Direct Testimony and Schedules
Daniel W. Gunderson

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-23-155

Exhibit ________

TRANSMISSION AND DISTRIBUTION

November 1, 2023

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Daniel ("Dan") W. Gunderson, 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 Transmission and Distribution.

Q. Please summarize your qualifications and experience.

A. I am originally from Virginia, Minnesota, where I graduated from high school before attending college at Michigan Technological University. I hold a Bachelor of Science degree in Electrical Engineering. I obtained a master's degree in business administration with an emphasis in business operations from the Carlson School of Management at the University of Minnesota in Minneapolis in 2006. I completed requirements for obtaining Professional Engineers licensure in Minnesota in 2007 and have held a Minnesota Class A Master Electrician's license since 2004.

I began my career with Minnesota Power in 2006 as a Meter Engineer and later a Supervising Engineer of the Electric Meter Department, where I was responsible for providing project management and oversight for the Smart Grid Investment Grant project, the Advanced Metering Infrastructure ("AMI") System technology and implementation and managing work for technicians that maintain all metering systems. In 2013, I served as Manager of Technical Systems, where I was responsible for oversight of Substation Maintenance, Substation Construction, and Relay and Protection Systems. In this role, I also managed transmission substation asset management programs. I have also worked as the Manager of Distribution Resources where I led our Distribution Services area—including line operations, operations planning, trouble, and dispatch—before being promoted to Director of Distribution Operations in 2015. In 2019, I was promoted to Vice President of Transmission and

Distribution. These areas include approximately 373 employees, with nearly 200 of those employees as members of International Brotherhood of Electric Workers Local 31.

Q. What is the purpose of your testimony?

A. The purpose of my Direct Testimony is to provide background on the Company's power delivery systems. I discuss the capital investments the Company has made since Minnesota Power's 2021 Rate Case, Docket No. E015/GR-21-335 ("2021 Rate Case"), our most recent 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 will provide information to support the Company's reasonable, necessary, and prudent investments in local and regional capital projects and ongoing maintenance of our power delivery systems. I am also providing testimony on the continued benefits of the Company's participation in the Midcontinent Independent System Operator ("MISO") and how that participation impacts revenue and expenses for Minnesota Power. Finally, I provide testimony on the Company's continued efforts to improve power delivery system reliability, customer relations, and business efficiency.

Q. How is your testimony organized?

A. Section II of my testimony provides an overview of the Transmission and Distribution work areas, explaining the role and the geographic reach of the transmission and distribution systems.

Section III provides both background and detail of the capital investments and projects in Transmission and Distribution, including the types of projects and the work processes involved with them. This section also details the Transmission Cost Recovery ("TCR") Rider information specific to this particular filing, information on how the Company works to ensure renewables can be interconnected to our system, and efforts related to regional transmission development.

Section IV describes the O&M processes and costs for Transmission and Distribution. This section also explains third-party transmission revenues and expenses, as well as the Company's vegetation management program and costs, and supply chain initiatives.

Finally, in Section V, I discuss the Company's system reliability and items related to the 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 schedules to my Direct Testimony:

- MP Exhibit ___ (Gunderson), Direct Schedule 1 – Minnesota Power Service Territory Map;
- MP Exhibit ___ (Gunderson), Direct Schedule 2 – North Shore Loop Transmission Projects Map; and
- MP Exhibit ___ (Gunderson), Direct Schedule 3 – Minnesota Power System Third-Party Transmission Revenue and Expense

II. TRANSMISSION AND DISTRIBUTION WORK AREAS

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

A. Minnesota Power's Transmission and Distribution department is responsible for the construction, management, and O&M of Minnesota Power's power delivery systems. This means that the department ensures that energy is safely and reliably transmitted from generating resources, whether Company-owned or third-party-owned, to the distribution system and, ultimately, to our customers. The department is also responsible for the residential and small commercial customer data from the meter to billing system. The Support Services area includes Fleet, Stores, and Project Execution. Support Services generally provides centralized management of key activities. These services are critical to operations, and this area works closely with leadership in the implementation of efficiency improvements and cost containment efforts.

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

A. Minnesota Power's transmission system consists of, generally, voltages between 115 kilovolts ("kV") up to 500 kV.[1] The Company's transmission system is located primarily in Minnesota and portions of North Dakota. These transmission facilities deliver power from various generating resources, including wind, solar, coal, biomass, natural gas, and hydro. Minnesota Power's transmission facilities serve local loads across nearly 26,000 square miles of central and northeastern Minnesota and are critical to supporting the larger regional transmission system reliability.

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

A. The Company's distribution system is located in northeastern 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. A map of Minnesota Power's distribution service territory is provided with my Direct Testimony as MP Exhibit ___ (Gunderson), Direct Schedule 1.

Q. Have the Transmission and Distribution work areas experienced any staffing challenges in recent years?

A. Yes. Over the period of 2018 to the present, the Company navigated multiple business challenges in an evolving job market, which led to an imbalanced allocation of resources. As employees resigned, retired, or otherwise left the Company, they were not replaced at the same pace. In parallel to higher-than-average turnover partially due to increased employment opportunities with remote work employers, the Company is also experiencing increased capital investment for grid transformation, increased maintenance requirements and corrective repairs with aging assets, and a higher volume of interconnection and solar requests.

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[1] Certain customers may receive energy at voltages of 115 kV, delivered directly to their facilities. These customers are generally large energy users that require transmission connections.

As discussed in the Direct Testimony of Company witness Ms. Laura E. Krollman, the Company continues to execute the *EnergyForward* strategy to meet the Company's commitment to long-term reliability and renewable goals. To address workload balance, the Company made process and organizational changes by documenting workstreams, leveraging existing tools to manage work, and adding strategic resources when necessary. As part of this initiative, resources were either internally reallocated or additional staff hired into these five strategic areas: engineering, project management, maintenance, technical training, and field operations.

Q. Has the Company experienced changes to its Capital and O&M to advance *EnergyForward* since the 2021 Rate Case?

A. In the testimony that follows, I will discuss grid transformation initiatives within the Capital and O&M areas of Transmission and Distribution. Within the O&M section, I discuss factors considered in preparation of each work area's zero-based budget. This section also discusses increases in costs related to higher internal labor, contract labor, and materials costs necessary to execute this work. These increases are primarily due to additional staff as discussed above, as well as increases in wages to reflect the competitive marketplace, as discussed in more detail by Company witness Ms. Krollman, and a continued but renewed focus on employee safety and training programs.

One of ALLETE's core values is safety. Since the 2021 Rate Case, Minnesota Power has renewed its focus on employee safety training. In an effort to boost the competency, proficiency, safety, and effectiveness of the workforce, a utility training program has been created and is staffed with employees who train new and existing employees on systems and safety procedures. The 2024 test year includes the costs associated with these critical safety training needs for new and existing employees.

III. CAPITAL INVESTMENTS AND PROJECTS

A. Capital Investments Budget Overview

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 Mr. Colin B. Anderson; this process affirms the projects that are required within a specific year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet work areas. The project assessments include 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 includes 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.

During the first phase of the annual capital budget process, each area reviews their long-range plan ("LRP") in conjunction with expected spending and necessary timing and identifies the slate of projects to move to the next phase. Along with the LRP, the biennial Integrated Distribution Plan ("IDP"), the Minnesota Biennial Transmission Projects Report, and the Integrated Resource Plan ("IRP") are fundamental budget and reporting tools that may be used during the budgeting process. The IDP provides guidance on the Company's distribution system and highlights continuous foundational investments related to serving customers, ensuring reliability, and preparing for a more resilient grid; the Minnesota Biennial Transmission Projects Report provides information about projects to address identified transmission needs; and the IRP reports how the Company will meet the expected energy needs of customers with a safe, reliable, sustainable, and cost-effective supply of energy. The second phase involves cross-functional organizational review; leadership and subject matter experts from Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet work areas collaborate on the review of proposed projects with a cross-functional lens. If not already identified through the Company's normal project scoping processes, projects that may be coordinated with one another to improve efficiency or that impact multiple areas are identified, and plans are made to allocate the necessary resources and align their schedules. Resource and budgetary constraints are also considered during this review stage. Once consensus over the portfolio of projects is achieved, the cross-functional group moves the portfolio forward to the Portfolio Review Board ("PRB") for approval. The PRB consists of leadership across the represented areas. The resulting capital budget must also receive management approval and is then compiled into the annual corporate capital budget presented for review and discussion to the ALLETE Board of Directors in October.

Q. Does the budgeting process ensure that capital investments are reasonable and necessary?

A. Yes. This budgeting process results in a reasonable budget for capital investments needed to maintain the safety and reliability of the transmission and distribution system. Additionally, this budget ensures the prudent investment of capital to provide electric service to our customers, provide necessary upgrades to the regional transmission system, comply with North American Electric Reliability Corporation ("NERC") reliability requirements and other policy drivers, meet system capacity needs, and ensure the health of existing assets.

Q. Please describe the PRB.

A. The PRB provides governance, control, and advice to senior management for the portfolio of capital projects led by the Transmission, Distribution, Facilities, Security, Cyber Technology Services, Land Management, and Fleet work areas. The PRB is responsible for reviewing the capital additions and removals to ensure that projects proposed are consistent with the Company's long-range strategic plans. The PRB is charged with seeking additional information or project budget development details from the appropriate work areas before approving a project. The PRB governs the review and approval of capital projects, budget, scope, and expenditure changes; along with communication of project execution controls and metrics such that critical project goals set forth by senior leadership are achieved. This group also fills an advisory role to senior leadership regarding the performance of capital projects.

Q. How are capital projects managed once they are approved?

A. Each project is assigned a project manager who is responsible for the efficient delivery of the project. As the leader of the project, the project manager coordinates with subject matter experts to ensure project scope, schedule, and budget are well defined and the appropriate resources are allocated to each project. As the project progresses from initiation to design to construction, the project manager monitors and controls the project and communicates to the PRB, any expected changes to scope, schedule, or cost.

Q. How is the capital budget monitored throughout the year?

A. Each month, the capital additions portfolio is reviewed and actuals are compared to budget at the project level from both a financial perspective and performance perspective. Any variances impactful to a project are immediately addressed and communicated to leadership. Project forecasts are reviewed monthly to maintain a steady and dependable flow of financial information regarding capital expenditures. This process of monitoring the capital budget throughout the year ensures prudent management of Company resources.

Q. Are changes to projects sometimes necessary after initial budgets have been established?

A. Yes. A monthly review of year-to-date actual performance with year-to-date and year-end forecasts may identify a project change; examples of project changes include:

- Project estimate has been refined from a planning estimate to a detailed estimate;
- Previously identified risks cease to exist, and any funds held for that risk are removed from the project's forecast;

- Budgeted schedule is no longer viable, and a portion of the project must be advanced or deferred to a different calendar year due to extended procurement times or inability to commit to delivery times by manufacturers based on current production constraints and delivery delays, as discussed later in my Direct Testimony;
- Change can be identified during the project, possibly related to scope addition or reduction, required resources, and/or pricing of contract(s); and
- Unplanned work arises that is required to be completed or is strategic in nature. This may include road relocations required due to local government decisions or meeting customer electric service requirements.

Q. Please describe the process the Company undertakes to manage project changes and break-in projects after establishing a capital budget.

A. The PRB reviews and manages capital spending, project risks, and project contingency levels. The PRB reviews monthly reports of financial performance and progress of high-spend or high-risk projects. The PRB also reviews all changes and associated impacts to the overall portfolio. Certain project changes—such as commodity and construction pricing, government requirements, customer electric requirements, line outage limitations, and supply chain delays—often fall outside of the Company's control. If overall portfolio deviations fall outside of an acceptable level, the PRB will make recommendations to meet financial targets. Changes to the annual forecast are reported to the accounting area, which also monitors capital spending.

Q. Please describe current capital budget risks and the Company's approach to managing risk after establishing a capital budget.

A. Over the last few years, the Company has experienced unprecedented uncertainty around capital projects relating to the risks of a changing and challenging supply chain, but also has developed a tremendous amount of experience in considering supply chain and cost changes in this environment. Vendors are challenging Company contract terms and conditions that were previously widely accepted, lengthening the procurement cycle as those terms are reconciled. At the same time, the Company is facing increased challenges in securing production timeslots for major materials due to the following: 1) longer than historical manufacturing lead times; 2) manufacturing companies not all being at full, pre-pandemic production capacity; and 3) large natural disasters that have put additional pressure on common commodity items, compounding the previously mentioned challenges. The Company is encountering increasing rates for major materials and contract labor due to this supply and demand tension and overall inflation. The Company assesses these factors that could increase project costs significantly compared to historical values.

The risks identified above are partially attributable to the overall economic challenges presented by the COVID-19 pandemic. In addition to challenging procurement schedules, the Company is experiencing increased difficulty in coordinating construction outages within available outage windows due to the availability of the labor workforce, which could result in modifications to project completion schedules or increased costs due to multiple mobilizations and demobilizations.

In this current environment, the Company continues to work diligently to identify ways it can mitigate some of these risks for the benefit of customers; mitigation efforts include: increased monitoring of inventory levels for major and commonly-procured materials; utilizing vendor alliances for both materials and services to assist in monitoring supply chain impacts and proactively identifying alternate material and backup suppliers; and bulk ordering earlier in the process to secure production timeslots. Further, because this environment has existed for a few years, the Company has developed a better understanding of where the risks in the marketplace might arise and how best to consider those on the front-end of project planning and adapt during project implementation.

Q. How are final decisions made with respect to canceling, delaying, or accelerating a project?

A. The Company's portfolio of capital projects is reviewed on a monthly basis. Projects with risks are flagged and monitored closely by the project manager. If the project manager indicates the project may fall outside of allowed variances, the project is reassessed by the business unit. Both Company and customer needs are balanced with resource availability. If one project is delayed or cancelled, other projects may be accelerated to maintain the overall capital budget as well as resource and customer commitments. Proposed changes to the portfolio of projects are reviewed and approved by the PRB, which is expected to manage the capital additions to the approved capital budget and which manages the Company's resources efficiently.

Q. Please explain why it may be necessary for the Company to replace projects it has identified in a test year with other projects during the pendency of a rate case.

A. The Company has identified and budgeted for certain capital projects to be placed in service in the 2024 test year. Because the Company must provide safe, reliable, and cost-efficient energy to customers, shifting in-service dates of certain projects may be necessary to meet changing needs. Maintaining some flexibility to replace projects within a test year is in the best interest of our customers for several reasons including the ability to respond to change in a timely, safe, and cost-effective way. By adapting to change, the Company can ensure safe and reliable transmission and delivery of electricity to our customers.

The Commission has previously allowed such flexibility in shifting projects, recognizing that the utility industry is a dynamic business and priorities change.[2] In doing so, the Commission has allowed substitution projects where: (1) the utility has shown the replacement projects are necessary, the costs are prudent, and the projects will be in service in the test year; and (2) the other parties had sufficient time to review the proposed replacement projects.[3]

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[2] *In the Matter of the Application of Minn. Power for Auth. To Increase Rates for Elec. Serv. In Minn.*, Docket No. E015/GR-21-335, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 13 (Feb. 28, 2023); *In the Matter of the Application of Minn. Power for Auth. to Increase Rates for Elec. Serv. in Minn.*, Docket No. E015/GR-16-664, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 22–23 (Mar. 12, 2018); *In the Matter of the Application of N. States Power Co. for Auth. to Increase Rates for Elec. Serv. in the State of Minn.*, Docket No. E002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 26–27 (May 8, 2015).

[3] *Id.*

Therefore, the Company will provide updates on any such changes, the reasons for the change, and any budget updates in Rebuttal Testimony. The Company requests that the Commission recognize the dynamic nature of this aspect of the Company's business as it has done in prior cases, including the 2021 Rate Case.

Q. Will all of the projects included in the 2024 test year be placed into service during 2024?

A. At this time, the Company is on track to place all capital projects identified in the 2024 test year budget in service in 2024. However, there may be extenuating circumstances, such as those mentioned above, that necessitate modifications to the overall projects that Minnesota Power places in service during 2024—although the Company manages such circumstances to ensure the overall portfolio remains balanced.

Q. What has the capital investment looked like from 2022 through 2024?

A. Table 1 provides the Company's regulated capital plant additions for 2022 actuals, the 2023 projected year, and the 2024 test year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas. Table 1 provides this information at the Total Company level. Capital plant additions at the Minnesota Jurisdictional level are provided in Table 2.[4]

[4] 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.

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

Capital Plant Additions (including Contra) -- Total Company	2022	2023	2024
Transmission, Distribution, General Plant, and Intangible	Actuals	Projected Year	Test Year
Transmission*	$33.4	$15.3	$51.1
Asset Management	$14.8	$5.8	$51.1
Baseline Reliability	$2.6	-	-
Externally Driven	$1.6	$0.6	-
Strategic/North Shore Loop	$14.5	$8.8	-
Distribution*	$47.7	$65.3	$53.3
Age Related & Asset Renewal	$23.4	$33.3	$18.7
Capacity	$2.0	$0.6	$3.8
Distribution Other	$5.2	$0.5	$0.4
Government Requirements	$1.2	$2.4	$1.9
Grid Modernization & Pilot Projects	$1.0	$3.6	$4.0
Metering	$2.5	$2.3	$2.4
New Customer_New Revenue	$8.4	$13.5	$13.9
Reliability & Power Quality	$4.0	$9.1	$8.2
Cyber Technology Services	$9.8	$20.5	$13.5
Communication System Improvements	$2.7	$4.2	$2.9
Cyber Technology	$7.1	$9.3	$10.6
Software Implementation	-	$7.0	-
Facility Management	$1.6	$13.0	$5.4
Fleet	$4.6	$7.0	$7.3
Security	$0.7	$0.6	$0.6
T&D Subtotal, excluding Riders	**$97.8**	**$121.6**	**$131.1**

Amounts in millions.

Amounts may not total due to rounding.

**Amounts may include Intangible & General Plant Additions.*

Table 2. Capital Plant Additions (Including Contra AFUDC)

(MN Jurisdictional)

Capital Plant Additions (including Contra) -- MN Jurisdictional	2022	2023	2024
Transmission, Distribution, General Plant, and Intangible	Actuals	Projected Year	Test Year
Transmission*	$27.5	$12.5	$42.2
Asset Management	$12.2	$4.8	$42.2
Baseline Reliability	$2.1	-	-
Externally Driven	$1.4	$0.5	-
Strategic/North Shore Loop	$11.9	$7.3	-
Distribution*	$45.1	$59.9	$52.0
Age Related & Asset Renewal	$21.4	$28.8	$18.3
Capacity	$1.9	$0.6	$3.7
Distribution Other	$5.0	$0.5	$0.3
Government Requirements	$1.1	$2.4	$1.9
Grid Modernization & Pilot Projects	$1.0	$3.5	$3.9
Metering	$2.5	$2.3	$2.4
New Customer_New Revenue	$8.3	$13.5	$13.8
Reliability & Power Quality	$3.8	$8.4	$7.6
Cyber Technology Services	$8.7	$18.1	$12.0
Communication System Improvements	$2.4	$3.7	$2.6
Cyber Technology	$6.3	$8.2	$9.4
Software Implementation	-	$6.2	-
Facility Management	$1.4	$11.5	$4.8
Fleet	$4.1	$6.2	$6.5
Security	$0.6	$0.5	$0.5
T&D Subtotal, excluding Riders	**$87.4**	**$108.7**	**$118.0**

Q. How are the Capital Additions in Table 1 summarized for purposes of your work areas?

A. As described above, many capital projects are cross-functional and include asset additions of varying types. General Plant assets exist at every transmission and distribution substation or facility. Some substations contain both transmission and distribution assets. For efficiency, the Company defines its capital projects by site, such that all of the impacted assets at the site—whether Transmission, Distribution, General, or Intangible Plant (Cyber Technology Services, Security, etc.)—are assessed as part of one overall project, assigned to a single project manager, and engineered and constructed in close coordination through this synchronized approach. The Company reflects the entire bundle of work included in such projects in one managing area in Table 1 based on which classification has the majority of additions for the particular project. This is a demonstration of the intricacies in budgeting that the Company undertakes in any year, but most notably in the development of a test year.

Many projects have capital additions to more than one classification, such as both Transmission and Distribution. Some examples from the 2024 test year where we encounter these combinations of assets—which are discussed in greater detail later in my Direct Testimony—are the Canosia Road Substation 34.5 kV Expansion Project, the 15th Avenue West Transformer Addition Project, and the Long Prairie Substation Modernization Project. These projects add both Transmission and Distribution assets for which the Company budgets, and for which the Company identifies in the various classifications for purposes of providing the necessary financial supporting information to the Commission. Therefore, classifying capital additions for each of these projects, particularly when the Company develops its test year budgets, is a painstaking and detailed process in which many factors are considered. These projects are illustrative of the inherent interconnectedness of the Company's operations, wherein some assets are not necessarily readily unbundled and obviously delineated from each other at the time of project initiation.

Q. How do the capital additions in the 2024 test year budget and the 2023 projected year in Table 1 compare to the Company's 2022 actuals?

A. The capital additions projected for the Transmission, Distribution, and Support Services work areas for the 2024 test year and the 2023 projected year are $33.3 million Total Company ($30.6 million MN Jurisdictional) and $23.8 million Total Company ($21.3 million MN Jurisdictional) greater than the capital additions in 2022, respectively.

Transmission capital additions in the 2024 test year are $17.7 million Total Company ($14.7 million MN Jurisdictional) greater than the capital additions in 2022, whereas and the capital additions in the 2023 projected year are $18.1 million Total Company ($15.0 million MN Jurisdictional) less than the capital additions in 2022. Transmission capital additions included in the 2024 test year are discussed further in Section III.B of my Direct Testimony.

Distribution capital additions in the 2024 test year and the 2023 projected year are $5.6 million Total Company ($6.9 million MN Jurisdictional) and $17.6 million Total Company ($14.8 million MN Jurisdictional) greater than the capital additions in 2022, respectively. Distribution capital additions included in the 2024 test year are discussed further in Section III.C of my Direct Testimony.

Cyber Technology Services capital additions in the 2024 test year and the 2023 projected year are $3.7 million Total Company ($3.3 million MN Jurisdictional) and $10.7 million Total Company ($9.4 million MN Jurisdictional) greater than the capital additions in 2022, respectively. Cyber Technology additions included in the 2024 test year are discussed further in Section V.B of my Direct Testimony.

Facility Management capital additions in the 2024 test year and the 2023 projected year are $3.8 million Total Company ($3.4 million MN Jurisdictional) and $11.4 million Total Company ($10.1 million MN Jurisdictional) greater than the capital additions in 2022, respectively. Facility Management additions included in the 2024 test year are discussed further in Section III.D of my Direct Testimony.

I address the reasons for these changes in more detail in my Direct Testimony.

B. <u>Transmission Capital Investments and Projects</u>

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

A. Transmission projects are divided into four general categories: Baseline Reliability Projects, Transmission Asset Management Projects, Externally-Driven Projects, and Strategic Projects. These categories correspond to the unique sets of drivers and sources of identification associated with various types of transmission projects in Minnesota Power's long-range plan.

Q. What are Baseline Reliability Projects?

A. Baseline Reliability Projects are transmission system upgrades necessary to ensure the transmission system complies with the Company's transmission planning criteria. Such criteria may establish acceptable pre- or post-contingent voltages, transmission line loading, or stability performance, among other things.

Q. What are the main drivers for Baseline Reliability Projects?

A. The main drivers for Baseline Reliability Projects are deviations from the Company's planning criteria identified pursuant to the NERC transmission planning standards.

Q. How are Baseline Reliability Projects identified?

A. Baseline Reliability Projects are typically identified through the annual transmission planning assessments required under the applicable NERC Reliability Standard. These assessments are typically completed for the Company by MISO. Through the annual MISO Transmission Expansion Planning ("MTEP") study process, the Company submits proposed projects, reviews power flow models, provides contingency definitions, and evaluates study results. If a need is identified in the MTEP assessment, the Company submits a corrective action plan to MISO. In some cases, the corrective action plan may involve the operation of an existing Remedial Action Scheme, an existing Operating Guide, or reconfiguration of the system-by-system operators. In other cases, the corrective action plan for the condition may be a new Baseline Reliability Project.

Q. How does the Company augment the MISO MTEP review process for planning purposes?

A. The Company augments its involvement in the MTEP process and refines its list of Baseline Reliability Projects through internal targeted evaluation of criteria violations identified in the MTEP assessment. Where significant issues are identified in the MTEP assessment related to the Company's transmission system, the Company will often perform its own targeted study of the local area to further refine its understanding of the issue and potential solutions. The internal study yields a deeper understanding of the issue, its causes, and potential solutions—driving the process toward a particular Baseline Reliability Project that may be scoped and incorporated into long-range planning and capital budgeting activities to be implemented at the proper time.

