173 MWh	0.07 %
TOTAL	**129,322 MWh**	**3.88 %**



Section 1: Background

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

Section 2: Model Development

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

Section 3: Study Methodology

The loss study utilized historical data and GIS-based feeder models to calculate the losses on a representative subset of Minnesota Power distribution feeders. The study pertains only to Minnesota Power distribution feeders. Losses on distribution systems owned by external entities are not included. The results of loss analysis for the subset of feeders included in the study were used to estimate peak and energy loss percentages by voltage class for Minnesota Power's entire distribution system. The study methodology is described in detail below. A comparison of the assumptions applied in the previous (2016) loss study and the current (2021) loss study is provided in Appendix A: Comparison of 2016 & 2021 Loss Study Assumptions.

3.1 Historical Data Analysis

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

3.2 WindMil Model Simulation

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

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

3.3 Calculation of Peak and Energy Loss Percentages

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

(1) $$Feeder\ Peak\ Loss\ Percentage = Feeder\ Losses\ at\ Peak\ Demand / Feeder\ Peak\ Demand$$

Feeder energy losses were also calculated. The peak loss percentage represents only the instantaneous losses on the feeder at the moment of peak load. In reality, demand for electric power is not constant and power flow on a given distribution feeder varies over time, increasing as demand increases and decreasing as demand decreases. Since feeder losses are proportional to the current flowing on the line, the losses on the feeder will also vary over time. Feeder energy losses represent the average annual energy losses accumulated on the feeder as the loading varies over time. The annual energy consumption for a feeder can be calculated by adding demand (kW) from all hours in a given year to get total energy in kilowatt-hours (kWh). There is no precise way to calculate average annual energy losses, but one common method[1] uses the peak and average feeder demand and the losses at peak demand to estimate average annual energy losses according to the following formulas:

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

(2) $Load\ Factor = Average\ Demand/Peak\ Demand$

(3) $Loss\ Factor = (0.3 \times Load\ Factor) + (0.7 \times Load\ Factor^2)$

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

The average demand and peak demand values in equation (2) are derived from historical data as described in Section 3.1. The losses at peak demand in equation (4) are derived from the WindMil model as described in Section 3.2. Normally the "Hours" in equation (4) would be 8,760, which is the total number of hours in a typical year. However, since this study used historical data from 2020, which was a leap year, the total number of hours used in equation (4) for this study was 8,784. The feeder energy loss percentage may then be calculated according to the following formula:

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

3.4 Calculation of System Loss Percentages

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

System Peak Loss Percentages

a) For each voltage class, calculate the peak loss percentage for that voltage class based on the average of peak loss percentages for all feeders of that voltage class included in the study
b) From historical data, calculate the coincident peak load served by Minnesota Power's distribution system at the transmission-to-distribution substation interface for calendar year 2020, excluding an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)
c) For each substation, determine the share of the coincident peak load associated with each voltage class present at the substation
    a. For substations with multi-voltage (parent/stepdown) feeder systems, develop an allocation factor for the substation to split the total substation load between the voltage classes that are present on the feeders. In general, the parent voltage class will carry the full load of the feeder while the stepdown voltage classes will only carry what is attributable to the stepdowns based on historical data or engineering estimates
d) For each substation, calculate peak distribution system losses by voltage class according to the following formula:
$$Peak\ Loss_{VC} = Peak\ Load_{VC} \times Peak\ Loss\ Percentage_{VC}$$
Where *Peak Load*$_{VC}$ is the share of that voltage class in the coincident peak load by substation from (c) and *Peak Loss Percentage*$_{VC}$ is the voltage class peak loss percentage from (a)
e) Add up the peak losses calculated for each substation in (d) to obtain system peak losses by voltage class. Add up the peak losses for all voltage classes to obtain total system peak losses.
f) The contribution of each voltage class to total system peak losses may then be represented both in terms of physical units (kW or MW) as well as a percentage of the total system peak losses

Energy Loss Percentages

a) For each voltage class, calculate the energy loss percentage for that voltage class based on the average of energy loss percentages for all feeders of that voltage class included in the study
b) From historical data, calculate the total annual energy served by Minnesota Power's distribution system at the transmission-to-distribution substation interface for calendar year 2020, excluding

an distribution system load that is not served by a Minnesota Power distribution system feeder (e.g., it is served directly from the substation bus)

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

d) For each substation, calculate distribution system energy losses by voltage class according to the following formula:

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

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

e) Add up the energy losses calculated for each substation in (d) to obtain system energy losses by voltage class. Add up the energy losses for all voltage classes to obtain total annual energy losses.

f) The contribution of each voltage class to total annual energy losses may then be represented both in terms of physical units (kWh or MWh) as well as a percentage of the total annual energy losses

Table 1: Feeders Included in the Study

Feeder	kV	Area	Type
23 LINE	46	Central	Parent
ASK-6521	12	Central	Stepdown
CLQ-406	14	Central	Simple
CLQ-409	14	Central	Parent
CLQ-410	14	Central	Simple
COL-240	14	Central	Simple
COL-241	14	Central	Simple
COL-242	14	Central	Simple
COL-244	14	Central	Simple
COL-245	14	Central	Simple
CQB-6301	12	Central	Stepdown
FOR-262	14	Central	Stepdown
FOR-262	14	Central	Stepdown
FRR-275	14	Central	Simple
GRY-200	14	Central	Simple
GRY-201	14	Central	Simple
KER-6501	12	Central	Stepdown
LSP-208	34	Central	Parent
NIN-246	14	Central	Stepdown
NIN-248	14	Central	Stepdown
RGV-253	14	Central	Simple
SLA-203	34	Central	Parent
SND-217	14	Central	Stepdown
SND-218	14	Central	Stepdown
TFW-243	14	Central	Stepdown
WRN-411	14	Central	Parent
WRR-6321	12	Central	Stepdown
31 LINE	46	Northern	Parent
32 LINE	46	Northern	Parent
33 LINE	46	Northern	Parent
HYN-1	4	Northern	Stepdown
HYN-2	4	Northern	Stepdown
BAL-1	12	Northern	Stepdown
BAL-2	12	Northern	Stepdown
CHL-1	4	Northern	Stepdown
CHL-2	4	Northern	Stepdown
CHL-3	4	Northern	Stepdown
AUR-313	23	Northern	Parent
HIB-308	23	Northern	Parent
HIB-310	23	Northern	Parent
HIB-312	23	Northern	Simple
HIB-315	23	Northern	Parent

Feeder	kV	Area	Type
INF-1	12	Northern	Simple
INF-2	12	Northern	Simple
INF-3	12	Northern	Simple
INF-4	12	Northern	Simple
KLY-1	4	Northern	Stepdown
MTU-330	23	Northern	Parent
STZ-1	4	Northern	Stepdown
STZ-2	4	Northern	Stepdown
SVE-1	4	Northern	Stepdown
SVW-2	4	Northern	Stepdown
SWB-1	4	Northern	Stepdown
VRG-302	23	Northern	Simple
BAX-534	34	Western	Parent
BBR-1	12	Western	Stepdown
BRW-1	12	Western	Stepdown
BRW-2	12	Western	Stepdown
CLR-1	12	Western	Stepdown
CLR-2	12	Western	Stepdown
EGV-517	34	Western	Parent
FLN-1	12	Western	Stepdown
FLN-2	12	Western	Stepdown
GGR-1	12	Western	Stepdown
HPS-1	12	Western	Stepdown
LCH-1	12	Western	Stepdown
LGP-1	12	Western	Stepdown
LLK-1	12	Western	Stepdown
LNL-1	12	Western	Stepdown
LPD-2	4	Western	Stepdown
LPN-1	12	Western	Stepdown
LPR-501	34	Western	Parent
LPR-527	34	Western	Parent
LPR-535	34	Western	Parent
PIL-1	12	Western	Stepdown
PNB-1	12	Western	Stepdown
PNB-2	12	Western	Stepdown
PPL-514	34	Western	Parent
RVT-532	34	Western	Parent
RVD-1	12	Western	Stepdown
SWN-1	12	Western	Stepdown

Section 4: Loss Analysis Results

4.1 Historical Data Analysis

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

4.2 WindMil Model Simulation

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

4.3 Calculation of Peak and Energy Loss Percentages

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

Table 2 below shows an example of feeder loss analysis for COL-240, a 14 kV feeder originating at the Colbyville Substation in East Duluth, using historical data and WindMil model values to calculate individual peak and energy loss percentages for the feeder.

Line	Description	Value	Units	Source
0	Feeder	COL-240		
1	Feeder Peak Date	12/24/2020 17:00		Historical Data
2	Peak Loading @ Source	7.53	MW	Historical Data
3	Peak Loading @ Source	7.54	MW	WindMil Model following Load Allocation
4	Peak Losses	495.90	kW	WindMil Model following Load Allocation
5	Peak Loss Percentage	6.58%		[Line 4] / [Line 3]
6	Avg Loading @ Source	4.17	MW	Historical Data
7	Load Factor	55.31%		[Line 6] / [Line 2]
8	Loss Factor	38.01%		(0.3 x [Line 7]) + (0.7 x [Line 7]^2)
9	Average Losses	188.48	kW	[Line 8] x [Line 4]
10	Annual Energy Losses	1,656	MWh	[Line 9] / 1000 x 8784 (leap year)
11	Annual Energy	36,605	MWh	Historical Data
12	Energy Loss Percentage	4.52%		[Line 10] / [Line 11]

Table 2: Colbyville 240 Feeder Loss Analysis Table

4.4 Calculation of System Loss Percentages

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

Voltage Class	Peak Loss Percentage	Energy Loss Percentage
4 kV	8.79 %	5.69 %
12 kV	8.11 %	5.28 %
14 kV	5.87 %	4.07 %
23 kV	2.47 %	1.70 %
34 kV	1.59 %	1.08 %
46 kV	1.42 %	0.89 %

Table 3: Peak & Energy Loss Percentages by Voltage Class

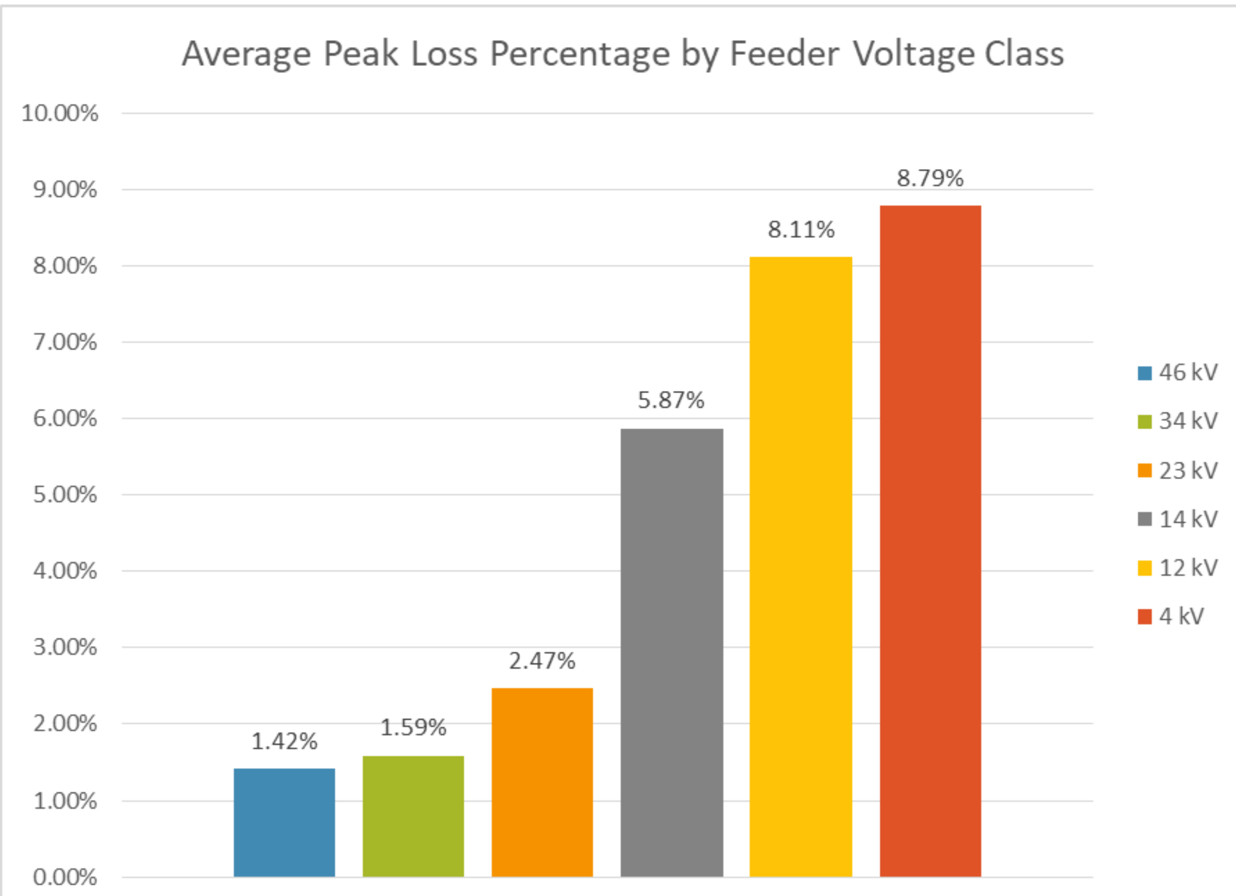


Figure 1: Average Peak Loss Percentage by Feeder Voltage Class

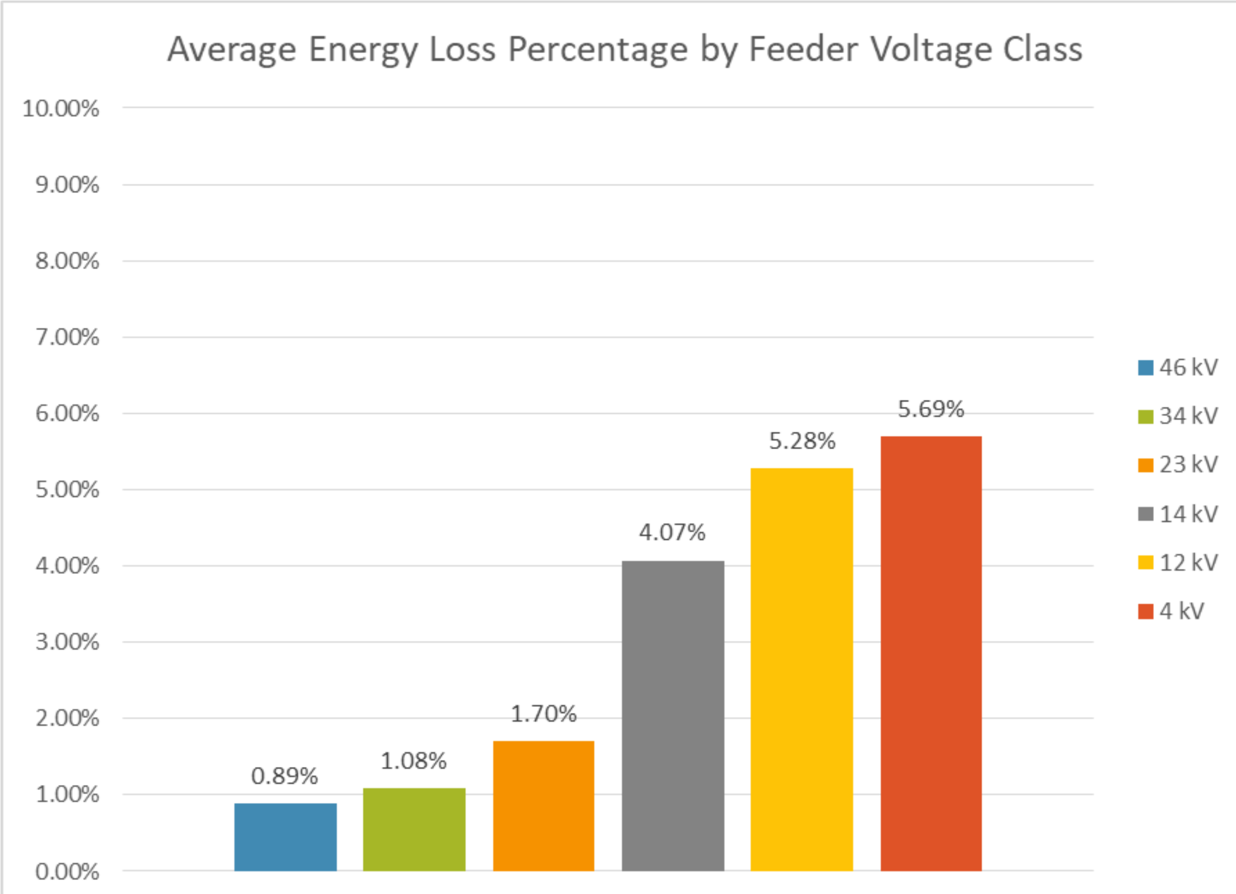


Figure 2: Average Energy Loss Percentage by Feeder Voltage Class

This methodology assumes that the sample set of feeders for each voltage class is sufficiently representative of the entire voltage class and that the inclusion of more feeders would not significantly change the average loss percentages. Within the initial results, significant outliers were re-evaluated to ensure modeling errors were not driving high losses on the feeders. Where obviously incorrect equipment accounting for a significant portion of the feeder losses could be identified from comparing the model and the GIS database, the equipment was corrected and the initial loss study results were updated.

