Direct Testimony and Schedule
Joshua P. Goutermont

Before the Minnesota Public Utilities Commission

State of Minnesota

In the Matter of the Application of Minnesota Power
For Authority to Increase Rates for Electric Utility
Service in Minnesota

Docket No. E015/GR-26-199

Exhibit _____

DISTRIBUTION

November 2, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Joshua (Josh) P. Goutermont, and my business address is 30 West Superior Street, Duluth, Minnesota 55802.

Q. By whom are you employed and in what position?

A. I am employed by ALLETE, Inc. ("ALLETE"), doing business as Minnesota Power ("Minnesota Power" or the "Company"), as the Vice President of Minnesota Power Grid Operations.

Q. Please summarize your qualifications and experience.

A. I am originally from Silver Bay, Minnesota, where I graduated from high school before attending Lake Superior College. I earned an Associate of Applied Science degree in Electrical Technology. I also attended the College of Saint Scholastica, where I earned a Bachelor of Arts in Management and a Master of Business Administration with an emphasis on leadership and change management.

I began my career with Minnesota Power in 2002 at Taconite Harbor Energy Center and later moved into roles with progressing leadership responsibility. I have held subsequent advanced leadership positions in Human Resources and in Transmission and Distribution operations both at Minnesota Power and at Superior Water, Light, and Power.

Currently, I am the Vice President of Grid Operations and have responsibility for field technicians in Line, Substation, and Metering. I also have oversight of vegetation management, inventory, fleet, engineering, design, and asset management programs.

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to provide background on the Company's distribution system. I discuss the capital investments the Company has made since Minnesota Power filed its rate case in 2023 (Docket No. E015/GR-23-155) ("2023 Rate

Case") and the operating and maintenance ("O&M") necessary to continue to provide efficient and reliable electricity to Minnesota Power customers in a cost-efficient manner. I provide information to support the Company's reasonable, necessary, and prudent investments in local and regional capital projects and ongoing maintenance of our distribution systems. I also provide testimony on the Company's wildfire mitigation planning and expenses for Minnesota Power. Finally, I discuss the Company's continued efforts to improve reliability and system performance. Note that the Company's Transmission systems are discussed in the Direct Testimony of Company witness Daniel W. Gunderson.

Q. How is your testimony organized?

A. Section II of my Direct Testimony provides an overview of the Distribution work areas, explaining the role and geographic reach of the distribution system.

Section III provides background and details of the capital investments and projects in Distribution, including the types of projects and the work processes involved with them.

Section IV describes the O&M processes and costs for Distribution. This section also explains third-party Distribution revenues and expenses, as well as the Company's Federal Energy Regulatory Commission ("FERC") Accounts, storm response and restoration, and vegetation management.

Finally, in Section V of my Direct Testimony, I discuss the Company's system reliability and items related to customer experience and technology updates as they relate to the modernization of systems used to complete our work.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following schedule to my Direct Testimony:

- MP Exhibit ___ (Goutermont), Direct Schedule 1 – Minnesota Power Distribution Service Territory Map.

II. DISTRIBUTION WORK AREAS

Q. Please explain the role of Minnesota Power's Distribution department.

A. Minnesota Power's Distribution department is responsible for the operations, maintenance, and monitored coordination of the Company's power delivery systems. The Distribution department ensures that energy is safely and reliably delivered throughout the distribution system, and, ultimately, to our customers. The department is also responsible for managing residential and small commercial customer data from meters to the billing system.

Q. What other areas are being covered in your testimony?

A. Cyber Technology Services ("CTS"), electric vehicles ("EVs"), facility management, fleet, and wildfire mitigation work areas are also included in the Distribution department. These services are critical to operations, and these work areas coordinate closely with leadership in the implementation of efficiency improvements and cost containment efforts.

Q. What is the geographic reach of Minnesota Power's distribution system?

A. The Company's distribution system is located in northern and central Minnesota. Certain areas within these general borders receive distribution service from municipalities or rural electric cooperatives. As such, Minnesota Power routinely coordinates closely with these entities to ensure efficient transmission delivery to distribution systems that may be located near our service territory. A map of Minnesota Power's distribution service territory is provided with my Direct Testimony as MP Exhibit ___ (Goutermont), Direct Schedule 1.

Q. How does the Distribution department approach its work?

A. One of ALLETE's core values is safety. Minnesota Power continues to focus on employee safety training and hazard identification on the distribution system. The training department's goal is to boost the competency, proficiency, safety, and effectiveness of the workforce. This utility training program has matured and has continued its mission since the last case. This team is staffed with employees who train

new and existing employees on systems and safety procedures with a focus on the hazards specifically related to the changes occurring on the system. The 2027 test year includes the costs associated with these critical safety training needs for new and existing employees.

Q. What challenges has the Distribution department experienced in recent years?

A. Weather-related challenges like storms with increased intensity and frequency, coupled with aging infrastructure, have led to challenges in reliability and resiliency on the distribution system. Storm events have brought higher wind speeds, leading to more damage from trees adjacent to lines. Trees have been challenged by pests and are dying at higher rates, leading to more danger from trees than in the past years. Combined with stronger storms, dying trees present an increased hazard that is creating increased vegetation management costs, challenging reliability, presenting new risks related to wildfire, and stressing equipment across the distribution system. Wildfire is also creating challenges for the operation and planning of the distribution system. The frequency of wildfires and the length of fire season is increasing. Maintaining a reliable and resilient system in the face of wildfire threat, while protecting people and communities, is challenging traditional planning methods and will expedite equipment change-outs for high-risk areas.

With the growing capabilities of grid modernization technologies, the distribution system is designed with more automated functions and is deploying new technologies at a rapid pace. While innovative, this has posed some planning challenges and led to upgrades to the system to support new equipment. With the deployment of new technology, more advanced automation is needed to maximize the benefit of these systems. The need to implement new software systems and data analytics tools are increasing costs, while the system is also aging and needing more investment. Balancing the timely adoption of new systems plus the replacement of aging assets to maintain reliability makes cost containment increasingly more difficult.

III. DISTRIBUTION AND CAPITAL INVESTMENTS AND PROJECTS

A. Budget Process

Q. How is the capital budget developed?

A. The Company maintains a long-range capital investment plan based on identified needs and priorities. Analyzing, assessing, and prioritizing projects is the first step in determining their necessity and timing, which informs the annual capital budget. The annual capital budget process employs a zero-based budgeting process, explained in more detail in the Direct Testimony of Company witness Joshua G. Rostollan. This process affirms the projects that are required within a specific year for the Distribution, Facilities, CTS, Fleet, Customer Experience, and Wildfire Mitigation work areas. The project assessments include considerations like personnel and public safety; compliance and legal requirements; reliability; cost recovery; financial payback; efficiency and cost savings; and impact on Company strategy. The project assessment also evaluates overall project value, timing of external entity needs driving the project, timing of system capacity needs associated with the project, magnitude of customer load and number of customers that benefit from the project, the necessary start date for project execution based on the project schedule and workflow, and the date when any relevant compliance requirements become effective.

Q. Does another witness provide additional information on the capital budget process the Distribution department uses?

A. Yes. The Distribution department follows the same process as the Transmission department, which is laid out in the Direct Testimony of Company witness Gunderson.

Q. Does the Distribution department utilize the Portfolio Review Board ("PRB") and manage, monitor, and adjust to changes in the capital budget in the same way as the Transmission department, as discussed in the Direct Testimony of Company witness Gunderson?

A. Yes. These processes are discussed in detail in the Direct Testimony of Company witness Gunderson. These processes operate in the same manner in the Distribution department. Additionally, capital budget risks and decision making regarding canceling,

delaying, or accelerating a capital project are also discussed. All of these processes operate in the same way in the Transmission and the Distribution departments.

Q. Has the Distribution department's budget process changed at all with the acquisition of ALLETE's outstanding stock by Canada Pension Plan Investment Board and Global Infrastructure Partners?

A. No.

Q. Do you anticipate any changes to the capital budget process if the Commission approves the Company's proposed reorganization?

A. No.

B. Distribution Investments and Projects

Q. What has Minnesota Power's capital investment looked like from 2023 through 2027?

A. Table 1 below provides the Company's regulated capital plant additions for 2023, 2024, and 2025 actuals, the 2026 projected fiscal year, and the 2027 proposed test year for the Distribution, CTS, Electric Vehicle Service Equipment ("EVSE") Expansion Project, Facility Management, Fleet and Wildfire Mitigation areas. Table 1 provides this information at the Total Company level. Capital plant additions at the MN Jurisdictional level are provided in Table 2.[1]

Q. How do the capital additions in the 2027 test year budget and the 2026 projected year in Table 1 compare to the Company's 2025 actuals?

A. The capital additions for the Distribution, CTS, EVSE Expansion Project, Facility Management, Fleet, and Wildfire Mitigation work areas for the 2027 proposed test year and the 2026 projected fiscal year are $61.9 million Total Company ($50.8 million MN Jurisdictional) and $22.6 million Total Company ($18.2 million MN Jurisdictional) greater than the capital additions in 2025, respectively.

[1] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided in Volume 3, Direct Schedules B-16 to B-19 and Direct Schedules C-13 to C-16.

Distribution capital additions in the 2027 proposed test year are $8.2 million Total Company ($8.2 million MN Jurisdictional) less than the capital additions in 2025. The capital additions in the 2026 projected fiscal year are $7.9 million Total Company ($5.3 million MN Jurisdictional) greater than the capital additions in 2025. Distribution capital additions included in the 2027 proposed test year are discussed further in Section III.B of my Direct Testimony.

CTS capital plant additions in the 2027 proposed test year are $8.6 million Total Company ($7.7 million MN Jurisdictional) less than the capital additions in 2025. The capital additions in the 2026 projected fiscal year are $13.5 million Total Company ($11.9 million MN Jurisdictional) greater than the capital additions in 2025. CTS capital additions are discussed further in Section III.C of my Direct Testimony.

The EVSE Expansion Project is only included in the 2026 projected fiscal year and is discussed further in Section III.C of my Direct Testimony.

The Facility Management capital plant additions in the 2027 proposed test year are $61.3 million Total Company ($52.0 million MN Jurisdictional) greater than the capital additions in 2025. The capital additions in the 2026 projected fiscal year are $1.2 million ($1.1 million MN Jurisdictional) greater than the capital additions in 2025. Facility Management additions are discussed further in Section III.C of my Direct Testimony.

The Fleet capital plant additions in the 2027 proposed test year are $14.0 million Total Company ($11.8 million MN Jurisdictional) greater than the capital additions in 2025. The capital additions in the 2026 projected fiscal year are $0.5 million ($0.5 million MN Jurisdictional) less than the capital additions in 2025. Fleet additions are discussed further in Section III.C of my Direct Testimony.

The Wildfire Mitigation capital plant additions are only included in the 2027 proposed test year at $3.3M Total Company ($2.8 million MN Jurisdictional). This item was not

included in the 2026 projected fiscal year or 2025 actuals. The Company's Wildfire Mitigation is discussed further in Section III.C of my Direct Testimony.

Table 1. Regulated Capital Plant Additions (including Contra Allowance for Funds Used During Construction ("AFUDC"))

Capital Plant Additions (including Contra)—Total Company	2023	2024	2025	2026	2027
Distribution, General Plant, and Intangible	**Actual**	**Actual**	**Most Recent Fiscal Year**	**Projected Fiscal Year**	**Proposed Test Year**
Distribution*	**$63.0**	**$53.5**	**$98.1**	**$106.0**	**$89.9**
Age Related & Asset Renewal	$35.0	$14.4	$23.7	$45.1	$16.7
System Expansion or Upgrades for Capacity	$0.6	$0.8	$9.0	$4.3	$0.4
Distribution Other	$0.5	$0.5	$2.1	$1.3	$0.4
Government Requirements	$4.0	$2.6	$2.1	$3.4	$3.0
Grid Modernization & Pilot Projects	$1.9	$3.2	$5.9	$6.4	$6.8
Metering	$3.4	$4.1	$8.3	$5.9	$6.3
New Customer – New Revenue	$12.4	$22.1	$30.6	$6.5	$8.8
System Expansion or Upgrades for Reliability & Power Quality	$5.2	$5.8	$16.4	$33.2	$47.5
Cyber Technology Services	**$14.2**	**$14.6**	**$14.7**	**$28.2**	**$6.1**
Communication System Improvements	$4.0	$2.2	$1.5	$2.1	$1.1
Cyber Technology	$7.9	$8.1	$11.2	$19.3	$4.9
Software Implementation	$2.3	$4.2	$2.0	$6.8	-
EVSE Expansion Project	**-**	**-**	**-**	**$0.4**	**-**
Facility Management	**$6.4**	**$6.7**	**$10.1**	**$11.3**	**$71.4**
Facility Improvements	$0.1	-	$2.2	-	-
Facility Management	$6.3	$6.7	$8.0	$11.3	$12.8
Little Falls Service Center	-	-	-	-	$58.6
Fleet	**$4.3**	**$6.7**	**$4.4**	**$3.9**	**$18.4**
Wildfire Mitigation	**-**	**-**	**-**	**-**	**$3.3**
Distribution Total, excluding Riders	**$87.9**	**$81.4**	**$127.2**	**$149.8**	**$189.1**

Amounts in millions.
Amounts may not total due to rounding.
**Amounts may include Intangible & General Plant Additions.*

Table 2. Regulated Capital Plant Additions (including Contra AFUDC)
(MN Jurisdictional)

Capital Plant Additions (including Contra)— MN Jurisdictional	2023	2024	2025	2026	2027
Distribution, General Plant, and Intangible	**Actual**	**Actual**	**Most Recent Fiscal Year**	**Projected Fiscal Year**	**Proposed Test Year**
Distribution*	**$59.6**	**$51.7**	**$95.9**	**$101.2**	**$87.7**
Age Related & Asset Renewal	$31.7	$12.6	$23.3	$42.3	$16.7
System Expansion or Upgrades for Capacity	$0.6	$0.8	$9.0	$4.3	$0.4
Distribution Other	$0.5	$0.4	$2.1	$1.1	$0.3
Government Requirements	$4.0	$2.6	$2.1	$3.4	$3.0
Grid Modernization & Pilot Projects	$1.9	$3.2	$5.9	$6.4	$6.8
Metering	$3.4	$4.1	$8.2	$5.9	$6.3
New Customer – New Revenue	$12.4	$22.1	$30.5	$6.5	$8.8
System Expansion or Upgrades for Reliability & Power Quality	$5.2	$5.8	$14.8	$31.3	$45.4
Cyber Technology Services	**$12.6**	**$13.0**	**$12.9**	**$24.8**	**$5.2**
Communication System Improvements	$3.6	$2.0	$1.3	$1.8	$1.0
Cyber Technology	$7.0	$7.2	$9.9	$17.0	$4.2
Software Implementation	$2.0	$3.7	$1.7	$6.0	-
EVSE Expansion Project	**-**	**-**	**-**	**$0.3**	**-**
Facility Management	**$5.7**	**$6.0**	**$8.9**	**$10.0**	**$60.9**
Facility Improvements	$0.1	-	$1.9	-	-
Facility Management	$5.6	$6.0	$7.0	$10.0	$10.9
Little Falls Service Center	-	-	-	-	$50.0
Fleet	**$3.8**	**$6.0**	**$3.9**	**$3.4**	**$15.7**
Wildfire Mitigation	**-**	**-**	**-**	**-**	**$2.8**
Distribution Total, excluding Riders	**$81.7**	**$76.6**	**$121.6**	**$139.8**	**$172.4**

Amounts in millions.
Amounts may not total due to rounding.
**Amounts may include Intangible & General Plant Additions.*

Q. What are the main categories of distribution projects as the Company develops its long-range plan and capital budget?

A. Minnesota Power has adopted the categories outlined in the Integrated Distribution Plan ("IDP"), most recently filed on November 3, 2025, for purposes of discussing the

Company's Distribution capital.[2] The IDP addresses the requirements outlined by the Commission, and the Company uses the IDP in addition to its normal capital planning processes to build internal consensus on the direction of future projects impacting the planning and operation of the distribution system and to facilitate an integrated planning approach that brings together distribution planning, transmission planning, and resource planning. The IDP also provides an opportunity for interested stakeholders to provide input on the Company's current and future plans. Minnesota Power's IDP utilizes the following categories, which are also used in this rate case filing for purposes of the Company's capital additions (Table 1 and Table 2 above) to allow for consistency across filings. The categories required for the IDP are:

- Age-Related Replacements and Asset Renewal;
- System Expansion or Upgrades for Capacity;
- System Expansion or Upgrades for Reliability and Power Quality;
- New Customer Projects and New Revenue;
- Grid Modernization and Pilot Projects;
- Government Requirements;
- Metering; and
- Other (CTS, EVSE Expansion Project, Facility Management, Fleet, and Wildfire Mitigation).