Q. How does the Company evaluate alternatives for Baseline Reliability Projects?

A. Depending on the type of issue and its magnitude, the Company considers a broad range of alternatives for Baseline Reliability Projects. Alternatives evaluation is typically performed during the internal targeted study phase described above. Alternatives considered may include both wire and non-wire solutions, including, among other things, establishing new operating guides or procedures (including load management), upgrading or reconfiguring existing transmission facilities, building new transmission facilities, and implementing new transmission- or distribution-connected supply-side solutions. The types of alternatives considered for a particular issue are dependent on the nature of the problem to be addressed. To be a viable alternative, a solution must be available (1) at the necessary time, (2) with the necessary response, and (3) for the necessary duration, to address the particular issue at hand.

For example, if the issue is a voltage collapse caused by an unanticipated transmission line outage, any viable solution must be capable of being in-service and online or running prior to, during, and after the unanticipated outage independent of any operator intervention. For an issue such as this, certain types of operating guides and peaking or intermittent power supply resources would not be sufficient to solve the problem because they could not be counted upon to be running prior to, during, and after the unanticipated outage or capable of responding rapidly enough to mitigate the collapse.

Q. How does the Company coordinate evaluation of non-wire solutions in Transmission Planning along with its existing Resource Planning activities?

A. Where a non-wire solution is determined to be a viable alternative for a Baseline Reliability Project or other transmission system issue, scoping-level information about the non-wire solution (necessary size, location, and operational characteristics) will be developed by Transmission Planning and discussed with Resource Planning to facilitate further development of the non-wire solution. Where appropriate, Resource Planning will further develop the non-wire solution by identifying an anticipated cost, implementation timeline, power supply benefits, societal benefits, and other potential benefits specific to that non-wire alternative. If any non-wire alternatives identified through this exercise show potential benefits for the transmission system and customers, are economical compared to other alternatives from a holistic utility planning perspective, and can be implemented on a timeline sufficient to satisfy the identified transmission system issue, these alternatives could be considered as resource options for implementation. When reasonable, a non-wire alternative can be considered in the Company's current IRP,[5] and then a petition requesting approval for implementation could move forward. If the non-wire resource option did not fit with the timing of the current IRP analysis, then it could be considered in the next IRP submittal or a separate petition. If the transmission system issue needed to be addressed on a timeline prior to the next IRP approval, then additional requirements could be included in the development of the solution to address the resource fit and timing. The Company also considers the role of non-wire alternatives on the distribution system in its most recent IDP (Docket No. E015/M-23-258). This process of integrated system planning allows for a more holistic approach to the system as a whole.

Q. What are Transmission Asset Management Projects?

A. Transmission Asset Management Projects include: (1) Contingency Programs and (2) Asset Renewal Programs. Contingency Programs provide funding for emergency restoration and replacement of failed assets due to unforeseen events. Asset Renewal Programs provide funding for planned replacements or upgrades where priority assets have been identified in advance of equipment failure.

[5] The Company's most recent IRP was filed in February 2021 in Docket No. E015/RP-21-33 and an order was received in that docket on January 9, 2023.

Q. What are the main drivers for Transmission Asset Management Projects?

A. The primary driver for all Transmission Asset Management Projects is the age and condition of existing equipment on the transmission system. Asset Renewal Programs are intended to ensure safety and reliability, enhance long-term planning, and optimize asset lifecycle value through the proactive replacement or upgrade of certain types of high-priority, high-impact, and/or high-value assets. Contingency Programs are intended to enable the Company to respond to unanticipated failures that occur throughout the year. While Contingency Programs respond on an as-needed basis and are necessary, the goal of the overall Transmission Asset Management Program is to maximize the life of all transmission equipment and, in most cases, repair or replace that equipment as part of an Asset Renewal Program at or near the end of the equipment's useful life and ahead of the Contingency Program.

Q. How are Transmission Asset Management Projects identified?

A. Transmission Asset Management Projects are generally identified by historical operating experience, facility age and condition data, and through the judgment of subject matter experts and cross-functional project teams. Contingency Programs are generally similar from year to year and the funding level is based on recent experience with the particular type of asset they are intended to address. Asset Renewal Programs are developed to enhance lifecycle asset management across the fleet of transmission assets methodically and intentionally over a defined period of time. Asset Renewal Programs are typically coordinated with a cross-functional group of internal stakeholders to identify, prioritize, and scope replacements or upgrades of high-priority, high-impact, or high-value assets. In recent years, previously unconnected asset renewal programs involving substation equipment have been integrated into a single substation modernization program designed to efficiently and holistically address all of the asset renewal and known long-term reliability needs at a site with one comprehensive project. Additionally, Minnesota Power has strategically taken a more methodical approach to identification of asset management projects—the Company is able to leverage its experience with equipment to identify equipment and other assets that are nearing the end of life for replacement or renewal, instead of waiting for equipment to begin to experience operational issues before replacement.

Q. What are Externally-Driven Projects?

A. Externally-Driven Projects are transmission system modifications or upgrades necessary to facilitate the needs of external (*i.e.*, non-Minnesota Power) entities, such as the following: customers; federal, state, or local agencies; new generators; or other utilities.

Q. What are the main drivers for Externally-Driven Projects?

A. The main drivers for Externally-Driven Projects are the needs or requirements of external entities affecting the transmission system. Examples include transmission line relocations due to changes in other infrastructure, system modifications required by NERC outside of the NERC transmission planning standards, and facilitating third-party transmission system access pursuant to Federal Energy Regulatory Commission ("FERC") open access transmission service rules.[6]

Q. How are Externally-Driven Projects identified?

A. Externally-Driven Projects are identified when requested by an external entity. To minimize the schedule and cost risks associated with external project requests, the Company has developed close coordination practices with major stakeholders such as its Large Power ("LP") customers and other utilities that serve the areas adjacent to Minnesota Power's transmission system.

Q. How does the Company coordinate with LP customers to ensure that Externally-Driven Projects are timely and appropriate?

A. The Company works closely with existing and potential future LP customers through regular two-way communications about upcoming needs and plans. The Company

[6] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Serv. by Pub. Util.; Recovery of Stranded Costs by Pub. Util. and Transmitting Util.*, Docket Nos. RM95-8-000 and RM94-7-001, FERC ORDER 888 (Apr. 24, 1996).

communicates its upcoming projects and required outages that may impact existing LP customer operations. Additionally, LP customers communicate their upcoming projects and infrastructure needs. The Company also participates in dialogue with potential future LP customers to identify the upgrades or investments that would be necessary to meet the potential customer's needs. Ongoing communication and customer relationships are maintained through the Company's dedicated Strategic Account professionals.

Q. How does the Company coordinate with other utilities to ensure that Externally-Driven Projects are timely and appropriate?

A. In addition to coordinating through the MISO MTEP process discussed above, the Company generally holds coordination meetings with neighboring utilities on an annual basis or as needed. Great River Energy is the second highest user of the Company's transmission system after Minnesota Power. Because of the increased level of coordination between the Company and Great River Energy, the Company has developed coordinated planning practices with Great River Energy to ensure timely and appropriate two-way project coordination between the two companies. Planning coordination with Great River Energy includes all projects proposed by either utility that will modify or interconnect to the transmission system in Minnesota Power's control area. The companies have agreed to specific requirements and timelines with regard to coordination of transmission planning studies, mutual agreement on long-term transmission solutions, project scoping review and approvals, review of major permit applications, and equitable delineation of ownership and investment in the transmission system. These efforts have been in place since 2016 and have greatly improved transmission planning coordination between the Company and Great River Energy.

Q. How are the costs of Externally-Driven Projects shared between the Company and the external entity driving the need for the project?

A. Cost responsibility for Externally-Driven Projects varies depending on the situation. The Company ensures that all potential cost-sharing avenues are explored and utilized when working with an external entity. However, in some cases, the Company must bear the cost of the externally driven project. For projects coordinated with Great River Energy, the utilities have agreed to bear the costs for the facilities they own and determine ownership of new projects in a way that corresponds to benefits received and facilitates overall revenue neutrality between the two utilities. Transmission revenue sharing with Great River Energy is governed by the Joint Pricing Zone ("JPZ") Agreement, which is discussed further in Section IV.D.2 of my Direct Testimony. The JPZ Agreement remains in effect until December 31, 2023, unless an extension is mutually agreed to by Great River Energy and Minnesota Power. Each company is currently evaluating the JPZ Agreement and will continue discussions in preparation of the December 31, 2023 date. Minnesota Power will provide an update on the JPZ Agreement discussions in Rebuttal Testimony.

Q. What are Strategic Projects?

A. Strategic Projects are transmission system upgrades related to larger Company initiatives like generation fleet transition or regional economic development. Like Baseline Reliability Projects, Strategic Projects are necessary to resolve deviations from the Company's transmission planning criteria. Planning criteria violations may include pre- or post-contingent voltage issues, transmission line overloads, or stability issues, among other things.

Q. What are the main drivers for Strategic Projects?

A. The main drivers for Strategic Projects, like Baseline Reliability Projects, are deviations from the Company's planning criteria, identified pursuant to NERC transmission planning standards. The difference between Strategic Projects and Baseline Reliability Projects is that Strategic Projects are associated with a change on the transmission system that is due to a Company-driven initiative.

Q. How are Strategic Projects identified?

A. Unlike Baseline Reliability Projects, Strategic Projects are most often identified first through the Company's own internal transmission planning studies. Where a strategic initiative is being evaluated, the transmission system impacts of that initiative are determined from an internal targeted evaluation of the potential changes associated with the initiative. The internal targeted evaluation is used to evaluate different scenarios pertaining to the strategic initiative being considered (for example, different combinations of generator retirements) and the system impacts of those scenarios are captured. Where system impacts result in needs, potential solutions to those issues are considered through a similar alternatives evaluation as was described previously under Baseline Reliability Projects. Both wire and non-wire solutions are considered, as appropriate. This internal study process ultimately results in a potential Strategic Project (or set of Strategic Projects) for which preliminary cost estimates may be developed and incorporated into the Company's overall evaluation of the strategic initiative. Where a need has been identified through such a study, Strategic Projects will continue to be evaluated and refined through further internal studies—and eventually through the MTEP assessment process—as more definition develops around the nature and timing of the Company strategic initiative.

Q. How do projects in each of these categories get incorporated into the Company's long-range plan?

A. The Company maintains a long-range transmission project plan that incorporates all four categories of transmission projects. Transmission Asset Management Projects are included in the long-range plan on an annual basis, generally assuming similar year-to-year spend for Contingency Programs and based on specific identified projects and priorities for Asset Renewal Programs. Baseline Reliability Projects, Externally-Driven Projects, and Strategic Projects are initially included in the long-range plan based on the anticipated need date indicated by the studies. For Baseline Reliability Projects, the need date most often corresponds to the model-year in which it was first identified in the MTEP assessment. for Externally-Driven Projects, the need date corresponds to the timing given by the external entity driving the need for the project. For Strategic Projects, the need date corresponds to the Company's anticipated timing for the particular strategy initiative causing a need for the project.

Projects may then be shifted, when possible, within the long-range plan to optimize cash flow, constructability, and internal resource loading. This type of shifting depends on the relative flexibility of need dates and is not always possible. As project scopes become more well defined nearer to the need date, the cost estimate, cash flow, and timing of a project included in the long-range plan is refined. As applicable, transmission projects in the Company's long-range plan are reported in the MISO MTEP process and the Minnesota Biennial Transmission Projects Report.

Q. Please explain the initiation and scoping process for each type of transmission project.

A. Once a project has been identified through the evaluation processes discussed above, the project enters an initiation phase, where the project team is assigned, and several planning activities occur to develop the baseline project scope, schedule, and budget. The initial project scope is defined by the Transmission and Distribution Planning Department and further refined through input from various stakeholder departments such as Project Management, Substation Engineering, Transmission Line Engineering, Safety, Security, Relay and Maintenance Engineering, Meter Engineering, Communications Infrastructure, Distribution Engineering, System Operations, Construction and Maintenance, and Environmental Permitting and Land Management. These stakeholders provide input about required permits or approvals, coordination with external entities, project location and layout, construction sequencing, supply chain lead times, safety and security considerations, and project risks to determine the formal project scope, schedule, and budget for the Project Manager to deliver. Depending on the nature of the project, including permitting requirements and equipment lead times, the timeline from initial project scoping to project completion may be anywhere from three to ten years.

Q. What Baseline Reliability Projects are included in the 2024 test year?

A. There are no Baseline Reliability Projects included in the test year. However, there are several Strategic Projects, discussed below, that address baseline reliability issues tied to specific Company initiatives.

Q. What Transmission Asset Management Projects are included in the 2024 test year?

A. Transmission Asset Management Projects in the test year include asset renewal and contingency programs for substation equipment such as transmission circuit breakers, relay panels, and power transformers; asset renewal and contingency programs for transmission line equipment such as poles and hardware; and asset renewal and contingency programs for the Company's High Voltage Direct Current ("HVDC") assets. For clarification, "Asset Management" is a broad term that encompasses contingency plus targeted projects and, in some cases, may also encompass maintenance. The term "Asset Renewal" is generally used with reference to targeted projects that involve replacing old equipment with new equipment. Aside from regular annual programs, specific larger Asset Renewal Projects in the test year include the Two Islands 115 kV Project, the HVDC Line Hardening Project, the 40 Line Rebuild Project, and the 907 Line Asset Renewal Project.

Q. What is the Two Islands 115 kV Project and what will it address?

A. The Two Islands 115 kV Project involves the construction of a new 115 kV Switching Station in the Taconite Harbor area tying two existing 115 kV lines from the Hoyt Lakes area (1 Line and 2 Line) together with the existing 115 kV Line running up the North Shore from Silver Bay (128 Line). This new switching station will replace the existing 1950s-era substation located adjacent to the Taconite Harbor Energy Center ("THEC") in a new location roughly half a mile from the existing substation. The Two Islands 115 kV Switching Station will enable the existing end-of-life equipment at the THEC Substation to be removed and will be configured as a ring bus to enhance the reliability of the North Shore Loop transmission system. The new switching station will also have two tie lines to a new Great River Energy 115 kV/69 kV substation nearby, enhancing reliability to the load-serving Great River Energy 69 kV system northeast of Taconite Harbor. The Two Islands 115 kV Project was included in the 2021 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-21-111) under tracking number 2021-NE-N1. Construction is expected to begin in 2023 with completion to occur by the end of 2024.

Q. What is the HVDC Line Hardening Project and what will it address?

A. The Square Butte HVDC Line Hardening Project involves targeted structure replacements at critical infrastructure crossings along the existing 465-mile HVDC transmission line between Center, North Dakota and Duluth, Minnesota. The existing original HVDC transmission line structures have proven to be susceptible to failure in extreme weather events. At certain locations—for example, where the HVDC transmission line crosses an interstate highway—existing HVDC transmission line structures will be replaced with robust steel pole structures designed to limit the impact of failures and allow for rapid line restoration. The HVDC Line Hardening Project was included in the 2021 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-21-111) under tracking number 2021-NE-N1. The project is planned to be constructed in blocks (phases) over a four to five year period, with the first two blocks being included in the 2024 test year. The HVDC Line Hardening Project is separate from the HVDC Modernization Project pending before the Commission which, is simply replacement of the two terminals and associated interconnection (Docket Nos. E015/CN-22-607 and E015/TL-22-611).

Q. What is the 40 Line Rebuild Project and what will it address?

A. The 40 Line Rebuild project involves rebuilding the aging Dog Lake – Badoura 115 kV Line (40 Line) with new structures, conductor, shield wire, and optical ground wire ("OPGW"). The project will replace wood poles, conductor, and hardware installed when the line was originally constructed in the 1950s, lower overall system losses, and add utility fiber-optic communication capability that will allow for upgraded relaying and communications equipment. The project was identified and prioritized through Minnesota Power's transmission line asset renewal program, which was still in development during 2021, so it was not reported into the 2021 Minnesota Biennial Transmission Projects Report at the time. The project will be included in the 2023 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-23-91), which is anticipated to be filed on or before November 1, 2023. Construction of the project is anticipated to be complete by the first quarter of 2024.

Q. What is the 907 Line Asset Renewal Project and what will it address?

A. The 907 Line Asset Renewal Project involves targeted structure replacements along the existing 82-mile 230 kV line connecting the Shannon and Littlefork Substations (907 Line) and the section of 230 kV line on the north side of the Littlefork Substation that is owned by the Company. This project is driven by the age and condition of the existing wood poles, many of which are showing signs of unacceptable damage and decay after recent field surveys. The full scope of the project was not identified at the time the 2021 Minnesota Biennial Transmission Projects Report was filed, and therefore the project was not included at that time. The project will be included in the 2023 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-23-91), which is anticipated to be filed on or before November 1, 2023. Construction of the project is anticipated to be completed in early 2024.

Q. What major Externally-Driven Projects are included in the 2023 projected year or 2024 test year?

A. There is only one Externally-Driven Project included for the 2023 projected year—a Great River Energy project that involves building a new substation in the Company's existing Riverton – Cromwell 115 kV transmission line ("Portage Lake 115 kV Project").

Q. What is the Portage Lake 115 kV Project and why is it needed?

A. Great River Energy's Portage Lake 115 kV Project involves building a new 3-position ring bus substation ("GRE Portage Lake Substation") in the Company's existing Riverton – Cromwell 115 kV Line (13 Line). The GRE Portage Lake Substation will include a 115 kV/69 kV transformer that will provide a redundant source into Great River Energy's existing 69 kV system in the area. While this is primarily a Great River Energy project, the Company does have responsibility for constructing the extensions of the existing 115 kV transmission line into the new GRE Portage Lake Substation. This will split the existing 13 Line into two segments, from Riverton – GRE Portage Lake (13 Line) and from GRE Portage Lake to Cromwell (158 Line). The Company is also responsible for upgrading the communication system used for relaying on the transmission line to fiber-optic communications, which will require upgrading existing relay panels and removing old relaying and communications equipment at the Company's Riverton and Thomson Substations. The project was included in the 2021 Minnesota Biennial Transmission Projects Report (Docket No. E999/M-21-111) under tracking number 2019-NE-N15. Construction of the project is anticipated to be completed in 2023.

Q. What Strategic Projects are included in the 2023 projected year?

A. The Strategic Projects included in the 2023 projected year are related to the transition of the Company's baseload coal generation fleet and resource mix. All projects are located in or adjacent to the North Shore Loop and are related to Company decisions to cease coal-fired operation and retire, idle, or convert generators to peaking operation in addition to the decision by Silver Bay Power Company—an external entity—to idle baseload generators at a cogeneration facility in Silver Bay following a contractual agreement with Minnesota Power While there are no projects in the test year related to the future ceasing of coal-fired operations at the Company's Boswell Energy Center ("BEC") Units 3 ("BEC3") and 4 ("BEC4") or the broader regional transmission planning implications of the clean energy transition in MISO as epitomized by the MISO Long Range Transmission Plan ("LRTP") Tranche 1 portfolio, I have included a discussion of the local and regional impacts of these issues for overall transparency and context of the Company's planning efforts.

Q. Are there any Strategic Projects included in the 2024 test year?

A. There are not any Strategic Projects included in the 2024 test year. I will discuss the reasons for this in more detail below. I will discuss some details around the North Shore Loop and Duluth Loop transmission projects, which I also discussed in our 2021 Rate Case, as well as additional Strategic Project drivers for the Company.

Q. What is the North Shore Loop?

A. The North Shore Loop refers to an approximately 140-mile portion of 115 kV and 138 kV transmission lines in the northeastern Minnesota transmission system. The North Shore Loop extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the now retired THEC near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center ("Laskin") near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to serve customers in an area extending from Duluth to the Canadian border to the eastern end of the Iron Range—including east Duluth, Two Harbors, Silver Bay, Grand Marais, Hoyt Lakes, and the surrounding areas. The North Shore Loop transmission system is shown in MP Exhibit ___ (Gunderson), Direct Schedule 2.

Q. How has the North Shore Loop changed in recent years?

A. Historically, the North Shore Loop contained an abundance of coal-fired baseload generation, including Minnesota Power's Laskin Energy Center and THEC, as well as a large industrial cogeneration facility located in Silver Bay. The Silver Bay generators are owned by Silver Bay Power Company, a subsidiary of Cleveland-Cliffs, Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites were idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to natural gas capacity units. Also in 2015, Minnesota Power retired one of the units at THEC.[7]

With Commission approval in the 2015 IRP (Docket No. E015/RP-15-690), Minnesota Power idled the other two THEC units in the fall of 2016 and ceased coal-fired operations at the facility in 2020.[8] The remaining two THEC units were retired in March

[7] *See In the Matter of Minn. Power's 2013-2027 Integrated Res. Plan*, Docket No. E015/RP-13-53, ORDER APPROVING RESOURCE PLAN, REQUIRING FILINGS, AND SETTING DATE FOR NEXT RESOURCE PLAN at 7, Order Point 3 (Nov. 12, 2013).

[8] *See In the Matter of Minn. Power's 2016-2030 Integrated Res. Plan*, Docket No. E015/RP-15-690, ORDER APPROVING RESOURCE PLAN WITH MODIFICATION at 14, Order Point 3 (July 18, 2016).

2023 as approved by the Commission in Minnesota Power's 2021 Integrated Resource Plan, Docket No. E015/RP-21-33 ("2021 IRP").[9] In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, in September 2019, Silver Bay Power Company idled both of the Silver Bay units and began operating with no generators online. The cumulative impact of these operational changes has effectively "decarbonized" the North Shore Loop, leaving no baseload generators normally online in an area of the system that was originally designed in the mid-1900s to support customers with redundant baseload coal generation.

Q. What are the transmission impacts of the transition away from local baseload generators in the North Shore Loop?

A. The local baseload generators at Laskin, THEC, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing redundancy, voltage support, and power delivery capacity, among other things. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016, with implementation of additional projects continuing through the 2024 test year. These projects are necessary to ensure the continued reliability of the transmission system in the area by replacing the inherent redundancy that was lost with the idling and retiring of multiple coal fired generation units, addressing unacceptably low voltage and voltage stability concerns, and mitigating transmission line and transformer overloads. The projects have been progressively implemented throughout the transition of the North Shore Loop generators to ensure that the right projects are implemented at the right time to support the continued reliable operation of the transmission system. Where project implementation timelines were difficult to align with fleet transition decisions, the Company took the necessary steps to ensure operating guides or temporary solutions were implemented to support transmission reliability.

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[9] *See In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, ORDER APPROVING PLAN AND SETTING ADDITIONAL REQUIREMENTS at 6, Order Point 13 (Jan. 9, 2013).

Q. What has the Company concluded from its evaluations of the transmission impacts from shutting down local baseload generators?

A. The transmission system is designed to be highly reliable and redundant, yet affordable. Where local baseload generators have provided reliability services to the local transmission system for many years, the transmission system is designed to rely on the local baseload generators being online. As long as the baseload generators were around to provide these reliability services, the cost of transmission upgrades that would decrease reliance on the generators was difficult to justify. With the removal of the local baseload generators, the transmission system in the surrounding area will require some modifications in order to offset the loss of the reliability services formerly provided by the generators. The more dependent the transmission system was on the generators, the more significant the upgrades are likely to be. In the case of the North Shore Loop, the Company found that the transmission system was dependent on the local baseload generators. Where the cost of transmission upgrades to decrease reliance on the local baseload generators was difficult to justify while the generators were running, those network upgrade costs are now necessary due to the series of generation fleet transition decisions that have taken place since 2015.

Q. What projects has Minnesota Power implemented to address fleet transition in the North Shore Loop, and what issues do these projects resolve?

A. Between 2016 and 2023, Minnesota Power has implemented, or is in the process of implementing, several projects throughout and adjacent to the North Shore Loop transmission system to address system impacts from fleet transition. These projects:

- Strengthen and increase the capacity of existing 230 kV/115 kV sources and transmission lines supplying the North Shore Loop;
- Replace the voltage regulation and voltage support capability formerly provided by the local baseload generators with new capacitor banks and a new static synchronous compensator; and
- Restore redundancy by eliminating single points of failure and establishing additional 115 kV transmission connections to the North Shore Loop.

The 2023 projected year specifically includes the Mesaba Junction 115 kV Project and the Laskin – Taconite Harbor Voltage Conversion Project.

Q. Are there any other North Shore Loop-related projects that will be underway in 2024?

A. Yes. The Duluth Loop Project[10] will also incur spending in 2023 and 2024, but the project is expected to be included in the TCR. The Duluth Loop Project and the TCR are both discussed in subsequent sections.

Q. What is the Mesaba Junction 115 kV Project and what will it address?

A. The Mesaba Junction 115 kV Project involves the development of a new "Mesaba Junction" switching station interconnected to existing transmission lines in the Hoyt Lakes area in conjunction with the construction of the "38 Line Extension" consisting of approximately 5.4 miles of new 115 kV transmission along the existing Laskin – Hoyt Lakes ("38 Line") transmission line corridor to extend the existing 38 Line into Mesaba Junction.

Together, the Mesaba Junction 115 kV Project and the 38 Line Extension Project provide a third transmission source to the North Shore Loop to support redundancy, enhance reliability by providing a modern utility-controlled path for power flow into the North Shore Loop, and continue the process of offsetting the loss of voltage support and power delivery capacity formerly provided by local baseload generators in the North Shore Loop. The Mesaba Junction 115 kV Project, including the 38 Line Extension Project, has been reported in the Minnesota Biennial Transmission Projects Report since 2017 under tracking number 2017-NE-N23 (formerly as the "Hoyt Lakes 115 kV Project"). The first phase of the Mesaba Junction 115 kV Project, in which the new Mesaba Junction Switching Station was constructed, was completed in 2020.