FOR-262 is an example of where this process greatly improved the accuracy and confidence level of the loss study results. Initially, total losses on FOR-262 were 366.1 kW (14.08%) from the WindMil model. Since this was more than double the average loss percentage of other 14 kV feeders included in the study, further investigation was warranted. Upon inspection, it was found that four overloaded elements accounted for over 80 percent of total losses on the feeder. The four elements are shown in Table 4.

Element Name	Thru Amps	Thru kW	Capacity Percent	KW Loss
TX147635	20.251 A	457.962 kW	483.93%	51.791 kW
TX31737	26.817 A	849.780 kW	298.02%	57.082 kW
SecUG242387	582.292 A	406.042 kW	766.17%	90.745 kW
SecUG244627	1058.757 A	790.683 kW	471.81%	101.284 kW
			TOTAL	**300.902 kW**

Table 4: FOR-262 High-Loss Equipment Model Corrections

The first two elements are transformers for which the transformer size was incorrectly imported into WindMil from the GIS, most likely due to a data entry irregularity in the GIS. Review of existing GIS data showed that TX147635 has a nameplate rating of 750 kVA and TX31737 has a nameplate rating of 1000 kVA, both of which are sufficient to mitigate the overloads flagged in the model. The other two elements are conductor segments for which no conductor data was populated in the GIS. When unknown conductors are present in the underlying GIS data, they are conservatively assigned a small conductor size in the WindMil model. In this case, the small conductor size did not drive any performance issues with the overall feeder, but did significantly increase losses for the two conductor segments, as shown in Table 4. Based on inspection of adjacent conductor segments, both of these elements were updated to 500 CU, which has a capacity of 470 Amps. While this does still leave the conductor elements overloaded, it appears consistent with field data and the magnitude of the modeled overloads and associated conductor losses was greatly reduced. After modifying these four elements, total losses on FOR-262 were reduced to 93.8 kW (3.61%).

The results of making similar updates to other high-loss feeders are shown in a table in Appendix B: Feeder Loss Calculations.

After the data validation process described above, variations in loss percentage within each voltage class appear reasonable, leading to a high level of confidence in the modeled losses. Within each voltage class, loss percentages generally center on the average, and outliers on both the high and low end can be explained based on the specific circumstances for the feeders. Examples are discussed below.

Within the 34 kV voltage class, the minimum individual feeder peak loss percentage was 0.14% (LPR-527), the maximum was 2.66% (SLA-203), and the average was 1.59%. Considering LPR-527, which produced the smallest individual peak loss percentage of all 34 kV feeders – and the second-smallest loss percentage of all feeders of any voltage class – we find the following underlying circumstances. First, most of the load on LPR-527 is served from two stepdowns, Gutches Grove (GGR) and Long Prairie Distribution (LPD), which are located just outside the Long Prairie 115/34 kV Substation. The only load flowing past those two stepdowns serves a Great River Energy delivery point (Pillsbury) located toward the end of the feeder near the tie switch. On average, over 70 percent of the total feeder load gets off just outside the Long Prairie Substation. The remaining power flowing on the line to the Great River Energy delivery point flows on mostly 336 ACSR conductor, which is a higher-capacity, lower-impedance conductor for the 34 kV system. The configuration of LRP-527, therefore, helps explain why the loss percentage is lower – there isn't a lot of power flowing on most of the line, and the power that is flowing on the line flows on one of the least lossy distribution conductors on the Minnesota Power system.

On the other hand, the feeder with the highest individual loss percentage in the 34 kV class was SLA-203, where we find the following underlying circumstances. First, all of the load on SLA-203 is located over 5.75 miles away from the Swan Lake Road 115/34 kV Substation. The first delivery point is to the St Luke's Hospital, while subsequent delivery points serve 34/14 kV stepdowns in and near Downtown Duluth. While the feeder is primarily 636 ACSR overhead conductor, the fact that all feeder load must travel at least 50 percent the length of the entire feeder is what drives up the losses.

4.5 Distribution System Loss Analysis

As described in Section 3.4, the calculated loss percentages by voltage class shown in Table 3 were utilized to estimate total Minnesota Power distribution system peak and energy losses and to identify the contribution of each voltage class to the totals. Calculated demand and energy losses are provided in Table 5 & Table 6, while the contribution of each voltage class to the total system losses is provided in Figure 3 and Figure 4. Details of the analysis are discussed below.

Voltage Class	Estimated Peak Losses	Percentage of Peak Load
4 kV	3.37 MW	0.59 %
12 kV	9.24 MW	1.61 %
14 kV	14.43 MW	2.51 %
23 kV	1.69 MW	0.29 %
34 kV	3.60 MW	0.63 %
46 kV	0.66 MW	0.12 %
TOTAL	**33.00 MW**	**5.75 %**

Table 5: Distribution System Peak Losses

Voltage Class	Estimated Energy Losses	Percentage of Annual Energy
4 kV	12,588 MWh	0.38 %
12 kV	34,492 MWh	1.04 %
14 kV	59,173 MWh	1.78 %
23 kV	6,457 MWh	0.19 %
34 kV	14,439 MWh	0.43 %
46 kV	2,173 MWh	0.07 %
TOTAL	**129,322 MWh**	**3.88 %**

Table 6: Distribution System Energy Losses

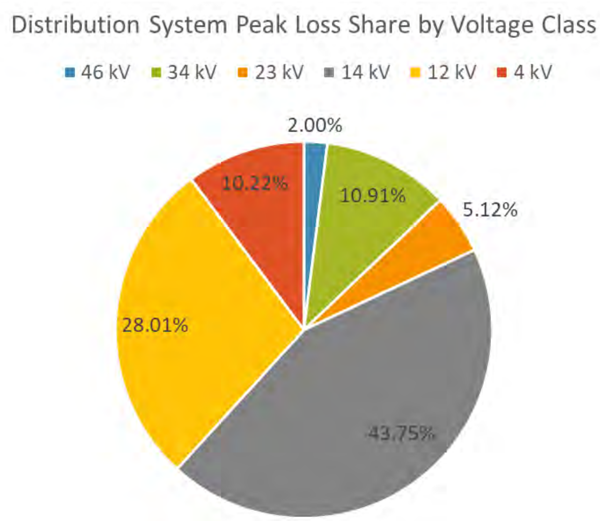


Figure 4: Peak Loss Share by Voltage Class

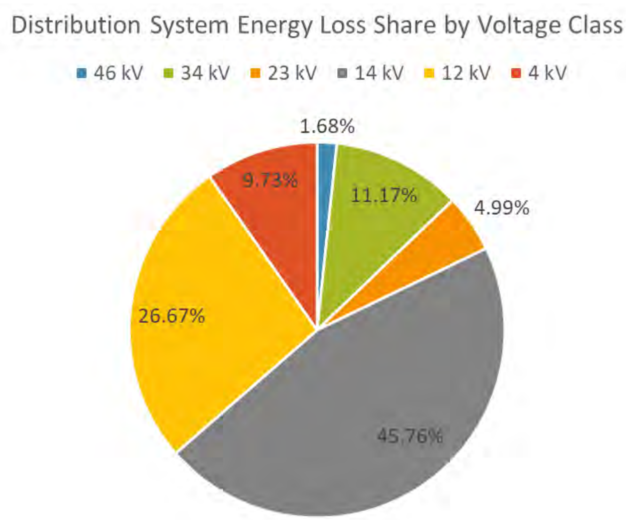


Figure 3: Energy Loss Share by Voltage Class

Identification of Peak Loss Percentage

To determine total peak distribution system losses, historical load data from all Minnesota Power distribution feeders was grouped by substation and then evaluated to find the coincident historical peak hour for Minnesota Power distribution system loading from calendar year 2020. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. As shown in Figure 5 below, the peak distribution system load from 2020 that was used for the loss analysis was 574 MW on February 13, 2020 at 8:00 AM.

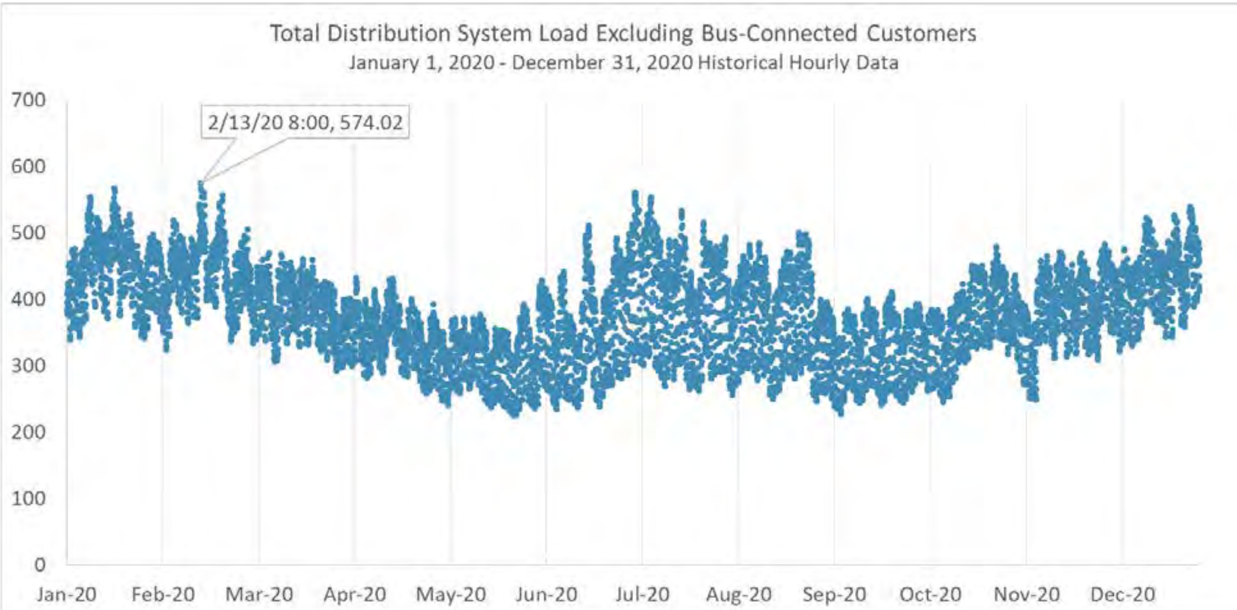


Figure 5: Minnesota Power 2020 Distribution System Coincident Loading

The contribution of each substation to peak-hour loading was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average peak loss factors from Table 3 to estimate the actual losses incurred on each voltage class at each substation during the 2020 peak load hour. The Akeley Substation is provided as an example in Table 7.

Akeley 34/12/4 kV	Allocation Factors	kV Class Peak Loss Factor	kV Class Peak Load	kV Class Peak Losses
4 kV	14.53 %	8.79 %	2.09 MW	0.18 MW
12 kV	40.11 %	8.11 %	5.78 MW	0.47 MW
14 kV	0.00 %	N/A	N/A	N/A
23 kV	0.00 %	N/A	N/A	N/A
34 kV	100.00 %	1.59 %	14.40 MW	0.23 MW
46 kV	0.00 %	N/A	N/A	N/A
		Total on 2/13/20 0800	**14.40 MW**	**0.88 MW**

Table 7: Akeley Substation Peak Loss Analysis Example

Finally, the results from the individual substations were added up to determine the estimated peak losses by voltage class, the total system peak loss percentage, and the contribution of each voltage class to the total peak losses, as shown in Table 5 and Figure 3 above.

Identification of Energy Loss Percentage

To determine distribution system annual energy losses, hourly historical load data from all Minnesota Power distribution feeders was grouped by substation and then all 8,784 hours were added up to obtain total annual energy for calendar year 2020. Bus-connected distribution customer loads, such as wholesale municipal customer loads, were excluded from this analysis as those loads do not drive losses on the Minnesota Power distribution system. The total annual energy for the Minnesota Power distribution system in 2020 that was used for the loss analysis was 3,330,942 MWh.

The contribution of each substation to annual energy consumption was determined based on the historical data. For each substation, the contribution of each of the feeder voltage classes associated with the substation was determined based on allocation factors derived from historical data and engineering estimates, as discussed in Section 3.4. The allocation factors were combined with the average energy loss factors from Table 3 to estimate the actual energy losses incurred on each voltage class at each substation during 2020. The Akeley Substation is provided as an example in Table 7.

Akeley 34/12/4 kV	Allocation Factors	kV Class Energy Loss Factor	kV Class Energy	kV Class Energy Losses
4 kV	14.53 %	5.69 %	10,716 MWh	610 MWh
12 kV	40.11 %	5.28 %	29,592 MWh	1,562 MWh
14 kV	0.00 %	N/A	N/A	N/A
23 kV	0.00 %	N/A	N/A	N/A
34 kV	100.00 %	1.08 %	73,774 MWh	797 MWh
46 kV	0.00 %	N/A	N/A	N/A
	Total Annual Energy for 2020		**73,774 MWh**	**2,969 MWh**

Table 8: Akeley Substation Peak Loss Analysis Example

Finally, the results from the individual substations were added up to determine the estimated annual energy losses by voltage class, the total system energy loss percentage, and the contribution of each voltage class to the total energy losses, as shown in Table 6 and Figure 4 above.

Appendix A: Comparison of 2016 & 2021 Loss Studies

The table below gives an overview of the differences in methodology and assumptions from the previous 2016 Loss Study to the current 2021 Loss Study. The methodology for the 2021 Loss Study was updated to be more direct and accurate when compared to the 2016 Loss Study.

2016 Loss Study	2021 Loss Study
Did not have readily available software tools integrated with GIS to perform loss calculations	Used previously-built WindMil models populated directly with data from GIS to perform loss calcuations
Evaluated a total of 9 feeders	Evaluated a total of 78 feeders
Includes the impact of other companies, cooperatives, and municipalities only up to the point of primary service point	Includes the impact of external utilities' loading as it flows across Minnesota Power distribution feeders. Bus-connected distribution loads excluded.
Assumed data in GIS was accurate	Assumed data in GIS was accurate
Assumed loads along feeder sections are uniformly distributed and balanced between phases	Load allocation and per-phase loading based on WindMil model and billing load data; feeders may be unbalanced
Feeders are only serving their own customer load and not tied to other feeders	Feeders are in their normal configuration and not tied to other feeders
Effect of capacitor banks and line regulators on feeders ignored	Capacitor banks disconnected and line regulators allowed to adjust
Transformer losses approximate and generalized, not based on actual transformer impedances	Transformer losses included in WindMil calculation based on transformer impedances by nameplate kVA
Transformer loss evaluation assumes 1.025pu voltage on primary side	Voltage on transformer primary side determined by WindMil or set to 1.00pu
All secondary lines are modeled as #2 AL Triplex conductor	All conductor assumptions in WindMil model are based on GIS data
Feeder voltage at substation source is 5 percent above nominal (1.05pu)	Feeder voltage at substation source is nominal (1.00pu)
Distribution feeders that do not serve any customers are modeled as sub-transmission lines and included in total percent loss of the distribution system	Losses calculated directly for parent feeders by voltage class consistent with other feeders included in the study
Feeder power factor is equal to unity	Feeder power factor based on historical load data from head of feeder

Appendix B: Feeder Loss Calculations

Table 8 below provides a comparison of feeders for which the loss percentages changed significantly after review and refinement of model data, as discussed in Section 4.4 of the report. The table on the following page provides detailed feeder loss calculation data for all feeders included in the study.

