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-19-442

Exhibit ________

TRANSMISSION AND DISTRIBUTION

November 1, 2019

TABLE OF CONTENTS

Page

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., 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 Supervisor Engineer of the Electric Meter Department, where I was responsible for providing project management and oversight for the Smart Grid Investment Grant ("SGIG") 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 389 employees, with approximately 204 of those employees as members of International Brotherhood of Electric Workers ("IBEW") 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. My Direct Testimony discusses the capital investments the Company has made since our last rate case in Docket No. E015/GR-16-664 (the "2016 Rate Case") and the operations and maintenance ("O&M") necessary to continue to provide efficient and reliable electricity to Minnesota Power customers in a cost-efficient manner. I provide information to support the Company's reasonable, necessary, and prudent investments in local and regional capital projects and ongoing maintenance of our power delivery systems. I am also providing testimony on the continued benefits of the Company's participation in the Midcontinent Independent System Operator, Inc. ("MISO") and how that participation impacts revenues 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 related to this critical Company function.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

- MP Exhibit ___ (Gunderson), Direct Schedule 1 – Service Territory Map
- MP Exhibit ___ (Gunderson), Direct Schedule 2 – North Shore Loop
- MP Exhibit ___ (Gunderson), Direct Schedule 3 – Grand Rapids Area
- MP Exhibit ___ (Gunderson), Direct Schedule 4 – Third-Party Transmission Revenues and Expenses

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, Purchasing, Security, Facility Management, and Engineering Services. This area provides centralized strategic sourcing and other supply chain efficiencies. These services are critical to operations and work 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 is, generally, voltages between 115 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. The transmission facilities are also critical to supporting 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, with which Minnesota Power often coordinates closely 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.

III. TRANSMISSION AND DISTRIBUTION BUDGETING

Q. How is the capital budget developed?

A. Minnesota Power currently employs a zero-based budgeting process, as explained in more detail in the Direct Testimony of Company witness Joshua G. Rostollan. The capital budget goes through a bottom-up, multi-level gated process to identify the capital projects

[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.

that need to be completed within a specific year for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas. Each of these areas maintain long-range plans based on identified needs and priorities that are used to build each year's capital budgets.

During the first phase of the annual capital budget process, each area reviews their long range plan in conjunction with expected spend and necessary timing and identifies the slate of projects to move to the next phase. The second phase involves cross-functional review. Leadership and subject matter experts from Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas come together to review the slate of 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 considered again 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. All projects in the capital budget must receive management approval and are then compiled into the annual capital budget presented for review and approval to the Minnesota Power Board of Directors and the ALLETE Board of Directors.

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 reliability of the transmission and distribution system used 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 projects led by the Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas. The PRB is responsible for reviewing the projects to ensure that those proposed are consistent with the Company's long-range and overall strategic plans. The PRB may request additional information or project budget development from the appropriate work areas before passing a project along to management and the Board of Directors for approval as discussed above. The PRB governs the review of capital projects, budget, scope, and expenditure changes, and is responsible for developing and executing policies and procedures that ensure desirable capital outcomes are achieved. This group also fills an advisory role to senior leadership regarding their approval of capital projects.

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

A. Each project is assigned to a project manager who is responsible for the effective delivery 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 any expected changes to scope, schedule, or cost to the PRB.

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 a performance perspective. Any variances material to the project are immediately addressed and communicated. Project forecasts are reviewed monthly to maintain a steady and dependable flow of financial information regarding capital expenditures.

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 have passed with no occurrence and funds no longer held for that potential emergent need are removed from the project's forecast.
- Budgeted schedule is no longer viable and a portion of the project must be advanced or delayed to a different calendar year.
- Unanticipated change is identified during the project, possibly related to scope addition or reduction, change in required resources, or pricing of contract(s).
- Unplanned work arises that is required to be completed or strategic in nature.

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 spend, project risks, and project contingency levels. The PRB reviews monthly reports of financial performance and updates related to high-spend or high-risk projects. The PRB reviews all changes and associated impacts to the overall portfolio. If 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. How are final decisions made with respect to canceling, delaying, or accelerating a project?

A. The portfolio of projects is reviewed in its entirety monthly. Projects with risk of execution are flagged and monitored closely by the project manager. If these projects indicate they may fall outside of allowed variances, they are reassessed by the business unit. 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 and resource commitments. Proposed changes to the portfolio are reviewed and approved by the PRB. The PRB is expected to manage the capital additions to the approved capital budget and needs to have flexibility in managing 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 the rate case.

A. Maintaining some flexibility is in the best interest of our customers. While the Company identifies the portfolio of projects for the coming year, as the lead-in year progresses, changes to that portfolio may be necessary to ensure the safe and reliable transmission and delivery of electricity to our customers. The Company actively manages its capital portfolio to ensure the highest priority projects are being addressed as they arise and that the Company is able to balance the financial aspects of the portfolio as well. As time progresses, higher priority projects may be identified, necessitating adjustments to the capital portfolio while still balancing the overall capital budget and resource requirements. The Company must have the ability to leverage capital and other resources as necessary when conditions require changes in our capital infrastructure investment.

Q. Please explain how you would like the Commission to consider this issue.

A. The Company has budgeted for, and identified, certain Transmission Projects to place in service in the 2020 test year. Minnesota Power is required to provide safe, reliable, and cost-efficient energy to our customers, which may necessitate shifting in-service dates of certain transmission projects to meet changing needs.

The Commission has previously allowed such flexibility, 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. In fact, the Commission has found sufficient time where such substitution was included in an information request response and detailed in Rebuttal testimony.

---

[2] *In the Matter of the Application of Minnesota Power for Auth. to Increase Rates for Elec. Serv. in Minnesota*, 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).

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.

Q. Will all of the projects identified in the 2020 test year be placed into service during 2020?

A. At this time, the Company is on track to place all of the transmission capital projects identified in the 2020 Budget in-service in the 2020 test year. There may, however, be extenuating circumstances, such as those mentioned above, that necessitate modifications to the overall transmission projects that Minnesota Power ends up placing in-service during 2020, although the Company manages such circumstances to ensure the overall portfolio remains balanced.

Q. What has the capital investment looked like from 2018 through 2020?

A. Table 1 illustrates the Company's Regulated Plant-in-service 2018 Actuals, 2019 projected year, and 2020 test year Budget for the Transmission, Distribution, Facilities, Security, Cyber Technology Services, and Fleet work areas. Table 1 is provided at the Total Company level. Capital plant additions at the Minnesota Jurisdictional level are provided in Table 2.[3]

---

[3] A summary of allocation factors used across the Company for purposes of calculating the Minnesota Jurisdictional totals is provided with the Direct Testimony of Company witness Mr. Stewart J. Shimmin at MP Exhibit ___ (Shimmin), Direct Schedule 1—Guide to Minnesota Power's CCOSS, at Table 4.

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

Capital Plant Additions (including Contra) -- Total Company	2018 Actuals	2019 Projected Year	2020 Test Year
Transmission*	$17.0	$35.5	$32.9
Baseline Reliability	$5.5	$4.0	$1.7
Externally Driven	$0.9	$1.5	$3.7
Externally Driven / Credit	-	($8.1)	-
Strategic / Grand Rapids Area	$1.9	$8.6	-
Strategic / NSL	$4.3	$21.1	$19.7
Transmission Asset Management	$4.3	$8.4	$7.8
Distribution*	$29.2	$23.2	$29.3
Age Related & Asset Renewal	$11.8	$8.9	$10.0
Capacity	$0.4	$0.1	$0.7
Government Requirements	$1.4	$1.1	$1.4
Grid Modernization & Pilot Projects	-	$0.3	$1.0
Metering	$6.6	$4.9	$4.6
New Customer / New Revenue	$4.5	$4.1	$4.4
Other	$1.6	$0.4	$2.5
Reliability & Power Quality	$2.9	$3.3	$4.7
Cyber Technology Services	$4.4	$6.1	$7.1
Facility Management	$1.3	$4.7	$8.3
Fleet	$6.6	$5.8	$4.7
Security	$0.1	$0.4	$0.2
Grand Total	**$58.5**	**$75.7**	**$82.6**

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	2018 Actuals	2019 Projected Year	2020 Test Year
Transmission*	$14.2	$30.1	$28.2
Baseline Reliability	$4.6	$3.4	$1.5
Externally Driven	$0.7	$1.2	$3.2
Externally Driven / Credit	-	($7.1)	-
Strategic / Grand Rapids Area	$1.6	$7.3	-
Strategic / NSL	$3.6	$18.0	$16.9
Transmission Asset Management	$3.6	$7.2	$6.6
Distribution*	$30.0	$22.6	$28.9
Age Related & Asset Renewal	$12.8	$8.5	$9.8
Capacity	$0.4	$0.1	$0.6
Government Requirements	$1.4	$1.1	$1.4
Grid Modernization & Pilot Projects	-	$0.3	$1.0
Metering	$6.5	$4.8	$4.6
New Customer / New Revenue	$4.5	$4.1	$4.4
Other	$1.5	$0.3	$2.4
Reliability & Power Quality	$2.9	$3.3	$4.7
Cyber Technology Services	$3.9	$5.5	$6.3
Facility Management	$1.1	$4.2	$7.5
Fleet	$5.8	$5.1	$4.2
Security	-	$0.3	$0.2
Grand Total	**$55.0**	**$67.9**	**$75.3**

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

Q. Why are the capital additions in the 2019 projected year and 2020 test year budget in Table 1 higher than the 2018 actuals?

A. In 2018 and 2019, the Company commenced substantial investments in the North Shore Loop, discussed in further detail later in my testimony, the bulk of which will begin going into service in 2019. These investments will continue for several years in this area to support the Company's overall Energy*Forward* strategy and generation fleet transition in this part of the state, as explained in more detail in the Direct Testimony of Company witnesses Mr. Joshua J. Skelton and Ms. Julie I. Pierce. Additionally, Minnesota Power's capital additions in Transmission Asset Management projects were lower in 2018 because they reflect $2.4 million Total Company ($2.0 million MN Jurisdictional) of one-time insurance proceeds received in 2018 as reimbursements for capital additions made in prior years as well as lower overall Transmission Asset Management program requirements during 2018.

A. Transmission Capital Investments and Projects

1. Overall Transmission System Support and Maintenance

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 criteria 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 in two ways: (1) Through elective involvement in the Minnesota Transmission Owners Assessment and Compliance Team ("MN TACT"); and (2) Through internal targeted evaluation of criteria violations identified in the MTEP and MN TACT assessments.

Q. What is the MN TACT's function?

A. The MN TACT performs an annual assessment in parallel with the MTEP and consistent with the transmission planning criteria from the NERC Reliability Standard that focuses on the specific system conditions that stress the transmission system in Minnesota. While the MTEP is a MISO-wide study reflective of MISO-wide system stressors, the MN TACT is a Minnesota-centric study with Minnesota-centric study cases. The MN TACT study cases are based on MTEP cases, with modifications to achieve the intended Minnesota-centric system conditions. In that way, the MN TACT assessment usually provides an early indication for issues that may show up on the Minnesota transmission system and an additional gauge for the severity of those issues.

Q. What occurs if either of these assessments identify issues related to the Company's transmission system?

A. Where significant issues are identified in the MTEP and MN TACT assessments 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 sources, 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 and 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 study phase described previously. 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 a single 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. 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. If the resource option fits with the existing resource plan then a petition for implementation could move forward. If the resource option did not fit with the current plan, then it could be considered in the next Integrated Resource Plan submittal. If the transmission system issue needed to be addressed on a timeline prior to the next Resource Plan approval, then additional requirements could be included in the petition request to detail the resource fit and timing.

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.

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. Large Transmission assets are part of inspection and monitoring programs that help identify operating issues and age related condition problems. A description of some of those programs are included later in this testimony. Contingency programs are also in place intended to enable the Company to respond to unanticipated failures that typically occur throughout the year. 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. 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 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 and through the judgment of subject matter experts and cross-functional asset management 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 identified as-needed to enhance lifecycle asset management across the fleet of transmission assets. Asset Renewal Programs are typically coordinated with a cross-functional group of stakeholders to identify, prioritize, and scope replacements or upgrades of high-priority, high-impact, or high-value assets. Year-to-year funding of Asset Renewal Programs is typically based on a pre-determined number of replacements per year, based on the above factors and overall equipment replacement cycles.

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 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 FERC open access transmission service rules.[4]

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

[4] FERC Order 888.

Company has developed close coordination practices with major stakeholders such as its large power customers and other utilities that serve the areas adjacent to Minnesota Power's transmission system.

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

A. The Company works closely with existing and potential future large power customers through regular two-way communications about upcoming needs and plans. The Company communicates its upcoming projects and required outages that may impact existing large power customer operations, while the customers communicate their upcoming projects and infrastructure needs, and potential future customers reach out, and the Company participates in dialogue, 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 Professional.

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 and the MN TACT group, as discussed above, the Company generally holds coordination meetings with neighboring utilities on an annual basis or more frequently, 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 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.B.2 of my Direct Testimony.

Q. What are Strategic Projects?

A. Strategic Projects are transmission system upgrades related to larger Company strategic initiatives such as fleet transition or regional economic development. Like Baseline Reliability Projects, they are necessary to fix 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 strategic 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 strategy 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 strategy initiative being considered (for example, different combinations of generator retirements) and the system impacts of those scenarios are captured. Where system impacts result in criteria 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 strategy 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 and MN TACT assessment processes – as more definition develops around the nature and timing of the Company strategy 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. 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 project scoping process for each type of transmission project.

A. Once a project has been identified through the evaluation processes discussed above, a project scope is defined by Transmission Planning. The project scope is intended to capture the information necessary to initiate a capital project. The project scope includes general project description; purpose; permitting and schedule considerations; engineering and construction considerations; cost estimate; and cash flow. A scoping lead, typically from Transmission Planning, facilitates further development of the project scope in coordination with the various departments that will be involved in the project, including but not limited to Substation Engineering, Transmission Line Engineering, Relay and Maintenance Engineering, Meter Engineering, Communications Infrastructure, Distribution Engineering, Engineering Project Delivery, System Operations, Construction and Maintenance, the Land Department, and Environmental Permitting. Through this cross-functional coordination, preliminary indications of the schedule, required permits or approvals, route, site, layout, cost, cash flow, and construction plan for a project are developed and incorporated into the project scope. The project scope is reviewed and refined by the internal group and coordinated with affected external entities, until the scoping lead determines that it is complete.

Q. Please explain the capital budgeting process for each type of transmission project.

A. The capital budgeting process for transmission projects begins with Minnesota Power's long range plan. Confirmation or update to the requested budget amounts for Transmission Asset Management Projects is requested from the subject matter experts for the assets. The required timing for Baseline Reliability, Externally-Driven, and Strategic Projects is confirmed, if necessary, and project scopes are developed for these projects if not already complete. All projects potentially targeted for the budget year are then evaluated based on value and priority.

Assessed project value components include personnel and public safety; compliance and legal requirements; reliability; cost recovery; financial payback; efficiency and cost savings; and impact on Company strategy. Assessed project prioritization components include the overall project value; the timing of any external entity needs driving the project; the timing for any system capacity need associated with the project; the magnitude of customer load that benefits 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. For multi-year projects with previous phases completed or in progress, a work-in-progress component is also included in the priority evaluation. Transmission Asset Management Projects are generally given the highest priority to ensure that baseline utility needs are met. The remaining projects are assessed to ensure that the highest-priority projects are included in the capital budget. Lower-priority projects may be deferred, or project staging and project budget amounts may be refined until a reasonable, prudent, and necessary final budget proposal is developed that will address Company needs and meet Company capital spending plans.