[10] *In the Matter of the Application of Minn. Power for a Certificate of Need for the Duluth Loop Reliability Project*, Docket No. E015/CN-21-140, APPLICATION FOR A CERTIFICATE OF NEED AND ROUTE PERMIT (Oct. 21, 2021); *Notification of Intent to File a Route Permit Application for the Duluth Loop Project Pursuant to the Alt. Permitting Process*, Docket No. E015/TL-21-141, APPLICATION FOR A CERTIFICATE OF NEED AND ROUTE PERMIT (Oct. 21, 2021).

Construction on the 38 Line Extension Project and the second phase of the Mesaba Junction 115 kV Project was completed in 2022. Final connections to the Mesaba Junction Switching Station will be completed in coordination with construction of the Laskin – Taconite Harbor Voltage Conversion Project in 2023.

Q. What is the Laskin – Taconite Harbor Voltage Conversion Project and what will it address?

A. The Laskin – Taconite Harbor Voltage Conversion Project involves converting the legacy 138 kV system between the Laskin and Taconite Harbor substations to 115 kV operation. The Project includes removing 138 kV/115 kV transformers, replacing 138 kV equipment with 115 kV equipment, establishing a new transformer and feeder at the Skibo Substation, and replacing other aging equipment at the existing Laskin, Skibo, Hoyt Lakes, and Taconite Harbor substations. The project also includes minor upgrades to the existing transmission lines between Laskin, Mesaba Junction, and Taconite Harbor to increase their rated capacity when operating at 115 kV. The Laskin – Taconite Harbor Voltage Conversion Project enhances the reliability of the transmission system by eliminating single points of failure with long replacement lead times (138 kV/115 kV transformers) and providing a more redundant and reliable transmission connection for the North Shore Loop. In addition to these reliability benefits, the Project achieves the inherent benefits of replacing aging equipment, eliminating a non-standard voltage class (138 kV) from the Company's transmission system, and avoiding the cost of additional 138 kV/115 kV transformers for redundancy, replacement, or the establishment of new transmission connections (such as the 38 Line Extension mentioned above). The Laskin – Taconite Harbor Voltage Conversion Project has been reported in the Minnesota Biennial Transmission Projects Report since 2017 under tracking numbers 2017-NE-N2 and 2017-NE-N21. Construction of the Laskin – Taconite Harbor Voltage Conversion Project is being coordinated with the 38 Line Extension Project and the Mesaba Junction 115 kV Project and is planned for completion in 2023.

Q. Please describe the Duluth Loop, generally.

A. Although the Duluth Loop Project is anticipated to be placed in the TCR and no capital additions related to this project are included in the test year plant in-service, the Duluth Loop Project is a part of the North Shore Loop transmission impacts and will be in progress in 2023 and 2024.

The Duluth Loop is a network of 115 kV transmission lines and substations at the south end of the North Shore Loop which form two parallel connections between the 230 kV/115 kV transmission source at the Arrowhead Substation and the North Shore Loop connection at the Colbyville Substation. Many customers in the Duluth area are served from substations connected to the Duluth Loop—including customers in Hermantown, Duluth Heights, Kenwood, Woodland, Lakeside, Hunter's Park, and Congdon—as well as the areas around the Miller Hill Mall, the Duluth International Airport, the universities, and the downtown hospital district, among others.

Q. Can you provide additional information about the Duluth Loop Project and why it is needed?

A. Yes. The Duluth Loop Project includes: (1) construction of about 14 miles of new 115 kV transmission line between the Ridgeview, Haines Road, and Hilltop Substations; (2) construction of a new one-mile extension connecting an existing 230 kV transmission line to the Arrowhead Substation; (3) upgrades to the Ridgeview, Hilltop, Haines Road, and Arrowhead substations; and (4) reconfiguration, rebuild, and upgrade to existing transmission lines and communications infrastructure in the project area. The Duluth Loop Project is needed to replace the system support once provided to this area by coal-fired baseload generators located along Minnesota's North Shore. The Duluth Loop Project will address severe voltage stability concerns, relieve transmission line overloads, and enhance the reliability of Duluth-area transmission sources—all of which are needs that have resulted from the retirement of these generation sources.

The Duluth Loop Project has been reported in the Minnesota Biennial Transmission Projects Report since 2019 under tracking number 2019-NE-N12, and a combined Certificate of Need and Route Permit Application for the Project was submitted to the Commission under Docket Nos. E015/CN-21-140 and E015/TL-21-141, respectively, on October 21, 2021, and deemed complete on December 14, 2021. The Commission subsequently granted the Certificate of Need and Route Permit for the Duluth Loop Project on April 3, 2023. Test year activities for the project include engineering, procurement, and initiation of construction activities. Construction of the Duluth Loop Project began in September 2023, with targeted completion of the project in 2026.

Q. Do the projects included in this rate case and discussed in your testimony address all of the transmission system investments associated with fleet transition in the North Shore Loop?

A. The projects discussed in my testimony and projects implemented prior to the 2024 test year encompass the full portfolio of North Shore Loop projects identified by the Company. The North Shore Loop projects implemented in earlier years generally represented the most urgently required transmission system improvements. They addressed single-contingency issues that were either high-impact, high-likelihood, or both. These types of issues must be addressed proactively in order to continue to operate reliably on a day-to-day basis with no North Shore Loop generators online.

While the last remaining baseload generating unit in the North Shore transitioned to a normally offline status in September 2019 and the THEC units ceased coal-fired operation in 2020, projects like the Mesaba Junction 115 kV Project and Laskin – Taconite Harbor Voltage Conversion have been in a process of implementation that will see completion when they are placed in service in 2023. These projects generally address lost redundancy and related voltage or power delivery issues associated with multiple contingency events, for which either the risk profile is less severe than the single contingency issues mentioned above and/or the Company was able to devise temporary operational solutions to manage the risk, thus allowing sufficient time to implement long-term solutions.

The Duluth Loop Project, which will not be fully implemented until 2026, is similar to these in that it addresses issues of redundancy for which a long-term solution is necessary, but short-term impacts are able to be managed—with increased risk due to the lost support from the generators—until the long-term solution may be implemented. The Duluth Loop Project will be the final transmission project directly related to the impacts of fleet transition in the North Shore Loop.

Q. What additional Strategic Project drivers has the Company identified as it prepares for the future of transmission grid needs?

A. In addition to the transmission planning practices and projects discussed so far in my testimony, several areas of additional study, coordination, and project development are currently taking place to prepare for the future of transmission grid needs. The Company's 2021 IRP highlighted the extensive study work that the Company has undertaken to begin to understand the transmission impacts associated with changing operations of BEC3 and BEC4, which are the last remaining baseload generators on the Company's system and in all of Northern Minnesota. On a regional level, the Company is an active participant with MISO in the LRTP effort and is in the process of developing the Northland Reliability Project, a LRTP Tranche 1 project, jointly with Great River Energy. The Company has also recently made significant progress toward the modernization of its existing HVDC converter stations to provide reliable renewable energy transfer capability and grid support for decades to come. Finally, the Company continues to work with its neighboring utilities on transmission planning initiatives that will be foundational to meeting the long-term needs of an evolving regional electric grid. These particular projects are not included in the 2024 test year but are discussed in my Direct Testimony to give an idea of the types of projects that the Company considers "Strategic."

Q. What information is provided in the Company's 2021 IRP related to transmission impacts resulting from the changing operations of BEC3 and BEC4?

A. In its 2021 IRP and the Baseload Retirement Study included with the 2021 IRP, the Company described the significance of the BEC units and the support that they provide to the Northern Minnesota transmission system. The Company's conclusions about the BEC units in the 2021 IRP are described as "six pillars that are key to understanding the significance of BEC to the region and the transmission system impacts from changing operations at BEC."[11] The six pillars are informed by recent experience from the transition of smaller coal units in the North Shore Loop and the Grand Rapids area, as discussed previously in my testimony and in greater detail in Appendix F, Part 6 of the 2021 IRP. The six pillars are also informed and supported by a number of studies that have evaluated various types of transmission impacts associated with changing operations of the BEC units. The supporting transmission studies are described in the 2021 IRP, and an overview of conceptual solutions and costs for issues related to different types of changes in operation of the BEC units is also provided.

Q. Are any transmission projects related to the changing operations of BEC3 and BEC4 included in the 2024 test year?

A. No. The Company continues to evaluate the scope and timing of projects necessary to support continued reliable operation of the local transmission system as BEC3 and BEC4 cease coal-fired operations in 2030 and 2035, respectively. The resulting projects are expected to begin implementation in 2025 or later as needed. The Northland Reliability Project, discussed below, will address regional voltage and transfer capability concerns related to the ceasing of coal-fired operations at BEC.

Q. Is all of the transmission planning related to this fleet change complete?

A. No. As noted in Appendix F, Part 8 of the 2021 IRP, there is a "considerable amount of work left to understand and develop long-term solutions to the transmission issues

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[11] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, APPENDIX F at 40 (Feb. 1, 2021).

discussed in [Appendix F,] Part 7."[12] The Company continues this work, advancing transmission studies and projects that build upon the analysis presented in the 2021 IRP to identify and develop appropriate solutions that can be inserted into the Company's transmission plan and implemented at the appropriate time to prepare the transmission system for eventual changes in operations of the BEC units. The Company's internal efforts in this area are also being coordinated with neighboring utilities directly and through the regional MISO LRTP and Grid North Partners efforts. In summary, the Company has been—and continues to be—very engaged in proactively planning for the long-term transmission needs of its customers and the Northern Minnesota region, and it is expected that continued investment in the transmission system will be necessary to ensure the long-term reliability of the system as the local and regional generation fleet continues to evolve.

Q. What is the MISO LRTP?

A. As described earlier in my testimony, MISO conducts and Minnesota Power contributes to an annual MTEP reliability study process. Periodically, MISO also conducts additional transmission studies to look more broadly at long-term transmission needs, focusing on the big picture of regional and interregional infrastructure. In 2020, MISO announced it would begin an LRTP effort as part of a broader Reliability Imperative. Increasing renewable generation, continuing retirements of conventional baseload generation, and expected changes in load through electrification will bring challenges to the reliability of the transmission system. MISO's LRTP is a multi-year initiative to develop potential transmission solutions for those challenges, starting from a base of the utility and state plans on where to site new resources and continuing to look at more aggressive decarbonization and electrification future scenarios to proactively identify, evaluate, and advance the transmission necessary to support the future grid. MISO approved the first "tranche" of regional LRTP projects on July 25, 2022 ("Tranche 1"). The LRTP Tranche 1 portfolio consists of 18 individual 345 kV transmission line projects spread across the Upper Midwest totaling over $10.3 billion estimated cost in

[12] *In the Matter of Minn. Power's 2021-2035 Integrated Res. Plan*, Docket No. E015/RP-21-33, APPENDIX F at 56 (Feb. 1, 2021).

2022 dollars. Once constructed, the Tranche 1 portfolio is expected to provide quantifiable benefits to the region on the order of 2-4 times its cost over the coming decades.

In early 2023, MISO initiated formal stakeholder workshops to begin to develop LRTP Tranche 2, which will also focus on the Upper Midwest. The Tranche 2 portfolio will address significantly higher renewable penetration levels than the Tranche 1 portfolio and is therefore expected to be considerably larger than Tranche 1.

Minnesota Power is actively engaged in MISO's LRTP initiative. Multiple employees attend LRTP-related presentations, committee meetings, and workshops to keep abreast of activities. In addition, Minnesota Power engineers review and provide feedback on MISO's published models and meet with MISO's transmission planning engineers to discuss concerns specific to northern Minnesota and the interests of Minnesota Power's customers. Minnesota Power also coordinates with neighboring utilities on future transmission needs directly and through its involvement in Grid North Partners.

Q. What is Grid North Partners?

A. Grid North Partners (an evolution of the CapX2020 Initiative) is a group of ten investor-owned and not-for-profit cooperative and municipal utilities working together to ensure continued safe, reliable, and affordable electric service to their customers in the Upper Midwest. Minnesota Power has been a member of this collaborative organization since its inception in 2004.[13]

As the electric grid continues to transition, Minnesota Power will continue to cooperate and communicate with neighboring utilities, MISO, and organizations like Grid North Partners to bring cost-effective solutions that maintain reliability for customers.

[13] *CapX2050 Transmission Vision Report*, CapX2020 (Mar. 2020), https://gridnorthpartners.com/wp-content/uploads/2021/02/CapX2050_TransmissionVisionReport_FINAL.pdf; *Finding True North Conference*, Grid N. Partners (June 16, 2021), https://gridnorthpartners.com/conference/.

Q. Is the Company involved in any of the LRTP Tranche 1 projects?

A. Yes. The Company is jointly responsible with Great River Energy for the permitting, development, and construction of LRTP Project #3 (the Northland Reliability Project) (Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415). The Company is also a part owner of one segment of LRTP Project #2 (the Big Stone South – Alexandria – Big Oaks 345 kV Transmission Line Project) (Docket Nos. E017, ET2, E002, ET10, E015/CN-22-538 and E002, ET2, ET10, E015, E017/TL-23-159).

Q. What is the Northland Reliability Project and what does it address?

A. The Northland Reliability Project consists of two major segments totaling approximately 180 miles. Segment 1 includes construction of a new, approximately 140-mile long, double-circuit 345 kV transmission line connecting the existing Iron Range Substation, a new Cuyuna Series Compensation Station, and the existing Benton County Substation. Segment 2 includes replacement of two existing, approximately 20-mile, high-voltage transmission lines south of the Benton County Substation with new double-circuit 345 kV structures. The project also involves expansions of the existing Iron Range and Benton County Substations and the establishment of a new Cuyuna Series Compensation Station near the existing Riverton Substation.

The Northland Reliability Project is needed to maintain transmission system reliability as coal-fired generation ceases operations in northern Minnesota and significant renewable generation comes online in the region. The project was studied and approved by MISO as part of the LRTP Tranche 1 Portfolio. The Northland Reliability Project had not been identified and approved by MISO at the time of the 2021 Minnesota Biennial Transmission Projects Report. The Company and Great River Energy jointly filed a combined Certificate of Need and Route Permit Application for the project on August 4, 2023 (Docket Nos. E015,ET2/CN-22-416 and E015,ET2/TL-22-415). Construction of the project is anticipated to start in 2025 with a targeted in-service date of June 2030. The Northland Reliability Project is anticipated to be placed in the TCR and no capital additions related to the project are included in the 2024 test year plant in-service.

Q. What is LRTP Project #2 and how is the Company involved?

A. LRTP Project #2, also known as the Big Stone South – Alexandria – Big Oaks 345 kV Transmission Line Project, consists of a new 345 kV transmission line between Big Stone City, South Dakota and Sherburne County, Minnesota, which will be comprised of two segments. The Western Segment will run from the existing Big Stone South Substation near Big Stone City, South Dakota to the existing Alexandria Substation near Alexandria, Minnesota. The Eastern Segment will continue on from the existing Alexandria Substation to a new Big Oaks Substation in Sherburne County, Minnesota (Alexandria – Big Oaks Project). The majority of the Eastern Segment will include adding a second set of wires that will be strung on existing transmission line structures, except for a short extension of new construction to connect the new 345 kV transmission line to the new Big Oaks Substation. This second circuit was originally considered as part of the CapX2020 Certificate of Need issued in 2009 (Docket No. ET2, E002, et al./CN-06-1115) by the Commission and studied as part of the Minnesota Renewable Energy Integration and Transmission Study in 2014.[14] Through its participation in the CapX2020 Fargo Project, the Company is a part-owner of the existing transmission line structures which will be modified to accommodate the Eastern Segment, and therefore the Company will also be a part-owner of the project. The entire project was studied, reviewed, and approved by MISO as part of the LRTP Tranche 1 portfolio. The project had not been identified and approved by MISO at the time of the 2021 Minnesota Biennial Transmission Projects Report.

Northern States Power Company, along with the Company, Great River Energy, Ottertail Power Company, and Western Minnesota Municipal Power Agency, jointly filed a Certificate of Need Application for the entire project on September 29, 2023 (Docket Nos. E017,ET2,E002,ET10,E015/CN-22-538). The Certificate of Need Application was also combined with a Route Permit Application for the Eastern Segment of the project (E002,ET2,ET10,E015,E017/TL-23-159) filed on September 29,

[14] Minnesota Renewable Energy Integration and Transmission Study (Oct. 31, 2014) *available at* https://mn.gov/commerce-stat/pdfs/mrits-report-2014.pdf.

2023. A Route Permit Application for the Western Segment of the project will be filed at a later date. The targeted in-service date for the entire project is June 2030. The Alexandria – Big Oaks Project is anticipated to be placed in the TCR and no capital additions related to the project are included in the 2024 test year plant in-service.

Q. Is the Company involved in any other regionally-significant transmission projects?

A. Yes, the Company has spent many years evaluating options for the modernization of the HVDC converter stations on each end of its existing Square Butte HVDC line ("HVDC Line") and submitted a combined Certificate of Need and Route Permit Application for the HVDC Modernization Project (Docket Nos. E015/CN-22-607 and E015/TL-22-611) on June 1, 2023. The Commission found that the application was complete on August 8, 2023.

Q. What is the HVDC Modernization Project and what does it address?

A. The HVDC Modernization Project involves modernizing and upgrading both HVDC converter stations for the 465-mile-long HVDC Line and interconnecting the upgraded HVDC converter stations to the existing AC transmission system. These HVDC converter stations are currently located near the Arrowhead Substation in Hermantown, Minnesota and the Center Substation in Center, North Dakota. To modernize the HVDC terminals and implement the latest in grid-supporting voltage source converter ("VSC") HVDC technology, new buildings and electrical infrastructure need to be constructed on a new site near the existing HVDC terminals. New 345 kV and 230 kV AC transmission facilities will be constructed to facilitate the interconnection of the new VSC HVDC converter station to the existing AC transmission system.[15] The Company was included in legislation in the 2023 session to receive $15 million for the HVDC Modernization Project, as proposed. On October 18, 2023, the Company was informed that this project could receive a $50 million grant from the U.S. Department of Energy.

[15] *See* line 293.15 in HF No. 2310, Conference Committee Report - 93rd Legislature.

The HVDC Modernization Project is needed to modernize aging HVDC assets that are critical to the grid, continue to position the grid for the clean energy transition, and improve the reliability of the transmission system in Minnesota and North Dakota. In addition to the replacement of the existing HVDC converter stations, the new VSC HVDC technology implemented for the Project will be designed to provide voltage regulation, frequency response, blackstart capability, and bidirectional power transfer capability, all of which will enable Minnesota Power and the region to continue to support its clean energy transition reliably. The need for the HVDC Modernization Project has been reported in the Minnesota Biennial Transmission Projects Report since 2013 under tracking numbers 2013-NE-N16 and 2013-NE-N17.

The Company anticipates starting construction in late 2024 and placing the Project in service between 2028 to 2030. The HVDC Modernization Project is anticipated to be placed in the TCR and no capital additions related to the project are included in the 2024 test year plant in-service.

C. <u>Distribution Capital Investments and Projects</u>

Q. How is Minnesota Power categorizing Distribution capital project information in this rate case?

A. Minnesota Power has adopted the categories outlined in the IDP, filed on October 16, 2023 (Docket No. E015/M-23-258), for purposes of discussing the Company's Distribution capital. 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 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.

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 capital spending addresses asset replacements that are generally age-related. Some of these replacements are identified through inspection programs, such as ground-line or pole maintenance inspections, while some are in response to difficult-to-predict failures. Past practice and historical averages inform the 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 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 funnel that work automatically into our work management system. At the transmission-to-distribution substation level, previously unconnected asset renewal programs have been integrated into a single substation modernization program designed to efficiently and holistically address all of the asset renewal needs at a site with one comprehensive project.

Projects may also be identified through system modeling and analysis. Distribution planning performs baseline system analysis on the distribution system, generally in conjunction with the planning of substation modernization or feeder automation projects. The types of projects identified through this means 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. Are there strategic projects in the Distribution capital budget?

A. Yes. There are a number of strategic projects in the Distribution capital budget as well. These are identified as part of broader strategic Minnesota Power initiatives that directly benefit the Company's customers. An example of a strategic project would be the Company's state-leading deployment of AMI, a multi-year concerted effort that has already resulted in numerous customer benefits discussed in Section V.B.1 of my Direct Testimony. The addition of AMI radio poles for the expansion of our radio system to achieve a 98 percent coverage design is another example of a strategic project in the Distribution capital budget that has started in 2023 and will continue through 2024.

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

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

The long-range plan generally utilizes historical spending to establish amounts for routine 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, a fair amount of 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. Some age-related replacements and asset renewal projects are planned in advance and implemented proactively as engineers identify and prioritize age- and condition-based replacements or areas prone to failure based on reliability metrics and feedback from field crews. Other Age Related Replacements and Asset Renewal Projects are implemented in response to unanticipated failures. Engineering expertise helps prioritize proactive age-related and asset renewal efforts. In some cases, the Company experiences a number of failures in a certain area of the system or with a particular type of asset, and these failures inform where to direct capital spending. However, some Age Related Replacements 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.

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 Replacement and Asset Renewal Projects in the 2024 test year?

A. Ground-line restoration is an example of an Age Related Replacement and Asset Renewal Project on the distribution system. Ground-line inspections are conducted on every distribution pole over a ten-year period. External contractors visit the poles throughout the year, excavate the base of the poles, and test the shell thickness of the pole to determine if the pole is at the end of its useful life. Engineering then reviews the results and remediates all issues found. The ground-line program was improved starting in 2022, as discussed below.

The modernization of the existing Long Prairie 115 kV/34.5 kV Substation, Canosia Road Substation Expansion, and 15th Avenue West Transformer Addition are examples of Age Related Replacement and Asset Renewal Project at the transmission-to-distribution substation level. These projects are also discussed below.

Q. How has the ground-line program improved since 2022?

A. In 2022, Minnesota Power kicked off the first year of a more extensive ground-line inspection program to help prolong the life of poles as well as proactively catch and remedy more "reject" poles before they fail and cause outages. The inspections vary depending on the age and species of the pole being inspected. Each pole will either receive a visual, sound and bore, a partial excavation, or a full excavation. Each passing pole is treated to prevent or stop decay and to deter insects if needed. Poles that fail are added to a queue for truss installation or complete replacement. Of the roughly 9,000 poles that were inspected in 2022, about 2.7 percent were rejected. This number is lower than initially expected; however, the Company could see vast differences year-to-year depending on the areas being inspected, age of the pole plant, and soil type in that region.

Q. What is the Long Prairie Substation Modernization Project, and what will it address?

A. The Long Prairie Substation Modernization Project involves replacing aging electrical equipment, structures, and civil work at the existing Long Prairie 115 kV/34.5 kV Substation. Much of the original equipment at the Long Prairie Substation is nearing or beyond the end of its useful life, including transformers, circuit breakers, disconnect switches, and site infrastructure. In addition to these asset renewal needs, the Project addresses distribution reliability needs including transformer overloads and low 34.5 kV system voltages under certain outage conditions. Multiple substation asset renewal needs were combined into one project that also provides the needed reliability improvements in order to facilitate efficient coordination of engineering and construction. The Long Prairie Substation Modernization Project is a predominantly distribution project that also involves 115 kV transmission modifications. The Project is part of the Company's Substation Modernization Program, which is intended to identify and prioritize holistic substation modernization Asset Renewal Projects.

Q. What is the Canosia Road Substation 34.5 kV Expansion, and what will it address?

A. The Canosia Road Substation 34.5 kV Expansion involves expansion of the existing Canosia Road Substation to accommodate a new 115 kV/34.5 kV transformer, as well as extension of a new 34.5 kV feeder from Canosia Road to the existing Scanlon 24 kV/14 kV Substation. A new Cloquet East Side 34.5 kV/14 kV step-down will be established near the Scanlon Substation, and the existing 24 kV system will be updated and converted to 34.5 kV from Scanlon to the existing step-downs at Moorhead Road and Sawyer. The Moorhead Road and Sawyer step-downs will also be replaced in coordination with the project. New fiber optic communications will be routed in conjunction with the new and converted 34.5 kV feeder to enhance visibility and control of the distribution system in the area and prepare for a future fault location, isolation, and system restoration ("FLISR") project once 34.5 kV is established to the Mahtowa Substation on the other end of the local area backbone distribution system. The Canosia Road Substation 34.5 kV Expansion will be the first step and foundation in a multi-year plan to modernize and improve the Cloquet-area distribution system.