The categories listed above are the short-hand category titles used in Table 1 and Table 2 above, and in the IDP. These categories are discussed in further detail below.

Q. How are Distribution capital projects identified?

A. Distribution capital projects are identified through a variety of methods. The majority of Minnesota Power's current capital spending addresses asset replacements that are generally age-related. Some of these replacements are identified through inspection programs, such as groundline or pole maintenance inspections, while some are in response to difficult-to-predict failures. Past practice and historical averages inform the

[2] *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Docket No. E015/M-25-140, COMPLIANCE FILING (Nov. 3, 2025) (eDocket No. 202511-224624-01).

annual budget for cable and switch replacements and help predict where replacement of other failed assets may become necessary. Age-Related Replacements and Asset Renewal projects are also identified through local engineering expertise and experience with failures on the system. Some other means of identifying areas for replacements and asset renewals are the use of Geographic Information System ("GIS") applications such as Survey123 and Collector by technicians out in the field. These applications are used to collect issues in the field and channel that work automatically into the work management system.

Projects may also be identified through system modeling and analysis. System planning performs baseline analysis on the distribution system, generally in coordination with the planning of substation modernization or feeder automation projects. The types of projects identified through this process most often involve improvement of feeder capacity and voltage support in order to maintain or enhance backup capability and redundancy. Such projects would typically be categorized as "System Expansion or Upgrades for Capacity" and "System Expansion or Upgrades for Reliability and Power Quality"—though sometimes they may also support Grid Modernization Projects that make use of full-capacity feeder ties by enhancing or automating restoration capability.

Q. Can external needs impact how Distribution projects are identified?

A. Yes. There are multiple external drivers of projects; in particular, local government and customer needs. The Distribution capital budget addresses the need to respond to road relocations, new commercial and residential development, and other customer needs.

Q. How is the Distribution long-range plan developed?

A. The Distribution long-range plan is reviewed comprehensively on an annual basis. The Distribution Planning, Distribution Engineering, and Distribution Grid Modernization departments coordinate in the development of the plan, including identifying projects affecting transmission-to-distribution substations, as well as distribution feeders and step-downs. The long-range plan incorporates localized distribution system reliability and asset renewal needs as well as larger-scale projects 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.

The long-range plan generally utilizes historical spending to establish amounts for routine capital replacements. 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. Because many projects are dependent on timelines and needs outside of the Company's control, some changes occur naturally in the long-range plan as the Company learns more information.

Q. What are Age-Related Replacements and Asset Renewal Projects?

A. Similar to the transmission system, distribution system Age-Related Replacements and Asset Renewal Projects are used to replace failing and end-of-life distribution system infrastructure. In some cases, Asset Renewal Projects are planned 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. In other cases, Asset Renewal Programs are maintained to facilitate rapid responses to unanticipated failures or field survey findings. Engineering expertise helps prioritize proactive age-related and asset renewal efforts. In some cases, the Company experiences several 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 and Asset Renewal Projects also 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. The Company's current practice for transmission-to-distribution substation projects is to maintain a substation modernization program designed to efficiently and

holistically address all asset renewal and known long-term reliability needs for a given substation with one comprehensive project.

Q. What are the main drivers for these projects?

A. The main drivers for these projects are age and condition. With many assets more than 40 years old, asset management programs and investments have increasingly become an area of significant focus for the Company.

Q. What are examples of Age-Related Replacements and Asset Renewal Projects or Programs in the 2026 projected year and 2027 test year and what will they address?

A. The Annual Groundline Program, Failed Underground Cable Replacement Program, and Substation Conversions and Replacement Program are examples of Age-Related Replacements and Asset Renewal Programs in the 2026 projected year and 2027 test year. The Winton Substation Modernization, College Street Duct Bank, and the Birch Lake 509 34.5 kV Relocation Project are examples of major Age-Related Replacements and Asset Renewal Projects in the 2026 projected and 2027 test year. These projects are also discussed below.

Q. What is the Annual Groundline Program and what will it address?

A. The Company has expanded the Annual Groundline Program by using contractors to evaluate poles at the groundline and other equipment to determine if maintenance or replacement is needed. With the expanded inspections, poles experiencing deterioration below the surface will be identified more frequently. While this may create the appearance of an increased failure rate, it more accurately reflects a proactive remediation approach with enhanced detection. Additionally, this new program treats the poles with an Environmental Protection Agency-approved chemical that extends the life of the pole, identifies areas to truss the pole to increase the life expectancy, or determines if the pole is a candidate for replacement. These expanded inspections result in additional costs compared to the existing inspection program. However, this new

program will provide better reliability, resiliency, and a longer life expectancy of pole assets across the Company's distribution system.

Q. What is the Failed Underground Cable Replacement Program and what will it address?

A. The Company's Failed Underground Cable Replacement Program focuses on direct-buried cable and cable installed in duct systems within feeder segments that have experienced recurring failures or present a high risk of failure due to age, deterioration, excavation-related damage, or other physical damage. Replacing damaged and aging cable with new infrastructure improves system reliability, reduces the risk of recurring outages, and addresses the operational risks associated with deteriorated underground assets. Given the ongoing condition and performance needs of the underground distribution system, this is a recurring annual capital program.

Q. What is the Substation Conversions and Replacement Program and what will it address?

A. The Substation Conversions and Replacement Program rebuilds end-of-life distribution step-down substations. The program evaluates facilities based on equipment condition, capacity, reliability, performance, safety, and maintainability. Projects may include replacement of transformers, switchgear, protection equipment, and associated civil infrastructure. Where appropriate, existing lower-voltage systems, such as 4.16 kV or 12.47 kV networks, may be converted to higher distribution voltages to improve the distribution system's efficiency, performance, and operation. The annual program reduces the risk of equipment failures by addressing aging infrastructure and enhances system resiliency.

Q. Please describe the Winton Substation Modernization Project and what it will address.

A. The Winton Substation Modernization Project will relocate the existing 46 kV Winton Substation to a nearby location due to identified safety and expandability constraints and reconstruct it for future 69 kV operation in preparation for the Company's Tower-

Ely-Babbitt 69 kV Conversion. During an evaluation of the Winton substation, the existing retaining wall was flagged as needing to be repaired or replaced to rectify safety concerns with the wall tilting towards the substation, posing a threat of catastrophic failure and collapse into the substation. As a result, there is an urgent need to rebuild the substation to address the retaining wall and other age and condition-related issues. Further, the Company is progressively transitioning its remaining 46 kV facilities, including the Winton facilities, to standard distribution voltages because 46 kV is no longer a commonly supported utility voltage class. The Company determined that converting the existing Tower-Ely-Babbitt 46 kV network, including the Winton Substation, to 69 kV would provide the most long-term benefits to improve backup capability and system performance. While the full 69 kV conversion involves many facilities and will not be completed for several more years, the Winton Substation Modernization must be designed to operate at 69 kV, even though it will initially be energized at 46 kV. Constructing the Winton substation to 69 kV standards would require expanding the substation beyond its current available space, requiring relocation of the substation to an adjacent site. A relocation would also minimize outages and risks on the network during construction.

Q. What is the College Street Duct Bank Project and what will it address?

A. The College Street Duct Bank Project is part of a broader portfolio of projects to enhance and expand the Duluth 34.5 kV system. The Duluth 34.5 kV network is being designed and expanded to modernize the existing distribution system, address aging overhead infrastructure, and improve reliability by establishing stronger backup ties throughout Duluth, particularly in areas where new transmission-to-distribution substations are not feasible. Expansion of the network includes construction of new 34.5 kV feeders and 34.5/13.8 kV step-down facilities throughout Duluth and surrounding communities.

This College Street Duct Bank Project will be completed in coordination with the City of Duluth's planned College Street Construction Project in 2027. This project will install a new duct bank to convert existing overhead 13.8 kV feeders to underground, add a

new 34.5 kV feeder and remove aging overhead distribution assets. The new feeder will serve a planned 34.5/13.8 kV step-down in the University of Minnesota-Duluth ("UMD") area. Upon completion, the project will improve reliability of the UMD campus and surrounding area as well as provide a back-up tie to the Duluth 34.5 kV network that serves downtown Duluth and the city's two primary hospitals.

Q. What is the Birch Lake 509 34.5 kV Relocation Project and what will it address?

A. The Birch Lake 509 34.5 kV Relocation Project will relocate the Birch Lake-509 Feeder on an underground route of approximately 4.3 miles alongside Highway 371 near the Walker area. The relocated 34.5 kV feeder will connect to the existing 34.5 kV Akeley-543 feeder. This project will address age and condition concerns with the existing Birch Lake-509 feeder while improving the reliability to the Walker area by creating a 34.5 kV loop that provides enhanced operational flexibility and backup capability for the area's distribution step-down facilities. The relocation is necessary because the current Birch Lake-509 feeder is an aging overhead line that crosses approximately 4.8 miles of National Forest land. After the completion of the underground cable installation, this existing section of overhead feeder will be de-energized and permanently removed.

Q. What are System Expansion or Upgrades for Capacity?

A. System Expansion or Upgrades for Capacity projects are projects that increase the baseline load-serving capacity of the distribution system. For example, 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 also needed to build new distribution substations to increase load-serving capacity.

Upgrades for Capacity are often secondary benefits of implementing a reliability project or an asset renewal project. While many projects provide benefits in all three areas, creating additional value for customers, 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. Ideally, existing capacity chokepoints are identified through the Company's proactive system modeling and distribution planning practices, though they may sometimes be discovered by field crews or during a switching event. Sometimes these capacity limitations are limited to a few spans of undersized conductor. The Company does not currently have many load-serving constraints on the system during normal conditions. Feeder backup capability is being evaluated and improved methodically by distribution planning in coordination with the development of substation modernization asset renewal projects and grid modernization projects.

Q. What are the main drivers for System Expansion or Upgrades for Capacity?

A. The main driver of System Expansion or Upgrades for Capacity is load growth. This load growth is almost always driven by commercial and industrial customers expanding their operations at a local level taking more service from the distribution system. Some examples of recent load growth include new apartment buildings, hospital expansions, pumping station changes and new electric loads being installed as older equipment ages out. Upgrades for Capacity may or may not arise due to any single new customer but often are needed after many years of concentrated load growth on a capacity-constrained area of the system. As noted above, capacity improvements may also be achieved incidentally or intentionally as part of multi-purpose projects that involve strong age and condition, reliability, and grid modernization components. Minnesota Power analyzes alternative technology that is available to identify if there is another way of supporting the load. For examples, non-wire alternative ("NWA") studies help determine how best to meet the additional load.

Q. What are examples of System Expansion or Upgrades for Capacity in the 2026 projected year and 2027 test year?

A. Relatively few projects in the 2027 test year are driven solely by a need for increased system capacity, but many projects address capacity-related needs in addition to other needs. The Biwabik-1 12 kV to 23 kV Conversion, is an example of a System Expansion or Upgrade for Capacity in the 2026 projected year and 2027 test year. These types of projects address reliability, age and condition, and even grid modernization needs.

As another example of Upgrades for Capacity, the Tower-Ely-Babbitt 46 kV to 69 kV Conversion initiative, discussed previously in the context of the Winton Substation Modernization Project, has many increments of project construction which will take place over several years before the shift to 69 kV operation can be fully realized. As a result, the effort has been broken down into a series of individual projects, which will be implemented between 2025 and roughly 2032. This series of projects will enable Minnesota Power to fully transition away from 46 kV equipment by standardizing on 69 kV, address asset renewal needs at step-down substations and along some sections of feeder, provide a higher distribution system voltage for more robust local load-serving to mitigate reliability concerns, and enable grid modernization improvements that will provide enhanced visibility and rapid system restoration. Even though there are no Tower-Ely-Babbitt 69 kV Conversion subprojects categorized as Upgrades for Capacity in the 2027 test year, there will be several subprojects of this initiative categorized as Upgrades for Capacity in future years.

Q. What is the Biwabik-1 12 kV to 23 kV Conversion Project and what will it address?

A. The Biwabik-1 12 kV to 23 kV Conversion Project addresses low voltages and transformer overloads associated with commercial load growth in the Giants Ridge Recreation Area. This project will convert the existing Biwabik-1 Feeder from 12 kV to 23 kV feeder, enabling it to interconnect to the nearby Embarrass 115/23 kV Substation. Upon completion of the voltage conversion and substation interconnection, the Giants Ridge Recreation Area will be served by a dedicated feeder from the Embarrass Substation. This will mitigate the identified low voltage and transformer overloads.

Shifting the Giants Ridge Recreation Area's load to a dedicated feeder will also improve reliability by strengthening backup ties to nearby feeders. With the load redistributed, each backup tie will be required to carry less load during a contingency involving the Embarrass Substation.

Q. What are System Expansion or Upgrades for Reliability and Power Quality?

A. System Expansion or Upgrades for Reliability and Power Quality are projects that directly benefit customer reliability. Often these projects involve building or strengthening ties to other feeders to restore power more easily to customers during outage events. These projects can be identified through field experience, analysis of reliability data, and system planning.

Q. What are the main drivers for System Expansion or Upgrades for Reliability and Power Quality?

A. Improving operational flexibility and customer reliability are the main drivers of these projects. If a certain area experiences exceptionally poor reliability over a short period of time, engineers and planners may evaluate the local system and identify potential reliability improvements. Field crews are also invaluable resources for feedback on areas of the system that could benefit from additional operational flexibility. Power quality issues are primarily identified through customer reporting and power quality monitoring. With the prevalence of Advanced Metering Infrastructure ("AMI") on the system, the Company has been able to identify areas of the system with power quality issues before customers notify the Company.

Q. What is an example of a System Expansion or Upgrade for Reliability and Power Quality in the 2027 test year?

A. The strategic undergrounding program across the Company's service territory is the largest Upgrade for Reliability and Power Quality program being implemented for the next several years. This project impacts a number of IDP categories including Age-Related Replacements and Asset Renewal, Capacity Upgrades, and Upgrades for

Reliability. The strategic undergrounding program is described further in Section V.A of my Direct Testimony.

An example of a Power Quality improvement project is the implementation of voltage regulators in various areas of the Company's distribution system. Voltage regulators are routinely installed on the system in order to control feeder voltage and mitigate end-of-line power quality issues. Distribution voltage regulators help to shield distribution-connected customers from the negative impacts of wide variations in system voltages by maintaining a consistent feeder voltage profile across a wide array of system conditions. These types of Power Quality improvements are becoming increasingly necessary as transmission voltages become more unpredictable due to the retirement or idling of local baseload generators and as large distribution-connected generators or aggregations of small-scale distribution-connected generators produce less predictable system conditions locally on the feeders.