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

A. There is only one Baseline Reliability Project included for the test year: a capacity increase on the Grand Rapids to Riverton 115 kV line ("11 Line Upgrade Project").

Q. What is the 11 Line Upgrade Project and why is it needed?

A. The 11 Line Upgrade Project involves targeted structure replacements to increase the thermal capability of the existing Grand Rapids – Riverton 115 kV Line ("11 Line"). The existing 11 Line provides an inter-area tie between the Company's 115 kV system on the Iron Range and its 115 kV system in the Brainerd/Little Falls Area. Pre- and post-contingent overloads on the line have been consistently identified in the annual MTEP and MN TACT assessments for several years, in part because it is one of the oldest, lowestcapacity, and longest 115 kV lines on the Company's transmission system. In the past, an operating guide was an effective strategy for managing potential overloads, deferring significant investment in the 70-mile transmission line. Recent MTEP, MN TACT, and internal Company studies have indicated that this operating guide is becoming less effective, and a more permanent mitigation solution needs to be implemented. The 11 Line Upgrade Project was reported in the 2019 Minnesota Biennial Transmission Projects Report under tracking number 2019-NE-N1. The 11 Line Upgrade Project is intended to be placed in-service by the spring of 2020.

Q. What Transmission Asset Management Projects are included in the 2020 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.

Q. What major Externally-Driven Projects are included in the test year?

A. There is one major Externally-Driven Project included in the 2020 Test Year: a reroute of an existing 115 kV line around an expanding United Taconite tailings basin in the Forbes area ("16 Line Relocation"), which was approved by the Commission in Docket No. E015/TL-14-977.

Q. What is the 16 Line Relocation Project and why is it needed?

A. The 16 Line Relocation Project involves rerouting of a segment of the existing Arrowhead – 16 Line Tap 115 kV Line ("16 Line") around a United Taconite tailings basin expansion. The Company submitted a Route Permit Application for the 16 Line Re-Route Project (Docket No. E015/TL-14-977) on January 16, 2015. An existing segment of 16 Line is located on property that the Company leases from United Taconite. To accommodate its tailings basin expansion, United Taconite has cancelled the Company's lease and is requiring the Company to reroute 16 Line around the expanded tailings basin. The total length of the new 115 kV line along the re-route is approximately three miles. The 16 Line

Relocation Project has been reported in the Minnesota Biennial Transmission Projects Report since 2015 under tracking number 2015-NE-N5. The project will be constructed during the winter 2019-20 construction season and is planned to be in service in 2020. The 16 Line Relocation Project was initially intended to be placed in service in the first quarter of 2016, as stated in the Company's Route Permit Application for the Project. The in-service date was subsequently delayed in coordination with United Taconite to correspond with the updated timing of United Taconite's planned basin expansion.

Q. What Strategic Projects are included for the 2020 test year?

A. The two Strategic Projects included in the 2020 test year are related to the ongoing transition of the Company's baseload coal generation fleet and resource mix, which is discussed in the Direct Testimony of Company witness Mr. Joshua Skelton. Both projects are located in the North Shore Loop and are related to Company decisions to 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.[5] While there are no projects in the test year related to the Company's decision to retire Boswell Units 1 and 2, I have included a discussion of the impacts of this decision on the Grand Rapids area transmission system and the project that was completed prior to the test year to address these impacts.

2. <u>North Shore Loop</u>

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 Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to

[5] *In the Matter of a Petition by Minnesota Power for Approval of an Amended and Restated Electric Service Agreement (ESA) Between United Taconite LLC, Northshore Mining Company (subsidiaries of Cliffs Natural Resources, Inc.), and Minnesota Power*, Docket No. E016/M-16-534, ORDER OF THE COMMISSION at 1 (Nov. 9, 2016).

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 Taconite Harbor Energy Center 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 Cliffs Natural Resources Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been 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 Taconite Harbor Energy Center.[6] With Commission approval in the 2015 Integrated Resource Plan (Docket No. E015/RP-15-690), Minnesota Power idled the other two Taconite Harbor Energy Center units in the fall of 2016 with all coal-fired operations to cease at the facility by 2020.[7] While these two Taconite Harbor units remain available for resource adequacy and energy marketing purposes, they are not capable of being restarted rapidly enough from their present idled state to address day to day transmission reliability issues. 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 through base load coal generation.

---

[6] *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 at Order Point 3 (Nov. 12, 2013).

[7] *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 at Order Point 3 (July 18, 2016).

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 Energy Center, Taconite Harbor Energy Center, 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 and several more projects are planned over the next five years. These projects are necessary to ensure the continued reliability of the transmission system in the area by restoring redundancy, addressing unacceptably low voltage and voltage stability concerns, and mitigating transmission line and transformer overloads. The projects have been implemented progressively 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.

Q. What are the redundancy impacts from shutting down local baseload generators?

A. When a local baseload generating facility consists of multiple generating units, redundancy is built in to both the generation facility and the local power system. The Taconite Harbor Energy Center, for example, consisted of three 75 MW generating units. At any given time, the redundancy built into the generating facility meant that it was highly likely that at least two of the three units would be running, and it was virtually guaranteed that at least one unit would be running at all times. In that sense, Taconite Harbor provided a dependable source capable of delivering 75 to 150 MW of power to the North Shore Loop with availability comparable that of the transmission system. In the event of a planned or unanticipated transmission line outage, the generation facility could continue to provide power to the area as its output could be adjusted up or down to mitigate transmission line loading or voltage issues.

In an area of the system where transmission sources are relatively sparse, like the North Shore Loop, local baseload generators can even be designed to operate with no transmission connections beyond the isolated area to restore electric service following multiple-contingency events resulting in loss of all transmission sources. Without these local baseload generators in the North Shore Loop, transmission system redundancy for the area has been lost. The resulting redundancy-related issues include post-contingent transmission line overloads, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

Q. What are the voltage support impacts from shutting down local baseload generators?

A. Local baseload generators provide reactive power and voltage support to the local transmission system. Electric power generated in an alternating current power system includes the generation of both real power, measured in MW, as well as reactive power, measured in mega volt amps reactive ("MVAR"). Reactive power is required to maintain an appropriate system voltage, stabilize the system, and enable the delivery of real power. Generators provide a dynamic source of reactive power, able to ramp MVAR output up and down within the limits of the generator to regulate system voltage. This dynamic reactive support becomes particularly important for system stability, as abrupt changes in the power system can result in rapid voltage collapse if there is not a fast-responding source of reactive power. Unlike real power, which can be transmitted over long distances with relatively minimal losses, reactive power tends to be consumed locally by loads and by the transmission system itself. As more power is transferred on the transmission system, the reactive power needed to maintain appropriate system voltage increases. Without the local baseload generators in the North Shore Loop, the main sources of reactive power and voltage support have been lost. The resulting voltage-support-related issues include increased difficulty regulating transmission system voltage, post-contingent high or low voltage conditions, and increased risk of voltage collapse.

Q. What are the power delivery capacity impacts from shutting down local baseload generators?

A. As mentioned above, local baseload generators provide a dependable, available, and controllable source of power delivery to the local power system. Local customers benefit from the redundancy and voltage support provided by the local source of power. When baseload power is no longer provided locally, the replacement power must come from remote sources. In some cases, this can cause power flows on the transmission system well in excess of what the system was originally designed to accommodate.

The North Shore Loop was historically an area with sufficient to excessive amounts of local generation going back to the mid-1900s when the local baseload generators were built, and as such the transmission system was not designed to accommodate significant flows into the North Shore Loop from remote sources. Without the local baseload generators online, the North Shore Loop now imports significant amounts of power over the transmission system from remote sources over the 230 kV/115 kV transmission system. The issues resulting from this changing use of the transmission system to deliver power formerly generated locally in the North Shore Loop include transmission line and transformer overloads as well as increased severity associated with outages that weaken or sever the connection to the remote sources of power now serving the area.

Q. What do you conclude from this discussion of the redundancy, voltage support, and power delivery capacity 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 tends to be 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 is likely to require some amount of upgrading 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 particular case of the North Shore Loop, we have found that the transmission system was highly 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 have we learned about the North Shore Loop since the 2016 Rate Case?

A. At the time of the 2016 Rate Case, the Company's evaluation of the long-term needs in the North Shore Loop following the transition of local baseload generators was ongoing. Initial evaluations had identified several necessary transmission improvements, some of which were implemented before and during the 2016 Rate Case's 2017 test year. Since then, the Company has completed the majority of the evaluations necessary to determine the scope and timing of transmission upgrades in and adjacent to the North Shore Loop. Several additional projects have been identified and implemented by the Company, including two projects in the 2020 test year. Other projects identified by the Company for potential construction and in-service beyond the 2020 timeframe and are in various stages of development.

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 2020, 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 are designed to:

- 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 ("STATCOM"), and

- restore redundancy by eliminating single points of failure and establishing an additional 115 kV transmission connection to the North Shore Loop.

The 2020 test year specifically includes the 38 Line Upgrade Project and Phase 1 of the Mesaba Junction 115 kV Project.

Q. What is the 38 Line Upgrade Project and why is it needed?

A. The 38 Line Upgrade Project involves replacement of the existing conductor on the Forbes – Laskin 115 kV Line ("38 Line") with a higher-capacity conductor. The existing 38 Line provides a critical outlet for delivery of power from the Forbes 230/115 kV source to the eastern end of the Iron Range and the North Shore Loop. In connection with the Mesaba Junction 115 kV Project, the line will be extended to provide a redundant connection to the North Shore Loop transmission system in parallel with the existing Laskin – Hoyt Lakes transmission line. The 38 Line Upgrade provides increased power delivery capacity from the Forbes source to the surrounding area to offset the loss of power formerly delivered by local baseload generators. The 38 Line Upgrade Project was first reported in the 2019 Minnesota Biennial Transmission Projects Report under tracking number 2019-NE-N11. Construction on the project is underway and is planned to be complete in 2020.

Q. What is the Mesaba Junction 115 kV Project and why is it needed?

A. The Mesaba Junction 115 kV Project involves the development of a new switching station interconnected to existing transmission lines in the Hoyt Lakes area. Approximately 5.4 miles of new 115 kV line will be constructed along the existing Laskin – Hoyt Lakes transmission line corridor to extend the existing 38 Line into Mesaba Junction. The existing connection to the Laskin Substation will be eliminated. The Mesaba Junction 115 kV Project supports redundancy for the North Shore Loop by providing a third transmission source to the area, enhances reliability by providing a modern utility-controlled path for power flow into the North Shore Loop, and continues 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 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"). Construction on the first phase of the project, involving construction of the new Mesaba Junction Switching Station, is planned for completion in late 2020.

Q. Since fleet transition in the North Shore Loop will be completed by 2020, do the projects included in this Rate Case address all of the associated transmission system investments?

A. No. The North Shore Loop projects implemented through 2020 generally represent the urgent transmission system improvements. They address single-contingency issues that are either high-impact, high-likelihood, or both. These types of issues must be addressed in order to continue to operate reliably on a day-to-day basis with no North Shore Loop generators online. Following this stage, there are several remaining issues of importance that will be addressed by projects to be implemented over the next five years. These projects generally address lost redundancy and related voltage or power delivery issues associated with multiple contingency events.

Q. What future projects will Minnesota Power implement to continue to address fleet transition in the North Shore Loop, and what issues do these projects resolve?

A. Between 2020 and 2024, Minnesota Power plans to implement additional projects throughout and adjacent to the North Shore Loop to:

- modernize and convert a legacy 138 kV system to 115 kV;
- continue establishing and enhancing transmission redundancy to the North Shore Loop and adjacent areas;
- continue strengthening existing 230 kV/115 kV sources; and
- continue increasing the capacity of existing transmission lines to support reliable delivery of power to the North Shore Loop.

Q. Does Minnesota Power need a Certificate of Need under Minnesota Statutes section 216B.243 and/or a Route Permit under Minnesota Statutes chapter 216E for any of the North Shore Loop projects?

A. None of the projects that have been implemented to date or are currently in progress have met the threshold for requiring a Certificate of Need. Only one project to be implemented in the test year, the Mesaba Junction 115 kV Project, meets the threshold for requiring a Route Permit. In that case, the necessary approval has been obtained through the local permitting authority under Minnesota Stat. § 216E.05. Future projects will be reviewed, as overall scope and design are finalized, to determine what, if any, Commission approvals are necessary before construction commences.

Q. Will Great River Energy or its cooperatives served by the North Shore Loop transmission system be providing any cost support for any of the North Shore Loop projects?

A. As a general principle, where projects involve the transmission system jointly used by the Company and Great River Energy, each party pays for the improvements to the transmission assets it owns. Because the vast majority of the North Shore Loop projects have involved only Minnesota Power-owned transmission lines and substations, Great River Energy has directly contributed to only one project, in the Two Harbors area where a Great River Energy-owned facility was involved. However, Great River Energy does compensate Minnesota Power for the use of transmission assets – including new assets – through the JPZ Agreement, as described in Section IV.B.2 of my Direct Testimony. Through the JPZ Agreement, the cost of Minnesota Power's North Shore Loop project investments will be shared appropriately by Great River Energy.

3. <u>Grand Rapids Area</u>

Q. Please describe the transmission system in the Grand Rapids area.

A. The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230/115 kV sources at the Blackberry and Riverton Substations. These transmission lines are the Nashwauk – Canisteo – Boswell

115 kV Line, the Blackberry – Grand Rapids/Blandin 115 kV Line, and the Riverton – Grand Rapids 115 kV Line. While four coal-fired generators were historically located at the Boswell Energy Center ("Boswell"), only Boswell Units 1 and 2 were interconnected directly to the Grand Rapids area 115 kV system. Boswell Units 3 and 4 interconnect directly to the 230 kV system and, prior to the upgrade discussed below, the nearest 230 kV/115 kV transformer that tied back to the Grand Rapids area 115 kV system was located at the Blackberry Substation. There was no local electrical connection between the 230 kV and 115 kV systems in the Grand Rapids area, in part because the 115 kV system was supported by the operation of Boswell Units 1 and 2. The transmission system in the Grand Rapids Area is depicted in MP Exhibit ___ (Gunderson), Direct Schedule 3.

Q. How did Boswell Units 1 and 2 support the Grand Rapids area transmission system prior to their retirement?

A. Similar to the North Shore Loop units, the presence of the Boswell Units 1 and 2 local baseload generators contributed to the reliability of the Grand Rapids area transmission system for decades by providing redundancy, voltage support, and power delivery capacity, among other things.

Q. What impacts did the retirement of Boswell Units 1 and 2 have on the Grand Rapids area transmission system?

A. Without the redundancy, power delivery capacity, and voltage support formerly provided by Boswell Units 1 and 2 to the 115kV system, contingencies impacting one or more transmission facilities in the Grand Rapids area may lead to transmission line overloads, post-contingent high or low voltage conditions, increased risk of voltage collapse, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

Q. What projects has Minnesota Power implemented to address these transmission system impacts?

A. Minnesota Power completed a project in 2019 to establish a new 230 kV/115 kV source in the Grand Rapids area by expanding the existing Boswell 230 kV Substation and connecting it to the existing 115 kV system. No additional projects are necessary at this time in the 2020 test year.