Q. What is driving the need for the Canosia Road Substation 34.5 kV Expansion?

A. There are several factors driving the need for improvements in the Cloquet area:

1) Asset Renewal and Standardization: The project will continue implementation of a standard 34.5 kV backbone distribution network for the Duluth/Cloquet area. There are presently three different backbone distribution voltages between Duluth, Cloquet, and Hinckley. The Canosia Road 34.5 kV Expansion and subsequent projects will convert existing 24 kV and 46 kV systems to 34.5 kV while addressing asset renewal needs for existing feeders and step-downs associated with these systems;
2) System Capacity and Asset Renewal Project Constructability: The project will enable a comprehensive Cloquet Substation Modernization Asset Renewal Project to take place. The Cloquet Substation is one of the highest-priority asset renewal sites in the Minnesota Power system, but the distribution system lacks sufficient capability to reliably support the Cloquet area during the extended outage of the Cloquet Substation that would be needed to implement the Asset Renewal Project; and
3) Reliability and Grid Modernization: The project will improve reliability for Cloquet-area customers by reducing feeder exposure, providing backup capability from new feeders and 34.5 kV/14 kV step-downs, and enabling feeder automation projects to be implemented for enhanced visibility and rapid system restoration.

The Canosia Road Substation 34.5 kV Expansion Project is a predominantly distribution project that also involves 115 kV transmission additions at the existing Canosia Road Substation.

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. Many projects provide benefits in all three areas, and identifying the primary category for such projects is not a precise exercise. A project with a strong reliability component, such as reconductoring a section of feeder to a tie switch to ensure adequate backup capability for planned or unplanned outages, might also increase the capacity of the feeder. Although the main purpose of the project is to reliably serve load from another source during an outage, there is an inherent increase in capacity gained as well. The very same project may also involve the replacement of end-of-life poles and conductor, thus achieving a strong asset renewal benefit at the same time. 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. Upgrades for Capacity 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.

Q. What is an example of a System Expansion or Upgrade for Capacity in this rate case?

A. Relatively few projects in the 2024 test year are driven solely by a need for increased system capacity, but many projects address capacity-related needs in addition to other needs. Examples are the systematic upgrade of the 46 kV system between Winton, Babbitt, Tower, and Virginia (*i.e.*, Tower-Ely-Babbitt 69 kV Conversion). All of these projects also have strong reliability, age and condition, and even grid modernization components to them.

Q. What is the Tower-Ely-Babbitt 69 kV Conversion, and what will it address?

A. The Tower-Ely-Babbitt 69 kV Conversion involves upgrading all 46 kV lines between the Tower, Winton, and Babbitt Substations from 46 kV to 69 kV distribution standards and then converting the entire system over to 69 kV operation by upgrading the substations and transformers. Many increments of project construction will take place over several years before the shift to 69 kV operation can be fully realized. 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. In the 2024 test year and extending into 2025, the existing 46 kV line from Winton to Ely ("33 Line") will be rebuilt to 69 kV standards. Rebuilding the 33 Line will be the first step and foundation in this multi-year plan to modernize and improve the bulk distribution system between Tower, Ely, and Babbitt.

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 a potential reliability improvement. 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 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 2024 test year?

A. The strategic undergrounding program across the service territory is the largest Upgrade for Reliability and Power Quality program going on for the next several years. This project impacts a number of IDP categories including Age Related and Asset Renewal, Capacity Upgrades, and Upgrades for Reliability. The strategic undergrounding program is described more fully in Section V.A of my Direct Testimony.

An example of a Power Quality improvement project is the rollout 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.

Q. What are New Customer Projects and New Revenue?

A. New Customer Projects and New Revenue includes construction of distribution line extensions to serve new customer load. Most new customer projects result in new (*i.e.*, increased) revenue to the Company. A small number of customer projects are revenue neutral. Most line extension costs are driven by the distance from existing facilities to the new service point. Line extensions are made in accordance with the Company's Electric Service Regulations and Commission-approved tariffs. The extension rules specify an allowance (*i.e.*, credit) for each rate class. Extension costs that exceed the allowance are paid by the customer or may be covered by a guaranteed annual revenue agreement (excluding single-phase services) if the customer enters into a five-year electric service agreement.

Q. What are the main drivers for New Customer Projects?

A. The Company has an obligation to serve new load within our service territory, and the main drivers for New Customer and New Revenue Projects are customer requirements. While overall residential and commercial kWh energy sales are relatively flat across the service territory, construction spending for customer and revenue projects has remained stable for nearly ten years.

Q. How have New Customer Projects been affected since the COVID-19 pandemic?

A. Supply chain and inflationary increases continue to affect customers after the pandemic. Customers have seen delays in connecting new load as a result of supply chain issues such as transformers and meter pedestals. Customers h ave also noticed increased extension costs related to inflationary increases due to material and labor.

Q. What are examples of New Customer Projects?

A. New customer projects and new revenue are limited to line extensions on the Company's Distribution System. Over the last two years, on average, new connects are 26 percent commercial, 72 percent residential, one percent municipal and one percent industrial.

Over the two-year period of 2021 and 2022, there was an annual average of 1,813 work orders written for new customer connects. Streetlights and area lights are also considered line extensions, but instead of being metered, they provide fixed revenue per fixture. In addition, there are customer projects that do not result in any increased sales (*i.e.*, revenue). For example, a customer requests an extension to a new service point but is going to retire the existing connection to the system and is not adding new load. The new extension is revenue neutral (*i.e.*, no net sales increase or decrease).

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 but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These 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. Most often, this involves the deployment of more intelligence on the distribution system such as line sensors, motor operated switches, automatic switches, fault indicators, trip savers, and reclosers. The Company is also in the process of rolling out a multi-year plan to install smart switches (*i.e.*, IntelliRupters) and the associated communications infrastructure improvements in strategic locations on the distribution system. Increased information from the distribution system helps improve customer communications and reliability of service.

Minnesota Power is planning to make significant investments to modernize the Distribution grid over the next decade as described more fully in the 2023 IDP. In general, increased spending will be focused on grid modernization, strategic undergrounding, and pilot projects. Current plans include drastically increasing the number of FLISR devices installed on the system as noted above. The implementation has currently started on the remote motor operated switch pilot to increase reliability in areas further from service centers by enabling system operators to remotely operate switches to isolate a faulted section of feeder and restore service to as many customers as possible. The pilot includes using the existing radio system to provide status and control to the devices. The Company continues its strategic undergrounding initiative in 2023 and 2024. Eighteen projects have been engineered and are currently being worked on throughout the Central and Western service areas.

Q. How does the Company evaluate grid modernization investments?

A. Grid Modernization Projects are efforts that augment the Company's baseline efforts to maintain safe, reliable, and affordable energy, but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. Grid modernization is and has been a priority for Minnesota Power, and the Company has developed a plan to modernize the system and ensure reliability of service. With many assets more than 40 years old, asset management programs and investments have become an area of significant focus for the Company. Asset renewal programs have been bolstered in recent years in an effort to target areas known or likely to impact customer reliability and system resiliency. Minnesota Power has taken a strategic approach that targets key feeder and substation connected assets that are both at end-of-life and contributing negatively to reliability. At the substation level, programs have been integrated into a single substation modernization project designed to efficiently address all of the asset renewal needs at once. Reliability improvements will continue to be implemented using equipment such as TripSavers, storm hardening the system via strategic undergrounding, and using FLISR technologies utilizing a secure fiber-optic network to quickly isolate and restore customers through the use of IntelliRupters, intelligent reclosers, smart sensors, and motor operated equipment. The Company will expand the use of TripSavers, which are maintenance free and significantly lower cost than traditional oil filled reclosers that have been historically used for similar applications. TripSavers are also being installed to replace cutouts, including porcelain fused cutouts that have a poor reliability history. TripSavers will clear temporary faults, resulting in improved reliability and reduced incidents requiring a line worker to be dispatched to restore an outage. The Company is also piloting solid-dielectric vacuum 30 reclosers to replace the traditional oil-filled reclosers. These new reclosers do not require maintenance and should eliminate potential environmental incidents since they no longer have any oil to retire.

Q. Please explain 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. Minnesota Power is currently working on a micro-grid battery pilot project as a non-wires alternative to building new lines into remote areas of the service territory. Preliminary plans for this pilot include approximately three megawatt-hours ("MWh") of storage connected to the Kerrick 12.5 kV distribution system operating as a redundant source.[16]

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 requires close internal coordination across many departments, some of which have not previously needed to be involved with the planning, construction, and

[16] Docket No. E015/M-23-258.

operation of the distribution 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 Grid Modernization and Pilot projects can be found in the Company's 2023 IDP.

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

A. The main drivers for Grid Modernization and Pilot Projects are reliability, safety, cost savings, increasing 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 that have lower reliability performance, as the benefit to customers is greater on underperforming systems. This increased knowledge is used to improve reliability and provide better information to our customers during an abnormal event.

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 relocation of 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. This category has tripled in spend over the last few years due to the addition of Americans with Disabilities Act ("ADA") compliant sidewalks, bike and walking trails, and road moves increasing every year. The rural nature of Minnesota Power's service territory is much more likely to have unplanned projects executed in short time frames to align with legislative schedules and the short construction season in northern Minnesota.

Q. What are Metering Projects?

A. Metering Projects are related to the procurement, installation, and communications of energy measurement technologies used for financial transactions. Minnesota Power will be finishing the initial deployment of AMI meters in 2023. AMI communications infrastructure upgrades are planned for 2023 and 2024. These upgrades are in preparation of the next generation of AMI meters that allow for more communications channels and enhanced alarming. Once available, these next generation AMI meters will be deployed on new services and to replace failed first generation AMI meters.

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 app;
- Reduced billing estimations when compared with the legacy Automated Meter Reading ("AMR") system;
- Support billing of 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;
- Integration of AMI and the Outage Management System ("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 support 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/reconnect capability. This technology is being deployed on a limited basis through Minnesota Power's Reconnect Pilot Program, described in Docket No. E015/M-19-766. The Company estimates up to ten percent or approximately 12,250 residential customers will have remote capable AMI meters and be eligible for this Pilot.

Q. What are the Distribution "Other" projects?

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

D. <u>Other Capital Projects</u>

Q. What other categories of capital additions are listed in Table 1?

A. The Company also has capital additions for Cyber Technology Services ("CTS"), Facility Management, Fleet, and Security.

Q. What are some of the projects for CTS in Table 1 and what will they address?

A. CTS Projects include the following:

- Microsoft 365 Implementation (2024) – Involves upgrading the Company's end-of support for Microsoft products. The upgrade will allow a better internal and external collaboration for all employees and ensure continued support;
- Human Capital Management Upgrade ("HCM") (2023) – Involves transitioning to the cloud offered software. This project addresses the on-premise Oracle eBusiness Suite solution, which is nearing end of life and moving to a modern solution to maintain support, security, and flexibility. Transitioning to cloud based assets will allow more frequent patching, updates, and continuous improved functionality and security enhancements;
- Pandell Landworks (2023 and 2024) – Involves two concurrent efforts that advance the Company's real estate group by digitizing land records and creating a spatial connection to the Company's GIS. The first effort is the installation of a software solution, Landworks, which visualizes and manages land records in an electronic interface. The other parallel effort involves Pandell integrating over 30,000 of the Company's land records into Landworks;

- Energy Management System Upgrade ("EMS") (2024) – Involves upgrading and replacing the end-of-life software and hardware. The upgrade will allow for maintained support and security; and
- 2023 Customer to Meter ("C2M"), 2023 Outage Management System ("OMS"), 2023 GIS", 2023 and 2024 Microwave Radios Program ("MDR"), 2023 and 2024 Synchronous Optical Networking System ("SONET"), each of which is described in more detail later in the System Reliability section of my testimony.

Q. What are some of the projects for Facility Management in Table 1 and what will they address?

A. Facility Management Projects include the following:

- The Rowe Energy Control Center ("RECC") Electrical Upgrade and RECC Heating (2024) – Involves replacing the existing emergency generator and electrical system to maintain reliable emergency backup power for the control center. This project will also upgrade the switchgear electrical system to address existing maintenance and outage concerns due to end of life;
- Ventilation and Air Conditioning ("HVAC") Project (2024) – Involves replacing an end-of-life HVAC system to ensure reliable cooling of the critical control system and computers, as well as ensure temperature control of the control center facility;
- ALLETE Headquarters ("ALE HQ") Electrical Upgrade (2023) – Involves upgrading and replacing an end-of-life electrical system and adding electric vehicle charging stations in the ALE HQ parking ramp;
- ALE HQ Renovation (2023) – Involves upgrading and improving meeting and office space, a new fire suppression system, electrical system, HVAC system, LED lighting, and improving the restrooms to be compliant with the ADA; and
- Herbert Service Center ("HSC") Renovation (2023) – Involves upgrading and improving the appearance and functionality of the shared spaces as well as adding technology capabilities to make conference rooms more functional and efficient.

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

A. Fleet and Security Projects include:

- Fleet Vehicle replacement projects (2023 and 2024) – Provide funding for planned replacements or upgrades where priority assets have reached their end of life or have been identified for replacement or upgrade in advance of equipment failure;
- Security Access control panel programs (2023 and 2024) – Provide funding for planned replacement or upgrades where priority assets have reached their end of life or have been identified for replacement or upgrade in advance of equipment failure; and
- Security Contingency Projects (2023 and 2024) – Provide funding for emergency restoration and replacement of failed assets due to unforeseen circumstances.

E. Service Centers

Q. Please discuss any new developments related to Company-owned service centers.

A. As part of the Company's long-range facility planning process, Minnesota Power conducts a thorough and ongoing analysis of the current use of our service centers. All Transmission and Distribution service centers currently in use are under the scope of this review. Service centers are facilities that our line workers, meter technicians, substation crews, relay technicians, engineering staff, and service dispatching and support staff work out of to support both Transmission and Distribution systems. The service centers also act as a base where our trucks, inventory, and tooling are stored, repaired, and trained on. Service centers do not have direct customer transactions or service interactions. These facilities support our field operations workers. Also, not all service centers are the same. Minnesota Power has seven smaller service centers in outlying areas that serve customers in rural communities and three regional service centers that are much larger and where significant transmission and distribution equipment is delivered and stored, multiple types of maintenance equipment are based and serviced, training of field personnel occurs, and security is more extensive than elsewhere—these particular facilities are more akin to command centers for the Transmission and Distribution department.

Minnesota Power identified a need to address facility concerns with aging service center assets. Older assets lack features that accommodate workers of all ability types, adequate storage space for materials and vehicles, and sufficient space for work groups that are supporting large capital projects. Minnesota Power also identified a need for spaces that could be used for training employees and spaces to accommodate large groups that respond to storm restoration events or participate in project meetings.

To assess these concerns, Minnesota Power engaged a consultant to determine whether existing service centers could be updated or if replacement service centers were necessary. The consultant brought on to assist with the analysis was a full-service engineering, architecture, and planning firm. The assessment involved extensive collaboration with internal stakeholders, including department heads, managers, and other key personnel to gather information about the current state of the Company's facilities, assess the needs and requirements of each department, and identify any deficiencies or limitations. Based on the information gathered and analyzed, the consultant determined the need for replacement of three service centers to address the existing issues and meet the future needs of the organization. Identified drivers for replacement were the lack of ADA compliant spaces, access and egress for both people and traffic patterns, lack of storage areas, lack of adequate space to house trucks and equipment, as well as a high cost to bring the existing facilities up to current building code. Minnesota Power determined that the current locations lacked space to expand the buildings and are very cost prohibitive to bring up to code and expand. Other identified challenges were related to security concerns for material and equipment, exposing new equipment to adverse weather causing escalating wear to expensive equipment as it does not fit into a covered space. The Company anticipates needing replacement of the three command centers in approximately the fall of 2026, but have not included any capital costs in the 2024 test year.

As the needs of the distribution system evolve, Minnesota Power is required to install larger poles, equipment, and material, which requires larger equipment to install. Minnesota Power's current facilities cannot handle the larger size equipment and material.

The three service centers identified as needing replacements are Duluth, Eveleth, and Little Falls. These facilities buildouts would allow Minnesota Power to better train the next generation of workers, house new and expensive equipment, make facilities accommodating for employees with physical challenges, and provide workspaces that accommodate workers of all abilities and talents. In addition to supporting the daily operations of Transmission and Distribution (which includes storm and trouble response, new customer work, system maintenance and operations), these facilities are direct support centers for the design, operation and maintenance of the large capital projects, such as Duluth Loop and Northland Reliability Project that Minnesota Power plans to execute in the coming years.

Q. How does the Company handle service centers that are no longer viable for operation?

A. Where the Company ceases to operate at any given facility moving forward, a thoughtful transition plan is required to ensure that employees are informed of these changes in a timely manner and these assets can be marketed to maximize market value for customers. The Company's operational use of facilities continues to evolve over time. If the required maintenance investments associated with continued ownership are greater than the benefits of the service center, Minnesota Power then will consider options ranging from continued ownership and renting or leasing out unused portions of the Service Center to closure and sale.

F. <u>Cost Recovery Rider</u>

Q. Does the Company propose to move any investment recovery of transmission system capital investments from the TCR into base rates?

A. Yes, one project currently in the TCR, Great Northern Transmission Line ("GNTL"), is in-service and will be transferred from the TCR to recovery in base rates with the implementation of proposed rates. The Direct Testimony of Company witness Mr. Stewart J. Shimmin provides additional information regarding this roll-in.

Q. What is the GNTL project and why was it needed?

A. GNTL project is the Minnesota portion of the 500 kV interconnection from southern Manitoba to northeastern Minnesota. Minnesota Power filed a Certificate of Need Application (Docket No. E015/CN-12-1163) and Route Permit Application (Docket No. E015/TL-14-21) on October 29, 2012, and April 15, 2014, respectively. The purpose of GNTL is to efficiently provide Minnesota Power's customers and other utilities in the Upper Midwest access to a predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements. Additionally, the Manitoba Hydro hydropower purchases made possible by GNTL will help meet the region's growing long-term energy demands; advance Minnesota Power's *EnergyForward* strategy to increase its generation diversity and renewable portfolio; strengthen system reliability; and fulfill Minnesota Power's obligation under its power purchase agreements with Manitoba Hydro. GNTL project was first energized and placed in-service on schedule in June 2020.

Q. Did Minnesota Power prudently incur the costs it spent to complete the GNTL project?

A. Yes, the costs incurred by the Company to complete the GNTL project were prudently and reasonably incurred to complete this necessary project. Minnesota Power was able to complete this project near the low end of the projected cost range at a total cost of $584.6 million (2013$) Total Company, after adjusting nominal costs to 2013 dollars using the Handy Whitman factors. The total nominal cost of the project was $659.7 million Total Company ($541.1 million MN Jurisdictional) in 2023.

Q. What does the Company request the Commission do with the costs for the GNTL project?

A. Minnesota Power requests that the Commission allow the Company to recover all GNTL project costs, including those currently in the TCR plus additional amounts not in the rider, in base rates, as described by Company witness Mr. Shimmin.

Q. Are there any transmission projects that the Company is not moving from the TCR into base rates?

A. Yes. On October 21, 2021, Minnesota Power filed a combined Certificate of Need Application (Docket No. E015/CN-21-140) and Route Permit Application (Docket No. E015/TL-21-141) to the Commission for the proposed Duluth Loop Project. As discussed in Section III.B.1 of my Direct Testimony, the Duluth Loop Project is a network of 115 kV transmission lines and substations at the south end of the North Shore Loop which form two parallel connections between the 230 kV/115 kV transmission source at the Arrowhead Substation and the North Shore Loop connection at the Colbyville Substation. The Duluth Loop Project is needed to replace the system support once provided to this area by coal-fired baseload generators located along Minnesota's North Shore. The Duluth Loop Project will address severe voltage stability concerns, relieve transmission line overloads, and enhance the reliability of Duluth-area transmission sources—all of which are needs that have resulted from the retirement of these generation sources. On April 3, 2023, the Commission issued an Order approving the requested Certificate of Need and Route Permit for the Duluth Loop Project.

Q. Are there any other transmission projects that the Company anticipates it will eventually include in the TCR?

A. The Company is in the early stages of permitting several projects that are expected to be TCR-eligible pending approval of the Commission of each project's Certificate of Need application. I discuss these projects in more detail earlier in my Direct Testimony:

- The Northland Reliability Project with Great River Energy (Certificate of Need Application (Docket No. E015,ET2/CN-22-416) and Route Permit Application (Docket No. E015,ET2/TL-22-415));
- The Big Stone South to Alexandria to Big Oaks 345 kV transmission project (Certificate of Need Application (Docket No. E017,ET2,E002,ET10,E015/CN-22-538) and Route Permit Applications (Docket Nos. ET2,ET10,E015,E017,E002/TL-23-160 and E002,ET2,ET10,E015,E017/TL-23-159)). This project is expected to be TCR-eligible pending approval by the Commission of the Certification of Need application; and
- The HVDC Modernization Project (Certificate of Need Application (Docket No. E015/CN-22-607) and Route Permit Application (Docket No. E015/TL-22-611)).

G. 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. For many years, the Company's SolarSense rebate program has offered customers the opportunity to receive a rebate when installing customer-sited solar projects. The vast majority of solar applications that the Company receives each year were incentivized by this rebate and it was the primary driver for DER adoption in the Company's service territory through 2020. With the Company's success to penetrate solar into the market, the Company continued to offer reduced rebates with a decreased budget for the SolarSense program years 2021–2024 and increased the budget for the Low Income Solar Grant Program. Interconnection activity has grown and continues to show stable or increasing demand despite the decreasing budget for customer rebates. Interconnections receiving a utility rebate are now the minority of systems installed. This trend is an indicator that the customer rebate program is no longer the driving force for small scale solar market. The Company also participates in the Commission's Distributed Generation Working Group to develop technical standards, garner feedback from stakeholders, and ultimately to refine internal processes.

In late 2018, the Company also became part of the Electric Power Research Institute ("EPRI") Distribution Resource Integration and Value Estimation Tool ("DRIVE") User Group to gain understanding of hosting capacity analysis and the data and labor requirements for performing hosting capacity studies. The Company's efforts related to distribution system modeling and hosting capacity analysis will be discussed in greater detail in its 2023 IDP, to be filed by November 1, 2023.

In 2021, the Commission approved Minnesota Power's proposal to build three new solar arrays at Laskin, Duluth, and Sylvan as part of the *EnergyForward* strategy to transition to a more renewable grid and zero carbon future while also supporting the economic recovery of Minnesotans following the COVID-19 pandemic (Docket No. E015/M-20-828). There are no associated capital costs in the 2024 test year. These projects were constructed by the Company's affiliate, ALLETE Enterprises and associated project companies, and are currently in-service. Minnesota Power entered into a purchased power agreement for the related solar energy. The costs are being recovered through the Solar Energy Adjustment Rider ("SEA Rider"), in conjunction with the Company's existing Rider for Fuel and Purchased Energy Adjustment ("FPE Rider").

Minnesota Power is also developing additional Request for Proposals as part of the approved 2021 IRP to have up to 300 MW of solar connected.

Q. Please summarize the Company's Transmission and Distribution Capital in the 2024 test year.

A. The Company's 2024 test year Capital requests includes projects necessary to ensure the safe and reliable delivery of electricity to Minnesota Power customers as we advance *EnergyForward* and make investments in overall grid and safety modernization.

IV. TRANSMISSION AND DISTRIBUTION O&M

A. O&M Budget Overview

Q. Please describe the Transmission and Distribution annual O&M budget development process.

A. The consolidated annual budget process is described by Company witness Mr. Anderson. Each year, the work areas in Transmission and Distribution (and related support services) prepare a zero-based budget. The budget is typically submitted during the second quarter of the prior year. As with capital, the Company undertakes a zero-based (*i.e.*, bottom-up) approach to budgeting, as further described by Company witness Mr. Anderson.

Q. What factors are considered in preparation of each work area's zero-based budget development?

A. Each work area follows a collaborative process facilitated by a Budget Analyst and the Budget Owner, using information from various systems, databases, and departments. The budgeting process considers the work expected to occur the following year, taking into account the current workforce and how their time may be allocated across capital, O&M, or billable work, as well as anticipated changes in salary, pay grades, and head count. The analyst reviews prior data to gain the historical view of spend, then applies appropriate methodology to the various components to develop the budget. Technological advancements and efficiency gains are considered, outlying events are normalized, and one-time events are excluded. Known and measurable changes expected to take effect in the upcoming year are considered, with required O&M dollars adjusted accordingly.

Q. How does the Company incorporate FERC Accounts into its O&M Budget process?

A. Budget information is reviewed by FERC Account rather than primarily focusing on work areas and cost types. As functions shift between work areas or leadership, a departmental view does not provide effective trend data. The Company places significant emphasis on FERC Account budgeting and data validation, as core functions will retain the same FERC Accounts regardless of the Company reporting structure.