The Mahtowa Feeder Conversion to 34.5 kV Project, Cloquet 34.5 kV Loop Expansion, and Hat Trick Feeder Addition are examples of other major System Expansion or Upgrade for Reliability and Power Quality projects in the 2027 test year. These projects are discussed below.

Q. What is the Mahtowa Feeder Conversion to 34.5 kV Project and what will it address?

A. The Mahtowa Feeder Conversion to 34.5 kV Project is part of a broader portfolio of projects that make up the I-35 Voltage Conversion plan. This project will convert the existing Mahtowa 46 kV line and 23 kV feeder to operate at 34.5 kV. The 46 kV line conversions support the Company's ongoing transition of its remaining 46 kV facilities to standard distribution voltage classes because 46 kV is no longer a commonly supported utility voltage class. In this case, the existing 23 kV feeder will also be converted to 34.5 kV to align with the standard voltage class used in the Cloquet area distribution system. Transitioning these facilities to 34.5 kV will improve reliability by creating back-up ties to adjacent feeders and support the addition of Fault, Location,

Isolation, and Service Restoration ("FLISR") technology. It will also simplify system operations and maintenance, replace aging infrastructure, and better integrate the Mahtowa feeders with the surrounding 34.5 kV distribution system between Cloquet and Hinckley.

Q. What is the Cloquet 34.5 kV Loop Expansion Project and what will it address?

A. The Cloquet 34.5 kV Loop Expansion Project is part of a broader portfolio of projects that make up the I-35 Voltage Conversion plan as well as supporting the future modernization and replacement of the Cloquet Substation. The project includes construction of a 34.5 kV feeder around the city of Cloquet, along with new step-down substations to serve the existing 13.8 kV and 12.47 kV feeders in the area. The project is needed to establish additional sources to serve the Cloquet area, which is currently supplied primarily by the Cloquet Substation with limited adjacent feeder support, and to improve reliability and resiliency in the area which includes the Tribal lands of the Fond du Lac Band of Lake Superior Chippewa. The project will redistribute load among the existing feeders, the new 34.5 kV feeder, and the new step-down substations, reducing the amount of load that must be carried by backup ties during contingency scenarios.

In addition, the new 34.5 kV feeder will strengthen the overall I-35 Voltage Conversion project by creating additional back-up ties to the 34.5 kV distribution system between Cloquet and Hinckley. This project is also necessary to strengthen backup capability to the existing Cloquet Substation so it can be taken out of service and rebuilt as part of a separate substation modernization project. Lastly, FLISR technology will be installed as part of this project to further improve reliability for the Cloquet-area distribution system.

Q. What is the Hat Trick Feeder Addition Project and what will it address?

A. The Hat Trick Feeder Addition Project will expand the Hat Trick substation, located in Eveleth, MN, through the installation of a second 115/23 kV transformer and three additional 23 kV distribution feeders. The project is needed to address low-voltage and

thermal overloads during contingency scenarios, including conditions in which existing Hat Trick feeders are required to provide backup support to adjacent feeders or adjacent feeders are required to support Hat Trick loads. By redistributing load across the existing and new 23 kV feeders, the project will reduce the amount of load that must be carried by backup ties during feeder contingency events involving the existing Hat Trick feeders and the adjacent feeders. Additionally, one of the new 23 kV feeders will replace a 46 kV line that will be converted to 23 kV. The Company is transitioning its remaining 46 kV facilities to standard distribution voltages because 46 kV is no longer a commonly supported utility voltage class. In this case, converting this 46 kV line to 23 kV will improve reliability, simplify operations and maintenance, replace aging infrastructure, and better integrate the feeder with the surrounding 23 kV distribution system.

Q. What are New Customer and New Revenue Projects?

A. New Customer Projects include the construction of distribution line extensions required to serve new customer load. These extensions are installed in accordance with the Company's Electric Service Regulations and Commission-approved tariffs. The service extension rules establish the methodology for determining customer costs, which vary depending on the type of service and specific job characteristics.

Q. How many New Customer Projects does the Company complete annually?

A. In 2024 and 2025, the Company completed 1,192 and 1,015 New Customer Projects, respectively. Over the past two years, new connections have averaged 84 percent residential, 14 percent commercial, 0 percent industrial, and 2 percent municipal.

Q. Which customers do the service extension rules apply to?

A. The service extension rules apply to all customer classes connecting to the Company's distribution system. Transmission extensions are outlined on an individual customer basis in an Electric Service Agreement.

Q. Please describe the Company's current service extension policy and how it applies to new customer construction.

A. Customer costs are calculated using one of three methods, depending on the type of service and specific job characteristics:

- A pre-determined cost per foot based on the length of the extension;
- An estimate developed using the Company's Compatible Unit Estimator ("CUE"); or
- Actual costs incurred.

The Company applies a service extension allowance (*i.e.* a credit) based on customer class. This allowance is determined by using the average embedded cost of line extensions, as calculated in the Company's annual compliance filing. 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.

Q. What challenges has the Company observed with the current service extension rules?

A. Customers requesting new service often require an upfront cost estimate for a variety of purposes, including evaluating project feasibility, planning, and securing financing. Under the Company's current service extension rules, however, it can be difficult for customers to determine an estimated project cost until a Minnesota Power representative visits the site and determines the applicable cost methodology. For example, if a line extension exceeds 1,000 feet or involves three-phase service, a detailed design must be completed before the Company can provide an estimate.

The Company has found that this structure can create customer frustration, as it requires Minnesota Power to complete detailed designs even when a customer has not yet committed to proceeding with the project. This results in inefficiencies, including potentially unnecessary work and extended project timelines.

In addition, the current allowance framework creates situations in which projects with costs below the allowance are provided at no charge to the customer, while projects exceeding the allowance require customer payment. This dynamic can lead to inequities in the recovery of fixed costs associated with all projects, such as labor and travel expenses.

Q. What specific changes to the service extension rules are being proposed in this case?

A. The Company proposes to revise its service extension rules to create a simpler, more transparent, and more standardized billing structure for customers and contractors. Specifically, the Company proposes to eliminate the current service extension allowance and replace it with a fixed fee per customer job.

Under the proposed approach, the fixed fee would be based on the average labor and vehicle cost of a three-person crew for one hour for single-phase jobs and two hours for three-phase jobs. In addition, the total job cost would include a fixed per-foot charge based on average material costs.

These proposed changes are intended to make the billing structure easier for customers to understand, allow the Company to provide estimates without waiting for a site visit and completed system design, and help contractors working in Minnesota Power's service territory better understand the Company's charges. Overall, the proposal is expected to improve transparency, promote more equitable billing, streamline the design process, and reduce timelines for customers and contractors. The Company expects that this change would improve access to the distribution system by helping to level the costs of attachment while creating minimal cost impact to overall rates. As more customers attach to the system, the costs for operating and maintaining the system for all customers is distributed across a wider customer base helping with cost control. These changes are shown in Volume 3, Direct Schedules J-2 and J-3 (clean and redline format, respectively), Minnesota Power Electric Rate Book, Section VI, Page No. 4, Extension Rules, which are sponsored by Company witness Leah N. Peterson.

Q. Are there any adjustments to the test year as a result of these proposed changes?

A. Yes, the proposed changes result in an increase to the test year rate base, as discussed in the Direct Testimony of Company witness Amanda L. Turner. The test year rate base increases under the proposed Service Extension Policy because a larger share of extension-related capital investments will be included in rate base rather than offset through direct customer contributions.

Q. What are Grid Modernization Projects?

A. Grid Modernization Projects are efforts that go beyond the Company's baseline efforts to maintain safe, reliable, and affordable energy and are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, smart switches, fault indicators, and TripSavers. The Company is in the process of rolling out a multi-year plan to install smart switches ("IntelliRupters" and logic enhanced reclosers) and the associated communications infrastructure improvements in strategic locations on the distribution system. These smart switches make up the Company's FLISR projects. Increased information from the distribution system helps improve situational awareness to inform customer communications and condition of service.

Minnesota Power continues to test control capabilities on the distribution system. With the aid of smart sensors and Faulted Circuit Indicators ("FCIs"), the Company plans to continue installing remotely controlled motor operated switches on the distribution system for voltages 46 kV and higher in order to enhance fault isolation and system restoration capabilities. Motor operated switches enable Minnesota Power's system operators to remotely control feeder switches. Smart sensors and FCIs give indication to the system operators about where the fault is located on the feeder. Combining motor operated switch installations with fault location information on a feeder enables Minnesota Power's system operators to utilize the motor operated switches to rapidly isolate the faulted section of the feeder and restore service to customers on the sections

of the feeder without electrical faults. All of this switching can be completed by the system operators in minutes, well before a trouble crew could reach the feeder to begin to identify the cause of the fault. With the faulted section of feeder identified and isolated by the system operators, the trouble crew can then focus its efforts on only the faulted feeder section to identify and fix the cause of the fault. The end result is a more rapid and efficient response to feeder-level fault events, which should greatly enhance reliability for the customers served from the feeders where this approach is implemented. FCIs are also being deployed as standalone devices to aid in normal fault location and restoration efforts by crews.

Q. How does the Company evaluate Grid Modernization Project investments?

A. Grid Modernization Projects are identified and selected by analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability on the system. 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.

Q. Please describe the pilot projects that the Company undertakes.

A. Pilot projects are the Company's efforts to work with new and emerging applications on the distribution system. Pilots are most often projects and technology that the Company has little to no experience with but are meant to facilitate learning and ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. One key advantage of piloting technology on the distribution system is that a thesis can generally be proven at a small-scale utilizing metrics and benefits and expanded to larger levels and optimized accordingly, without significant risk to customers if the technology or application is determined to not be cost-effective.

One such pilot was evaluated in a consultant-led Non-Wires Alternative Study that was provided in the Company's 2023 IDP and is currently moving forward as a Grid

Modernization Project is the implementation of a 2.5 MW/5 MWh Battery Energy Storage System ("BESS") near Kerrick, Minnesota, a small town on Highway 23 south of Duluth. Step-down substations connected to the Bear Creek-Kerrick 46 kV Line serve just over 750 customers with a peak load of 1.80 MW. The Kerrick BESS pilot project will be connected to the secondary side (12.47 kV) of the Kerrick 46 kV/12.47 kV Step-down and will support reliability of the local distribution system by providing a redundant source to the city of Kerrick. This backup source will eliminate the need to rebuild almost 30 miles of aging 46 kV infrastructure and a 115 kV/46 kV transformer, thereby avoiding significant capital costs. As part of the Non-Wires Alternative Study, a Benefit Cost Analysis was developed and determined that the Benefit Cost Ratio ("BCR") for the Kerrick BESS project was greater than one. A BCR greater than one means the estimated lifetime benefits of the project exceed the cost of the project.

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

There have also been a number of challenges associated with modernizing the grid and implementing pilot projects. Moving to a more complex distribution system with

intelligent devices has meant projects are more complex in nature to plan, coordinate and execute than distribution projects in past years. The complexity involves more resources with skillsets needed to make technology perform as expected, while balancing outage constraints on the system. The Company continues working on the communication infrastructure plans dealing with new cyber security concerns as more intelligent devices are installed on the system. More detailed information about Pilot projects can be found in the Company's 2025 IDP.[3]

Q. What are the main drivers for Grid Modernization and Pilot Projects?

A. Grid Modernization projects take advantage of technologies that can significantly reduce outage times for customers. FLISR allows the Company to leverage technology that automatically determines the location of faults. Customers outside the fault area can be restored immediately and allow field personnel to focus on the remedy of the fault cause and restore remaining customers more quickly.

Pilot Projects are a key means to increase internal knowledge and experience with new and emerging technologies and keeping pace with regulatory requirements and customer expectations. Minnesota Power's Grid Modernization Projects are typically deployed on systems to increase reliability and enhance performance. Circuits are targeted for this investment based on customer count, past performance, expected benefits and cost. This has the additional benefit of increasing knowledge used to improve reliability and provide better information to our customers during an abnormal event.

Q. When did Minnesota Power deploy its first-generation AMI system, and what benefits has it provided?

A. Minnesota Power completed deployment of its first-generation of its AMI system in 2023, following a deployment that began in 2009. The first-generation AMI system has provided several operational and customer service benefits, including outage

[3] *In the Matter of Minnesota Power's 2025 Integrated Distribution Plan*, Docket No. E015/M-25-140, Compliance Filing (Nov. 3, 2025) (eDocket No. 202511-224624-01).

notification, voltage monitoring, improved billing accuracy, and support for demand response and time-of-day rates. As of June 1, 2026, 54 customers elected to take service under the AMI opt-out rate and, as a result, do not have AMI technology installed at their premises.

Q. Why is Minnesota Power updating its AMI system?

A. Since Minnesota Power began its AMI deployment, metering technology has continued to advance, and the initially deployed meters are now approaching the end of their useful lives (15 to 20 years). To address these developments and ongoing system needs, Minnesota Power initiated an ongoing project in 2023 to enhance the radio communications network and deploy the next generation of meters. The purpose of this project is to strengthen communications with deployed meters and to support the increased data and functionality requirements associated with future generations of metering technology. This work will be complete over a roughly 10-year deployment period and will gradually replace meters as they reach the end of their useful lives. Minnesota Power will continue to evaluate new technologies and capabilities as they become available and incorporate them back into our AMI systems.

Q. What changes are being made in the next phase of AMI deployment?

A. Standardizing remote-capable functionality will position Minnesota Power to support grid modernization initiatives and innovative customer programs. It will also improve the Company's ability to develop and support demand response offerings and rate options such as Time-of-Day rates. These meters reduce reconnection times when customers meet reconnection requirements. They also reduce the labor and truck rolls needed for the reconnection by eliminating the need for the field visit. As of May 2026, the AMI system had recorded 1,285 hot socket alarms across 926 unique locations. Of these, 1,158 alarms were determined to be actionable, while the remainder were attributed to factors such as sensor issues, conditions external to electric service, or meter-related conditions.

Q. Are there other technologies that support Grid Modernization and Pilot Programs?

A. Yes, digital information systems like GIS, the advanced distribution management system ("ADMS"), and communication system improvements all play an important role in Grid Modernization and Pilot Programs.

Q. What is the GIS?

A. Minnesota Power's GIS is a critical system that enables the Company to store, analyze, and report on the spatial and geographic characteristics of its electric system. GIS functions as a relational data platform that tracks information related to system "features," including infrastructure assets and their associated attributes, and allows those assets to be visualized and analyzed in relation to other spatial datasets.

The GIS includes both geographic location data and asset-specific information for each component within the system. This information allows the Company to understand the configuration of its electric system, evaluate system conditions, and support a wide range of operational and planning activities.

Q. What is the GIS's role in supporting electric operations?

A. GIS serves as a core system supporting Minnesota Power's electric operations and is closely integrated with other operational technologies. Most notably, the GIS provides critical system data to the Company's Outage Management System ("OMS"), which relies on GIS data to model the electric system and support outage detection, analysis, and restoration.

In addition to outage response, GIS supports a wide range of operational functions, including asset tracking, infrastructure analysis, and coordination across internal teams and external stakeholders.

Q. What is the GIS's role in distribution planning and grid modernization?

A. GIS is a foundational component of Minnesota Power's broader grid modernization efforts and plays a critical role in the Company's distribution planning processes. GIS provides the data platform necessary to support advanced system analysis and informed decision making.