B. <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 Integrated Distribution Plan ("IDP"), filed contemporaneously with the Company's current rate case, for purposes of discussing the Company's Distribution capital. The Company's IDP identifies the following categories, which are also used in this rate case filing (Table 1 and Table 2 above) to allow for consistency across filings. The categories required for the IDP are:

- Age Related & Asset Renewal
- Capacity
- Reliability & Power Quality
- New Customer/New Revenue
- Grid Modernization & Pilot Projects
- Government Requirements
- Metering
- 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 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 while some are the result of unexpected failures. Failures are difficult to predict. Based on past practice and historical averages, amounts are included in the annual budget for cable replacements, switch replacements, and where replacement of other failed assets is necessary. Age-related Replacements and Asset Renewal projects are also identified through local engineering expertise and experience with failures on the system.

Projects are also identified through system modeling and analysis. Distribution planning performs biannual baseline system analysis on the distribution system. The types of projects identified through this means are most often System Expansion or Upgrades for Capacity and System Expansion or Upgrades for Reliability and Power Quality.

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

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 most often directly benefit the Company's customers. An example of a strategic project would be the Company's deployment of Advanced Metering Infrastructure, a multi-year concerted effort that has already resulted in numerous customer benefits discussed in Section V.C.1 of my Direct Testimony.

Q. How is the long range plan developed?

A. The Distribution long range plan is reviewed comprehensively on an annual basis for budgeting purposes. Distribution Planning leads the development of the plan, working closely with localized distribution engineers and coordinating across departments to ensure the timing of projects is as accurate as possible. Local engineering resources continually advise planning on the state and condition of areas of the system that are underperforming and may require targeted replacement of assets, with reliability being central to our planning efforts to identify these replacements.

The long range plan utilizes historical spending to establish amounts for routine maintenance. Specific projects are slotted into the plan based on timing and need date as identified though system analysis or external constraints. Many of these specific projects require close coordination with customers, local government, or other business groups within the company. Since many projects are dependent on timelines and needs outside of the Company's control, there are a fair number of changes that occur naturally in the long range plan as the Company learns more information.

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

A. Age Related Replacements and Asset Renewal Projects are used to replace failing and end of life infrastructure on the distribution system. Some of these projects are planned in advance as engineers may have identified an area prone to failure based on reliability metrics and feedback from field crews. Engineering expertise is relied on to help prioritize age related and asset renewal efforts. Typically 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, a lot of this work naturally occurs throughout the year due to unplanned failures.

Q. What are the main drivers for these Projects?

A. The main drivers for these projects are age and condition.

Q. What is an example of an Age Related Replacement and Asset Renewal Project in the Rate Case?

A. Ground-line restoration is an example of an Age Related Replacement and Asset Renewal Project. 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.

Q. What are System Expansion or Upgrades for Capacity?

A. System Expansion or Upgrades for Capacity projects are projects that increase the baseline capacity of the distribution system. For example, if voltage or capacity issues are identified because of load growth on a circuit, Minnesota Power may need to reconductor a portion of a circuit to ensure reliable service. In the past, the Company has also needed to build new distribution substations in order to increase load serving capacity.

Upgrades for Capacity are often secondary benefits of implementing a reliability project or asset renewal. A project with a strong reliability component, such as reconductoring a section of feeder to a tie switch, might also increase the capacity of the feeder although the main purpose of the project is to be able to reliably serve load from another source during an outage. The Company does not currently have many load serving constraints on the system during normal conditions as identified through system planning. Additional capacity and reliability projects are anticipated to be identified when the contingency planning study is completed in late 2020.

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.

Q. What is an example of a System Expansion or Upgrade for Capacity in the Rate Case?

A. There is one project in the 2020 test year that has a capacity component: the construction of a new feeder in the Two Harbors area. The purpose of this project is to more reliably serve customers in the Two Harbors area by building new capacity. The new portion of this feeder will be approximately two miles long and will be mostly underbuilt on an existing distribution line. Furthermore, implementation of this project will allow the Company to avoid investment in an aging substation.

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

A. System Expansion or Upgrades for Reliability and Power Quality are projects that directly benefit customer reliability. Often these projects involve building or strengthening ties to other feeders in order to more easily restore power 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 planning 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 complaints 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 Rate Case?

A. An example of a reliability capacity improvement project is the creation of a new tie location between the Canosia and Midway substations. Local engineers identified a location on the system where primary three phase could be extended by approximately only one mile and provide a feeder with a reliable backup source. Power regulators are also regularly installed on the system in order to control feeder voltage and mitigate end of line power quality issues.

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 (increased) revenue. A small number are revenue neutral. Most individual line extensions are less than $2,000. The distance from existing facilities to the new service point is the most common condition that will determine the cost. Line extensions are made in accordance with Company's Electric Service Regulations and commission-approved tariffs. The extension rules specify an allowance (credit) for each rate class. Extension costs that exceed the allowance are paid by the customer or may be covered by a guaranteed annual revenue agreement (excluding single-phase services) if the customer enters into a five year electric service agreement.

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

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

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 three years, on average, new connects are 56 percent commercial, 43 percent residential, and 1 percent municipal and industrial.

Over the three-year time frame of 2016, 2017, and 2018, there was an annual average of 1,947 work orders written for new customer connects. Street lights and area lights are also line extensions, but instead of being metered they provide us revenue per fixture. In addition, there are customer projects that do not result in any increased sales (revenue). For example, a customer requests an extension to a new service point, but is going to retire their existing connection to the system and is not adding any new load. The new extension is revenue neutral (no net sales).

Q. What are Grid Modernization and Pilot Projects?

A. The Company plans annually on baseline budgets to manage resolution of pole replacements as part of the ground line program, public road moves, transformer replacements, and other asset programs. Grid Modernization Projects for the most part are efforts that go beyond the Company's baseline work to maintain safe, reliable, and affordable energy but are necessary to keep pace with changing technology, regulatory requirements, and customer expectations. These projects are identified and selected through analyzing reliability metrics and determining what solution or suite of solutions is best suited to improve reliability performance on the system. Most often, this involves the deployment of intelligent devices on the distribution system such as line sensors, motor operated switches, automatic switches, fault indicators, and trip savers. Increased information from the distribution system helps improve customer communication and improves reliability.

Pilot projects are the Company's efforts to work with new and emerging applications on the distribution system. These small-scale projects allow the Company to explore various customer benefit and costs in a way that is affordable to customers. Pilots are most often projects and technology that the Company has little to no experience with and are meant to ensure that an effort is worth pursuing on a larger scale before expending large amounts of capital. The Company has pursued a number of pilot projects in the past that have resulted in tangible customer benefits and cost savings. Since 2016, the Company piloted the use of Trip Savers, a cutout mounted recloser, to improve reliability on areas of the system that often experience temporary faults and that are relatively far away from a service center. This pilot resulted in a reduction in the number of outages which sometimes completely eliminates the need to dispatch a service truck. The Company has since increased deployment of these devices. Moving forward, the primary goal of pilot projects is to find more cost savings and customer benefits with new and emerging technology and applications. More detailed information about Grid Modernization and Pilot projects can be found in the Company's 2019 Integrated Distribution Plan.

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, and increasing internal knowledge and experience with new and emerging technologies. 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.

Q. What are Metering Projects?

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

Q. What are the main drivers for Metering Projects?

A. The main drivers include:

- Supply usage information to our customers. Interval usage information is loaded into the MyAccount customer portal available on the Minnesota Power website.
- Increased communications failures, unsupported technology, or limitations of the technology of the legacy Advanced Meter Reading ("AMR") system due to end of life and obsolescence of technology. These meters are replaced with AMI meters, decreasing the frequency of billing estimations.
- 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 that support reliability with increased variable renewable energy on the system.

Q. What are the Distribution "Other "projects?

A. Projects included in the Other category for distribution include Facilities, Security, and Fleet. The drivers for these projects are improved operations and security of distribution facilities. Examples could include items that improve facilities and operations but do not meet the above-listed categories.

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

Q. Does the Company propose to move any investment recovery of transmission system capital investments from the Transmission Cost Recovery Rider ("TCR") into base rates?

A. Yes, one project currently in the TCR, Dog Lake, 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 Dog Lake Expansion Project and why was it needed?

A. The Dog Lake Expansion Project is part of the larger Motley Area 115 kV Project. On March 19, 2015, Minnesota Power and Great River Energy jointly filed a combined Certificate of Need Application (Docket No. ET-2, E015/CN-14-843) and Route Permit Application (Docket No. ET2, E015/TL-15-204) to the Commission for the proposed Motley Area 115 kV Project. The overall project was needed to address local load-serving and power-system overload issues in the area, as well as establishing service to a new oil-pipeline pumping station. The Company's part of the project was completed, and all portions of the project were placed in-service, in 2017.

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

A. Yes, the costs incurred by the Company to complete the Dog Lake project were prudently and reasonably incurred to complete this necessary project. Through the usage of Handy-Whitman factors, the Minnesota Power Project Estimate for the project was $3.9 million (2014$) which increases to $4.2 million (2018$) Total Company ($3.4 million MN

Jurisdictional). Minnesota Power was able to construct this project on budget at $4.2 million Total Company ($3.4 million MN Jurisdictional).

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

A. Minnesota Power requests that the Commission allow the Company to recover all Dog Lake project costs, including those currently in the TCR plus additional amounts not in the rider, in base rates, as discussed in the Direct Testimony of Company witness Mr. Shimmin.

Q. Does Minnesota Power anticipate incurring other presently known TCR-eligible project costs in the future?

A. Yes. On July 9, 2019 Minnesota Power submitted its TCR Petition (Docket No. E015/M-19-440) for the cost recovery of Minnesota Power's portion of the Great Northern Transmission Line's construction costs. Construction for the project began in 2016 and currently Minnesota Power is pleased to report that in addition to construction of the project being on schedule for the required in-service date of June 1, 2020, the construction costs are also on budget in accordance with the project's Certificate of Need approval stipulations (Docket E015/CN-12-1163).[8]

IV. TRANSMISSION AND DISTRIBUTION O&M

A. O&M Budget Development

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

A. The consolidated annual budget process is described in the Direct Testimony of Company witness Mr. Joshua G. Rostollan. 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

[8] Further discussion of the Great Northern Transmission Line's construction costs related to the TCR and this rate case are included in the Direct Testimony of Company witness Mr. Shimmin.

Company undertakes a zero-based (i.e. bottom-up) approach to budgeting, as further described by Mr. Rostollan.

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

A. Each department 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. What budget improvements has the Company made since the 2016 Rate Case?

A. Company witness Mr. Rostollan discusses this issue in detail in his Direct Testimony. However, the largest change for Transmission and Distribution relates to increasing our data validation practices. As a Company, we have shifted to reviewing budget information by FERC Account rather than the historic practice of primarily focusing on work areas and cost types. During the Company's 2016 Rate Case, the Company identified that, as functions shift between work areas or report to different leadership in the Company, relying on the departmental view can become problematic as it relates to trend data. Additionally, while the Company has a good history of actual spend to budgeting by cost type, certain work areas were not correctly estimating financial impacts to individual FERC accounts within a cost type to the level of detail we now employ. Acknowledging that core functions will retain the same FERC Accounts regardless of the Company reporting structure, the data is now primarily being viewed by FERC Account.

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

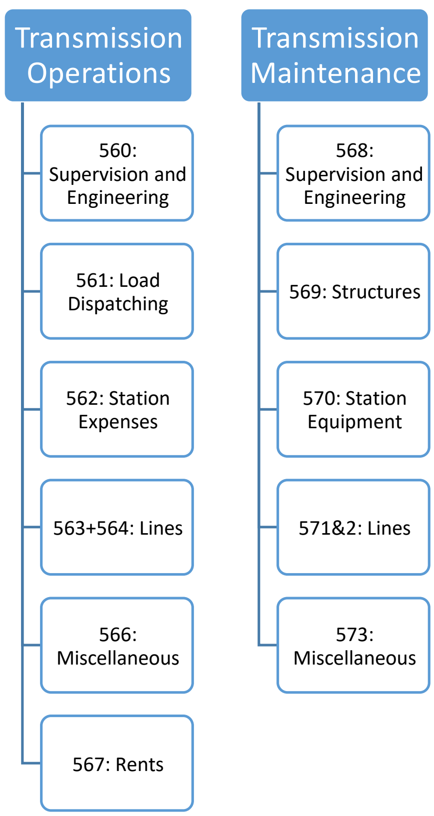
A. The Transmission O&M budget includes costs associated with the reliability-centered operation and maintenance of our transmission system. This includes performing routine inspections; engineering, planning, and performing maintenance activities and emergency repairs for overhead lines, substations, 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 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, I discuss it separately from the other FERC O&M Accounts for the Transmission work area. FERC Account 565 is discussed in Section B below.

Q. What is the 2020 test year budget for major Transmission O&M expenses?

A. Table 3 shows total Company actual and budgeted expenses from 2016 through 2018, 2019 projected year expenses, and test year 2020 expenses. We have budgeted $23.4 million Total Company ($20.1 million MN Jurisdictional) in 2020, which is an increase of $1.4 million Total Company ($1.7 million MN Jurisdictional) from 2018 actual expenses. This increase is primarily due to increased expenses associated with anticipated upgrades of leased transmission lines and substation equipment owned by Superior Water Light and Power ("SWL&P"), discussed in further detail below. Table 4 provides these amounts at the Minnesota Jurisdictional level.

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

Transmission O&M ($ millions)	2016 Budget	2016 Actual	2017 Budget	2017 Actual	2018 Budget	2018 Actual	2019 Projected	2020 Test Year
Transmission Operations	$ 13.1	$12.4	$ 15.0	$13.9	$ 15.4	$14.3	$ 10.5	$ 14.7
560	3.5	2.3	4.3	2.4	2.7	2.1	1.4	1.9
561	7.3	7.7	8.2	8.6	9.7	8.8	6.4	8.4
562	0.1	0.1	0.0	0.1	0.1	0.2	0.0	0.2
566	0.7	0.7	0.8	1.1	1.1	1.4	0.9	0.7
567	1.4	1.6	1.8	1.8	1.8	1.9	1.9	3.5
Transmission Maintenance	$8.1	$8.2	$9.4	$9.1	$9.8	$7.7	$9.5	$8.8
568	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
569	2.3	2.1	2.7	2.7	2.3	1.8	2.2	1.7
570	2.2	3.0	3.0	3.4	4.7	3.6	4.2	3.4
571	3.5	2.8	3.6	2.9	2.7	2.2	2.9	3.6
573	0.0	0.2	0.1	0.1	0.0	0.1	0.0	0.1
Grand Total	**$21.1**	**$20.7**	**$24.5**	**$23.0**	**$25.1**	**$22.0**	**$20.0**	**$23.4**

Amounts may not total due to rounding.