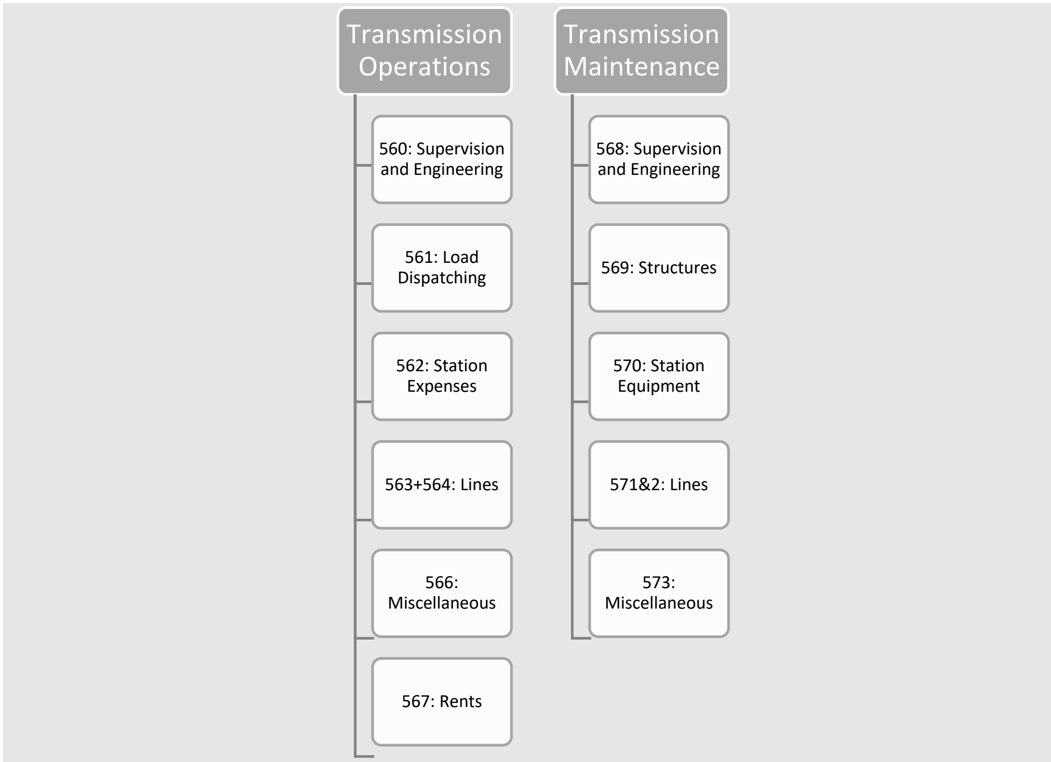
Q. Please describe the key functions within the Transmission organization that are included in the annual Transmission O&M Budget.

A. The Transmission O&M budget includes costs associated with the reliability-centered operation and maintenance of our transmission system. This includes: performing routine inspections; engineering, planning, and performing maintenance activities and emergency repairs for overhead lines, substations, and communication sites; maintaining the overhead line right-of-way through vegetation management; performing system studies; operating the transmission system in real time; and maintaining compliance with NERC reliability standards and FERC standards of conduct.

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

A. Figure 1 provides the FERC Accounts included as major Transmission O&M expenses.

Figure 1. Transmission FERC Accounts



Q. Why is FERC Account 565 omitted from Figure 1?

A. Because FERC Account 565 is primarily associated with the MISO Tariff and budgeted based on external inputs from MISO, it will be discussed separately from the other FERC O&M Accounts for the Transmission work area. FERC Account 565 is discussed in Section IV.D of my Direct Testimony.

Q. What is the 2024 test year budget for major Transmission O&M expenses?

A. Table 3 provides Total Company actual and budgeted expenses from 2018 through 2022, 2023 projected year expenses, and test year 2024 expenses. Minnesota Power has budgeted $31.2 million Total Company ($25.9 million MN Jurisdictional) in 2024, which is an increase of $4.9 million Total Company ($4.2 million MN Jurisdictional) from 2022 actual expenses. This increase is primarily due to increased labor allocations in the following: Station Equipment, Load Dispatch, and Line and increased contract expenses for Load Dispatch and Lines; and expenses associated with anticipated upgrades of leased transmission lines and substation equipment owned by Superior

Water Light and Power ("SWLP"), discussed in further detail below. Table 4 provides these amounts at the Minnesota Jurisdictional level.

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

Account	'18 Budget	'18 Actuals	'19 Budget	'19 Actuals	'20 Budget	'20 Actuals	'21 Budget	'21 Actuals	'22 Budget	'22 Actuals	'23 Projected	'24 Unadjusted Test Year
560	$2.7M	2.1M	$1.4M	$1.9M	$1.9M	2.3M	$2.5M	$3.2M	$2.8M	$3.6M	$3.9M	4.6M
561	$9.7M	8.8M	$6.4M	$7.6M	$8.4M	7.6M	$8.0M	$8.6M	$8.5M	$8.7M	$9.4M	9.9M
562	$0.1M	0.2M	$0.0M	$0.1M	$0.2M	0.1M	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	0.1M
566	$1.1M	1.4M	$0.9M	$0.8M	$0.7M	0.6M	$0.7M	$0.6M	$0.7M	$0.7M	$0.8M	0.7M
567	$1.8M	1.9M	$1.9M	$2.1M	$3.5M	2.4M	$2.6M	$2.3M	$2.6M	$2.8M	$3.1M	3.2M
568		0.0M	$0.0M	$0.0M	$0.0M	0.0M	$0.0M		$0.0M		$0.0M	0.0M
569	$2.3M	1.8M	$2.2M	$1.7M	$1.7M	2.0M	$2.3M	$2.5M	$2.0M	$2.3M	$2.3M	2.3M
570	$4.7M	3.6M	$4.2M	$3.5M	$3.4M	3.2M	$3.8M	$4.6M	$3.9M	$3.7M	$4.2M	5.0M
571	$2.7M	2.2M	$2.9M	$3.9M	$3.6M	3.7M	$4.8M	$4.5M	$4.3M	$4.4M	$5.2M	5.3M
573		0.1M	$0.0M	$0.0M	$0.1M	0.0M	$0.0M	$0.0M				
Total	**$25.1M**	**22.0M**	**$20.0M**	**$21.6M**	**$23.4M**	**21.9M**	**$24.8M**	**$26.4M**	**$24.8M**	**$26.3M**	**$29.1M**	**31.2M**

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

Account	'18 Budget MNJ	'18 Actuals MNJ	'19 Budget MNJ	'19 Actuals MNJ	'20 Budget MNJ	'20 Actuals MNJ	'21 Budget MNJ	'21 Actuals MNJ	'22 Budget MNJ	'22 Actuals MNJ	'23 Projected MNJ	'24 Unadjusted MNJ
560	2.3M	1.7M	1.2M	1.6M	1.6M	1.9M	2.1M	2.6M	2.3M	2.9M	3.2M	3.8M
561	8.1M	7.4M	5.4M	6.5M	6.9M	6.3M	6.6M	7.1M	7.0M	7.1M	7.7M	8.2M
562	0.1M	0.2M	0.0M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M
566	0.9M	1.2M	0.7M	0.7M	0.6M	0.5M	0.6M	0.5M	0.6M	0.6M	0.6M	0.6M
567	1.5M	1.6M	1.6M	1.7M	2.9M	2.0M	2.1M	1.9M	2.1M	2.3M	2.6M	2.6M
568	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
569	1.9M	1.5M	1.9M	1.5M	1.4M	1.7M	1.9M	2.0M	1.6M	1.9M	1.9M	1.9M
570	4.0M	3.0M	3.6M	3.0M	2.8M	2.7M	3.2M	3.8M	3.2M	3.1M	3.5M	4.2M
571	2.3M	1.9M	2.5M	3.3M	3.0M	3.0M	4.0M	3.7M	3.5M	3.6M	4.3M	4.4M
573	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M				
Total	**21.1M**	**18.4M**	**17.1M**	**18.4M**	**19.5M**	**18.2M**	**20.5M**	**21.8M**	**20.4M**	**21.7M**	**23.9M**	**25.9M**

Q. Please describe the costs in Account 560 Operation Supervision and Engineering.

A. Account 560 is for Operation Supervision and Engineering, which includes the cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, and expenses incurred in the general supervision and direction of the operation of the transmission system as a whole. The increase from 2022 actuals to the 2024 test year 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 the continued but renewed focus on employee safety and training programs such as the Company's newly created utility training department.

Q. Please describe the costs in Account 561 Load Dispatch.

A. Account 561 is for Load Dispatch, which includes cost of labor, employee pensions and benefits, social security and other payroll taxes, injuries and damages, property insurance, property taxes, materials used, and expenses incurred by a regional transmission service provider or other transmission provider to manage the reliability coordination function as specified by NERC and individual reliability organizations. The increase from 2022 actuals to the 2024 test year is primarily due to higher overall internal salaries and associated overheads along with external fees on assessments and studies trending higher than historically seen.

Q. Please describe the costs in Account 570 Maintenance of Station Equipment.

A. Account 570 is for Maintenance of Station Equipment, which includes labor, materials used, and expenses incurred in maintenance of station equipment. The increase from 2022 actuals to the 2024 test year is primarily driven from the shifting of internal resources from capital to O&M related to required maintenance of the substation assets.

Q. Please describe the costs in Account 571 Maintenance of Overhead Lines.

A. Account 571 is for Maintenance of Overhead Lines, which includes labor, materials used, and expenses incurred in maintenance of transmission plant. The increase from 2022 actuals to the 2024 test year is primarily due to an increase in vegetation management spending as described in more detail later in my testimony.

Q. Please describe the costs in Account 567 Rents.

A. Account 567 is for Rents and includes a lease expense paid to SWLP in accordance with the Transmission Asset Lease Agreement ("TALA") approved by the Commission in

Docket No. E015/AI-08-1297. Through the TALA, the Company leases all 115 kV transmission lines and substation equipment owned and operated by SWLP. As capital additions and associated operating costs of these assets change, the lease payment will change accordingly. The TALA defines the methodology for calculating the Minnesota Power expense for leasing the SWLP transmission system assets. The Company has included $3.2 million Total Company ($2.6 million MN Jurisdictional) in the 2024 test year, reflecting capital additions by SWLP and the calculation methodology included in the TALA.

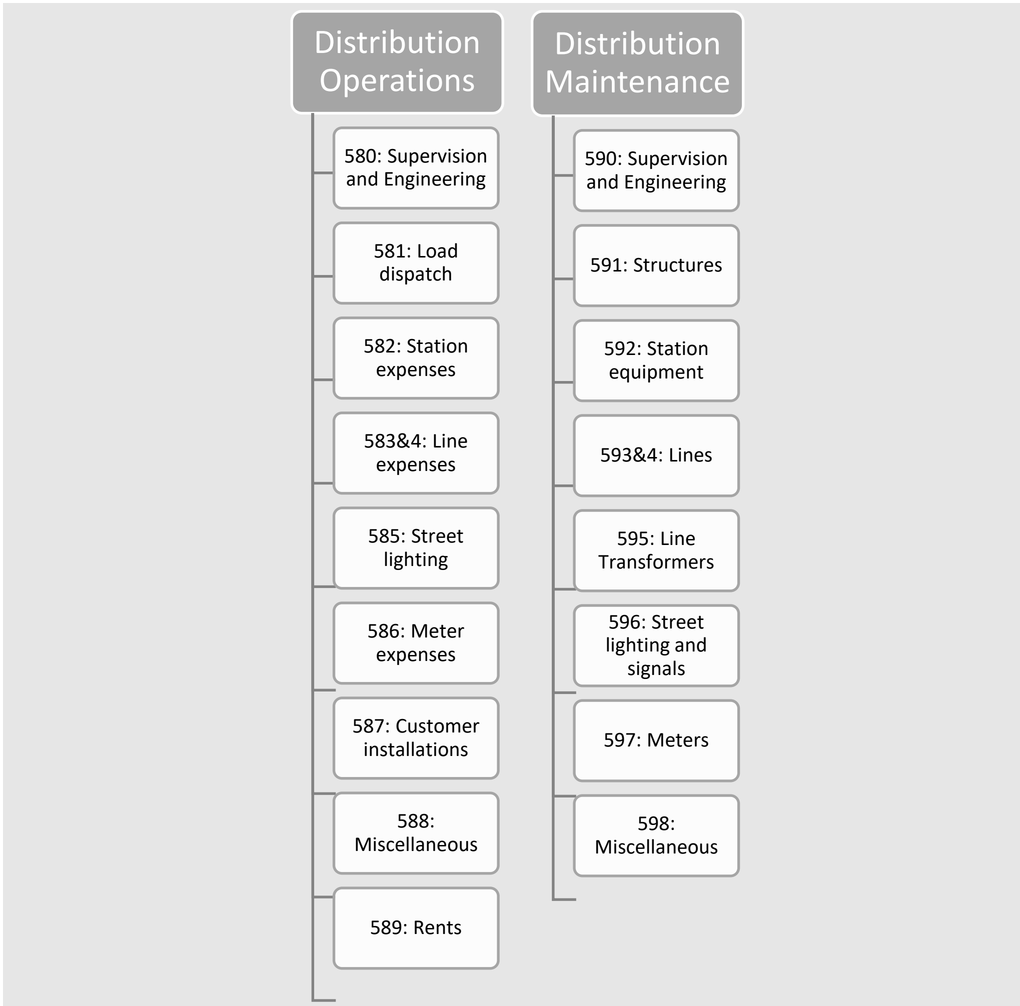
Q. Please describe the key functions within the Distribution work area that are included in the annual Distribution O&M Budget.

A. The Distribution O&M budget includes costs associated with the reliability-centered O&M of the distribution system. This includes: performing routine inspections and audits on assets such as ground-line poles, transformers, reclosers, switches, and regulators, which also can be audited through the Company's service request system; engineering, planning, and performing maintenance activities and emergency repairs for overhead and underground lines, substations, and customer connections; maintaining the overhead line right-of-way through vegetation management; performing system reliability studies and reporting; installing, testing, maintaining, and reading customer meters; and responding to the changing energy landscape through grid modernization efforts and distributed generation interconnections.

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

A. Figure 2 provides the FERC Accounts included as major distribution O&M expenses.

Figure 2. Distribution FERC Accounts



Q. What is the 2024 test year budget for Distribution O&M expenses?

A. Table 5 shows Total Company Distribution actual and budgeted expenses from 2018 through 2022, 2023 projected year expenses, and test year 2024 expenses. The Company has budgeted $29.3 million Total Company ($27.7 million MN Jurisdictional) in 2024, which is a decrease of $1.6 million Total Company ($1.2 million MN Jurisdictional) from 2022 actual expenses. The decrease from 2022 actuals to 2024 test year is primarily due to the 2022 year-end storms that went through the Company's territory numerous times, along with a five-year average budget for unpredictable storm-related maintenance. Storm budgets are discussed in further detail later in my testimony. Table 6 provides these amounts at the Minnesota Jurisdictional level.

Table 5. Distribution Budget and Actual Expenses by FERC Account (Total Company)

Account	'18 Budget	'18 Actuals	'19 Budget	'19 Actuals	'20 Budget	'20 Actuals	'21 Budget	'21 Actuals	'22 Budget	'22 Actuals	'23 Projected	'24 Unadjusted Test Year
580	$1.2M	1.1M	$0.6M	$0.9M	$1.1M	0.7M	$1.0M	$1.0M	$1.0M	$1.0M	$1.1M	1.1M
581	$0.8M	0.3M	$0.7M	$0.8M	$0.8M	0.6M	$0.6M	$0.6M	$0.6M	$0.5M	$0.6M	0.5M
582		0.0M	$0.0M	$0.0M	$0.0M	0.0M	$0.0M	$0.0M	$0.0M	$0.0M		
583	$0.2M	0.2M	$0.2M	$0.2M	$0.3M	0.2M	$0.3M	$0.3M	$0.2M	$0.3M	$0.5M	0.2M
584	$0.0M	0.1M	$0.1M	$0.1M	$0.1M	0.1M	$0.1M	$0.1M	$0.1M	$0.2M	$0.1M	0.1M
585	$0.2M	0.1M	$0.2M	$0.2M	$0.1M	0.1M	$0.1M	$0.1M	$0.1M	$0.0M	$0.1M	0.1M
586	($0.0M)	0.3M	$0.0M	$0.4M	$0.3M	-0.8M	($0.8M)	$0.4M	$1.6M	$0.8M	$1.7M	1.8M
587		0.0M		$0.0M		0.0M		$0.0M		$0.0M		
588	$7.5M	5.4M	$6.8M	$5.8M	$6.6M	4.9M	$6.6M	$6.0M	$6.4M	$7.5M	$6.6M	6.0M
589	$0.1M	0.1M	$0.1M	$0.1M	$0.1M	0.1M	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M	0.1M
590	$0.7M	0.7M	$0.3M	$0.8M	$0.8M	0.8M	$0.8M	$0.9M	$0.9M	$0.8M	$1.0M	1.0M
592		0.0M		$0.0M	$0.1M	0.0M	$0.1M	$0.1M	$0.1M	$0.0M	$0.0M	0.0M
593	$8.8M	9.4M	$9.4M	$8.9M	$10.9M	10.9M	$13.7M	$13.0M	$14.9M	$17.1M	$13.7M	15.3M
594	$1.8M	1.7M	$1.6M	$1.6M	$1.6M	1.7M	$1.6M	$1.8M	$1.7M	$1.7M	$1.8M	1.8M
596		0.0M	$0.0M	$0.0M	$0.0M	0.0M	$0.0M	$0.0M	$0.0M	$0.0M	$0.0M	0.0M
597	$0.0M	0.0M	$0.0M	$0.0M	$0.0M	0.0M	$0.0M	$0.0M	$0.0M			
598	$0.9M	0.8M	$0.7M	$0.6M	$0.9M	0.8M	$0.7M	$0.9M	$0.9M	$0.8M	$1.0M	1.3M
Total	**$22.3M**	**20.2M**	**$20.6M**	**$20.2M**	**$23.8M**	**20.2M**	**$24.9M**	**$25.2M**	**$28.6M**	**$30.9M**	**$28.3M**	**29.3M**

Table 6. Distribution Budget and Actual Expenses by FERC Account (MN Jurisdictional)

Account	'18 Budget MNJ	'18 Actuals MNJ	'19 Budget MNJ	'19 Actuals MNJ	'20 Budget MNJ	'20 Actuals MNJ	'21 Budget MNJ	'21 Actuals MNJ	'22 Budget MNJ	'22 Actuals MNJ	'23 Projected MNJ	'24 Unadjusted MNJ
580	1.1M	1.0M	0.5M	0.9M	1.0M	0.7M	1.0M	0.9M	0.9M	1.0M	1.0M	1.0M
581	0.8M	0.3M	0.6M	0.7M	0.8M	0.5M	0.5M	0.5M	0.6M	0.5M	0.5M	0.5M
582	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
583	0.2M	0.1M	0.2M	0.2M	0.2M	0.2M	0.2M	0.3M	0.2M	0.3M	0.4M	0.2M
584	0.0M	0.1M	0.1M	0.1M	0.0M	0.1M	0.1M	0.1M	0.1M	0.2M	0.1M	0.1M
585	0.2M	0.1M	0.2M	0.2M	0.1M	0.1M	0.1M	0.1M	0.1M	0.0M	0.1M	0.1M
586	0.0M	0.3M	0.0M	0.4M	0.3M	-0.8M	-0.8M	0.4M	1.6M	0.8M	1.7M	1.7M
587		0.0M		0.0M		0.0M		0.0M		0.0M		
588	7.2M	5.2M	6.5M	5.5M	6.2M	4.6M	6.2M	5.6M	6.0M	7.0M	6.2M	5.7M
589	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M	0.1M
590	0.7M	0.7M	0.3M	0.8M	0.7M	0.8M	0.7M	0.8M	0.8M	0.7M	0.9M	0.9M
592	0.0M	0.0M	0.0M	0.0M	0.1M	0.0M	0.1M	0.1M	0.1M	0.0M	0.0M	0.0M
593	8.4M	9.0M	9.0M	8.5M	10.3M	10.3M	12.9M	12.3M	13.9M	15.9M	12.9M	14.4M
594	1.7M	1.6M	1.5M	1.5M	1.5M	1.6M	1.5M	1.7M	1.6M	1.6M	1.7M	1.7M
596	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M
597	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M	0.0M				
598	0.8M	0.8M	0.7M	0.6M	0.9M	0.8M	0.7M	0.9M	0.8M	0.8M	1.0M	1.2M
Total	**21.3M**	**19.3M**	**19.8M**	**19.4M**	**22.4M**	**19.0M**	**23.5M**	**23.8M**	**26.8M**	**28.9M**	**26.6M**	**27.7M**

Q Why has Account 586 increased by $1.0 million Total Company ($0.9 million MN Jurisdictional) from 2022?

A. Account 586 is Meter Expenses and includes costs associated with installing, testing, maintaining, and reading customer meters. This account has seen historical low O&M costs during a multi-year (capital) deployment of AMI meters throughout the Company's service territory. The completion of the AMI capital meter additions has returned this account to normal operations and provided a more representative outlook for Meter Expenses. AMI meter deployment is discussed in further detail in Section V.B.1 of my Direct Testimony.

Q Why has Account 588 decreased by $1.5 million Total Company ($1.3 million MN Jurisdictional) from 2022?

A. Account 588 is Miscellaneous Distribution Expenses and includes: costs associated with internal and external labor costs to prepare and maintain records, maps, and prints; janitorial work at distribution office buildings including snow removal, cutting grass, etc.; and communication services, building service expenses, and miscellaneous office supplies not accounted for in other FERC Accounts. The decrease in Account 588 from 2022 actuals to the 2024 test year is primarily due to expenses for safety related materials in 2022 and 2023 that are not expected to continue into future years.

Q Why has Account 593 decreased by $1.8 million Total Company ($1.5 million MN Jurisdictional) from 2022?

A. Account 593 is Maintenance of Overhead Lines and includes costs associated with planned and unplanned overhead line maintenance as well as vegetation management within the overhead line rights-of-way. The decrease in this account is primarily due to the 2022 year-end storms that went through the Company's service territory numerous times along with a five-year average budget for unpredictable storm-related maintenance. Storm budgets are discussed in further detail later in my testimony.

Q Why has Account 598 increased by $0.5 million Total Company ($0.4 million MN Jurisdictional) from 2022?

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.

Q How has employee count changed in Transmission, Distribution, and Support Services?

A. Overall, employee count has increased in the Transmission, Distribution, and Support Services areas, largely related to increases in capital projects described throughout my testimony. When employees are working on capital projects, their compensation and benefit expenses are also allocated to capital, and therefore not increasing O&M.

B. Storm Response and Restoration

Q. How are storm response and restoration costs incorporated into the 2024 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 dollars, Contract Services, and Purchased Materials escalated to 2024 dollars in Account 593 from our Line Operations work area. 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 takes into account both high-year and low-year expenses for this response.

Q. What is the 2024 test year Budget for "trouble" work included in Overhead Line Maintenance?

A. The 2024 test year budget associated with "trouble" work is $2.6 million Total Company ($2.5 million MN Jurisdictional). It is based upon a five-year average of spending for FERC Account 593 (Maintenance of Overhead Lines). The budget averages spend for Overtime dollars, Contract Services, and Purchased Materials in our Line Operations department.

Q. Does Minnesota Power design and build its transmission and distribution systems to withstand storms?

A. To the greatest extent practicable, yes. The reliable, safe, and efficient delivery of electricity to customers is of the utmost importance to the Company and without the transmission and distribution infrastructure, Minnesota Power is unable to provide that service. Minnesota Power designs and builds the system to sustain various weather conditions, including high winds, ice, snow, and extreme heat and cold. Extreme weather conditions, however, are beyond the Company's control and, at times, do impact service to customers. In those instances, the Company responds as expeditiously as possible, while also ensuring the continued safety of personnel and the public. The capital projects described previously in my Direct testimony help to ensure not only the reliability of our system, but its increasing resilience in the face of more extreme weather events.

Q. Does Minnesota Power complete all storm response and restoration work using its own line workers?

A. Minnesota Power has historically relied on its own line workers to successfully complete all storm response and restoration. In 2015 and 2016, intense storms rolled through our service territory and Minnesota Power had to request mutual assistance from its other utility partners to ensure timely restoration of electric service to

Minnesota Power customers. 2022 was also an exceptional storm year for Minnesota Power and the Company had to call upon industry partners to provide mutual assistance during the December 2022 winter storm. Minnesota Power was able to manage nearly all of the 2022 storm responses with a mix of internal crews and contractors. Only the December 2022 winter storm was so severe that it required the Company to reach out for mutual assistance.

Minnesota Power maintains mutual assistance agreements with multiple electric utilities and contractors. Under these agreements, utilities can obtain the assistance of other utilities' employees when experiencing widespread outages. This means that Minnesota Power will respond to other utilities' requests, when it is able to do so and, when Minnesota Power and its customers need additional response assistance, those utilities respond as their resources allow them to assist in northern Minnesota.

Q Does Minnesota Power provide mutual assistance to other utilities?

A. Yes. For example, in 2017, Minnesota Power provided mutual assistance to assist the southern United States and Puerto Rico to restore electric service after the devastating effects of hurricanes Irma and Maria. Minnesota Power also assisted Manitoba Hydro in restoring power after experiencing heavy snow and high winds in a slow-moving storm in 2019. In 2020, crews responded to Illinois and Iowa to restore power after violent summer storms caused widespread damage to the grid. In 2021, underground crews helped restore power to areas of New York City after a Nor'easter caused widespread damage. The City of Grand Rapids, Minnesota suffered major damage during a July 2021 storm that crews assisted with restoration efforts. Minnesota Power sent crews to help Xcel Energy three times in less than a year between, twice to the Twin Cities metro area and once to Manitowish Waters, Wisconsin, after summer and winter storms passed through. Minnesota Power crews have also joined utility hurricane responses seven times in the past 15 years, including responding to needs in Florida, Maryland, New Jersey, and in Puerto Rico from late 2017 into early 2018 after Hurricanes Irma and Maria. Minnesota Power crews were deployed in 2022 to Jacksonville, Florida for Hurricane Ian.