Feeder	Voltage Class	Original Loss Percentage	Refined Loss Percentage
FOR-263	14 kV	10.94 %	3.72 %
FOR-262	14 kV	14.08 %	3.61 %
SND-218	14 kV	11.42 %	5.29 %
BRW-2	12 kV	13.59 %	13.07 %
FLN-1	12 kV	20.20 %	4.53 %
FLN-2	12 kV	10.78 %	8.00 %
SWB-1	4 kV	20.15 %	16.40 %
KYL-1	4 kV	10.79 %	8.75 %
STZ-1	4 kV	11.64 %	9.55 %

Table 9: Model Validation & Refinement of Individual Feeder Loss Percentages

Feeder	Voltage Class (kV)	Area	Feeder Peak Date	Peak Loading @ Source (MW)	Peak Losses (kW)	Peak Loss Percentage	Avg Loading @ Source (MW)	Load Factor	Loss Factor	Average Losses (kW)	Energy Losses (MWh)	Annual Energy (MWh)	Energy Loss Percentage
31 Line	46	N	2/13/20 11:00 PM	4.60	5.00	**0.11%**	2.55	55.51%	38.23%	1.91	16.79	22,431.40	**0.07%**
32 Line	46	N	1/17/20 12:00 AM	8.40	136.00	**1.62%**	4.37	52.06%	34.59%	47.04	413.22	38,413.00	**1.08%**
33 Line	46	N	1/17/20 12:00 AM	12.50	429.00	**3.43%**	5.32	42.59%	25.48%	109.30	960.13	46,769.30	**2.05%**
BCR-23	46	C	2/20/20 7:00 AM	1.80	9.00	**0.50%**	0.98	54.55%	37.19%	3.35	29.40	8,624.90	**0.34%**
BAX-534	34	W	7/3/20 5:00 PM	6.15	155.00	**2.52%**	2.71	44.01%	26.76%	41.48	364.36	23,767.18	**1.53%**
RVT-532	34	W	12/1/20 8:00 AM	2.08	44.83	**2.16%**	0.52	25.08%	11.93%	5.35	46.97	4,572.72	**1.03%**
LSPI-208	34	C	7/6/20 3:00 PM	8.10	50.00	**0.62%**	4.81	59.36%	42.48%	21.24	186.56	42,237.20	**0.44%**
SLA-203	34	C	7/6/20 4:00 PM	13.60	362.11	**2.66%**	9.47	69.66%	54.86%	198.66	1,745.04	83,214.10	**2.10%**
LPR-501	34	W	7/31/20 3:00 PM	6.70	57.00	**0.85%**	4.22	62.97%	46.65%	26.59	233.57	37,087.46	**0.63%**
LPR-527	34	W	7/7/20 6:00 PM	7.48	10.80	**0.14%**	4.70	62.79%	46.44%	5.02	44.05	41,242.15	**0.11%**
LPR-535	34	W	7/7/20 1:00 PM	11.84	244.00	**2.06%**	7.44	62.89%	46.55%	113.59	997.73	65,388.85	**1.53%**
EGV-517	34	W	1/8/20 5:00 PM	7.90	102.00	**1.29%**	4.52	57.21%	40.08%	40.88	359.08	39,701.90	**0.90%**
PPL-514	34	W	2/13/20 11:00 PM	8.40	167.97	**2.00%**	5.09	60.65%	43.94%	73.81	648.34	44,749.80	**1.45%**
AUR-313	23	N	7/3/20 2:00 PM	4.26	79.02	**1.85%**	1.65	38.59%	22.00%	17.38	152.70	14,450.31	**1.06%**
HIB-308	23	N	6/11/20 12:00 PM	4.55	128.00	**2.82%**	3.34	73.48%	59.83%	76.59	672.74	29,356.44	**2.29%**
HIB-310	23	N	1/8/20 6:00 PM	6.69	462.00	**6.91%**	4.02	60.03%	43.24%	199.75	1,754.63	35,270.81	**4.97%**
HIB-315	23	N	12/30/20 7:00 PM	1.19	17.00	**1.43%**	0.69	57.93%	40.87%	6.95	61.03	6,275.38	**0.97%**
MTU-330	23	N	12/14/20 10:00 AM	2.80	53.00	**1.89%**	0.87	31.15%	16.14%	8.55	75.12	7,661.00	**0.98%**
HIB-312	23	N	12/22/20 9:00 AM	7.38	47.00	**0.64%**	2.41	32.70%	17.30%	8.13	71.41	21,188.07	**0.34%**
VRG-302	23	N	1/16/20 7:00 PM	4.77	83.00	**1.74%**	2.90	60.90%	44.23%	36.71	322.47	25,500.11	**1.26%**
GRY-200	14	C	7/18/20 5:00 PM	3.14	150.80	**4.81%**	1.78	56.61%	39.41%	59.43	522.07	15,592.96	**3.35%**
GRY-201	14	C	7/26/20 4:00 PM	3.25	153.00	**4.71%**	2.00	61.41%	44.82%	68.58	602.42	17,548.99	**3.43%**
FRR-275	14	C	2/14/20 8:00 AM	3.10	272.30	**8.78%**	1.43	46.20%	28.80%	78.42	688.81	12,579.50	**5.48%**
RGV-253	14	C	2/14/20 7:00 AM	4.50	336.60	**7.48%**	2.39	53.03%	35.60%	119.82	1,052.54	20,963.30	**5.02%**
CLQ-406	14	C	7/2/20 3:00 PM	10.32	509.00	**4.93%**	5.97	57.90%	40.83%	207.83	1,825.60	52,482.55	**3.48%**
CLQ-409	14	C	7/2/20 4:00 PM	7.32	394.78	**5.37%**	4.38	59.77%	42.94%	169.53	1,489.12	38,433.55	**3.87%**
CLQ-410	14	C	2/19/20 9:00 AM	4.13	196.00	**4.75%**	2.48	60.11%	43.33%	84.92	745.95	21,780.82	**3.42%**
WRN-411	14	C	12/24/20 9:00 AM	3.67	290.59	**7.92%**	1.91	52.15%	34.68%	100.78	885.25	16,796.74	**5.27%**
COL-240	14	C	12/24/20 5:00 PM	7.53	495.90	**6.58%**	4.17	55.31%	38.01%	188.48	1,655.65	36,604.66	**4.52%**
COL-241	14	C	12/24/20 6:00 PM	4.16	230.90	**5.55%**	2.17	52.21%	34.74%	80.22	704.62	19,091.83	**3.69%**
COL-242	14	C	1/16/20 6:00 PM	6.27	358.60	**5.71%**	3.83	60.97%	44.32%	158.92	1,395.93	33,601.07	**4.15%**
COL-244	14	C	12/24/20 5:00 PM	4.78	255.80	**5.35%**	2.76	57.73%	40.64%	103.97	913.26	24,231.71	**3.77%**
COL-245	14	C	2/14/20 7:00 AM	1.67	203.20	**12.15%**	1.19	71.36%	57.05%	115.92	1,018.27	10,478.11	**9.72%**
TFW-243	14	C	7/6/20 4:00 PM	3.20	157.30	**4.92%**	1.47	45.79%	28.41%	44.70	392.61	12,871.10	**3.05%**
FOR-263	14	C	6/26/20 1:00 PM	2.90	107.80	**3.72%**	1.64	56.59%	39.40%	42.47	373.06	14,416.40	**2.59%**
FOR-262	14	C	2/13/20 11:00 AM	2.60	93.80	**3.61%**	1.14	43.69%	26.47%	24.83	218.07	9,977.70	**2.19%**
SND-217	14	C	7/2/20 11:00 AM	3.70	143.70	**3.88%**	1.97	53.32%	35.89%	51.58	453.07	17,328.40	**2.61%**
SND-218	14	C	12/24/20 11:00 AM	2.40	127.00	**5.29%**	1.07	44.43%	27.15%	34.48	302.86	9,366.90	**3.23%**
NIN-248	14	C	1/16/20 6:00 PM	3.80	235.00	**6.18%**	2.17	57.03%	39.88%	93.71	823.12	19,035.90	**4.32%**
NIN-246	14	C	7/9/20 2:00 PM	2.60	149.10	**5.73%**	1.63	62.75%	46.39%	69.16	607.53	14,330.90	**4.24%**
INF-1	12	N	7/3/20 6:00 PM	2.26	306.80	**13.56%**	1.29	57.10%	39.95%	122.57	1,076.64	11,345.69	**9.49%**
INF-2	12	N	7/2/20 5:00 PM	3.54	193.80	**5.48%**	2.11	59.59%	42.74%	82.82	727.51	18,527.68	**3.93%**
INF-3	12	N	7/3/20 4:00 PM	4.51	401.90	**8.91%**	2.64	58.48%	41.48%	166.70	1,464.33	23,177.16	**6.32%**
INF-4	12	N	7/1/20 4:00 PM	2.85	148.90	**5.23%**	1.59	55.68%	38.41%	57.19	502.32	13,929.73	**3.61%**

Feeder	Voltage Class (kV)	Area	Feeder Peak Date	Peak Loading @ Source (MW)	Peak Losses (kW)	Peak Loss Percentage	Avg Loading @ Source (MW)	Load Factor	Loss Factor	Average Losses (kW)	Energy Losses (MWh)	Annual Energy (MWh)	Energy Loss Percentage
WRR-6321	12	C	[redacted]	0.68	79.60	**11.71%**	[redacted]	52.15%	34.68%	27.61	242.49	2,924.13	**8.29%**
PIL-1	12	W	[redacted]	0.30	46.50	**15.50%**	[redacted]	44.01%	26.76%	12.44	109.31	2,078.75	**5.26%**
LNL-1	12	W	[redacted]	0.20	19.30	**9.65%**	[redacted]	44.01%	26.76%	5.16	45.37	1,385.83	**3.27%**
PNB-1/PNB-2	12	W	[redacted]	2.93	240.50	**8.21%**	[redacted]	44.01%	26.76%	64.36	565.34	20,302.42	**2.78%**
CQB-6301	12	C	[redacted]	1.20	108.80	**9.07%**	[redacted]	59.77%	42.94%	46.72	410.40	6,300.66	**6.51%**
RVD-1	12	W	[redacted]	0.47	35.10	**7.47%**	[redacted]	25.08%	11.93%	4.19	36.78	1,033.32	**3.56%**
LGP-1	12	W	[redacted]	0.81	93.80	**11.58%**	[redacted]	62.97%	46.65%	43.76	384.37	4,483.65	**8.57%**
GGR-1	12	W	[redacted]	2.69	152.00	**5.65%**	[redacted]	62.79%	46.44%	70.58	619.99	14,831.00	**4.18%**
BBR-1	12	W	[redacted]	1.20	31.50	**2.63%**	[redacted]	62.89%	46.55%	14.66	128.81	6,650.00	**1.94%**
HPS-1	12	W	[redacted]	0.51	22.50	**4.41%**	[redacted]	62.89%	46.55%	10.47	92.00	2,826.00	**3.26%**
LCH-1	12	W	[redacted]	0.65	60.20	**9.26%**	[redacted]	62.89%	46.55%	28.02	246.16	3,589.00	**6.86%**
LPN-1	12	W	[redacted]	0.05	3.90	**7.80%**	[redacted]	62.89%	46.55%	1.82	15.95	276.00	**5.78%**
CLR-1	12	W	[redacted]	2.20	160.00	**7.27%**	[redacted]	57.21%	40.08%	64.12	563.26	11,056.00	**5.09%**
CLR-2	12	W	[redacted]	0.20	16.50	**8.25%**	[redacted]	57.21%	40.08%	6.61	58.09	1,005.00	**5.78%**
BRW-1	12	W	[redacted]	3.03	236.00	**7.79%**	[redacted]	57.21%	40.08%	94.58	830.80	15,227.00	**5.46%**
BRW-2	12	W	[redacted]	3.45	451.00	**13.07%**	[redacted]	57.21%	40.08%	180.75	1,587.68	17,338.00	**9.16%**
FLN-1	12	W	[redacted]	0.15	6.80	**4.53%**	[redacted]	60.65%	43.94%	2.99	26.25	799.00	**3.29%**
FLN-2	12	W	[redacted]	0.65	52.00	**8.00%**	[redacted]	60.65%	43.94%	22.85	200.71	3,462.00	**5.80%**
LLK-1	12	W	[redacted]	0.72	67.80	**9.42%**	[redacted]	60.65%	43.94%	29.79	261.70	3,835.00	**6.82%**
SWN-1	12	W	[redacted]	2.27	133.00	**5.86%**	[redacted]	60.65%	43.94%	58.44	513.36	12,093.00	**4.25%**
BAL	12	N	[redacted]	1.41	23.80	**1.69%**	[redacted]	60.03%	43.24%	10.29	90.39	7,433.80	**1.22%**
KER-6501	12	C	[redacted]	0.80	87.70	**10.97%**	[redacted]	54.55%	37.19%	32.62	286.53	3,622.46	**7.91%**
ASK-6521	12	C	[redacted]	1.10	65.10	**5.92%**	[redacted]	54.55%	37.19%	24.21	212.69	5,002.44	**4.25%**
HYN-1	4	N	[redacted]	0.56	25.30	**4.52%**	[redacted]	38.59%	22.00%	5.57	48.89	1,899.57	**2.57%**
HYN-2	4	N	[redacted]	1.89	146.30	**7.74%**	[redacted]	38.59%	22.00%	32.19	282.72	6,411.05	**4.41%**
LPD-2	4	W	[redacted]	0.58	24.20	**4.17%**	[redacted]	62.79%	46.44%	11.24	98.71	3,197.90	**3.09%**
SWB-1	4	N	[redacted]	0.20	32.80	**16.40%**	[redacted]	73.48%	59.84%	19.63	172.41	1,290.40	**13.36%**
CHL-1	4	N	[redacted]	2.30	184.00	**8.00%**	[redacted]	60.03%	43.24%	79.56	698.81	12,126.00	**5.76%**
CHL-2	4	N	[redacted]	1.15	80.70	**7.02%**	[redacted]	60.03%	43.24%	34.89	306.49	6,063.00	**5.06%**
CHL-3	4	N	[redacted]	1.87	146.40	**7.83%**	[redacted]	60.03%	43.24%	63.30	556.01	9,859.00	**5.64%**
KYL-1	4	N	[redacted]	0.56	49.00	**8.75%**	[redacted]	57.93%	40.87%	20.03	175.91	2,952.00	**5.96%**
SVE-1	4	N	[redacted]	0.09	12.00	**13.33%**	[redacted]	31.15%	16.14%	1.94	17.01	245.20	**6.94%**
SVW-1	4	N	[redacted]	0.26	24.50	**9.42%**	[redacted]	31.15%	16.14%	3.95	34.73	711.40	**4.88%**
STZ-1	4	N	[redacted]	0.22	21.00	**9.55%**	[redacted]	31.15%	16.14%	3.39	29.77	601.90	**4.95%**

Averages by Voltage Class	Peak Loss %	Energy Loss %
4	8.79%	5.69%
12	8.11%	5.28%
14	5.87%	4.07%
23	2.47%	1.70%
34	1.59%	1.08%
46	1.42%	0.89%

MINNESOTA POWER'S

2023 TRANSPORTATION ELECTRIFICATION PLAN

APPENDIX E

Docket No. E-015/M-23-258

October 16, 2023

Contents

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of a Commission Inquiry into Electric Vehicle Charging and Infrastructure	Docket No. E-015/M-23-258 **2023 Transportation Electrification Plan**

I. Introduction

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

General Findings:

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

Specific Findings:

- Minnesota's investor-owned utilities should take steps to encourage the cost-effective adoption and integration of EVs.
- The following should be included at a minimum in any EV-related utility proposals:
    - Any EV-related proposals that involve significant investments for which the utility is seeking or will seek cost recovery should include a cost-benefit analysis that

- shows the expected costs along with the expected ratepayer, system and societal benefits associated with the proposal.
- In the case of a proposed pilot, the utility filing should include specific evaluation metrics for the pilot and identify what the utility expects to learn from the pilot.

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

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

1. Minnesota Power shall provide a summary of the utility's ongoing transportation electrification efforts, including existing programs and projects in development over at least the next 2 years.