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

Transmission O&M ($ millions)-MN Jurisdictional	2016 Budget	2016 Actual	2017 Budget	2017 Actual	2018 Budget	2018 Actual	2019 Projected	2020 Test Year
Transmission Operations	$10.6	$10.1	$12.4	$11.5	$12.9	$12.0	$9.0	$12.6
560	2.8	1.8	3.5	1.9	2.3	1.7	1.2	1.7
561	6.0	6.3	6.8	7.1	8.1	7.4	5.4	7.2
562	0.0	0.1	0.0	0.1	0.1	0.2	0.0	0.1
566	0.6	0.6	0.7	0.9	0.9	1.2	0.7	0.6
567	1.2	1.3	1.5	1.5	1.5	1.6	1.6	3.0
Transmission Maintenance	$6.6	$6.7	$7.8	$7.5	$8.2	$6.4	$8.1	$7.5
568	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
569	1.9	1.7	2.3	2.2	1.9	1.5	1.9	1.5
570	1.8	2.5	2.5	2.8	4.0	3.0	3.6	2.9
571	2.9	2.3	2.9	2.4	2.3	1.9	2.5	3.1
573	0.0	0.2	0.1	0.1	0.0	0.0	0.0	0.0
Grand Total	**$17.2**	**$16.8**	**$20.2**	**$19.0**	**$21.1**	**$18.4**	**$17.1**	**$20.1**

Amounts may not total due to rounding.

Q. Why has Account 567 more than doubled when comparing 2016 actuals to the 2020 test year?

A. Account 567 is for Rents and includes a lease expense paid to SWL&P 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 SWL&P. 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 SWL&P transmission system assets. The Company has included $3.5 million Total Company ($3.0 million MN Jurisdictional) in the 2020 test year, reflecting additional capital additions by SWL&P and the calculation methodology included in the TALA.

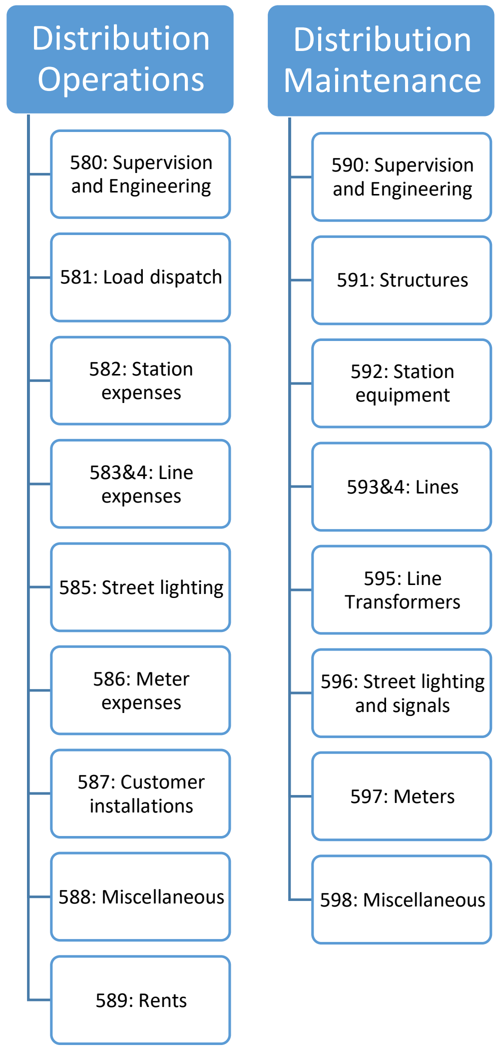
Q. Please describe the key functions within the Distribution organization that are included in the annual Distribution O&M Budget.

A. The Distribution O&M budget includes costs associated with the reliability-centered O&M of our Distribution system. This includes performing routine inspections; 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 expenses.

Figure 2. Distribution FERC Accounts



Q. What is the 2020 test year budget for Distribution O&M expenses?

A. Table 5 shows total Company Distribution actual and budgeted expenses from 2016 through 2018, 2019 projected year expenses, and test year 2020 expenses. We have budgeted $23.8 million Total Company ($22.8 million MN Jurisdictional) in 2020, which is an increase of $3.6 million Total Company ($3.5 million MN Jurisdictional) from 2018 actual expenses, but a significant decrease from prior years. This increase from 2018 actuals to the 2020 test year is primarily driven by the inclusion of storm-related expenses not previously budgeted by the Company and increased vegetation management expenses. Table 6 provides these amounts at the Minnesota Jurisdictional level.

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

Distribution O&M ($ millions)	2016 Budget	2016 Actual	2017 Budget	2017 Actual	2018 Budget	2018 Actual	2019 Projected	2020 Test Year
Distribution Operations	$11.1	$9.6	$10.9	$9.7	$10.1	$7.5	$8.6	$9.3
580	1.3	0.9	1.4	1.1	1.2	1.1	0.6	1.1
581	0.6	0.7	0.0	0.7	0.8	0.3	0.7	0.8
582	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
583	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.3
584	0.2	0.1	0.0	0.1	0.0	0.1	0.1	0.1
585	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.1
586	1.0	1.2	1.1	0.3	(0.0)	0.3	0.0	0.3
587	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
588	7.6	6.1	8.1	7.0	7.5	5.4	6.8	6.6
589	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Distribution Maintenance	$ 13.1	$17.8	$ 14.4	$15.9	$ 12.2	$12.7	$ 12.0	$ 14.4
590	1.1	0.6	0.8	0.7	0.7	0.7	0.3	0.8
592	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.1
593	9.6	14.6	11.0	12.5	8.8	9.4	9.4	10.9
594	1.2	1.7	1.3	1.6	1.8	1.7	1.6	1.6
595	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
596	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
597	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
598	1.3	0.7	1.3	0.9	0.9	0.8	0.7	0.9
Grand Total	**$24.3**	**$27.4**	**$25.3**	**$25.6**	**$22.3**	**$20.2**	**$20.6**	**$23.8**

Amounts may not total due to rounding.

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

Distribution O&M ($ millions)-MN Jurisdictional	2016 Budget	2016 Actual	2017 Budget	2017 Actual	2018 Budget	2018 Actual	2019 Projected	2020 Test Year
Distribution Operations	$11.1	$9.5	$10.9	$9.6	$9.6	$7.2	$8.3	$9.0
580	1.3	0.9	1.4	1.1	1.1	1.0	0.5	1.0
581	0.6	0.7	0.0	0.7	0.8	0.3	0.6	0.8
582	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
583	0.3	0.3	0.2	0.2	0.2	0.1	0.2	0.2
584	0.2	0.1	0.0	0.1	0.0	0.1	0.1	0.1
585	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.1
586	0.9	1.2	1.1	0.3	0.0	0.3	0.0	0.3
587	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
588	7.6	6.1	8.1	7.0	7.2	5.2	6.5	6.4
589	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Distribution Maintenance	$ 13.1	$17.7	$ 14.3	$15.8	$ 11.7	$12.1	$ 11.5	$ 13.9
590	1.1	0.6	0.8	0.7	0.7	0.7	0.3	0.7
592	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.1
593	9.5	14.5	11.0	12.4	8.4	9.0	9.0	10.5
594	1.2	1.7	1.3	1.6	1.7	1.6	1.5	1.5
595	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
596	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
597	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
598	1.3	0.7	1.3	0.9	0.8	0.8	0.7	0.9
Grand Total	**$24.1**	**$27.3**	**$25.2**	**$25.5**	**$21.3**	**$19.3**	**$19.8**	**$22.8**

Amounts may not total due to rounding.

Q Why has account 593 increased by more than 25 percent from 2018?

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 right-of-ways. This account's variability is associated with unpredictable storm-related maintenance, discussed in further detail later in my testimony.

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

Q. What is the purpose of this section of your 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. <u>Overview of the Transmission System in Minnesota and the Upper Midwest</u>

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. The Company serves the residents of Duluth, several major cities including Grand Rapids, Hibbing, and about 13 other communities in Minnesota, while other utilities serve areas between the Company's territories. Electric utilities in Minnesota and the upper Midwest (investor-owned, cooperatives, municipal utilities) have worked together for many years to develop a transmission network that will serve our respective native load customers. 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 a general decrease in costs to customers throughout Minnesota.

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

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 Transmission System (i.e., MISO MTEP); 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 Joint Pricing Zone ("JPZ") arrangement developed to compensate Minnesota Power and Great River Energy for facilities in the Minnesota Power pricing zone consistent with the MISO Transmission Owners agreement.

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 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 zones.

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. Please describe the transmission third-party expenses and wholesale revenues affecting the 2020 test year.

A. The Minnesota Power system is operated as an integrated system and is treated as one under the relevant provisions of the MISO Tariff. Using third-party transmission is necessary to serve Minnesota Power system loads, including Minnesota Power retail native loads in Minnesota, and thus the costs should be included in rates. However, these costs are offset by various transmission service revenues, thereby reducing total costs to Minnesota Power customers. MP Exhibit ___ (Gunderson), Direct Schedule 4 provides the detailed third-party transmission revenues and expenses, including revenues and expenses shared through the TCR Rider, for the 2017 and 2018 actuals, 2019 projected year, and 2020 test year in Total Company and MN Jurisdictional amounts.

Q. What are the third-party transmission revenues and expenses in base rates in the 2020 test year?

A. As shown in MP Exhibit ___ (Gunderson), Direct Schedule 4, the 2020 test year base rates include \$37.97 million Total Company (\$32.57 million MN Jurisdictional) of transmission expenses and \$35.91 million Total Company (\$30.98 million MN Jurisdictional) of transmission revenues, net of costs recovered and revenues shared through the TCR Rider.

Q. How does the 2020 test year compare to the amounts currently in base rates?

A. The 2020 test year third-party transmission expenses exceed revenues in base rates by \$2.06 million Total Company (\$1.59 million MN Jurisdictional) whereas the 2018 actual third-party transmission expenses exceeded revenues in base rates by \$6.73 million Total Company (\$5.68 million MN Jurisdictional).

Q. What are the main drivers impacting the differences between 2018 actuals and the 2020 test year budget third-party transmission revenues and expenses in base rates?

A. The 2020 test year third-party transmission revenues are \$7.12 million Total Company (\$6.90 million MN Jurisdictional) higher than 2018 actuals. The 2020 test year third-party transmission expenses are only \$2.45 million Total Company (\$2.81 MN Jurisdictional) higher than 2018 actuals.

The largest revenue increase between 2018 actuals and the 2020 test year budget is related to the inclusion of the Great Northern Transmission Line ("GNTL") in 2020 transmission revenue requirements (FERC Account 456: Base Transmission – AC Schedules 7, 8, and

9). The 2018 actuals included an accrued reduction ($4.4 million Total Company ($3.68 million MN Jurisdictional)) of revenues primarily associated with the timing of the GNTL project whereas the 2020 test year accrual ($1.0 million Total Company ($0.86 million MN Jurisdictional)) reflects an increase in revenues. The 2020 test year revenue for Ancillary Services (FERC Account 456: Ancillary Services Schedules 1 and 2) is $1.91 million Total Company ($1.72 million MN Jurisdictional) higher than 2018 actuals, reflecting an update to the MISO Schedule 2 stated rate, discussed later in my testimony.

Third-party transmission revenues and expenses in the 2020 test year are higher than 2018 actuals for NERC-related projects (FERC Account 456: NERC Required Schedule 45 and FERC Account 565: NERC Required Schedule 45, respectively) and lower than the 2018 actuals for Base Transmission for the DC system (FERC Account 456: Base Transmission – DC Schedules 7, 8, and 9 and FERC Account 565: Base Transmission – DC Schedules 7, 8, and 9). These increases and decreases largely offset each other. The increased revenue from NERC related projects is due to the2018 rate including a negative true up to revenue requirements from 2016 while the 2020 projected rate does not include that same type of reduction in revenue requirements. The 2018 rate for Base Transmission – DC included a positive true up to revenue requirements from 2016, while the 2020 rate does not include the same type of increase to revenue requirements, thus accounting for the decrease in revenues.

The largest expense increases between 2018 actuals and the 2020 test year budget are Base Transmission for the AC system (FERC Account 565: Base Transmission – AC) and Oconto (and FERC Account 565: Oconto) expenses. The Base Transmission expenses increased due to the inclusion of the GNTL line in 2020 transmission revenue requirements and the Oconto contract beginning in 2019.

Q. Do the 2020 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 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 ("MVP"). 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 4. A summary of the various MISO Schedules and impacts on revenues and expenses is provided in Table 7.

Table 7.

Summary of MISO Schedules

	Transmission Owner (revenue received)	Transmission Customer (expense paid)
Schedule 1: Scheduling, System Control and Dispatch	X	X
Schedule 2: Reactive Supply and Voltage Control from Generation or Other Sources	X	X
Schedule 7: Long-Term and Short-Term Firm Point-To-Point Service*	X	X
Schedule 8: Non-Firm Point-To-Point Transmission Service**	X	X
Schedule 9: Network Integration Transmission Service***	X	X
Schedule 10: ISO Adder & FERC Annual Charges Recovery		X
Schedule 26: Network Upgrade Charge from Transmission Expansion Plan	X	X
Schedule 26A: Multi-Value Project Usage Rate		X
Schedule 35: HVDC Agreement Cost Recovery Fee		X
Schedule 37: MTEP Project Cost Recovery for ATSI Zone	X	
Schedule 38: Allocation of Annual Revenue Requirements to the DEO/DEK Zone	X	
Schedule 45: Cost Recovery of NERC Recommendation or Essential Action	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 2020 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 4. 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. The Company's payments consist of both expense and revenue components. The 2020 expense is for our use of the Great River Energy transmission facilities to serve the Minnesota Power System loads in the Minnesota Power pricing zone. The 2020 revenue reflects use of the Minnesota Power system facilities by Great River Energy to serve their respective loads in the Minnesota Power pricing zone. The JPZ agreement includes a maximum annual payment cap of $2.8 million Total Company ($2.32 million (2017), 2.35 million (2018), 2.39 million (2019 projected), 2.40 million (2020 test year) MN Jurisdictional).

- *Ancillary Service Costs* – The Minnesota Power system currently incurs costs and receives revenue under the MISO Tariff for Reactive Supply and Voltage Control ancillary service needed by the Minnesota Power system to serve native load within the Minnesota Power pricing zone.
- *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. What has historically been one of the larger revenue contributors to the third-party transmission revenues?

A. In the past, one of the most significant revenue sources is from a number of Point-to-Point Transmission Service Requests ("TSRs") that could be directed for delivery or "sunk" into the Minnesota Power MISO pricing zone. The TSRs are reflected in FERC Account 456 in MP Exhibit ___ (Gunderson), Direct Schedule 4. The financial impact of these particular TSRs can contribute millions dollars of third-party transmission revenue. These TSRs do not serve Minnesota Power load nor are they controlled by the Company. These TSRs could either be directed to the Minnesota Power pricing zone or to a different MISO pricing zone on an annual basis and be charged monthly based on individual start and stop dates of each TSR.

Q. How is Point-to-Point TSR revenue distributed in MISO?

A. In MISO, Point-to-Point transmission revenues are distributed among the pricing zones as follows: (i) fifty percent of such revenues shall be distributed in proportion to transmission investment (calculated each month based on the relevant proportion of transmission investment reflected in the then applicable rates determined by the formula in Attachment O to the Tariff); and (ii) fifty percent of such revenues shall be shared based upon power flows.

Q. Are these TSRs stable revenue sources, such that the company can count on this revenue in the future?

A. No. These TSRs provide welcome third-party transmission revenue but the revenue is not within Minnesota Power's control. If these TSRs were delivered to a different pricing zone, the revenue received by Minnesota Power through the MISO revenue distribution formula for TSRs of this nature would be significantly less. Currently Minnesota Power makes up only 1.2 percent of the transmission investment in MISO, so without the power flow component of revenue distribution calculation for these TSRs Minnesota Power receives minimal revenue for Point-to-Point TSRs.