Minnesota Power transitioned to a next generation GIS model, often referred to as a Utility Network model. This modernized platform is designed to integrate data across generation, transmission, and distribution systems, creating a more comprehensive and connected representation of the electric system. This enhanced integration supports the development of a more real-time and holistic view of system conditions, enabling improved planning, operational coordination, and responsiveness to system needs

Q. What are the modernization drivers and system enhancements for the GIS?

A. The Company's investment in GIS modernization is driven by the need to address limitations of legacy systems and to meet increasing demands for data accessibility, system visibility, and real-time decision-making.

Both internal and external drivers are pushing the GIS to provide more information to more users, in more locations, and at faster speeds. The Company recognizes that future systems will require a higher level of consolidation of data within the GIS for ease of integration with other systems.

The Company is improving integration across systems, reducing the need for manual data transfers, and enabling more efficient workflows. These improvements support more timely analysis and allow employees to respond more quickly to system conditions and customer needs.

Q. What are the customer and operational benefits?

A. Enhancements to the GIS system provide tangible benefits for both customers and Company operations.

For customers, GIS improvements contribute to:

- More accurate and timely outage information;
- Improved restoration estimates and communication; and
- Enhanced access to system-related information that supports customer decision making.

For the Company, GIS improvements contribute to:

- Improved operational efficiency by reducing manual processes;
- Faster and more accurate decision making; and
- More advanced system analysis and planning capabilities.

In summary, consistent with prior testimony and filings, Minnesota Power's GIS is a critical system that supports electric system operations, distribution planning, and customer service. The Company's continued investment in GIS modernization reflects the increasing importance of integrated, real-time data systems in supporting a safe, reliable, and efficient electric grid.

Q. What is the OMS?

A. Minnesota Power's OMS is a critical operational system used to manage the detection, location, isolation, repair, and restoration of outages on the Company's distribution system. The OMS supports operators throughout the full outage lifecycle—from the initial identification of an outage event through final service restoration by integrating information from multiple sources, including customer outage reports, AMI notifications, SCADA systems, and field crew observations. Using these inputs, the OMS provides operators with the information necessary to coordinate outage response activities and efficiently manage restoration efforts.

Q. Please describe ADMS and the benefits of it.

A. As discussed throughout this testimony, the Company continues to invest in foundational systems that enhance visibility, operational awareness, and reliability

across the distribution system. These investments include AMI, GIS, and enhancements to OMS and Energy Management System ("EMS") capabilities.

As these foundational systems mature and become increasingly integrated, the Company is evaluating opportunities to further enhance distribution system operations through advanced control capabilities. These capabilities, often referred to as ADMS and related technologies, are designed to support improved coordination of distributed energy resources ("DER"), enhance situational awareness, and enable more efficient system operations.

The primary near-term objective for this investment is to enable centralized FLISR capabilities to improve electric distribution reliability. As the distribution system becomes more dynamic and operationally complex, centralized FLISR provides important advantages over more fragmented or manual restoration processes. An ADMS serves as the operating platform that brings together feeder topology, device status, outage information, and control functionality in a single environment. This allows the Company to identify faulted sections more quickly, isolate the outage more precisely, and restore unaffected customers faster and more consistently. In practical terms, this investment is intended to reduce outage duration, limit the number of customers experiencing sustained interruption, and improve operator situational awareness during both routine events and larger outage conditions. In rural areas, centralized FLISR with wireless communications to isolating field devices is a cost-effective alternative to building out fiber optic networks to enable peer-to-peer communications between devices capable of decentralized FLISR.

Q. How is Minnesota Power implementing ADMS?

A. The first phase of ADMS includes establishing the platform and capabilities necessary for centralized FLISR and supports core implementation activities such as system configuration, model development, integration with existing operational systems, communications and interface work, testing, cybersecurity, and training and change

management. These are necessary prerequisites to place centralized FLISR into service in a controlled and reliable manner.

This is a targeted reliability investment tied to a specific operational priority for the coming year: centralized FLISR for improved restoration performance. In addition to delivering near-term reliability benefits, the ADMS platform establishes the operational foundation for future distribution capabilities as system needs evolve. This includes the potential separation of distribution operations from the EMS, implementation of DER Management System ("DERMS") and Integrated Volt/VAR Optimization ("IVVO") functionality, and enhanced coordination of growing customer-connected and utility-controlled resources. As Minnesota Power expands demand response, beneficial electrification, and other flexible load programs, the Company expects the amount of controllable customer load to increase significantly. An ADMS platform provides the visibility, monitoring, and operational framework necessary to manage these resources effectively while maintaining reliability and supporting efficient system operations.

Q. Please describe the communications system improvements made in recent years.

A. 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 information technology systems, voice, video and other applications. A variety of communications methods are used based on the cost and needed reliability of each application.

Q. What are the benefits of these systems?

A. The Company has recently completed the replacement of the Land Mobile Radio ("LMR") system. The updated system is fully supported by the vendor, allowing for increased security through firmware and security patches. It also includes expanded functionality such as over-the-air programming and support for low-speed data radios providing a low-cost solution for small distribution and transmission SCADA needs.

Minnesota Power's transport microwave radios provide reliable backhaul communications to many portions of its service territory and are a critical part of the communications transport system. The technology advancements in the new radios allow for faster speeds, enabling data-intensive grid modernization initiatives and are fully supported by the vendor allowing for increased security through firmware and security patches. The system will provide a secure and reliable fiber optic transport platform while leveraging new technology, allowing Minnesota Power to expand its communications capabilities, enabling data intensive grid modernization initiatives.

Q. Are additional improvements under consideration?

A. As the Company's communication strategy continues to evolve, Minnesota Power is evaluating Field Area Network ("FAN") options to support communications needs of distribution automation, distributed energy resources, and others. This effort will include working with internal stakeholders to develop a list of use cases and the specific communication requirements of each use case. The Company will explore FAN options including private Long-Term Evolution, which is a 4G wireless broadband standard developed to deliver high-speed data, low latency, and reliable cellular connectivity, public cellular, FirstNet, Multiple Address radio solutions and others to determine the best fit for its purposes. The Company will then develop a project plan to build out the chosen solution to support the growing need for communication to field devices.

Q. What are projects related to Local Government Requirements?

A. The most common Local Government Requirements are relocation of lines located in public rights-of-way and relocating distribution lines to avoid road construction conflicts. By the rules of the governing authority having jurisdiction, most projects are not reimbursable to Minnesota Power by local governments. Only relocation of existing lines outside road rights-of-way and protected by private property rights may be reimbursable. The rural nature of Minnesota Power's service territory is more likely to require unplanned projects executed in short time frames to align with legislative schedules and the short construction season in northern Minnesota.

Q. What are Metering Projects?

A. Metering Projects are related to the procurement, installation, and communications of energy measurement technologies used for financial transactions.

Q. What are the main drivers for Metering Projects?

A. The main drivers include:

- Supply usage information to our customers. Interval usage information is loaded into the MyAccount customer portal available on the Minnesota Power website and through the Minnesota Power application;
- Shorter life span with solid state meters and components associated with them;
- Software and firmware management of AMI meters and communication network systems;
- Needed network upgrades to accommodate new technology for deployed AMI meters;
- Supporting billing for advanced rate designs, such as Minnesota Power's residential time-of-day rate structure (Docket No. E015/M-20-850). Minnesota Power is the first utility in the state to have a plan to transition its entire residential class to a default time-of-day rate structure, which provides customers with more control over their energy bills and encourages customers to shift energy use from periods of high energy demand and high prices;
- Integrating AMI meters and the OMS. Every AMI meter acts as an outage detection sensor and also reports power restorations;
- 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 for this important customer-focused demand response program that supports reliability with increased variable renewable energy on the system; and
- More timely and cost-effective restoration of service to customers who have been disconnected by using meters with remote disconnect and reconnect capability. This technology was deployed on a limited basis through Minnesota

Power's Reconnect Pilot Program, described in Docket No. E015/M-19-766, with a target of approximately 12,250 remote-capable meters installed with residential customers. That target was met in January 2025 and the Pilot has since closed, with a shift to remote-capable meters as standard for AMI going forward, where available and applicable. As of August 31, 2026, there were 29,026 remote-capable meters installed, net of those related to Dual Fuel offerings.

Q. What was the Reconnect Pilot Program?

A. The Reconnect Pilot Program, described in Docket No. E015/M-19-766, was a program that allowed customers to opt in for a remote-capable residential meter, at no additional charge, enabling disconnection and reconnection across the Company's AMI metering network.

Q. How is the Company transitioning this work to normal operations?

A. Minnesota Power uses and will continue to use remote-capable residential meters as part of our normal operations around disconnect and reconnect, offering the service to customers at no charge. The Company will continue to comply with all applicable Minnesota laws, Commission rules, and tariff provisions governing service disconnections. Customer protections include requirements applicable to customers receiving or eligible for energy assistance and protections provided under the Cold Weather Rule.

The Company has not changed its disconnection process or sought a variance from Minnesota Rule 7820.2500. The availability of remote servicing does not alter the Company's compliance obligations under those requirements. Where reconnection is required, Minnesota Power will provide in-person reconnection when remote reconnection is unavailable or otherwise necessary, consistent with applicable rules and tariffs.

Q. How do reconnection costs differ for remote reconnected meters?

A. For meters that do not have remote reconnect capability, Minnesota Power has to send a field technician to reconnect those meters in order to restore service. The expense of that order can vary depending on a number of factors, such as the crew's distance to the site needing to be reconnected, crew availability and the type of equipment used during the reconnect. At times, our meter reader/collectors are busy and we may have to send an area line worker or a small crew to perform this work in a timely manner. The cost difference can fluctuate depending on whether the request is completed as a business hours reconnect or an after-hours reconnect. The costs of either technical group performing the reconnection is factored into the O&M budgets of the operating areas.

As Minnesota Power continues to replace meters as part of its metering program, remote-capable residential meters are the standard going forward for all meters. The cost difference is small compared to the operational, safety, and customer service benefits gained through reduced truck rolls and the ability to remotely connect and disconnect service.

Q. How do the costs of remote and on-site reconnections compare?

A. As stated above, as of August 31, 2026, there were approximately 29,026 remote-capable meters installed (net of those related to Dual Fuel offerings) for residential accounts. There were 2,441 involuntary residential disconnections and 1,824 reconnections associated with these accounts in 2026. Of those, 1,695 were remote disconnections and 1,347 were remote reconnections.

Although costs may vary based on the circumstances of an individual reconnection, the average cost to complete an on-site reconnection during normal operating hours is approximately $90 estimating one hour of labor as well as vehicle costs. In contrast, a remote reconnection completed during normal operating hours does not result in an incremental field-service cost, because existing personnel can issue the reconnection command remotely as part of their regular duties.

Q. Are costs shifts anticipated as a result of remote-capable residential meters?

A. Minnesota Power does not expect a shift or increase in costs related to remote-capable residential meters. The process involves time to contact the customer, verify safety, and execute the command through the AMI system. The majority of this work is performed by a combination of operators that are staffed around the clock and call center employees. The costs of these employees performing this work are also built into the O&M budgets for these operating areas, as these employees perform many duties in addition to reconnecting work at times.

As such, Minnesota Power does not anticipate cost shifting due to remote reconnection operations related to remote-capable residential meters.

Q. What are the Distribution "Other" projects?

A. Projects included in the "Other" category improve distribution asset operations but do not meet the above-listed categories or drivers. Some examples include replacement of assets due to damage incurred to the system by an unidentified third party for which the Company cannot receive reimbursement or due to storms.

C. Other Capital Projects

Q. What other categories of capital additions are listed in Table 1, represented within my testimony?

A. The Company also has capital additions for Facility Management, Wildfire Mitigation, Electric Vehicle System Expansion, Fleet, and CTS.

1. Facility Management

Q. What are some of the projects for Facility Management?

A. Facility Management projects include the Little Falls Service Center project, the Cloquet Service Center Remodel project, and the ALLETE Headquarters ("AHQ") 4th Floor Remodel project.

Q. Please describe the Little Falls Service Center project.

A. The Little Falls Service Center project is a strategic investment to replace an aging facility that no longer adequately supports Minnesota Power's operational safety, workforce, and customer service needs in central Minnesota.

The existing facility has reached the end of its useful life and presents limitations related to operational efficiency, employee accommodations, equipment storage, training capabilities, and support for modern utility operations. The facility was not designed to accommodate the current workforce, fleet requirements, technology systems, and operational coordination necessary to safely and reliably serve customers.

Minnesota Power's transmission, distribution, fleet, customer service, engineering, technical systems, relay, operations, inventory, and support personnel increasingly require collaborative workspaces, specialized equipment storage areas, training facilities, and modern infrastructure that are not available within the existing facility. With a growing transmission footprint in this area, supporting staff will be added in the future to operate and maintain many of the projects underway. The new investment will ensure that these important assets are supported as they go into service to support the electric system. Continued investment in the existing building would not address the underlying functional deficiencies and would not provide a cost-effective long-term solution.

The new Little Falls Service Center will serve as a regional operations hub designed to improve workforce productivity, operational coordination, employee safety, equipment readiness, and customer service. The facility will provide modern office, warehouse, fleet, training, and operational support spaces that align with current and future utility needs. In addition, the facility is designed to support efficient deployment of field personnel and equipment, improve inventory management, enhance emergency response capabilities, and provide the infrastructure necessary to support Minnesota Power's ongoing commitment for safe and reliable electric service.

Q. Please describe key benefits of the Little Falls Service Center.

A. The key benefits of the Little Falls Service Center include, but are not limited to:

- Improved safety for employees through modern building systems, vehicle circulation, equipment storage, and operational layouts.
- Enhanced reliability and service restoration capabilities through improved coordination of field operations and staging of personnel and equipment.
- Increased operational efficiency through consolidation of functions and modern workspace design.
- Improved workforce recruitment and retention through the provision of a safe, functional, and modern work environment.
- Reduced long-term maintenance and operating costs associated with aging infrastructure.
- Enhanced training and collaboration opportunities to support employee development and knowledge transfer.
- Increased indoor storage for vehicles and equipment to increase equipment longevity and response times.
- Improved ergonomics throughout the building.
- Capacity to support future operational needs and evolving utility technologies.

Q. Please discuss project execution and the 2027 in-service plan.

A. Construction of the Little Falls Service Center began in March 2026 and is progressing in accordance with the approved project schedule. Major construction activities include site development, utility installation, building foundations, structural systems, building enclosure, interior construction, mechanical and electrical systems installation, and site improvements.

Throughout 2026 and 2027, Minnesota Power will continue active project oversight through a collaborative team consisting of internal stakeholders, design consultants, construction management representatives, and independent construction inspection services. Project controls, cost monitoring, schedule management, quality assurance, and safety oversight processes are in place to support successful project delivery.

Q. What are the key activities planned for 2027?

A. The key activities planned for 2027 include, but are not limited to:

- completion of building enclosure and weather-tight construction;
- installation and commissioning of mechanical, electrical, plumbing, communications, and security systems;
- completion of interior finishes and operational support spaces;
- installation of furniture, fixtures, equipment, and technology systems;
- site restoration, paving, landscaping, and final utility connections; and
- testing, commissioning, occupancy readiness, and employee move-in activities.

The facility is currently anticipated to achieve substantial completion during 2027 and to be placed in service during the 2027 test year. Upon completion, the facility will provide long-term operational value and will support Minnesota Power's ability to safely and reliably serve customers throughout the region.

Minnesota Power will continue to manage the project using prudent construction management practices and ongoing oversight to ensure the project is delivered safely, efficiently, and in alignment with approved scope, schedule, and budget objectives.