2. Minnesota Power shall provide a discussion of how it plans to facilitate: a. availability and awareness of public charging infrastructure, including an assessment of the private sector fast charging marketplace for the utility's service territory; b. availability of residential charging options for both single family and multiple unit dwellings; c. programs or tariffs in development to address flexible load or reduce metering and data costs; and d. fleet electrification.

3. Minnesota Power shall provide a discussion of how it plans to optimize EV benefits, including a discussion of how to align charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency.

4. Minnesota Power shall include a discussion of how it plans to encourage more customers with electric vehicles to participate in managed charging.

5. Minnesota Power shall provide a discussion that addresses divestment issues and identifies possible divestment strategies for its DCFC Network approved in Docket 21- 257 at the conclusion of the pilot program.

6. Minnesota Power shall provide evaluations of non-pilot EV programs that examine the cost-effectiveness of the programs as currently designed and potential changes that could improve their cost-effectiveness.

7. Minnesota Power shall provide a summary of customer EV education initiatives. The Company does not need to provide specific examples of outreach materials.

8. Minnesota Power shall provide summaries of any proposals or pilots, including links to full reports, submitted to other regulatory agencies or jurisdictions (for example, proposals submitted under Conservation Improvement Programs or pilots run in other states).

9. Minnesota Power shall provide attachments or links to the most recent reports for any ongoing EV pilots or programs.

10. Minnesota Power shall provide historical spending for the past 5-years on all transportation electrification initiatives, broken down across the sections of its budget.

This 2023 Transportation Electrification Plan ("TEP") is submitted on behalf of Minnesota Power (or, "the Company") in response to the Commission's findings and actions.

II. Background

Minnesota Power's Electrification Guiding Principles

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

Education

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

Accessibility

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

Optimization

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

Environment

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

Simplicity

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

Security

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

III. Response to Order Points

Minnesota Power continues to plan for and encourage increased EV adoption in its service territory. In the following sections the Company outlines how its current and planned EV-related initiatives address the specific requirements in the orders in this docket.[1]

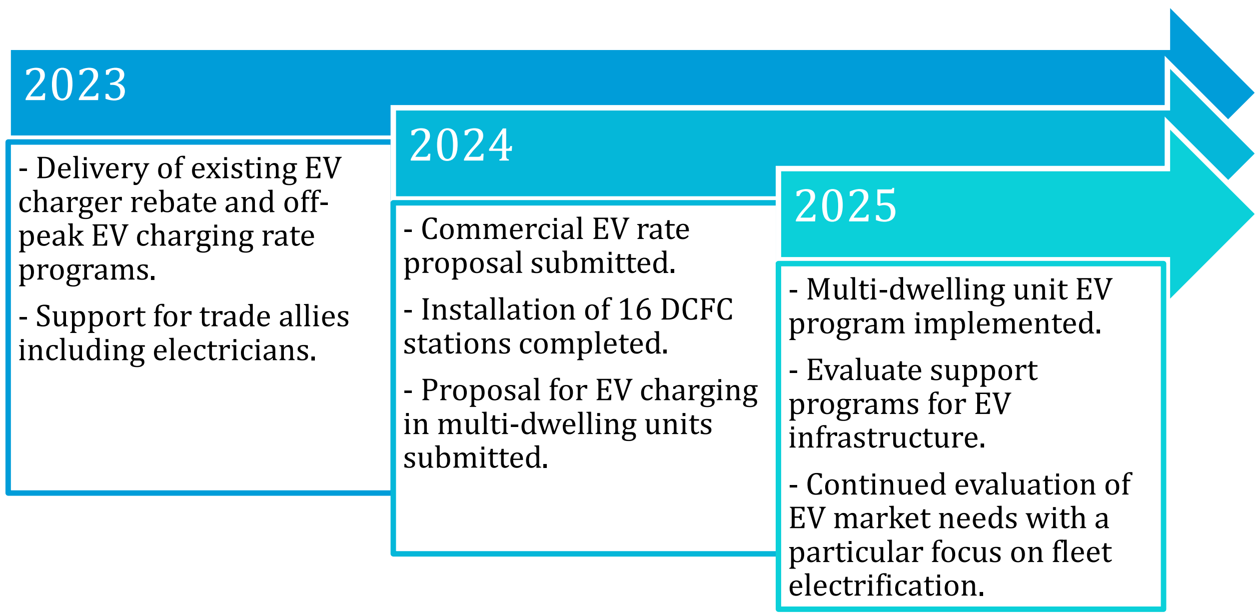
1. Summary of Minnesota Power's Ongoing Transportation Electrification Efforts

Minnesota Power continues to deliver and enhance existing EV programs while also identifying opportunities to support expanded adoption of EVs in northern Minnesota. Figure 2 below provides an overview and timeline of planned EV initiatives. The Company continues to make progress on installation of 16 direct current fast charging ("DCFC") stations throughout its service territory as approved in Docket No. E015/M-21-257. Additionally, Minnesota Power will submit a permanent Commercial EV Rate by January 31, 2024 as required in Docket No. E015/M-19-337 and a program to support EV charging in multifamily-dwelling units by the fourth quarter of 2024 as required in Docket No. E999/CI-17-879. In addition to these specific programs, Minnesota Power also intends to continuously monitor the need for EV infrastructure, including both EV chargers and make-ready infrastructure, and fleet advisory and support services.

This list is not final or exclusionary and the Company anticipates there will be modifications to the timeline and proposals as EV growth, programs, and policy advance. It is also important to note that the Company has experienced program distruptions and implementation delays as a result of unexpected changes in the rapidly evolving EV industry and anticipates that trend to continue. For example, Minnesota Power was forced to cancel it's Smart Charge Rewards pilot program when the vendor delivering the program was acquired and decided to discontinue the service.

[1] Docket No. E-999/CI-17-879 & E-015/M-21-390, December 08. 2022

Figure 2: EV Initiatives Implementation Timeline



Minnesota Power has been working to address many of the barriers to EV adoption and areas of focus outlined by the Commission and commonly discussed across the industry. To date these efforts have resulted in a number of EV programs. These programs include; Residential EV Tariff, EV Residential Charging Rebates, Commercial EV Tariff and EV Charging Infrastructure Investment Project.

Details regarding these programs are outlined below.

Residential EV Tariff

Minnesota Power has offered a Residential Off-Peak Electric Vehicle Service tariff[2] ("Residential EV Tariff") since 2015. The details of the tariff are as follows:

Service Charge $4.25

Off-Peak Energy Charge

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[2] Docket No. E-015/M-15-120

All kWh (per kWh) 2.391¢

On-Peak Energy Charge

All kWh (per kWh) 10.251¢

On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Minnesota Power had 27 customers enrolled in the Residential EV Tariff as of April 2023. The Company has seen increased interest in this rate option as customers see the benefit of discounted overnight charging rates. However, the Company has also heard feedback from customers that the necessity to install a second metered service is a barrier to participation. Installing a second service may not be possible for all customers for a variety of reasons including upfront cost and access to off-street parking.

As an alternative to the Residential EV Tariff, Minnesota Power's Residential Time-of-Day rate[3], implemented in October 2022, allows EV customers to get a discount for charging during off-peak and super off-peak times without the requirement of installing a second service.

EV Residential Charging Rebates

Minnesota Power proposed and received approval[4] to implement two EV charger rebate offerings to help address the up-front costs associated with at home charging.

EV Second Service Rebate

The Company offers a $500 rebate for costs related to installing the required second service to participate in the Residential EV Tariff. For the period May 1, 2022 to April 30, 2023, Minnesota Power provided 7 rebates.

Level 2 Smart Charger Rebate

[3] Docket No. E015/M-20-850
[4] Docket No. E015/M-20-638

Minnesota Power provides a $500 rebate towards the purchase of Level 2 smart chargers for home charging. This rebate is designed to further offset upfront costs and to encourage the use of smart chargers over standard chargers. Chargers must be OCPP compliant, and customers must be enrolled in time-of-use program or rate to qualify. For the period May 1, 2022 to April 30, 2023, the Company provided 18 rebates.

Commercial EV Tariff

Minnesota Power implemented its Electric Vehicle Commercial Charging Rate Pilot for Commercial and Industrial Customers ("Commercial EV Tariff") in March 2020.[5] The Commercial EV Tariff consists of; On-Peak, Off-Peak and Super-Off Peak periods as well as a 30 percent cap on demand charges. The Commercial EV Tariff is designed to address the high demand charges associated with EV charging, particularly in fleet and public charging applications. This Commercial EV Tariff is an initial step towards incentivizing EV charging and will need to be refined as current barriers are overcome and knowledge is gained. Details of the Pilot are as follows:

Service Charge $12.00

Demand Charge for On-Peak kW $6.50

Energy Charge for all kWh 6.054¢

On-Peak periods are defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. Super Off-Peak is defined as 11:00 p.m. to 5:00 a.m., Monday through Friday, inclusive, excluding holidays. Off-Peak is all other hours other than On-Peak or Super Off-Peak. There are no Demand Charge applied during Off-Peak or Super Off-Peak hours.

Minnesota Power currently has nine customers, representing fourteen separate locations, enrolled in the Commercial EV Tariff, of which the largest consumer of energy is the Duluth Transit Authority. The Company will continue to work with participating customers to understand how well the rate meets customer needs.

EV Charging Infrastructure Investment Project

[5] Docket No. E015/M-19-337

Minnesota Power's EV Charging Infrastructure Investment project approved by the Commission on October 22, 2021[6] allows the Company to install and own 16 DCFC throughout its service territory. This project aims to increase customer access to electric vehicle charging in both rural and more densely populated communities in Minnesota Power's service territory and along major travel corridors in northern Minnesota or where there are large distance gaps between existing public chargers. Once complete, this initiative will support EV drivers by increasing access to public EV charging stations and position the region to accommodate the anticipated growth of EV adoption in the coming years.

Minnesota Power notified the Commission in a letter filed in Docket No. E015/M-21-257 on May 9, 2023 of a vendor issue that has delayed the project. Minnesota Power reissued a request for proposals ("RFP") to select a new vendor to complete installation of the chargers on August 22, 2023 and anticipates that the chargers will be operational in 2024. The Company remains committed to meeting the goals of the State of Minnesota and the Minnesota Public Utilities Commission for greenhouse gas reduction and electrification of transportation.

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

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

In 2019, Minnesota Power worked with customers to donate 20 Level 2 EV chargers to businesses in strategic locations across the Company's service territory expanding the availability of Level 2 chargers. Minnesota Power also received approval by the Commission on October 22, 2021 to expand access to fast charging via the installation of 16 DCFC stations throughout Minnesota

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

Power's service territory.[7] The target locations were identified based on three criteria: gaps in existing public fast chargers, population clusters and proximity to major travel corridors. Where possible, the Company will ensure that chargers are located within areas identified as a concern for environmental justice. Building a minimum network of EV fast chargers will help to ensure that EV drivers are able to conveniently travel throughout the state, reducing range anxiety, particularly for drivers traveling outside the metro area.

According to the AFDC Station Locator for Minnesota there are currently nine public DCFC stations in Minnesota Power's service territory, and one DCFC station operating in support of a fleet operator. All but one of the public stations are enrolled in Minnesota Power's Commercial EV Tariff. Additionally, the singular private fleet based DCFC station is enrolled in the Commercial EV Tariff is utilized for electrified public transportation. Level 2 public charging continues to grow. According to the Minnesota Department of Transportation's Electric Vehicle Dashboard[8] there are an estimated 87 Level 2 charging ports within Minnesota Power's territory. The Company will continue to monitor charging infrastructure within its territory and evaluate if more EV infrastructure programs and offerings are needed to support current and future EV adoption.

In addition to monitoring and expanding access to public charging infrastructure, Minnesota Power is committed to providing outreach and education to customers and the general public regarding EV charging. This includes information on its website, promotion at public events and awareness campaigns on how to charge an EV and where to find public chargers. The Company understands that lack of awareness and information is a major barrier to EV adoption and as such, Minnesota Power has increased its focus on EV education in recent years.

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

As described above, Minnesota Power currently offers two time-of-use program or rates to residential customers:

[7] Docket No. E015/M-21-257
[8] https://atlaspolicy.com/evaluatemn/

Residential EV Tariff

Minnesota Power has offered a Residential Off-Peak Electric Vehicle Service tariff[9] ("Residential EV Tariff") since 2015. Customers are required to install a separate metered service to participate. The details of the tariff are as follows:

Service Charge $4.25
Off-Peak Energy Charge
All kWh (per kWh) 2.391¢
On-Peak Energy Charge
All kWh (per kWh) 10.251¢

On-Peak and Off-Peak Energy Defined: The On-Peak Energy shall be defined as energy used from 8:00 a.m. to 10:00 p.m., Monday through Friday, inclusive, excluding holidays. The Off-Peak Energy shall include energy used in all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Residential Time-of-Day Rate

The company implemented a Residential Time-of-Day rate[10] in October of 2022. This rate option provides discounted Off-Peak rates without a second metered service requirement. The Details of the Time-of-Day rate are as follows:

Service Charge $8.00
Super-Off-Peak Energy Charge
All kWh (per kWh) 5.707¢
Off-Peak Energy Charge
All kWh (per kWh) 8.145¢
On-Peak Energy Charge
All kWh (per kWh) 12.051¢

[9] Docket No. E-015/M-15-120
[10] Docket No. E-015/M-20-850

The On-Peak Periods shall be defined as 3:00 p.m. to 8:00 p.m., Monday through Friday, inclusive, excluding holidays. The Super Off-Peak Period shall be defined as 11:00 p.m.

to 5 a.m., inclusive. The Off-Peak Periods shall include all other hours. Holidays shall be those days nationally designated and celebrated as New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving and Christmas.

Minnesota Power will continue to work with customers and stakeholders to understand how well these programs meet customer needs and address barriers to entry. The Company is also currently assessing opportunities to better serve multifamily residents and expects to submit a proposal to facilitate EV charging in multiple-dwelling units by the fourth quarter of 2024.

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

Minnesota Power currently provides several programs and tariffs designed to address flexible load and/or reduce metering costs. Specifically, the Company currently offers two EV charging rates designed to encourage charging during off-peak times. The commercial EV charging rate pilot introduced in 2020 established a time-of-day schedule for commercial EV charging, includes no charges for demand incurred during off-peak times and limits total demand to 30 percent of a customer's total bill. Minnesota Power is required to submit a permanent rate to replace the commercial EV charging rate pilot by January 31, 2024.[11]

As described above, the Company also offers a residential EV charging rate that provides a discount for off-peak charging. However, Minnesota Power is aware that the requirement to install a second service is a barrier to participation in this rate. To overcome this barrier, the Company offers two rebates totaling up to $1,000 per customer to reduce the upfront costs associated with installing a second service; 1) a $500 rebate towards the cost of installing a second service and 2) a $500 rebate on a (Wi-Fi or internet enabled) smart charger. For customers that don't want to or are not able to install a second service, the Company's Residential Time-of-Day rate provides an option for discounted off-peak charging.

[11] Docket No. E015/M-19-337

2d. Fleet Electrification

Minnesota Power is actively engaging fleet operators throughout its service territory to better understand customer interest in fleet electrification. While some customers have expressed specific goals and interest in converting their fleets to electric vehicles, others are working to understand the impact of fleet electrification to their operations and expenses. As each customer has unique considerations, Minnesota Power is actively exploring options to assist fleet managers in analyzing fleet conversion for their specific businesses. The Company received Commission approval in Docket No. E015/M-20-638 for an EV outreach budget, which includes funding for online tools and fleet analytics. As a result, Minnesota Power has supported two fleet electrification assessments. The Company will continue to work with customers to identify cost effective and impactful approaches to fleet analytics as EV adoption in fleets increases. In addition to assisting customers with fleet electrification, Minnesota Power has also announced plans for electrification of its own fleet. In September of 2020[12], as part of its Energy***Forward*** strategy, the Company identified a goal of electrifying 50 percent of its light-duty vehicles and 25 percent of its medium and heavy-duty vehicles, including line trucks, to be transitioned to plug-in technology by 2030.

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

The Company has started exploring ways in which it can align charging periods for EV rates with periods of lower electric system demand and higher renewable energy production. Minnesota Power's Residential EV Tariff, Commercial EV Tariff, and its Residential Time-of-Day Rate utilize time of use periods. These programs will prepare customers for anticipated time varying and dynamic pricing-based rates and will allow the Company to collect data around EV charging behavior and patterns, demand and other system impacts, and price responsiveness. These insights will improve Minnesota Power's ability to perform the necessary forecasting and analytics to create effective programming in the future.