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. The Schedule 2 rate is based on stated revenue requirements,[9] updated only when the existing revenue requirements are no longer viable. This Schedule was most recently updated (FERC Docket ER19-283) to appropriately reflect the closure of Boswell Units 1 and 2 as well as account for additional generator changes since the last Schedule 2 update in 1996 (ER96-1580). Revenue requirements for schedules 1, 7, 8, 9, 26, and 45 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

[9] Note that the phrase "revenue requirements" in this section does not refer to the "revenue requirements" to be established as part of this rate case. Instead "revenue requirements" used in this section and in the context of third-party transmission revenues and expenses refers to transmission system related revenue requirements for transmission rate calculation/determination purposes.

Administration staff to reflect current year projected costs and the true-up of prior period costs and loads.

Q. How is the 2018 Schedule 1 and Attachments O, GG, and ZZ true-up of revenue and load included in the 2020 test year budget?

A. Minnesota Power monitors the major drivers of the Attachments O, GG, and ZZ revenue requirements throughout the year for which they are projected. At the end of 2018, Minnesota Power made an accrual entry related to the 2018 revenue requirements, as a regulatory liability. This accrual will be reversed during 2020, when the true-up is applied to revenue requirements in Attachments O, GG, and ZZ. This process ensures the Company is reporting revenues in the year for which they are earned. It also ensures the rate filings are not impacted by prior year events, thereby eliminating any retroactive ratemaking. Similarly, an accrual will be made during 2019 for the anticipated 2019 true-up of MISO Schedule 1 and MISO Attachments O, GG, and ZZ. This entry will be reversed in 2021, when the actual true-up for 2019 revenue requirements and load are processed with MISO.

Q. Has Minnesota Power reasonably and prudently developed its third-party transmission revenues and expenses budget for the 2020 test year?

A. Yes. The Company has taken into account all the details available to it, known trends, and system expectations to carefully, thoughtfully, and reasonably develop the third-party transmission revenues and expenses for the 2020 test year.

3. <u>Pending FERC Proceeding</u>

Q. Please explain the relevance of the pending FERC proceedings in FERC dockets EL14-12-000 and EL15-45-000.

A. In November 2013, a group of customers filed a complaint at FERC against MISO transmission owners, including the Minnesota Power System (Docket EL14-12-000). The complaint argued for a reduction in the return on equity (“ROE”) in transmission formula rates in the MISO region from 12.38 percent to 9.15 percent, a prohibition on capital structures in excess of 50 percent equity, and the removal of ROE incentive adders.

After a series of proceedings in 2018, FERC approved a ROE of 10.32 percent, plus a 50-basis point ROE incentive adder. This approved ROE value is utilized in the overall calculation of Minnesota Power's wholesale transmission revenue requirements through Attachments O, GG, and ZZ. A reduction in ROE results in a reduced revenue credit to Minnesota customers.

An additional complaint was filed in February 2015 proposing to reduce the MISO region ROE to 8.67 percent (Docket EL 15-45-000). FERC has established a refund effective date of February 12, 2015 for this second complaint and initiated hearing procedures. Hearings were held in February 2016, and an initial Administrative Law Judge decision of 9.7 percent was issued on June 30, 2016. FERC initially estimated it would issue an order at the end of May 2017 but an order has not yet been issued.

Q. What ROE was assumed for purposes of this case?

A. The 2020 test year budget for wholesale transmission revenue and third-party transmission expense was prepared based on the currently authorized FERC ROE of 10.32 percent plus the 50 basis point adder for a total ROE of 10.82 percent.

Q. Why was this ROE selected?

A. Establishment of a just and reasonable ROE is the responsibility of FERC. FERC issued an order authorizing an ROE of 10.32 percent and separately authorized the 50 basis point adder, resulting in a total ROE of 10.82 percent. Minnesota Power complies with these FERC authorizations by including the resulting total ROE amount in its wholesale transmission revenue requirement.

C. <u>Storm Response and Restoration</u>

Q. How are storm response and restoration costs incorporated into the 2020 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 solution could be 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 in Account 593 from our Line Operations work area.

Q. What is the 2020 test year Budget for "trouble" work included in Overhead Line Maintenance?

A. The 2020 test year budget associated with "trouble" work is $2.4 million Total Company ($2.3 million MN Jurisdictional). It is based upon a five-year average of spend 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. How is Minnesota Power changing the way it reports on O&M costs associated with storm response in this rate case?

A. In the 2016 Rate Case, the Company used a method that was intended to illustrate these costs but, despite the Company's best efforts, the calculation was, admittedly, not easily understood. O&M costs associated with storm restoration are captured in FERC Account 593 (Maintenance of Overhead Lines). In this current rate case, for clarity and understanding, we are requesting recovery of all costs associated with Maintenance of Overhead Lines, understanding that the budgeted costs related to storm recovery and restoration use a five-year average calculation. While averaging is not traditionally the most appropriate way to set budgets for the Company, in this instance where Minnesota Power is requesting, for the first time, inclusion of an amount in our base rates, the Company believes that averaging is the most prudent and reasonable basis upon which to set an initial amount. In future years, if this request is approved in this case, other methods may be more appropriate to set future test year budget amounts based on annual expectations. In the current instance, the proposed five-year average takes into account both high-year and low-year expenses for this response.

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

A. To the greatest extent practicable, yes, we do. The reliable, safe, and efficient delivery of electricity to our customers is of the utmost importance to the Company and without our transmission and distribution infrastructure, we are unable to provide that service. Minnesota Power designs and builds our system to sustain various weather conditions, including high winds, ice, snow, and extreme heat and cold. Intense weather conditions, however, are beyond our control and at times, do impact service to our customers. In those instances, we respond as expeditiously as possible, while also ensuring the continued safety of our personnel and the public.

Q. Please explain how Minnesota Power has previously handled the financial impact of storm response and restoration costs.

A. In prior years, Minnesota Power has only budgeted for some overtime labor related to storm response but not the major storm response costs we have included in the 2020 test year Budget. Minnesota Power has not previously included an amount in base rates for storm response.

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

A. For over 15 years, until the summers of 2015 and 2016, Minnesota Power was able to successfully complete all storm response and restoration work using its own line workers. In 2015 and 2016, Minnesota Power had to request mutual assistance from its other utility partners to ensure timely restoration of electric service to Minnesota Power customers.

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.

Q Does Minnesota Power provide mutual assistance to other utilities?

A. Yes. For example, in 2017, Minnesota Power provided over 17,000 hours of mutual assistance to assist the southern United States and Puerto Rico to restore electric service after the devastating effects of hurricanes Irma and Maria.

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 those mobilization sites. Minnesota Power then includes corporate overheads in final bills to the utility that our line workers and personnel were assisting. This practice is followed by other 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, our customers receive a direct benefit from that response in faster restoration of service and, therefore, those costs paid to the responding utilities are covered by the regulated side of our business.

D. <u>Vegetation Management</u>

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 non-compatible species and encouraging growth of compatible species under, on, or adjacent to its transmission and distribution facilities, rights-of-way, or easements. Non-compatible species are defined as those trees that mature at a height that allows them to grow into the electric facilities and cause outages. 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 FAC-003, ANSI Z133.1, and A300 standards, and follows NESC 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. Minnesota Power also maintains a link on our webpage to the "Right Tree" brochure. This brochure is intended to assist our customers in selecting the type and species of vegetation that are compatible near power lines.

The Vegetation Management O&M budget allows Minnesota Power to trim, 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, dykes, dams, and hydro facilities as needed to protect the electrical system from vegetation related interactions. Minnesota Power also responds to customer requests to remove or trim 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.

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 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 precaution 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 our customers which effects 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 2016 Rate Case.

A. In 2019, Minnesota Power began using mobile workforce solutions to aid the vegetation department in field work. This includes electronic Geographic Information System ("GIS") mapping, a quick capture application for aerial patrols, and an electronic application that allows Minnesota Power field employees to report vegetation issues. All of these applications have led to increased productivity, getting the data faster and most importantly achieving accurate data points for work identified. These changes have been incorporated into our budgeting process as well. We continue to explore other electronic alternatives and new technology to aid our vegetation management work.

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

A. Minnesota Power utilizes a contracted workforce, which allows the company the flexibility to seek out, through a competitive bid process, the most cost-effective, skilled workforce to provide vegetation management services. 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. Use of products such as herbicide are tools which also save money in the long run by eliminating trees and brush from the system.

Minnesota Power bids 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/lines that are made to improve reliability. Awarding bids annually provides flexibility to address contractor availability, performance and cost management. Minnesota Power contracts for the following year's vegetation maintenance approximately six months in advance to assure we have the contract resources to complete our vegetation plan.

Minnesota Power employs a vegetation management program that relies on trained and educated foresters. 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.

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

A. Minnesota Power's 2020 Vegetation Management budget for both transmission and distribution is $6.0 million Total Company ($5.5 million MN Jurisdictional). This budget amount is an increase over the 2019 projected year by $1.0 million Total Company ($0.9 MN Jurisdictional). The increase is needed to address higher vegetation related cost increases in labor, equipment, chemicals and off cycle growth. Minnesota Power is currently 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 (pipeline, utilities, municipal) for the specialized type of tree care these contractors provide has led to higher costs. Because unemployment is very low, it is also difficult to draw new employees into the field in a demanding, physical occupation like Vegetation Management. The Company anticipates continued increased spending will be needed in the future to address these costs, labor constraints, and management of off-cycle circuits.

Finally, a number of substations and other electrical systems have been added to improve reliability following the idling, retirement and re-missioning of baseload coal generation in the region and also to facilitate delivery of variable renewable energy, which has led to more facilities to maintain. For example, the Great Northern Transmission Line is a newly-built transmission line that will add approximately 230 miles of new vegetation management (along with associated facilities) to our operating budget. Minnesota Power will need to begin active vegetation management along this line in 2020 in accordance with the NERC FAC-003 standard. The vegetation management for 2020 has been included in the 2020 Test Year. Full vegetation management will begin on this line in 2023 at higher O&M expense levels.

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

A. Minnesota Power is responsible for maintenance on approximately 1,105 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 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 2020 is $2.0 million Total Company ($1.7 million MN Jurisdictional). The remaining O&M budget for 2020 of $4.0 million Total Company ($3.8 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-19-254). When 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 a couple of years to get all circuits back into their six-year 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.

E. <u>Reliability Compliance</u>

Q. **What is the regulatory oversight for transmission system reliability?**

A. Maintaining transmission system reliability involves compliance with NERC Reliability Standards. In 2007, FERC granted NERC the legal authority to enforce reliability standards on all transmission owners and operators. NERC delegates its authority to monitor and enforce compliance to Regional Entities established across North America. The Midwest Reliability Organization ("MRO") is the Regional Entity that oversees Minnesota Power's compliance with NERC Reliability Standards. There are roughly 75 NERC Reliability Standards consisting of over 1000 standard requirements and sub-requirements applicable to Minnesota Power, with six new or revised Reliability Standards coming into effect in 2020.

Q. **How does Minnesota Power approach its NERC compliance obligations?**

A. Minnesota Power's NERC compliance program is designed to achieve safe, reliable system operation and reinforce high standards of performance in meeting compliance obligations. This includes striving to meet its compliance obligations and effectively responding when noncompliance occurs. Through an open culture of compliance, Minnesota Power thoroughly investigates instances of potential noncompliance, reports the instances to the MRO and implements mitigating activities to reduce the risk of reoccurrence. The MRO has approved Minnesota Power for the Self-Logging program, making the company one of approximately 30 registered entities (out of the 198 overseen by the MRO) who are allowed to self-log potential minimal-risk compliance discrepancies.

To grant participation in the self-log program, the MRO evaluates an entity's demonstrated effectiveness at identifying noncompliance, assessing the risk posed by noncompliance, and mitigating noncompliance using the principles of a High Reliability Organization, i.e.

demonstrating the capacity to anticipate and contain unanticipated problems. Minnesota Power believes its acceptance into the Self-Logging program is affirmation of the strength of its NERC compliance efforts.

Q. Describe the necessity for heightening cyber and operational security at Minnesota Power.

A. While technology allows for faster response times in maintaining grid integrity and minimized customer disturbance/outages, it also provides a vulnerability to bad actors who would exploit cyber vulnerabilities and create disruptions. Such disruptions could result in outages, damage to grid infrastructure and/or exposed company data. Due to this heightened risk attributed to cyber access, NERC has mandated Critical Infrastructure Protection Standards to reduce the likelihood and impact of such an event.

Q. Describe the challenge of implementing mandated compliance related activities into existing work practices.

A. The July 2016 implementation of Version 5 of NERC Critical Infrastructure Protection Standards presented multiple challenges as Minnesota Power assessed and revised its transmission system assets, facilities, and work processes/procedures. Conducting a system-wide inventory while interpreting the applicability of various standards and requirements – and sustainable technical solutions – necessitated that many Company employees expand their knowledge beyond their previous levels of expertise.

Q. How has Minnesota Power responded to the new challenges of Critical Infrastructure Protection compliance?

A. Minnesota Power employees with compliance obligations are trained in the skills needed, including attending industry training events where there is an increased focus in research and development towards automation and asset management. Employees use resources available through the Company's membership in the North American Transmission Forum to inform their compliance methods. The Company has procured software tools to track and trend asset performance including test data to enable the ability to predict equipment failures and ensure timely maintenance to lower operational expense and improve system reliability. To support these compliance efforts, the Company has increased overall compliance support by two individuals, on a net basis.

Q. What is the next major NERC Critical Infrastructure Protection compliance milestone for Minnesota Power?

A. The NERC Critical Infrastructure Protection Reliability Standards expand on January 1, 2020, to include the regulation of Bulk Electric System Cyber Systems at low impact sites. For Minnesota Power, this will add approximately 80 low-impact substations (most substations operated at 100kV or higher voltage) and seven generation sites into Critical Infrastructure Protection compliance scope. To meet this compliance deadline, Minnesota Power has incurred both labor (O&M) and capital costs. Additional labor has been required at the low impact sites to install, and now maintain, firewall/Virtual-Private-Network ("VPN") hardware with two-factor authentication at all low impact substations, new key control procedures, new locking system, installation of signage reflecting Minnesota trespassing statutes, development of new access procedures at multiple joint-owner sites, new fencing, new gates, new access control systems, new cameras, respective procedural changes, and, in general, increased monitoring. All capital costs for this compliance will be incurred by the end of 2019. In the 2020 test year and beyond, however, the Company will incur additional labor costs to ensure continued compliance with the various requirements and maintain the newly-installed systems. In total, increased O&M labor hours related to NERC compliance have increased as much as 85 percent since 2015 to facilitate the Company's compliance with the various requirements.

Q. Are there additional NERC compliance impacts beyond those you have already mentioned?

A. Yes. Changes and updates to NERC operational standards have required improvements to tools used for situational awareness and real-time assessments, staff resources to support and maintain the expansion of data and tools, and increased training needs for system operators.

NERC Reliability Standards continue to evolve and develop. This requires continued training, dedication of resources, and ongoing system and process improvements to meet compliance obligations efficiently and effectively.

F. Service Centers

Q. The 2016 Rate Case discussed cost savings related to the sale and closure of company-owned service centers. Have there been any new developments in this area since then?

A. As part of our long range facility planning process, Minnesota Power continues to work through 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. Many of these Service Centers may require either upgrades or remodeling and several may cease to be Minnesota Power assets moving forward if they are no longer viable for operations.