Q. When Minnesota Power provides mutual assistance, how are costs recovered?

A. Costs and reimbursements associated with mutual assistance provided by Minnesota Power to other utilities are captured in the non-regulated side of our business and therefore have no impact on our customers. When the Company sends crews to assist in outage restoration efforts for other utilities, Minnesota Power creates unique work orders to record all actual direct costs—including labor, support, overtime, transportation, meals, lodging, etc.—that are incurred by our line workers and any support personnel assisting the line workers. Minnesota Power records all of the charges for time, equipment, and expenses against that work order from the time our line workers depart from their mobilization site until they arrive back to the mobilization site. Minnesota Power then includes corporate overheads in final bills to the utility that our line workers and personnel were assisting. This industry practice is followed by other investor-owned utilities when they send line workers to assist us in any widespread storm response and restoration effort when Minnesota Power requests mutual assistance. When Minnesota Power receives mutual assistance, customers receive a direct benefit of faster restoration of service and, therefore, those costs paid to the responding utilities are covered by the regulated side of our business.

C. Vegetation Management

Q. Please describe Minnesota Power's current vegetation management program.

A. The goal of Minnesota Power's vegetation management program is to provide safe and reliable transmission and distribution of electricity by controlling growth of noncompatible species and encouraging the growth of compatible species under, on, or adjacent to its transmission and distribution facilities, rights-of-way, or easements. Noncompatible species are defined as those that mature at a height that allows them to grow into or near the electric facilities and cause outages, creating unsafe conditions. This is accomplished through adherence to Integrated Vegetation Management principles, which include mechanical, chemical, and cultural methods of control. The vegetation management program minimizes tree-related interruptions, adheres to NERC Facilities Design, Connections and Maintenance (FAC)-003, American National

Standards Institute ("ANSI") Z133.1 and A300 standards, and follows National Electrical Safety Code Section 218. Other goals and objectives include: positive customer relations, adherence to all regulatory and legal requirements, continuous environmental improvement, and support of public and worker safety through maintenance of adequate clearances between conductors and vegetation. To assist our customers in selecting the type and species of vegetation that are compatible near power lines, Minnesota Power also maintains a link on our webpage to the "Right Tree" brochure.

Minnesota Power employs a vegetation management program that relies on trained and educated foresters and International Society of Arboriculture ("ISA") Certified Arborists. Ongoing monitoring of contractor timesheets/invoices by Minnesota Power Vegetation Management staff assures that Company resources are being utilized in the most cost-effective manner. Minnesota Power also has regular evaluation meetings with our contractor to ensure compliance with our agreement. Various vegetation management techniques and tools are employed to get the best value from resources allocated.

The Vegetation Management O&M budget allows Minnesota Power to prune, remove, mow, and apply herbicide to control the growth of vegetation along transmission and distribution power line rights-of-way. Vegetation is also controlled in and around substations, dikes, dams, and hydro facilities as needed to protect the electrical system from vegetation related interactions. Minnesota Power also responds to customer requests (tree orders) to prune or remove vegetation that is interfering or threatening Company facilities.

Minnesota Power monitors its progress through the analysis of tree-related outage data collected, percent completion of planned work, and regular site visits. Minnesota Power utilizes vegetation management methods that are the most cost effective to ensure the best use of limited resources. The Integrated Vegetation Management plan is executed by trained and educated foresters and ISA Certified Arborists.

Q. Does Minnesota Power employ a cyclical vegetation management program?

A. Yes. Minnesota Power maintains a Vegetation Management plan that addresses routine vegetation management on distribution lines approximately every six years and on transmission lines every seven years.

Q. Is this approach to vegetation management used among other electric utilities?

A. Yes. Cyclical vegetation management is the industry standard. Maintaining cycles is critical to effectively managing cost. It takes longer and creates more biomass to trim and remove trees once a circuit is off-cycle. Tree workers must take extra precautions to ensure safe work distances are maintained once vegetation has grown between and beyond the conductors. Off-cycle circuits also contribute to an increase in outages or momentary losses of service to customers, which affects System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI").

Q. Please describe any changes made to the program since Minnesota Power's 2021 Rate Case.

A. Minnesota Power has increased the use of mobile workforce solutions to aid the vegetation department in fieldwork. This includes electronic GIS mapping, a quick capture application for aerial patrols, and an electronic application that allows Minnesota Power field employees to report vegetation issues. In 2023, tree orders (customer requested vegetation assistance) were switched over to a mobile electronic version from the previously printed paper method of receiving tree orders. All tree orders are now available in real time on a mobile device, which allows employees to receive up to date information electronically and eliminates management of orders on paper. This change should also allow the Company to facilitate better management of tree orders during storms or prolonged outages. All of these applications have resulted in increased productivity, faster data gathering, and most importantly, achieving accurate data points for work identified.

The Company is looking for alternate data driven methods to see if there are areas that can further optimize vegetation management. Minnesota Power initiated an Artificial Intelligence ("AI") satellite vegetation analysis software trial in late 2022. This type of software is relatively new in the industry and uses satellite imagery to analyze vegetation conditions in relation to the Company's GIS-mapped electrical facilities. The objective of the software is to identify which line segments may need vegetation management in a given year, since not all tree species grow at the same rate, there may be segments within a circuit that could forego the planned vegetation cycle or may need vegetation clearing sooner. This strategy has potential to reduce overall cost or mitigate reliability issues related to tree overgrowth. The Company is currently in the trial period.

The Company continues to explore other electronic alternatives and new technology to aid its vegetation management work.

Q. Describe the processes Minnesota Power has historically had in place to ensure the cost of the vegetation management program is reasonable.

A. Minnesota Power utilizes a contracted workforce, which allows the flexibility to seek out the most cost-effective, skilled workforce to provide vegetation management service through a competitive bid process. The most cost-effective vegetation management technique is to target immature trees for removal and control. It is generally less expensive to treat with herbicide or remove immature trees than to trim them repeatedly. By removing a tree, the cost to prune that tree during the next cycle is eliminated and for every cycle thereafter. Some mature trees can be removed as well due to declining health issues, proximity to facilities, rate of regrowth, or due to the negative impression left by unsightly trees near the power lines. It is more expensive to remove mature trees, but that may ultimately be the best option. The up-front costs of clear rights-of-way and easements lead to reduced cost of upgrades and reduced time for storm restoration events and promote safe operating conditions. Herbicide use saves money in the long run by eliminating trees and brush from the system, while also converting vegetation to a higher percentage of compatible species.

Minnesota Power contracts vegetation work on a circuit/line basis for a period of one year. This period of time allows Minnesota Power to account for electrical changes in circuits and lines that are made to improve reliability. Awarding contracts annually provides flexibility to review and address contractor availability, performance, and cost management. Minnesota Power contracts for the following year's vegetation maintenance approximately four months in advance to assure it has the contract resources to complete the vegetation plan.

Minnesota Power has historically relied on a fixed bid (*i.e.*, lump sum) contracting process for distribution circuit maintenance. However, this method of bidding is based on tree pruning and does not account for a large number of tree removals because bidders do not know at the time of bid preparation, which customers will be accepting of tree removal versus a tree prune. Under this approach, there is no financial incentive for contractors in a fixed bid contract to obtain removals, which are generally more costly to perform for the contractor. Over time, the Company has seen a decline in tree removals on the Distribution system and attributed this to the lack of incentive in a fixed bid contract.

The Company implemented a time and material ("T&M") contracting pilot during the 2021 and 2022 calendar years to address tree removals and seek better overall clearances to electrical facilities. In 2021, Minnesota Power experienced an average of thirty-five percent greater tree removals than the previous maintenance cycle. In 2022, the average declined from the previous cycle by twelve percent. The Company attributed this decline from the previous cycle to circuits that had experienced widespread storm damage prior to maintenance, where a large number of trees were damaged and removed during the storm events. Another reason for the decline is circuits that reside in urban areas where customers are less likely to grant removals.

While the Company did remove more trees that will prevent outages and reduce cycle costs over the long term, it was very difficult to budget effectively for the normal cost to prune a circuit and then also budget for an unknown increase in tree removals.

Utilizing previous T&M contracting methods did not allow Minnesota Power to know the exact cost of a circuit and resulted in higher circuit costs than anticipated. As a result, during bid preparation for 2023, Minnesota Power chose to return to fixed bid (*i.e*, lump sum) bidding with a change order clause in the contract that would allow an incentive for tree removal. This method allows Minnesota Power to approve tree removals based on information that the contractor provides and has received permission from the customer to remove. Minnesota Power is able to budget a specific amount for these change orders which provides consistency in the budget. Fixed bids also provide a known budget spend during each bidding cycle.

Transmission vegetation maintenance contracting strategy has remained the same as the past and is competitively bid and awarded on a fixed price.

Q. How is the scope of vegetation management currently communicated to customers?

A. In the Company's Rate Book, Section VI, pages 3.6 and 4.5, the Company explains that the maintenance of rights-of-way are necessary for construction, operation, and maintenance (including facility maintenance and vegetation management rights).

Q. Why is Minnesota Power proposing an increase in vegetation management spending?

A. Minnesota Power's 2024 Vegetation Management budget for both transmission and distribution are $12.3 million Total Company ($11.2 million MN Jurisdictional). This budget amount is an increase over the 2023 projected year by $0.9 million Total Company ($0.9 million MN Jurisdictional) and over the 2022 actuals by $1.5 million Total Company ($1.4 MN Jurisdictional). The increase is needed to address higher vegetation related cost increases in labor, equipment, chemicals, and off-cycle growth.

Similar to the current experiences in other industries, Minnesota Power is experiencing the effects of a labor shortage in the tree care industry. Additionally, some contractors lack trained workers to operate specialized equipment, and there are not enough tree workers to respond to time sensitive projects. The competition between various industries (*e.g.*, pipeline, utilities, and municipal) for the specialized type of tree care these contractors provide has led to higher costs related to labor and equipment. It is also difficult to draw new employees into the field in a demanding, physical occupation like Vegetation Management. The Company anticipates rising costs will continue in the future to address these market challenges, labor constraints, and management of off-cycle circuits. A recent indicator of additional expected increases to obtain skilled labor in Northern Minnesota was a wage increase back payment notification from a few of the contractors after the ratification of their union contract in mid-2021.

Minnesota Power is also managing vegetation on the distribution system that is off cycle from the six-year cycle. In the current plan for 2024, 73 percent of circuit miles are beyond six years since the last maintenance cycle. In 2025, 46 percent are beyond the six years since the last maintenance cycle. Maintenance on off cycle circuits results in increased cost due to vegetation overgrowth. This overgrowth increases biomass cost and requires more labor to complete maintenance. The current budget reflects the costs needed to return all distribution circuits on cycle by 2026.

Emerald Ash Borer (“EAB”) is a current concern for Minnesota Power. This forest pest was first detected in the United States in 2002. The City of Duluth first reported its presence in 2015. This forest pest attacks all species of Ash and causes death of the tree within a short period of time (two to five years). The Minnesota Department of Natural Resources (“MnDNR”) estimates there are more than one billion ash trees in the state. Many of the communities Minnesota Power serves with electricity contain high numbers of this species. The Company is beginning to see increasing effects of the pest in its service territory and has been dealing with dead ash trees killed by the pest for approximately two years. The Company anticipates increasing costs to deal with these trees over the next decade as the pest continues to expand across the state. Because the pest kills the tree quite rapidly, ash trees become brittle and have unpredictable failure characteristics. Removal of these trees once the tree is heavily infected requires mechanized equipment to maintain safe working conditions for tree workers.

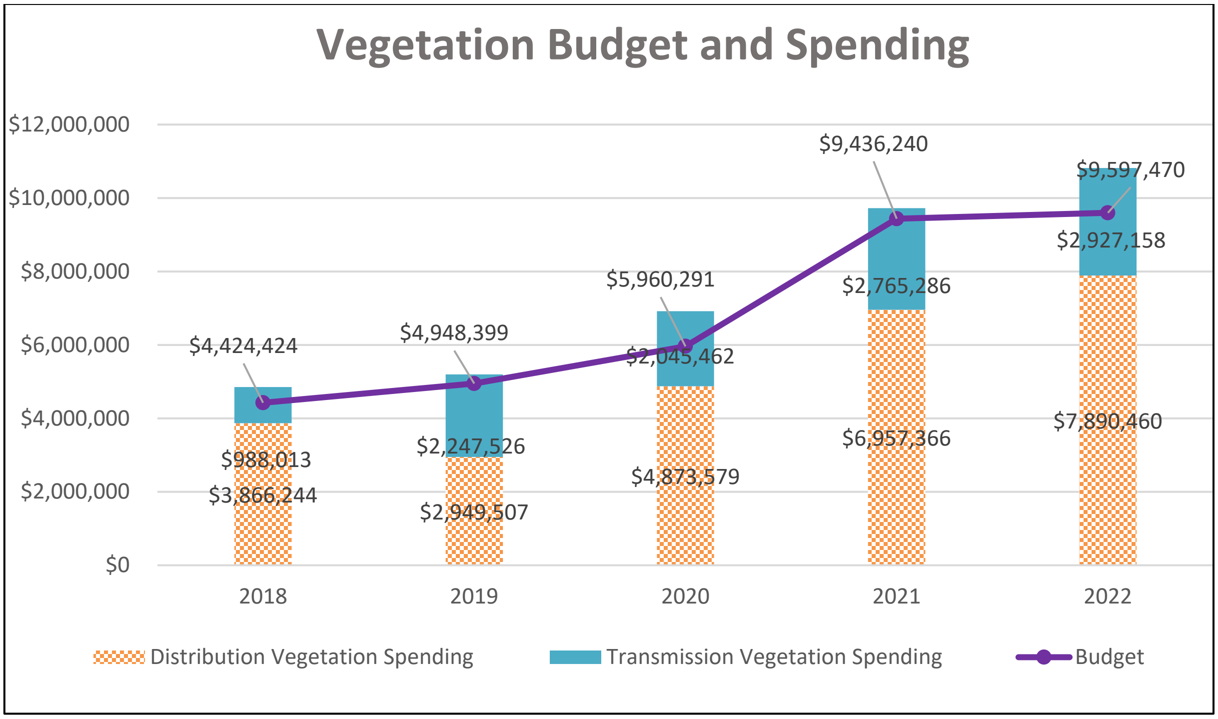
Finally, eleven substations and other electrical systems have been added to improve reliability, and also to facilitate delivery of variable renewable energy, which has led to more facilities to maintain.

Q. Please describe the budget/actual spending for Minnesota Power's current vegetation management program.

A. The Company is responsible for maintenance on approximately 1,321 miles of lines 200 kV and above under the NERC FAC-003 standard. These lines are monitored annually and corrective maintenance is performed as needed to maintain code and safety compliance. Routine vegetation maintenance occurs on a rotating seven-year cycle. The remaining transmission lines are scheduled for routine vegetation maintenance on a rotating seven-year cycle, but may not receive an annual inspection like those of 200 kV and above.

The total O&M budget for transmission vegetation maintenance in 2024 is $3.6 million Total Company ($3.0 million MN Jurisdictional). The remaining O&M budget for 2024 of $8.7 million Total Company ($8.2 million MN Jurisdictional) is allocated to distribution vegetation maintenance, customer requests, and construction or facilities replacement vegetation work. Currently there are distribution circuits that are behind the six-year maintenance cycle as reported in the last Safety, Reliability and Service Quality Standards ("SRSQ") report (Docket No. E015/M-23-75). When Distribution circuits fall behind, every effort is made to prioritize the maintenance of these circuits in the following year. Due to industry resource limitations and desire to balance spend year over year, it typically takes several years to get all circuits back into their six-year cycle. Table 6 below (which is Figure 9 from the Company's SRSQ report) shows an increase in the vegetation budget spend since 2018 when maintenance was deferred due to insufficient funds required to clear all vegetation for the 2018 maintenance cycle. As a result, the O&M budget was increased to account for extra clearing and additional vegetation growth being more expensive to clear and maintain.

Table 6. Vegetation Budget and Spending (Total Company)



D. <u>Third-Party Transmission Revenues and Expenses</u>

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

A. I am including this section of my Direct Testimony to provide a baseline understanding of the Company's third-party transmission revenue and expenses.

1. Overview of the Transmission System in Minnesota and the Upper Midwest

Q. Please describe the inter-utility connectivity of transmission facilities in Minnesota and the upper Midwest.

A. Electric utilities in Minnesota serve retail service areas that are spread throughout the state, sometimes non-contiguous to other parts of their retail service areas. Minnesota

Power serves the residents of Duluth, Grand Rapids, Hibbing, Virginia, Little Falls, and many other communities in northern and central Minnesota through both retail and resale electric service, while other utilities serve the predominantly rural areas between the Company's territories. Electric utilities in Minnesota and the upper Midwest (*e.g.*, investor-owned, cooperatives, transmission owners, and municipal utilities) have worked together for many years to develop a transmission network that will serve the various customer loads in this area. As a result, electric utilities in Minnesota and the region have highly interconnected transmission facilities that do not necessarily follow the patchwork of retail service area boundaries. This cooperation benefits our customers by providing the transmission infrastructure needed to serve our loads at a lower cost than if the Company and neighboring utilities each independently constructed facilities to reach their respective service area loads.

Q. How does this interconnectivity of the transmission system affect the costs to Minnesota customers?

A. As designed and implemented, the jointly developed multi-owner transmission grid in Minnesota has resulted in less duplication of facilities and increased system efficiency. This has resulted in lower costs to customers than they would have otherwise seen if systems were developed independently instead of through collaborative efforts of the owners.

Today, access to that multi-owner transmission grid is available under the MISO Tariff, which dictates how revenues and expenses must be accounted for within the transmission system. Essentially, the Company receives revenue from other entities that use the Minnesota Power transmission system, thus reducing the revenue required from Minnesota Power's customers. The Company also incurs an expense for using the transmission systems of other entities. Minnesota Power accounts for these third-party transmission revenues and expenses predominantly in FERC Accounts 456 and 565, respectively.

2. Third-Party Transmission Expenses and Revenues

Q. Please describe MISO and its role with respect to the transmission system.

A. The Company is a transmission-owning member of MISO. This means that, while Minnesota Power owns and maintains transmission assets, MISO operates the combined system, including Minnesota Power's assets, in conjunction with the transmission systems of more than 50 transmission owners. Furthermore, MISO establishes: (1) the process and rules for wholesale customers to access the transmission system on a non-discriminatory basis; (2) the annual transmission planning process for expanding or upgrading the regional transmission system, which includes the Minnesota Power transmission system (*i.e.*, MISO MTEP as discussed in Section III of my testimony); and (3) the policies and procedures that provide for the allocation of costs incurred to construct certain transmission upgrades and the distribution of revenues associated with those costs. Through MISO and in compliance with the MISO Tariff, wholesale revenues and third-party expenses are charged and recovered, accordingly.

Q. How are wholesale revenues and third-party expenses recovered?

A. The MISO Tariff recovers the costs of transmission facilities through rates established and billed by "pricing zones." These pricing zones roughly match the boundaries of the local balancing authority areas operated by individual MISO member utilities. The local balancing authority areas closely resemble the control areas from the pre-MISO operational days. Control areas were used to designate transaction schedules and system dispatch responsibilities to specific utilities. When the transmission owners first began interconnecting, control area boundaries were established to roughly encompass a utility's transmission and generation assets. The concept of control areas (now local balancing authority areas) is still used for utility energy accounting purposes.

The concept of a pricing zone is that the "network loads" within the pricing zone, including a utility's retail native load customers, will bear the Annual Transmission Revenue Requirement ("ATRR") associated with the transmission facilities in the zone on a load ratio share basis. The ATRR is calculated using the transmission cost of service rate formula set forth in the MISO Tariff for each transmission owner.

Q. What pricing zone is Minnesota Power's load located in?

A. All Minnesota Power load is located in the Minnesota Power pricing zone. There are, however, transmission facilities owned by and load served by Great River Energy included in that zone as well. As explained further below, the Minnesota Power system incurs third-party transmission expenses in the zone through a JPZ Agreement developed to compensate Minnesota Power and Great River Energy for facilities in the Minnesota Power pricing zone.

Q. How does the billing work?

A. The Company is party to a JPZ Agreement for the Minnesota Power pricing zone. Under this agreement, the transmission-owning utilities are compensated for their facilities in the zone, and the load serving utilities are billed for their loads in the zone. Because Minnesota Power is both a transmission owner and a load serving entity in the Minnesota Power pricing zone, the Minnesota Power System (1) receives revenues for the use of its facilities in the Minnesota Power pricing zone and (2) incurs expenses for its loads in the zone.

Furthermore, as a MISO transmission owner, Minnesota Power collects third-party wholesale transmission service revenues for others' use of the Company's system under both the MISO Tariff and other wholesale transmission agreements. The Minnesota Power system also incurs transmission and/or ancillary expenses for its load.

Q. What are the third-party transmission revenues and expenses applicable to base rates in the 2024 test year?

A. As shown in MP Exhibit ___ (Gunderson), Direct Schedule 3, the 2024 test year base rates include $56.3 million Total Company ($46.7 million MN Jurisdictional) of transmission revenues and $33.7 million Total Company ($28.0 million MN Jurisdictional) of transmission expenses, net of costs recovered and revenues shared through Minnesota Power's TCR Rider.

Q. How does the 2024 test year compare to the 2022 actuals for the amounts applicable to base rates?

A. The 2024 test year third-party transmission revenues exceed expenses applicable to base rates by $22.6 million Total Company ($18.7 million MN Jurisdictional) whereas the 2022 actual third-party transmission revenues exceeded expenses applicable to base rates by $20.2 million Total Company ($16.4 million MN Jurisdictional).

Q. What are the main drivers impacting the differences between 2022 actuals and the 2024 test year budget third-party transmission revenues and expenses applicable to base rates?

A. The 2024 test year third-party transmission revenues are $2.4 million Total Company ($1.4 million MN Jurisdictional) lower than 2022 actuals. The 2024 test year third-party transmission expenses are $4.8 million Total Company ($3.7 million MN Jurisdictional) lower than 2022 actuals.

The difference between 2022 actuals to the 2024 test year budget amounts can be attributed to the MISO Tariff Attachment O true up process. The Attachment O true up for 2020 impacted 2022 actuals. Loss of load during the pandemic in 2020 created a shortfall in revenues for MISO Transmission Owners in 2020, leading to higher rates in 2022. This increased revenues for MISO Transmission Owners in 2022 but also created an increase in expenses in 2022 for Transmission Customers. MISO/FERC refund amounts changed from $0.9 million Total Company ($0.7 million MN Jurisdictional) in 2022 to $3.1 million Total Company ($2.6 million MN Jurisdictional) in 2024 primarily due to the amounts being accrued for by the Company related to estimated MISO Attachment O true ups for 2021 and 2022, respectively.

Q. Do the 2024 transmission expenses and revenues in base rates include charges under MISO Schedules 26 and 26A to recover the costs of investments by MISO members recovered through the Regional Expansion Criteria and Benefits ("RECB") tariff mechanism?

A. No. Schedules 26 and 26A of the MISO Tariff provide for cost recovery of certain transmission projects. Schedule 26 recovers from MISO loads the costs of projects determined to be eligible for partial regional cost recovery as a "reliability" or "economic" project under the RECB mechanisms. Schedule 26A recovers from MISO loads the costs of projects determined to be eligible for full regional cost recovery as a Multi-Value Project. The Company includes MISO Schedules 26 and 26A charges in the TCR Rider recovery mechanism. Schedules 26 and 26A charges would thus be in addition to the third-party transmission expenses described in my testimony. The Company also includes Schedules 26, 37, and 38 revenues in the TCR Rider as an offset to Schedules 26 and 26A expenses paid to MISO. These amounts are detailed in MP Exhibit ___ (Gunderson), Direct Schedule 3. A summary of the various MISO Schedules and impacts on revenues and expenses is provided in Table 7.

Table 7. Summary of MISO Schedules

Schedule Number and Description	Schedule Type	Transmission Owner (revenue received)	Transmission Customer (expense paid)
Schedule 1: Scheduling, System Control and Dispatch	Ancillary Service	X	X
Schedule 7: Long-Term and Short-Term Firm Point-To-Point Service*	Base Transmission	X	X
Schedule 8: Non-Firm Point-To-Point Transmission Service**	Base Transmission	X	X
Schedule 9: Network Integration Transmission Service***	Base Transmission	X	X
Schedule 10: ISO Adder & FERC Annual Charges Recovery	Admin Schedule		X
Schedule 26: Network Upgrade Charge from Transmission Expansion Plan	Cost-Shared Projects	X	X
Schedule 26A: Multi-Value Project Usage Rate	Cost-Shared Projects		X
Schedule 35: HVDC Agreement Cost Recovery Fee	Admin Schedule		X
Schedule 37: MTEP Project Cost Recovery for ATSI Zone	Cost-Shared Projects	X	
Schedule 38: Allocation of Annual Revenue Requirements to the DEO/DEK Zone	Cost-Shared Projects	X	
Schedule 45: Cost Recovery of NERC Recommendation or Essential Action Charge (NREAC)	NREAC	X	X

* Border Owner Exemption
** Minnesota Power typically does not use Schedule 8 Non-Firm Transmission Service but would be charged accordingly under the tariff in the event it was reserved.
*** Minnesota Power does not pay MISO for Network Transmission Service because of the Bundled Load exemption. Network Transmission Service charges are imputed, however, for purposes of the JPZ Agreement with Great River Energy.