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[12] https://minnesotapower.blob.core.windows.net/content/Content/Documents/Company/PressReleases/2020/20200928_NewsRelease.pdf

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

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

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

In its October 22, 2021 Order, the Commission adopted the Department of Commerce's recommendation for divestment-related reporting. Minnesota Power's stated goal in Docket 21-257 is to stimulate the EV charging market and alleviate range anxiety for EV drivers in the Company's service territory, not to undercut private sector charging networks or establish a long-term EV charging business model. The Company will investigate any and all possible divestment strategies at the conclusion of this pilot, including the sale of EV charging infrastructure to site hosts or third-party charging companies. As Minnesota Power is still in the process of procuring chargers with plans to complete installation in 2024, no divestment plan has been developed yet.

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

Minnesota Power currently offers a residential EV rate. At this time there are less than 30 customers on the rate. As such, the program does not currently have significant cost-effectiveness implications. However, the rate is evaluated on an on-going basis through annual EV rate compliance filings and rate case efforts. Through these efforts, Minnesota Power evaluates participants usage patterns as well as the on to off-peak price differential to ensure it is meaningful enough to encourage beneficial charging behavior – one of the main objectives of the rate, reviews the peak period hours from both the participants perspective and to understand impacts on the system, considers whether the benefits are high enough to off-set the costs to the participant of the program, and ensures that the rate is well aligned relative to other residential rates. The Company uses this information to inform any proposed changes to the rate through its rate case proceedings.

7. Summary of Customer EV education initiatives.

Minnesota Power has invested resources to develop and promote EVs in its service territory and statewide over the past year. An overview of the various methods and channels the Company has been using to educate customers on the benefits of electric vehicles and to inform them of the Company's EV tariff and rebate programs is provided in Table 2 starting on below. For its 2022/2023 Annual Report in Docket No. E-015/M-15-120, Minnesota Power tracked direct costs related to promotional activities at $5,113 (this does not include labor, materials or advertisements that the Company designed and printed in-house). Minnesota Power received approval for a dedicated EV Education and Outreach budget in the Commission's April 21, 2021 Order in Docket No. E-015/M-20-638.

EV Outreach and Education expenditures

Table 1: Outreach and Education Expenditures

Date	Event	Description	Estimated Attendance	Cost
7/13/2022	Duluth Sidewalk Days	MP hosted booth to promote electric vehicles and programs to Duluth Sidewalk Days attendees.	2,000	$0
7/13/2022	Kolar Auto Show	MP Hosted booth with five local EV owners to promote electric vehicles and programs to local car dealer show attendees.	500	$60
8/30/2022	North Country EV Show and Tell	MP Hosted booth to promote electric vehicles and programs to North Country Show and Tell attendees.	100	$421
9/10/2022	Harvest Festival	MP hosted booth to promote electric vehicles and programs to North Country Show and Tell attendees.	2,000	$60
9/24/2022	Electric Car Show	2nd annual electric car show in Duluth, MN, where EV drivers can display their EVs and speak with attendees. The event featured giveaways to attract attendees.	100	$1,072
9/26/2022	Duluth Superior Eco Rotary Club	EV Presentation to Duluth Superior Eco Rotary Club.	17	$0
10/4/2022	Meadowlands City Council Meeting	EV Presentation to Meadowlands city council and citizens.	12	$0
2/22/2023	Energy Design Conference (EDC)	Presentation on electric vehicles to EDC attendees including builders, architects, students, energy professionals, etc.	50	$1,000
3/30/2023		Arrowhead Home & Builders Show MP Hosted Booth	5,000	$0
Various	Customer Presentations	Minnesota Power has made a number of direct presentations to customers and customer groups who have expressed interest in transportation electrification	50	$0
		Sponsorship for Drive Electric Minnesota	N/A	$2,500

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

Minnesota Power serves retail customers solely within the state of Minnesota and has submitted no other proposal or pilots to other agencies or jurisdictions.

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

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

- Commercial EV Charging Rate Pilot: Docket No. E015/M-19-337
- Portfolio of Electric Vehicle Programs: Docket No E015/M-20-638
- EV Charging Infrastructure Investment: Docket No. E015/M-21-257

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

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

Table 2: Historical Spending

Budget Category	Capital	O&M	Marketing & Communications	Other*
Customer Programs			$10,808.24	$524,089.98

*Other expenses include rebate incentives and labor

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

Minnesota Power received Commission approval to install and own 16 DC fast charging stations throughout its service territory in Docket No. E015/M-21-257. The figures below represent the costs associated with that initiative as well as delivery of the Company's rebate and educational programs over the next 5 years.

Budget Category	Capital	O&M	Marketing & Communications	Other*
Distribution	$2,602,161.00	$549,838		
Customer Programs			$275,000.00	$1,424,724.00

*Other expenses include rebate incentives and labor.

IV. Conclusion

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

Dated: October 16, 2023

Respectfully submitted,

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BENEFIT-COST ANALYSIS (BCA) FRAMEWORK REPORT

PREPARED FOR

Minnesota Power

6 SEPTEMBER 2022

BLACK & VEATCH

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Introduction

As part of Minnesota Power’s request to develop a Business Case Non-Wire Alternative (NWA) projects, Black & Veatch utilized our professional expertise and industry best practices to develop a realistic Business Case for the evaluation and justification for NWA projects. A summary of the activities which were conducted as part of this are:

- Identify the benefit opportunity areas that are relevant to the NWA projects.
- Gather Minnesota Power data to support the calculation of benefits
- Define calculations for each benefit calculation and apply the data to generate each benefit
- Define, review, and adjust benefit assumptions based on Minnesota Power’ feedback
- Identify costs related to the activities required to Implement the NWA projects and achieve the benefits
- Develop a Business Case, including a 20-year NPV, for the Kerrick, Wrenshall and Silver Bay projects.

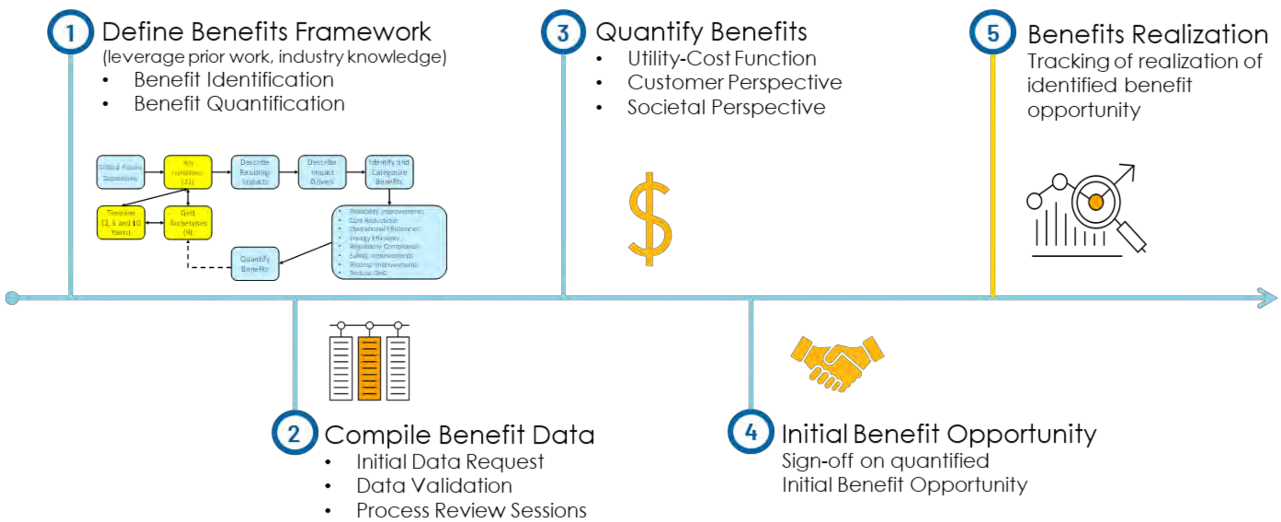

Figure 1 - Business Benefit Approach

METHODOLOGY OF THE BCA FRAMEWORK

The methodology for the BCA is depicted in Figure 2 below.

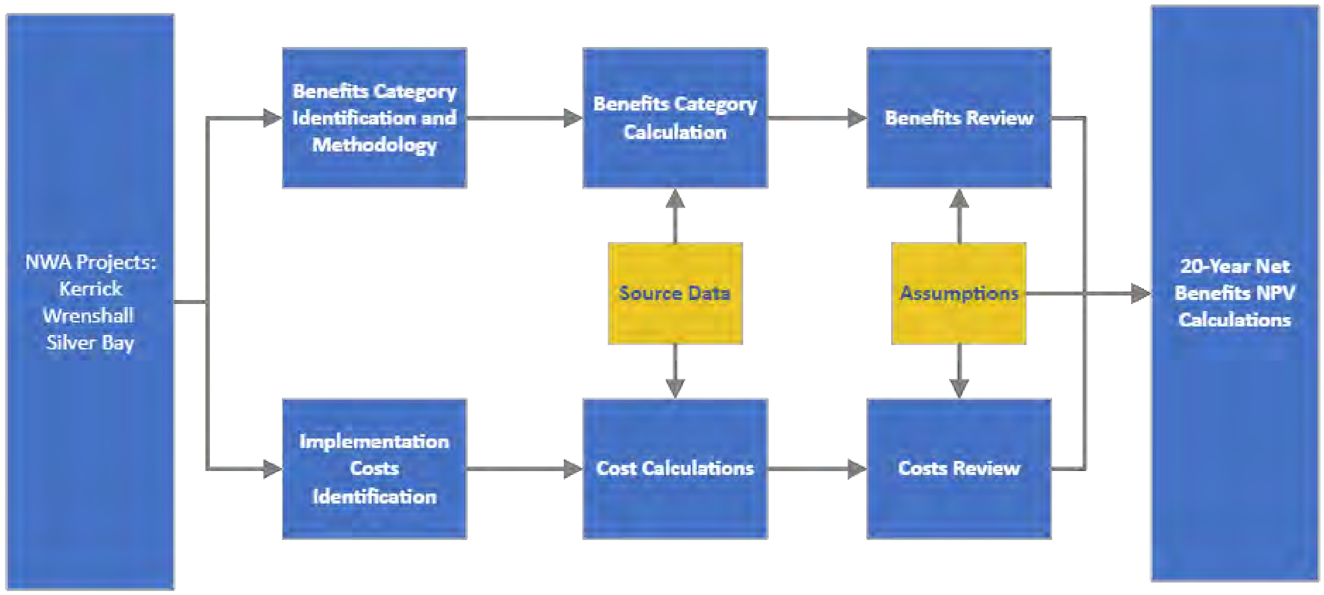

Figure 2 - BCA Methodology

For example, a reduction in the number of minutes of interruption from an outage (as measured in Customer Minutes of Interruption or CMI and related reductions in SAIDI and CAIDI) as a result of the NWA Project would be applied against an O&M unit cost factor or a cost per field crew metric to monetize the utility-related benefit of the reduced field time (including reduced truck rolls) enabled by the Program.

The BCA is comprised of the following 4 files:

- BCA Framework & Summary Final – This file contains the Benefit Mapping, Cost Backup, Cost Summary, Annual Benefit Summary and the 20 Year NPV.
- Circuit Backup Calculations Final – This file contains the Circuit Backup detail benefit calculations, assumptions, and key source data. This program's benefits were applied to Kerrick, Wrenshall and Silver Bay for the BESS solution benefits.
- FLISR Calculations Final - This file contains the FLISR detail benefit calculations, assumptions, and key source data. This program's benefits were applied to Kerrick and Wrenshall as reclosers were added in the solution providing this program's benefits.
- IVVC Calculations Final - This file contains the IVVC detail benefit calculations, assumptions, and key source data. This framework was designed to calculate the benefits of a system-wide IVVC deployment and was ultimately not used for the project evaluations.

The benefits category mapping to the 3 programs (Circuit Backup, FLISR and IVVC) is shown below. The calculation files contain the calculation details for each of the benefits mapped to the programs.

			Utility-Cost Function								Customer Perspective		
			Reduced/ Avoided Capital Costs	Generation Capacity Benefits	Energy Benefits	Reduced/ Avoided Ancillary Services Costs	Reduced/ Avoided T&D Losses	Avoided Restoration Costs	Compliance Risk	Improved Power Quality	Customer Outage Reduction Value	Increased Customer Satisfaction	Avoided Customer Fuel Cost
No.	Program	Project Short Description	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category
D-01	FLISR	Circuit segmentation and automation						✓	✓		✓	✓	
D-02	Circuit Backup	BESS, Solar, Combination providing reliability backup	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
D-03	IVVC	BESS, Solar, Combination providing IVVC		✓	✓	✓	✓		✓	✓			✓

Figure 3 - Benefit Mapping

The following Societal Benefits were identified but were not quantified.

			Societal Perspective				
			Avoided Outage Costs	DER Enablement	Increased Customer Flexibility and Choice	Environmental Benefits	Improved Safety
No.	Program	Project Short Description	Benefits Category	Benefits Category	Benefits Category	Benefits Category	Benefits Category
D-01	FLISR	Circuit segmentation and automation	✓	✓		✓	✓
D-02	Circuit Backup	BESS, Solar, Combination providing reliability backup	✓	✓	✓	✓	✓
D-03	IVVC	BESS, Solar, Combination providing IVVC		✓	✓	✓	✓

Figure 4 - Societal Benefit Mapping

Quantification of Benefits

This section describes how specific categories of benefits can be quantified using a combination of the operational value(s) derived by the NWA projects and a risk-based framework.

Understanding the impact of an investment is an important step within the BCA. Benefit estimates should be supported by explanations of how a proposed technology or initiative functions in order to drive impacts (e.g., one must describe how circuit reclosers reduce the occurrence of day-to-day sustained interruptions before applying data and reduction factors to estimate the operational value of such improvements). Additionally, secondary levels of impacts such as reduced field trips to investigate outage conditions should also be explored to understand how they too might translate into specific impacts (e.g., reduced O&M costs). This discipline of linking investment, technology, functionality, and multi-layer impacts is a key step in the benefit identification process.

BENEFIT RATIONALE FOR DISTRIBUTION ASSET MANAGEMENT

The benefits identified fit into three categories detailed below: Calculated Benefits, Risk Based Benefits and Non-Quantified Benefits. Both Minnesota Power and their customers benefit through the system improvements outlined for each of the projects. The solutions are anticipated to lead to customer benefits related to reduced outages, improved customer satisfaction, improved power quality and fuel cost savings. The solutions will also reduce O&M costs through avoided restoration costs, reduced line losses and reduced ancillary services costs plus avoided capital costs by installing BESS instead of traditional and expensive line and substation re-builds.

Each of these benefits are described in more detail in the section below.

CALCULATED BENEFITS

Avoided Capital Costs

Program Application: Circuit Backup

The avoided capital cost was estimated as the cost of a traditional solution. For Kerrick, this was the estimated cost of rebuilding the Thomson line. For Wrenshall, this was the estimated cost of rebuilding Wrenshall and Military Road substations. For Silver Bay, this was the estimated cost of adding a 115/13.8 kV source at North Shore Substation. These benefits were included in year 10 as a one-year benefit.

Generation Capacity Benefits

Program Application: IVVC, Circuit Backup

<u>Avoided Generation Capacity</u>

Avoided capacity and energy costs are based upon the costs an electric utility would incur to either construct or operate new electric power plants, purchase power from another source or to operate existing power plants. These avoided costs of electricity include both fixed and variable costs that can be directly avoided through a reduction in electricity usage. The capacity cost component includes costs associated with the capability to deliver electric energy during peak load periods. Capacity costs consist primarily of the costs associated with building peaking generation facilities.

For the IVVC program, a system-wide benefit assuming a system-wide IVVC implementation was calculated. The portion of the benefit for each circuit was determined by the circuit's peak load divided by the coincident system-wide 2023 peak. This percentage was applied to the total system-wide benefit.

Generation Capacity Revenue

For the Circuit Backup program, the BESS provided additional generation capacity. This was calculated for each BESS.

Energy Benefits

Program Application: IVVC, Circuit Backup

Avoided Energy Costs

For the IVVC program, this calculation represents the avoided energy due to the voltage reduction. An avoided Energy (kWh) was calculated based on the circuit's peak load using capacity factor and voltage reduction percentage assumptions.