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

A. Where we cease 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 we can market these assets to maximize market value. Currently, the only service center that has been slated for closure and sale as of this rate case is located in Crosby, Minnesota. In the event of a sale that exceeds $100,000, the Company will file for Commission approval, consistent with Minn. Stat. § 216B.50. Any savings resulting from the sale of a service center would be returned to customers appropriately.

G. Purchasing and Procurement Initiatives

Q. What business improvement efforts have been made in purchasing and procurement since the 2016 Rate Case?

A. Minnesota Power utilizes a competitive bidding process for all capital projects and other purchases over $10,000. Buyers manually track savings achieved through the bidding process. When calculating, buyers average the total dollars of quotes within a competitive range, excluding the low bid, then subtract the low bid from the average calculated to get the actual hard dollar savings of the purchase. Total competitive bidding cost savings was calculated to be $18.4 million Total Company for 2017 and $18.8 million Total Company for 2018.

Since late 2017, Purchasing has also been working with our vendors on payment initiatives. Our goal is to get as many vendors switched from check payments to the Automated Clearing House ("ACH") to reduce check printing and processing costs. We have increased our standard payment terms from Net 30 to Net 60 to improve our cash flow and working capital. The purchasing department continues to work on development of initiatives such as this to improve procurement processes and efficiency.

Savings are also achieved through our sustainable performance initiative ("SPI") where buyers partner with Operations personnel to identify cost savings opportunities. Examples of these include transmission and distribution pole contracts, waste management services, underground cable locating services, and currently our tool usage and spend. These are typically areas where we have multiple contracts that can be consolidated to one vendor or areas where we believe standardization will reduce costs.

Q. Has the Transmission and Distribution work area undertaken any of these efforts with other Company work areas?

A. Yes. Purchasing also partnered with the tax, inventory, and accounts payable areas to enhance an existing software module already in use within our Enterprise Resource Planning ("ERP") system that allows us to be more accurate when calculating sales tax on purchase orders and invoices. This module works with the purchasing, inventory, and accounts payable modules and requires the user to identify the purchasing category and intended use of the item or service they are requesting. The ERP system then calculates the rates as taxable, non-taxable, or exempt depending on the ship-to location and the State, County, and City tax rules. This enhancement helps us identify when an item or service is tax exempt or non-taxable to avoid paying tax when it isn't required, and when an item or service is taxable, the right tax rates are applied.

V. SYSTEM RELIABILITY AND CUSTOMER EXPERIENCE

A. System Reliability

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 and is focused on 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 also help to mitigate potential reliability issues. The company annually describes overall system reliability in intricate detail in the Safety, Reliability and Service Quality Report (Docket No. E015/M-19-254). 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 2016 that have significantly impacted customer reliability. Overall, the total number of outage events resulting in trouble tickets has averaged over 20 percent above historic averages since the last rate case. 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.

Q. What is Minnesota Power doing to improve System Reliability?

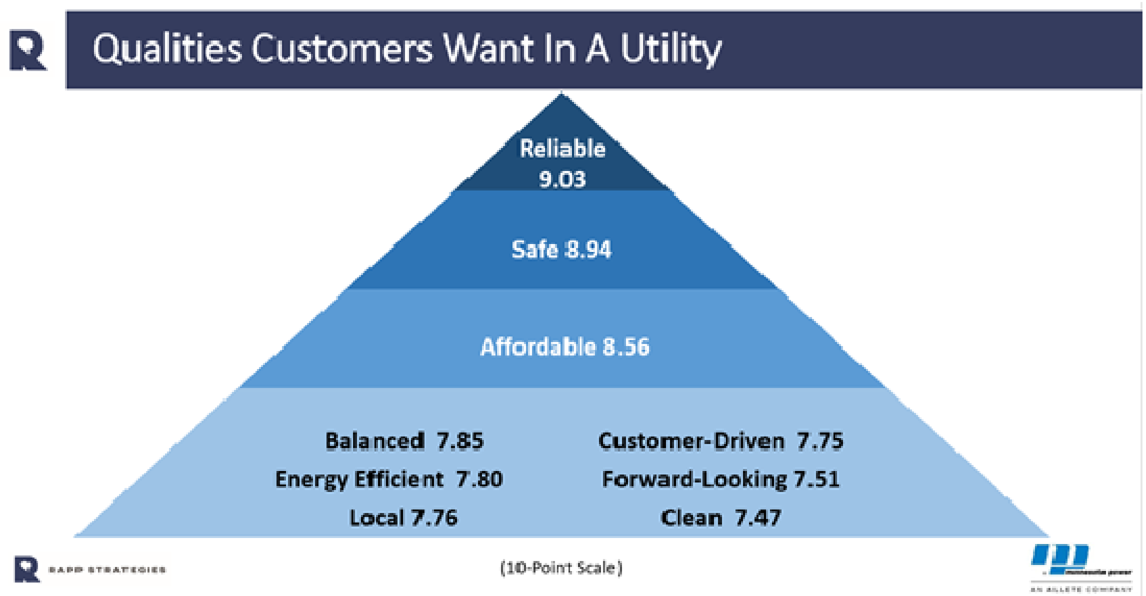
A. Minnesota Power has made both core infrastructure and technology related investments described later in my testimony to make measurable improvements in reliability.

B. Customer Relations/Customer Experience

Q. What is Minnesota Power's approach to customer relations and the customer experience?

A. Minnesota Power recognizes that, above all else, customers expect reliable, safe, and affordable electricity, as illustrated in Figure 3. Inherent to each of these are quality customer interactions through a variety of channels (i.e. in person, in writing, via email, over the phone, online, through social media, and in the field). Further, convenience, transparency about services, timely updates regarding interruption to services, and clarity about costs and program offerings are essential to the customer experience.

Figure 3. Customer Expectations Survey Results[10]



The Rate Case Overview Direct Testimony of Company witness Mr. Frank L. Frederickson discusses each of these expectations in more detail. Our approach is to continue to provide core customer services such as establishing and maintaining service, accurate and timely billing, inquiry resolution, and general customer care as effectively as possible while meeting or exceeding formal service quality expectations related to response times for customer calls and establishing or restoring service in a timely manner.

Minnesota Power also seeks to leverage technology advances where applicable and practical to improve convenience and ensure a positive experience for our customers, which means customer relations and the customer experience are always evolving. This is inclusive of day-to-day interactions between the Company and our customers through traditional channels such as the Company's call center, billing services, and in the field. It is also inclusive of emerging channels such as online tools and social media, both of which

[10] *Minnesota Power Residential Customer Survey - Reputation*, RAPP STRATEGIES (2019).

have proven to be effective for requesting services and for receiving updates affecting services such as outages.

Q. How is Minnesota Power currently delivering on residential and commercial customer expectations?

A. In addition to our continued focus on the fundamental objective of providing reliable, affordable, and safe electricity, Minnesota Power offers a wide range of services that impact how customers receive, manage, and pay for their electricity. For example, we have launched enhancements to our MyAccount online tool and improved customer accessibility through the Minnesota Power App, and delivered additional online tools for customers to self-service billing, payment, and service requests.

Q. How is Minnesota Power prioritizing its offerings?

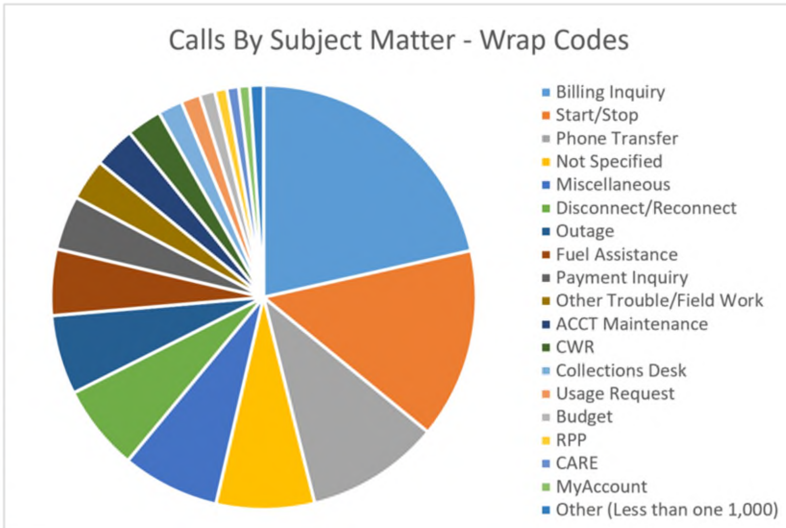
A. Minnesota Power prioritizes its offerings to (1) address the greatest areas of opportunity for improvement and increased customer satisfaction; (2) continue investment in grid modernization and innovation; (3) leverage the AMI functionality available today with an eye toward full deployment by 2023, and (4) recognize emerging customer interests in renewable energy options.

Minnesota Power draws upon customer insights gained through traditional channels such as our interactions, satisfaction surveys, and benchmarking tools, as well as emerging tools, including voice of customer tools and stakeholder processes, to ensure that we provide experiences that meet the needs and expectations of our customers today and into the future. Minnesota Power also utilizes occasional surveys of its customers, such as the residential survey previously referenced, and after call surveys. These surveys assess how well Minnesota Power is serving its customers under current circumstances.

Further, Minnesota Power reviews call volume and calls by subject matter for timely insights regarding customer needs and the greatest opportunities for improvement to the customer experience. The figure below provides a breakdown of calls received in 2018 by subject matter category. This breakdown is based on the wrap codes that are used by representatives when closing and documenting a call.

Figure 4. Customer Calls by Subject Matter

	Totals
Billing Inquiry	36,800
Start/Stop	24,841
Phone Transfer	17,458
Not Specified	12,806
Miscellaneous	12,715
Disconnect/Reconnect	11,222
Outage	10,375
Fuel Assistance	8,671
Payment Inquiry	7,093
Other Trouble/Field Work	5,430
ACCT Maintenance	5,427
CWR	4,572
Collections Desk	3,203
Usage Request	2,517
Budget	1,988
RPP	1,573
CARE	1,557
MyAccount	1,439
Other (Less than one 1,000)	1,773

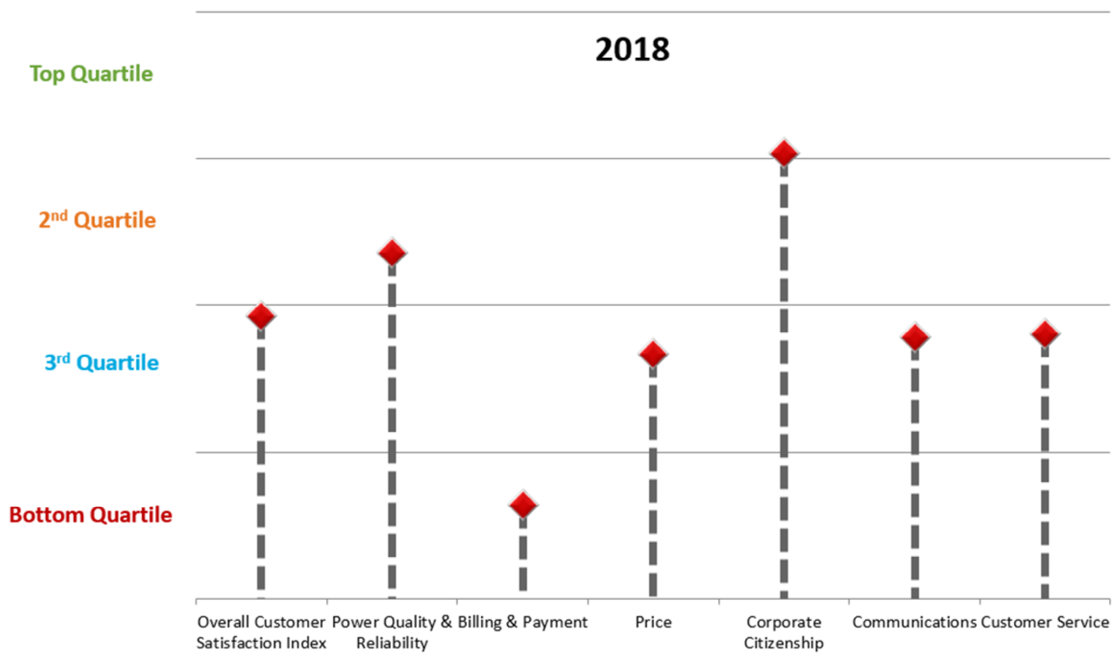


Minnesota Power also participates in industry groups, such as Edison Electric Institute and the Association of Edison Illuminating Companies, to gain insights about industry best practices. In addition, the Company has participated in the J.D. Power Electric Utility Residential Customer Satisfaction Study to benchmark against utilities across the nation as well as Minnesota Power-specific year over year trending across six factors for measuring customer satisfaction (i.e. power quality and reliability; price; billing and payment; communications; corporate citizenship; and customer service, along with an overall customer satisfaction index). All of this information collectively is used to inform prioritization decisions in terms of the offerings that are anticipated to be the most impactful to the customer experience and customer satisfaction.

Q. What are some examples of how Minnesota Power has used customer insights to enhance the customer experience?

A. Since the 2016 Rate Case, the Company has added several programs responsive to what customers want in addition to reliable and reasonably priced service. Specifically, Minnesota Power has upgraded its mobile app to include both outage notification and reporting in addition to MyAccount billing and usage monitoring. Drawing from the Company's call volume assessment and call reason insights, the Company launched a start, stop, transfer feature to allow new and existing customers to handle service requests, transfers, and disconnects from the convenience of the Minnesota Power website and mobile app. As another example, Minnesota Power recognized that it lagged in the billing and payment customer satisfaction factor, as determined by J.D. Power research and shown in Figure 5,[11] and the Company proposed a no-fee credit and debit card payment option in the 2016 Rate Case and, with the Commission's approval, was able to eliminate the customer charge for paying bills by credit or debit card.

Figure 5. 2018 Industry Quartile Chart – Minnesota Power



The Company also recently launched Renewable Source, which allows customers to select the amount of renewable they want to meet their individual needs. These amounts will be in excess of the state-leading percentage that Minnesota Power has already committed to

[11] J.D. Power 2018 Electric Utility Residential Customer Satisfaction Study.SM

in its base energy supply, as discussed in more detail in the Rate Case Overview Direct Testimony of Company witness Mr. Frederickson.

Q. Does enhancing customer service require Minnesota Power to make investments in customer-service resources?

A. Yes. To meet our customers' needs, the Company must continually invest in new technologies and customer-facing improvements. This includes system optimizations and integrations to ensure a more comprehensive and streamlined experience for the customer, regardless of what channel they choose for interaction or receiving information. For example, Minnesota Power is investing in a Customer Information System ("CIS") upgrade and implementation of a meter data management system ("MDM") starting in 2019, to further leverage advanced metering infrastructure deployment and transparency of information to customers. This will allow for additional enhancements to customer self-service options through the Company's MyAccount tool as well as sophisticated meter read estimations and advanced rate design. These investments are in addition to the Mobile Workforce System and Outage Management System referenced in the following section of my testimony. All of these systems have a customer-facing element. In addition to the system investments themselves, considerable investment in resources such as training, process improvements, web site updates, and analytics are needed to enhance the customer experience and ensure desired outcomes are measurable and attainable.

C. <u>Grid Modernization Technology Solutions/Systems</u>

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 services, 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.