Q. Please describe the 2024 Minnesota Power system third-party transmission revenues and expenses.

A. There are several types of third-party revenues and costs summarized in MP Exhibit ___ (Gunderson), Direct Schedule 3. These are Minnesota Power system transmission costs necessary to serve Minnesota Power system loads, including Minnesota Power retail native loads, pursuant to rate schedules accepted for filing by FERC:

- *JPZ Costs* – As I previously discussed, the Minnesota Power system incurs costs for serving its native loads within the Minnesota Power JPZ. The Company and

Great River Energy own transmission facilities and serve loads in the Minnesota Power pricing zone and are compensated for each other's use of the transmission facilities to serve their respective loads through an agreed-upon methodology. The Company's transactions consist of both expense and revenue components, with expenses for our use of the Great River Energy transmission facilities to serve the Minnesota Power System loads and revenues for Great River Energy's use of the Minnesota Power system facilities to serve their respective loads in the Minnesota Power pricing zone. Each company in the zone may have larger or smaller revenues and expenses depending on their load and investment of transmission assets within the zone as a share of the overall load and investment of transmission assets within the zone. The JPZ Agreement includes a maximum annual payment cap of $2.5 million Total Company ($2.1 million MN Jurisdictional). The MN Jurisdictional amounts for these years were $2.3 million (2019), $0.3 million (2020), $16 million (2021), and $3.0 million (2022). The 2022 amount included a true up resulting from an underpayment in 2021. The 2024 test year includes an expected payment of $2.5 million Total Company ($2.1 million MN Jurisdictional) to Great River Energy which is consistent to what Minnesota Power has budgeted in other years;

- *Ancillary Service Costs* – The Minnesota Power system currently incurs costs and receives revenue under the MISO Tariff for Scheduling, System Control and Dispatch Service (Schedule 1) for ancillary services needed by the Minnesota Power system to serve native load within the Minnesota Power pricing zone; and
- *MISO Administrative Charges* – MISO charges its transmission service customers, such as the Minnesota Power System, its Schedule 10 and Schedule 35 administrative charge to recover the costs of administering its Tariff and providing other transmission functions.

Q. How are the wholesale transmission revenues kept accurate and current?

A. Minnesota Power provides updated third-party transmission revenue requirements to MISO and builds the Wholesale Transmission Revenue budget based on these updated revenues and expected loads. Revenue requirements for Schedules 1, 7, 8, 9, 26, and

45 of the MISO Tariff are updated every year through Schedule 1 and Attachments O, GG, and ZZ filings. These updates are required by the MISO Tariff and coordinated with MISO Tariff Administration staff to reflect current year projected costs and the true-up of prior period costs and loads.

Q. Has Minnesota Power reasonably and prudently developed its third-party transmission revenues and expenses budget for the 2024 test year?

A. Yes. The Company has taken into account all the details available, known trends, and system expectations to carefully, thoughtfully, and reasonably develop the third-party transmission revenues and expenses for the 2024 test year.

E. <u>Supply Chain</u>

Q. How have challenges in the supply chain impacted Minnesota Power?

A. Over the last two years, the global supply chain has been in a critical state driving from three main factors: raw materials, logistics and freight, and labor. While raw materials and logistics seem to be correcting themselves, labor continues to be a major challenge for many manufacturers and contractors. To combat the challenges of labor and demand imbalance, manufacturers have invested heavily into capital expenditures to increase capacity (additional "lines" and robotics). Couple these challenges with increased demand in the utility space and it has resulted in aggressive increases in costs over the last two years. While the frequency of price increases is going down, the Company is not seeing decreases as expected with commodities softening. This is due to demand remaining extremely high in the utility sector and from vendors intent on recouping their major investments into capacity to meet the demand. This increase in demand has also led to a shortage in critical equipment and materials and has caused average lead times in the electrical utility segment to increase more than 160 percent from pre-pandemic levels.

Due to the increase in energy infrastructure projects, contractors are in high demand as well. They are struggling with staffing to execute projects and in some cases, choose not to submit a bid because they do not have the labor to execute the work. Most contractors have raised their rates 9–10 percent including construction contractors, vegetation management contractors, and engineering consultants.

Q. What actions has Minnesota Power taken in response to these challenges?

A. To mitigate supply chain risks, Minnesota Power is starting to execute the procurement phase of projects much earlier than ever before. The Company has increased critical inventory, is considering alternate materials, looking at new sources for materials and equipment, and working closely with vendors to understand how to help one another. The Company remains committed to obtaining the best value for customers and in certain circumstances with long lead time items or hard-to-find items may be forced to buy from the only available option, regardless of price, to ensure reliability.

Q. What has Minnesota Power done to enhance supplier diversity and equity?

A. Minnesota Power continues to work with multiple utilities, prime contractors, and Edison Electric Institute ("EEI") to learn and build best practices into the supplier diversity programs including: incorporating supplier diversity language into all new contracts; attaching supplier diversity questionnaire in bids over $250,000; completing a data enrichment process, finding 200+ diverse active suppliers in the Company's procurement database, along with 500+ small businesses; building an internal dashboard to track spend with diverse and small businesses; providing internal training with guidance for employees to include diverse businesses when bidding projects; and also asking Minnesota Power's vendors to provide information on their own supplier diversity programs. Minnesota Power has attended and sponsored over a dozen in-person and virtual networking events held by:

- Women's Business Development Center;
- North Central Minority Supplier Development Council;
- EEI;
- Minnesota Tribal Contractor Council;
- Small and Disadvantaged Business Opportunities Council;
- Quorum;
- Disability: IN (Minnesota and Wisconsin);

- National Veterans-Owned Business Association; and
- National Veterans Business Development Council.

Minnesota Power is managing a Tier-2 spend reporting process with over a dozen prime contractors. This process gathers information on subcontractors or suppliers used by those prime contractors. Minnesota Power added Tier-2 supplier diversity language into all new contracts starting in 2022, is seeking Tier-2 information from prime suppliers on bids over $250,000, is gathering data quarterly from our credit card provider on diverse supplier spend, and is publishing an external supplier website for all prospective and current suppliers to utilize in working with the Company (www.allete.com/supplier).

Q. Please summarize the Transmission and Distribution O&M in the 2024 test year.

A. The Transmission and Distribution O&M for the 2024 test year was developed to ensure that Company operations continue to support the critical efforts of the Company's *EnergyForward* strategy through continued efficiency in work processes and delivery of safe and reliable service to Minnesota Power's customers while balancing increasing cost challenges in supply chain and contractor availability, extreme weather events, and aging equipment.

V. SYSTEM RELIABILITY

A. <u>System Reliability</u>

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 SRSQ report.[17] In that report, Minnesota Power outlines how the Company continuously strives to provide efficient, reliable service to all customers across a unique service territory in northeastern and central Minnesota.

Q. What trends has Minnesota Power seen related to system reliability?

A. Minnesota Power has seen a significant increase in weather related outages since 2020 that have impacted customer reliability. Since 2020, the total number of incidents per year has averaged over 50 percent above historic averages compared against 2013–2019 data. Besides weather impacts, Minnesota Power has seen significant increases in outages related to human causes (*e.g.*, vehicle incidents and dig-ins) and aging underground and overhead infrastructure. One example of the Company's efforts to improve reliability is the Company's work to strategically underground certain overhead distribution lines.

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. 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 in inaccessible areas with heavy vegetation. The main drivers for strategic distribution undergrounding are reliability improvement, storm resiliency, aging asset replacement, potential O&M vegetation reduction costs, and reductions in trouble costs as reliability improves. Locations are prioritized based on feeder reliability, vegetation costs, accessibility for maintenance, and geology. Industry consultants have been used to develop a long-term plan over 2023 and 2024 that prioritizes distribution undergrounding efforts based on projects that provide the best cost-benefit for our customers. Based on the experiences of other utilities that have implemented similar programs, the Company anticipates

[17] *In the Matter of Minnesota Power's 2022 Safety, Reliability and Service Quality Standards Report*, Docket No. E015/M-23-75 (Apr. 3, 2023).

several customer benefits including fewer outages, O&M cost savings, enhanced safety, and enhanced reliability.

Q. What is Minnesota Power doing to improve system reliability?

A. Minnesota Power has made both core infrastructure and technology related investments described later in my testimony to make measurable improvements in reliability. In this section of my testimony, I discuss efforts on Grid Modernization along with Reliability and Power Quality spending.

B. Grid Modernization Technology Solutions/Systems

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 the Company ensuring grid, customer, and data security with these initiatives in technology?

A. As any new technology or cyber system is developed and deployed, the Company conducts a cyber security risk review and incorporates cyber security and data protection language in vendor contracts where deemed appropriate. Following the review, as part of the overall vulnerability management program, a vulnerability management process is developed based on the risk of the specific system. Additionally, new technology is subject to the Company's comprehensive cyber security layers of defense, including "need to know" access to data and systems, system monitoring and cyber security protections, disaster recovery planning, and periodic internal and third-party security assessments. These additional controls result in a reduction of cyber-attack risk, an increase in system reliability and resilience, and an increase in cost of service. The Company is currently an active participant in the Department of Commerce workgroup ordered by the Commission in its June 7, 2023 order in Docket No. E999/CI-20-800,[18] as well as with the Commission process establishing open data access standards and privacy policies in Dockets Nos. E, G-999/M-19-505[19] and E,G-999/CI-12-1344.[20]

1. Advanced Metering Infrastructure ("AMI")

Q. What is AMI?

A. AMI is a two-way communication between utilities and customers that provides an integrated system of smart meters, communications networks, and data management.

In 2010, Minnesota Power began deploying the infrastructure and endpoints of an AMI system. This was done in part to help transition to a next generation technology required to overcome some of the operating and emerging obsolescence challenges associated with the AMR technology. Communications infrastructure investments for the AMI system are planned for 2023 and 2024 with purchases and deployment of AMI meters continuing through 2023. The infrastructure investments are in preparation of the next generation of AMI meters that allows for additional communications channels and enhanced alarming capabilities. Capital additions for AMI meters are included in the Metering section of Table 1 above. In Table 8, the Company has provided details related to the AMI deployment since the Minnesota Power's 2016 Rate Case, Docket No. E015/GR-16-664.

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[18] *In the Matter of a Commission Investigation on Grid and Customer Security Issues*, Docket No. E999/CI-20-800.

[19] *In the Matter of a Petition by Citizens Utility Board of Minnesota to Adopt Open Access Data Standards*, Docket No. E, G-999/M-19-505.

[20] *In the Matter of a Commission Inquiry into Privacy Policies of Rate-Regulated Energy Utilities*, Docket No. E,G-999/CI-12-1344.

Table 8. Deployment Plan for AMI Meters

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

* Minnesota Power anticipates that some of the 203 remaining meters may never be replaced as customers may opt out of the meter replacement program.

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

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 service and when the power is restored to a customer service. The AMI system allows service dispatchers to "ping" individual customer meters to verify power restoration and service status manually.

Overall, the AMI system allows for efficient metering access, enhanced communication, and situational awareness between Minnesota Power and its customers. The meters act as "smart nodes" at each customer's premises, allowing a number of benefits including: efficient deployment of advanced time-based customer rate offerings; outage notifications; notification of service issues (such as low/high voltage, over current, and tamper warnings); improved load control (such as Dual Fuel and Controlled Access programs); more frequent customer usage data; and the ability to more quickly reconnect customers who have been involuntarily disconnected due to non-payment. The expansion of Minnesota Power's AMI capabilities lays the groundwork for further vSmart Grid initiatives and improvements to the customer experience. Additionally, the Company's AMI deployment was foundational in Minnesota Power being the first utility in the state to implement a default time-of-day rate structure for residential customers.[21]

Q. How has the AMI system directly benefited customers?

A. Since the AMI system installation was initiated, there have been many customer benefits realized. One of the most critical improvements is the read rate improvement versus the legacy AMR system, which has resulted in fewer estimated bills sent to customers. The customer read rate percentage that the Company tracks is the number of billing reads the Company receives from the system that are acceptable for billing during the billing window. The AMI system currently provided a read rate greater than 99.9 percent of meters during the billing window of June 2023. The historic AMR system read rate was just over 97.4 percent, which resulted in a higher rate of estimated bills.

In addition, AMI usage data has been integrated with Minnesota Power's MyAccount customer portal. This allows for more granular usage data to be displayed and to be compared with historical usage and/or average temperature. This data can be used by the customer to better understand their energy usage and see the changes when shifting activities or replacing appliances, lighting, or other electrical systems. As mentioned above, the AMI system has also enabled Minnesota Power's first-in-the-state plan to transition all residential customers to a default time-of-day rate structure, which provides customers with even more control over their energy bills and encourages customers to shift their energy use from periods of high energy demand and high prices to times when energy demand and prices are lower.

Another critical benefit has been the ability for the AMI system to detect an over-temperature, sometimes referred to as a "hot socket" condition, to minimize the likelihood of a potential catastrophic failure at a meter socket. Minnesota Power began tracking these alarms since 2012 and has had 1,019 unique hazard alarms, 883 of which were conditions that required further action to remediate a hazard.

[21] In the Matter of the Petition Approval of Changes to Minnesota Power's Residential Rate Design, Docket No. E015/M-20-850

In addition, AMI meters with remote capability can be used to disconnect and reconnect customers. While disconnections need to follow Minnesota Rules and Statutes regarding in-person contact attempts, the remote aspect for reconnections can provide for more timely reconnections. This functionality and related savings are being explored as part of the Company's Reconnect Pilot.

Q. What is the status of the Company's Remote Reconnect Pilot Program?

A. Minnesota Power's Remote Reconnect Pilot was approved by the Commission on December 9, 2020 in Docket No. E015/M-19-766. This is a voluntary three-year pilot program under which residential electricity customers whose service has been disconnected due to non-payment would have the option to have their service reconnected remotely after meeting reconnection requirements. A participating customer with a remote-capable meter could have service reconnected within minutes after calling customer service, eliminating the need for Minnesota Power to send staff to the customer's location to reconnect service in person and allowing for a waived reconnection fee for the customer. The Company's target remote-capable meter deployment is 10 percent of residential meters, or about 12,250. Minnesota Power requested an extension of this program on September 26, 2023.

Due to the economic impacts of the COVID-19 pandemic, and particularly in response to the issuance of the Governor's Emergency Executive Order, Minnesota Power voluntarily took several proactive measures to provide protections and enhance safety for employees, customers, and communities during the peacetime emergency. Part of these actions included suspension of disconnections for residential customers facing financial hardship as a result of the coronavirus pandemic. In its August 13, 2020 Order under Docket No. E,G999/CI-20-375, the Commission ordered: suspension of disconnections for residential customers; suspension of negative reporting to credit agencies for residential customers; and waiving reconnection, service deposits, late fees, interest, and penalties for residential customers. In the Commission's May 26, 2021 Order in Docket No. E,G999/CI-20-375, the Commission adopted a modified Consumer

Advocates' Transition Plan and allowed for the resumption of disconnections on August 2, 2021. With the resumption of disconnections, Minnesota Power started the three-year pilot by further deploying remote-capable meters, timed with reconnection of service, to realize operational efficiency and maximize the potential savings to customers in terms of Company costs as well as direct costs such as future reconnection fees. On September 26, 2023, Minnesota Power requested a two-year extension of the pilot under Docket No. E015/M-19-766. This extension, if granted, will provide for a better evaluation period to further assess benefit and cost impacts and more definitively inform the business case for a broader offering going forward.

Q. What are the net cost changes due to the Company's Remote Reconnect Pilot Program?

A. The Remote Reconnect Pilot Program rollout was delayed due to the suspension of many collections activities in response to the COVID-19 pandemic. Resumption of disconnections began on a limited basis as of August 2, 2021 and the three-year pilot began simultaneously. As of December 31, 2022, there were approximately 4,437 remote-capable meters installed for residential accounts, as reported in the Company's SRSQ report. The cumulative net cost changes for the pilot are $512,000 Total Company ($505,000 MN Jurisdictional), using 2021 and 2022 calendar year data. As of August 31, 2023, there were approximately 8,201 remote-capable meters installed for residential accounts, with 1,091 disconnections and 765 reconnections within 24 hours associated with these accounts in 2023. The Company will continue to report on the Remote Reconnect Pilot Program status in its SRSQ report.

2. Customer to Meter Project

Q. What is C2M?

A. Minnesota Power's Customer to Meter ("C2M") system is a flexible, highly scalable customer information solution with Meter Data Management ("MDM") capabilities designed to meet the needs of electric, gas, and water services. It includes functionality for Billing, Credit and Collections, Payments, MDM, Meter Asset Management, and Service Order Management.

Q. What is the Company doing to maximize the value of C2M?

A. C2M went live in April 2021, and the system was in a stabilization period for a year after implementation. It has since gone through numerous system enhancements and advanced functionality to further benefit customers and processes for serving customers. These include:

- Enhanced estimation routines. For example, estimation during outages to estimate zero usage for the minutes/hours/days a customer is out of power, which results in more accurate billing;
- Implemented, supported, and automated complex rates, such as the new time-of-day rate for residential customers;
- Automated communication from C2M to meters for starting and stopping service, and remote connection and disconnection;
- Ability to store historical data from AMI, such as meter alarms and service voltage information;
- Customers with AMI are able to view their 15-minute interval meter reads in MyAccount, providing a clearer, more granular view of how they use energy;
- Ability to add logic to meter alarms, allowing Minnesota Power to use the information meters are sending to more proactively investigate potential issues;
- Ability to provide Cost of Service Study information based on actual data, using Minnesota Power's entire meter population rather than a sample; and
- Ability to store process scripting to ensure consistent, informative conversations with customers.

This solution provides the foundation to respond more quickly to changing regulatory and marketing demands. Meter and customer data in one system of record drives deeper insights and service capabilities. It has improved the Company's understanding of its customers via data analytics and dashboards, rate guidance, and targeted program offerings to customers, as well as the efficiency and accuracy of the meter asset management process. Additionally, it has reduced risk through elimination of the in-house developed system for distributing and analyzing meter data.

3. Mobile Workforce Management

Q. What is the Mobile Workforce System?

A. The Mobile Workforce System is a set of software applications that allows field workers to use a mobile device to complete service requests. The Mobile Workforce System capabilities include: automated scheduling based on work type, priority, and location; collection of various types of data in the field; automated completion of work in our source systems for work management; and creation of service requests in the field.

Q. What opportunities does the Mobile Workforce System provide for efficiency and cost savings?

A. Minnesota Power has identified Mobile Workforce technology as a company-wide priority for our field workforce. As part of a broader strategy of business process automation, the Mobile Workforce System provides the following efficiencies: eliminates paper work orders, optimizes schedule and automates routing, increases transparency with data, and provides real-time status of work. The scheduling transparency and improved access to hazards at customer premises in the field also benefits worker safety.

Q. What does the Mobile Workforce System provide to customers?

A. The Mobile Workforce System benefits customers by connecting field to office in a way not previously available to our employees. The benefits mentioned above—specifically real-time completion of orders, elimination of paper, and automated routing—all contribute to more efficient operations and result in better billing accuracy and a better customer experience. The system also positions Minnesota Power to systematically share scheduling and completion information with our customers.

Q. How does Minnesota Power plan to extend the Mobile Workforce System to the remaining field workforce?

A. The first phase of the Mobile Workforce System initiative (Meter and Collections) went live in June 2018, and resulted in the elimination of nearly all manual phone calls and data entry for meter and collections field activity completions (an average of 26,000 field activities completed via mobile device per year). Since going live with this phase, more field activities have been completed with fewer staff, which allows staff to respond more quickly to customer requests with more accurate data entry.

The second phase of the Mobile Workforce System initiative (Line Operations) began with the extension of the system to trouble orders from the OMS at the end of 2019. In 2021–2022, an average of 6,800 outage and trouble orders have been completed annually via a mobile device. Scheduled line work assignments from our Work Management System were added to the system in 2021, with an average of 4,200 work assignments completed annually via mobile device since then, and full paper replacement for Line Operations work orders is scheduled for mid-2024.

Additional groups Minnesota Power is extending the Mobile Workforce System to in 2023 include Vegetation Management, Substation and Relay technicians, Utility Workers, and Fleet mechanics.

4. Reevaluation of Transmission and Distribution Maintenance Program Needs

Q. What work is Minnesota Power doing to reevaluate its maintenance program needs in the Transmission and Distribution areas?

A. Minnesota Power continues to prioritize sound investments in the distribution system to maintain and improve reliability and is focused on the maintenance and replacement of critical assets as necessary to maintain safe system performance. Minnesota Power continues to increase the focus on distribution equipment maintenance and replacement and will continue to develop these programs into the future. Resources and engineering staff have been added to the Distribution Asset Management department to focus on inspections, preventative maintenance activities, and work creation as an outcome of these activities.

Q. How is this changing the maintenance program?

A. Minnesota Power can now monitor larger areas for power quality issues. Over 99 percent of its system has AMI meters installed on customer premises. These meters are polled each month and the voltage tolerances are reviewed to aggregate a list of potential issues. These issues are then reviewed by engineering resources to look for signs of failing equipment, overloaded transformers, or long secondary runs to customer sites.

Q. How does Minnesota Power resolve customer power quality issues?

A. Minnesota Power also resolves customer power quality issues on a case-by-case basis. When a customer calls with a complaint or questions regarding a power quality issue, Minnesota Power investigates and resolves all problems found to be caused by the Company. In the event of complaints regarding low voltage or high voltage, Minnesota Power will do an investigation of the customer's service and check for loose or overheated connections. If no problem is found or if the problem is intermittent, the Company will install a recording voltmeter. This meter allows for monitoring of the voltage over time and under various customer and system loading conditions. If those recordings demonstrate that the Company is not meeting its ANSI C84.1 service entrance voltage standards of +/- five percent of nominal voltage, Minnesota Power performs the required maintenance in order to bring the voltage within the prescribed limits. Requests from customers for power quality studies are infrequent.

Q. What other initiatives has the Company been undertaking to reevaluate and improve its maintenance program?

A. The Company has made several advancements with regard to tracking and improving the frequency of failed equipment.

First, Minnesota Power recently developed an application that allows any employee to identify areas of concern as employees are making observations on the system. The employee reports the issue by scanning a barcode placed on the equipment and reporting the repairs/replacement needed. This application creates a service request and is followed up with a work order to prevent the issue from creating an outage in the future.

Since 2021, the Company has received 7,755 service requests and has remedied over 83 percent of those issues identified. The Company expects to see rates of failed equipment decrease in future years as these issues are resolved.

Second, the Company has focused on preventative maintenance activities on distribution assets such as switches, reclosers, regulators, and capacitor banks. By performing proactive maintenance on equipment, the Company anticipates a reduced equipment failure rate and improved reliability.

Third, Minnesota Power has invested in equipment that requires little to no maintenance. This new equipment has better technology to clear temporary faults, which should increase reliability and reduce line crews being dispatched to respond to outage calls. Also, the newer equipment is lower cost than traditional distribution equipment. Between the lower purchase cost and a reduced need for maintenance, it will be less expensive to operate the equipment over its service life. Trip Savers are a great example of this newer technology; Trip Savers are a re-closer in a cutout body. The Company decided to use this equipment to replace its aging oil-filled re-closers out on the distribution feeders. Aging cutouts are another opportunity to use Trip Savers instead of replacing the older cutout with the same technology.

Fourth, the Company is conducting audits throughout its distribution service territory to identify equipment that may need attention. This equipment will be brought into the work management system and placed on a preventative maintenance schedule. These audits allow Minnesota Power to prioritize which equipment needs the most attention based on age and number of customers affected if the equipment fails. By conducting preventative maintenance activities on equipment, customers will see decreased outages and increased reliability, and Minnesota Power will see longer service life of its equipment with less failure rates.

Fifth, the ground-line program has been updated to treat every pole as mentioned in Section III.C of my Direct Testimony. The ground line inspections that result in capital projects that extend the lives of the poles has shifted from traditionally O&M expense to mostly capital, resulting in lower O&M costs since 2022.

Finally, Minnesota Power is pursuing more strategic undergrounding projects, which will reduce system maintenance and costs related to outage response and vegetation management activities. More information on the Company's strategic undergrounding program can be found in Section IV.A of my Direct Testimony and in Minnesota Power's 2023 IDP, filed on October 16, 2023 (Docket No. E015/M-23-258).