Lost Sales Revenue

For the Circuit Backup program this calculation represents revenue that is recovery by supplying customers in what would have been an outage from the BESS. When customers experience an outage, utilities lose this revenue both from the sales and delivery of the energy. This was calculated based on the average load and outage duration for every circuit and the difference between discharging and charging costs for the BESS on that circuit.

Reduced/ Avoided Ancillary Services Costs

Program Application: IVVC, Circuit Backup

Ancillary Services Costs are costs occur when energy resources cause ancillary service costs on the utility's system (e.g., spinning reserves, and frequency regulation).

For the IVVC program, these savings were calculated similar to the Generation Benefit. A system-wide benefit assuming a system-wide IVVC implementation was calculated. The portion of the benefit for each circuit was determined by the circuit's peak load divided by the coincident system-wide 2023 peak. This percentage was applied to the total system-wide benefit of estimated ancillary cost savings.

For the Circuit Backup program, the percentage of the circuit peak load to the coincident system peak load was calculated and applied to the estimated annual ancillary costs. These estimated costs need to be validated and are changeable in the workbook. In addition, there may be some revenue benefits for including the BESS as a generation capacity source. This option should be explored with MISO.

Reduced/ Avoided T&D Losses

Program Application: IVVC, Circuit Backup

For the IVVC program, these savings were calculated similar to the Generation Benefit. A system-wide benefit assuming a system-wide IVVC implementation was calculated. The portion of the benefit for each circuit was determined by the circuit's peak load divided by the coincident system-wide 2023 peak. This percentage was applied to the total system-wide benefit T&D loss savings.

For the Circuit Backup program, the T&D losses were calculated based on the annual energy savings in the Energy Benefits category. The 7.83% T&D losses were based on Minnesota Power's 2021 IRP.

Avoided Customer Fuel Cost

Program Application: IVVC, Circuit Backup

For the IVVC program, these savings were calculated similar to the Generation Benefit. A system-wide benefit assuming a system-wide IVVC implementation was calculated. The portion of the benefit for each circuit was determined by the circuit's peak load divided by the coincident system-wide 2023 peak. This percentage was applied to the total system-wide fuel cost savings.

For the Circuit Backup program, the Fuel Cost savings were calculated based on the annual energy savings in the Energy Benefits category. An average Fuel Cost of $16.45/MWh was sourced from United States LCOE 2021 Data.

Avoided Restoration Costs

Program Application: Circuit Backup, FLISR

Avoided Restoration Costs includes any benefits for avoided costs of restoring power during outages.

For the Circuit Backup program, the avoided costs were calculated by average outage cost and the number of outages that may be avoided for restoring power

For the FLISR program, outages are not avoided, but the duration is reduced because of faster fault location due to fault location technology on reclosers and the addition of sectionalizing equipment. The avoided costs were calculated by estimated the patrol time savings per outage, number of annual outages and average restoration cost per minute.

Customer Outage Reduction Value

Program Application: Circuit Backup, FLISR

Customer Outage Reduction includes Minnesota Power's customers benefits for reducing outages. The benefit was calculated using the Interruption Cost Estimate (ICE) Calculator (www.icecalculator.com) for Minnesota Power's territory by customer category. An average dollar per customer minute of interruption ($/CMI) was applied to the estimated improvement in minutes of interruptions due to equipment failures.

RISK BASED BENEFITS

Risk based benefits use the concept of Probability and Consequence of the risk occurring to quantify the level of risk and the monetary value of that risk. For each of the risks, appropriate levels of probability and consequence have been selected and used to drive benefits.

Table 1 - Probability Table

Level	Description	Range	Midpoint/Representative Value
Almost Certain	Imminent (100% chance of occurring this year)	> 0.90	1.00
Once in 1 - 2 Years	Approximately 70% chance of consequence occurring this year (e.g. 1 in 1-2-year consequence)	0.5 - 0.90	0.70
Once in 2 - 5 Years	Approximately 35% chance of consequence occurring this year (e.g. 1 in 2-5-year consequence)	0.2 – 0.5	0.35
Once in 5 - 10 Years	Approximately 15% chance of consequence occurring this year (e.g. 1 in 5-10-year consequence)	0.1 – 0.2	0.15
Once in 10 - 20 Years	Approximately 7.5% chance of consequence occurring this year (e.g. 1 in 10-20-year consequence)	0.05 - 0.1	0.075
Once in 20 -100 Years	Approximately 3% chance of consequence occurring this year (e.g. 1 in 20-100-year consequence)	0.01 - 0.05	0.03
None	The consequence is unlikely to occur in the next 100 years	<0.007	0.00

Compliance Risk

Program Application: IVVC, Circuit Backup, FLISR

For the IVVC program, the "event" was defined as a low voltage event. The consequence of a low voltage event on primarily residential customers is assumed to be moderate but more frequent, and more severe and less frequent on large industrial customers due to assumed on-site voltage regulation.

For the Circuit Backup and FLISR programs, the "event" was defined as reliability compliance. The consequences of a reliability compliance event are minimal for average outage durations under 2 hours and moderate for average outage durations over 2 hours.

Table 2 - Compliance Risk Consequences Table

CONSEQUENCE	MINIMAL	MODERATE	SIGNIFICANT	SEVERE	CRITICAL	CATASTROPHIC
Compliance Risk	• Self reportable incident to regulator, no follow up	• Reportable incident with limited follow up	• Impact on relationship with state regulatory bodies	• Violation of Minnesota Power standard	• Violation of legal, regulatory, or statutory requirement resulting in an extended shutdown of a major facility or transmission line	• Revocation of license

			• Legal or compliance issue resulting in fines or penalties of $200K-$800K	• Significant impact on relationships with national or international regulatory bodies such as NERC, FERC, EPA, etc.	• NERC violation with no option to load shed	• Criminal charges against a Minnesota Power employee, officer, or director
			• Likely to have an impact of $200K-$800K on future projects or rate case submissions			• Off-site impact: civil penalties or regulatory violations/intervention, possible to mitigate for >$2.5M

Improved Power Quality

Program Application: IVVC, Circuit Backup

For the IVVC and Circuit Backup program, the "event" was defined as low voltage event. The consequence of a low voltage event on primarily residential customers is assumed to be moderate but more frequent, and more severe and less frequent on large industrial customers due to assumed on-site voltage regulation.

Table 3 - Power Quality Consequences Table

CONSEQUENCE	MINIMAL	MODERATE	SIGNIFICANT	SEVERE	CRITICAL	CATASTROPHIC
Power Quality Risk	•Customers/Community: complaints to Call Centers	• Policy Makers: questioning from Regulators, Legislators, and/or Community Leaders	• Litigation: likely to result in legal costs of $200K - $800K	• Litigation: likely to result in legal costs of $800K-$1.5M	• Litigation: likely to result in legal costs of $1.5M-$2.5M	• Litigation: likely to result in legal costs > $2.5M

	• Customer files claims • Negative Impact to External Stakeholders resulting in recovery costs < $50k	• News Media: negative Local coverage • Customer files claims • Negative Impact to External Stakeholders resulting in recovery costs of $50K - $200K	• News Media: negative National coverage • Negative Impact to External Stakeholders resulting in recovery costs of $800K - $1500K	• Negative Impact to External Stakeholders resulting in recovery costs of $800K-$1.5M	• Negative Impact to External Stakeholders resulting in recovery costs of $1.5M-$2.5M	• Investors: major backlash resulting in financial re-statement or dividend-cut • Negative Impact to External Stakeholders resulting in recovery costs > $2.5M

Improved Customer Satisfaction

Program Application: Circuit Backup, FLISR

For the Circuit Backup and FLISR programs, the "event" was defined as outage durations. Customer satisfaction is neutral for average outage durations under 2 hours and detractor for average outage durations over 2 hours.

Table 4 - Customer Satisfaction Consequences Table

CONSEQUENCE	MINIMAL	MODERATE	SIGNIFICANT	SEVERE	CRITICAL	CATASTROPHIC
Customer Satisfaction Risk	Customers/Community: complaints to Ethics line & Call Centers	Customers/Community: active protests and picketing	• Litigation: likely to result in legal costs of $200K - $800K	• Litigation: likely to result in legal costs of $800K-$1.5M	• Litigation: likely to result in legal costs of $1.5M-$2.5M	• Litigation: likely to result in legal costs > $2.5M

	• Negative Impact to External Stakeholders resulting in recovery costs < $50k	• Policy Makers: questioning from Regulators, Legislators, and/or Community Leaders • News Media: negative Local coverage • Negative Impact to External Stakeholders resulting in recovery costs of $50K - $200K	• News Media: negative National coverage • Negative Impact to External Stakeholders resulting in recovery costs of $800K - $1500K	• Negative Impact to External Stakeholders resulting in recovery costs of $800K-$1.5M	• Negative Impact to External Stakeholders resulting in recovery costs of $1.5M-$2.5M	• Investors: major backlash resulting in financial re-statement or dividend-cut • Negative Impact to External Stakeholders resulting in recovery costs > $2.5M

Quantification of Costs

The costs for implementing IVVC, Circuit Backup and FLISR projects were estimated using per unit installed costs from a variety of sources. The details are included in the BCA Framework & Summary document. A summary of the project implementation costs is shown In the table below.

Table 5 - Cost Summary by Circuit by Program

Circuit	IVVC	Circuit BU		FLISR
	Installed Cost	Installed Cost	Annual Maintenance and Warranty	Installed Cost
Askov 6521	$ 620,000	$ 1,547,167	$ 13,162	$ 137,157
Kerrick 6501	$ 620,000	$ 1,547,167	$ 13,162	$ 34,815
Wrenshall 411	$ 620,000	$ 4,125,778	$ 35,098	$ 125,315
Thomson 23L	$ 620,000	$ 3,094,333	$ 31,879	$ 15,315
Silver Bay 271/277	-	$ 3,094,333	$ 26,323	-
Silver Bay 271&277	-	$ 6,188,667	$ 52,647	-

Business Case Summary

The benefits and costs detailed in the sections above have been applied across as 20-year Net Present Value (NPV) framework. Minnesota Power-provided Inflation factors and discount rate have been applied to the calculation as defined in the assumptions table below.

Table 6 - Business Case Summary

PROJECT	NET BENEFITS (WITH IVVC)	NPV	BCR
Kerrick and Askov	IVVC	$105,431	1.09
	Circuit Backup	$4,940,789	2.13
	FLISR	-$45,031	0.72
	Net Project Benefits	**$5,001,190**	**1.88**
Wrenshall and Thomson	IVVC	$900,089	1.78
	Circuit Backup	-$2,885,985	0.72
	FLISR	$229,371	2.75
	Net Project Benefits	**-$1,756,525**	**0.85**
Silver Bay 271 or 277	IVVC	$124,311	1.11
	Circuit Backup	-$1,497,496	0.65
	Net Project Benefits	**-$1,373,185**	**0.75**
Silver Bay 271 and 277	IVVC	$124,311	1.11
	Circuit Backup	-$5,785,958	0.33
	Net Project Benefits	**-$5,661,647**	**0.42**

Key Assumptions

Table 5 - Key Assumptions – Business Case Summary

KEY ASSUMPTIONS	VALUE	COMMENT
Discount Rate	7.0	Provided by Minnesota Power
Escalation Rate	3.0	Provided by Minnesota Power

Appendix A – System-wide IVVC Benefit Results

The benefits of a system-wide IVVC deployment have been applied across as 20-year Net Present Value (NPV) framework. Minnesota Power-provided an Escalation Rate and Discount Rate that have been applied to the calculation. The results are shown in the table below:

Benefits	NPV
Avoided Capacity	$382,992.32
Avoided Ancillary Services	$2,689.37
Avoided T&D Losses	$11,062.91
Avoided Fuel Cost	$391,035.55

Appendix B – Supporting Documents

The following documents contain all details, assumptions, and calculations for the resulting BCA analysis and each of the programs:

1. BCA Framework & Summary Final-090222
2. FLISR Calculations Final-080522
3. Circuit Backup Calculations Final–080522.xls
4. IVVC Calculations Final-080522.xls

The following list of documents were used for the BCA calculations:

1. 23L and Kerrick-Askov - Outage.xlsx
2. 2021 IRP Page 144.pdf
3. BearCreek-23Line_2020 Load Data (Kerrick).xlsx
4. BearCreek-23Line_2020 Load Data.xlsx
5. BV Data Request.xlsx
6. Cost_Recovery_for_Standby_and_Ancillary_Services_Final.pdf
7. Kerrick Area Non Wire Alternative Solution Final Report 10-9-2021_Rev1.docx
8. Kerrick.xlsx
9. PNNL Battery Costs - 1 MW 2 Hour.pdf
10. Silver Bay Customer Count.xlsx
11. Silver Bay Loading.xlsx
12. Siver Bay Reliabilty Info 2021_2017.xlsx
13. Thomson-23Line_2020 Load Data (MilitaryRd).xlsx
14. United-States-LCOE-2021_Data.xlsx
15. VOLL by Circuit.xlsx
16. Wrenshall - Outage.xlsx
17. Wrenshall _ 2020 Load Data.xlsx
18. Wrenshall Non Wire Alternative Solution Final Report 9-23-2021_Rev2.docx
19. Wrenshall.xlsx

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Kerrick Area Non-Wire Alternative (NWA) Solution Final Report

Prepared by:

Black & Veatch
and
K&A Engineering Consulting, P.C.

10/08/2021
BV Project #: 409724

Table of Contents

List of Figures

List of Tables

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Revision History

Rev.	Date	Revised By	Updates
1	10-08-2021	H.L	Draft Release
2	03-16-2022	H.Z.	FINAL Release

Executive Summary

Two NWA solutions are offered to improve the reliability at Kerrick "23 Line". Option 1 is 3 MW BESS at Kerrick Stepdown high side, parameters are given in Table 3. Option 1 is two 1.5 MW BESS at Kerrick Stepdown low side & Askov Stepdown low side, parameters are given in Table 3. The proposed BESS would provide several layers of redundancy and flexibility for future expansion which is also cost effective. Both options will back up the Kerrick feeder when it loses the source and supporting the local customers.

There is no violation detected due to the interconnection of the proposed NWA solutions.

I. Introduction

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, maintenance on this connection has been limited, in part due to the rough and sometimes inaccessible terrain that it traverses, and it is no longer a reliable backup source. 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 with no backup options. This scenario will evaluate one or more non-wire alternatives involving battery energy storage and automated fault location, isolation, and restoration as a reliability backup solution for 23 Line. Minnesota Power will provide scope and cost of traditional solutions for comparison.

II. Scope of Study & Assumption

The study was conducted in accordance with Minnesota Power Technical Specifications Manual (TSM) [Ver 1.1 05-01-2020], standards, study guidelines, procedures, practices and IEEE 1547-2018, IEEE 1453-2015, UL 1741.

It is assumed that Minnesota Power will conduct further studies of the possible impact on the transmission level, to ensure adequacy of any equipment in conjunction with the proposed upgrades.

The following studies were performed to evaluate the base circuit and the impact from the proposed non-wire alternative to distribution equipment and performance of the circuit and the substation:

- Load-Flow
  - Peak Load + BESS Full Discharging
  - Peak Load + BESS Full Charging
  - Off-Peak Load + BESS Full Discharging
  - Off- Peak Load + BESS Full Charging
- Battery Energy Storage System (BESS) Control Mode
  - Volt Var (+/-0.95 power factor) with designed operation window
  - Fixed power factor at unity with designed operation window
- Voltage Impact
  - Steady State Voltage Analysis
  - Voltage Change Analysis
- Short-Circuit Analysis
- Circuit Protection
  - Transformer Inrush Analysis
  - Distribution Circuit Protection Coordination
- Effective Grounding
- Reliability Analysis
- Islanding Analysis

III. Feeder Overview

Historical load from the past 24 months for Kerrick Area (L23) was used as the basis for the load modeling in the base and generation cases. The following Table 1, give an overview of the historical load for peak and off-peak conditions. Refer to Appendix for substation one-line diagram.