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 Automated Meter Reading ("AMR") technology. Communications infrastructure for the AMI system will be complete in 2019 with purchases and deployment of AMI meters continuing through 2023. Capital additions for AMI meters through 2020 are reflected in the Metering section of Table 1. Future year capital additions will be reflected in later periods. In Table 8., the Company has provided the AMI deployment since the last rate case as well as test year and future plans.

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 Projected	13,500	53,953
2020 Plan	13,500	40,453
2021 Plan	13,500	26,953
2022 Plan	13,500	13,453
2023 Plan	13,453	0*

*Likely won't be "0" in 2023 due to opt-outs

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

A. Since 2011, the Outage Management System ("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; 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 Smart Grid initiatives and improvements to the customer experience.

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 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 provides a read rate greater than 99.5 percent of meters during the billing window. 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 customer portal. This allows for more granular hourly 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.

Another critical benefit has been the ability for the AMI system to detect an over-temperature, sometimes referred to as a "hot socket" condition so that we can minimize the likelihood of a potential catastrophic failure at a meter socket. Minnesota Power began tracking these alarms since 2012 and has had 367 unique hazard alarms, 310 of which were conditions that required further action to remediate a hazard.

2. <u>Meter Data Management ("MDM")</u>

Q. What is the MDM project?

A. The MDM system interfaces with other Company systems and provides a data engine that performs validation, editing, estimating, and organized storage of both rate and operational information from metering systems. Our metering systems include our AMI, AMR, and directly connected, interconnected, and industrial meters. The MDM system allows data from these disparate systems and technologies to be gathered and analyzed as a whole.

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

A. Currently, the MDM functions are performed in a variety of systems in a limited fashion depending on the size of the customer and metering system. As part of a larger billing system upgrade for the MDM project implementation, the Company is installing functionality to access and analyze meter data. This functionality will make our customer billing much more consistent and accurate and will allow us to have organized operational data across all of our metering systems. While the Company initially anticipated this project to be completed after the 2020 test year, because of the value to customers, Minnesota Power is currently accelerating the first phase of this project for completion in 2020, although the associated capital additions are not included in the 2020 test year.

3. <u>Mobile Workforce Management</u>

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?

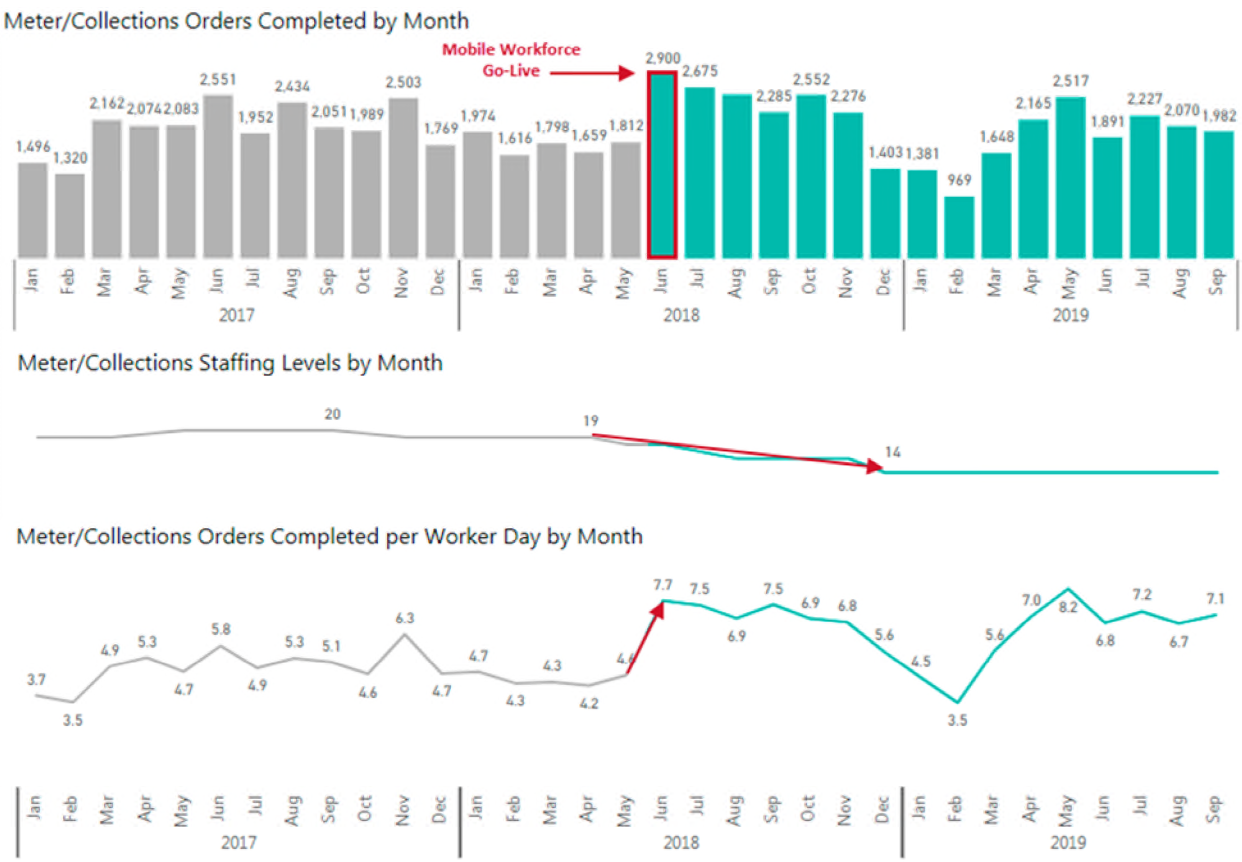
A. The Mobile Workforce System benefits customers by connecting field to office. Real-time completion of orders, elimination of paper, and automated routing all contribute to more efficient operations and result in better billing accuracy and a better customer experience. The system also positions Minnesota Power to systematically share scheduling and completion information with our customers.

Q. Please explain how the mobile workforce system improves customer service for Minnesota Power.

A. The first phase (meter and collections work) of the Mobile Workforce System initiative realized the elimination of nearly all manual phone calls and data entry for work order completion plus an increase in field productivity after the first full year of implementation (June 2018 to May 2019). During this time period, the Company completed 5 percent more orders with 5 fewer field employees. The Company transitioned its staffing with a reduction in field meter and collections employees from 19 to 14 and an increase in meter dispatch support employees from 1 to 2 for back office support. This ultimately reduces cost for Minnesota Power customers while improving service levels.

Mobile Workforce went live for meter and collections employees on May 30, 2018. The charts in Figure 6 below show before and after metrics for Orders Completed by Month, Staffing Levels, and Orders Completed per Worker Day by Month. Counts of Worker Days per month exclude holidays and weekends. Figure 6 shows a significant increase in productivity once Mobile Workforce went live, and sustaining at that higher level throughout the year. Note there was a drop in orders completed in January and February 2019 due to extreme cold weather during which our workforce remained indoors unless the outside work was critical to customer service and reliability.

Figure 6. Meter Order Completed by Month and by Worker Day by Month



4. <u>Reevaluation of Transmission and Distribution Maintenance Program Needs</u>

Q. What work is Minnesota Power doing to reevaluate its operations 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 maintenance and replacement of critical assets as necessary to maintain safe system performance. Minnesota Power increased focus on distribution equipment maintenance and replacement in 2018 and will continue to develop these programs into the future. Resources and engineering staff were hired in May 2017 to develop a trouble order tracking and remediation system. The effort successfully developed the trouble order system on the intended schedule, and the trouble order was put in place in the fourth quarter of 2018. In addition, the project also began implementation of necessary switch replacements and began auditing the Company's system in order to develop an asset management preventative maintenance program throughout the Company's service territory. This preventative maintenance program was fully developed in 2018 and should increase the reliability of Minnesota Power's distribution assets going forward.

Q. How is this changing the maintenance program?

A. Minnesota Power can now monitor larger areas for power quality issues. Over half 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 +/- 5 percent of nominal voltage, Minnesota Power performs the required maintenance in order to bring the voltage within the prescribed limits. There are seldom requests from customers for power quality studies.

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 a pole 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. In the last 18 months, the company has received over 2,000 observations and has remedied over 70 percent of those observations. 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. The Company has also implemented a program for replacing re-closers with maintenance–free trip savers. These trip savers look like a standard fused cutout, but use a vacuum re-closer and require no maintenance. The trip savers are also being installed to replace porcelain fused cutouts and will reduce failures and clear temporary faults, which results in improved reliability.

Third, we have invested in equipment that requires less or 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. We have decided to use this equipment to replace our 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, we are conducting audits throughout our distribution service territory to identify equipment that may need attention. This equipment will be brought into our 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 our equipment, customers will see decreased outages and increased reliability and Minnesota Power will see longer service life of our equipment with less failure rates.

5. Geographic Information System

Q. What is the Geographic Information System ("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. For instance, the GIS can tell us how many transformers we have and allow for queries on specific customer attributes for those served by that transformer. While the GIS system has been in place since 2003, we continue to find ways to maximize the technology to support out 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. Data is translated out of the GIS and into the OMS and allows for rapid restoration of power during storms or other outages and feeds the information in the customer outage map.

The GIS also sends data to Gopher State One Call in support of the state-wide 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 transitioning to an emerging GIS model that connects data across all of the systems, from generation to customer. As a result, GIS staff will no longer need to spend time transferring data between systems in order to model impacts between the various components of the electrical system 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 staff 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 we have 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.

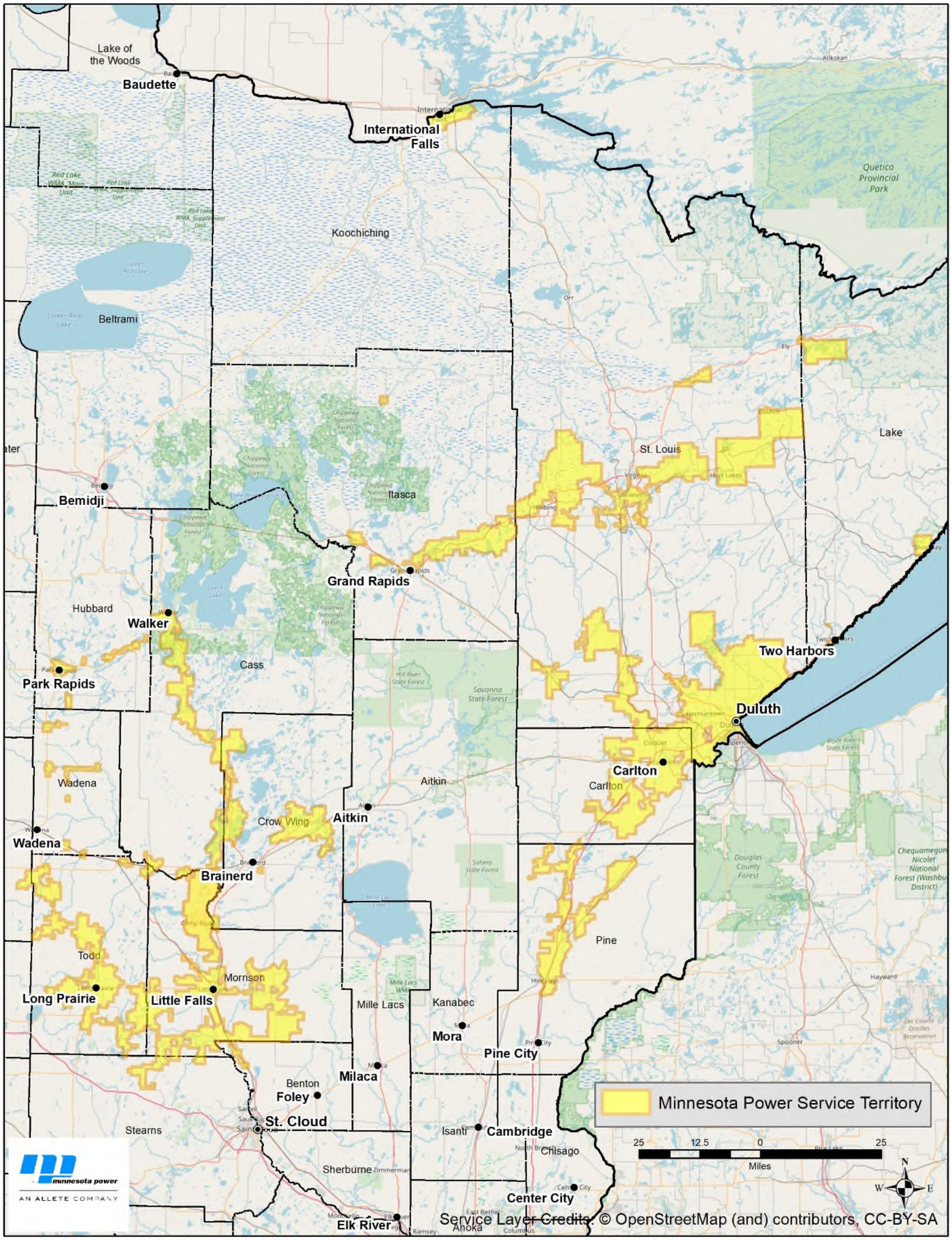
VI. CONCLUSION

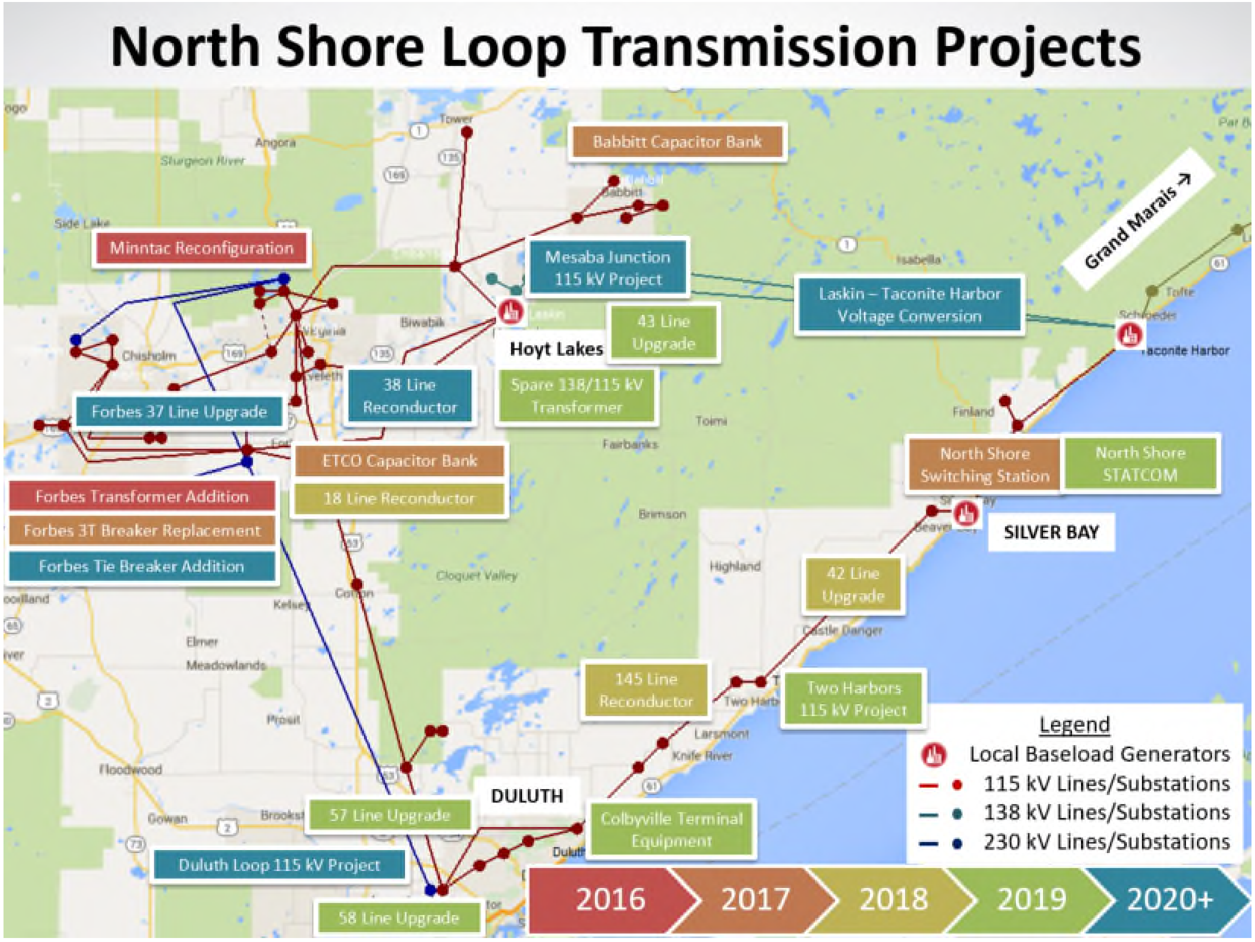
Q. What are your overall conclusions and recommendations regarding Minnesota Power's Transmission and Distribution work areas?