5. Geographic Information System

Q. What is the GIS?

A. GIS is the suite of spatial technologies that Minnesota Power uses to store, analyze, and report on the location and geographical aspects of its electrical system. At its core, GIS is a relational database that tracks information related to "features," meaning specific assets or components within the system. The GIS contains information on the geographic location of the feature and also contains asset or component-specific information about each feature. The information about each feature can be used to visualize that feature on a map as well as analyze it in relation to other spatial datasets. These datasets can be ones maintained by Minnesota Power, like connected customers or primary, or third-party datasets like rail lines. Using the data within the GIS, Minnesota Power can tell how many transformers are installed within our service territory. These data allow Minnesota Power to count the customers served by those transformers and identify which counties those customers reside in. While the GIS system has been in place since 2003, Minnesota Power continues to find ways to maximize the technology to support customer needs.

Q. How does the existing GIS system serve customers?

A. The GIS, as well as the staff that support and operate it, serves external customers in a variety of visible and invisible ways. Perhaps its most core support is with the OMS, discussed later in this section. Data is translated out of the GIS into the OMS, which allows for rapid restoration of power during storms or other outages and feeds the information in the customer outage map, which is available for viewing by customers on the Company's website and through the Minnesota Power app.

The GIS also sends data to Gopher State One Call in support of the statewide one-call hotline. The information is used to determine which utilities have underground facilities that could be affected by customer construction activities. This same information is also provided to locating contractors that then verify the physical location of underground assets and ensure the safety of customers. This data is also provided to customers on an ad-hoc basis for planning purposes.

Customers calling into the call center to report streetlight issues are indirectly interacting with a system created out of the GIS. Call center staff interact with a map of existing lights and a simple form to collect information on the reported issue. This data is then automatically routed to field staff who find and fix the issue.

The GIS system also supports AMI meter alarms and feeder voltage analysis, allowing internal support personnel to identify customer power quality and service symptoms prior to an outage or other major problem.

Q. How will future changes improve the Company's GIS abilities?

A. The Company is in the midst of transitioning to an emerging GIS model that connects data across all of the systems, from generation to customer. This work began in 2019 and the first phase was completed in 2022. The second phase of this project is under way.

Following this work, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system or create backups of the GIS in order to do historical studies and reports.

The underlying technology supporting the GIS is being changed to support a scalable and mobile workforce. This change allows for centralized administration of users and editors of the GIS and will reduce the hardware needed to support the GIS. Moving to a more real-time GIS system will also remove some of the delays in current data integrations. This will allow the Company to act on information faster and resolve issues in a more timely manner.

The GIS system also features a survey application that has led to the elimination of many paper processes for data collection. This survey tool is one of the most used applications from our GIS vendor. It is a form-based entry tool that runs across all of the mobile and desktop technologies, providing easy access with desired information requested in a logical format.

6. Outage Management System

Q. What is the OMS?

A. The OMS manages the detection, location, isolation, repair, and restoration of faults that occur unexpectedly on the distribution system in addition to managing planned distribution outages. It provides support to operators at all stages of the outage life cycle, starting from events (customer reports, AMI outage notifications, Supervisory Control and Data Acquisition ("SCADA") operations, and notification from the field crews) and concluding with the restoration of electric service. The OMS is the overall coordinator of all tasks, processes, and recordkeeping associated with the resolution of distribution outages and is the single source for communicating outage information to internal and external stakeholders (primarily through the outage map on the website and available through the Minnesota Power app).

Q. How is the Company utilizing the current OMS system?

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

Q. How will future changes to the OMS impact customers?

A. Given these issues, Minnesota Power is executing a project to replace the OMS with a product that will improve integration with the GIS to eliminate or greatly reduce the mapping errors described above. This mapping improvement will result in the OMS having a more accurate representation of the distribution system. This will reduce restoration times by locating isolated outages and improving prioritization of restoration work in multi-outage situations. Customers will be provided more accurate restoration times. An upgraded OMS will position Minnesota Power to more readily implement a Distributed Energy Resource Management System and/or an Advanced Distribution Management System to control widespread use of solar and other distribution generation sources if and when the need arises.

7. Communication System Improvements

Q. Please describe the communication system improvements made during recent years and explain how they benefit the Company and its customers?

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 IT systems, voice, video and others. A variety of communications methods are used based on the cost and needed reliability of the application. The Company has recently commenced three large system replacements and an expansion of fiber optic infrastructure to ensure uninterrupted and reliable communications to support all aspects of utility operations and provide communications for distribution automation and smart grid expansions. The annual capital additions related to these improvements are reflected in the Cyber Technology Services section of Table 1 in my Direct Testimony.

Q. What is the first large system replacement?

A. The first large project is a replacement of the existing Synchronous Optical Networking ("SONET") system. The SONET system is the core fiber optic transport platform at Minnesota Power. SONET technology is no longer commercially available, and our system is past manufacturer end of sale and manufacturer end of support, meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. A Multiprotocol Label Switching ("MPLS") system has been selected to replace the SONET system. This new MPLS system will provide a secure and reliable fiber optic transport platform while leveraging new technology, allowing Minnesota Power to expand its communications transport system, and enabling data-intensive grid modernization initiatives. The Company has completed the deployment of the core routers and has a thoughtful plan to complete the project by 2027.

Q. Please describe the second large system replacement.

A. The second large project is a replacement of the existing transport microwave radios. 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 current fleet of radios are past manufacturer end of sale and manufacturer end of support, meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. The Company has completed 50 percent of the replacements and is on schedule to complete the project by 2025. The technology advancements in the new radios allow for faster speeds, enabling data-intensive grid modernization initiatives.

Q. What will be required for the third large system replacement?

A. The third large project is an upgrade of our land mobile radio ("LMR") system. Minnesota Power owns and operates a private LMR system to provide reliable mission critical push to talk voice communications for utility operations. The existing hardware is past manufacturer end of sale and manufacturer end of support, meaning the Company can no longer purchase replacement parts or upgrade firmware for security enhancements. The Company has completed the dispatch console replacement, and has replaced all of the mobile and portable radios and ten percent of the base station hardware. Minnesota Power is on schedule to complete the full system upgrade by the end of 2025. With this upgrade, the new digital mobile radio ("DMR") system is also providing low speed data for SCADA and distribution automation applications.

Q. How do these Grid Modernization Projects support the Company's operations and *EnergyForward* transition?

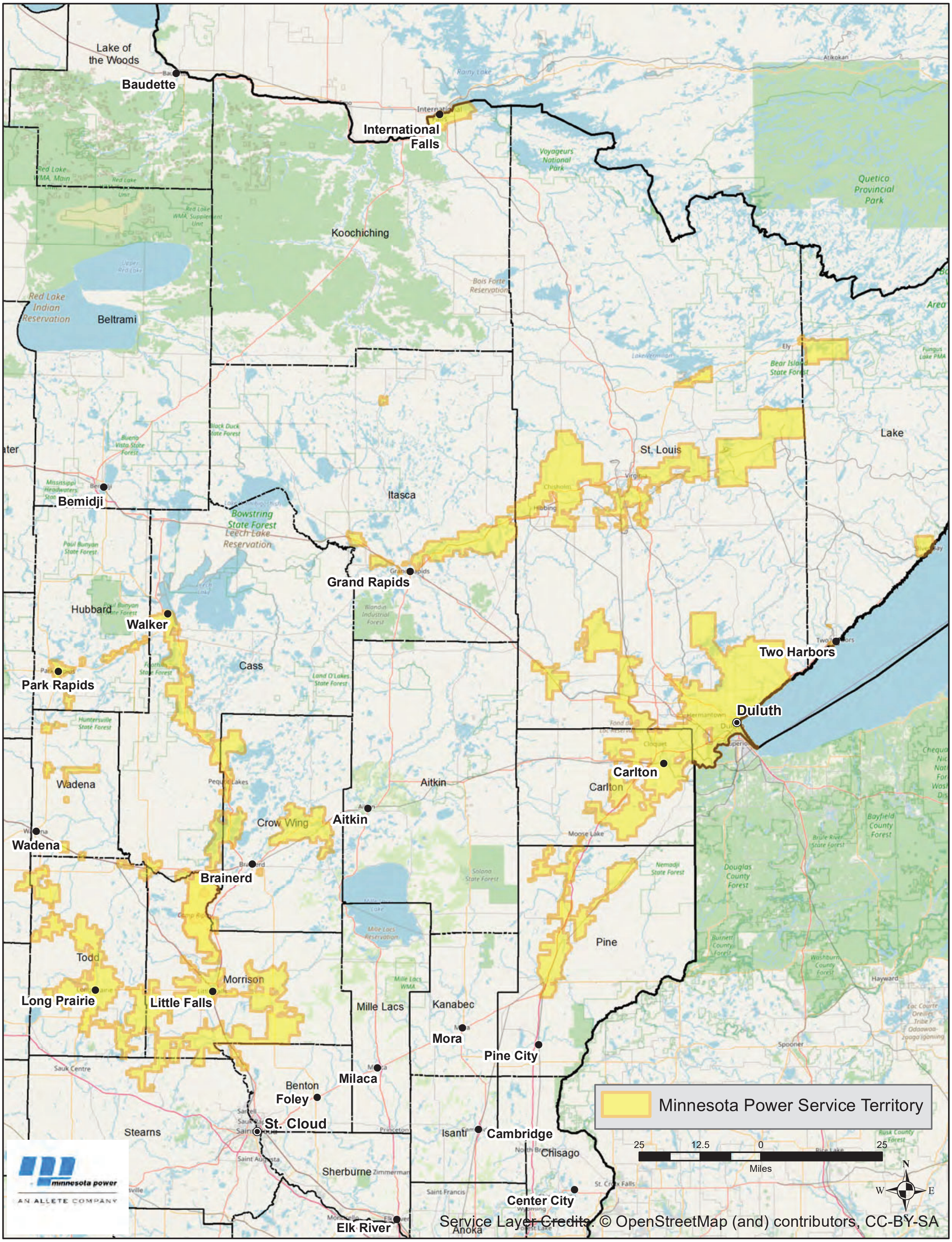
A. Each of these projects enhances the way we provide electricity to our customers. Continued innovation around, and funding for, these types of projects are critical to be able to maintain a nimble service support for our energy delivery systems and continuing to deliver value for our customers.

VI. CONCLUSION

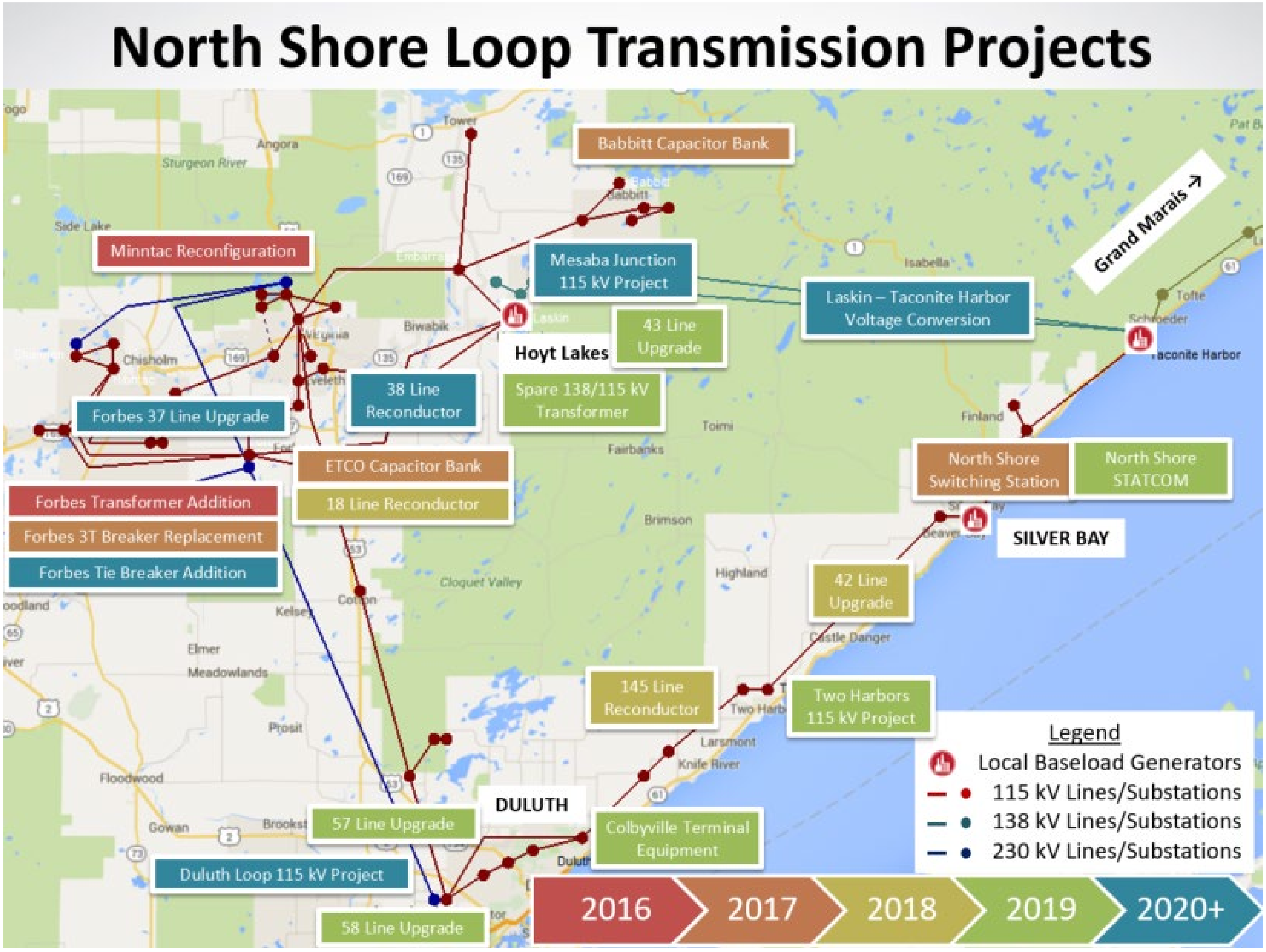
Q. Does this complete your Direct Testimony?

A. Yes.

Minnesota Power
Docket No. E015/GR-23-155



Minnesota Power
Docket No. E015/GR-23-155



Minnesota Power
Docket No. E015/GR-23-155

Minnesota Power System Third-Party Transmission Revenue and Expenses
(Total Company)

	2019 - Actuals			2020 - Actuals			2021 - Actuals			2022 - Actuals			2023 - Budget			2024 - Test Year		
	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin
Base Rates	**$ 34.60**	**$ 32.40**	**$ 2.20**	**$ 49.90**	**$ 33.70**	**$ 16.20**	**$ 61.00**	**$ 37.20**	**$ 23.80**	**$ 58.70**	**$ 38.50**	**$ 20.20**	**$ 57.20**	**$ 34.40**	**$ 22.80**	**$ 56.30**	**$ 33.70**	**$ 22.60**
Admin Schedules	$ -	$ 2.30	$ (2.30)	$ -	$ 2.30	$ (2.30)	$ -	$ 2.40	$ (2.40)	$ -	$ 2.50	$ (2.50)	$ -	$ 2.20	$ (2.20)	$ -	$ 2.70	$ (2.70)
Ancillary Services	$ 0.50	$ 1.10	$ (0.60)	$ 0.20	$ 0.90	$ (0.70)	$ 0.70	$ 1.20	$ (0.50)	$ 0.30	$ 0.90	$ (0.60)	$ 0.30	$ 0.20	$ 0.10	$ 0.60	$ 0.20	$ 0.40
Base Transmission	$ 26.20	$ 23.30	$ 2.90	$ 26.70	$ 21.30	$ 5.40	$ 27.00	$ 22.10	$ 4.90	$ 27.50	$ 22.20	$ 5.30	$ 24.30	$ 21.40	$ 2.90	$ 25.10	$ 21.40	$ 3.70
GRE Joint Pricing Zone	$ -	$ 2.80	$ (2.80)	$ 0.30	$ 0.40	$ (0.10)	$ 0.20	$ 1.90	$ (1.70)	$ (0.20)	$ 3.70	$ (3.90)	$ -	$ 2.50	$ (2.50)	$ -	$ 2.50	$ (2.50)
Manitoba Must Take Fee	$ -	$ -	$ -	$ 12.90	$ -	$ 12.90	$ 21.70	$ -	$ 21.70	$ 20.90	$ -	$ 20.90	$ 20.20	$ -	$ 20.20	$ 19.30	$ -	$ 19.30
MISO / FERC Refund Accrual	$ (3.80)	$ (4.30)	$ 0.50	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.90	$ 0.50	$ 0.40	$ -	$ -	$ -	$ 3.10	$ -	$ 3.10
MISO Transmission Rates True-up	$ 3.40	$ -	$ 3.40	$ (0.60)	$ -	$ (0.60)	$ 0.90	$ -	$ 0.90	$ (1.80)	$ -	$ (1.80)	$ 2.50	$ -	$ 2.50	$ -	$ -	$ -
NREAC	$ 7.70	$ 7.20	$ 0.50	$ 10.00	$ 8.80	$ 1.20	$ 10.00	$ 9.60	$ 0.40	$ 10.20	$ 8.70	$ 1.50	$ 7.70	$ 8.10	$ (0.40)	$ 6.70	$ 6.90	$ (0.20)
Wheeling	$ 0.60	$ -	$ 0.60	$ 0.40	$ -	$ 0.40	$ 0.50	$ -	$ 0.50	$ 0.90	$ -	$ 0.90	$ 2.20	$ -	$ 2.20	$ 1.50	$ -	$ 1.50
Direct Customer	**$ 2.90**	**$ 1.00**	**$ 1.90**	**$ 2.80**	**$ 1.20**	**$ 1.60**	**$ 3.30**	**$ 1.40**	**$ 1.90**	**$ 3.60**	**$ 1.50**	**$ 2.10**	**$ 3.10**	**$ 1.30**	**$ 1.80**	**$ 3.30**	**$ 1.40**	**$ 1.90**
Customer	$ 1.00	$ 1.00	$ -	$ 1.20	$ 1.20	$ -	$ 1.40	$ 1.40	$ -	$ 1.50	$ 1.50	$ -	$ 1.30	$ 1.30	$ -	$ 1.40	$ 1.40	$ -
GRE Distribution	$ 1.90	$ -	$ 1.90	$ 1.60	$ -	$ 1.60	$ 1.90	$ -	$ 1.90	$ 2.10	$ -	$ 2.10	$ 1.80	$ -	$ 1.80	$ 1.90	$ -	$ 1.90
Transmission Cost Recovery Rider	**$ 19.70**	**$ 36.40**	**$ (16.70)**	**$ 17.50**	**$ 32.10**	**$ (14.60)**	**$ 19.40**	**$ 36.80**	**$ (17.40)**	**$ 20.50**	**$ 36.60**	**$ (16.10)**	**$ 21.70**	**$ 32.80**	**$ (11.10)**	**$ 19.60**	**$ 30.60**	**$ (11.00)**
Cost Shared Projects	$ 19.70	$ 36.40	$ (16.70)	$ 17.50	$ 32.10	$ (14.60)	$ 19.40	$ 36.80	$ (17.40)	$ 20.50	$ 36.60	$ (16.10)	$ 21.70	$ 32.80	$ (11.10)	$ 19.60	$ 30.60	$ (11.00)
										$ -	$ -							
Total	**$ 57.20**	**$ 69.80**	**$ (12.60)**	$ 70.20	$ 67.00	$ 3.20	$ 83.70	$ 75.40	$ 8.30	$ 82.80	$ 76.60	$ 6.20	$ 82.00	$ 68.50	$ 13.50	$ 79.20	$ 65.70	$ 13.50

Minnesota Power System Third-Party Transmission Revenue and Expenses
(Minnesota Jurisdictional)[1]

	2019 - Actuals			2020 - Actuals			2021 - Actuals			2022 - Actuals			2023 - Budget			2024 - Test Year		
	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin	Revenue	Expenses	Margin
Base Rates	**$ 28.70**	**$ 26.80**	**$ 1.90**	**$ 41.40**	**$ 27.90**	**$ 13.50**	**$ 50.60**	**$ 31.00**	**$ 19.60**	**$ 48.10**	**$ 31.70**	**$ 16.40**	**$ 47.00**	**$ 28.40**	**$ 18.60**	**$ 46.70**	**$ 28.00**	**$ 18.70**
Admin Schedules	$ -	$ 1.90	$ (1.90)	$ -	$ 1.90	$ (1.90)	$ -	$ 2.00	$ (2.00)	$ -	$ 2.10	$ (2.10)	$ -	$ 1.80	$ (1.80)	$ -	$ 2.20	$ (2.20)
Ancillary Services	$ 0.40	$ 0.90	$ (0.50)	$ 0.20	$ 0.70	$ (0.50)	$ 0.60	$ 1.00	$ (0.40)	$ 0.20	$ 0.70	$ (0.50)	$ 0.20	$ 0.20	$ -	$ 0.50	$ 0.20	$ 0.30
Base Transmission	$ 21.70	$ 19.30	$ 2.40	$ 22.20	$ 17.70	$ 4.50	$ 22.40	$ 18.40	$ 4.00	$ 22.60	$ 18.30	$ 4.30	$ 20.00	$ 17.60	$ 2.40	$ 20.80	$ 17.80	$ 3.00
GRE Joint Pricing Zone	$ -	$ 2.30	$ (2.30)	$ 0.20	$ 0.30	$ (0.10)	$ 0.20	$ 1.60	$ (1.40)	$ (0.20)	$ 3.00	$ (3.20)	$ -	$ 2.10	$ (2.10)	$ -	$ 2.10	$ (2.10)
Manitoba Must Take Fee	$ -	$ -	$ -	$ 10.70	$ -	$ 10.70	$ 18.00	$ -	$ 18.00	$ 17.20	$ -	$ 17.20	$ 16.60	$ -	$ 16.60	$ 16.00	$ -	$ 16.00
MISO / FERC Refund Accrual	$ (3.10)	$ (3.60)	$ 0.50	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.70	$ 0.40	$ 0.30	$ -	$ -	$ -	$ 2.60	$ -	$ 2.60
MISO Transmission Rates True-up	$ 2.80	$ -	$ 2.80	$ (0.50)	$ -	$ (0.50)	$ 0.70	$ -	$ 0.70	$ (1.50)	$ -	$ (1.50)	$ 2.10	$ -	$ 2.10	$ -	$ -	$ -
NREAC	$ 6.40	$ 6.00	$ 0.40	$ 8.30	$ 7.30	$ 1.00	$ 8.30	$ 8.00	$ 0.30	$ 8.40	$ 7.20	$ 1.20	$ 6.30	$ 6.70	$ (0.40)	$ 5.60	$ 5.70	$ (0.10)
Wheeling	$ 0.50	$ -	$ 0.50	$ 0.30	$ -	$ 0.30	$ 0.40	$ -	$ 0.40	$ 0.70	$ -	$ 0.70	$ 1.80	$ -	$ 1.80	$ 1.20	$ -	$ 1.20
Direct Customer	**$ 2.40**	**$ 0.80**	**$ 1.60**	**$ 2.30**	**$ 1.00**	**$ 1.30**	**$ 2.80**	**$ 1.20**	**$ 1.60**	**$ 2.90**	**$ 1.20**	**$ 1.70**	**$ 2.60**	**$ 1.10**	**$ 1.50**	**$ 2.80**	**$ 1.20**	**$ 1.60**
Customer	$ 0.80	$ 0.80	$ -	$ 1.00	$ 1.00	$ -	$ 1.20	$ 1.20	$ -	$ 1.20	$ 1.20	$ -	$ 1.10	$ 1.10	$ -	$ 1.20	$ 1.20	$ -
GRE Distribution	$ 1.60	$ -	$ 1.60	$ 1.30	$ -	$ 1.30	$ 1.60	$ -	$ 1.60	$ 1.70	$ -	$ 1.70	$ 1.50	$ -	$ 1.50	$ 1.60	$ -	$ 1.60
Transmission Cost Recovery Rider	**$ 16.30**	**$ 30.10**	**$ (13.80)**	**$ 14.50**	**$ 26.70**	**$ (12.20)**	**$ 16.10**	**$ 30.60**	**$ (14.50)**	**$ 16.90**	**$ 30.10**	**$ (13.20)**	**$ 17.90**	**$ 27.00**	**$ (9.10)**	**$ 16.30**	**$ 25.40**	**$ (9.10)**
Cost Shared Projects	$ 16.30	$ 30.10	$ (13.80)	$ 14.50	$ 26.70	$ (12.20)	$ 16.10	$ 30.60	$ (14.50)	$ 16.90	$ 30.10	$ (13.20)	$ 17.90	$ 27.00	$ (9.10)	$ 16.30	$ 25.40	$ (9.10)
Total	**$ 47.40**	**$ 57.70**	**$ (10.30)**	**$ 58.20**	**$ 55.60**	$ 2.60	$ 69.50	$ 62.80	$ 6.70	$ 67.90	$ 63.00	$ 4.90	$ 67.50	$ 56.50	$ 11.00	$ 65.80	$ 54.60	$ 11.20

[1] Please note that the application of allocators in Schedule 3 to determine Minnesota Jurisdictional amounts have been simplified from the application of allocators in the Class Cost of Service Study ("CCOSS"). Therefore, total project costs at the Minnesota Jurisdictional level may not exactly total the amounts from the actual CCOSS or amounts from the 2021 Rate Case.