Table 1: Kerrick 34 kV feeder load Information

Kerrick	Load	MW	MVAR	PF (%)	TIME
Peak	Winter – 2019	2.0	-0.8	92.8	1/29/2019 18:00
	Summer – 2019	1.3	-0.7	88.0	7/2/2019 18:00
	Winter – 2020	1.8	-0.7	93.2	2/20/2020 7:00
	Summer– 2020	1.6	-0.6	93.6	7/5/2020 18:00
	Peak Study Case	**1.8**	**0.366**	**98.0**	**N/A**
Off-Peak	Daytime Min – 2019	0.4	-0.9	40.6	6/16/2019 8:00
	Absolute Min – 2019	0.4	-0.9	40.6	6/16/2019 4:00
	Daytime Min – 2020	0.4	1.3	29.4	9/14/2020 16:00
	Absolute Min – 2020	0.4	1.3	29.4	9/14/2020 16:00
	Off-Peak Study Case	**0.4**	**-0.9**	**40.6**	**6/16/2019 4:00**

Note: The lagging power factor used for the peak has been confirmed with Minnesota power. The off-peak considers the leading power factor based on the load data provided.

The given source impedance at the substation bus is:

Z_1: 1.45214+j10.8928 [Ω]
Z_2: 1.45208+j10.8918 [Ω]
Z_0: 0.68783+j7.63119 [Ω]

Previous 46 kV Aspen Results are:

Bus Fault on: 713 BCR 46. kV 3LG

+ SEQ	- SEQ	0 SEQ	A PHASE	B PHASE	C PHASE
2416.7@ -82.4	0.0@ 0.0	0.0@ 0.0	2416.7@ -82.4	2416.7@ 157.6	2416.7@ 37.6

SHORT CIRCUIT MVA= 192.6 X/R RATIO= 7.50122 R0/X1= 0.06315 X0/X1= 0.70057
ANSI X/R RATIO= 16.1337

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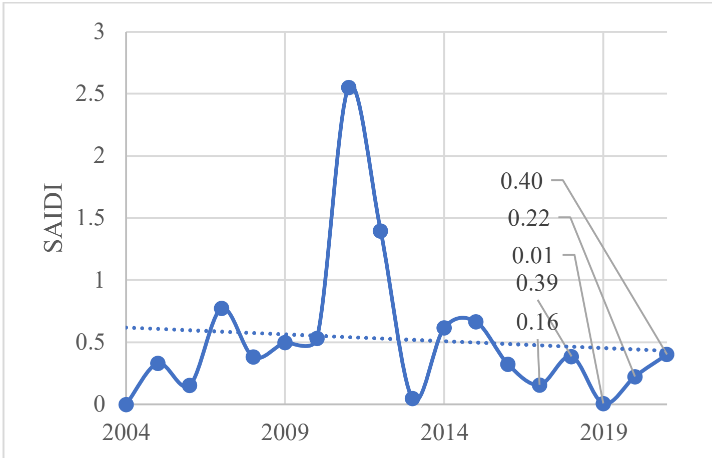
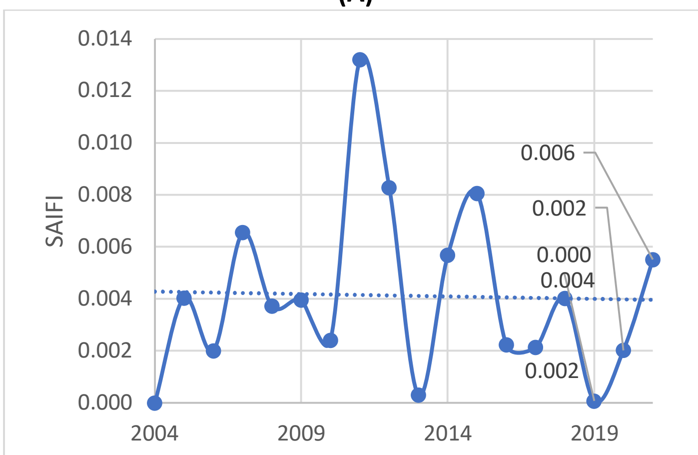


(A)



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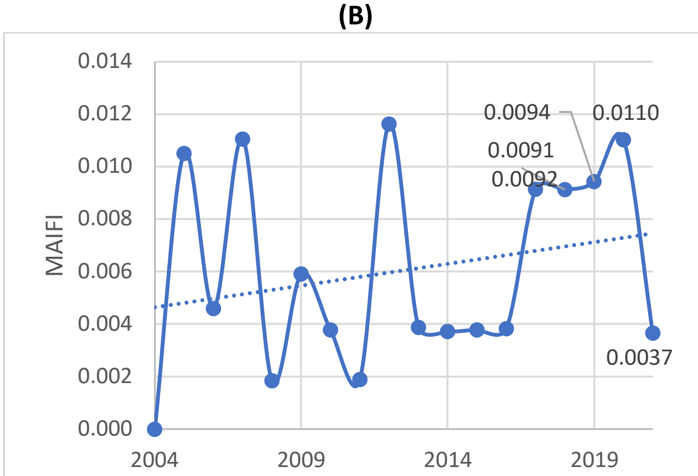

(C)

Figure 1. Historical Data- (A) SAIDI; (B) SAIFI; (C) MAIFI

Table 2. List of major components

Device	Number
Regulator	0
3P recloser	0
Capacitor	2
Breaker	0
Generator	0
Motor	0
Switch	15
Auto-Switch	0
3P cutouts	7

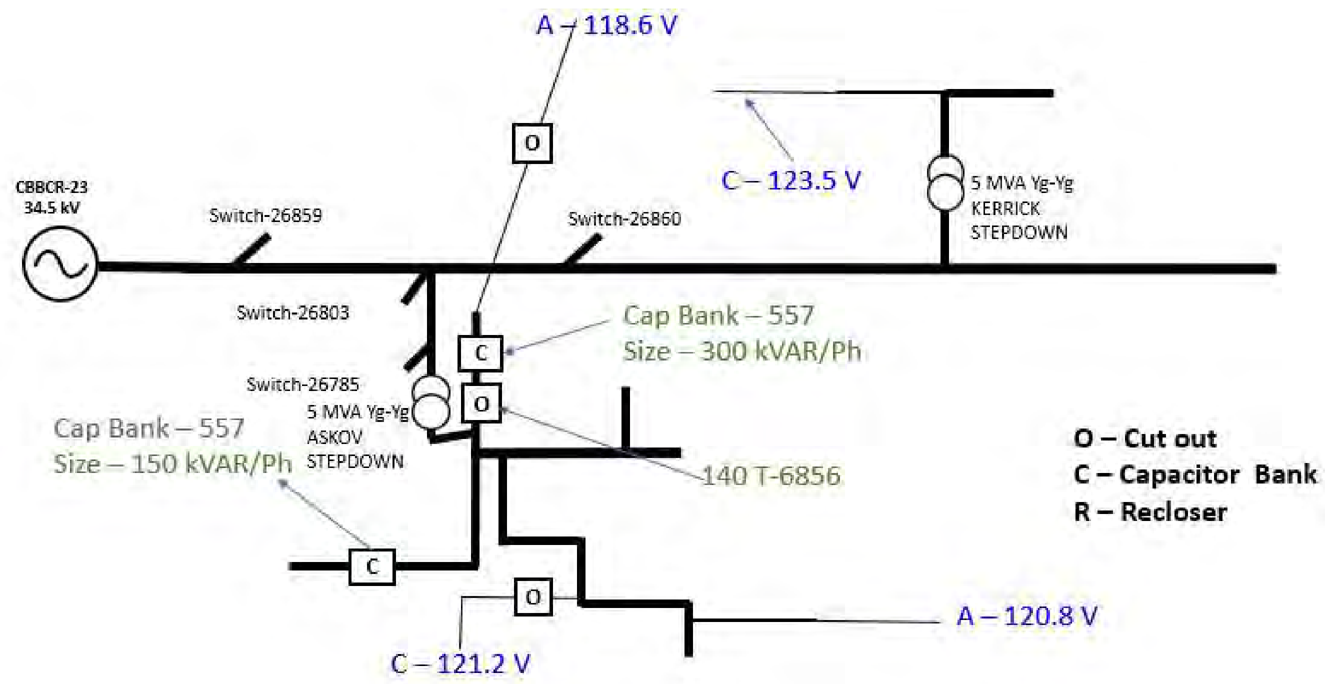

Figure 2. Kerrick One Line Diagram prior to the NWA

There are two exiting voltage-controlled cap banks as shown in Figure 2. The two cap banks are switched off during the given peak base case model. By revising the cap bank control phase from phase A to phase B will improve the voltage profile and feeder power factor. However, following sections have found conflicts between the cap banks controlling phase B with BESS discharging during the Off-Peak. Therefore, no setting revision or upgrade is proposed for the two existing cap banks. The following sections consider the given base model.

IV. Proposed Non-Wire Alternative Solution

Non-wires alternatives are defined as "an electricity grid investment or project that uses non-traditional transmission and distribution (T&D) solutions, such as distributed generation (DG), energy storage, energy efficiency (EE), demand response (DR), and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level. Several NWA solutions have been considered, based on the simulation result in the following sections, a new battery energy storage system (BESS) is determined as the best solution and is chosen for this report.

The proposed BESS would provide several layers of redundancy and flexibility for future expansion which is also cost effective.

No landscape or footprint has been considered as constraints for the location of the BESS, this report offers two options for the BESS in case there is any landscape acquisition.

Option 1: 3MW, 6MWH BESS at Kerrick Stepdown primary 34 kV side.

Tables below presents the parameters, required features and recommended operation window for the BESS.

Table 3. BESS parameters and required feature of Option 1

Size	3 MW, 6 MWH
Location (POI)	OH4527. 34 kV (At Kerrick 5 MW Stepdown)
Distance from Source	20.521 miles
Impedance between Source and POI	Z_1=6.942 + j 13.98; Z_0= 18.834 + j 40.816 [Ω]
Upstream Capacity Limitation	#1/0 ACSR 6/1 conductor with 230 A rating, 13.743 MW Capacity at 34 kV.
Transformer	One (1) 3000 kVA Grounded Wye – Grounded Wye, 34.5 kV/600 V, Z% = 6%, X/R = 10
Grounding Bank	50 kVA Grounded Wye – Delta, 34.5 kV/480 V, Z% = 6%, X/R = 10
Primary Protection Device	3P Recloser, with SEL – 651R Recloser
Control Mode	Constant Unity Power Factor Mode with Volt-Var control mode stand by.
Emergency Power	The BESS is required to delay the recharging for 30 min after the restoration of the power outage.

Note: The Kyle Nova SEL-651 R is recommended in terms of small clearing tolerance, capability for harmonics blocking and reverse fault blocking. Also, the coordination is based on the Kyle Nova SEL-651R.

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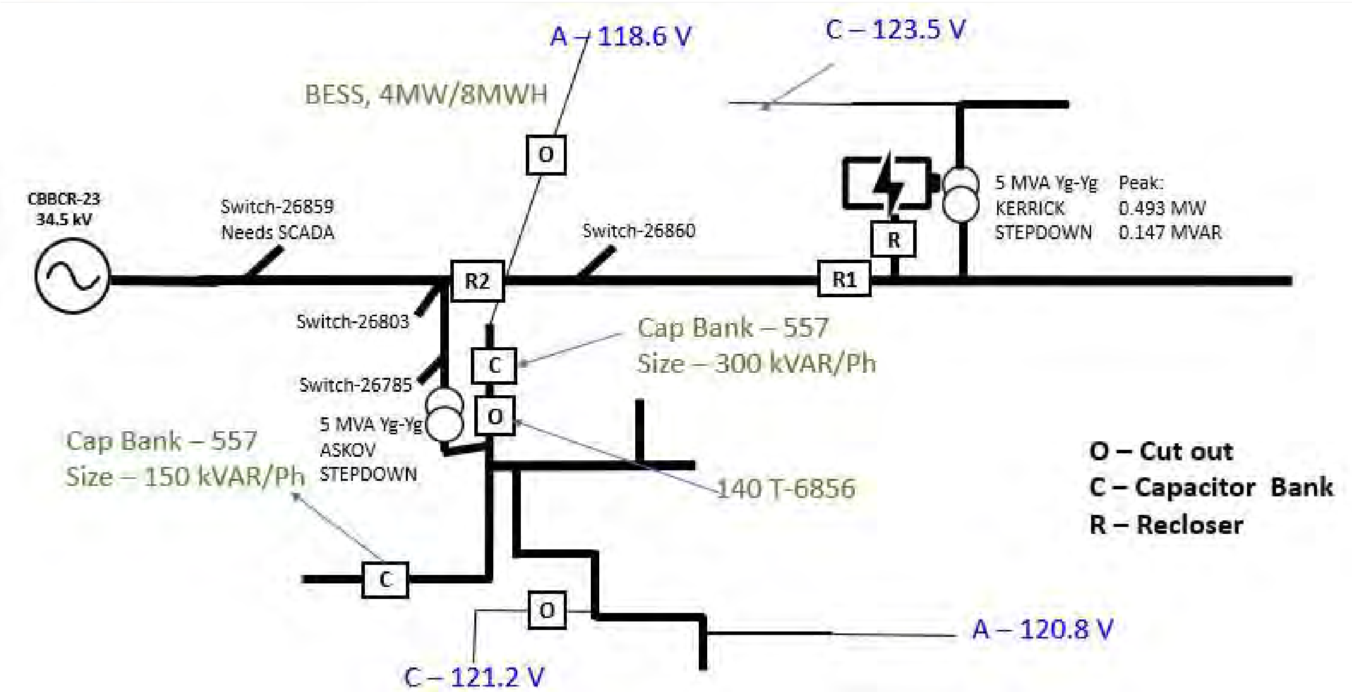

Figure 3. Kerrick One Line Diagram with the NWA Option 1

Table 4. BESS parameters and required feature of Option 2

Size	Two (1.5 MW, 3 MWH)
Location (POI)	BESS#1 at PriOH1124375 (Kerrick) (12 kV); BESS#2 at PriOH330983 (Askov) (12 kV)
Impedance between Source and POI (PriOH1124375 (Kerrick))	Z_1=-0.185 - j 5.979; Z_0= 2.052 + j 0.33 [Ω]
Impedance between Source and POI (PriOH330983 (Askov))	Z_1=-0.694 - j 7.12; Z_0= 0.56 - j 3.05 [Ω]
Upstream Capacity Limitation	5 MVA Transformer
Transformer	One (1) 1500 kVA Grounded Wye – Grounded Wye, 12.47 kV/600 V, Z% = 6%, X/R = 10
Primary Protection Device	3P Recloser, with SEL – 651R Recloser
Control Mode	Constant Unity Power Factor Mode with Volt-Var control mode stand by.
Emergency Power	The BESS is required to delay the recharging for 30 min after the restoration of the power outage.

Note: The Kyle Nova SEL-651 R is recommended in terms of small clearing tolerance, capability for harmonics blocking and reverse fault blocking. Also, the coordination is based on the Kyle Nova SEL-651R.

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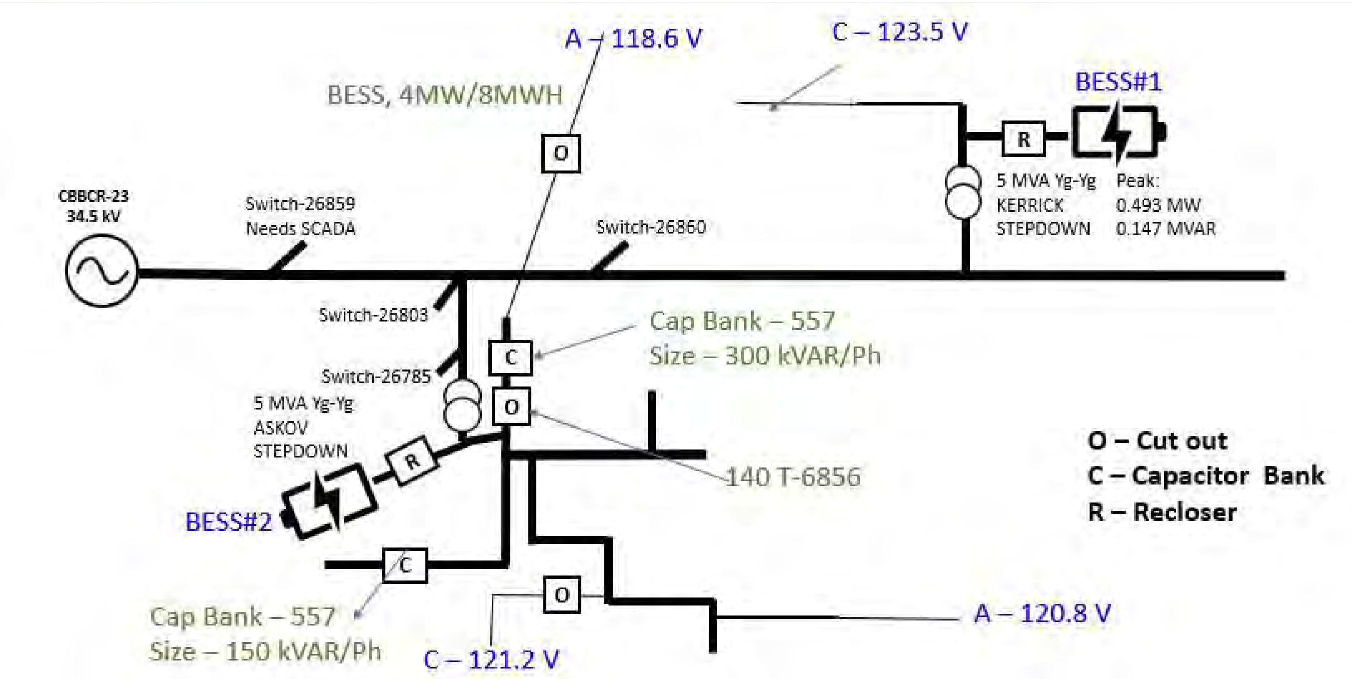


Figure 4. Kerrick One Line Diagram with the NWA Option 2

Table 5. Recommended Summer & Winter schedule for Charging and Discharging of BESS under normal operation.