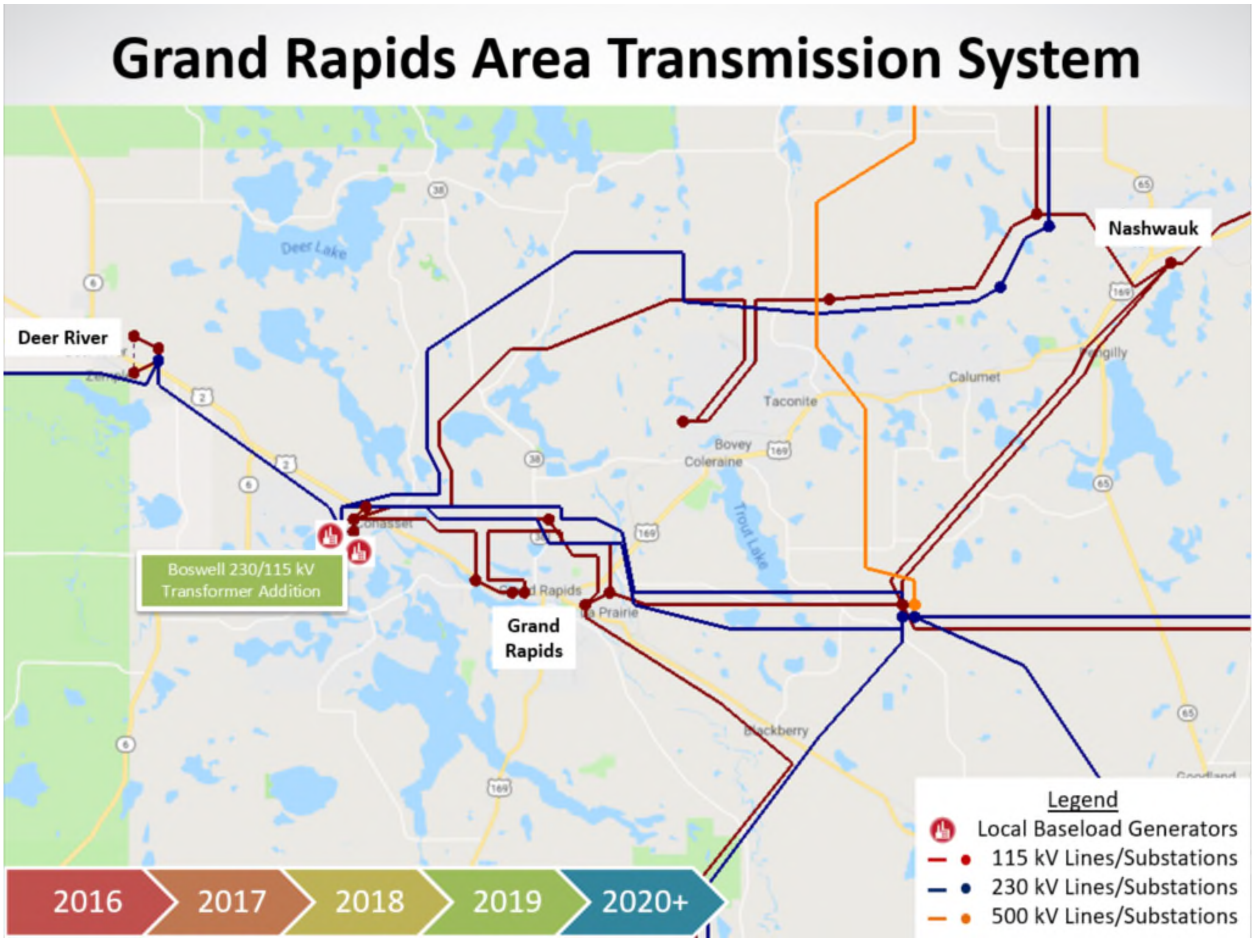
A. The Transmission and Distribution work areas provide critical services for Minnesota Power's customers. The Company has taken a diligent and proactive approach to its planning and budgeting processes, and consistently strives to improve our operations and ensure consistency with various requirements and customer expectations. The Transmission and Distribution work areas took very seriously the comments of the various stakeholders and the Commission in the 2016 Rate Case regarding the overall quality of our estimates and supporting documentation, spending a significant amount of time improving planning and processes in these areas. I fully support the information in my Direct Testimony and have worked with my staff to provide this information for this rate case.

Q. Does this complete your testimony?

A. Yes.


Lake of the Woods
Baudette
International Falls
Koochiching
Beltrami
Quetico Provincial Park
Lake
St. Louis
Bemidji
Itasca
Grand Rapids
Hubbard
Walker
Cass
Park Rapids
Two Harbors
Duluth
Carlton
Wadena
Aitkin
Crow Wing
Brainerd
Pine
Todd
Morrison
Long Prairie
Little Falls
Mille Lacs
Kanabec
Mora
Pine City
Milaca
Benton
Foley
St. Cloud
Stearns
Isanti
Cambridge
Chisago
Sherburne
Center City
Elk River
Minnesota Power Service Territory
25 12.5 0 25
Miles
minnesota power
AN ALLETE COMPANY
Service Layer Credits: © OpenStreetMap (and) contributors, CC-BY-SA


North Shore Loop Transmission Projects
Babbitt Capacitor Bank
Minntac Reconfiguration
Mesaba Junction 115 kV Project
Laskin – Taconite Harbor Voltage Conversion
Grand Marais
43 Line Upgrade
Hoyt Lakes
38 Line Reconductor
Spare 138/115 kV Transformer
Forbes 37 Line Upgrade
ETCO Capacitor Bank
18 Line Reconductor
Forbes Transformer Addition
Forbes 3T Breaker Replacement
Forbes Tie Breaker Addition
North Shore Switching Station
North Shore STATCOM
SILVER BAY
42 Line Upgrade
145 Line Reconductor
Two Harbors 115 kV Project
DULUTH
57 Line Upgrade
Colbyville Terminal Equipment
Duluth Loop 115 kV Project
58 Line Upgrade
Legend
Local Baseload Generators
115 kV Lines/Substations
138 kV Lines/Substations
230 kV Lines/Substations
2016
2017
2018
2019
2020+


Grand Rapids Area Transmission System
Deer River
Nashwauk
Deer Lake
Taconite
Bovey
Coleraine
Calumet
Trout Lake
Blackberry
Boswell 230/115 kV Transformer Addition
Grand Rapids
2016
2017
2018
2019
2020+
Legend
Local Baseload Generators
115 kV Lines/Substations
230 kV Lines/Substations
500 kV Lines/Substations

Minnesota Power System Third-Party Transmission Expenses and Revenues
$ amounts shown in million
Total Company

Expenses

FERC Account		2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
56500	Base Transmission - AC Schedules 7, 8 and 9	$ 6.57	$ 6.72	$ 6.84	$ 7.50
56500	Base Transmission - DC Schedules 7, 8 and 9	$ 16.08	$ 17.68	$ 16.18	$ 14.56
56500	Ancillary Services Schedules 1 and 2	$ 0.39	$ 0.63	$ 0.47	$ 0.31
56500	Cost Shared Projects Schedules 26 and 26A	$ 35.35	$ 34.41	$ 36.32	$ 39.56
56500	NERC Required Schedule 45	$ 7.74	$ 5.33	$ 6.65	$ 9.09
56140	MISO Admin Schedule 10	$ 1.96	$ 2.03	$ 1.64	$ 2.06
56500	MISO Admin Schedule 35	$ 0.34	$ 0.34	$ 0.29	$ 0.36
56500	GRE NITS/JPZ	$ 2.80	$ 2.80	$ 2.80	$ 2.80
56500	MISC/FERC Refund	$ (0.00)	$ -	$ -	$ -
56500	Oconto	$ -	$ -	$ 1.62	$ 1.30
	total for FERC Accounts	$ 71.23	$ 69.93	$ 72.81	$ 77.52

	Costs Recovered through the Transmission Cost Recovery Rider	2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
56500	Cost Shared Projects Schedules 26 and 26A	$ 35.35	$ 34.41	$ 36.32	$ 39.56
	Transmission Expenses in base rates	$ 35.88	$ 35.52	$ 36.49	$ 37.97

Revenues

FERC Account		2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
45620	Base Transmission - AC Schedules 7, 8 and 9	$ 10.23	$ 7.22	$ 5.06	$ 7.12
45620	Base Transmission - DC Schedules 7, 8 and 9	$ 16.38	$ 17.36	$ 16.18	$ 14.56
45620	Ancillary Services Schedules 1 and 2	$ 2.58	$ 2.46	$ 5.18	$ 4.37
45620	Cost Shared Projects Schedules 26, 37, and 38	$ 27.18	$ 25.18	$ 19.47	$ 19.19
45620	NERC Required Schedule 45	$ 8.68	$ 5.59	$ 6.25	$ 8.19
45620	Wheeling	$ 0.47	$ 0.57	$ 0.69	$ 0.66
45620	GRE Distribution	$ 2.70	$ 2.00	$ 2.23	$ 2.24
45620	Schedule 11	$ (0.00)	$ -	$ -	$ -
44700	Mesabi Metallics	$ 1.14	$ -	$ -	$ -
44700	Oconto	$ -	$ -	$ 1.62	$ 1.30
45620	Manitoba Must Take Fee	$ -	$ -	$ -	$ 14.37
45620	True-up Accrual/reversal	$ -	$ (4.40)	$ 2.80	$ 1.00
	total for FERC Accounts	$ 69.36	$ 55.97	$ 59.48	$ 73.01
45620	GRE Distribution	$ 2.70	$ 2.00	$ 2.23	$ 2.24
44700	Mesabi Metallics	$ 1.14			
44700	Oconto			$ 1.62	$ 1.30
	Total Transmission	$ 65.52	$ 53.97	$ 55.62	$ 69.47

	Revenues Shared through the Transmission Cost Recovery Rider	2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
45620	Cost Shared Projects Schedules 26, 37, and 38	$ 27.18	$ 25.18	$ 19.47	$ 19.19
45620	Manitoba Must Take Fee				$ 14.37
	Transmission Revenues in base rates	$ 38.34	$ 28.79	$ 36.15	$ 35.91

Minnesota Power System Third-Party Transmission Expenses and Revenues
$ amounts shown in million
MN Jurisdictional Amounts

Expenses

FERC Account		2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
56500	Base Transmission - AC Schedules 7, 8 and 9	$ 5.44	$ 5.62	$ 5.83	$ 6.43
56500	Base Transmission - DC Schedules 7, 8 and 9	$ 13.30	$ 14.81	$ 13.81	$ 12.49
56500	Ancillary Services Schedules 1 and 2	$ 0.32	$ 0.53	$ 0.40	$ 0.27
56500	Cost Shared Projects Schedules 26 and 26A	$ 29.24	$ 28.82	$ 30.99	$ 33.93
56500	NERC Required Schedule 45	$ 6.40	$ 4.46	$ 5.67	$ 7.79
56140	MISO Admin Schedule 10	$ 1.62	$ 1.70	$ 1.40	$ 1.76
56500	MISO Admin Schedule 35	$ 0.28	$ 0.28	$ 0.25	$ 0.31
56500	GRE NITS/JPZ	$ 2.32	$ 2.35	$ 2.39	$ 2.40
56500	MISC/FERC Refund	$ (0.00)	$ -	$ -	$ -
56500	Oconto	$ -	$ -	$ 1.38	$ 1.11
	total for FERC Accounts	$ 58.92	$ 58.58	$ 62.12	$ 66.50

	Costs Recovered through the Transmission Cost Recovery Rider	2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
56500	Cost Shared Projects Schedules 26 and 26A	$ 29.24	$ 28.82	$ 30.99	$ 33.93
	Transmission Expenses in base rates	$ 29.68	$ 29.76	$ 31.13	$ 32.57

Revenues

FERC Account		2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
45620	Base Transmission - AC Schedules 7, 8 and 9	$ 8.46	$ 6.04	$ 4.31	$ 6.15
45620	Base Transmission - DC Schedules 7, 8 and 9	$ 13.55	$ 14.52	$ 13.78	$ 12.56
45620	Ancillary Services Schedules 1 and 2	$ 2.14	$ 2.05	$ 4.41	$ 3.77
45620	Cost Shared Projects Schedules 26, 37, and 38	$ 22.48	$ 21.05	$ 16.58	$ 16.55
45620	NERC Required Schedule 45	$ 7.18	$ 4.67	$ 5.32	$ 7.07
45620	Wheeling	$ 0.38	$ 0.48	$ 0.59	$ 0.57
45620	GRE Distribution	$ 2.23	$ 1.67	$ 1.90	$ 1.94
45620	Schedule 11	$ (0.00)	$ -	$ -	$ -
44700	Mesabi Metallics	$ 0.94	$ -	$ -	$ -
44700	Oconto	$ -	$ -	$ 1.40	$ 1.12
45620	Manitoba Must Take Fee	$ -	$ -	$ -	$ 12.40
45620	True-up Accrual/reversal	$ -	$ (3.68)	$ 2.38	$ 0.86
	total for FERC Accounts	$ 57.37	$ 46.80	$ 50.68	$ 62.99
45620	GRE Distribution	$ 2.23	$ 1.67	$ 1.90	$ 1.94
44700	Mesabi Metallics	$ 0.94			
44700	Oconto			$ 1.40	$ 1.12
	Total Transmission	$ 54.20	$ 45.13	$ 47.38	$ 59.93

	Revenues Shared through the Transmission Cost Recovery Rider	2017 Actual	2018 Actual	2019 Projected Year	2020 Test Year
45620	Cost Shared Projects Schedules 26, 37, and 38	$ 22.48	$ 21.05	$ 16.58	$ 16.55
45620	Manitoba Must Take Fee				$ 12.40
	Transmission Revenues in base rates	$ 31.71	$ 24.08	$ 30.79	$ 30.98