Q. Please discuss the Cloquet Service Center Remodel project and why it is needed.

A. The Cloquet Service Center was built in 1982 with very minimal upgrades since then. The service center houses crucial equipment, serving as a backup control center for Thompson Dam and local dispatch in the event of an incident. If evacuation of the Thompson Dam is needed, operations would be conducted out of the Cloquet Service Center.

A new heating and cooling system was installed in 2010 and presented many challenges related to efficiency. After years of attempted improvements to the heating and cooling system, a temporary system was installed to assist with heating and cooling at the service center. In recent years, the temporary system has been unable to keep up with

demand, which has resulted in increased costs for repairs and modifications The remodel project will replace this temporary heating and cooling system with a more efficient system, resulting in fewer expenses.

The Cloquet Service Center Remodel project will bring the facility into compliance with current state and federal safety codes. The remodel will create a new layout to add much-needed office space, conference rooms, and additional cubicle space for expansion of the growing workforce. The remodel will also improve ergonomics throughout the building. Interior walls will be removed, creating an open-floor plan to help departments collaborate more efficiently. Two new secure rooms will be added with one room utilized for dispatch backup and one for Thompson Hydro. Additionally, new carpet, lighting, paint, and an additional Americans with Disabilities Act ("ADA") compliant restroom will be added. The electrical and mechanical systems will be completely upgraded, creating a safe and controlled environment for employees.

Q. Please discuss the schedule for the Cloquet Service Center Remodel project.

A. To ensure the Cloquet Service Center Remodel project is completed by the end of 2027, work on the design, scope, and schedule began in July 2026. Starting the process in 2026 allows the drawings, permits, and schedule to begin in the early part of 2027, allowing ample time for the completion of the project to be completed by late summer. Planning early also gives additional time for the current lead times on new mechanical and electrical updates that are needed.

Q. What is the AHQ 4th Floor Remodel project?

A. The AHQ building is comprised of buildings constructed in 1928, 1956, and 1979. The AHQ 4th Floor Remodel project is part of a broader workplace modernization initiative intended to improve operational efficiency, support evolving workforce needs, and maximize the utilization of existing corporate facilities in furtherance of the Company's continued commitments to effectively provide service for the benefit of customers.

The existing AHQ 4th floor underwent a limited remodel in 2014; however, much of the original floor layout, including conference rooms and other common areas, has remained largely unchanged for more than two decades and reflects the organizational structure, workspace standards, and building functions in place at that time. The floor also included the employee cafeteria, which is a function that ceased six years ago and has since been relocated to the 1st floor and reformatted to match current needs of our employees. Since that time, departmental structures, workspace standards, work practices, and space needs have evolved, resulting in opportunities to more effectively utilize the 4th floor to support current business operations and allow for flexibility for future operations.

The project will reconfigure the 4th floor to align with current workplace standards and create a more efficient and functional environment for employees. The remodel will improve departmental adjacencies, support collaboration between teams, provide flexible workspace options to ensure space is used effectively when needs shift, and incorporate updated technology infrastructure.

In addition to addressing functional and operational needs, the project will replace aging finishes, improve building systems where necessary, and create a consistent workplace standard that can be applied across future headquarters renovation efforts. This approach supports long-term stewardship of the headquarters facility while maximizing the value of existing assets. Finally, as a cornerstone Duluth employer in downtown Duluth for more than a century, the continued investment in our headquarters building is an important part of a broader community effort to revitalize downtown Duluth and support the economic health and vibrancy of our community.

Q. What are some benefits of the AHQ 4th Floor Remodel project?

A. Some key benefits of the AHQ 4th Floor Remodel include:

- improved operational efficiency through optimized space utilization and workplace planning;

- enhanced collaboration by aligning departments and teams based on business functions and operational needs;
- increased flexibility through modern workspace standards, hoteling space, meeting rooms, and focus areas;
- improved technology integration to support current and future workplace requirements;
- replacement of aging finishes and infrastructure components; and
- improved productivity and workplace functionality to accommodate a growing and changing workforce.

By investing in the existing office space, Minnesota Power will be able to extend the useful life of its headquarters facility while adapting the workplace to meet current and future business needs.

Q. What are some key activities anticipated during the 2027 test year?

A. To effectuate the AHQ 4th Floor Remodel, many activities will need to be undertaken in the 2027 test year. However, several key activities will include competitive procurement of construction services; relocation of employees from the project area to temporary work locations; demolition of existing offices, workstation, and support spaces; and construction of workstations, offices, collaboration spaces, conference rooms, and support areas.

Upon completion, the remodeled 4th floor will provide a flexible and efficient workplace environment that supports current operational needs while positioning the organization to adapt to future workforce and business requirements. The project will also establish principles that can be leveraged in future headquarters renovation initiatives.

2. Wildfire Mitigation

Q. Is Minnesota Power including wildfire mitigation activities in the 2027 test year?

A. Yes. Wildfire mitigation has become an increasing area of focus and a dedicated topic in this rate case as wildfire presents more visible and materially significant risks to public safety, reliability, and business continuity for utilities including Minnesota Power. As such, Minnesota Power believes it is important to address the issue directly with the Commission and explain the prudent, cost-effective actions the Company is taking in response.

Additionally, the 2025 IDP order requires development and submission of the Company's Wildfire Mitigation Plan by February 1, 2027. Significant effort in both 2026 and 2027 is going into developing and executing the plan. The Plan will be tailored to unique regional conditions and evolving utility wildfire risk management practices to document the Company's approach to identifying, assessing, and reducing wildfire risk while continuing to deliver safe, affordable, and reliable electric service for the communities we serve.

This topic is being addressed within my Direct Testimony because the areas under my leadership are responsible for the construction, operation, inspection, maintenance, vegetation management, and overall field performance of Minnesota Power's power delivery system. Wildfire mitigation is directly connected to those responsibilities as it is a key factor in how the Company designs, maintains, monitors, and operates its transmission and distribution of assets in changing environmental conditions.

Q. What additional understanding has developed since Minnesota Power's 2023 rate case about wildfire risk in Minnesota and for utilities more broadly?

A. Wildfire mitigation has long been integral to Minnesota Power's facility designs and operational processes and procedures, but several things have changed since Minnesota Power's previous rate case. Since that case, Minnesota Power has also added community engagement to our wildfire mitigation approach.

First, wildfires have become a more prominent utility issue nationwide. Wildfire is a significant and growing risk to the utility business model, not only in the western United States but increasingly nationwide. Utilities across the country are taking a wider range of actions to mitigate both physical and financial risks associated with wildfire.

Second, wildfire conditions and awareness in Minnesota have evolved. Recent wildfire activity in northern Minnesota in 2025 and 2026 reinforced that wildfire risk in this region is real, even if it differs from the risk profile in some western states. Minnesota Power's service territory includes heavily forested areas, remote corridors, and communities where wildfire risk can be influenced by localized vegetation and fuel conditions, drought, wind, and other fire-weather factors.

Third, the understanding of wildfire risk in Minnesota must be broader than just historic fire occurrences. Wildfire risk in Minnesota is shaped by multiple, interacting conditions, including forest health and fuel conditions, climate and drought trends, the frequency and severity of elevated fire-weather days, land use and human activity, and the location and operation of electric infrastructure across the landscape.

Reports from the Minnesota Department of Natural Resources and the U.S. Forest Service indicate that forest health conditions in much of northern Minnesota are being significantly affected by invasive species like emerald ash borer and native species such as larch beetle, and spruce budworm. The combination of damage by invasive and native species along with disease and storm damage have increased the risk that ignitions will become large, destructive fires.

In addition, climate and fire-weather patterns have changed. Minnesota Power's wildfire risk is influenced not only by the condition of the forest, but also by when weather patterns create more days with low humidity, dry vegetation, and strong winds. Those dynamic conditions are important because wildfire risk can change rapidly even where long-term average conditions may appear moderate.

Finally, legal and liability exposure have become a much more prominent part of the wildfire discussion for utilities. Wildfire-related risks now extend well beyond physical damage to utility equipment and include major exposure to third-party claims, insurance market challenges, credit impacts, and pressure on customer rates. Additionally, there are many acres of state and federal managed lands in Minnesota Power's service territory that have their own forest management plans.

For these reasons, prudent wildfire mitigation is not only affecting the customers and communities we serve, representing a public safety issue and impacting reliability, but also a significant business risk issue for utilities and their customers. A single major event can have significant consequences for customers, communities, the environment, and the utility. Minnesota Power believes it is prudent to continue developing a measured, risk-informed wildfire mitigation approach now.

Q. What types of costs does Minnesota Power anticipate in the 2027 test year related to wildfire mitigation?

A. Minnesota Power is working, and will continue to work in 2027, through development of a formal Wildfire Mitigation Plan. This is required by the IDP order and will take our existing procedures and plans and combine them into a comprehensive document.

Q. What will Minnesota Power's Wildfire Mitigation Plan look like?

A. Minnesota Power is developing a Wildfire Mitigation Plan in response to the IDP order by using a practical, risk-informed approach focused on reducing the risk of utility-related ignitions and improving readiness when wildfire danger is elevated. The focus is to reduce the likelihood of utility-related ignitions, improve awareness of elevated fire conditions, strengthen readiness for wildfire events, and make prudent, cost-effective investments to harden the system against damage from wildfires.

At a high level, the plan will be divided into sections that focus on

- Assessment of wildfire risks and risk drivers;

- Risk-informed planning and prioritization of system hardening efforts and asset renewal;
- Operational procedures, inspections, and maintenance practices;
- Enhanced situational awareness;
- Vegetation management; and
- Coordination with public agencies, first responders, and other stakeholders.

This work is not a standalone effort. It is tied to the Company's broader safety, reliability, vegetation management, asset renewal and operational planning work, as highlighted in Minnesota Power's Integrated Distribution Plans and the Company's Safety, Reliability, and Service Quality filings. Minnesota Power recognizes that effective wildfire mitigation requires sustained focus and integration into day-to-day operations.

Q. Please describe Minnesota Power's work to assess the wildfire risks in its region.

A. Minnesota Power is developing a layered, risk-informed approach to assess wildfire risk across its service territory and in relation to its electric system. That work is intended to help the Company better understand where wildfire conditions, asset characteristics, and community exposure may combine to create elevated risk so that mitigation efforts can be prioritized.

Minnesota Power partnered with a wildfire consultant to assist in identifying and assessing key drivers of wildfire risk across Minnesota Power's operating areas. First, Hazardous Fire Area ("HFA") maps were developed that incorporate baseline wildfire risk drivers including vegetation, fuels, terrain, modeled fire behavior potential, historical fire-weather patterns, and population-based exposure.

Second, a risk model was developed to integrate landscape hazard information with Minnesota Power asset data to better evaluate risk associated with its facilities and more effectively prioritize mitigation work. This process involved evaluating electric asset characteristics and operational risk factors including asset age and condition, conductor

and equipment configuration, protection and control capabilities, vegetation exposure, access constraints, system topology, switching flexibility, customer and load characteristics, and proximity to critical facilities, all of which may affect ignition potential, operational response, restoration sequencing, or the consequences of a wildfire-related outage.

Q. Please describe Minnesota Power's work on system hardening as it relates to wildfire mitigation.

A. Minnesota Power evaluates wildfire risk information alongside other factors, such as safety, cost, and reliability, to develop a comprehensive assessment of system hardening efforts and to justify and prioritize specific measures relative to other initiatives intended to improve reliability, enhance safety, and reduce wildfire ignition risk.

Minnesota Power will be utilizing newly created HFA maps and data to identify risks near its assets. Mapping from the United States Forest Service, the Minnesota Department of Natural Resources and other forest management agencies will be utilized in HFA mapping to create a comprehensive look at the fire risk and health of the surrounding vegetation. This data will inform which circuits and what methods would be most effective and will help to mitigate future fire ignition risks from utility related equipment.

These efforts include continued asset renewal and equipment replacement, application of appropriate design and construction practices, and targeted evaluation of measures such as conductor and equipment improvements, wildlife protection, and other location-specific hardening measures where those actions are justified by risk and customer value. Minnesota Power's goal is not a one-size-fits-all program. Rather, it is to apply prudent, cost-effective mitigation in a manner that reflects the differing conditions across the Company's system.

Q. Please describe Minnesota Power's inspections and maintenance practices to reduce the potential for utility-caused ignitions.

A. Minnesota Power uses routine inspections and focused maintenance activities to help ensure the system operates safely and as designed. These practices are an important part of the Company's existing safety and reliability approach and are already serving as a foundational means of reducing conditions that could contribute to utility-caused ignitions.

As part of its normal Transmission and Distribution responsibilities, Minnesota Power conducts inspection and maintenance work to identify, prioritize, and address equipment or field conditions that could affect safe system operation. This includes routine inspection programs, corrective maintenance, and additional follow-up when conditions warrant. These practices are effective because they are designed to find issues before they become larger operational or safety concerns and to support timely corrective action where needed. That basic discipline of inspection, prioritization, and repair is one of the most important ways a utility reduces ignition risk across a broad and diverse service territory.

In addition, Minnesota Power's developing wildfire framework recognizes that inspection and maintenance are not limited to routine cycles alone. The Company is also incorporating more event-driven and risk-informed follow-up, particularly as wildfire conditions, weather, and asset information become better integrated into operations.

The Company recently hired a Wildfire Mitigation Manager to support ongoing development and coordination of Minnesota Power's wildfire mitigation efforts across operations. A key function of that role will be to improve the effectiveness of field inspections and maintenance over time by increasing the consideration of wildfire risk as the Company's wildfire risk tools continue to mature. For example, as Minnesota Power advances its geospatial hazard mapping, HFA analysis, and asset risk modeling work, those tools can help to better inform where enhanced inspections, targeted maintenance, or additional mitigation measures may provide the greatest value.

While Minnesota Power's current inspection and maintenance practices are already effective as core utility safety measures, the Company's objective is to continue improving them by making them increasingly risk-informed. That means building on a strong existing foundation and using better wildfire risk information to sharpen prioritization and improve field awareness during elevated fire conditions, thereby further reducing ignition risk.

Q. What is Minnesota Power doing to improve situational awareness and operational practices and readiness for wildfire conditions?

A. The addition of a dedicated Wildfire Mitigation Manager is an important next step in maturing Minnesota Power's wildfire mitigation program and strengthening the connection between wildfire risk awareness and day-to-day operational decision-making.

This role is intended to improve coordination across operations, engineering, vegetation management, and field functions so that wildfire risk information is translated into practical, timely actions on the system. A key part of that work will be supporting implementation and use of Minnesota Power's developing situational awareness tools, including enhanced wildfire risk forecasting capabilities and the deployment of a limited number of wildfire smoke detection cameras placed strategically in the service territory in 2027. Minnesota Power is working with the vendor to leverage partnerships near its service territory to expand the range of the cameras and partner with adjacent emergency response entities and utilities.

These tools are not used in isolation but instead are incorporated into a structured operational process. In practical terms, that means establishing how fire danger information, weather forecasts, active wildfire information, and asset exposure are reviewed, communicated, and acted upon when conditions begin to escalate. During periods of heightened fire risk, operational practices such as increased monitoring, enhanced internal communications, review of planned field work, adjustment of certain

work practices, and evaluation of system operating conditions can be used to reduce ignition risk and support public safety.

Over time, this should improve Minnesota Power's ability to identify when conditions warrant heightened readiness, to focus attention on the areas of greatest concern, and to deploy prudent mitigation measures in a disciplined and cost-effective manner. In that way, the new role helps bridge the gap between wildfire risk assessment and operational execution, particularly when fire weather and other conditions create elevated risk across the region.