Start Time	Mode	Power	Control Mode	Reference
12:00:00 AM	Idling	-	-	-
03:00:00 AM	Charging	100%	Volt Var Mode	Max Charging Power
6:00:00 AM	Idling	-	-	-
06:00:00 PM	Discharging	100%	Volt Var Mode	Max Discharging Power
09:30:00 PM	Idling	-		-

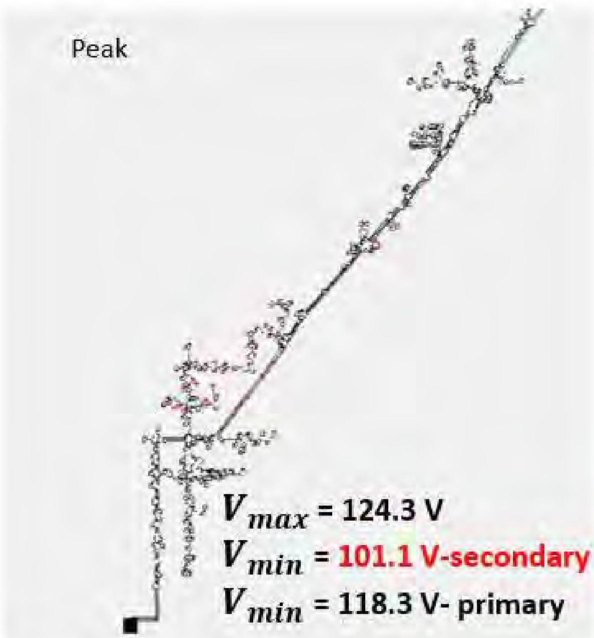
Note:
The BESS needs to synchronize with local EPS without causing any abnormal conditions while entering service.
The Charging start time is subject to change based on the local utility price.

V. Load Flow Analysis

A Steady State Voltage Analysis was conducted to determine the project's impact on the distribution circuit voltage. To ensure adequate service voltage to customers, 114 to 126 volts, the circuit voltage must remain within the range of 117 to 126 volts (120 volt base) during normal operation. In general, the circuit voltage at the substation must remain in the range of 123 to 126 volts to maintain an adequate voltage under all anticipated load conditions, regardless of project operation.

The peak load case is using a 1.04 pu source operating voltage.
The off-peak load case is using a 1.02 pu source operating voltage with a V_{max} = 125.6 V, as there will be overvoltage violations by using a 1.04 pu. This has been supported by the field line voltage monitoring data provided by Minnesota Power.

A. *Prior the non-wire alternative*



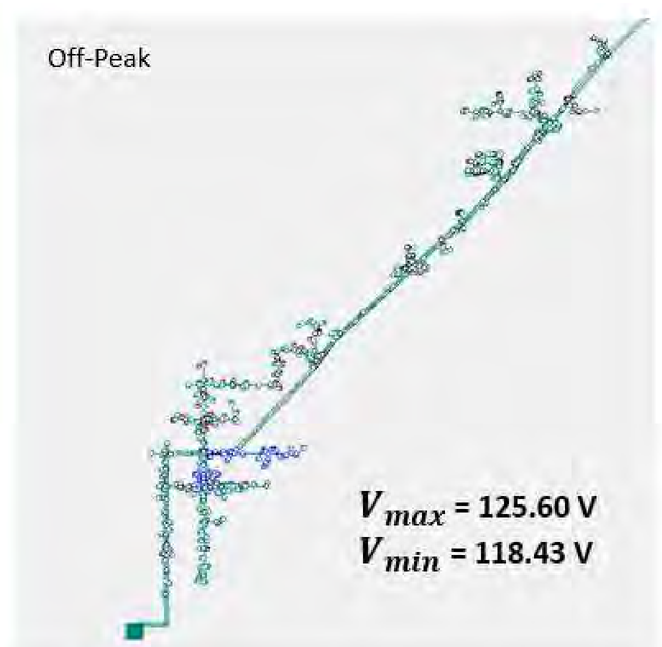


Figure 5. Load Flow Results – Prior to the NWA

From load flow results shown above, there are some pre-existing under-voltage violations detected at secondary voltage level. Load Balancing has been tried on several branches without any significant improvements on the secondary side voltage violations.

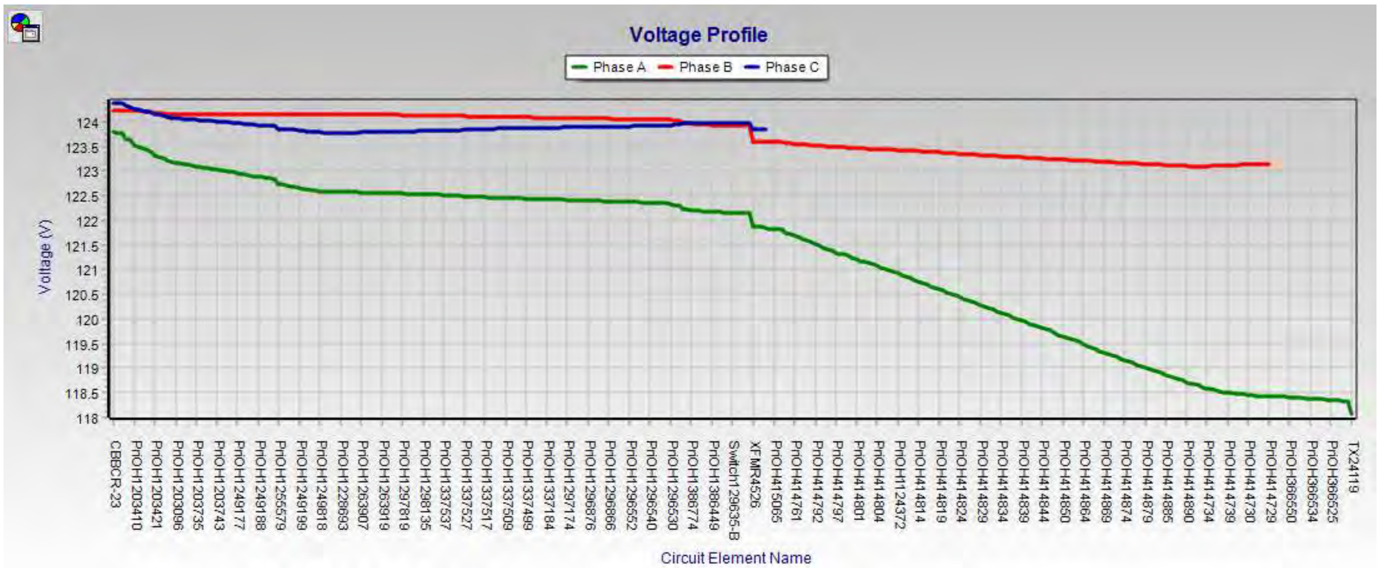


Figure 6. Voltage profile during Peak of Vmin (pri) nodes to source, 27.141 miles from source.

Figure above presents the Vmin element PriOH404352 on the primary voltage side which is above the 0.975 p.u.

B. *After the non-wire alternative*

OPTION 1

- ❖ BESS in Constant unity PF operation mode with 3 MW Charging & Discharging Rate.

Table 6. Load Flow results for Discharging/Charging of BESS

Scenario	**Control Mode**	**Site Operation**	**Load Flow at POI**	**Load Flow at CBBCR Substation**
Peak	Constant Unity PF	Discharging at 3MW	P = -2982.4 kW Q = 162.2 kVAR	P = -1176.4 kW Q = 469.7 kVAR
Peak	Constant Unity PF	Charging at 3 MW	P = 2990.8 kW Q = 179.5 kVAR	P = 4894.2 kW Q = 856.8 kVAR
Off Peak	Constant Unity PF	Discharging at 3MW	P = -2981.9kW Q = 162.7 kVAR	P = -2257.5 kW Q = -397.6 kVAR
Off Peak	Constant Unity PF	Charging at 3 MW	P = 3032.0 kW Q = 180.1 kVAR	P = 3803.5 kW Q = -1155.8 kVAR

Table 7. Voltage results for Discharging of BESS under unity pf operation.

Scenarios	BESS	Voltage at Substation [V]	Voltage at POI [V]	Vmax [V]	Vmin [V]
Peak (Base Volt = 124.7V, 1.039 p.u.)	OFF	124.1	123.4	125.0	104.0(A)
	Charging	123.2	119.9	125.9	99.7 (A) - Sec 117.2 - Pri
	Discharging	124.4	125.4	125.5	105.3 (A)
Off-peak (Base Volt = 122.5V, 1.02 p.u.)	OFF	123.1	124.2	125.5	106.9 (B)
	Charging	123.3	121.6	125.8	105.3 (B)
	Discharging	123.3	125.8	127.1	109.7 (B)

There is overvoltage violation detected during the discharging at off-peak scenarios which is the worst case. It can be avoided by enabling the volt-var operation mode from inverter as shown in the next section.

- BESS in Volt-Var operation mode.

"*The DER shall not cause the Area EPS primary circuit voltage at any location to go outside the requirements of ANSI C84.1 for primary service voltage.*"

----IEEE 1547-2018

IEEE 1547-2018 requires that the DER should have the ability of injecting and absorbing reactive power for DER voltage impact mitigation, and the reactive power magnitude needs to be controlled automatically. However, Minnesota Power TSM requires the settings for Volt-Var Power control to be disabled. This section will provide the setting for the reference.

This project shows over voltage violation under constant power factor mode; therefore, "Volt-Var mode" is provided. The suggested dead bandwidth is from 1.03 to 1.045 V p.u. (V_{Ref}=1.03) on 120V base.

The assumed inverter setting is as followed:
Rating: 3000 kVA
Rated Real Power Max: 3000 kW
PF capable: -98.6 - +98.6
Maximum reactive power absorbed = 500.23 kVAR
Maximum reactive power injected = 500.23 kVAR

By using the Volt-Var mode, the power factor of the BESS can vary from leading 98.6% to lagging 98.6% based on the circuit voltage condition. However, based on the current feeder condition, the BESS will be constantly running a unity power factor during the normal operation.
If there is any voltage disturbance that within 0.88 p.u. to 1.1 p.u., by enabling the volt-var mode of the inverter, the BESS can give the voltage support.
Following figures presents the load flow results with a lagging 98.6% & a leading 98.6% p range which would be determined based on the circuit conditions.

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Table 8. Load Flow results for Discharging/Charging of BESS under Volt-Var mode

Scenario	Control Mode	Site Operation	Load Flow at POI	Load Flow at CBBCR Substation
Peak	Volt Var Mode	Discharging at 3MW	P = -2939.9 kW Q = 668.7 kVAR	P = -1130.7 kW Q = 996.2 kVAR
Peak	Volt Var Mode	Charging at 3 MW	P = 2990.8 kW Q = 179.5 kVAR	P = 4894.2 kW Q = 856.8 kVAR
Off Peak	Volt Var Mode	Discharging at 3MW	P = -2939.4 kW Q = 669.1 kVAR	P = -2216.6 kW Q = 113.7 kVAR
Off Peak	Volt Var Mode	Charging at 3 MW	P = 3032.0 kW Q = 180.1 kVAR	P = 3803.5 kW Q = -1155.8 kVAR

Table 9. Voltage results for Discharging of BESS under Volt-Var mode

Scenarios	BESS	Voltage at Substation [V]	Voltage at POI [V]	Vmax [V]	Vmin [V]
Peak (Base Volt = 124.7V, 1.039 p.u.)	OFF	124.1	123.4	125.0	104.0(A)
	Charging	123.2	119.9	125.9	99.7 (A) -Sec 117.2 - Pri
	Discharging	123.8	124.1	125.0	104.3 (A)
Off-peak (Base Volt = 122.5V, 1.02 p.u.)	OFF	123.1	124.2	125.5	106.9 (B)
	Charging	122.5	121.8	124.2	105.2 (B)
	Discharging	122.7	124.0	125.8	108.2 (B)

By enabling the volt-var mode of the BESS, there is no over-voltage violation caused by the interconnection and there is no overloading issue detected with the interconnection.

OPTION 2

- BESS in Constant unity PF operation mode with two 1.5 MW Charging & Discharging, one at Kerrick 12 kV feeder, one is at Askov 12 kV feeder.

Table 10. Load Flow results for Discharging/Charging of BESS

Scenario	Control Mode	Site Operation	Load Flow at POI (PriOH1124375 (Kerrick))	Load Flow at POI (PriOH330983 (Askov))	Load Flow at CBBCR Substation
Peak	Constant Unity PF	Discharging at 1.5 MW each (Cumulative 3 MW)	P = -1491.7 kW Q = 82.0 kVAR	P = -1500 kW Q = 0.02 kVAR	P = -1204.3 kW Q = 343.7 kVAR
Peak	Constant Unity PF	Charging at 1.5 MW each (Cumulative 3 MW)	P = 1525.5 kW Q = 89.6 kVAR	P = 1552.2 kW Q = 89.7 kVAR	P = 4965.6 kW Q = -568.3 kVAR

Off Peak	Constant Unity PF	Discharging at 1.5 MW each (Cumulative 3 MW)	P = -1491.7 kW Q =82.0 kVAR	P = -1491.6 kW Q = 82.8 kVAR	P = -2275.6 kW Q = -410.8 kVAR
Off Peak	Constant Unity PF	Charging at 1.5 MW each (Cumulative 3 MW)	P =1522.4 kW Q = 89.7 kVAR	P = 1545.6 kW Q =89.8 kVAR	P = 3821.6 kW Q = -1138.2 kVAR

Table 11. Voltage results for Discharging of BESS under unity pf operation.

Scenario	1.50 MVA PriOH1124375 (Kerrick)	1.50 MVA PriOH333098 3 (Askov)	Substation [V]	POI (PriOH1124375 (Kerrick)) [V]	POI (PriOH330983 (Askov)) [V]	Vmax [V]	Vmin [V]
Peak (Base Volt = 124.7V, 1.039 p.u.)	OFF	OFF	124.1	123.1	122.7	125.4	104.0 - Sec 120.8 - Pri
	Charging	Charging	124.7	122.3	124.4	125.4	103.0- Sec 119.9 - Pri
	Discharging	Discharging	124.4	124.7	123.8	125.2	105.5
Off-peak (Base Volt = 122.5V, 1.02 p.u.)	OFF	OFF	123.1	123.5	123.4	125.8	106.9
	Charging	Charging	123.3	122.0	123.9	125.8	105.6
	Discharging	Discharging	123.3	124.4	125.0	126.7	109.1

❖ BESS in Volt-Var operation mode.

This project shows over voltage violation under constant unity power factor mode; therefore, "Volt-Var mode" is provided. The suggested dead bandwidth is from 1.03 to 1.045 V p.u. (V_{Ref}=1.03) on 120V base.

The assumed inverter setting is as followed:
Rating: 1500 kVA
Rated Real Power Max: 1500 kW
PF capable: -99.5 - +99.5
Maximum reactive power absorbed = 149.81 kVAR