Q. Is Minnesota Power also working with public agencies and others on wildfire mitigation issues?

A. Yes. Minnesota Power recognizes that effective wildfire mitigation depends not only on internal practices, but also on strong coordination with external partners. Consistent with stated objectives to protect customers, communities, emergency responders, infrastructure, and the natural environment, and to support safe operations through planning, awareness, training, and coordination during elevated wildfire conditions, Minnesota Power is actively engaging with local, state, federal, public and private entities to foster communication and awareness around wildfire mitigation in Minnesota. This includes engagement with the Minnesota Department of Natural Resources, the Minnesota Department of Commerce, the Minnesota Municipal Utilities Association, neighboring and regional utilities such as Otter Tail Power, Great River Energy, and Xcel Energy, as well as local, state, and federal emergency management organizations. Through these relationships and continued outreach, Minnesota Power is working to share information, improve mutual understanding, improve mutual awareness of wildfire risk and mitigation practices, support coordination during heightened fire conditions, and help align utility planning with broader public safety, land management, and emergency response efforts across the region.

The collaborative approach is consistent with Minnesota Power's broader wildfire mitigation framework, which emphasizes community coordination, responder safety,

situational awareness, and continuous improvement. The planned deployment of wildfire detection cameras in 2027 is expected to provide substantial value to local communities and in particular to fire departments and first responders by providing more immediate visibility into developing smoke and fire activity near Minnesota Power's service territory.

By supplementing existing wildfire and fire-weather monitoring with camera-based detection, the system can improve early awareness, help validate potential ignitions more quickly, and provide location-based information that supports faster mobilization and more informed response decisions.

Direct access to camera views and alerts can be especially valuable to local fire departments, emergency managers, and other response agencies because it can improve their ability to size up an incident, coordinate resources, identify likely access routes, and respond before a small fire grows into a larger event. That early awareness can benefit not only nearby homes, businesses, and infrastructure, but also the highly valued, forested landscapes of northern Minnesota, including the Boundary Waters Canoe Area Wilderness, national forest lands, and state forest lands, where rapid detection and coordinated initial attack can be especially important given remote terrain, fuel conditions, and the ecological and economic importance of those resources.

In that way, the camera system can strengthen protection of communities, responders, infrastructure, and the natural environment, while supporting Minnesota Power's broader objective of improving situational awareness and operational readiness during periods of elevated wildfire risk.

Q. What does Minnesota Power anticipate regarding wildfire mitigation costs in the future?

A. At this time, Minnesota Power cannot precisely quantify total wildfire mitigation costs beyond 2027 for several reasons, including that the Company's wildfire mitigation program is evolving, that many wildfire-related investments are coupled with other

system hardening activities, and the overall risk continues to transform. The Company's wildfire mitigation program is still maturing, the supporting risk tools are being refined, and future needs will depend in part on what the Company learns from continued implementation, changing field conditions, and the evolution of available technologies.

Because wildfires pose a significant threat to public safety, the regional economy, and Company risk exposure, wildfire mitigation will remain a high priority. The Company expects that ongoing investment will continue to be necessary in areas such as situational awareness, inspection and maintenance practices, vegetation management, operational readiness, and targeted system hardening. As with other aspects of Transmission and Distribution operations, those efforts will be evaluated using a prudent, risk-informed, and cost-effective approach.

Minnesota Power also expects that system hardening activities will continue. Wildfire mitigation is closely tied to the Company's ongoing work in asset renewal, equipment replacement, design practices, and targeted infrastructure improvements. Those types of investments are not one-time actions; rather, they are part of an ongoing effort to reduce ignition risk and improve system resilience over time.

While the Company cannot yet forecast a fixed cost trajectory beyond 2027, Minnesota Power does expect wildfire mitigation to remain an important operational and planning priority, with continued investment in tools, practices, and infrastructure improvements that are justified by risk and customer value.

3. Electric Vehicle Service Equipment Expansion Project

Q. What is the EVSE Expansion Project?

A. The EVSE Expansion Project, approved in the Commission's October 22, 2021 Order,[4] outlined Minnesota Power's plan to install 16 Direct Current Fast Charger ("DCFC")

[4] *In the Matter of Minnesota Power's Electric Vehicle Charging Infrastructure Investment*, Docket No. E015/M-21-257, ORDER APPROVING PROPOSAL AS MODIFIED, AUTHORIZING DEFERRED ACCOUNTING, AND REQUIRING REPORTING (Oct. 22. 2021) (eDocket No. 202110-179031-01).

stations throughout its service territory. Charging stations were strategically located along major travel corridors, near population clusters and in areas where public fast chargers were not available. The Company also selected locations that were identified as a concern for environmental justice when possible.

Q. When was the EVSE Expansion Project completed?

A. Charging stations were installed from September 2025 to May 2026 with the final charger being commissioned on May 30, 2026.

Q. How Many EV Chargers were installed?

A. Fifteen DCFC stations were installed. The Company's original proposal included the installation of 16 DCFC stations with the goal of putting all Minnesota Power customers within 30 miles of a public EV charger in the following target communities: Bigfork, Cloquet, Duluth (two chargers), Eveleth, Floodwood, Hermantown, Hinckley, International Falls, Little Falls, Long Prairie, Park Rapids, Silver Bay, and along Highway 2, Highway 53, and Highway 371.

While most of the proposed locations were successfully developed, the Park Rapids location did not move forward because the Company was unable to identify a suitable site host despite extensive outreach and evaluation efforts. Additionally, the project was unable to secure Minnesota Pollution Control Agency ("MPCA") grant funding as originally anticipated, resulting in timeline delays and increased costs.

Park Rapids was originally selected as a target location due, in part, to its location along the Highway 34 corridor, which the Company identified as a priority area. However, since the original target locations were identified, additional DCFC infrastructure has been installed or is planned along Highway 34. As a result, electric vehicle drivers traveling through the region have access to alternative fast-charging options, continuing to support one of the objectives of Minnesota Power's DCFC Expansion Project by reducing gaps in regional charging infrastructure.

Q. What challenges did the Company encounter throughout the EVSE Expansion Project?

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

Q. Has Minnesota Power experienced other challenges implementing this project?

A. The Company also experienced significant supply chain and project development challenges. Lead times for key equipment—including DC fast chargers, transformers, switchgear, and other utility infrastructure—reached as much as 50 weeks due to industry-wide supply chain constraints and increased demand for electric vehicle charging infrastructure. In addition, developing charging sites across 16 communities required coordination with numerous site hosts and local jurisdictions, each with unique business considerations, permitting requirements, ordinances, and construction constraints. Balancing these local factors with program objectives, such as placing chargers in visible, convenient, and publicly accessible locations, added complexity to project development and extended project timelines beyond initial estimates.

Q. Did Minnesota Power receive any federal or public funding towards this project?

A. Yes. Minnesota Power received funding through the MPCA Volkswagen Environmental Mitigation Trust program for two charging locations totaling approximately $104,500. The Company also submitted a proposal for National Electric Vehicle Infrastructure ("NEVI") Formula Program funding for two project sites; however, those applications were not selected for award.

Q. Has the Company recovered any money from customers related to the EVSE Expansion Project?

A. No, as noted in the Direct Testimony of Company witness Turner, the Company removed all EVSE components from the revenue requirement calculation.

Q. What would the Company like the Commission to do related to the EVSE Expansion Project?

A. The Company requests that the Commission approve recovery, through base rates, of the prudent and reasonable costs associated with the previously approved EVSE Expansion Project. This is addressed further by Company witness Turner's Direct Testimony where she explains treatment of the project in the 2027 interim and proposed test year.

4. Fleet and Cyber Technology Services

Q. What are the projects for Fleet and CTS in Table 1?

A. Fleet and CTS Projects include:

- Fleet Vehicle Replacement projects provide funding to replace existing assets based on established lifecycle schedules, helping maximize vehicle uptime and productivity while minimizing total cost of ownership.
- The 2027 Fleet Trailer Replacements project funds the replacement of trailers identified through prior-year inspections as nearing the end of their useful life. It also provides funding for emergent needs for new or replacement trailers expected during the year.
- The CTS Synchronous Optical Networking System ("SONET") is described in more detail later in the Communication System Improvements section of my testimony.
- Fiber for Distribution Automation – A CTS project to install fiber optic cable supporting the deployment of decentralized FLISR in urban areas. The fiber optic communication enables remote monitoring, control, and low latency peer-

to-peer communication allowing fast, automated reconfiguration of distribution feeders reducing and potentially eliminating some customer outages.

- CTS Strategic Projects – A collection of projects supporting upgrades and end-of-life replacement of various technology systems and infrastructure. It is important to keep underlying technology supported and modernized to reduce cyber risks and improve system reliability. The systems in the blanket include mobile devices, laptops, cyber security applications, network infrastructure, printers, video conferencing, telephone infrastructure, and telecommunications shelters.

D. Renewable Interconnection

Q. Please describe Minnesota Power's efforts related to renewable interconnection.

A. Minnesota Power works in a variety of ways to ensure renewables can be interconnected to our system safely and efficiently. Customer programs like SolarSense, software system integration, regulatory workgroup participation, and continual focus on process improvements maintain the Company's ability to deliver a positive experience for customers while increasing the rate of renewable integrations.

Q. Please describe how the Distribution department supports customer renewable interconnections.

A. Minnesota Power's Distribution team supports customer renewable energy interconnections by reviewing interconnection applications in accordance with the Distributed Energy Resources Interconnection Process ("MnDIP"). Through this review, Distribution Engineering evaluates the proposed generating facility and its anticipated effects on Minnesota Power's distribution system. Where necessary, the review identifies distribution system modifications or upgrades needed to accommodate the interconnection while maintaining safe, reliable service for the interconnecting customer and other customers served by the system.

Q. What programs does the Company offer for customer renewable energy and how have they changed over recent years?

A. The Company's SolarSense rebate program continues to offer customers the opportunity for rebates when installing customer-sited solar projects. The Company's programmatic approach has been successful, bringing robust customer-sited solar into the market. The Company reduced rebates with a decreased budget for the SolarSense program in years 2021–2024 and increased the budget for the Low-Income Solar Grant Program. The Commission approved an extension for SolarSense programming in 2025 for program years 2025-2027.[5] This extension included further modifications that prioritize low to moderate income households. Over the past five years, the rebate program has ceased to be the primary driver for customer-sited solar adoption in the Company's service territory. At the same time the number of applications and amount of solar capacity installed by customers remains higher than historical volumes.

Q. Does Minnesota Power participate in distributed generation working groups?

A. The Company participates in the Commission's Distributed Generation Working Group to develop technical standards, garner feedback from stakeholders, and ultimately to refine internal and external processes. There is increased activity in this working group in a number of emerging areas such as flexible interconnections, export capacity limitations, and upgrading cost sharing protocols.

Q. How does Minnesota Power work to advance customer renewable energy?

A. Minnesota Power continually analyzes process flow and software solutions to review interconnections to streamline and improve results. The Company has implemented an online interconnection application submission software tailored to track the interconnection process. The Company also selected and integrated DNV's Synergi platform as its Distribution Planning software. Synergi is able to perform the basic distribution analysis routines currently available to the Company distribution planners

[5] *In the Matter of Minnesota Power's Ongoing Compliance of its SolarSense Program with Minnesota's Solar Energy Standards*, Docket No. E015/M-20-607, ORDER ACCEPTING REPORT AND APPROVING PROGRAM EXTENSION WITH CERTAIN PROPOSED MODIFICATIONS (Jan. 8, 2025) (eDocket No. 20251-213680-01).

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 the Electric Power Research Institute ("EPRI") Distribution Resource Integration and Value Estimation ("DRIVE"). These improvements continue to be refined for processing increasing numbers and complexity of interconnection requests.

The Company also just filed its first petition[6] for approval of a 10 MW solar site as part of the Distributed Solar Energy Standard ("DSES"), which will advance localized, equitable, and small-scale utility solar projects across Minnesota Power's service territory.

Q. What is the process for transmission projects?

A. The Midcontinent Independent System Operator ("MISO") uses the Definitive Planning Phase ("DPP") process for transmission renewable interconnection requests. In 2025, MISO initiated the Expedited Resource Addition Study ("ERAS") to expedite generation interconnections to address the region's resource adequacy and reliability needs. Two of the projects submitted to MISO's ERAS are interconnected to the Company's transmission system. The Company will review and verify the study results where MISO will identify any required network upgrades. The Company will also facilitate any needed facility studies to provide the interconnecting customer the scope, estimate, and schedule to construct the required interconnecting facilities and network upgrades.

IV. DISTRIBUTION O&M

A. O&M Budget Overview and Distribution FERC Accounts

Q. Please describe the distribution annual O&M budget development process.

A. The consolidated annual budget process is described in the Direct Testimony of Company witness Rostollan. Each year, the work areas in Distribution (and related

[6] *In the Matter of the Implementation of the New Distributed Solar Energy Standard Pursuant to 2023 Amendments to Minnesota Statutes, Section 216B.1691*, Docket No. E002, E015, E017/CI-23-403, PETITION FOR PPA APPROVAL AND COST RECOVERY (Oct. 9, 2026) (eDocket No. 202610-237356-01).

support services) prepare a zero-based (i.e., bottom-up) approach to budgeting. The budget is typically submitted during the second quarter of the prior year.

The factors considered in the budgeting process and how FERC accounts are incorporated into the budgeting process are discussed in the Direct Testimony of Company witness Gunderson.

Q. Please describe the key functions within the distribution work area that are included in the annual distribution O&M budget.

A. The distribution O&M budget includes costs associated with the safe, reliable, and resilient operation and maintenance of the Company's electric distribution system. These activities support the delivery of electricity to customers while maintaining compliance with applicable reliability, safety, and regulatory requirements.

Key functions included in the distribution O&M budget include performing inspections, testing, condition assessments, and audit of distribution assets such as poles, transformers, switches, reclosers, regulators, capacitor banks, underground facilities, and distribution automation equipment. The budget also supports engineering, planning, and execution of corrective and preventive maintenance activities, emergency response and service restoration, and repairs to overhead and underground distribution facilities, substations, and customer service connections.

In addition, distribution O&M includes vegetation management activities necessary to maintain system reliability and mitigate wildfire, storm, and outage risks; monitoring and analysis of system performance and reliability metrics; distribution system planning studies; and asset management programs designed to optimize system performance and lifecycle costs.

The budget further supports customer metering operations, including the installation, testing, maintenance, communication, and data management functions associated with AMI and related technologies. Distribution O&M also includes activities necessary to

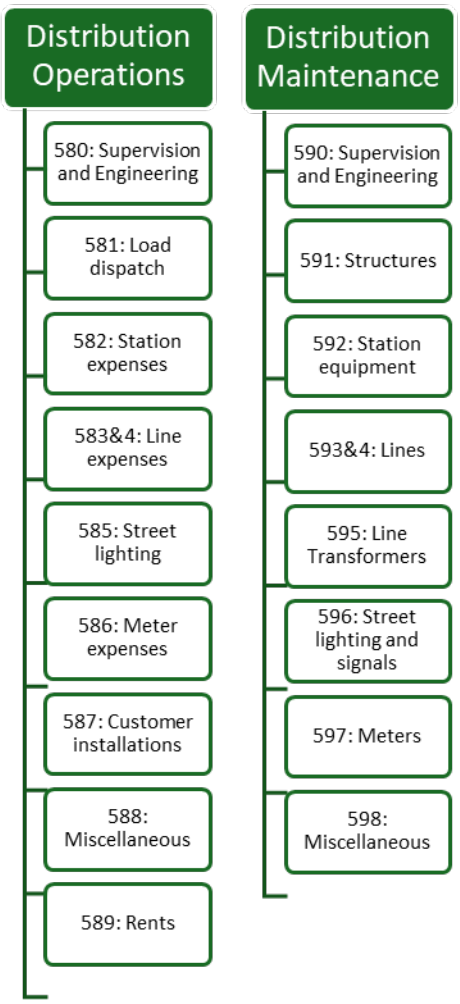
support grid modernization initiatives, deployment and maintenance of smart grid technologies, cybersecurity and operational technology support for distribution systems, and the evaluation and interconnection of DER, including solar generation, battery storage, electric vehicles, and other emerging customer-sited technologies.

These key functions collectively enable the Company to maintain reliability, improve efficiency, enhance customer experience, and support the continued evolution of the electric distribution system.

Q. What FERC Accounts are included as major distribution expenses by FERC Account?

A. Please see the FERC Accounts in Figure 1.

Figure 1. Distribution FERC Accounts



Q. What is the 2027 test year budget for distribution O&M expenses?

A. Table 3 shows total Company distribution actual expenses for 2023 through 2025, 2026 projected year expenses, and 2027 test year expenses. The Company has budgeted $35.6 million Total Company ($32.9 million MN Jurisdictional) in 2027, which is an increase of $8.1 million Total Company ($7.5 million MN Jurisdictional) from 2025 actual expenses. The increases from 2025 to the 2027 test year are discussed in further detail later in my testimony. Table 4 provides these amounts at the Minnesota Jurisdictional level.

Table 3. Distribution Budget and Actual Expenses by FERC Account (Total Company)

Account[7]	'23 Actual	'24 Actual	'25 Most Recent Fiscal Year Actual	'26 Projected Fiscal Year	'27 Proposed Test Year	'27 Proposed test Year vs '25 Actual
580	$1.0M	$1.2M	$1.0M	$1.M	$1.2M	$0.2M
581	$0.5M	$0.5M	$0.4M	$0.7M	$0.9M	$0.4M
583	$0.3M	$0.3M	$0.5M	$0.2M	$0.4M	($0.1M)
584	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	($0.0M)
586	$1.0M	$1.5M	$0.9M	$1.4M	$1.0M	$0.1M
588	$7.8M	$6.3M	$6.8M	$7.4M	$8.4M	$1.6M
589	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	(0.0M)
590	$0.7M	$0.6M	$0.6M	$1.0M	$0.6M	$0.0M
592	$0.0M	$0.0M	$0.3M	$0.1M	$0.3M	$0.0M
593	$13.9M	$14.4M	$13.6M	$14.8M	$18.4M	$4.8M
594	$2.2M	$2.2M	$2.4M	$2.3M	$2.9M	$0.5M
598	$0.7M	$0.8M	$0.7M	$1.0M	$1.2M	$0.5M
Total	**$28.4M**	**$28.0M**	**$27.5M**	**$30.4M**	**$35.6M**	**$8.1M**

Table 4. Distribution Budget and Actual Expenses by FERC Account (MN Jurisdictional)

Account[8]	'23 Actual	'24 Actual	'25 Most Recent Fiscal Year Actual	'26 Projected Fiscal Year	'27 Proposed Test Year	'27 Proposed test Year vs '25 Actual
580	$1.0M	$1.1M	$0.9M	$1.2M	$1.1M	$0.2M
581	$0.5M	$0.4M	$0.4M	$0.6M	$0.8M	$0.4M
583	$0.3M	$0.3M	$0.4M	$0.2M	$0.4M	-
584	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	-
586	$1.0M	$1.4M	$0.9M	$1.4M	$1.0M	$0.1M
588	$7.3M	$6.0M	$6.3M	$6.8M	$7.7M	$1.4M
589	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	-
590	$0.7M	$0.6M	$0.6M	$0.9M	$0.6M	-
592	-	-	$0.4M	$0.1M	$0.4M	-
593	$13.1M	$13.5M	$12.5M	$13.5M	$16.9M	$4.4M
594	$2.1M	$2.1M	$2.2M	$2.1M	$2.7M	$0.5M
598	$0.7M	$0.7M	$0.6M	$1.0M	$1.1M	$0.5M
Total	**$26.9M**	**$26.3M**	**$25.4M**	**$28.0M**	**$32.9M**	**$7.5M**

[7] FERC Accounts 582, 585, 587, 595, 596, and 597 are not included as separate line items in this table as amounts are below the rounding threshold.
[8] FERC Accounts 582, 585, 587, 595, 596, and 597 are not included as separate line items in this table as amounts are below the rounding threshold.

Q. Why have Accounts 593 and 594 increased by $5.3 million Total Company ($4.9 million MN Jurisdictional) from 2025?

A. Accounts 593, Maintenance of Overhead Lines, and 594, Maintenance of Underground Lines, include costs associated with planned and corrective maintenance of overhead and underground distribution facilities due to age-related failures, vegetation management within overhead line rights-of-way, and transformer-related credits associated with capital asset expenditures. The increase from 2025 to the 2027 test year is primarily attributable to higher amounts of vegetation management costs for removing dead and dying trees along rights of way. More trees are impacting the operations of the distribution system, causing higher spending to either preemptively remove or remove after storms. Vegetation management cycles are evaluated to ensure frequency is on track to prevent damage; however, circuits are seeing more tree death impacting reliability. Other cost drivers include inflation on contractor costs related to vegetation management and line maintenance related to contractor costs. Cost of labor and vehicle rates have primarily driven higher dollars in this category.

Minnesota Power has seen an increase in aged underground cable failures, which is increasing costs. These failures are related to older cable that is not the same type and standard of the cable used by the Company in new designs. Overhead circuit costs have increased from aged equipment and increased costs related to materials for repairs.

Q. Why has Account 588 increased by $1.6 million Total Company ($1.4 million MN Jurisdictional) from 2025 to the 2027 test year?

A. Account 588 is Miscellaneous Distribution Expenses and includes costs associated with internal and external labor to prepare and maintain records, maps, and prints; janitorial work at distribution office buildings, including snow removal and grass cutting; communication services; building service expenses; and miscellaneous office supplies not accounted for in other FERC Accounts. The increase in Account 588 from 2025 actuals to the 2027 test year is primarily due to higher labor and related overhead

allocations, along with increased general operating support costs associated with maintaining Minnesota Power's distribution system.

Q. Why has Account 598 increased by $0.5 million Total Company ($0.5 million MN Jurisdictional) from 2025?

A. Account 598 is Maintenance of Miscellaneous Distribution Plant and includes costs associated with planned and unplanned maintenance of distribution assets. The increase in this account is primarily driven by departmental strategies to optimize the maintenance of assets by shifting internal resources from capital to O&M focused, as well as continued but renewed focus on employee safety and training programs.

B. Storm Response and Restoration

Q. How are storm response and restoration costs incorporated into the 2027 test year budget?

A. As previously discussed, FERC Account 593 includes both planned and unplanned maintenance of overhead lines. Unplanned maintenance is considered "trouble" work and includes responding to outage events that can be caused by multiple sources, including animals, storms, people, etc. Some of these outage events are caused by storms, which are unpredictable in both their timing and their associated impact. Depending on the nature of the storm damage, the restoration could result in O&M expenses or capital additions. Due to the unpredictability of trouble work, the budget for all trouble work is based upon a five-year average of Overtime, Contract Services, and Purchased Materials in Account 593. While averaging is not traditionally the most appropriate way to set Company budgets, Minnesota Power believes that averaging is the most prudent and reasonable basis upon which to budget for unpredictable storm expenses because the proposed five-year average considers both high-year and low-year expenses for this response.

A multi-year average provides a balanced and supportable estimate of the ongoing costs required to deliver safe and reliable service under Minn. Stat. § 216B.16. It mitigates the distortion that could result from a single unusually severe or unusually mild year

and produces a more representative measure of expected operating requirements. Consequently, the proposed budget reflects actual operating experience while appropriately accounting for the inherent variability of service restoration activities.

Q. What is the 2027 test year budget for "trouble" work included in Overhead Line Maintenance?

A. The 2027 test year budget associated with "trouble" work is $2.96 million Total Company ($2.73 million MN Jurisdictional). As described above, "trouble" work is based upon a five-year average of spending for FERC Account 593 (Maintenance of Overhead Lines).

Q. What does this budget item accomplish and why is it important?

A. This budget supports the Company's ability to maintain a reliable distribution system and restore service safely and efficiently when interruptions occur. The proposed budget does not represent a separate budget for incremental or dedicated resources. It reflects a normalized level of expected O&M costs associated with routine trouble response and restoration activities. This includes overtime labor, contractor support, materials, and related work necessary to respond to outages and maintain customer reliability across a wide range of operating conditions.

Maintaining reliable electric service requires continuous operational capability. While annual expenditures fluctuate in response to weather, outage activity, and restoration requirements, the Company's obligation remains constant: to operate, maintain, and restore the distribution system safely, efficiently, and reliably.

Q. What are the primary cost drivers of this budget item?

A. The five-year average incorporates the primary categories of cost associated with distribution outage response and restoration activities, including overtime labor, contractor services, and materials and supplies.

These cost categories have historically been used to develop normalized trouble work and restoration cost estimates and remain the principal drivers of Account 593 expenditures.

These fluctuations underscore the value of using a multi-year averaging methodology to establish a reasonable annual budget.

Q. How do contractor services and mutual aid resources play a role in storm response?

A. Contractor and mutual aid resources are essential components of Account 593 because they provide the additional capacity needed when outage activity exceeds normal operating levels.

Minnesota Power maintains access to contractors and mutual aid resources to support restoration efforts during significant outage events. These resources supplement the Company's existing workforce and enable safe, efficient restoration during times of heightened activity.

The operational value of these resources was demonstrated during the December 2022 winter storm. Heavy snowfall, strong winds, and widespread tree damage resulted in approximately 14,800 customer outages and challenging access conditions across portions of the service territory. Minnesota Power activated its Emergency Response Plan and deployed internal crews, contractors, and mutual aid resources to restore service under difficult winter conditions. While events of this magnitude occur unpredictably, they are a recurring operational reality and must be reflected in a reasonable estimate of annual operating requirements.

Restoration planning must account for the periodic need to expand response capabilities. Including contractor and restoration-related costs within a five-year historical average reflects actual operating experience while preventing any single event from disproportionately influencing the test-year budget. While the use of averaging in

establishing test year amounts is not the preferred methodology for the Company, using it in limited instances for expenses that experience unpredictability is reasonable. The resulting five-year average provides a balanced and representative estimate of the resources required to maintain restoration, readiness, and support reliable service under both routine and severe operating conditions.

Q. How have Minnesota Power's reliability performance metrics demonstrated the effectiveness of maintenance and restoration practices?

A. Minnesota Power's recent reliability performance demonstrates the effectiveness of its maintenance and restoration practices.

In 2025, the Company reported normalized reliability of:

- System Average Interruption Duration Index ("SAIDI"): 102.37 minutes
- System Average Interruption Frequency Index ("SAIFI"): 1.09 interruptions
- Customer Average Interruption Duration Index ("CAIDI"): 93.7 minutes

The results indicate that:

- Restoration performance remains effective and consistent.
- The Company achieved benchmark performance levels for SAIDI and CAIDI.
- Overall, reliability has been maintained despite variability in storm activity and outage volume.

Particularly noteworthy is CAIDI, which measures the average duration of customer interruptions. Strong performance in this metric reflects the effectiveness of Minnesota Power's restoration strategy, workforce readiness, and field operations capabilities. These outcomes demonstrate that investments in outage response and restoration capability are delivering tangible customer benefits through timely service restoration.

Q. How does this budget item support operations?

A. Account 593 supports a single integrated mission: maintaining system readiness and restoring service when interruptions occur.

Routine maintenance, outage response, and storm restoration are not separate functions. They are interconnected responsibilities supported by the same crews, equipment, operating procedures, and management systems. Resources are continually adjusted to meet changing system conditions and customer needs.

When significant outages occur, Minnesota Power executes its Emergency Response Plan using a safety-first approach grounded in Human and Organizational Performance ("HOP") principles. Restoration activities focus on:

- Protecting the public and employees.
- Assessing system damage.
- Restoring critical infrastructure.
- Returning customers to service as quickly and safely as possible.
- Coordinating effectively with contractors, emergency responders, and external agencies.

The costs recorded in Account 593 reflect the operational decisions required to execute these responsibilities, including labor deployment, contractor utilization, material replacement, and system restoration activities. Importantly, the baseline level of work remains substantial even in years without major storm activity, demonstrating that these costs are driven by the ongoing responsibilities of operating and maintaining a reliable distribution system, not solely by extraordinary events.

Q. How does this budget item support wildfire response and mitigation?

A. Although less frequent than storm-related events, wildfire response and mitigation activities are also supported through Account 593.

These activities share many of the same operational characteristics as storm restoration efforts, including rapid mobilization, field assessment, system protection, emergency repairs, and coordination between field operations and system control. As a result, they

are performed using the same workforce, equipment, and restoration processes that support traditional outage response.

Wildfire-related costs are not separately tracked within Account 593. However, associated expenditures including labor, contractor services, patrols, inspections, materials, and repairs are reflected within the historical cost data used to develop the five-year average.

Because wildfire-related work is episodic but recurring, inclusion within a multi-year average provides a reasonable and balanced representation of expected annual costs while preventing any single event from disproportionately affecting the budget.

Q. What has changed since the 2023 Rate Case?

A. The fundamental responsibilities supported by Account 593 have remained consistent since Minnesota Power's last rate case. However, the operating environment continues to evolve.

The Company increasingly operates in an environment that requires heightened readiness, enhanced coordination, and disciplined response across a broader range of events and operating conditions. While annual storm activity remains unpredictable, Minnesota Power must continuously maintain the workforce, contractor partnerships, equipment readiness, and restoration capabilities necessary to respond effectively when events occur.

Additionally, restoration activities increasingly require coordination across system operations, field personnel, contractors, mutual aid organizations, large power customers, governmental agencies, and other affected communities. Minnesota Power's continued use of a structured Emergency Response Plan, and the Company’s HOP-based operating philosophy reflects a deliberate focus on safety, operational excellence, and efficient restoration.

In conclusion, FERC Account 593 represents the investment required to maintain an operationally ready distribution system and to restore service when outages occur. The account supports planned maintenance, routine trouble response, storm restoration, wildfire-related response activities, and other event-driven operational needs.

Q. Has the 2027 test year been developed in a reasonable and prudent way?

A. Yes. The 2027 test year is based on actual historical experience and normalized through a five-year averaging methodology that appropriately reflects the recurring yet highly variable and unpredictable nature of outage response and restoration work. The resulting budget provides a reasonable and representative estimate of the resources necessary to maintain system readiness, restore service efficiently when interruptions occur, and continue delivering safe and reliable electric service to customers. The budget also preserves the operational flexibility required to respond effectively to changing system conditions, severe weather events, and other restoration needs.

Q. Why is the proposed budget reasonable and prudent to include in base rates for Minnesota Power's customers?

A. The proposed budget is necessary to safely maintain and restore the distribution system. It is reasonable because it is grounded in actual historical operating experience of the Company. The budget smooths the volatility of storm-driven expenditures through a normalized methodology and controls spending through oversight of labor, contractor utilization, and restoration spending. In other words, Minnesota Power has developed its budget for storm response and restoration for the benefit of our customers because it supports safe, reliable, and timely restoration of electric service while promoting long-term rate stability.

C. <u>Vegetation Management</u>

Q. What is Minnesota Power's vegetation management program?

A. Minnesota Power's vegetation management program manages vegetation on the Company's transmission system, overhead distribution system, and associated

substation, telecom, and hydro generation facilities. The program is a core reliability function and a non-discretionary component of safe utility operations.

Q. Why is vegetation management necessary?

A. Vegetation management is necessary to maintain safe clearances from energized equipment, comply with applicable reliability standards, and minimize outage frequency and duration for customers. An effective vegetation management program is directly tied to system reliability, public safety, and operational resilience.

Q. What approach to vegetation management does Minnesota Power use?

A. Minnesota Power uses an Integrated Vegetation Management ("IVM") program executed by the International Society of Arboriculture ("ISA") Certified Arborists. The program allows an industry-standard cyclical approach and includes the use of the most appropriate vegetation treatment methods based on site conditions and long-term reliability needs.

Q. What work is included in the IVM program?

A. The program includes tree pruning and removal; mowing and herbicide application; clearing around lines, substations, dams and hydro facilities; and responding to customer tree concerns.

Q. What are the vegetation management cycles for the system?

A. The transmission system is maintained on a seven-year cycle and is currently on-cycle. The distribution system is maintained on a six-year cycle and will be fully on-cycle beginning in 2027. Substation, telecom, and hydro generation elements are maintained on an annual or biennial basis.

Q. Why is staying on-cycle important?

A. Maintaining circuits on-cycle is critical to controlling outage risk and long-term costs. When circuits fall behind cycle, vegetation becomes more difficult and expensive to manage. Off-cycle circuits generally require more extensive pruning and removals,

create larger biomass handling requirements, and increase outage frequency and duration.

Q. How does an on-cycle system benefit customers?

A. An on-cycle system:

- Reduces vegetation-related outages;
- Improves customer reliability outcomes;
- Reduces customer complaints;
- Improves access for restoration during outage response; and
- Reduces vegetation conflicts with electrical equipment that may create wildfire ignition sources; and
- Lowers overall future costs.

These benefits support improved reliability performance, including standard metrics such as SAIDI and SAIFI.

Q. How does Minnesota Power monitor program performance?

A. The Company monitors the program using:

- Tree-related outage data;
- Completion tracking of planned work; and
- Site inspections.

These tools help confirm that work is being completed as planned and that the program is effectively supporting reliability outcomes.

Q. Is vegetation management required for regulatory compliance?

A. Yes. While vegetation management is required to ensure reliability of the system, there are also regulatory standards governing vegetation management that the Company must comply with, including North American Electric Reliability Corporation ("NERC") FAC-003 for transmission facilities, which mandates maintaining minimum vegetation clearances. However, while FAC-003 applies only to certain transmission facilities,

performing vegetation management on Minnesota Power' broader system is important to maintaining reliable service. This supports the Company's broader obligation under Minnesota law to provide safe, adequate, efficient, and reasonable service.

Q. What labor challenges has the Company experienced?

A. During and after the COVID-19 pandemic, Minnesota Power experienced a shortage of available tree workers and had to bring in traveling tree crews to complete scheduled work. At the same time, labor and equipment cost increases due to inflation increasing faster than general inflation indices leading to significantly higher costs for the same volume of work. That situation has since improved, and local contractors are now generally able to provide the labor needed to complete the Company's annual work plan.

Q. How is the program strategically evolving?

A. The IVM program is a critical component of Minnesota Power's overall reliability program and continues to evolve with a focus on leveraging data, improving field operational efficiency, and enhancing responsiveness during and after disruptive events.

Q. Has Minnesota Power made changes to its contracting model?

A. Yes, since its last rate case, Minnesota Power concluded its two-year time-and-materials ("T&M") trial and shifted back to a fixed-bid model with change order approval for tree removals. This approach allows ISA Certified Arborists to determine whether removal provides better long-term reliability value or whether pruning is sufficient to achieve required clearances.

Q. What is Minnesota Power doing to manage increased vegetation management costs?

A. The Company uses various approaches to actively manage costs, including:

- Competitive contracting approaches;
- Annual evaluation of contractor availability and pricing;
- Monitoring of work completion and outage data;
- Selection of the most cost-effective vegetation treatment methods;

- Improving long-term clearances and reducing repeat pruning;
- Enhancing customer engagement to support removal decisions;
- Evaluating new technologies to improve planning, imaging, and tracking of work.
- Using digital tools to improve productivity; and
- Using appropriate mechanized equipment to improve efficiency while supporting safe field operations.

Company witness Rostollan discusses Minnesota Power's vegetation management program as an example of cost containment and efficiency in his Direct Testimony. The Company is also increasing removals in appropriate situations to reduce future pruning needs and improve long-term reliability.

Q. Why can removals sometimes be more cost effective than pruning?

A. In some cases, removing a tree provides better long-term value than repeatedly pruning it over multiple cycles. Strategic removals can reduce repeat work, improve long-term clearances, lower future maintenance costs, and reduce the likelihood of vegetation-related outages.

Q. How do insects and disease affect Minnesota Power's vegetation management program?

A. Forest insect and disease conditions in Minnesota are increasingly important from a utility perspective because they increase the risk of hazard trees, line interference, access problems, and power outages. The most significant concern is emerald ash borer, which is causing widespread ash mortality in communities, rights-of-way, and lowland areas and creating a growing backlog of dead and declining trees near electric infrastructure. Spruce budworm and forest tent caterpillar can weaken or kill fir, spruce, and aspen in northern Minnesota, increasing fall-in risk and wildfire risk along transmission and distribution corridors. Oak wilt and Dutch elm disease also continue to cause mortality in areas of Minnesota Power's service territory. In addition, drought, severe weather, and warming temperatures can accelerate decline and increase failure risk.

Accordingly, Minnesota Power has increased transmission inspections and danger tree removal in areas experiencing insect or disease outbreaks.

Q. What is the overall conclusion regarding the program?

A. Minnesota Power's vegetation management program reflects a prudent, industry-aligned approach that balances cost control with the need to maintain safety, reliability, and regulatory compliance. The requested funding levels are necessary to address external cost pressures, maintain established maintenance cycles, and implement improvements that reduce long-term costs and outage risk for customers.

V. SYSTEM RELIABILITY

Q. What is the purpose of this section of your Direct Testimony?

A. This section of my Direct Testimony is to provide an understanding of how Minnesota Power measures and monitors system reliability as well as how Minnesota Power ensures its Distribution System meets the expected reliability standards. Each of these considerations weighs in on how Minnesota Power approaches its overall planning and work for the Distribution department.

A. End Use Customer Metrics

Q. What is Minnesota Power's approach to system reliability?

A. Minnesota Power continues to prioritize sound investments in the distribution system to maintain and improve reliability of the essential service provided and continues to focus on the maintenance and replacement of critical assets as necessary to maintain safe system performance. Further, routine inspection and vegetation management activities on the distribution system lower the cost of operation over the long-term and help to mitigate potential reliability issues. The Company annually reports overall system reliability in intricate detail in the Safety, Reliability, and Service Quality Standards ("SRSQ") report.[9] In that report, Minnesota Power outlines how the Company

[9] *In the Matter of Minnesota Power's 2025 Safety, Reliability and Service Quality Standards Report*, Docket No. E015/M-26-29, 2026 SRSQ REPORT (Apr. 1, 2026) (eDocket No. 20264-229916-01).

continuously strives to provide efficient, reliable service to all customers across a unique service territory in northeastern and central Minnesota.

Q. Has Minnesota Power changed the way it tracks reliability metrics?

A. Recently, Minnesota Power changed how it tracks and reports reliability metrics. Throughout the SRSQ reporting process, Minnesota Power has been directed to report the Company's reliability metrics, and additionally break out each area (Northern, Central, and Western) into smaller separate reliability reporting work centers.

Q. Has this reporting change affected the Company's reporting and benchmarking?

A. Yes, the Company is now measured against the five-year average for the Institute of Electrical and Electronics Engineers ("IEEE") second quartile medium-sized companies, and each individual work center is measured against the five-year average for IEEE 2nd quartile small sized companies.

Q. Historically, how has Minnesota Power's system reliability performed for customers?

A. Over the past five years, Minnesota Power has maintained strong safety, reliability, and service quality performance while continuing to modernize and strengthen its system. Company-wide reliability remained above 99.9 percent across all customer classes every year. Minnesota Power has maintained these levels while also maintaining an aging system.

Q. What trends does Minnesota Power see related to system reliability?

A. Minnesota Power continued to invest in asset renewal of aging infrastructure, grid modernization, strategic undergrounding, technology, and preventative maintenance programs to enhance system reliability and resilience. These investments contributed to significant reliability improvements, particularly on feeders with advanced automation, and supported the Company's long-term strategy to address aging infrastructure and evolving customer expectations.

Q. What aging infrastructure programs are targeted to improve reliability?

A. Substation renewals along with asset replacements such as line rebuilds are a few of the aging infrastructure programs targeted to improve reliability. More information on Asset Renewal Programs can be found in my testimony at Section III.B.

Q. What maintenance programs are targeted to improve reliability?

A. Vegetation management, inspections, audits, and preventative maintenance activities are a few of the maintenance programs targeted to improve reliability. More information on maintenance programs can be found in my testimony at Section IV.C.

Q. What grid modernization initiatives are targeted to improve reliability?

A. FLISR, reclosers, TripSavers, sensors, and strategic undergrounding are a few of the specific grid modernization programs targeted to improve reliability. More information on grid modernization can be found in my testimony at Section III.B.

Q. What is strategic undergrounding and how is Minnesota Power using it to improve reliability?

A. Strategic undergrounding was first initiated by Minnesota Power in 2020 and will continue with some of the Company's worst performing overhead distribution lines being prioritized for undergrounding to improve reliability for customers. The Company is targeting areas where customers do not allow access to distribution vegetation management, such as tree trimming, and areas where overhead distribution lines are installed cross-country through inaccessible areas with heavy vegetation. The main drivers for strategic distribution undergrounding are reliability improvement, storm resiliency, aging asset replacements, potential O&M vegetation reduction costs, wildfire risk, and reductions in trouble costs as reliability improves. Locations are prioritized based on feeder reliability, vegetation costs, accessibility for maintenance, and geology.

Q. Has Minnesota Power continued its efforts to incorporate technology into its systems to leverage these advancements for the benefit of customers?

A. Minnesota Power has a number of technology initiatives related to customer service, customer data, reliability, and business efficiency. These initiatives improve how information is provided as well as how data is gathered and will result in a number of gains in business efficiency. The section below talks about these initiatives in technology.

Q. How is Minnesota Power's AMI being used to improve reliability?

A. Since 2011, the OMS has been integrated with the Company's AMI system. This integration provides real-time messages from the AMI system when the power goes out at a customer's service and when the power is restored to a customer's service. The AMI system allows service dispatchers to manually "ping" individual customer meters to verify power restoration and service status. Alarming, similar to hot socket alarms, has also been used with the OMS to dispatch potential issues and mitigate problems before outages happen. AMI data is being used to detect more failing equipment for proactive response to the condition before customers are affected.

Q. What reliability results has Minnesota Power observed on feeders with TripSaver deployment?

A. Minnesota Power has observed strong reliability benefits from TripSaver deployment. On circuits with these technologies in place, the Company has seen meaningful reductions in outage duration and frequency, as well as improved storm response and restoration performance. In addition to reliability improvements, the Company also sees a reduction in O&M costs with less truck rolls and no maintenance on this device. In one feeder example with full TripSaver deployment, SAIDI minutes declined by 49.5 percent in 2025 compared to the five years preceding the upgrade. More reporting and examples can be found in the SRSQ filing.

Q. What reliability results were observed on feeders with IntelliRupters installed?

A. Minnesota Power has observed strong performance on feeders where IntelliRupters have been installed. Significant improvement in outage duration and customers affected have been witnessed on all feeders where Intellirupters are deployed. More reporting and examples can be found in the SRSQ filing.

Q. What actions has Minnesota Power taken in recent years to improve reliability and resilience?

A. In 2025, the Company advanced strategic undergrounding, added automated grid devices, standardized TripSaver settings, and completed additional feeder sectionalizing work to improve resilience and outage response. Asset renewal, substation modernization, vegetation management, inspections, and smart grid tools also continued to address aging infrastructure and outage risks, while supply chain challenges were managed through proactive planning and inventory strategies.

Q. How did Minnesota Power perform in customer service and operational support in 2025?

A. Customer service remained a priority in 2025. The OMS upgrade improved outage prediction and workflow, restoration timing remained strong, and digital platforms maintained high uptime. Although Call Center performance fell short of the annual response standard, results improved significantly late in the year. The Company also maintained strong meter reading performance, granted all Cold Weather Rule requests, and restored service to more than two-thirds of disconnected residential customers within 24 hours.

B. Load Management and Residential Programs

Q. What load management programs does the Company currently offer to residential and commercial customers?

A. Minnesota Power offers two load management programs, Dual Fuel and Fixed Off-Peak, that are intended to reduce system peak demand, support grid reliability, and mitigate purchased energy cost impacts. Dual Fuel is an interruptible service rate

designed primarily for customers using electric heating, under which participating customers receive a discount on electric usage in exchange for occasional service interruptions when necessary to avoid high-cost energy supply conditions, manage system peak demand, preserve system reliability, or test and verify interruptible load capability. Fixed Off-Peak is designed for customers with storage-based space and water heating equipment and operates under a defined daily interruption schedule in exchange for discounted energy rates. Collectively, these programs provide Minnesota Power with controllable load resources that support reliable system operations and help manage energy supply costs. The Company continuously evaluates these programs to identify opportunities to further leverage this resource.

Q. How does the Company administer these programs?

A. Minnesota Power utilizes its AMI network to facilitate interruptions through either disconnect meters or load control devices. The Company offers outbound notifications to advise customers of scheduled interruptions, allowing them to prepare any necessary backup systems. The Company continues to evaluate opportunities to enhance customer communications through expanded messaging capabilities to provide more timely and effective interruption-related information. Administration of these programs is supported by dedicated personnel who provide customer assistance and develop educational materials intended to support program awareness and participation and Minnesota Power has included amounts in the 2027 test year to support the development of the advanced distribution management system to support the customer experience. These personnel also actively promote demand response program enrollment to customers participating in other Company programs, such as air-source heat pump rebate offerings, helping increase awareness and participation among engaged customers.

Q. Is the Company considering any new load management programs for residential and commercial customers?

A. Minnesota Power is exploring additional load management opportunities to increase load flexibility and support the state's carbon-free standard. The Company's Integrated

Resource Plan identifies customer programs as a potential resource. To inform its evaluation of customer program opportunities, the Company is considering research and development pilot offerings through its Energy Conservation and Optimization ("ECO") programs, including thermostat setback, water heater load management, and managed EV charging. The Company is also evaluating potential enhancements to existing programs to make participation simpler and more affordable for customers. Minnesota Power believes a phased approach is appropriate so that lessons learned from initial efforts can inform future program design, implementation, and any broader deployment.

Q. What technology will be needed to facilitate these programs?

A. Facilitating additional load management programs may require further evaluation of enabling technologies, communications platforms, and system integration capabilities. Minnesota Power continues to assess its AMI capabilities to determine how customer devices can be effectively interacted with to support reliable demand response and potential broader deployment. Future interoperability standards may also be important to enable the integration of diverse devices and vendors to support the development and administration of future load management programs. In addition, DERMS capabilities may ultimately be needed to provide the visibility, coordination, and control necessary to manage flexible grid responsive resources.

Q. What changes in workforce management do you see with respect to this technology and these programs?

A. While this technology and these programs allow for additional capabilities, Minnesota Power still needs a workforce that is trained to use these technologies to ensure that our customers and the Company are able to fully leverage the benefits. This includes the need for us to have specialists who are able to alter the DERMS through advanced programming and engineering to provide the data necessary for the Company to manage the grid responsiveness.

VI. CONCLUSION

Q. Does this complete your Direct Testimony?

A. Yes.

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